CASCADE NATURAL GAS CORPORATION

A Subsidiary of MDU Resources Group, Inc.

In the Community to Serve®

2023
Integrated Resource Plan Draft

June 2, 2023

CASCADE NATURAL GAS CORPORATION
2023 INTEGRATED RESOURCE PLAN
TABLE OF CONTENTS

TABLE OF CONTENTS

Chapter 1

Executive Summary

Introduction

Cascade Natural Gas Corporation's (Cascade, CNGC, or the Company) Integrated Resource Plan (IRP or Plan) forecasts 28 years of expected system-wide customer and demand growth and analyzes the most reliable and least cost supply side and demand side resources that could be used to fulfill future customers' gas service needs. Planning how to best meet customers' future demand includes the consideration of possible policy changes and the resulting impact on customer prices, the Company's operations, and the ability of Cascade's distribution system to serve gas reliably as regional demand increases. This plan discusses these elements that impact how the Company may serve its customers from 2023 through 2050. While the Plan cannot predict the future, it is a useful guide. The following information is a progress report and a short summary of each chapter included in this IRP. The details regarding methodologies as well as specific results are found in the chapters and appendices.

Key Points

- Each chapter provides an *at-a-glance* summary of the key points.
- The Company's two-year action plan provides the road map for future resource and planning activities.
- Load growth is forecasted to average 1.56% per year over the 20-year planning horizon.
- Cascade modeled Social Cost of Carbon as its main carbon forecast.
- The total avoided cost ranges between \$0.79/therm and \$1.09/therm over the 20-year planning horizon.
- Cascade projects 14.62 million therms of energy efficiency in Oregon over the 20-year planning horizon (through 2042).
- Cascade does not anticipate any near-term material upstream capacity deficiency in the 2023 IRP.
- This plan was informed by five Technical Advisory Group meetings, with active engagement by stakeholders.
- Cascade continues to be fully

Progress Report

As part of the 2020 IRP acknowledgement letter, Oregon Public Utilities Commission (OPUC or Staff) Staff made several suggestions on areas where Cascade could make improvements to the 2023 IRP. The comments provided recommendations to the demand forecast, demand side management, and renewable natural gas. The progress from these recommendations is below:

Cascade has updated the demand forecast to include price as an explanatory variable. The Company utilized historical prices to create a variable, and then used the price forecast as an input to the load forecast model. More information can be found in Chapter 3.

Cascade is working with the Energy Trust of Oregon on targeted load management projects that could delay or replace distribution system projects. The distribution system projects must see a need for an upgrade no sooner than 3-4 years out to ensure there is enough time to plan and implement targeted demand side management. In this IRP, Cascade will have two targeted load management pilot programs in Ontario and Baker City. More information can be found in Chapter 8.

Staff recommended Cascade provide information on how the Washington RNG program may interact with programs being developed for customers in Oregon and whether RNG programs developed in Oregon might be used to comply with legislation in other states. Cascade will pursue RNG to the extent that the Company can meet compliance requirements. RNG will be treated as a system resource regardless of physical location. Therefore, the individual RNG plans of each state will not impact the decisions on when and where to acquire RNG. RNG is an important compliance tool that Cascade will need to balance between Washington and Oregon given the compliance obligations in both states. More information regarding RNG can be found in Chapter 4.

Cascade has revisited how the Company models Enbridge rupture-type events in its gas price forecast. Cascade has included a scenario in Chapter 9 that models the effects of pricing and the ability to serve customers if there was an event that impacted supply and price at a basin Cascade receives gas from.

Staff had made a suggestion that in a 2022 IRP Technical Advisory Group (TAG) meeting, incorporate gas price forecasts and price shocks into the discussion and work with Staff and stakeholders to potentially update its methodology. Staff had suggested to Cascade that the Companies Monte Carlo simulations included too many high price shock events, and a more reasonable approach to modeling extreme events would be to include a single price shock in the planning horizon. In the scenario modeling above, Cascade did scale back to Enbridge-type events to one in each basin to model the impacts at the basin level. However, with the Monte Carlo simulations, high price events are happening frequently, and they are not only caused by explosions. Cascade shared the Monte Carlo price results during a TAG meeting, where Staff did not indicate they had any issues with the results.

Staff suggested that Cascade refine the way distribution system costs are included in the avoided cost model. The Company has completely redone the way distribution system costs, which the calculation can be found in Chapter 5.

Staff recommended that the Company meet with Staff prior to the next IRP cycle. Cascade produced a Stakeholder Engagement document, which can be found in Appendix A, that lays out the expectations for Cascade as well as external stakeholders who participate in Cascade IRP process. Cascade met with Staff to go over this document prior to the IRP cycle in an effort to improve communication.

Chapter 2: Company Overview

Cascade has been providing natural gas service since 1953. Over the years, the Company has expanded its service territory by purchasing and merging with other small natural gas utilities. As of 2007, Cascade is a subsidiary of Montana Dakota Utilities (MDU) Resources Inc., which is based in Bismarck, North Dakota.

Cascade serves over 310,000 customers located in smaller, mostly rural communities spread across Oregon and Washington. The Company's service territory poses some challenges for operating an energy distribution system, including the fact that the areas served are noncontiguous and the weather in each area can be vastly different. To capture this, Cascade groups its citygates into seven weather zones.

Cascade purchases natural gas from a variety of suppliers and transports gas supplies to its distribution system using primarily three natural gas pipeline companies. Northwest Pipeline LLC (NWP) provides access to British Columbia and domestic Rocky Mountain gas, Gas Transmission Northwest (GTN) provides access to Alberta and Malin gas, and Enbridge (Westcoast Transmission) provides British Columbia gas directly into the Company's distribution system.

Chapter 3: Demand Forecast

Forecasting demand is foundational for both long- and short-term planning. The Company initiated its demand forecasting process by looking at each citygate serving firm or uninterruptible service. These citygates were then assigned a weather zone because a significant portion of Cascade's customer usage fluctuates with temperature and wind.

Demand forecasting first requires a customer forecast. The Company developed a unique customer forecast for each citygate/rate class by incorporating population and employment growth data from Woods and Poole as well as from internal market intelligence into a dynamic regression model.

Cascade developed a normal, or expected, future weather year by shaping 30 years of proprietary, historical weather data. Heating degree day (HDD values) were assigned to each day in the model weather year. To ensure the Company will be able to serve its firm customers during extreme weather, the Company tested a system weighted peak HDD (the system weighted coldest day in the last 30 years).

Peak day demand was then derived for each weather scenario by applying the HDD to the peak day forecast for each citygate.

Load growth across Cascade's system through 2050 is expected to average 1.10% annually. Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow at an annual rate near 1.21% and 0.94%, respectively, while industrial expects a growth rate of around 1.14%.

After determining system-wide demand over the planning period by multiplying the use per customer times the number of customers in the forecast, Cascade stress tested its results with high and low scenarios for varying future economic conditions.

In absolute numbers, system load under normal weather conditions is expected to grow annually at an average of 4.4 million therms. Residential customers are expected to grow from 53.3% of the total core load to 54.9% of the total core load by 2050.

Load across Cascade's two-state service territory is expected to increase 1.10% annually over the planning horizon, with the Oregon portion outpacing Washington at 1.43% versus 0.98%.

Chapter 4: Supply Side Resources

Chapter 4 provides an in-depth description of the supply side options the Company considered in this Plan.

Cascade's gas supply portfolio is sourced from three traditional supply areas of North America: British Columbia, Alberta, and the Rockies. The Company secures its gas through firm gas supply contracts and open market purchases. Cascade expects to add RNG to the supply portfolio beginning in Quarter 4 of 2024 when the Company plans to have Deschutes County Landfill come in service.

Firm supply contracts commit both the seller and the buyer to deliver and take gas on a firm basis, except during *force majeure* conditions. Supply contract terms for firm commodity supplies vary greatly. Some contracts specify fixed prices, while others are based on indices that float from month to month. Open market purchases are short-term and are subject to more volatile pricing.

The Company evaluates its demand curve and defines four categories of supply for meeting its demand. First, base load supply resources are used for the constant demand that occurs all year and does not fluctuate based on weather. Base load supplies are typically taken day in and day out, 365 days a year. Next, winter supplies meet demand occurring due to cooler weather. Winter gas supplies are firm gas supplies that are purchased for a short period during the winter months to cover increased loads, primarily for space heating. The contracts are typically three to five months in duration (primarily November through March). Next are peaking gas supplies which are used when colder weather spikes demand. Peaking gas supplies, similar to storage, are firm contracts purchased only as load actually materializes due to high winter demand. That is, the seller must deliver the gas when the Company requires it, but the Company is not required to take gas unless it is needed to meet customer load requirements. Lastly are needle peaking resources which are utilized during severe or arctic cold snaps when demand increases sharply for a few days. These resources are very expensive and are available for a very short period of time.

Cascade also utilizes natural gas storage to meet a portion of the requirements of its core market. Storing gas supplies, purchased and injected during periods of low demand, is a cost-effective way of meeting some of the peak requirements of Cascade's firm market. Cascade does not own any storage facilities and, therefore, must contract with storage owners to lease a portion of those owners' unused storage capacity.

Cascade has contracted for storage service directly from NWP since 1994. Storage is held in their Jackson Prairie underground and Plymouth Liquified Natural Gas (LNG) facilities. Jackson Prairie is located in Lewis County, Washington, approximately ten miles south of Chehalis. Plymouth is located in Benton County, Washington approximately 30 miles south of Kennewick. Both Jackson Prairie underground storage and the Plymouth LNG facility are located directly on NWP's transmission system. In addition, Cascade has leased Mist storage from NW Natural. The Mist facility is located in Columbia County, near Mist, Oregon. Mist has a direct connection to NWP for withdrawals and injections. Storage withdrawal rates can be changed several times during an individual gas day to accommodate weather driven changes in core customer requirements.

Cascade uses interstate pipeline transportation resources to deliver the firm gas supplies it purchases from three different regions or basins. Cascade has over 30 long-term annual contracts with NWP, numerous long-term annual and winter-only transportation contracts with GTN (including the upstream capacity on TransCanada Pipeline's Foothills and Nova systems), a long-term, annual contract with Ruby Pipeline, and one long-term annual contract with Enbridge (Westcoast Transmission) in British Columbia, Canada. These contracts do not include storage or other peaking services that may provide additional delivery capability rights ranging from nine to 120 days.

In order to evaluate the price of resource options, the Company analyzed gas price forecasts from various sources. Cascade used Wood Mackenzie, the Energy Information Administration (EIA), the Northwest Power and Conservation Council (NWPCC), and Cascade's trading partners to develop a blended long-range price forecast. With a monthly Henry Hub price from the above sources, the Company derived a weight for each source to develop the monthly Henry Hub price forecast for the 20-year planning horizon. These weights were calculated from the Symmetric Mean Absolute Percentage Error (SMAPE or Errors) of each source versus actual Henry Hub pricing since 2010. The inverse of these Errors was then used to determine the weight given to each source.

Besides currently used resources, Cascade considered alternative resources. Other potential incremental capacity options evaluated included: the Cross-Cascades Trail-West pipeline, additional GTN capacity, NWP Eastern Oregon Expansion, NWP Express Project or the I-5 Sumas expansion project, NWP Wenatchee Expansion, NWP Zone 20 (Spokane) Expansion, Pacific Connector, and Southern Crossing. Other storage options considered were: AECO, Gill Ranch Storage, Mist, Spire Storage (formerly Ryckman Creek Storage), and Wild Goose Storage.

Cascade also considered unconventional supplies such as satellite LNG, hydrogen, and the realignment of its Maximum Daily Delivery Obligations (MDDOs) on NWP. In addition to the Deschutes Landfill project, Cascade has also either contracted with or is in advanced stages with three other RNG projects. Cascade has significantly increased how RNG is modeled and evaluated in its resource integration model in an effort to reduce emissions and meet CCA/CPP rules.

Long-term planning is not an exact science. The Company has considered the various risks that may challenge the assumptions used in this analysis. Risk can stem from potential Federal Energy Regulatory Commission (FERC) or Canada's Energy Regulator (CER) rulings that may impact the cost or availability of gas. The Company also considers the risk that firm supply may not be available when Cascade needs it or that pricing could vary due to any factor impacting the economy of supply and demand.

To mitigate risk, Cascade constantly seeks methods to ensure price stability for customers to the extent that it is reasonable. In addition to methods such as long-term physical fixed price gas supply contracts and storage, another means for creating stability is through the use of financial derivatives. Derivatives generally lock-in a forward natural gas price with a hedge, consequently eliminating exposure to significant swings in rising and falling prices. The Company's annual Hedge Execution Plan (HEP), approved by the Gas Supply Oversight Committee (GSOC), provides oversight and guidance for the Company's gas supply hedging strategy.

Chapter 5: Avoided Cost

The avoided cost is the estimated cost to serve the next unit of demand with a supply side resource option at a point in time. Avoided cost forecasts are used to establish a cost-effective threshold for demand side resources. If demand side resources cost as much as or less than the avoided cost, then the demand side resource is cost-effective and should be the next resource added to the Company's stack of resources.

Cascade's avoided cost includes fixed transportation costs, variable transportation costs, storage costs, commodity costs, a carbon tax, upstream emissions, a 10%

adder, distribution system costs, and a risk premium. Essentially, the avoided cost is the cost of the Company's resource stack on a per therm basis plus three values for benefits specifically acquired with energy efficiency. The largest part of the avoided cost is the cost of gas.

A carbon compliance cost forecast was added in anticipation of carbon legislation. Currently, Cascade models the market driven costs to start at $83.13/metric ton CO_2e in 2023 and rising to $104.18/metric ton CO_2e in 2042. Cascade's use of this forecast does not indicate a preference towards this carbon future in Oregon, but rather signifies what the Company believes is the most probable form of carbon legislation in the state.

Next, 10% was added to the avoided cost to account for nonquantifiable, environmental benefits. This 10% adder was first recommended by the NWPCC based on Federal legislation.

For the 2023 IRP, the nominal system avoided costs ranges between $1.00/therm and $6.52/therm over the 28-year planning horizon. The increase over time is largely driven by the escalating cost of carbon.

Chapter 6: Environmental Policy

This chapter considers Greenhouse Gas (GHG) emission reduction policies and regulations that have the potential to impact natural gas distribution companies. In addition, this chapter examines methodologies for applying a cost of carbon to natural gas distribution companies and identifies the assumptions made in determining a 45-year avoided cost of natural gas and pairs these costs with associated two-year action items.

Significant emission policy development has occurred since Cascade's last IRP. The federal government as well as policymakers at the state and local levels in Washington and Oregon have actively pursued GHG emission reductions, and primarily CO_2 emission reductions. Since the previous IRP, policymakers in Washington have passed the Climate Commitment Act giving the Department of Ecology (Ecology) authority to regulate GHG emissions from natural gas distribution utilities, including customer emissions. In Oregon, Governor Brown issued an executive order directing state agencies to pursue GHG emission reductions under their authority, which included the Department of Environmental Quality issuing the Climate Protection Program in late 2021.

Cascade monitors environmental regulatory requirements in progress nationally, regionally, and locally that have impacts to natural gas distribution companies. As of November 21, 2022, there are no regulations at the federal level that would require the Company to reduce GHG emissions. However, the Climate Commitment Act (CCA) rule was finalized in Washington on September 29, 2022, and the Climate Protection Program (CPP) was finalized in Oregon on December 16, 2021, which require GHG emissions reductions from natural gas distribution companies' customers use of natural gas. The CCA also applies to Cascade's operational GHG emissions. Cascade's compliance plan for these rules is modeled within this IRP.

Chapter 7: Demand Side Management

Demand Side Management (DSM) refers to the reduction of natural gas consumption through the installation of energy efficiency measures such as insulation, more efficient gas-fired appliances or through load management programs. Cascade targets savings of approximately 64.5 million therms system-wide over the 20-year planning horizon; 16.5 million therms in Oregon and 48 million therms in Washington.

Cascade acquires therm savings through its energy efficiency programs. In Oregon, the Energy Trust of Oregon (Energy Trust) administers the Company's programs and in Washington, Cascade administers its own programs. In both states the programs offer Cascade customers financial incentives to install specific cost-effective energy efficiency measures. These measures cover a broad range of applications including new homes, retrofit appliances, and commercial appliances. The programs are funded in Oregon through a public purpose charge, which applies a percentage charge to customers' bills, and in Washington through a per therm charge.

To determine the Company's savings targets in Oregon, Energy Trust performed a resource analysis of all available energy efficiency for the 20-year planning period. This was a multi-step process beginning with determining all available and potentially available conservation measures. A demographic study of the age of the houses and buildings in Cascade's Oregon service territory was then performed to estimate when new buildings and homes would be built, and when existing homes would need replacement appliances. The total amount of energy savings that can be installed in an area without consideration of economic barriers is called the technical potential.

Once Energy Trust determined the technical potential, the industry standard of decrementing this by 15% was used to get to the achievable potential. Energy Trust then created the cost-effective potential by screening all DSM measures using the total resource cost (TRC) test, which is a benefit-cost ratio (BCR) that measures the cost effectiveness of the investment being made in an efficiency measure. The cost-effective achievable potential is smaller than the achievable potential because the potential savings from non-cost-effective measures are removed.

Energy Trust then applied its knowledge of market uptake to the cost-effective achievable potential which further reduced this amount and resulted in the program savings projections which are included in Appendix D by customer class, program and year.

Each measure comprising the cost-effective achievable potential was given a levelized cost which is that measure's annualized cost over annual therm savings. The levelized cost is used to demonstrate the total potential therms that could be saved at various costs.

Savings for the 2023 IRP increase in the early years, taper, and then increase again at the end of the forecast for a variety of factors. The early year forecast generally follows the actuals trend of increasing savings year over year, and Energy Trust sees 2023 and 2024 as infrastructure building years to increase savings even further in the next five years as Energy Trust works with Cascade to acquire energy savings to comply with Oregon greenhouse gas policy.

Chapter 8: Distribution System Planning

Cascade uses computer modeling for network demand studies to ensure its distribution system is designed to deliver gas reliably to customers as the number of customers and their demand change.

Cascade's geographical information system (GIS) keeps an up-to-date record of pipe and facilities, complete with all system attributes such as date of install and operation pressure. Using the Company's GIS environment and other input data, Cascade is able to create system models through the use of Synergi® software. The software provides the means to theoretically model piping and facilities to represent current pressure and flow conditions while predicting future events and growth. Combining these models with historical weather data can provide a design day model that will predict a worst-case scenario. Design day models that experience less than ideal conditions can then be identified and remedied before a real problem is encountered.

When modeling demonstrates that a portion of the distribution system is unable to meet future demand, Cascade engineers consider many possible remedies including reinforcements or expansions. Enhancements include pipeline looping, upsizing, and uprating. Pipeline looping is the most common method of increasing capacity in an existing distribution system. Pipeline upsizing involves replacing existing pipe with a larger size pipe. Pipeline uprating increases the maximum allowable operating pressure of an existing pipeline.

Besides modifying the pipelines, regulators or regulator stations can be added to reduce pipeline pressure at various stages in the distribution system. If pressures are too low, compressor stations can be added to boost downstream pressures.

Another possible solution is targeted demand side management. Area specific incentives for installed energy efficiency measures can reduce demand in a constrained area either eliminating or forestalling the need to add or reinforce infrastructure.

Once the optimal solution is determined, projects are ranked based on numerous criteria and are scheduled. Chapter 8, Distribution System Planning, presents a summary of costs by district and Appendix I lists all known distribution projects.

Chapter 9: Resource Integration

Cascade made a change to the model used for resource optimization from SENDOUT® to PLEXOS®. This software permits the Company to develop and analyze a variety of resource portfolios to help determine the type, size, and timing of resources best matched to forecast requirements. The model knows the exact load and price for every day of the planning period based on input and can therefore minimize costs in a way that would not be possible in the real world. It is important to acknowledge that PLEXOS® provides helpful but not perfect information to guide decisions. A large reason for switching to PLEXOS® is because of their ability to model everything SENDOUT® was capable of but PLEXOS® also allows for carbon emission modeling.

One of the purposes of integrated resource planning is to identify an illustrative resource portfolio to help guide specific resource acquisitions. In this planning cycle, the Company considered a host of resource alternatives that could potentially be added to its resource portfolio, including additional conservation programs, incremental off-system storage alternatives at AECO Hub, Mist, Spire, Wild Goose, and Gill Ranch. Additionally, incremental transportation capacity on NWP, Ruby, Nova Gas Transmission Ltd. (NGTL), Foothills and GTN pipeline systems was considered, along with on-system satellite LNG facilities, RNG, and imported LNG. Also included were other options to meet carbon compliance such as hydrogen, allowances, offsets, and Community Climate Investments (CCI). Typically, utility infrastructure projects are “lumpy,” since demand grows annually at a small percentage rate, while capacity is typically added on a project-by-project basis. Utilities often have surplus capacity and must “grow into” their new pipeline capacity, because it is more cost effective for pipelines to build for several years of load growth at one time than to make small additions each year. However, the Company can minimize the impacts through the acquisition of citygate peaking resources which include both the supplies and the associated pipeline delivery for a certain number of days or through the purchase of other’s excess capacity through short- or medium-term capacity releases.

Utilizing the PLEXOS® resource optimization model, several portfolios were run to test the viability of acquiring incremental storage, transportation resources, and incremental carbon compliance resources based on existing recourse rates and discounted rates, and via capacity release through a third party. Basin prices in the model over the 28-year planning horizon have AECO trading at a discount to Rockies, Malin, and Sumas. Shortfalls can come in two forms; the inability to serve increasing demand through lack of resources, or meeting demand but unable to secure enough carbon compliance options to meet the CCA or CPP.

Using input from these alternative resources, PLEXOS® derives a portfolio of existing and incremental resources that Cascade defines as the top-ranked portfolio. This provides guidance as to what resources should be considered to meet demand with a reasonable least cost and least risk mix of demand and supply side resources while meeting carbon reduction targets under expected pricing, weather, and growth environments.

The top-ranked candidate portfolio is then run through several scenarios to stress test the model. These scenario's include reducing carbon to 0 by 2050, limited RNG, electrification, high customer growth, and high price interrupted supply.

The top-ranked candidate portfolio includes all existing resources, expected DSM, as well as allowances, offsets, CCIs, RNG, and hydrogen. A more detailed discussion regarding the Company's resource integration and the results can be found in Chapter 9, Resource Integration.

Chapter 10: Stakeholder Engagement

Input and feedback from Cascade's Technical Advisory Group (TAG) is an important resource for ensuring the IRP includes perspectives beyond the Company's and is responsive to stakeholders' concerns. Cascade held five public TAG meetings with internal and external stakeholders. Due to continued concerns around COVID-19, all meetings were held virtually using Microsoft Teams. Participants invited to these public meetings include interested customers, regional upstream pipelines, Pacific Northwest Local Distribution Companies and other utilities, Commission Staff, stakeholder representatives such as the Northwest Gas Association, Oregon Department of Ecology, Washington Public Counsel, Oregon Citizens' Utility Board, the Alliance of Western Energy Consumers, the Northwest Energy Coalition, the League of Women Voters, and the Green Energy Institute. Cascade has a dedicated internet webpage where customers and parties can view the IRP timeline, TAG presentations, TAG minutes, and a video recording of TAG meetings, as well as current and past IRPs. This information can be found at https://www.cngc.com/rates-services/rates-tariffs/oregon-integrated-resource-plan.

Chapter 11: Four-Year Action Plan

Figure 1-1 on the following page shows Cascade's Two-Year Action Plan. Further descriptions can be found in Chapter 11, Four-Year Action Plan.

Figure 1-1: Highlights of 2023 Action Plan

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:
	    o Prineville Gate Upgrade.
	    o Baker City Reinforcement (Targeted Load Management Candidate).
	    o Ontario Reinforcement (Targeted Load Management Candidate).
		Ongoing over the next four to five years.

Chapter 2

Company Overview

Company Overview

> **Key Points**
> - Cascade serves diverse geographical territories across Washington and Oregon.
> - Cascade's primary pipelines are NWP, GTN, and Enbridge, also known as WCT, with access to three other pipelines.
> - Core customers represented 22% of total 2021 throughput, while non-core customers represented 78% of total throughput.
> - Cascade is a subsidiary of MDU Resources Group, Inc. based in Bismarck, North Dakota.

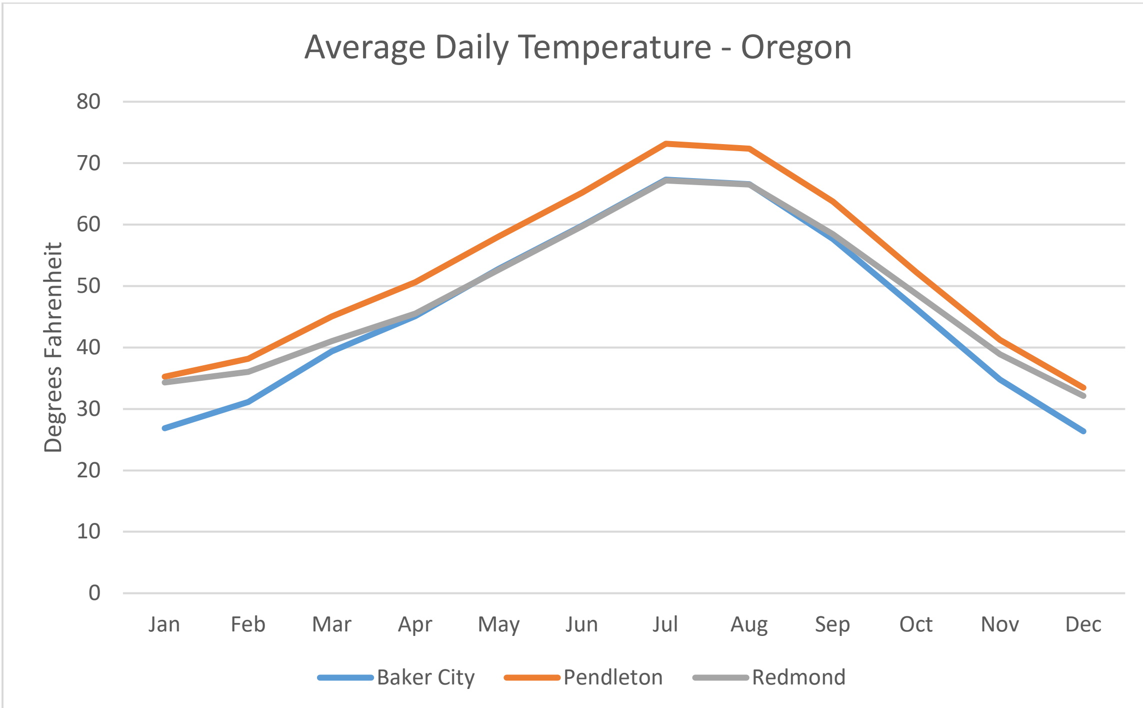
Cascade Natural Gas Corporation (CNGC or Cascade or Company) has a rich history that began over 65 years ago when business leaders and public officials in the Pacific Northwest initiated a campaign to bring natural gas to the region to replace other more expensive fuels. In 1953, five small utilities serving fifteen communities merged to form Cascade. Over the years, Cascade continued to grow, merging with, and acquiring other natural gas providers. The Company stock first traded on the New York Stock Exchange in 1973. In 2007, Cascade merged with Montana Dakota Utilities (MDU) Resources Group, Inc. which is headquartered in Bismarck, North Dakota[1]. Cascade's headquarters moved from Seattle, Washington to Kennewick, Washington in 2010.

Today, Cascade's service territory covers about 32,000 square miles and extends over 700 highway miles from end to end, encompassing a diverse economic base as well as varying climatological areas. Cascade delivers natural gas service to more than 310,000 customers with approximately 80,000 customers in Oregon and 230,000 customers in Washington. The Company's customers reside in 95 communities--28 in Oregon and 67 in Washington. Cascade's service area consists of smaller, rural communities in central and eastern Oregon, as well as communities across Washington.

The climate of Cascade's service territory is almost as diverse as its geographical reach. The western Washington portion of the service territory, nicknamed the I-5 corridor, has a marine climate with occasionally significant snow events. In general, the climate in the western part of the service territory is mild with frequent cloud cover, winter rain, and warm summers. Cascade's eastern Washington service territory has a semi-arid climate with periods of arctic cold in the winter and heat waves in the summer. Figure 2-1 compares the average temperatures by month of the two regions. Oregon's service territory is in rural areas throughout northern central and central Oregon as well as eastern Oregon. All regions of Oregon have semi-arid climates with periods of arctic cold in the winter and heat waves in the summer.

[1] For more information about MDU, see https://www.mdu.com

Figure 2-1: Average Temperature by Oregon Region

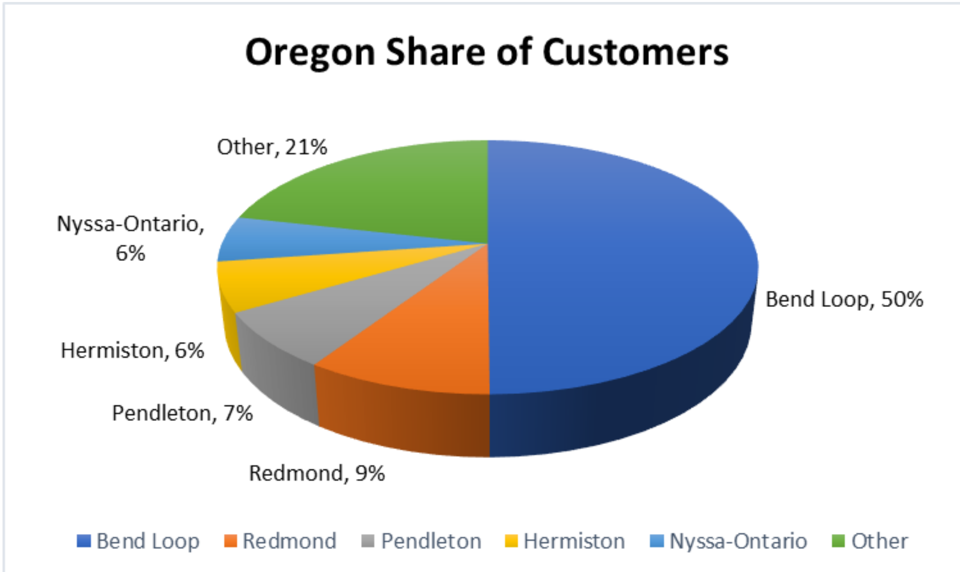


Below are some of the more populated towns within the regions Cascade provides distribution service:

- **Northwest** – Bellingham, Mt. Vernon, Oak Harbor/Anacortes, the Kitsap Peninsula, the Grays Harbor area and Kelso/Longview;
- **Central** – Sunnyside, Wenatchee/Moses Lake, Tri-Cities, Walla Walla and Yakima areas; and
- **Southern** – Bend and surrounding communities, Ontario, Baker City and the Pendleton/Hermiston areas.

Figure 2-2 shows a breakdown of Cascade's Washington customer density by citygate. A map of Cascade's certificated service territory is provided as Figure 12-13 in Chapter 13, Glossary and Maps.

Figure 2-2: Customer Density by Citygate in Oregon



Pipeline and Basin Locations

Cascade purchases natural gas from a variety of suppliers and transports gas supplies to its distribution system using three natural gas pipeline companies. Northwest Pipeline LLC (NWP) provides access to British Columbia and domestic Rocky Mountain gas, Gas Transmission Northwest (GTN) provides access to Alberta and Malin gas, and Enbridge (Westcoast or WCT) provides British Columbia gas directly into the Company's distribution system. Cascade also holds upstream pipeline transportation contracts on TransCanada Pipeline's Foothills Pipeline (FHBC), NOVA Gas Transmission Ltd. (also known as NGTL), and Ruby Pipeline. More information about the pipelines and the supply basins is provided in Chapter 4, Supply Side Resources. Maps of select pipelines are found in Chapter 13, Glossary and Maps.

Core vs Non-Core Service

Cascade offers core service, which is the procurement of gas supply from an upstream basin or pipeline interconnect, such as Sumas or AECO, that is then transported to Cascade's citygates. From the citygate, Cascade then delivers gas on its distribution system to the end-use customer. Although Cascade offers core service to all its customers, not all of them take advantage of this type of firm service.

In 1989, concurrent with the passage of the Natural Gas Wellhead Decontrol Act, Cascade began allowing its large volume customers to purchase their own gas supplies and gas transportation services upstream of Cascade's distribution system.[2] These customers, referred to as large volume non-core customers, procure their own supply and transportation through third parties such as marketers. Cascade is only responsible for the distribution of non-core gas supply from the upstream pipeline citygate to the point of delivery at the customer's site. The Company currently has approximately 240 large volume customers who have elected this type of non-core service.

Since the Company does not provide gas supply and upstream pipeline transportation capacity resources to non-core customers, the Company does not plan for non-core customers in the conventional upstream resource analysis of its Integrated Resource Plan (IRP). However, with the implementation of the Climate Commitment Act in Washington and the Climate Protection Plan in Oregon, non-core emissions are considered in Cascade's resource integration and compliance planning. Also, non-core demand is a consideration in Chapter 9, Distribution System Planning.

In 2021, Cascade's residential customers represent approximately 12% of the total natural gas delivered on Cascade's system, while commercial customers represent roughly 9%, and the core industrial customers account for around 1% of total gas throughput. The remaining non-core industrial customers represent the balance of the 78% of total throughput.

Company Organization

In 2007, Cascade became a subsidiary of MDU Resources Group, Inc., a multidimensional regulated energy delivery and construction materials and services business, operating in 43 states and traded on the New York Stock Exchange under the symbol MDU. Cascade, with headquarters in Kennewick, Washington, is part of its utility group of subsidiaries. MDU Resources Group's utility companies, when combined, serve approximately 1.2 million customers. Cascade distributes natural gas in Oregon and Washington. Great Plains Natural Gas Co. distributes natural gas in western Minnesota and southeastern North Dakota. Intermountain Gas Company distributes natural gas in southern Idaho. Montana-Dakota Utilities Co. generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Figure 2-3 provides a geographical representation of the various services/territories served by MDU Resources. Figure 2-4 shows the MDU Resources Electric and Natural Gas Services and Territory.

[2] *See* Natural Gas Wellhead Decontrol Act of 1989 amends the Natural Gas Policy Act of 1978 to declare that the price guidelines for the first sale of natural gas do not apply to: (1) expired, terminated, or post-enactment contracts executed after the date of enactment of this Act; and (2) certain renegotiated contracts. Decontrols as of May 15, 1991, natural gas produced from newly spudded wells. Repeals permanently wellhead price controls beginning on January 1, 1993.

Figure 2-3: MDU Resources Services and Territory

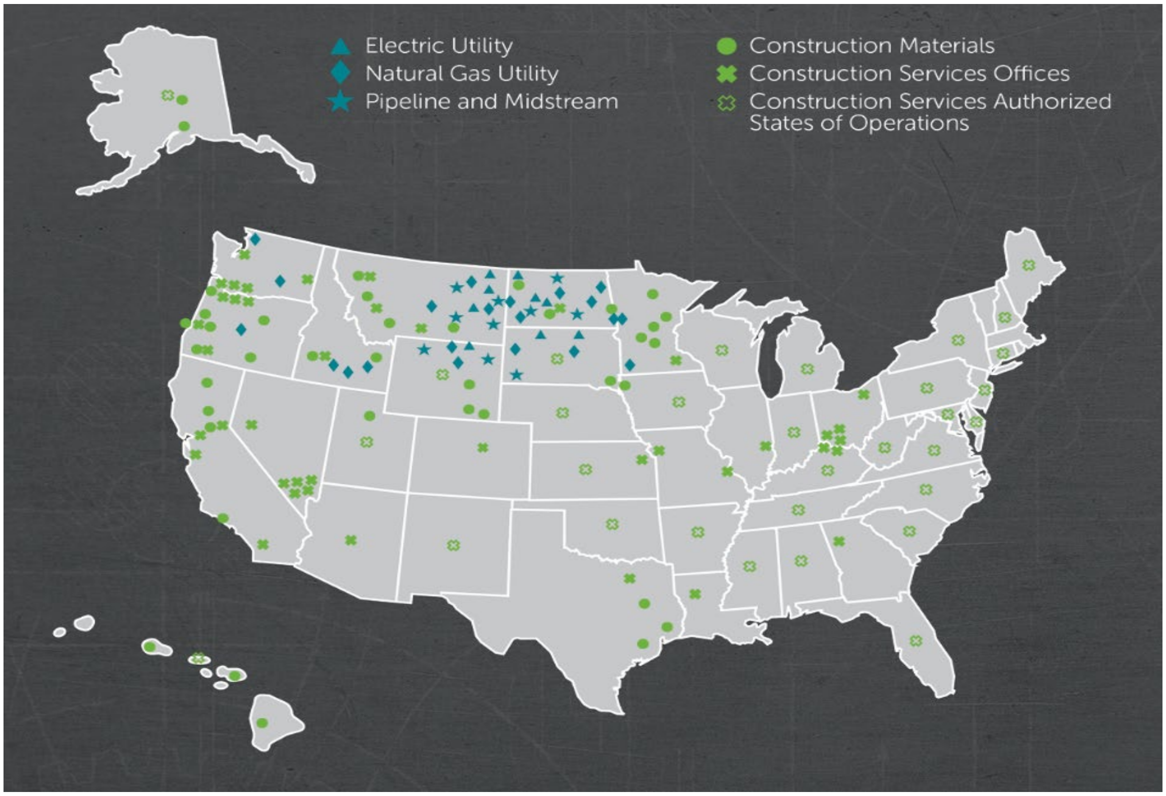
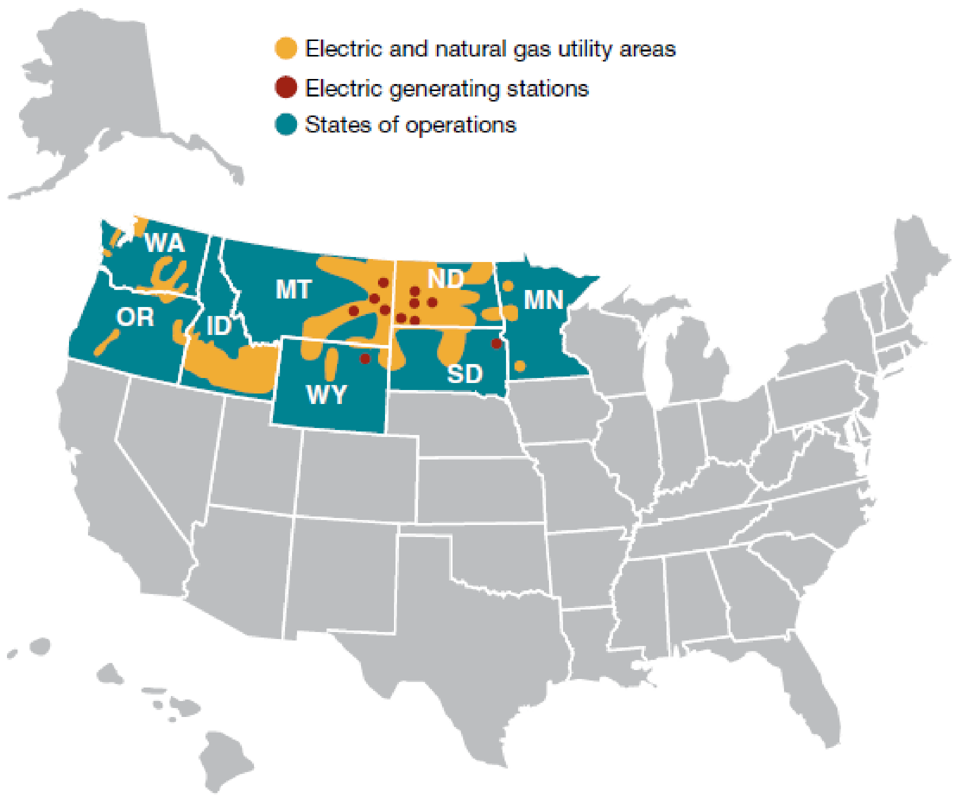


Figure 2-4: MDU Resources Electric and Natural Gas Services and Territory



Chapter 3

Demand Forecast

Overview

Each year Cascade develops a 20-year forecast of customers, therm sales, and peak requirements for use in short-term (annual budgeting) and long-term (distribution and integrated resource planning) planning processes. For this IRP, Cascade is extending its forecast to 28 years in order to better align with emissions modeling. Sources of this forecast include historic data, market intelligence (ie building code changes), and regional economic data from Woods & Poole. This forecast is a robust portfolio of estimates created by expanding a single best-estimate forecast, which includes various potential economic, demographic, and marketplace eventualities, into scenarios such as low, expected, and high growth. The scenarios are used for distribution system enhancement planning and as inputs in optimization models to determine the reasonable least cost, least risk mix of supply and energy efficiency resources, revenue budgeting, and load forecasts associated with the purchased gas cost process.

Key Points

- Cascade extended its forecast analyses of demand areas, HDDs, and wind from 20 years to 28 years to better align with emissions modeling.
- Peak day is analyzed stochastically using 10,000 Monte Carlo simulated draws for each weather zone.
- Cascade added a price regressor to the Use-Per-Customer forecast.
- The Company utilizes dynamic regression modeling techniques for customer and annual demand forecasts.
- High and low scenarios are included and alternative forecasting assumptions were considered.
- Cascade expects system load growth to average 1.10% per year over the 28-year planning horizon.
- For methodological changes from previous IRPs, please refer to the "Methodological Changes…" section of this chapter.
- Uncertainties in the future, such as economic and long-term weather conditions, as well as future legislation, may cause differences from the Company's forecast.

Demand Areas

For the 2023-2050 planning horizon, Cascade continued to forecast at both the citygate and rate class levels. Cascade has a total of 76 citygates of which nine citygates feed only non-core customers and the remaining 67 serve at least one core customer. Of the 67 citygates that serve core customers, 22 are grouped into nine different citygate loops. Therefore, Cascade forecasts a total of 57 areas. Each of these areas contain multiple rate classes, resulting in approximately 200 individual dynamic regression models. Each citygate is assigned to a weather location. For this IRP, the Company assigned the citygates to the closest weather location by distance. The citygate results are rolled up into zones and districts which segregate Cascade's system based on pipelines and weather, as shown in Appendix B. Figure 3-1 provides a cross reference for the demand areas.

Figure 3-1: Demand Areas

Citygate	Loop	State	Weather Location	Zone
7TH DAY SCHOOL		WA	Yakima	10
A/M RENDERING	Sumas SPE Loop	WA	Bellingham	30-W
ACME		WA	Bellingham	30-W
ARLINGTON		WA	Bellingham	30-W
ATHENA		OR	Pendleton	ME-OR
BAKER		OR	Baker City	24
BELLINGHAM 1 (FERNDALE)	Sumas SPE Loop	WA	Bellingham	30-W
BEND	Bend Loop	OR	Redmond	GTN
BREMERTON (SHELTON)		WA	Bremerton	30-S
BURBANK HEIGHTS	Burbank Heights Loop	WA	Walla Walla	20
CASTLE ROCK		WA	Bremerton	26
CHEMULT		OR	Redmond	GTN
DEHAWN DAIRY		WA	Yakima	10
DEMING		WA	Bellingham	30-W
EAST STANWOOD	East Stanwood Loop	WA	Bellingham	30-W
FINLEY		WA	Walla Walla	20
GILCHRIST		OR	Redmond	GTN
GRANDVIEW		WA	Yakima	10
HERMISTON		OR	Pendleton	ME-OR
HUNTINGTON		OR	Baker City	24
KALAMA #1		WA	Bremerton	26
KALAMA #2		WA	Bremerton	26
KENNEWICK	Kennewick Loop	WA	Walla Walla	20
LA PINE		OR	Redmond	GTN
LAWRENCE		WA	Bellingham	30-W
LDS CHURCH		WA	Bellingham	30-W
LONGVIEW-KELSO	Longview South Loop	WA	Bremerton	26
LYNDEN	Sumas SPE Loop	WA	Bellingham	30-W
MADRAS		OR	Redmond	GTN
MCCLEARY (ABERDEEN/HOQUIAM)		WA	Bremerton	30-S
MILTON-FREEWATER		OR	Walla Walla	ME-OR
MISSION TAP		OR	Pendleton	ME-OR
MOSES LAKE		WA	Yakima	20
MOUNT VERNON	Sedro-Woolley Loop	WA	Bellingham	30-W
MOXEE (BEAUCHENE)		WA	Yakima	11
NORTH BEND		OR	Redmond	GTN
NORTH PASCO	Burbank Heights Loop	WA	Walla Walla	20
NYSSA-ONTARIO		OR	Baker City	24
OAK HARBOR/STANWOOD	East Stanwood Loop	WA	Bellingham	30-W

Citygate	Loop	State	Weather Location	Zone
OTHELLO		WA	Walla Walla	20
PASCO	Burbank Heights Loop	WA	Walla Walla	20
PATTERSON		WA	Yakima	26
PENDLETON		OR	Pendleton	ME-OR
PRINEVILLE		OR	Redmond	GTN
PRONGHORN		OR	Redmond	GTN
PROSSER		WA	Yakima	10
QUINCY		WA	Yakima	11
REDMOND		OR	Redmond	GTN
RICHLAND (Richland Y)	Kennewick Loop	WA	Walla Walla	20
SEDRO/WOOLLEY	Sedro-Woolley Loop	WA	Bellingham	30-W
SELAH	Yakima Loop	WA	Yakima	11
SOUTHRIDGE	Kennewick Loop	WA	Walla Walla	20
SOUTH BEND	Bend Loop	OR	Redmond	GTN
SOUTH LONGVIEW	Longview South Loop	WA	Bremerton	26
STANFIELD		OR	Pendleton	GTN
STEARNS (SUNRIVER)		OR	Redmond	GTN
SUNNYSIDE		WA	Yakima	10
UMATILLA		OR	Pendleton	ME-OR
WALLA WALLA LOOP		WA	Walla Walla	ME-WA
WALLULA		WA	Walla Walla	ME-WA
WCT-CNG INTERCONNECT	Sumas SPE Loop	WA	Bellingham	30-W
WENATCHEE		WA	Yakima	11
WOODLAND		WA	Bremerton	26
YAKIMA CHIEF RANCH		WA	Yakima	10
YAKIMA TRAINING CENTER		WA	Yakima	11
YAKIMA/UNION GAP	Yakima Loop	WA	Yakima	11
ZILLAH (TOPPENISH)		WA	Yakima	10

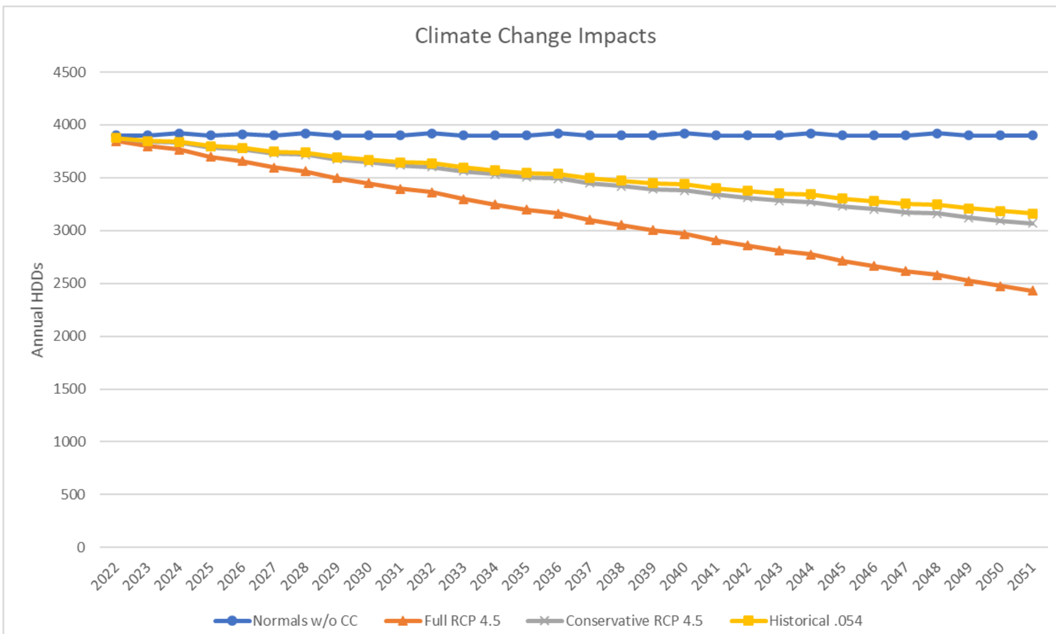
Weather

Heating Degree Day, or HDD, values are calculated with the daily average temperature, which is the simple average of the high and low temperatures for a given day. The daily average is then subtracted from an HDD degree threshold (for example 60 °F) to create the HDD for a given day. Should this calculation produce a negative number, a value of zero is assigned as the HDD. Therefore, HDDs can never be negative. The HDD threshold number is designed to reflect a temperature below which heating demand begins to significantly rise.[1]

[1] The historical threshold for calculating HDD has been 65 °F. However, as discussed in prior IRPs, Cascade has determined that lowering the threshold to 60 °F produces more accurate results for the Company's service area.

Historical weather data is provided by a contractor, Schneider Electric. Cascade has seven weather locations with four located in Washington and three in Oregon. The four locations in Washington are Bellingham, Bremerton, Walla Walla, and Yakima. Historically, Cascade has accessed data from NOAA (National Oceanic and Atmospheric Administration), but found many months/locations with missing data. The previous forecasts used 30 years of recent history as the normal or expected weather. For this IRP, Cascade has evolved its weather forecast with an analysis of climate change impacts and Monte Carlo peak day simulations. Cascade selected scenarios from the Intergovernmental Panel on Climate Change (IPCC). Figure 3-2 shows an annual HDD forecast comparison of Cascade's previous weather normals methodology in blue compared to climate change scenarios selected from the IPCC.[2]

Figure 3-2: Climate Change Impacts



- Normals w/o CC: This represents 30 years of historical data projected forward as normal weather, or expected weather.
- Full RCP 4.5: This represents the Coupled Model Intercomparison Project Phase 4 (CMIP5) with the RCP 4.5 scenario which included 36 different models. [1]
- Conservative RCP 4.5: This represents the 18 most conservative models in the Full RCP 4.5 project. [1]
- Historical 054: This represents the Environmental Protection Agency's noted historical temperature change (.54 F per decade since 1979). [3]

[2] https://ipcc-browser.ipcc-data.org/browser/search?format
[3] https://www.epa.gov/climate-indicators/climate-change-indicators-us-and-global-temperature

Cascade chose the Conservative RCP 4.5 forecast as it best represents the Western North America emission goals and was labeled as the most probable baseline scenario.[4] This is incorporated into the forecast by replacing the normal HDDs that would have been used to forecast years 2023-2150 with the HDDs in the Conservative RCP 4.5 scenario. This allows Cascade to better capture climate change's effects on HDDs, rather than simply relying on historical HDDs.

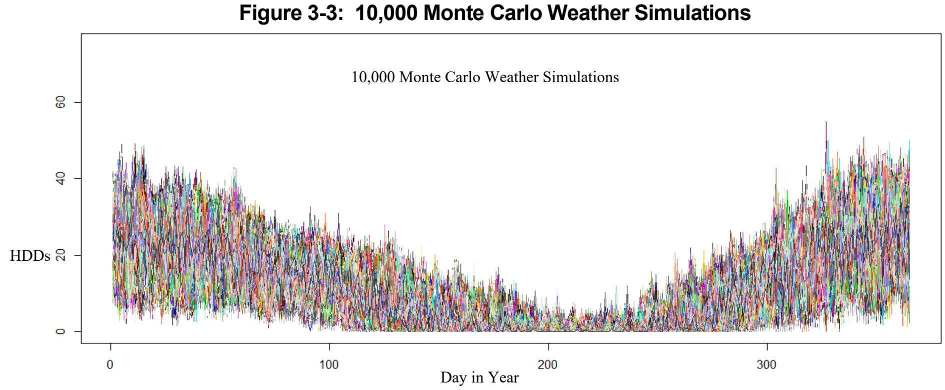
Peak Day Methodology

In order to ensure satisfaction of core customer demand on the coldest days, Cascade must use a methodology for determining what a peak day might be and then include it in the modeling. Since the prior IRP, Cascade has evolved its peak day methodology from a deterministic peak day to a stochastic peak day. Peak day forecasts enable Cascade to make prudent distribution system and peak upstream pipeline capacity planning decisions to fulfill its responsibility to provide heating under all but *force majeure* conditions, particularly as most space-heating customers will have no alternative heating source during the coldest days in the event gas does not flow.

The stochastic peak day that was analyzed in the forecast model is a weather zone specific 99th percentile peak day. This 99th percentile peak day will give Cascade the confidence that the system can handle a peak day based on the weather of each weather zone with varying amounts of demand. This peak day HDD methodology allows Gas Supply to plan for the highest peak event during a heating season.

The 99th percentile peak day is derived by running 10,000 Monte Carlo simulations on each of the seven weather zones. Once 10,000 draws are gathered and ordered for each weather zone, Cascade can pull the 9,900th draw as the 99th percentile to use in the demand forecast. Figure 3-3 displays all 10,000 draws graphed together.

Figure 3-3: 10,000 Monte Carlo Weather Simulations



[4] https://en.wikipedia.org/wiki/Representative_Concentration_Pathway

For PLEXOS® modeling, Cascade uses this peak day for each weather zone by applying the HDDs on December 21 of each year in the forecast. The selection of December 21st is mostly arbitrary, though one of Cascade's coldest peak days did occur on a December 21st, with the intention of mimicking a cold winter day. For example, all citygates associated with the Yakima weather station use the 99th percentile peak HDD for Yakima for each December 21st of the forecast period, and similarly for all the other weather stations and citygates. This provides a highest demand scenario for peak demand load based on Monte Carlo simulations of years of weather history for each citygate. Applying this stochastic peak day to December 21st of each forecasted year gives Cascade an accurate representation of the demand the Company could expect if this weather happened during the planning horizon.

Cascade is actively monitoring its peak day methodology to ensure an accurate and realistic peak day forecast.

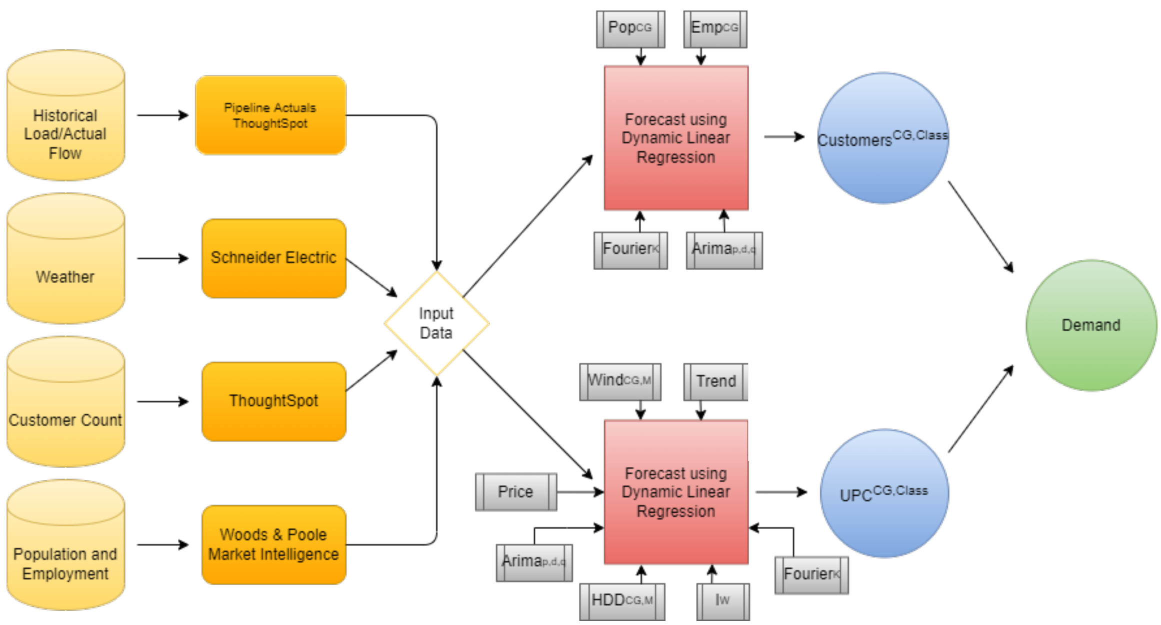
Wind

Wind values are calculated with the daily average wind speed, which is the simple average of the high and low wind speeds for a given day. Wind speeds are also weather location specific, similar to HDDs.

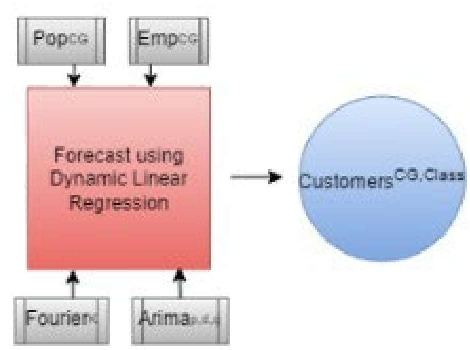
Demand Overview

Figure 3-4 provides a roadmap for Cascade's demand forecast. The inputs are displayed along with their sources in yellow and gold. The customer forecast and use-per-customer (UPC) forecast are shown in red along with their respective inputs into the model. Finally, the customer forecast is multiplied by the use-per-customer forecast to create the final demand forecast.

Figure 3-4: Demand Forecasting Process Overview



Customer Forecast Methodology



Customer count forecasts are designed to reflect both demographic trends and economic conditions both in the short- and long-term. Cascade uses population and employment growth data from Woods & Poole (W&P). Since the first quarter of 2020, Cascade has and will continue to monitor the COVID-19 impacts. Since Cascade relies on W&P for population and employment growth data, the Company is providing an update from W&P about the impacts of COVID-19 on those projections. W&P states "Despite significant 2020 impacts, COVID -19 itself does not appear to have made a quantifiable long-term economic impact that would affect forecasts: productive land area in the U.S. is still usable, productive capital (i.e. factories) are still in place, and the size of labor force has not been reduced significantly." [5] W&P growth forecasts are provided at the county level. It should be noted that W&P forecasts are adjusted when the internal intelligence about a demand area indicates a significant difference from W&P regarding observed economic

[5] Woods & Poole's 2020 State Profile: State and County Projections to 2020

trends. Cascade utilizes dynamic regression models for the customer forecast as well as regression models for the UPC forecast, which will be discussed in the next subchapter. Below is the formula the Company used to run the regressions:

$$C_{Class}^{CG} = \alpha_0 + \alpha_1 Pop^{CG} + \alpha_2 Emp^{CG} + Fourier(k) + ARIMA\epsilon(p, d, q)$$

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class$
- $Pop^{CG} = Population\ by\ Citygate$
- $Emp^{CG} = Employment\ by\ Citygate$
- $Fourier = Terms\ used\ to\ capture\ seasonal\ patterns$
- $k = Number\ of\ Fourier\ terms\ used\ in\ model$
- $ARIMA\epsilon(p, d, q) =$ $Indicates\ that\ the\ model\ has\ p\ autoregressive\ terms, d\ difference\ terms, and\ q\ moving\ average\ terms.$

Cascade runs this model approximately 200 times to account for each customer class by citygate. The Company begins by testing seven different combinations of the regressors in both dynamic regression models and one Autoregressive Integrated Moving Average (ARIMA) model. The dynamic regression models test Fourier, Population, Employment, Population + Fourier, Employment + Fourier, and Employment + Population + Fourier. The last model is called an ARIMA model, which uses ARIMA terms and no regressors. Unlike the dynamic regression models, the ‘ARIMA Only’ model’s ARIMA term is not strictly modeling the errors, but is used as a model for the entire data set. The method used to compare and select a model is called the AIC, or the Akaike Information Criterion. This is a measure of the relative quality of statistical models, relative to each of the other models. In each of the models, except for the ‘ARIMA Only’ model, an ARIMA term is used to capture any structure in the errors (or residuals) of the model. In other words, there could be predictability in the errors, so they could be modeled as well. If the data is non-stationary, the ARIMA function will difference the data. Most times, the data does not require differencing, or only needs to be differenced once. Once the best model is selected for each customer class by citygate, a forecast is performed using the selected model.

Customer count and therm forecasts are augmented by revisions to the base data and output to create a portfolio of potential scenarios. Low and high growth scenarios are created from the confidence intervals from the forecast model. These scenarios, along with the original, best-estimate, expected scenario encapsulate a range of most-likely possibilities given known data. The most recent W&P data indicates an average annual population growth of 0.81% between 2023 and 2050 for Cascade’s service territory. The projected customer growth is provided in Appendix B. Based on historical experience and given expected weather, Cascade expects system load will likely remain within a range bound by the low and high growth scenarios.

Cascade locked in the forecast model in June of 2022 as it is a key input for several other aspects of this IRP.

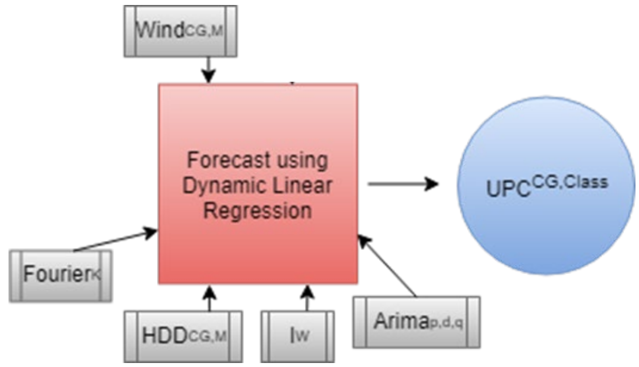
Among other reasons, the Company believes that high projected growth in the following regions is supported by the provided quantitative analysis:

- Burbank Heights Loop is expected to see a year over year average growth of 2.34%. This loop consists of the Pasco, North Pasco, and Burbank Heights citygates. These are located in southeastern Washington. Pasco sits in one of the fastest growing counties in the state, Franklin County. Future job growth is optimistic.[6]
- Kennewick Loop is expected to see a year over year average growth of 2.38%. This loop consists of the Richland Y, Kennewick, and Southridge citygates. These are located in southeastern Washington. Many new developments are a direct result of high population growth rates and optimistic job outlooks. [6]
- Bend Loop is expected to see a year over year average growth of 2.06%. This loop consists of the Bend and South Bend citygates. Bend is located in central Oregon. Bend is seeing a population boom coupled with optimistic job growth estimates. [6]
- Prineville is expected to see a year over year average growth of 2.02%. Prineville is located in central Oregon and much like Bend, Prineville has seen growth even during the pandemic. [7]

According to the Census Bureau, there has been a nationwide shift from larger cities to mid-size and smaller ones with the increase in remote work. Cities like Bend have been referred to as “Zoom towns”, referring to the new work-from-home culture allowing people to live where they want. [8]

[6] *See* According to bestplaces.net, worldpopulationreview.com, and city-data.com
[7] *See* According to bestplaces.net, worldpopulationreview.com, and city-data.com
[8] See United States Census Bureau, https://www.census.gov/newsroom/press-releases/2022/population-estimates-counties-decrease.html

Use-Per-Customer (UPC) Forecast Methodology



As previously mentioned, Cascade utilizes regression models for the UPC part of the demand forecast as well. [9] Sources for the inputs into this model are pipeline actuals, Cascade's gas management system, and Cascade's billing system data from ThoughtSpot. Cascade developed the UPC coefficient by first gathering historical pipeline demand data by day. The pipeline demand data includes core and non-core usage. The non-core data is backed out using Cascade's measurement data stored in the Company's Aligne energy transaction system which leaves only the daily core usage data. Then the daily data is allocated to a rate schedule for each citygate by using Cascade's ThoughtSpot system, which analyzes the therms billed for each rate class. Finally, this data is divided by number of customers to come up with a UPC number for each day and for each rate schedule at each citygate.

Below is the model used for the UPC forecast:

$$\frac{Therms}{C_{Class}^{CG}} = \alpha_0 + \alpha_1 HDD^{CG,M} + \alpha_2 I_w + \alpha_3 WIND^{CG,M} + Fourier(k) + ARIMA(p,d,q) + Price$$

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class.$
- $HDD^{CG} = Heating\ Degree\ Days\ from\ Weather\ Location$
- $m = month$
- $w = weekend$
- $I = Indicator\ variable, 1\ if\ weekend, and\ 0\ if\ weekday.$
- $WIND^{CG} = Daily\ average\ wind\ speed\ from\ Weather\ Location$
- $Fourier(k) = Captures\ seasonality\ of\ k\ number\ of\ seasons.$
- $ARIMA(p,d,q) = Indicates\ model\ has\ p\ autoregressive\ terms,\ d\ difference\ terms, and\ q\ moving\ average\ terms.$
- $Price = Front\ of\ Month\ (FOM)\ pricing$

Cascade runs this model for each of the 57 citygates and citygate loops by customer class where applicable, resulting in approximately 200 models. Cascade begins each model with a simple linear model regressing on HDDs, wind, price, and

[9] A regression model provides a function that describes the relationship between one or more independent variables and a response, dependent, or target variable. A regression analysis provides the means for many types of prediction and for determining the effects on target variables. Multiple regression indicates there are more than one input variables that may affect the outcome, or target variable.

weekend. If the residuals analyzed show structure, then the models are expanded to include ARIMA and Fourier terms.

Price as a New Regressor

Price is a new regressor for this IRP.[10] Overall, price has not seen much significance in the models. The largest coefficients were on the commercial and industrial customer classes, and even then the coefficients were quite small, seemingly insignificant. The residential coefficients were close to 0. Through the TAG process, specifically TAG 2, stakeholders suggested Cascade replace the price regressor with an income regressor in an attempt to better capture customer behavior. Cascade is excited to perform this analysis in the next demand forecast.

Building Code Impacts

As the Washington State Energy Codes (WSEC) continue to progress and impact new construction for natural gas end use appliance, Cascade must consider these impacts in the Company's customer and load forecasts.

RCW 19.27A.020(2)(a) is a broad goal that provides direction to the Washington State Building Code Council (SBCC) to adopt amendments to the WSEC that progressively moves the needle for new construction homes and buildings to be non-emitting by 2031. To achieve this goal, it is important to consider that a non-emitting (zero fossil-fuel greenhouse gas emission) home/building is typically considered based upon the net emissions; however, the legislative direction does not specify "net" in this circumstance. Consideration of net emissions is important, as it allows for a broader and more reliable energy portfolio. To achieve net-zero, emitting energy uses can be offset by renewable energy production (i.e. wind or solar) or energy that has a negative carbon intensity (i.e. Renewable Natural Gas); thus, allowing for emitting (i.e. Natural Gas) energy use during severe weather events, while still having a home/building that has net-zero emissions.

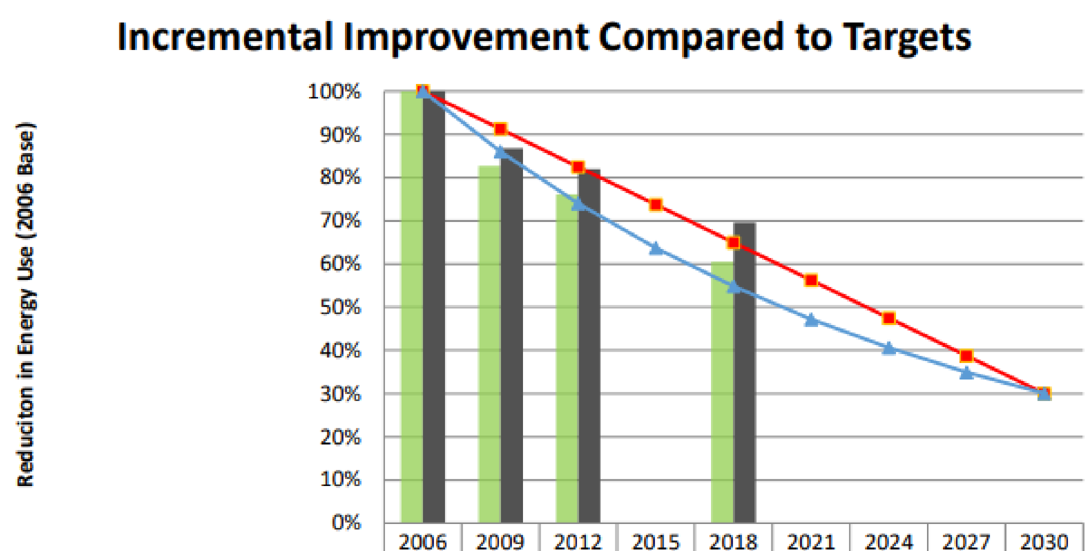
Under RCW 19.27A.020(2)(a), the SBCC is directed to "…help achieve the broader goal…" of zero emission homes/buildings. Note that this is a goal, not a mandate. Conversely, RCW 19.27A.160 is an explicit direction to the SBCC to move towards a 70% reduction in annual net energy consumption by 2031. This is a mandate, and is clear that the goal is a "net" energy.

Since RCW 19.27A.020(2)(a), the enacting legislation resulted from 2009 SB 5854. Therefore, the 2012, 2015, 2018, and 2021 code cycles were all likely impacted by

[10] A regressor is the name given to any variable in a regression model that is used to predict a response variable.

the legislation. Figure 3-5 provides an explanation of how the SBCC has addressed the more explicit legislative direction of RCW 19.27A.160.

Figure 3-5: Reduction Targets in Energy Use[11]



	2006	2009	2012	2015	2018	2021	2024	2027	2030
Residential	100%	82.7%	76.1%		60.5%				
Commercial	100%	86.8%	82.0%		69.6%				
Target: 8.75 % savings compared to the 2006 WSEC	100%	91%	83%	74%	65%	56%	48%	39%	30%
Target: 14% savings compared to each previous code	100%	86%	74%	64%	55%	47%	41%	35%	30%

The most impactful measures were found in the 2018 and 2021 WSEC. For example, NEEA's WA Residential Post Code Adoption Market Research Final Report[12] found that "…builder practices have significantly changed under the 2018 WSEC compared to the 2015 WSEC. This includes a shift towards electric space heating and water heating…" "…the incidence of electric primary space heating is 88% in this study of the 2018 WSEC; the 2015 WSEC study (CLEAResult 2020) recorded a 20% incidence of electric primary space heating for comparison. Water heating fuel is also showing significant changes. This study of the 2018 WSEC shows 87% electric water heating, while the 2015 WSEC study (CLEAResult 2020) recorded 44% electric water heating." (Note that this NEEA report was focused solely on residential; NEEA's 2018 WSEC Energy Savings Analysis for Nonresidential Buildings[13] may provide some additional insight for commercial projects).

[11] Final Cost Benefit Analysis for the 2021 WSEC-R
[12] *See* Washington Residential Post-Code Adoption Market Research (neea.org)
[13] *See* Northwest Energy Efficiency Alliance (NEEA) | 2018 Washington State…

With the forthcoming 2021 WSEC (effective July 1, 2023), the use of natural gas for space and water heating is generally prohibited for commercial buildings, and may only be used for supplementary (backup) heating or within gas heat pumps in residential buildings. Given the shift towards electric appliances already found from the 2018 WSEC, the 2021 WSEC will only further this trend.

Cascade has been monitoring the building code changes and will continue to monitor the impacts the current and future building code changes have. Due to the COVID-19 Pandemic, the 2018 WSEC did not go into effect until February 1, 2021. Cascade had one year's worth, which is a relatively small sample size, of historical data included in the customer and load forecast models for this current IRP. In future IRPs, once Cascade has gathered more data regarding the impacts of the 2018 and 2021 WSEC, the Company will investigate the impact these building code changes will have on the load and customer forecast.

Scenario Analysis

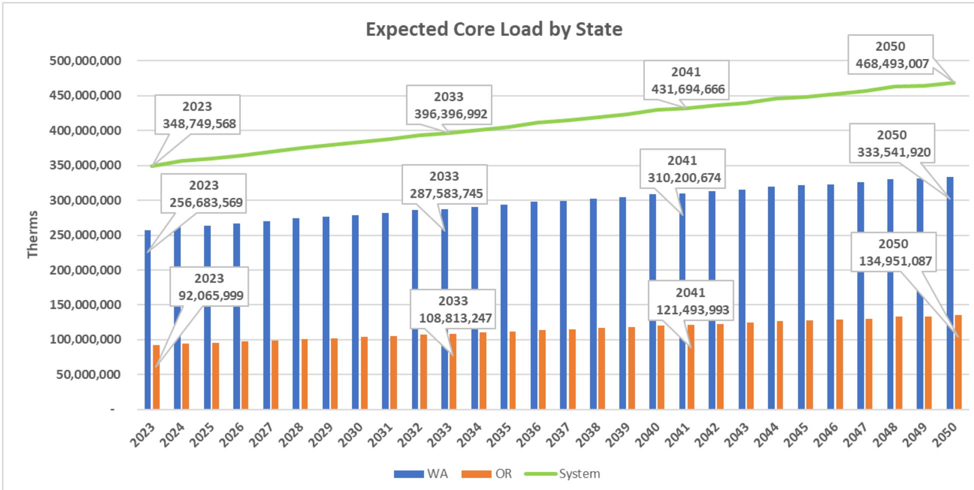
Cascade stress tests the load forecast in PLEXOS® by using alternative forecasting assumptions. These alternative forecasting assumptions refer to changing factors that influence demand. Alternative assumptions include high and low customer growth, and a stochastic study of weather using Monte Carlo simulations. These altered assumptions provide an effective tool for analyzing and stress testing the forecasts.

Cascade utilizes a low and high customer growth forecast to use in various PLEXOS® scenarios. Also, as mentioned previously in the peak day section, Cascade developed a peak day weather assumption based on 10,000 Monte Carlo simulations for each weather zone. The base case contains expected weather, customer growth, and use per customer. The base case also has an annual peak day event for each weather zone. Expected weather is the Conservative RCP 4.5 forecast previously discussed in this chapter. High and low growth scenarios, discussed more on page 3-20, are developed by using modifiers to represent higher than expected growth and lower than expected growth. Cascade also performs a deep sensitivity analysis utilizing Monte Carlo runs for other variables such as price. Monte Carlo analysis is discussed further in Chapter 10, Resource Integration.

Forecast Results

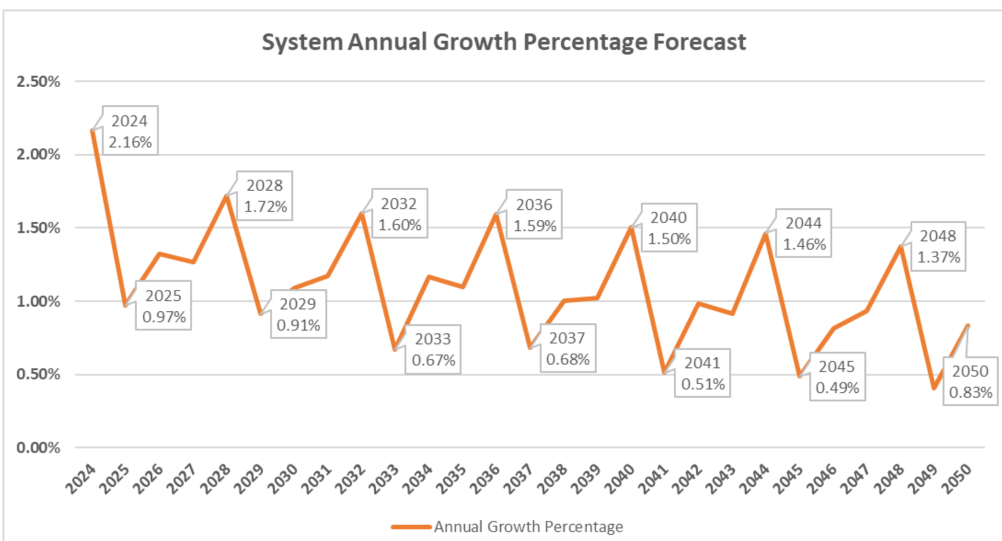
Load across Cascade's two-state service territory is expected to increase at an average annual rate of 1.10% over the planning horizon, with the Oregon portion outpacing Washington, 1.43% versus 0.98%. Figure 3-6 shows the expected core load volumes by state.

Figure 3-6: Expected Core Load by State (Volumes in Therms)



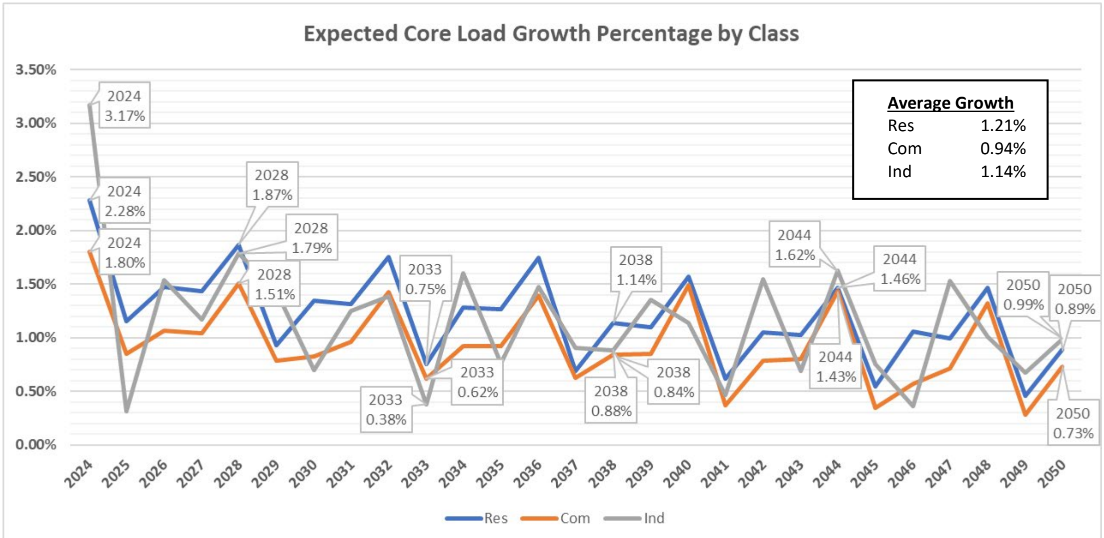
Load growth across Cascade's system through 2050 is expected to fluctuate between 0.41% and 2.16% annually, accounting for leap years. Figure 3-7 illustrates the growth forecast for Cascade's system load year over year, showing growth on Cascade's system but at a declining rate.

Figure 3-7: System Annual Growth Percentage Forecast



Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow annually at an average rate of 1.21% and 0.94%, while industrial expects a growth rate of approximately 1.14%. Figure 3-8 shows the percentage of core growth by class over the planning horizon.

Figure 3-8: Expected Core Load Growth Percentage by Class



In absolute numbers, system load is expected to grow annually at an average of 4.4 million therms. A majority of core load today is residential. Cascade projects the ratio between residential, commercial, and industrial to increase in favor of residential customers. Residential customers are expected to grow from 53.3% of the total core load to 54.9% of the total core load by 2050. Figure 3-9 compares the total system annual therm usage forecast of this IRP to past IRPs dating back to 2011. The differences in forecasts can be attributed to evolutions in methodology, customers changing between core and non-core, and having more data to forecast with. Figure 3-10 displays the relative percentage relationship of expected loads by class.

Figure 3-9: System Load Comparison to Previous IRPs (Volumes in Therms)

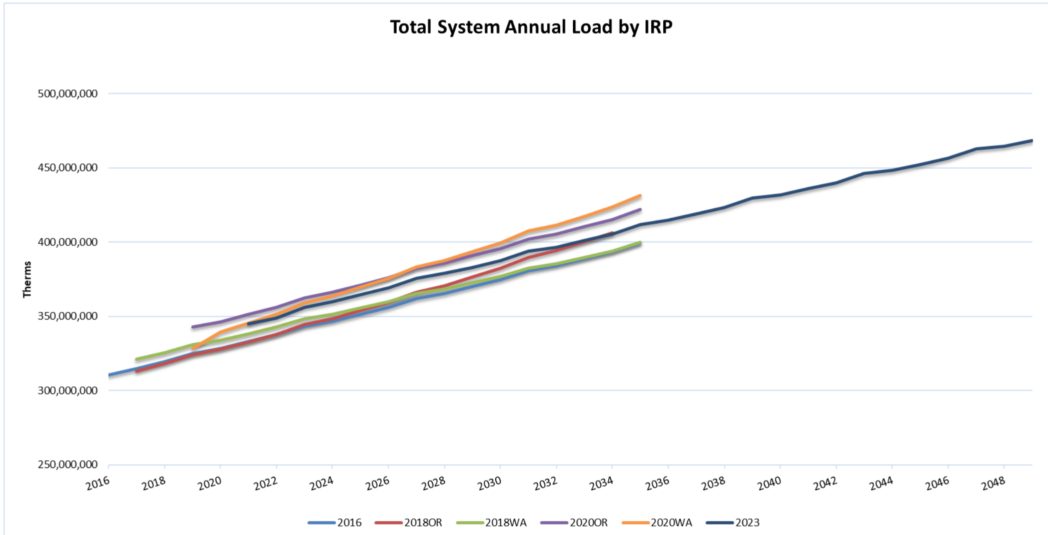
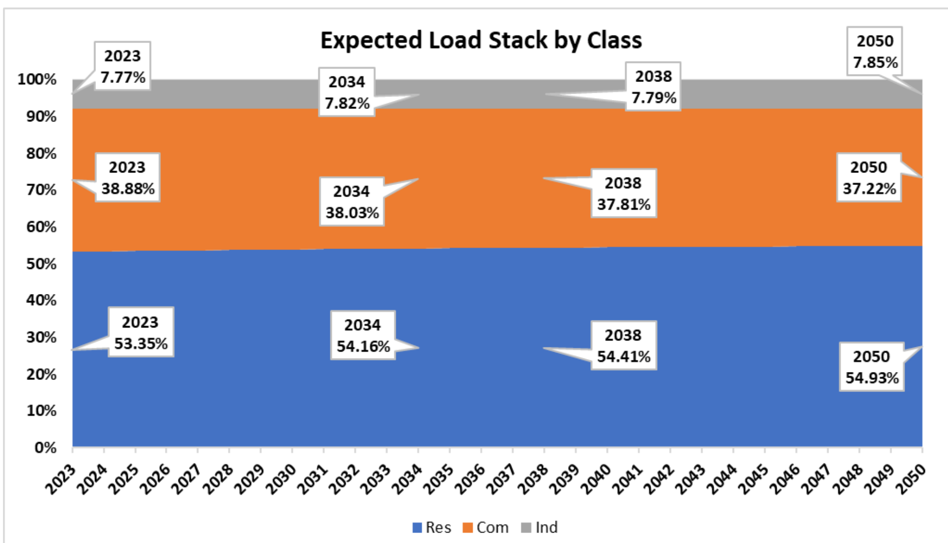
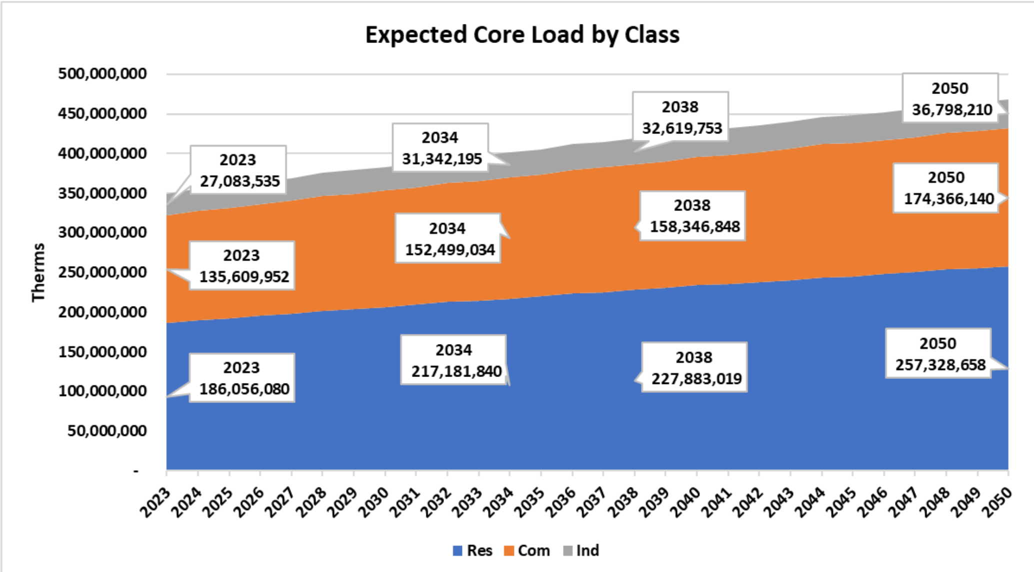


Figure 3-10: Expected Load Stack by Class



Cascade expects residential customers to increase load at an annual average growth of approximately 2.6 million therms and commercial core customers to increase load at an annual average growth of approximately 1.4 million therms over the 20-year planning horizon. Industrial customers are expected to increase load at an annual average growth of approximately 350,000 therms over the same period. Figure 3-11 displays the expected core load volumes by class.

Figure 3-11: Expected Load Growth by Class (Volumes in Therms)



Load growth is primarily a result of increased customer counts. The number of residential, commercial, and industrial customers is expected to increase at a slightly faster rate than therm usage. Figure 3-12 displays the expected customer counts by year and Figure 3-13 displays expected growth percentages by class.

Figure 3-12: Expected Customer Counts by Year

System	High	Base-Case	Low
2023	327,988	321,961	315,380
2030	393,099	364,076	334,873
2040	493,671	424,230	360,652
2050	602,450	484,386	384,533

WA	High	Base-Case	Low
2023	240,626	236,647	232,351
2030	283,937	264,754	245,475
2040	350,354	304,902	262,955
2050	421,696	345,032	279,239

OR	High	Base-Case	Low
2023	87,361	85,314	83,028
2030	109,162	99,322	89,398
2040	143,317	119,328	97,697
2050	180,754	139,354	105,293

Figure 3-13: Expected Customer Growth

System	High	Base-Case	Low
Residential	2.33%	1.56%	0.75%
Commercial	1.90%	1.28%	0.62%
Industrial	2.22%	1.47%	0.66%
Total	**2.28%**	**1.52%**	**0.74%**

WA	High	Base-Case	Low
Residential	2.12%	1.42%	0.69%
Commercial	1.95%	1.31%	0.64%
Industrial	1.87%	1.27%	0.58%
Total	**2.10%**	**1.41%**	**0.68%**

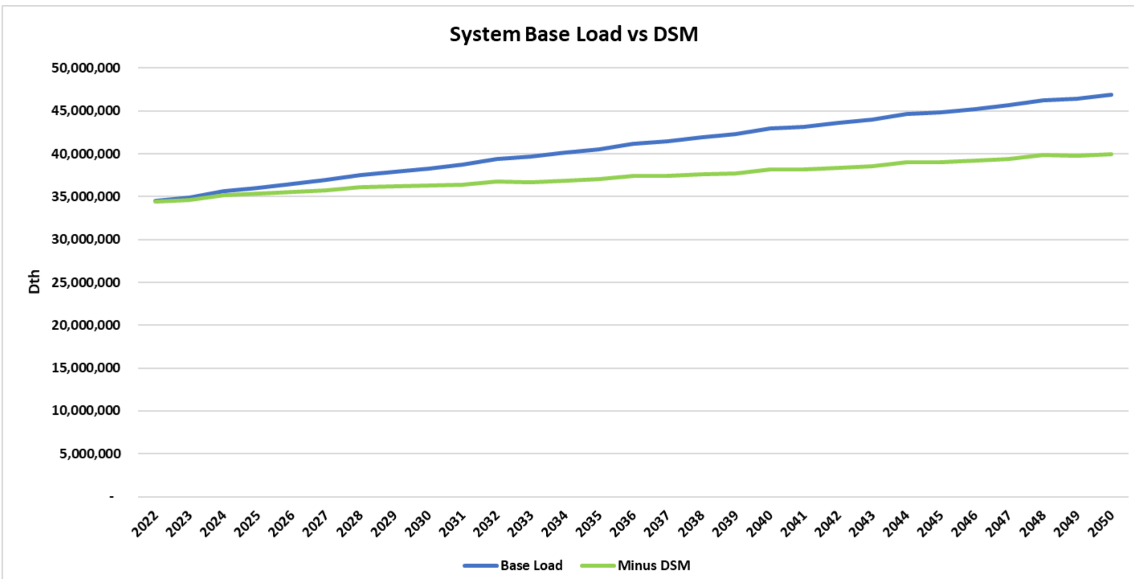
OR	High	Base-Case	Low
Residential	1.78%	1.19%	0.58%
Commercial	1.78%	1.19%	0.58%
Industrial	3.08%	2.02%	0.91%
Total	**2.73%**	**1.83%**	**0.88%**

System Load and Demand Side Management (DSM)

Demand Side Management (DSM) refers to the reduction of natural gas consumption through the installation of energy efficiency or through other load management programs such as demand response efforts that shift gas consumption to off-peak periods. For more details, please refer to Chapter 7, Demand Side Management.

Figure 3-14 displays total WA and OR DSM projected annual savings as it compares to Cascade's system load forecast.

Figure 3-14: System Base Load vs DSM



With DSM projections factored in, Cascade's anticipated system average annual growth rate drops from 1.10% to 0.54%. This represents an annual average DSM savings of 236,000 Dth, which when added cumulatively, has an important impact on overall system load.

Focusing on each individual state, Figures 3-15 and 3-16 display both OR and WA base load as it relates to projected DSM savings.

Figure 3-15 shows that with DSM projections factored in, Cascade's anticipated OR average annual growth rate drops from 1.43% to 0.86%. This represents an annual average DSM savings of 71,000 Dth, graphed as a cumulative number.

Figure 3-15: OR Base Load vs DSM

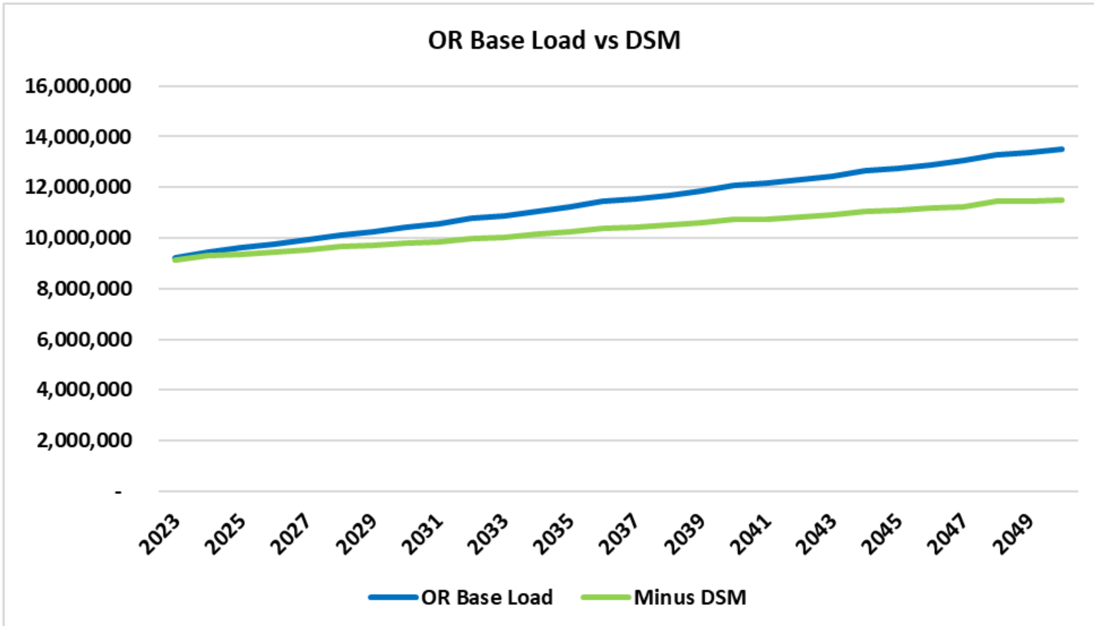
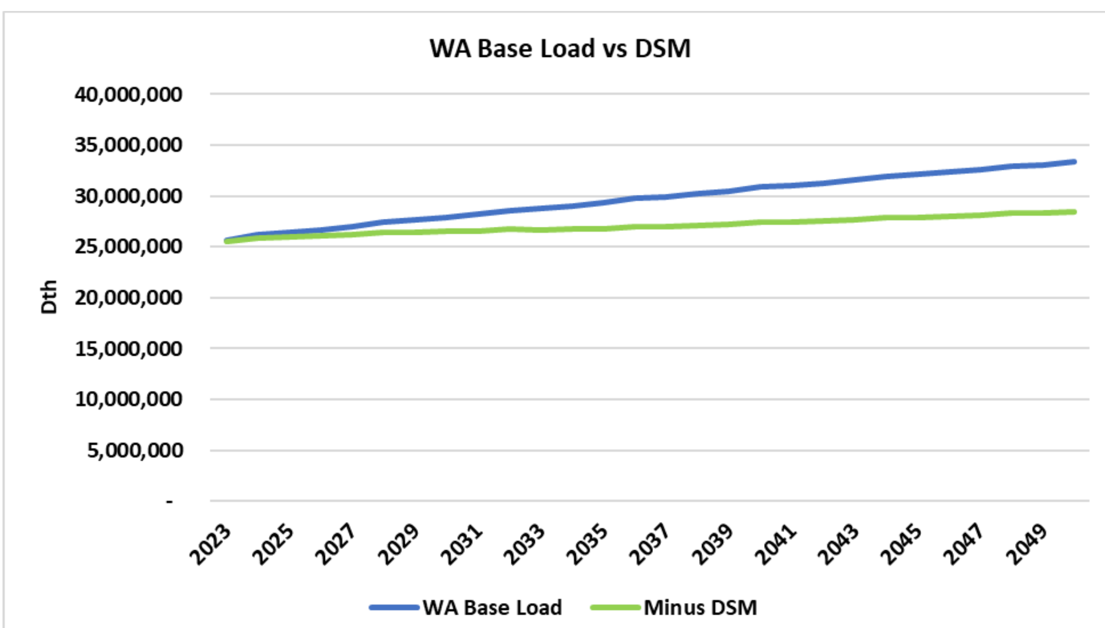


Figure 3-16 shows that with DSM projections factored in, Cascade's anticipated WA average annual growth rate drops from 0.98% to 0.41%. This represents an annual average DSM savings of approximately 168,000 Dth, graphed as a cumulative number.

Figure 3-16: WA Base Load vs DSM



Geography

Southeastern Washington and central Oregon are major drivers in Cascade's growth. These areas have multiple citygates serving counties with large increases in growth rates. Zone 20 contains the Kennewick Loop, a fast-growing area while Zone GTN contains the Bend loop, another fast growing area. Figure 13-17 shows the locations of the faster growing citygates on a map. Figure 3-18 shows the annual system load by each of Cascade's pipeline zones. Figure 3-19 shows the average annual percentage growth of load by each pipeline zone over the planning horizon. For a map of the pipeline zones, please refer to Figures 13-10 and 13-11. For a detailed list, Figure 3-1 gives information on each citygate's zone. Lastly, Figure 3-19 displays the expected system core peak day growth over the planning horizon. Peak day average annual growth is expected to be approximately 1.58%.

Figure 3-17: System 28-Year Load by Pipeline Zone (Volumes in Therms)

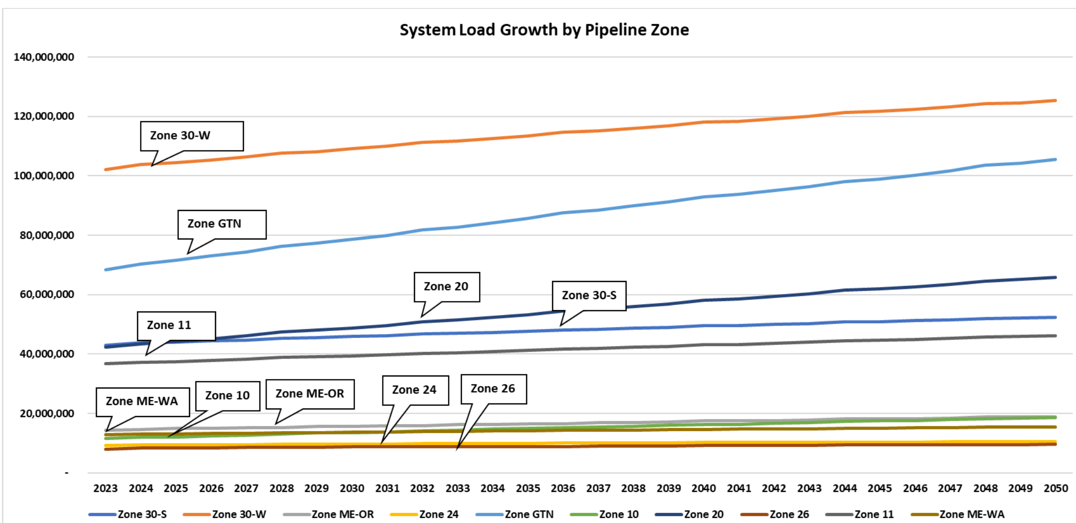
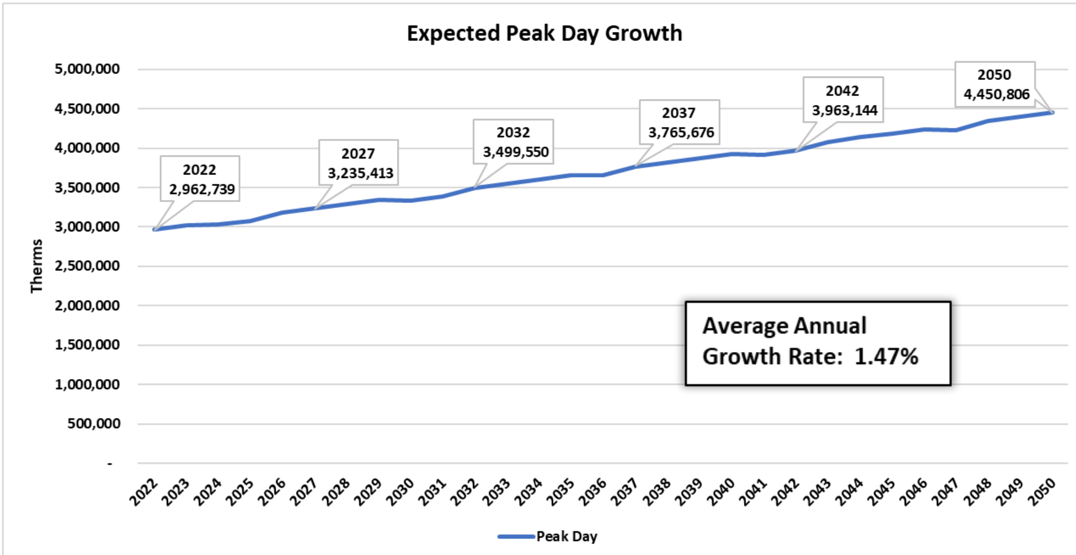


Figure 3-18: System 28-Year Average Load Growth by Pipeline Zone

Zone	Load Growth		Zone	Load Growth
Zone 10	1.79%		Zone 30-S	0.73%
Zone 11	0.86%		Zone 30-W	0.76%
Zone 20	1.65%		Zone GTN	1.62%
Zone 24	0.47%		Zone ME-OR	1.04%
Zone 26	0.71%		Zone ME-WA	0.67%

Figure 3-19: Expected System Peak Day Growth (Volumes in Therms)



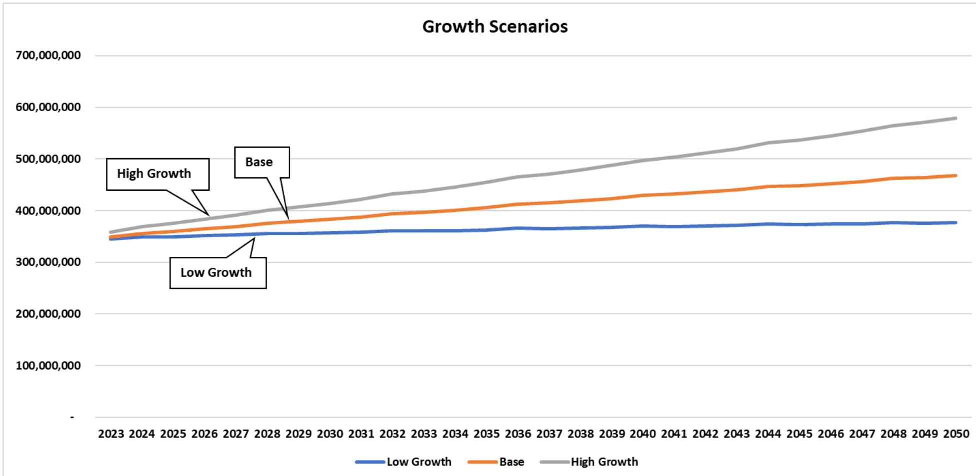
High and Low Growth Scenarios

In the previous IRP, the high and low growth scenarios were built from the confidence intervals of the customer growth forecast, which were approximately 5%. Cascade wanted a more robust scenario analysis and developed a methodology for better capturing realistic low growth and high growth scenarios. Cascade decided to analyze the slowest and fastest growth years of each citygate by comparing them to the average growth rate of each citygate. This gave a much more realistic idea of what a slow or rapid growth year might look like based on historical numbers. Cascade discovered that as a general rule, a slow growth year was about half the average growth rate whereas a fast growth year was about 1.5 times the average growth rate of a specific citygate. Figure 3-20 displays the total system load growth across the various growth scenarios.

More Scenarios

For more scenarios, including electrification, please refer to Chapter 9, Resource Integration. The section called “Portfolio Evaluation: Scenario Analyses” starts on page 9-25 and covers scenarios that vary supply, but have two scenarios (4 and 5) that vary customer growth.

Figure 3-20: Total System Load Growth Across Scenarios



Load growth under the low stochastic scenario is showing approximately 3 million less therms per year while load growth under the high stochastic scenario is showing approximately 3 million more therms per year than the stochastic All-in scenario. By analyzing historic slow growth and fast growth years, Cascade can assert with a high degree of certainty that these scenarios accurately encompass a potential range of load growth scenarios. Figure 3-21 shows the values for stochastic growth scenarios.

Figure 3-21: Stochastic Total System Load Growth Across Scenarios in Therms

Year	Low	Base	High
2023	345,673,078	348,749,568	358,789,712
2030	356,779,839	383,051,157	414,134,929
2040	369,855,291	429,497,908	497,686,804
2050	376,671,117	468,493,007	578,404,695

Non-Core Outlook

Unlike the core, non-core customers are customers who schedule and purchase their own gas, generally through a marketer, to get gas to the citygate. The customer then uses Cascade's distribution system to receive the gas. Forecasting non-core customers is different than forecasting core customers, as many of the non-core customers are not dependant on weather, but rather for their business use. Many non-core customers do not vary much from year to year, so Cascade utilizes previous years usage to forecast these customers future usage. For non-electric generation non-core customers, Cascade includes a 0.5% growth rate, which reflects the growth these customers have seen in recent history. For electric generation, the growth percentage is 1%. Cascade has approximately 244 non-core customers, with seven of those customers being electric generation customers. In both Washington and Oregon, the 2023 forecast for non-electric generation customers is approximately 518 million therms and that for electric generation customers is about 578 million therms for a total of 1.096 billion therms for the non-core customers. For information on the emissions for these customers, see Chapter 6 – Environmental Policy.

Cross-Validation

Cascade continues to evolve and improve its forecasting methodologies. For this IRP, Cascade performed model validation analysis, called cross-validation, in order to validate the assumptions going into the models as well as the results coming out. This process is time intensive, so Cascade selected two citygates to perform this analysis. There are many ways to cross-validate a forecasting model such as hold-out validation, k-fold validation, and bootstrap validation. Each technique has its benefits and disadvantages when it comes to strength of validation and computational time. [14] Cascade chose the hold-out method as it contains the best combination of having strong validation results with low computation time in reference to the other methodologies. The steps of the hold-out method involve selecting a specific citygate and rate class, limiting the historical data, developing a model using the same methodology as the original model, and then comparing the forecasted results to actual data. This is called out-of-sample testing. Cascade chose one of its more volatile citygates, Sumas SPE Loop, and one of its more stable citygates, Yakima Loop, in order to maximize the value of the cross-validation results by using both ends of the usage spectrum. Figure 3-22 shows the breakdown between the in-sample and out-of-sample parts. Figures 3-23 through 3-25 show the Sumas SPE Loop residential, commercial, and industrial rate classes. Figures 3-26 through 3-28 show the Yakima Loop residential, commercial, and industrial rate classes. The figures show both these citygates' ThoughtSpot data (billing data) compared to a forecast of a model made from Jan, 2015 – March, 2022. The out-of-sample range is April, 2022 to August, 2022.

[14] https://www.turing.com/kb/different-types-of-cross-validations-in-machine-learning-and-their-explanations

Figure 3-22: Sumas SPE Loop Cross-Validation

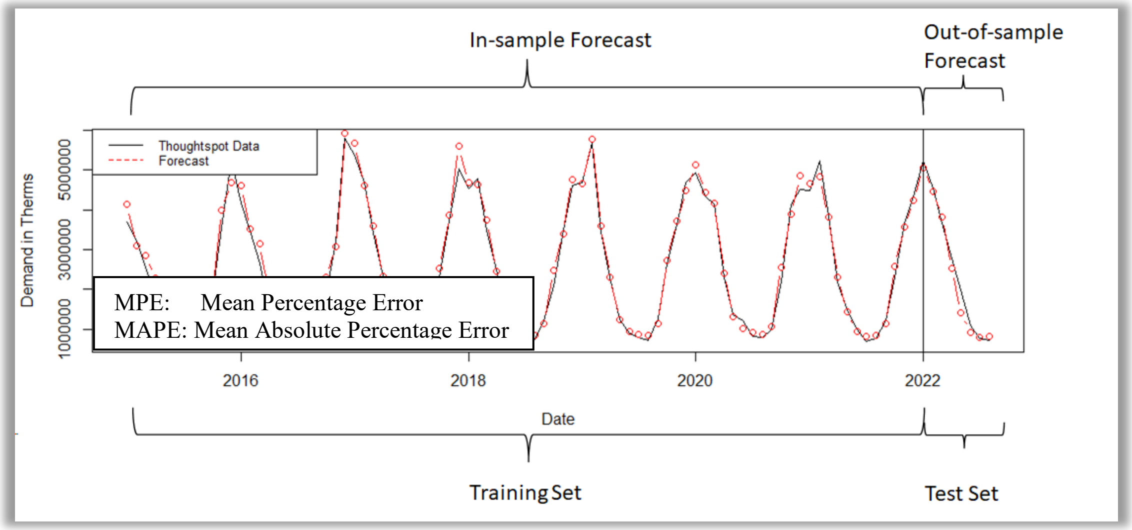


Figure 3-23: Sumas SPE Loop Residential Cross-Validation

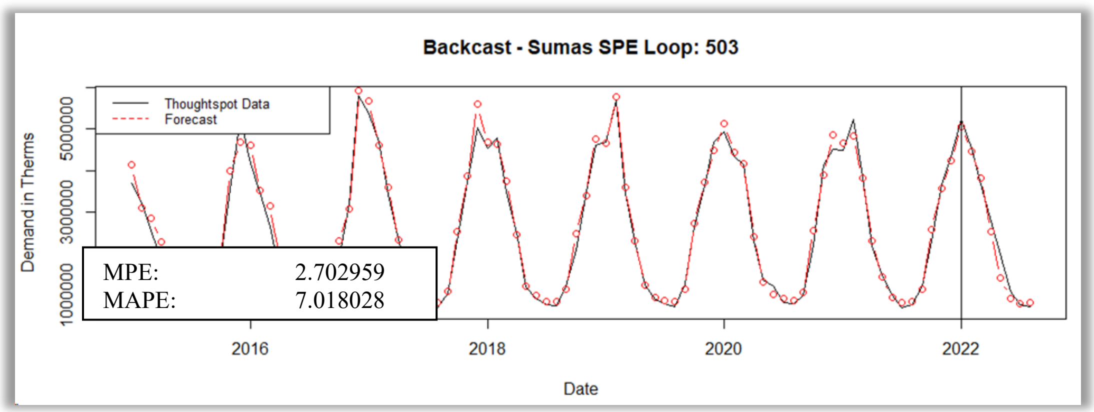


Figure 3-24: Sumas SPE Loop Commercial Cross-Validation

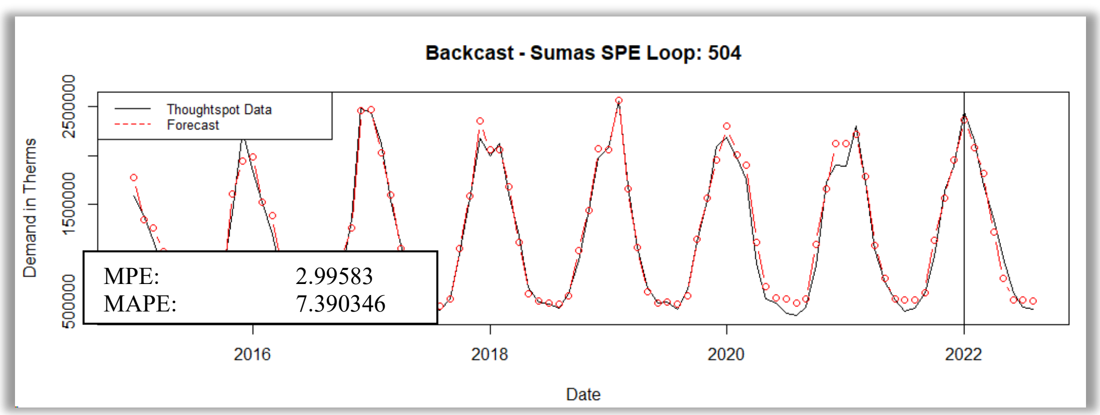


Figure 3-25: Sumas SPE Loop Industrial Cross-Validation

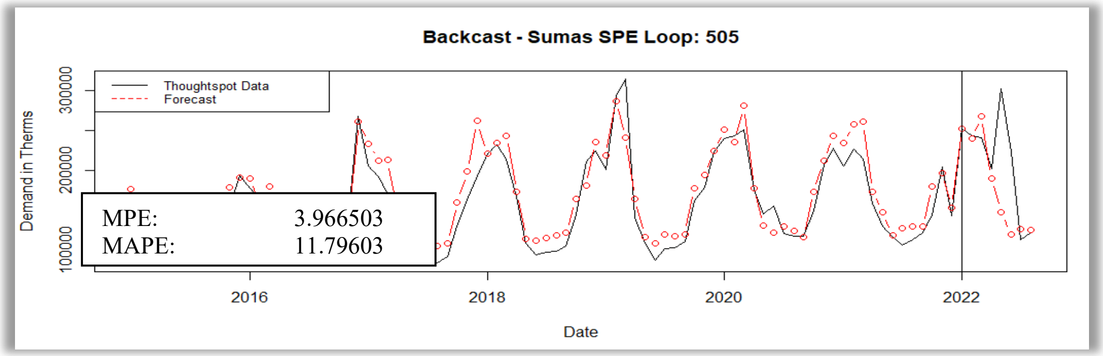


Figure 3-26: Yakima Loop Residential Cross-Validation

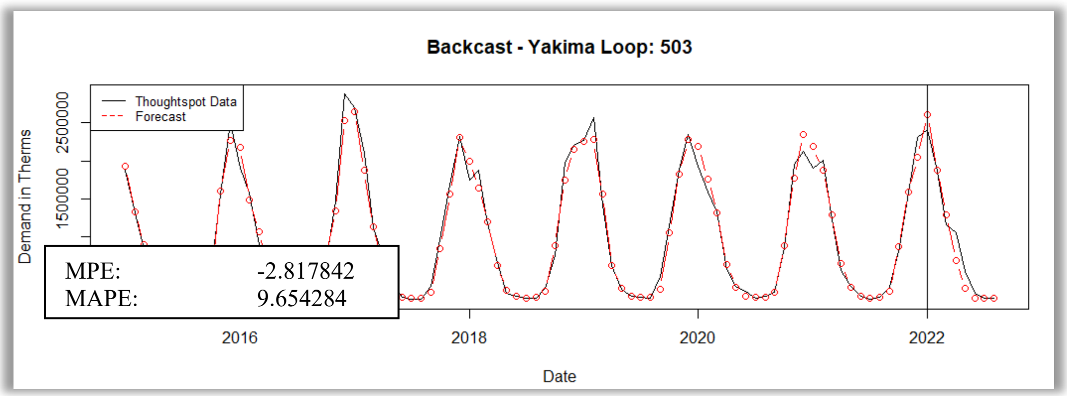


Figure 3-27: Yakima Loop Commercial Cross-Validation

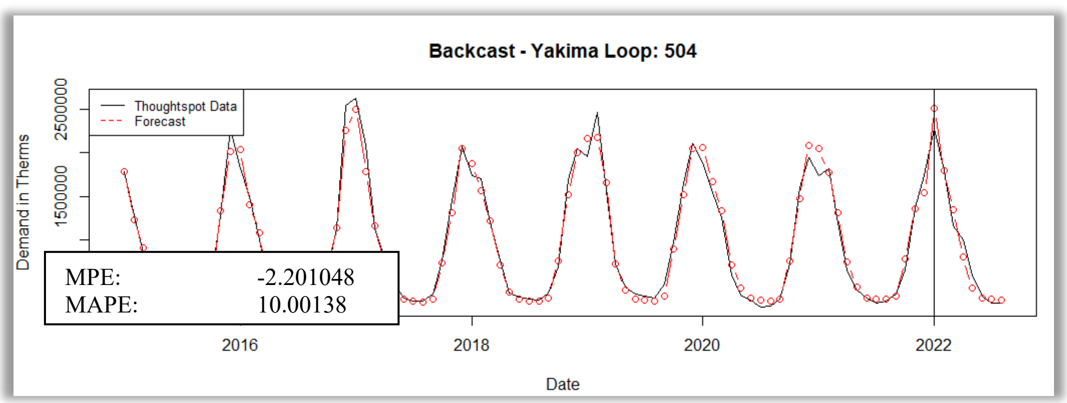
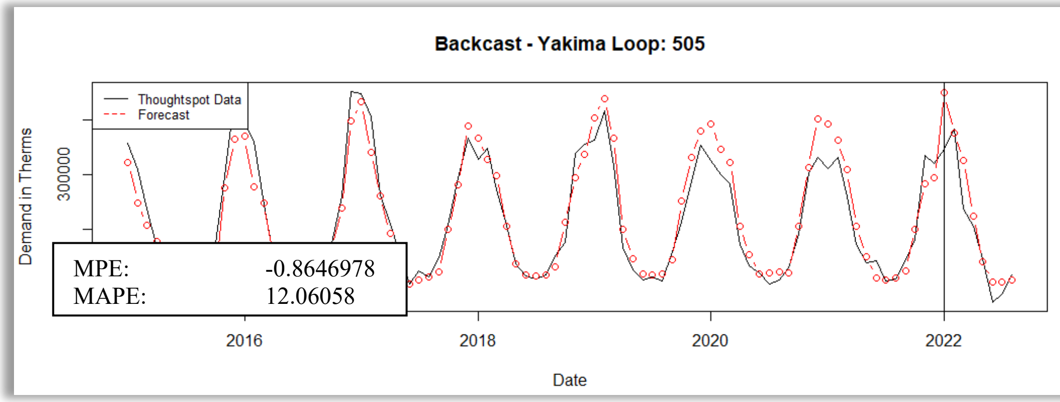


Figure 3-28: Yakima Loop Industrial Cross-Validation

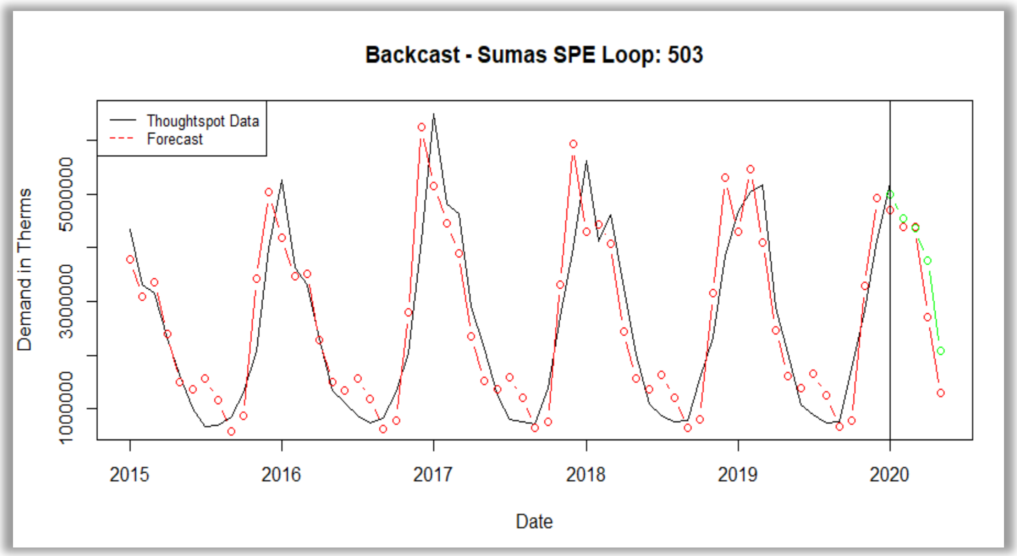


In the previous IRP, Cascade's cross-validation results showed a need to lag the Thoughtspot billing data in order to better correlate with pipeline data. The above figures show that this change in the forecast methodology increased the forecast accuracy significantly. The next section, Methodology Changes, provides more information about this change. For the next IRP, Cascade will investigate more ways to better forecast the industrial rate class and will investigate ways to make this process more efficient in order to validate more models, more often.

Methodology Changes From Previous IRPs

As mentioned in the cross-validation section, Cascade made a shift to the Thoughtspot billing data before beginning the demand forecast. Figure 3-29 shows the cross-validation results for one of Cascade's citygates from the last IRP.

Figure 3-29: Sumas SPE Loop Residential Cross-Validation



This identified that the forecast was consistently one month behind the actual pipeline flow data. After further examining the customer billing data, Cascade discovered customers on specific billing cycles should be shifted back one month to better account for the discrepancy between some billing receivables and pipeline data. After this shift, the forecasts' accuracies were vastly improved.

Another methodology change is Cascade captured price sensitivity in its use-per-customer forecast for this IRP by introducing price as a regressor (as described earlier in this chapter in the section labeled "Price as a New Regressor").

Alternative Forecasting Methodologies

Cascade's forecasting methodologies used in the customer forecast and the UPC forecast have remained consistent. Cascade continues to utilize Fourier terms and ARIMA terms in its forecasting methods. Cascade utilizes R as its primary statistical analysis software and uses models that follow a dynamic regression methodology. The Company plans to continue improving the customer and demand forecast model through R to enhance the process' efficiency.

The Company is responsive to several regulatory principles in forecasting. These include:

- A desire for precision and a high degree of accuracy;
- A universal understanding that forecasts should mirror future realities but may have unanticipated swings in either direction;
- A disconnect between planning and operational functions, in that natural gas purchasing and dispatch will be based on immediate needs which, in actuality, are guaranteed to vary from the plan (per the previous bullet);
- An understanding that an increased cost of improved precision sometimes has decreasing customer benefits;
- A need to meet regulators' expectation that the Company show continual improvement because new tools are available. For example, the concept of "adaptive management" can be applied;
- The major differences in accounting treatment between the states regarding test years for ratemaking purposes (that is, for general rate case filings) and not necessarily for planning. At this time, Oregon uses future test year accounting while Washington employs a historic test year;
- The fuzziness of historic data that includes effects of energy efficiency, retail price (from annual PGA—purchased gas adjustment—changes and other rate changes), sometimes abnormal weather, new technology, and then-unique economic conditions (e.g., recession, interest rates, etc.). Cascade uses actual historic data. The term fuzziness is used in the context of basing forecasts on past-period data that includes many variables, any one of which may have increased or decreased in the intervening time between historical occurrence and forecasted periods. This causes difficulty for utilities trying to isolate primary factors for greater precision of long-term calculations.
- Unknown and uncertain future changes such as the assumptions around carbon policy and other environmental externalities; and
- A need to demonstrate support for assumptions such as growth in customers, use per customer and changes from previous forecasts, type of use (i.e., heating, manufacturing, etc.), to name a few.

The preceding subchapter illustrates the complexity of forecasting and highlights areas of stakeholder attention. Best efforts at appropriate reasonable cost distill these factors into a generally accepted forecast with recognition of inherent uncertainties.

Uncertainties

This forecast represents Cascade's best estimate about future events. At this time, several important factors make predicting future demand particularly difficult such as – continued economic growth, carbon legislation, building code changes, direct use of natural gas campaigns, energy efficiency, and long-term weather patterns.

The range of scenarios presented here and in Chapter 10 encompass the full range of possibilities through econometric analysis. These forecasts were created after statistical analyses of a matrix of different functional forms and economic indicators. The chosen indicators were selected because of their consistency in returning statistically valid results. While they may be the best results mathematically, they are not the sole and only determinants of demand. As a result, while Cascade believes the numbers presented here are accurate and that the scenarios presented represent the full range of possibilities, there are and always will be uncertainties in forecasting future periods.

Conclusion

Cascade expects system load growth to average 1.10% per year over the 28-year planning horizon. High and low scenarios were considered and alternative forecasting assumptions were analyzed. Extensive modeling included: extending the forecast analyses of demand areas, HDDs, and wind from 20 years to 28 years to better align with emissions modeling; analyzing peak day stochastically using 10,000 Monte Carlo simulated draws for each weather zone; adding a price regressor to the Use-Per-Customer forecast and utilizing dynamic regression modeling techniques for customer and annual demand forecasts.

Chapter 4

Supply Side Resources

Overview

Cascade's core market residential and small volume commercial and industrial customers expect and require the highest reliability of energy service. Because of the Company's obligation to provide gas service to these customers, Cascade must determine and achieve the needed degree of service reliability and attain it at the most reasonable lowest cost and least risk possible while maintaining infrastructure that is sufficient for customer growth. Assuming such infrastructure is operating effectively, the most important functions necessary for reliable natural gas service are planning for, providing, and administering the gas supply, interstate pipeline transportation capacity, and distribution service purchased by core market customers.

This chapter describes the various gas supply resources, renewable natural gas (RNG), storage delivery services from Jackson Prairie underground storage and Plymouth liquified natural gas (LNG) service, and transportation resource options available to the Company as supply side resources.

Key Points

- To meet the Company's core market demand, Cascade accesses firm gas supplies and short-term gas supplies purchased on the open market, in addition to utilizing storage.
- Cascade purchases gas from the Rockies, British Columbia (Sumas), and Alberta (AECO). Gas is transported to the Company's system via pipelines by either bundled or unbundled contracts.
- Cascade is currently in the process of procuring Renewable Natural Gas and Renewable Thermal Credits.
- The long-term planning price forecast is based on a blend of futures market pricing along with long-term fundamental price forecasts from multiple sources.
- The Company identifies potential incremental supply resources for the 2023 IRP.
- Risk management policies are implemented to promote price stability.
- Cascade's Gas Supply Oversight Committee (GSOC) oversees the Company's gas supply purchasing strategy.
- Modeling of Cascade's available resources results in the lowest reasonably priced optimum portfolio.

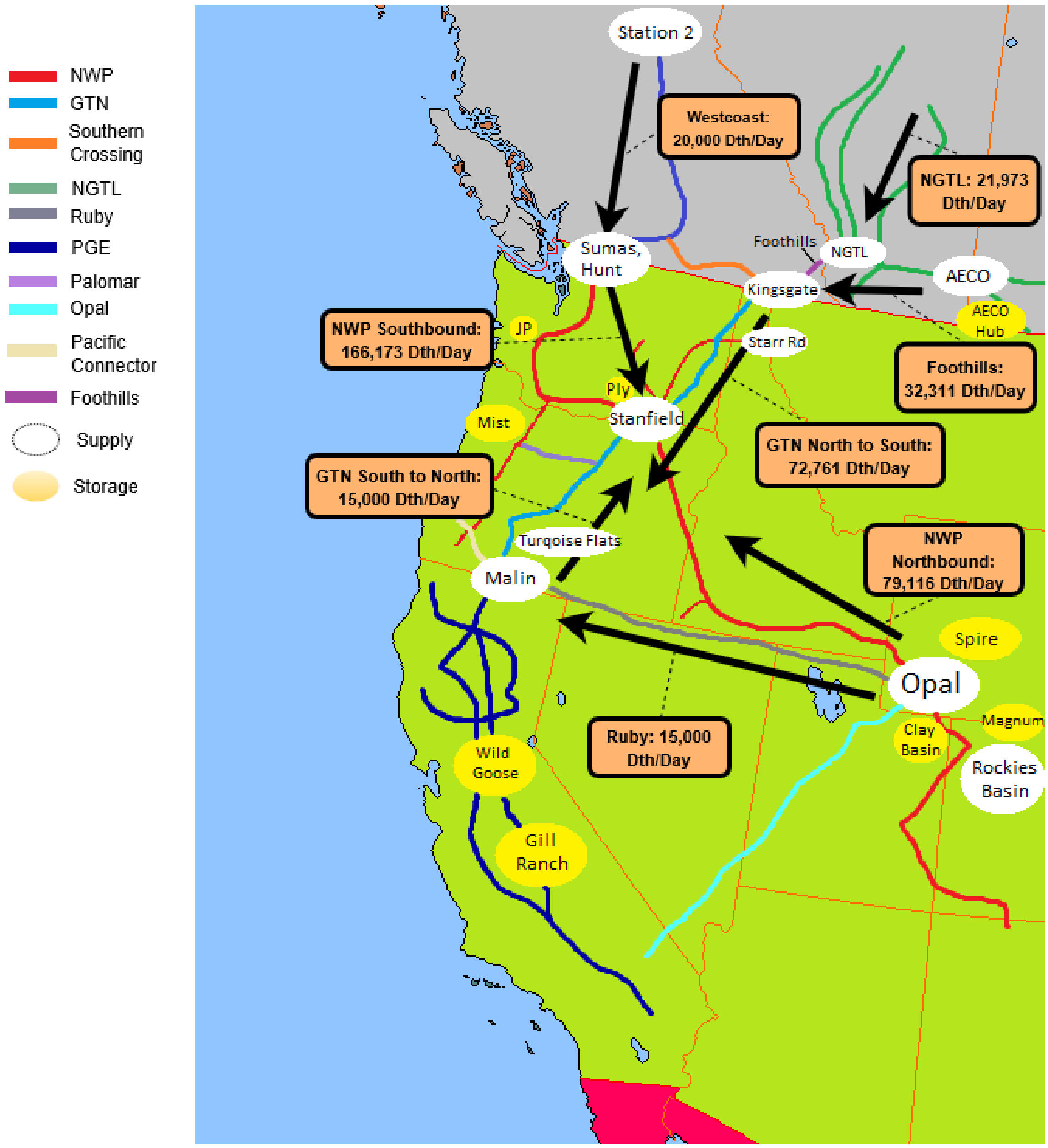
Gas Supply Resources

Gas supply options available to Cascade to meet the core market demand requirements generally fall into two groups: 1) Firm gas supplies on a short- or long-term basis, and 2) Short-term gas supplies purchased on the open market as needed in a particular month for one or more days. A third option, renewable natural gas, is emerging.[1] A separate and important source of gas supply is natural gas storage service, which is required to provide economical service to low load factor customers during seasonal and other high demand periods.

[1] In Cascade's last IRP, renewable natural gas was addressed in the Renewable Natural Gas chapter but is now included in this chapter.

Cascade's gas supply portfolio is sourced from three basic areas of North America: British Columbia, Alberta, and the Rockies. Figure 4-1 provides a general overview of regional gas flows to Cascade's distribution system.[2]

Figure 4-1: Regional Map Showing General Flow Paths for System Gas Supplies



[2] This map does not reflect three contracts Cascade anticipates acquiring November 1st, 2023: GTN North to South of 20,000 dth/day, 20,000 dth/day on NGTL, and 10,000 dth/day on Foothills.

Firm Traditional Supply Contracts

Firm supply contracts commit both the seller and the buyer to deliver and take gas on a firm basis, except during *force majeure* conditions. From Cascade's perspective, the most important consideration is the seller's contractual commitment to make gas available day in and day out regardless of market conditions. Firm supplies are a necessary component of Cascade's core market portfolio given its obligation to serve and the lack of easily obtainable alternatives for customers during periods of peak demand. Firm supply contracts can provide base load services, seasonal load increases during winter months, or they can be used to meet daily peaking requirements. Quantities vary, depending on the need and length of the contract. Operational considerations regarding available upstream pipeline transportation capacity and any known constraints must also be considered. Base load contracts can range from as small as 500 dths/day to quantities in excess of 10,000 dths/day. Blocks of 1,000, 2,500, 5,000 and 10,000 dths/day are standard as these are the most operationally and financially viable blocks for suppliers.

Base load supply resources are those that are typically taken day in and day out, usually 365 days a year. As a result, base load gas tends to be the least expensive of the firm supply contracts because it matches the production of gas and guarantees the producer that the volumes will be taken. The Company's ability to contract for base load supplies is limited because of the relatively low summer demand on Cascade's system. Base load resources are used to meet the non-weather sensitive portion of the core market requirements or may be used to refill storage reservoirs during periods of lower demand.

Winter gas supplies are firm gas supplies that are purchased for a short period during the winter months to cover increased loads, primarily for space heating. The contracts are typically three to five months in duration (primarily November through March). This enables the Company to ensure firm winter supplies without incurring obligations for high levels of supply contracts during periods of low demand in the summer months. Winter supplies combined with base load supplies are adequate to cover the moderately cold days in winter.

Supply contract terms for firm commodity supplies vary greatly. Some contracts specify fixed prices, while others are based on indices that float from month to month. Most contain penalty provisions for failure to take the minimum supply identified in the North American Energy Standards Board (NAESB) contract terms. Contract details will also vary for each individual supplier's needs and the NAESB contract special addendums.

Gas that is purchased for a short period of time (one to thirty days) when neither the seller nor the buyer has a longer-term firm commitment to deliver or take the gas is referred to as a spot market purchase. Spot market supplies differ from firm resources in that they are more volatile, both in terms of availability and price, and are largely influenced by the laws of supply and demand.

In general, spot market supplies (also called day gas) are provided from gas supplies not under any long-term firm contract. Therefore, as firm market demand decreases, more gas becomes available for the spot market. Prices for spot market supplies are market driven and may be either lower or higher than prices under firm supply contracts. In warmer weather, as firm market demand requirements decrease, usually more gas becomes available for the spot market, resulting in lower prices. In colder weather, as firm markets demand their gas supplies, the remaining spot market supplies can carry higher prices.

The role for spot market gas supply in the core market portfolio is based on economics. Spot market supplies may be used to supplement firm contracts during periods of high demand or to displace other volumes when it is cost effective to do so. Depending upon availability and price, spot market volumes may be used in place of storage withdrawal volumes to meet firm requirements on a given day or for mid-heating season refills of storage inventory during periods of moderate weather.

While Figure 4-1 provides a general overview of regional gas flows to Cascade's distribution system, supporting detail is included in Appendix E.

Renewable Natural Gas

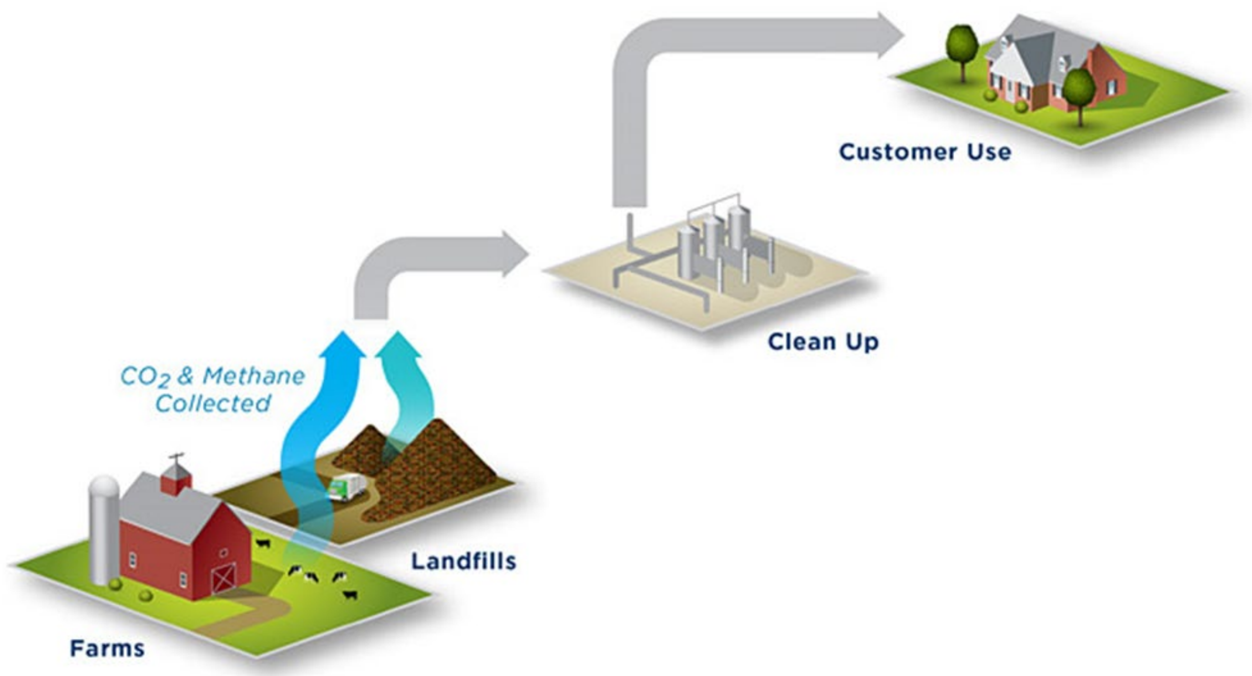
Renewable natural gas (RNG) is an emerging supply option that brings many benefits, chief among them emissions reduction. Since submitting its last IRP, Cascade has made significant strides in analyzing, planning, and acquiring RNG. In this section and elsewhere in this IRP, issues unique to RNG are found in the inset box to the right.

RNG, as defined in RCW 54.04.190,[3] is a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters. Cascade is committed to developing programs that allow the Company to acquire RNG under guidelines and rules stated in Washington HB 1257 and Oregon SB 98.

[3] *See* https://app.leg.wa.gov/rcw/default.aspx?cite=54.04.190

Figure 4-2,[4] provides an example of a general RNG process from landfill to end-user.

Figure 4-2: Example of RNG process from landfill to end user



Renewable natural gas, biomethane and biogas are sometimes used interchangeably but they are different biofuel products along the value chain:

- Biogas is a mixture of carbon dioxide and hydrocarbons, primarily methane gas, from the biological decomposition of organic materials.
- Biomethane is a biogas-derived, high BTU gas that is predominately methane after the biogas is upgraded to remove contaminants.
- Renewable natural gas is biomethane upgraded to natural gas pipeline-quality standards so it can substitute or blend with conventional natural gas.[5]

Examples of RNG sources include:

- Biogas from Landfills
  - Collect waste from residential, industrial, and commercial entities.
  - Digestion process takes place in the ground, rather than in a digester.
- Biogas from Livestock Operations
  - Collects animal manure and delivers to anaerobic digester.
- Biogas from Wastewater Treatment

[4] U.S. Department of Energy, Alternative Fuels Data Center, Renewable Natural Gas
[5] American Natural Gas.com

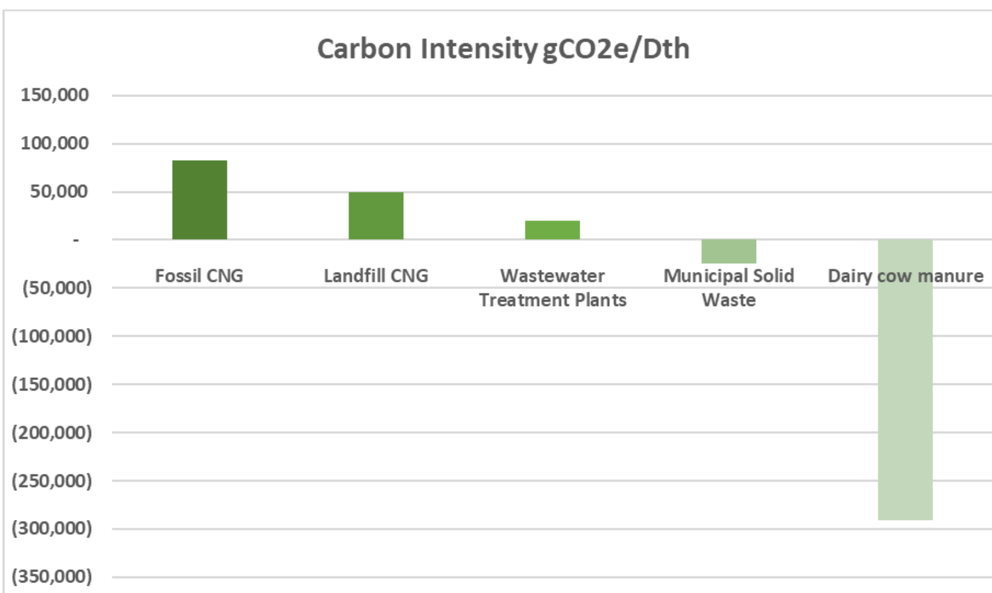
  - Produced during digestion of solids that are removed during the wastewater treatment process.
- Other sources include organic waste from food manufacturers and wholesalers, supermarkets, restaurants, hospitals, and more.[6]

Biofuel estimates vary, for example, E3 estimates 25 million dry tons of biomass supply available to Washington and Oregon, compared to Washington State's deep decarbonization study which assumed 23.8 million dry tons available to the state.[7]

Carbon Intensity

One of the major driving forces behind investment in RNG is the potential to mitigate the carbon footprint of the natural gas industry. For some types of projects such as compressed natural gas (CNG) from landfills, this means RNG is the utilization of a resource that still emits carbon into the environment, but at a lower intensity. For others like gas from solid waste and dairy cow manure, this means preventing the escape of gas with such high carbon intensity that the net impact to the environment by redirecting this gas to end-users would be positive. Figure 4-3 highlights the different impact of five different types of natural gas[8].

Figure 4-3: Carbon Intensity of Natural Gas by Source



[6] U.S. Department of Energy, Alternative Fuels Data Center, Renewable Natural Gas.
[7] Energy + Environmental Economics, Pacific NW Pathways to 2050: Achieving an 80% reduction in economy-wide greenhouse gases by 2050.
[8] https://ww2.arb.ca.gov/sites/default/files/classic//research/apr/past/13-307.pdf

According to the Climate Protection Program and the Climate Commitment Act, all RNG is treated equally when determining the CO_2e offset to traditional natural gas. However, in the LCFS program, Carbon Intensity is used to determine the offset to CO_2e, which make dairy projects much more attractive in California.

Applicable Regulations

On January 14, 2019, SB 98 was introduced in Oregon legislation. SB 98 requires the Oregon Public Utility Commission (OPUC) to adopt by rule renewable natural gas program for natural gas utilities to recover prudently incurred qualified investments in meeting certain targets for including renewable natural gas in gas purchases for distribution to retail natural gas customers. On June 23, 2019, SB 98 was signed into law effective September 29, 2019.

On August 27, 2019, the OPUC initiated docket UM 2030, an investigation into the use of Northwest Natural's RNG evaluation methodology. The Company is an active participant in UM 2030. Cascade has developed its own potential Cost Effectiveness Evaluation Methodology which can be seen in the next subsection.

On October 1, 2019, the OPUC Staff initiated docket AR 632, in the matter of rulemaking regarding the 2019 SB 98 RNG programs. Cascade has participated in multiple meetings regarding this docket. On February 20, 2020, the OPUC provided informal draft rules for the docket. On April 28, 2020, the OPUC held a hearing to discuss formal comments to the rules in AR 632. On July 16, 2020, OPUC adopted the initial rules to implement 2019 SB 98.

Below, Cascade lists key portions of the preliminary rule followed by the Company's compliance:

(1) According to rule 860-150-100 of AR 632, each large natural gas utility and small natural gas utility must, as part of an integrated resource plan (IRP) filed after August 1, 2020, include information relevant to the RNG market, prices, technology, and availability that would otherwise be required under the Commission's IRP guidelines, by order of the Commission, or by administrative rules.

Cascade has provided information relative to the RNG market, prices, technology, and availability throughout this IRP narrative.

(3) In addition to the information required under section (1), each small natural gas utility must also include in its IRP:

(a) An indication whether and when the utility expects to make a filing with the Commission, pursuant to OAR 860-150-0400, of its intent to begin participating in the RNG program described in these rules, if the utility has not already started to participate in the RNG program;

Cascade is currently preparing the petition to be filed with OPUC around the time of the filing of the 2023 IRP.

(b) Information about opportunities, challenges, perceived barriers, and the natural gas utility's strategy for participation in the RNG program described in these rules; and

The Company has met with several individuals and companies within the RNG industry such as producers, municipalities, wastewater treatment plants, biodigesters, and landfills. During these conversations, Cascade has gathered market intelligence around RNG. Some of the Company's findings include:

- Options for securing RNG will involve purchase and/or participation in infrastructure.
- No "spot market" for RNG at this point due to long off-take commitments.
- Lead times on new RNG projects up to 36 months.
- Landfill projects are typically the largest RNG opportunity at 300-600 dth/day and usually require lowest capital investment.
- Dairy projects, due to higher carbon intensity, do very well in the Renewable Identification Numbers (RINs) market and run 50-500 dth/day (expensive to operate).
- Food waste/Industrial wastewater treatment projects are seen as an ideal option for utilities as they have low RINs and Low Carbon Fuel Standards (LCFS) potential and can typically be online within 24 months of contracting. Municipal & County wastewater treatment plants can also be good utility partnerships although lead times can be substantially longer.
- $13-$30/dth long-term off-take deals.

Specific near-term opportunities are provided later in this chapter.

(c) The cost effectiveness calculation that the utility will use, pursuant to OAR 860-150-0200, to evaluate RNG resources, if the utility has not already filed this with the Commission pursuant to OAR 860-150-0400.

Cascade's cost effectiveness calculation is described in the following section.

Cascade Project Cost Effectiveness Evaluation Methodology

Several departments within the Company have collaborated to create a model that allows Cascade to evaluate the cost-effectiveness of all potential RNG projects before entering into an agreement with potential suppliers. Similar to the Company's PLEXOS® modeling, the results of this calculation help inform final acquisition decisions, but ultimately must be combined with qualitative analysis from RNG subject matter experts. This subsection will present the model notes, a discussion of the static and dynamic inputs to the model and provide an understanding of how the results should be interpreted.

Cost Effectiveness Evaluation Model Notes

$$\boldsymbol{C_{RNG} = I_{RNG} - AC_U - AC_D + \sum_{T=1}^{365} (P_{RNG} + VC - CIF) * Q}$$

$$\boldsymbol{C_{Conventional} = \sum_{T=1}^{365} (P_{Conventional} + VC) * Q}$$

Where:

C_{RNG} = The all-inclusive annual cost of a proposed RNG project
I_{RNG} = The annual required investment to procure a proposed RNG resource. If Cascade is simply buying the gas and/or environmental attributes, this value is zero.
AC_U = Avoided upstream costs
AC_D = Avoided distribution system costs
P_{RNG} = Daily price of renewable natural gas being evaluated
Q = Daily quantity of gas being evaluated
VC = Variable cost to move one dekatherm of gas to Cascade's distribution system. This value can be zero if a project connects directly to the Company's system.
CIF = Carbon Intensity Factor. This is calculated by multiplying the Company's expected carbon compliance cost by 1 minus the ratio of a proposed project's carbon intensity to conventional gas' carbon intensity. For the purpose of compliance with the CCA and CPP, the CIP factor is just Cascade's expected carbon compliance cost in the various jurisdictions, as these rules do not account for the variable carbon intensities of various sources of RNG.
$C_{Conventional}$ = The all-inclusive annual cost of conventional natural gas.
If $C_{Conventional} \geq C_{RNG}$, a project can be considered cost effective, and should be acquired. If not, the project may still be considered under the regulatory exceptions discussed earlier in this chapter.

Static Versus Dynamic Inputs

Inputs to Cascade's model can be classified as either static or dynamic. Static inputs are ones that are not project specific, but rather related to the Company's system as a whole. They include Cascade's avoided costs, costs associated with the price of conventional gas, and regulatory factors that are used to calculate the impact to revenue requirement. Dynamic inputs on the other hand, are ones that need to be updated on a project by project basis. These include the price and quantity of the RNG, initial investment required, and carbon intensity of the project.

Purchase Versus Build

Cascade utilizes different proprietary models based on whether the Company is evaluating the purchase of RNG or the building and ownership of an RNG generating facility. While philosophically the same, the models are calibrated to account for slight differences in the various decision-making processes. The build decision model allows for more detailed inputs and evaluation of overhead variables related to ownership, such as tax impacts of ownership and depreciation of assets. The purchase model, on the other hand, allows for analysis of variable purchase structures, where Cascade may only purchase a fraction of the RNG quantity that will ultimately be flowed from an RNG deal, which also allows the model to consider revenue that the Company would earn from transportation agreements related to the volumes of RNG that Cascade would not own, but would still flow on its system.

Based on results from Chapter 9, Resource Integration, Cascade states a need for RTCs/RNG/etc to meet environmental compliance needs, specifically under the CPP. The Company's model is used to compare the market value and revenue requirement per dekatherm per year for a project vs. other alternatives. Cascade does not have enough on system projects to provide the volumes needed for compliance, so acquiring RTCs/RNG/etc with off system contracts is necessary. Cascade compares the market value and revenue requirement per dekatherm per year of potential on system projects to off system contract opportunities via a model. If the on-system projects project favorably vs. off system opportunities based on the model results, the Company will consider other risks and factors:

- There is more risk with the assumptions made for on system projects vs. off system projects, specifically with estimates for the cost of capital investment, RNG production volume, timing for start of production. The values Cascade uses for these are estimates, and the actual costs, volumes, and timing could have variances. With off system contracts these values are more certain.

- On system projects may be viewed as more favorable than off system projects because the RNG environmental attributes as well as the molecules can be purchased as a bundle, and the RNG is injected directly into the Company's system and consumed by Cascade's customers.

- In Cascade's opinion, the pros and cons of on system projects vs. off system projects offset and Cascade considers any on system project that has a favorable market value and revenue requirement per dekatherm per year vs. known off system opportunities to be attractive because it will reduce the need to purchase RTCs/RNG/etc via more expensive means.

- Cascade's RNG Cost-Effectiveness model currently accounts for timing risks by recognizing the value of certainty in longer term deals versus uncertainty. The model evaluates costs in real dollars, so any opportunity to amortize investments over a longer period of time is valued appropriately in the model. Additionally, alternative costs for carbon compliance such as CCIs will increase over time, allowing the model to favorably evaluate a project that contains fixed prices for the environmental attributes associated with RNG. If a deal being considered is not a fixed price deal, the model will evaluate how any escalating factors compare to increases in cost for alternative compliance costs.

- One additional risk that will be important as the Company continues to evaluate build versus purchase decisions will be the uncertainty around investment costs for build projects. Since Cascade does not have data regarding the variance of potential build costs this variable is currently being evaluated deterministically, but the Company looks forward to being able to perform stochastic analyses around these costs to mitigate risk to ratepayers in future IRPs.

Model Results

Once all inputs are populated, the model provides three main pieces of information: The potential enterprise value of the project over its lifetime, the first year dollar impact to revenue requirement, and the first year percentage impact to revenue requirement. As discussed in the model notes, if the cost of conventional gas is greater than or equal to the cost of

RNG, the project can be considered cost effective. If not, the impact to revenue requirement provides a valuable insight as to whether the project is attractive from a regulatory perspective.

RNG Projects

Cascade is currently progressing with twenty-one on-system RNG projects at varying stages of development. Ten of these projects are what Cascade refers 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. These types of RNG projects are Cascade's highest RNG priority.

Currently, Transport Projects only occur where Cascade cannot cost effectively purchase the environmental attributes or where the nature of the projects financial development involves prior commitment of the attributes. One example of this is dairy projects where the current attribute values can be $60-$83/MMBtu because of the value it provides in the LCFS market. Some Transport Projects also come to Cascade with the attributes pre-sold as a part of the financing package to fund the facility. In these cases, if Cascade is capable of on-boarding the RNG, a business decision can be made to allow an RNG Transport Project. These projects are very similar to a normal non-core customer except that an interconnection facility with gas quality testing is constructed in addition to the interconnecting pipeline. Currently, these RNG customers would take service under Cascade's Rate Schedule OR800 in Oregon or Rate Schedule 663 in Washington. They only ship their fuel on Cascade's system and pay to transport that fuel, just as a typical non-core customer does. In most cases, these attributes are being transported for use in the LCFS market or they may also be used to produce green hydrogen for renewable diesel, aviation fuels, etc. These projects do not play a role in Cascade's compliance but do represent the evolving use of the Cascade's natural gas system for use in decarbonizing the transportation sector.

Cascade is now pursuing a middle ground on non-dairy RNG Transport Projects which provides greater benefits for core-customers. There are food waste, landfill, and industrial WWTF transport projects where Cascade has been able to provide a competitive offer that enables a partial purchase of attributes in return for a partial facilities investment. Early modeling and experience has shown that these purchases can be more cost effective than other off-system environmental attribute purchases in some cases. In these "Partial Purchase" RNG projects, the percentage of environmental attributes and physical biomethane which cannot be purchased are transported and treated as typical RNG Transport customer. This approach has created cost effective on-system attribute purchase opportunities where they did not exist previously, and Cascade is continuing to learn and evolve on applying this approach to procure new compliance attributes.

There are two different design and construction paths based on the type of RNG project.

- RNG Plant – Cascade is the producer of the RNG. RNG Plant projects include the development of the entire biogas processing plant to bring the biogas to pipeline quality standards. This entails analysis of the biogas itself, flowrates, and connected feed systems to enable determination of the most effective type of biogas scrubbing system(s) to be utilized. Other ancillary equipment must be designed such as the compressors to bring the RNG to pipeline operating conditions. In some cases, other upstream improvements are made to maximize the efficiency and cost effectiveness of the biogas collection such as adding additional gas wells in a landfill or improving air sealing on digester-based gas processing. Depending on the type, size, and scrubber technology, a project may have either skid mounted, containerized equipment or it may require constructing a building to house the processing, compression, and other ancillary equipment. These projects have much more extensive engineering needs. Cascade utilizes an outside engineering firm in these cases but is also supported by internal engineering and development resources. Additionally, these projects would require most of the work in the second type of project listed below.

- RNG System Interconnection & Related Infrastructure – This type of project generally has the RNG Plant constructed by the producer directly. Once contracted, Cascade's portion of the work includes the design and construction of the Interconnection Facility and the pipeline interconnecting with the existing distribution or transmission system. The pipeline portion of the project is designed and constructed in the manner of traditional construction protocols. The Interconnect Facility has additional design and construction but is essentially a small gate station similar to interconnections with interstate pipelines. In addition to typical regulation and metering systems, the facility also requires design of automated valving connected to gas quality measurement systems, odorant system, SCADA system, and two small buildings which contain the gas testing equipment and electrical & SCADA equipment. The Interconnect Facility design and construction has a more interactive project management requirement to resolve the numerous details which enable it to be interwoven with the larger project and site utilities. To date, these projects have been supported directly with Cascade's internal engineering resources.

Of the Purchase Projects in development, four projects are either under contract or at very advanced stages of contracting as detailed here:

City of Richland – Horn Rapids Landfill & Lamb Weston RNG Project – Richland, Washington

Source - 3rd party developer has rights to raw biogas from two sources in close proximity to each other.

1. Landfill Gas from the City of Richland's Horn Rapids Landfill
2. Food Waste from potatoes at Lamb Weston's Richland Processing Plant.

Scope of Cascade Work

- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms

- Under contract, engineering in progress
- 1,860,000 therm/yr or ~ 9,880mtCO2e
- 15-year term
- Projected in-service date late Q4 2023

Deschutes County Landfill RNG Project - Bend Oregon

Source - Cascade/Jacobs Engineering Team was successful candidate chosen through RFP process to own and operate processing facilities to convert landfill gas to RNG

Scope of Cascade Work

- Build, own, operate, and maintain the gas processing plant
- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms

- Working through final contact terms with Deschutes County
- Plant engineering and design in progress
- 3,100,000 therm/yr or ~ 16,460 mtCO2e
- 20-year term
- Projected in-service date Q4 2024

City of Pasco Process Water Reuse Facility - Pasco, Washington

Source – Expanding Industrial wastewater processing facility currently serving several aggregated industrial food processors & growers.

Scope of Cascade Work

- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms

- Under contract and advancing system design progressing
- 3,400,000 therm/yr or ~ 18,060 mtCO2e
- 20-year term
- Projected in-service date late Q4 2024

Landfill RNG Project under Non Disclosure Agreement- Washington

Scope of Cascade Work

- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms

- Partial Purchase Project
- Terms reached and progressing through contract language
- Total volume 4,000,000 therm/yr
- Purchase volume 600,000 therm/yr or ~ 3,186 mtCO2e
- 20-year term
- Projected in-service date mid-year 2025

The following two projects are Transport Projects either under contract or at advanced stages of contracting as detailed below:

Divert, Inc. RNG Project – Longview, Washington

Source – Aggregated food waste from approximately 100 chain grocery outlets in Washington and Oregon

Scope of Cascade Work

- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms

- Under contract, engineering in progress, project has 6 month customer-side delay for unexpected site Geotech work
- 1,800,000 therm/yr (mtCO2e not applicable as Cascade is not receiving the attributes)

- 10-year term
- Projected in-service date early Q3 2024

Diary RNG Project – Snohomish County, Washington

Source – Manure from 3,500 head dairy operation

Scope of Cascade Work

- Design and construct interconnect facilities
- Design and construct pipeline from interconnect facility to local distribution system

Status & Terms

- Interconnect Agreement terms reached, final contract draft in review
- 815,000 therm/yr (mtCO2e not applicable as Cascade is not receiving the attributes)
- 10-year term
- Projected in-service date TBD, developer is currently negotiating a purchase of the project and revised in-service date is not yet known

Cascade has several RNG projects that are at different levels of advancement in terms of Cascade's procurement of the project. The following projects include a list of the type of projects Cascade is either near advancement, or at the early stages of discussion.

5 Key Advancing Projects

Waste Source	Project Type	Volumes (therm/year)	Compliance Volumes (therm/year)
Food Waste WWTF, Landfill	Purchase or Partial Purchase	16,165,000	13,315,000 (~70,725 mtCO2e)
Dairy	Transport	1,370,000	0

Other Active Projects

Purchase	2 Projects
Transport	8 Projects

Renewable Thermal Certificates

The Oregon Department of Environmental Quality (DEQ) has adopted M-RETS as the tracking platform to validate and track environmental attributes from RNG and hydrogen in the CCP. M-RETS utilize Renewable Thermal Certificates (RTCs) to track the production, transfer and retirement of these qualified environmental attributes. The RTC includes specific details like source, vintage, location, feedstock and a unique identifier. Each RTC is equal to one dekatherm of RNG produced. Cascade has procured over 3.5 million RTC's contracted out through 2034 and is currently in discussions with several producers to secure the necessary environmental attributes to meet GHG reduction requirements in WA & OR.

Hydrogen

Hydrogen is believed to be a key component to achieving carbon compliance in the future. Hydrogen is being proven to be a safe, reliable option in specific applications and as a replacement option to tradition natural gas. Much research is underway to maximize understanding and reduce upstart costs. Currently, hydrogen is more cost prohibitive than other RNG options, but it is anticipated that costs will come down as hydrogen becomes a more viable option, which is further discuss later on in this chapter. Cascade is following various research projects that are underway.

RNG and hydrogen will be critical in meeting the dual goals of decarbonizing energy pipelines while maintaining the benefits of reliability and resiliency provided by the Company's distribution system. One challenge from utilizing hydrogen is that it burns at a lower heating quality than traditional natural gas. A blend of 20% hydrogen by volume, which is Cascade's base case blending volume in the 2023 IRP, only equates to an offset of about 7.4% of traditional natural gas by energy. For both the CCA in Washington and the CPP in Oregon, the hydrogen quantities blended by energy are considered a one-for-one offset to traditional natural gas. While there are concerns about whether a blend of hydrogen and traditional natural gas would require a higher usage of this blended product, thus offsetting the emissions reduction savings of using hydrogen in the first place, Cascade is confident through conversations with various subject matter experts in this field that the blended product would result in less than 1% loss of efficiency, creating a negligible need for additional use of the blend. That being said, the Company recognizes that thorough testing of hydrogen will still need to be performed before hydrogen can be utilized in Cascade's system.

Cascade has been closely monitoring hydrogen research such as the Hydrogen Shot[9] (111 Goal), H2Hubs, Low-Carbon Resources Initiative[10], and the Gas Technology Institute (GTI) Hydrogen Technology[11]. Hydrogen Shot was launched by the Department of Energy (DOE) and has a "111 goal," which is to reduce the cost of clean hydrogen by 80% to $1.00 per kilogram, down from $5.00 per kg, in the next decade. The DOE has released a notice of intent[12] to fund the bipartisan

[9] Hydrogen Shot | Department of Energy
[10] Low-Carbon Resources Initiative (epri.com)
[11] Hydrogen Technology Center • GTI Energy
[12] DOE Launches Bipartisan Infrastructure Law's $8 Billion Program for Clean Hydrogen Hubs Across U.S. | Department of Energy

infrastructure laws with an $8 billion program to set up hydrogen hubs. Cascade's sister company, Intermountain Gas, is a member of the GTI, which is a research organization made up of member companies. There are two sub organizations under GTI, where one researches topics related to operation of pipeline systems and the other looks at end use equipment, particularly, focusing on energy efficiency.

As an example, there is a joint venture between DOE, GTI, Frontier Energy, and the University of Texas to design, build, and operate one of the largest collections of renewable hydrogen production and induced technologies ever assembled at one site[13].

Figure 4-4: H2@Scale in Texas and Beyond

RNG and Hydrogen Projections

Cascade utilizes all known RNG project quantities and pricing that are described in the RNG Projects subsection, as well as actual RNG attribute offers Cascade has received for near term projections. For long term projections, Cascade is utilizing a 2019 ACF/ICF study on the potential of various feedstocks for Renewable Natural Gas supply[14]. Using this study, Cascade used a 50/50 blend of the High and Technical Resource Potential Scenario (Tables 39 and 40 of the study), since the Companies who are active in procuring RNG will have higher availability to RNG. Figure 4-5 shows the potential RNG volumes available to Cascade. The ACF/ICF study indicates that RNG potential may level off by 2040. On page 27 of the study, ICF says "the diversion of food waste from landfills may limit the long-term potential (post-2040) of landfill gas as a viable resource for RNG production." For the 2023 IRP, Cascade has adopted this assumption that, while existing RNG projects will

[13] H2@Scale Project Launched in Texas | Energy Institute | The University of Texas at Austin (utexas.edu)
[14] Renewable Sources of Natural Gas - American Gas Foundation

continue to generate gas through the planning horizon, no new RNG projects may be added to the portfolio beyond 2040. To model the pricing of RNG, the Company followed the example of another regional LDC in using a forecast that does not employ a traditional supply curve because of the "lumpy" nature of RNG projects coming online. To that end, prices are split into two tranches. The first tranche, covering the first 1/3rd of projected supply, is priced at $13/dth, while the second tranche, covering the remaining 2/3rd of supply, is priced at $19/dth. In scenarios where additional supply is modeled to be available, those are priced at a third tranche not shown in Figure 4-6, where the price for RNG would be $26/dth. Green Hydrogen pricing comes from market intelligence based on an article from S&P Global[15]. There is a significant amount of uncertainty regarding the potential cost and quantity of these resources, as the markets for RNG and Hydrogen are still in very early stages. As described further in Chapter 9, Resource Integration, Cascade's modeling includes a base volume of hydrogen that can be blended with traditional natural gas and renewable natural gas to 20% of the volume[16]. Cascade continues to gather information on hydrogen blending and is aware of multiple other studies such as the California Public Utilities Commission Hydrogen Study[17] as well as the Northwest Energy Efficiency Alliance Hydrogen-Ready Appliances Assessment Report[18]. While the information is helpful, Cascade recognizes that it will have to perform its own research before implementing Hydrogen in practice.

The Company recognizes that exogenous factors may lead to increased competition for these resources. In Chapter 9, Resource Integration, the RNG, RTC, Hydrogen projections are modeled in Plexos® along with the other carbon compliance measures, such as Energy Efficiency, Demand Response, and CCIs to determine the least cost, least risk portfolio that meets customers' load needs while also meeting carbon compliance obligations. To this end, Cascade addresses how its Top-Ranking Candidate Portfolio would perform under a number of scenarios related to reduce availability and increased prices for these resources. The result of these analyses can be found in Chapter 9, Resource Integration.

15 Green hydrogen costs 'can hit $2/kg benchmark' by 2030: BNEF | S&P Global Platts (spglobal.com)

16 Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues (nrel.gov)

17 CPUC Issues Independent Study on Injecting Hydrogen into Natural Gas Systems (ca.gov)

18 Northwest Energy Efficiency Alliance (NEEA) | Hydrogen-Ready…

Figure 4-5: RNG and Hydrogen Potential

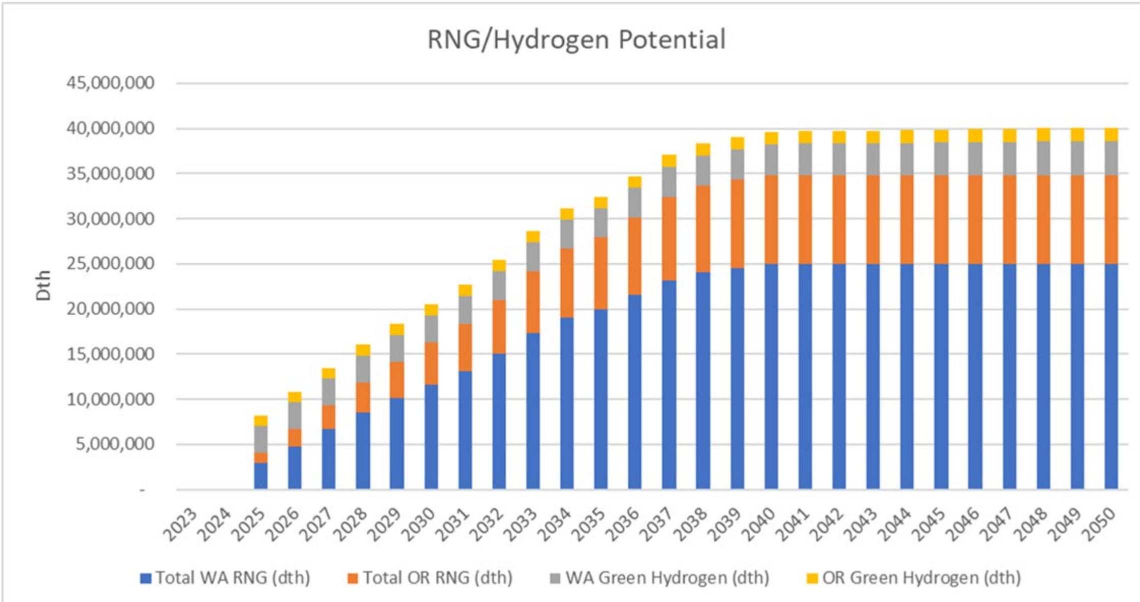
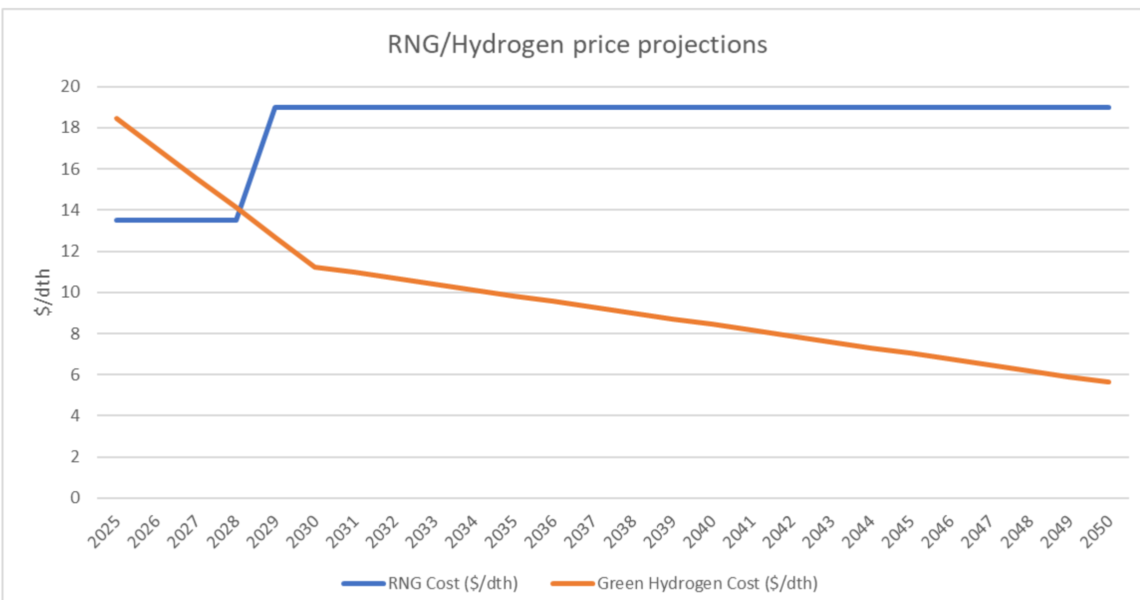


Figure 4-6: RNG and Hydrogen Price Projections



Storage Resources

Cascade also utilizes natural gas storage to meet a portion of the requirements of its core market. Storing gas supplies, purchased and injected during periods of low demand, is a cost-effective way of meeting some of the peak requirements of

Cascade's firm market. Natural gas can be stored in naturally occurring reservoirs, such as depleted oil or gas fields, salt caverns or other geological formations with an impermeable cap over a porous reservoir. Gas can also be stored in tanks under pressure as compressed natural gas (CNG) or cooled to a liquid state (LNG).

Natural gas storage service is not only an excellent supply source for meeting peak winter demand, but it can also be an important gas supply management tool. Storing excess or unused supply during periods of low demand increases the annual utilization rate of a supply contract, thereby improving the annual load factor for the Company's gas supplies. Improving the annual load factor of a supply contract improves the Company's ability to purchase gas supplies on a more economical basis. Purchasing natural gas for storage during periods of low demand generally yields prices at the low point on the seasonal price curve.

Depending upon the location of the storage facility, pipeline transportation may also be required to move the gas from the facility to the distribution system. Storage facilities located within the Company's distribution system or on the immediately upstream interstate pipeline are preferable to those located off-system. Off-system storage requires additional upstream pipeline transportation and may limit the flexibility of the resource. Cascade does not own any storage facilities and, therefore, must contract with storage owners to lease a portion of those owners' unused storage capacity. Figure 4-1 on page 4-3 displays the location of some of the storage facilities in the region.

Cascade has contracted for storage service directly from NWP since 1994. Jackson Prairie is located in Lewis County, Washington, approximately ten miles south of Chehalis. The following paragraph explaining the Jackson Prairie facility is found on Puget Sound Energy's website.[19] Puget is a one-third owner of the Jackson Prairie facility.

"Jackson Prairie is a series of deep underground reservoirs-basically thick porous sandstone deposits. The sand layers lie approximately 1,000 to 3,000 feet below the ground surface. Large compressors and pipelines are employed at JP to both inject and withdraw natural gas at 45 wells spread across the 3,200-acre facility. Currently it is estimated that Jackson Prairie can store nearly 25 BCF of working gas. The facility also includes "cushion" gas which provides pressure in the reservoir of approximately 48 BCF. In terms of withdrawal capability, the facility is capable of delivering 1.15 BCF of natural gas per day."

The Company also has contracted for service from NWP's Plymouth, Washington LNG facility. Plymouth is located in Benton County, Washington approximately 30 miles south of Kennewick. According to NWP's website, the total facility has storage

[19] *See:* Jackson Prairie Underground Natural Gas Storage Facility, https://www.pse.com/pages/energy-supply/natural-gas-storage, as of February 2, 2021.

capacity of 2.4 BCF. Cascade has leased approximately 28% of this storage capacity.

In addition to the other storage facilities, the Company leases storage capacity from Mist. The Mist facility is located near Mist, Oregon and is adjacent to Northwest Natural Gas' distribution system and has a direct connection to NWP for withdrawals and injections. The Mist facility is owned and operated by Northwest Natural Gas. Cascade has 1,640,000 dth of leased capacity.

Both the Jackson Prairie and the Plymouth facilities are located directly on NWP's transmission system, while Mist Storage is located on the Northwest Natural Gas system that is connected to NWP via two different citygates, therefore, storage withdrawal rates can be changed several times during an individual gas day to accommodate weather driven changes in core customer requirements. This type of operating flexibility would not necessarily be available with off-system storage. Withdrawal capabilities must also be accompanied by firm capacity on the transporting pipeline(s) to be of any value as a reliable source of gas supply. Cascade's Jackson Prairie storage and Plymouth LNG service require TF-2 firm transportation service, which is a secondary firm service right, for storage withdrawals; Cascade has sufficient firm TF-2 service to meet its storage daily deliverability levels. The Company's contracted storage services are summarized in Figure 4-7.

Figure 4-7: Cascade Leased Storage Services (Volumes in Therms)

Facility	Storage Capacity	Withdrawal Rights
Jackson Prairie (Principle)	6,043,510	167,890
Jackson Prairie (Expansion)	3,500,000	300,000
Jackson Prairie (2012)	2,812,420	95,770
Plymouth LNG (Principle)	5,622,000	600,000
Plymouth LNG (2016)	1,000,000	181,250
Mist	16,400,000	500,000

Capacity Resources

Capacity options are either interstate pipeline transportation resources or capacity on Cascade's local distribution system. Cascade's local distribution system is built to serve the entire connected load in its various distribution service areas on a coincidental demand basis, dependent upon the type of service the customer has contracted to receive.

Pipeline transportation resources are utilized to transport the gas supplies from the producer/supply sources to Cascade's system. Cascade currently purchases supplies from three different regions or basins: U.S. Rockies, British Columbia, and Alberta, Canada. Unless the supplier has bundled its sale of gas supplies with capacity (i.e. a citygate delivery), these resources require pipeline transportation to deliver them to Cascade's local distribution system. Transportation resources historically have been purchased from the pipeline(s) at the time of an expansion under long-term (20 to 30 year) contracts.

Cascade has over 30 long-term annual contracts with NWP, numerous long-term annual and winter-only transportation contracts with GTN (including the upstream capacity on TransCanada Pipeline’s Foothills and Alberta systems), a long-term, winter-only contract with Ruby Pipeline, and one long-term annual contract with Enbridge (Westcoast Transmission) in British Columbia, Canada. These contracts do not include storage or other peaking services that may provide additional delivery capability rights. Figure 4-1 on page 4-3 provides a general flow of Cascade’s combined contracted pipeline transportation rights.

GTN Xpress

In the 2018 IRP (LC 69), Cascade had identified an upstream shortfall along the GTN pipeline. A shortfall occurs when the Company’s customer demand exceeds the maximum daily quantity a company has contracted for on an upstream pipeline. As seen in Figure 4-8, Cascade identified this shortfall beginning in 2020 and exceeding 20,000 dth in the early 2030’s.

Figure 4-8: Oregon Load Centers with Potential Peak Day Unserved Demand in Dekatherms – As Is Scenario

Area	2018	2020	2025	2030	2035	2037
Bend Loop	-	1,504	8,488	15,835	23,266	26,262
Total	**-**	**1,504**	**8,488**	**15,835**	**23,266**	**26,262**

Once Demand Side Management options were included, it delayed the first shortfall until 2023 and the time to reach 20,000 dth shortfall to the mid 2030’s.

In the 2018 OR IRP Updated, Cascade gave an update to Action Item 11: *“Evaluate the cost of purchasing incremental GTN capacity now versus in 4 years. Confirm with GTN on the availability of upstream capacity either from Kingsgate to Malin or from Turquoise Flats to Kingsgate. At a minimum, on a quarterly basis analyze the potential availability and price of GTN capacity currently compared to at least four years out. Provide the results of this analyses to GSOC to determine actions necessary to meet Bend capacity shortfalls anticipated late in the upcoming decade.”*

Cascade's update stated: In the Oregon IRPs prior to the 2018 Oregon IRP, Cascade noted a potential shortfall along GTN. The 2016 WA IRP also noted a potential shortfall along GTN. During the 2018 OR IRP modeling period, Cascade purchased 10,000 dths/day of GTN north to south forward haul on December 1st, 2017. Due to the timing, Cascade did not include this 10,000 dths in the modeling and instead included it in the solve for the GTN shortfall. The 2018 OR IRP showed a GTN shortfall beginning in 2019-2020 which was delayed until 2026-2027 because of the 10,000 dths/day that was already purchased.

The Company takes into account many different factors when it comes to evaluating the cost of purchasing incremental GTN capacity now versus in four years. These factors include, but are not limited to, cost of capacity, risk of availability of capacity, and risk around error in the Company forecast. Looking further into these factors Cascade found:

- The cost of acquiring the 20,000 dths of capacity now will more likely be cheaper than capacity four years from now.
- It is Cascade's understanding that GTN is near fully subscribed.
- Cascade's Bend growth forecast from 2018 to 2019 in the OR IRP was 2.44% but has actually seen a 3.33% increase from January 2018 to January 2019. In the 2018 WA IRP, which accounted for the higher growth rate, it was shown that the GTN shortfall started in 2023.

The factors listed above were provided to GSOC which determined that purchasing 10,000 – 20,000 dths/day would be the necessary action to meet Bend capacity shortfalls. Cascade signed a non-binding term sheet between GTN and the Company on April 18, 2019. The non-binding term sheet essentially stated Cascade would participate in an Open Season with an interest in 10,000 – 20,000 dths/day of GTN capacity, GSOC authorized Cascade to continue to monitor the situation and will keep the OPUC up to date through the PGA quarterly meetings. September 13, 2019, consistent with GSOC's authorization, Cascade executed a binding precedent agreement with GTN to acquire 20,000 dths/day of GTN capacity as part of the GTN Xpress project.

In the 2020 and 2023 IRP, Cascade included the 20,000 dth of GTN Cascade contracted for beginning November 1, 2023 in the modeling. Since this new contract was included in the modeling Cascade did not identify any shortfalls in the 2020 IRP and identified a small shortfall on GTN in the 2023 IRP, but not until late 2040's.

Further evidence that Cascade needs the expansion occurred when Cascade flowed approximately 66,000 dth of gas along GTN on December 22, 2022. On this day, Cascade experienced 52 HDD temperatures, which is approximately 18 HDDs warmer than what the Company models for peak day HDDs. Cascade's contracted capacity without the 20,000 dth is 72,603. Therefore, Cascade was about 6,000 dth from exceeding upstream pipeline contracted capacity while experiencing cold, but not peak day temperatures.

In this 2023 IRP, Cascade shows in the Demand Forecast chapter that the Company anticipates growth to continue to go rise even with the carbon compliance around the CPP. In the Resource Integration chapter, Cascade identifies ways the Company plans to meet CPP decarbonization goals even with an increasing customer base.

Natural Gas Price Forecast

For IRP purposes, the Company develops a baseline, high, and low natural gas price forecast. Demand, oil price volatility, the global economy related to inflationary pressure, geopolitical turmoil, and LNG imports/exports, electric generation, opportunities to take advantage of new extraction technologies, hurricanes and other weather activity will continue to impact natural gas prices for the foreseeable future. Cascade is still closely monitoring the market for long term impacts of COVID-19. Cascade did reach out to its hedging consultant, Gelber & Associates, who provided the following analysis in the Company's 2022 Hedge Plan:

> "Excessively mild weather to begin the 2021/2022 winter caused prices to fall to a low of $3.56/MMBtu. However, in late December, the U.S. registered the coldest sustained winter period in January and early February of 2022 since the Polar Vortex of 2013/14. The brief advantage storage had built in winter's mild early days was erased, with peak demand and freeze-off crippled production supporting natural gas price increases including the largest one-day percentage climb of the Henry Hub natural gas futures contract. Repeat bouts of cold and depleted storage inventories placed the market into a much more bullish position than would have been anticipated preseason. Russia's invasion of Ukraine in late February served to compound tensions, maximizing the pull on U.S. gas from overseas and sending oil prices above $100/Bbls while NYMEX Henry Hub natural gas prices traded at $5.00/MMBtu."

Cascade considers price forecasts from several sources, such as Wood Mackenzie, Energy Information Administration (EIA), S&P Global, NYMEX Henry Hub, Northwest Power and Conservation Council (NWPCC), as well as Cascade's own observations of the market to develop the low, base, and high price forecasts. For confidentiality purposes, the Company refers to the selected sources as Sources 1-4 when discussing how these sources are weighted in Cascade's Henry Hub forecast. The following discussion provides an overview of the development of the baseline forecasts.

Cascade's long-term planning price forecast is based on a blend of futures market pricing along with long-term fundamental price forecasts from multiple sources. Since pricing on the market is heavily influenced by Henry Hub prices, the Company closely monitors this market trend. While not a guarantee of where the market will ultimately finish, the futures market (NYMEX) is the most current information available that provides some direction as to future market prices. On a daily basis, Cascade can see where Henry Hub is trading and how the future basis differential in the Company's physical supply receiving areas (Sumas, AECO, Rockies) is trading.

Cascade believes that relying on a single source for developing the Company's 20-year price forecast is not the most reasonable approach. Some sources such as EIA and Wood Mackenzie produce Henry Hub pricing over the long-term; whereas other sources like the NYMEX basis (e.g., Sumas) provide price indicators over a shorter period of time. Additionally, price forecast sources produce their forecasts or indicators at varying points in time throughout the year. Finally, most forecasts are at an annual level versus a monthly level. In order to capture the potential seasonality as well as the variances of monthly price within the producing basins, the Company blends the pricing data from these various forecast sources.

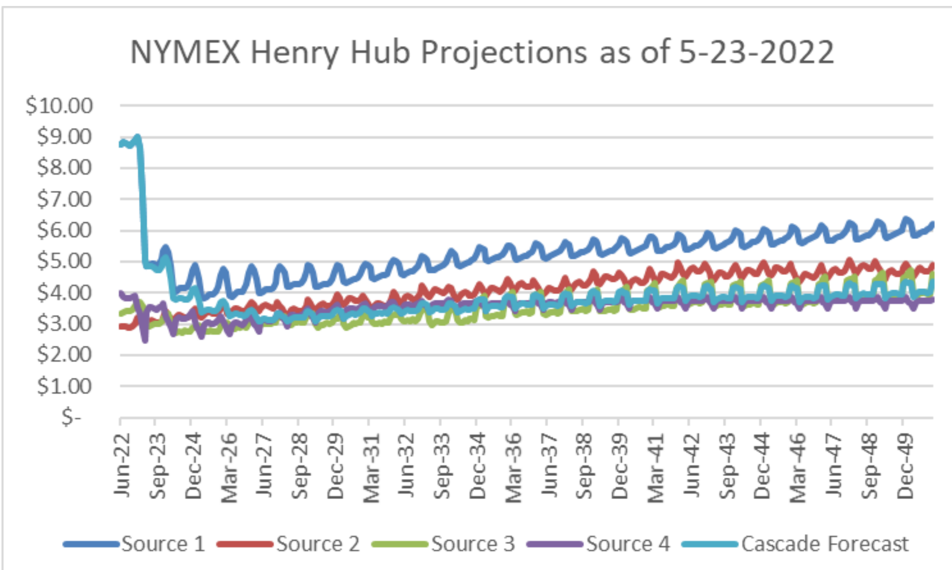
The fundamental forecasts of Wood Mackenzie, the EIA, NWPCC, Platts, S&P Global, and Cascade's trading partners are resources for the development of a blended long-range price forecast. Wood Mackenzie publishes a long-term price forecast twice a year to subscribing customers. This forecast was broken down by month through the planning horizon and includes Henry Hub as well as basis differentials, or price differential from Henry Hub, for the Company's receiving areas. Cascade also considers the EIA forecast; however, it has its limitations since it is not always as current as the most recent market activity. Further, the EIA forecast provides monthly breakdowns in the short-term, but longer-term forecasts are only by year. Many of the other sources mentioned only provide price forecasts by year. Given Cascade's load profile and the need for more winter gas than summer, the Company developed a pattern based on the market monthly forward prices to create a long-term, monthly Henry Hub price.

With a monthly Henry Hub price determined from the above sources, the Company assigned a weight to each source to develop the monthly Henry Hub price forecast for the 20-year planning horizon. These weights were derived by calculating the Symmetric Mean Absolute Percentage Error (SMAPE) of each source versus actual Henry Hub pricing since 2010. The inverse of these error terms was then used to determine the weight given to each source. A sample of the forecast weighting factors are shown in Figure 4-9. A comparison of the sources Cascade uses in its forecast and the actual blended forecast is provided in Figure 4-10. Cascade's price forecast was locked in on May 23, 2022.

Figure 4-9: Sample of Cascade's Henry Hub Price Forecast Weights

Date	Source 1	Source 2	Source 3	Source 4
T+24	75.000%	7.986%	10.504%	6.510%
T+25	72.917%	8.173%	11.587%	7.324%
T+26	70.833%	8.272%	12.701%	8.193%
T+27	68.750%	8.353%	13.809%	9.088%
T+28	66.667%	8.505%	14.862%	9.966%
T+29	64.583%	8.841%	15.800%	10.776%
T+30	62.500%	9.425%	16.574%	11.501%
T+31	60.417%	10.226%	17.191%	12.167%
T+32	58.333%	11.213%	17.675%	12.779%
T+33	56.250%	12.348%	18.056%	13.346%
T+34	54.167%	13.577%	18.377%	13.880%
T+35	52.083%	14.834%	18.686%	14.397%
T+36	50.000%	16.044%	19.040%	14.915%

Figure 4-10: Henry Hub Price Forecast by Source ($U.S./Dth)



Age-Dampening Mechanism

To ensure that the forecast is accounting for the most current information in the market, Cascade has introduced an age dampening mechanism to its price forecast. Every month, if there is a source that is over one year old, all sources' weights are reduced by their share of the total number of months that all sources are outdated by. For example, if Source 1's forecast was fifteen months old, Source 2's was seven months old, and Source 3's was two months old, then each of these sources would be reduced by 15/24, 7/24, and 2/24 respectively. The detracted weights are then added back into the weight of the forwards market since that will always be the most current source (as it is updated daily). The one-year threshold was chosen qualitatively, as this methodology could be too punishing if all sources were not that old. For example, if one source was two months old, another was one month old, and another brand new, the first source would lose 66% of its weight to the forward curve, even though it still contains relatively current information regarding the market.

Cascade weights the futures market at 100% for the first fifteen months of the forecasting period. The weights are then linearly interpolated over the next two years in order to align them with the calculated weights as described above.

The Company recognizes the importance of verifying forecast accuracy periodically and as such, will perform routine cross-validation to evaluate the impact of any modifications to the price forecast.

Development of the Basis Differential for Sumas, AECO and Rockies

Cascade utilizes the basis differential from Wood Mackenzie's most recently available update and compares that to the future markets' basis trading as reported in the public market because the Company's physical supply receiving areas (Sumas, AECO, and Rockies) are typically traded at a discount to Henry Hub. Correspondingly, the Company applied a weighted average to determine the individual basis differential in the price forecast.

Pros and Cons of Methodology Changes

The changes made in the 2018 and 2020 IRPs represent a continual methodological improvement over the forecasts in previous IRPs. Using the daily NYMEX forwards for short term forecasting allow the Company's forecast to incorporate current market data, such as weather and *force majeure* events, into its projections. Additionally, the age dampening mechanism favors sources that have been updated more recently, which better captures a paradigm shift in the markets on a long-term basis versus a forecast that may be a few months or even years old. Finally, the use of SMAPE to assign weights to the sources creates a more scientific rationale for the blending of forecasts.

While Cascade believes this forecast is accurate, there are always areas of potential improvement. Since the forecast is a blending of other forecasts, the Company relies on the accuracy of its sources. While the SMAPE calculation helps to reward the more accurate forecasts, if all sources failed to capture a major market movement, Cascade's forecast would ultimately end up inaccurate as well. Additionally, some sources produce fairly infrequent forecasts, creating a small sample size for them to be evaluated in the SMAPE calculation. The Company is monitoring these problems to ensure they do not skew the forecast and has mechanisms in place to allow for a manual adjustment if market intelligence deems such a modification to be appropriate.

Incremental Supply Side Resource Options

As is more thoroughly described in Chapter 10, Resource Integration, some of the load growth over the planning horizon may require Cascade to secure incremental supply side resources. The purpose of this section is to identify the potential incremental supply resources the Company considered for the current IRP.

Cascade models its incremental resources simultaneously through PLEXOS®. This allows the Company to evaluate each resource as a potential solution relative to all other resources, without any bias towards a particular option. Cascade utilizes functionality within PLEXOS® to allow the program to deterministically select the optimum timing and quantity of incremental supply resources. Any of the following resources that do not appear in Cascade's final preferred portfolio were deemed by PLEXOS® to be either not cost effective or not optimal in comparison with other resource options.

Pipeline Capacity

- **Cross-Cascades, Trail West (Palomar, NMax, Sunstone, Blue Bridge, et al):** Trail West is a proposed pipeline starting at GTN's system near Madras, Oregon, and connecting NWP's Grants Pass Lateral near Molalla, Oregon. Since portions of the Company's distribution system are not connected to Molalla, incremental pipeline capacity would be needed to transport gas northbound to certain load centers. NWP has proposed a transport service that would bundle Trail West capacity with NW Natural's northbound Grants Pass Lateral capacity. From Cascade's perspective, this might present an alternative means to move Rockies gas to the I-5 corridor. At this time, there has been no new activity associated with this project. The development of this project would likely have a two to three year lead time.

- **GTN Capacity Acquisition:** The Company would acquire currently unsubscribed capacity on GTN in order to secure its gas supplies at liquid trading points primarily to serve Central Oregon. Cascade is scheduled to pick up GTN North to South of 20,000 dth/day, 20,000 dth/day on NGTL, and 10,000 dth/day on Foothills, which was shown in the 2018[20] and 2020[21] IRPs as needed resources to meet central Oregon capacity.

- **NWP Eastern Oregon Expansion:** This alternative resource would be incremental NWP capacity from a Washington State receipt point that is designed to serve load growth needs in Zone 24 and Zone ME-OR. Examples of the Cascade service areas that would benefit from this project are Pendleton and Baker City. Similar to a proposed NWP Wenatchee expansion, it would be relatively small scale and could be expected to have a relatively high unit cost. The development of this project would likely have a three or four year lead time. As of this writing, there hasn't been any new activity associated with the potential project.

- **NWP Express Project/I-5 Sumas Expansion Project (Regional or Cascade Specific Project):** Cascade envisions this project as expanding capacity from Sumas on a potential NWP project that is the successor to the Western Expansion project. It would potentially combine Cascade's infrastructure expansion needs with other regional requests from parties such as local distribution companies (LDCs), power generators, and large petrochemical projects. The scale of this project is larger, potentially resulting in a more favorable unit cost; although with scale and multiple parties involved, timing for in-service dates may vary by the various participants. Examples of the Cascade service areas that would benefit from this project are Bellingham, Mount Vernon, Bremerton, and Longview. Cascade, through the Company's active membership in various industry task forces and associations, works with regional pipelines and LDCs to consider potential pipeline expansions. The development of this project would likely have a three or four year lead time. As of this writing, there hasn't been any new activity associated with the potential project.

- **NWP Wenatchee Expansion:** This alternative resource would be incremental NWP capacity from a Washington State receipt point (e.g. Sumas) that is designed to serve load growth needs in Zone 10 and Zone 11. Examples of the Cascade service areas that would benefit from this project are Yakima and Wenatchee. Accordingly, it would have a relatively small scale and so could be expected to have a relatively high unit cost. The development of this project would likely have a three or four year lead time. As of this writing, there hasn't been any new activity associated with the potential project.

[20] UTC Case Docket Detail Page | UTC (wa.gov)
[21] UTC Case Docket Detail Page | UTC (wa.gov)

- **NWP Zone 20 Expansion:** This alternative resource would be incremental NWP capacity from a Washington State receipt point that is designed to serve load growth needs in Zone 20. Examples of the Cascade service areas that would benefit from this project are Kennewick and Moses Lake. Similar to a proposed NWP Wenatchee expansion, it would have a relatively small scale and so could be expected to have a relatively high unit cost. The development of this project would likely have a three or four year lead time. As of this writing, there hasn't been any new activity associated with the potential project.

- **Pacific Connector:** The Pacific Connector Pipeline project is tied to the development of the Jordan Cove LNG export terminal in Coos Bay, Oregon. This pipeline would start near Malin, Oregon, and would cross NWP's Grants Pass Lateral (GPL) in the vicinity of Roseburg, Oregon. This project presents an opportunity as a potential supply resource for this IRP. Cascade would not be seeking to become a shipper on Pacific Connector. The Company views this project as a bundled pipeline supply service from Malin to the Company's citygates. The project was initially denied due to lack of demand, which has since increased, but faces considerable opposition including but not limited to landowners, activists, and protesters. Incremental transport involving GTN might be necessary to ensure transport from Malin to Cascade's GTN receipt point at Turquoise Flats. On January 19, 2021 federal regulators upheld Oregon's decision to deny a water quality certification for Jordan Cove and Pacific Connector.[22] This latest event has led to some concern the project may not proceed.

- **Southern Crossing Expansion:** FortisBC Southern Crossing is considering an addition of 300-400 MMcf/d of bidirectional capacity. FortisBC has proposed a reinforcement project for the Southern Crossing Pipeline that would permit more flow of Alberta gas to Sumas. This would also require an expansion of NWP from Sumas at the Canadian border which, in the Company's view, does not need to be modeled since it essentially is replicated by the current inclusion of the NWP I-5 expansion project. This is primarily a price arbitrage opportunity, but the Company does not see any significant advantage to the system at this point given limited availability to move the gas from Sumas. However, Cascade will continue to consider this resource to see if it might make sense as a potentially cost-effective dedicated resource for the Company's direct connect with Westcoast.

[22] *See* https://www.oregonlive.com/politics/2021/01/federal-regulators-deliver-potentially-fatal-blow-to-jordan-cove.html

Storage Opportunities

- **AECO Hub Storage:** This is Rockpoint's commercial natural gas storage business in Alberta, Canada. The service is comprised of two gas storage facilities: Suffield (South-eastern Alberta) and Countess (South-central Alberta). Although the two AECO facilities are geographically separated across Alberta, the toll design of the Nova Gas Transmission Ltd. (NGTL) system means they are both at the same commercial point. Capacity at one of the facilities is possible as an alternative resource. However, some services are available for limited periods of time but are subject to possible interruption. Incremental transport involving NGTL, Foothills, GTN, and possibly NWP would also be necessary.

- **Gill Ranch Storage:** Gill Ranch Storage is an underground intra-state natural gas storage facility near Fresno, Calif. It includes a pipeline that links the facility to Pacific Gas & Electric Company's (PG&E) mainline transmission system, allowing it to serve customers throughout California. Storage from this facility would require California Gas Transmission (CGT) transport, which has a potentially cost-prohibitive demand charge of $1.68/Dth. Incremental transport involving GTN would also be necessary.

- **Mist Storage:** This facility is located near Mist, Oregon and is adjacent to NW Natural Gas' distribution system and has a direct connection to NWP for withdrawals and injections. The Mist facility is owned and operated by NW Natural Gas. NW Natural's 2018 IRP (LC71), Chapter 9, Section 9.2.1 indicates that "Mist storage capacity is currently reserved for the core market… NW Natural has developed additional capacity in advance of core customer need. This capacity currently serves the interstate/intrastate storage (ISS) market but could be recalled for service to NW Natural's utility customers as those third-party firm storage agreements expire."

  In the past several years NW Natural has held a Mist open season in 2017, followed by two Mist RFPs. Cascade became a Mist ISS customer for the first time in May 2019. The Company leases 600,000 dths of storage capacity. This lease is set to expire in 2024.

  On January 14, 2021 NW Natural sent their latest RFP to Cascade with bids due by January 29, 2021. With assistance in modeling from Cascade's asset manager, Tenaska Marketing, Cascade's GSOC authorized Cascade to submit a bid at 76% of the maximum rate (for reference, the current Mist agreement is at 100% of the maximum rate). Cascade was awarded 540,000 dths of additional Mist capacity on February 1, 2021. The term of this additional Mist service is May 1, 2021 through April 30, 2026.

As the Company states throughout, the IRP is developed at a point in time. Unfortunately, Cascade had no advanced knowledge of the 2021 Mist RFP during the development of this IRP. Therefore, this latest Mist leased storage is not included in the IRP analysis. It is important to note that Cascade does not own any storage. In addition to the currently leased Mist storage, the Company leases storage at Jackson Prairie and Plymouth LNG. Given the Company's wide geographical and noncontiguous service territory, storage has a unique role in daily upstream operations compared to other regional LDCs. For Cascade, storage functions primarily as an operational tool for balancing and upstream pipeline operational flow orders as opposed to use primarily for price arbitrage. Also, Cascade continues to have the lowest ratio of customers to storage capacity in comparison to other regional LDCs. The addition of this second Mist account improves the Company's portfolio flexibility with minimal impact to customer rates.

- **Spire (formerly Ryckman Creek) Storage:** As of December 2017, Ryckman Creek, LLC operates as a subsidiary of Spire Inc. Spire Gas Storage Facility is located near the town of Evanston, Wyoming and approximately twenty-five miles southwest of the Opal Hub. Spire Storage has converted a partially depleted oil and gas reservoir into a gas storage facility with 35 BCF of working gas and a maximum daily withdrawal rate of 480,000 Dths/d. Spire Storage currently has interconnects with Questar Gas Pipeline, Kern River Transmission, Questar Overthrust Pipeline, Ruby Pipeline, and NWP. Incremental transport involving Questar and possibly Ruby would be necessary.

- **Wild Goose Storage:** Wild Goose is located north of Sacramento in northern California and is the first independent storage facility built in the state. The facility commenced full commercial operations in April 1999 and in April 2004 completed its first expansion. Storage from this facility would require California Gas Transmission (CGT) transport, which has a potentially cost-prohibitive demand charge of $1.68/Dth. Incremental transport involving GTN would also be necessary.

- **Magnum Gas Storage:** Magnum is currently developing the Magnum Gas Storage facility at the Western Energy Hub. Magnum Gas Storage will be the first high-deliverability storage facility in the Rocky Mountain Region. The facility will contain four solution mined storage caverns capable of storing 54 billion cubic feet (Bcf) of natural gas.[23] Magnum would be connected to the Kern River Gas Transmission and Questar

[23] *See* https://www.wyopipeline.com/magnum-gas-storage-llc-western-energy-hub-project/

Pipeline systems at Goshen, Utah. Incremental transport involving Questar and possibly Ruby would be necessary.

- **Clay Basin:** Clay Basin is located in Northeast Utah and is a 54 Bcf working gas storage facility. Clay Basin is connected to the Questar Pipeline system. Incremental transport involving Questar and possibly Ruby would be necessary.

Other Alternative Gas Supply Resources

- **Satellite LNG:** Some gas utilities rely on satellite LNG tanks to meet a portion of their peaking requirements. The term satellite is commonly used because the facility is scaled-down and has no liquefaction capability. LNG facilities in this context are peaking resources because they provide only a few days of deliverability and should not be confused with the much larger facilities such as LNG export or import terminals. The concept is that a small tank serving a remote area would be filled with LNG as winter approaches, and the site operated during cold weather episodes when vaporization is required. Since satellite LNG has no on-site liquefaction process, the facility is fairly simple in design and operation. While likely as expensive as some pipeline projects, satellite LNG may be more practical in areas where pipeline capacity shortfalls for peak day are the highest and most immediate. The addition of satellite LNG could defer significant pipeline infrastructure investments for several years. A project of this nature would likely have a three-four year lead time.

- **Additional transportation realignments:** The Company's geographically widespread service territory gives Cascade great flexibility to utilize 316,994 Dths/day of delivery rights vs 205,123 Dths/day of receipt rights. Cascade has the right to deliver gas to any delivery point within Washington and Oregon so long as the total MDDOs are not exceeded. Cascade and NWP have worked continuously in recent years for ways to address Cascade's potential peak day capacity shortfalls through re-alignment of the Company's contractual rights where possible, which mitigates the need to acquire incremental NWP capacity through expansions.

Cascade considers unconventional gas supply resources such as supplies from an LNG Import Terminal, local bio-natural gas, or other manufactured gas supply opportunities as potentially speculative supply side resources at this point in time. Ultimately these gas supply resources are treated as alternative resources and have to compete with traditional gas supplies from the conventional gas fields in Canada or the Rockies for inclusion in the Company's portfolio planning.

Supply Side Uncertainties

Several uncertainties exist in evaluating supply side resources. These include regulatory risks, deliverability risks, and price risks. Regulatory risks include the unknown impacts of future Federal Energy Regulatory Commission (FERC) or Canada's Energy Regulator (CER)[24] rulings that may impact the availability and cost of interstate pipeline transportation.

Cascade is examining design day reliability for distribution system operations of RNG on its system as part of Chapter Y.

Deliverability risk is the risk that the firm supply will not be available for delivery to the Company's distribution system. Purchasing resources from larger producers or marketers who typically have gas reserves in multiple locations may minimize this risk. The risks associated with prices rising or falling during any winter period represent another supply side uncertainty. To the extent the Company purchases firm contracts that are tied to an index price, it may be at risk for paying more than was initially anticipated for the resource after the resource decision has been made. Price risks associated with climbing prices can be minimized through the use of fixed price contracts or through the use of financial derivatives.

As the United States continues to search for environmentally friendly, economically viable options to displace gasoline and coal, natural gas is seen as a fuel that could be a viable resource in a greener future. It is worth noting that some planned and proposed projects could have a direct impact on the availability of supply or at least may pose potential risks to increasing the price of supplies sourced from British Columbia and Alberta. For example, Coastal GasLink Pipeline is currently under construction. Coastal GasLink, once completed in 2023, will transport natural gas from northeast British Columbia to an LNG export facility near Kitimat BC near the Pacific coast. Shippers using this pipeline will likely lead to increased competition for gas supplies in the region. Also, proposed expansions on the TransCanada pipelines in 2022 and 2023 may also increase competition for available gas supplies in Alberta and British Columbia. The Company will continue to monitor and be actively involved in the various pipeline forums as these initiatives develop.

[24] The Canada Energy Regulator (CER) is the agency of the Government of Canada under its Natural Resources Canada portfolio, which licenses, supervises, regulates, and enforces all applicable Canadian laws as regards to interprovincial and international oil, gas, and electric utilities. The agency came into being on August 28, 2019, under the provision of the Canada Energy Regulator Act of the Parliament of Canada superseding the National Energy Board from which it took over responsibilities.

Financial Derivatives and Risk Management

Cascade constantly seeks methods to ensure customers of price stability. In addition to methods such as long-term physical fixed price gas supply contracts and storage, another means for creating stability is through the use of financial derivatives. The general concept behind a derivative is to lock-in a forward natural gas price with a hedge, consequently mitigating exposure to significant swings in rising and falling prices. Financial derivatives include futures, swaps, and options on futures or some combination of these.

Natural gas futures contracts are actively traded on the NYMEX. The use of futures allows parties to lock-in a known price for extended periods of time (up to six years) in the future. Contracts are typically made in quantities of 10,000 dths to be delivered to agreed-upon points (e.g., NWP Sumas, Westcoast Station 2, NGTL AECO, NWP Rockies, etc.).

In a swap, parties agree to exchange an index price for a fixed price over a defined period. In this scenario, Cascade would be able to provide its customers with a fixed price over the duration of the swap period. In theory, the price would be levelized over the long-term. Futures and swaps are typically called costless collars.

Unlike futures and swaps, an option only provides protection in one direction - either against rising or falling prices. For example, if Cascade wanted to protect customers against rising gas prices but keep the ability to take advantage of falling prices, Cascade would purchase a call option on a natural gas future contract. This arrangement would give the Company the right (but not the obligation) to buy the futures contract at a previously determined price (strike price). Similar to insurance, this transaction only protects the Company from volatile price spikes, via a premium. The premium is typically a function of the variance between the strike price compared to the underlying futures price, the period of time before the option expires, and the volatility of the futures contract.

Cascade's Gas Supply Oversight Committee (GSOC) oversees the Company's gas supply hedging strategy. The Company's current gas hedging strategy is outlined below:

Hedged Fixed-Price Physical or Financial Swap Targets

- Year one target set at 50% of annual requirements.
- Year two target set at 40% of annual requirements.
- Year three target set at 25% of annual requirements.

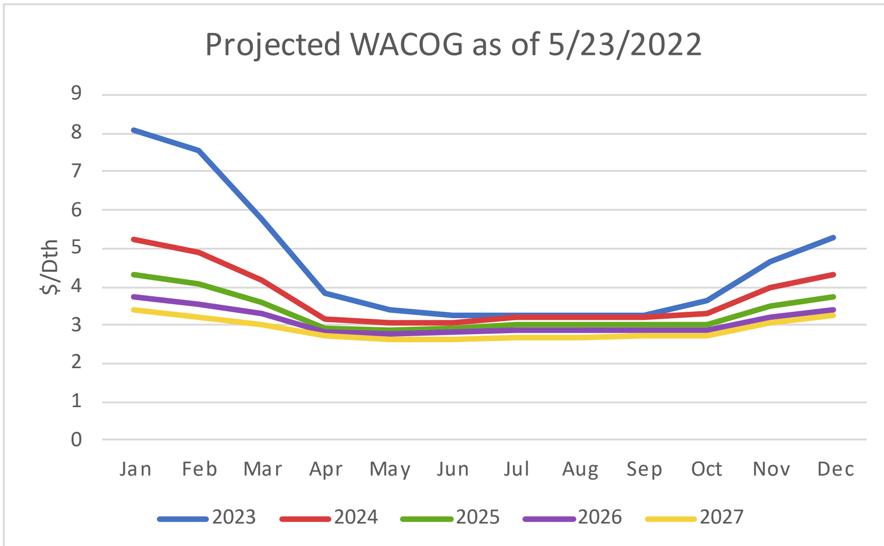
Depending on market conditions, the strategy allows for the ratchets to increase to 75%, 40%, and 25%, respectively, provided current market information supports moving to a different level.

Cascade employs prudent risk management strategies within designated parameters to minimize the risk of operating losses or assumption of liabilities from commodity price increases because the price the Company pays for gas is subject to market conditions. Risk is associated with business objectives and the external environment. The number of hedging strategies to deal with risk are almost infinite. The decision-making process to manage a risk categorizes whether the risk is one to be avoided, one to be accepted and controlled, or a risk left uncontrolled. When a risk is high impact with a high likelihood of occurrence, the risk is probably too high in relation to the reward and should be avoided. It is reasonable to accept business risks that can be managed and controlled. For some risk, the measurable impact is low, and the risk may not be worth controlling at all. These are risks where the Company can absorb a loss with little financial or operational impact. The Company's policy is directed toward those risks that are considered manageable, controllable, and worth the potential reward to customers. This manageable risk includes acceptable analysis of the possible side effects on the financial position of the Company as compared to the rewards.

The use of derivatives is permitted only after identified risks have been determined to exceed defined tolerance levels and are considered unavoidable. Cascade's GSOC makes these decisions. In recent years, GSOC has adjusted the percentage of the portfolio hedged based on volatility of the market. For example, in the early 2000s, the Company hedged up to 90% of the base gas supply portfolio. When MDU Resources acquired Cascade in 2007, this threshold was reduced to 75% to align with MDU Resources' Corporate Derivatives Policy. As the market began to fall dramatically in the 2008-2010 period, the Company continued to lower the percentage to approximately 30%. Current MDU Resources' corporate policy encourages Cascade to keep the hedging percentage at approximately 50%. For the 2020 procurement design, GSOC felt that it prudent for Cascade to enter into its first financial derivative during the 2019-2020 period, which the Company successfully executed.

The Company entered into fixed price physical transactions and one financial swap for the current programmed buying period. The Company entered into fixed price physical transactions rather than executing financial swaps for the current programmatic buying period. Fixed prices consist of locked-in prices for physical supplies. As discussed in Appendix E, the Company utilizes a multi-tiered buying approach for locking in or hedging gas supply prices. The Company monitors market conditions and stands ready to execute financial swaps when market and pricing conditions warrant. At the time the current procurement strategy was made, the forward price spread between the November 2019 through October 2020 period and the November 2022 through October 2023 period was less than 20%, which was deemed a reasonable and manageable spread given market intelligence available. Figure 4-11 provides a graph showing the Company's projected weighted average cost of gas (WACOG for the 2023 IRP.

Figure 4-11: Projected Cascade WACOG as of May 2022



With the assistance of Gelber & Associates (G&A or Gelber), an energy consulting firm with 30 years of experience in utility hedging, Cascade has continued to evolve its hedging practices to develop a hedging plan that uses a data-driven approach and provides the flexibility to manage both upside price risk and downside hedge loss risk.

Gelber has been working in close coordination with Cascade to design and implement processes and analytics to comply with the Washington Utility and Transportation Commission UG-132019 policy statement while simultaneously complying with Oregon Public Utility Commission UM-1286 PGA integrated hedging guidelines.

WUTC's Docket UG-132019 requires that hedging programs steer away from inflexible, programmatic practices employed previously to become more "risk responsive" and "data driven". WUTC requires an annual hedging plan submission that demonstrates risk responsive strategies in addition to retrospective hedge reporting. Gelber believes and Cascade concurs that the use of a diversified portfolio of hedging instruments including swaps, call options, and fixed-price physicals is the appropriate design criteria to satisfy Commission requirements.

An update on Cascade's work with Gelber on an evolving hedge program can be found in the Company's 2022 Annual Hedge Plan in Appendix E.

Portfolio Purchasing Strategy

As stated earlier, GSOC oversees the Company's gas supply purchasing strategy. Based on current stable prices and a robust supply picture, the Company considers contracting physical supplies for up to three years (based on a warmer-than-normal weather pattern). The Company's current gas procurement strategy is to secure physical gas supplies for approximately one-third of the core portfolio supply needs each year for the subsequent rolling three-year period. This method ensures some portion of the current market prices will affect a portion of the next three years of the portfolio.

GSOC determines the framework for the portfolio design including the allowable percentage of fixed-priced purchases. The execution of the portfolio and the hedging plan is accomplished primarily by the Supervisor of Gas Supply, under the leadership of the Manager of Gas Control & Supply for the Western Region. Either the Supervisor or Manager can execute purchases under the current plan; additionally, they may designate a backup within Gas Supply with the responsibility to execute trades in the event of their absence. The Manager of Supply Resource Planning functions as compliance manager regarding the WUTC's UG-132019 policy statement. These teams are overseen by the Director, Gas Supply—Utility Group.

Under this procurement strategy, approximately 10% to 20% of the annual portfolio is to be met with spot purchases. Spot purchases consist of either first of the month transactions, executed during bid week for the upcoming month, or day purchases which are utilized to meet incremental daily needs.

Once GSOC has approved the portfolio procurement strategy and design, the Company employs a variety of methods for securing the best possible transactions under existing market conditions. The Company employs a variety of methods for securing the best possible deal under existing market conditions. CNGC employs a number of processes when procuring fixed-price physical and indexed-riced spot physical. There is a separate process for financial derivatives as discussed throughout this annual hedge plan.

Physical Supply

CNGC utilizes TruMarx's COMET transaction bulletin board system to assist in communicating, tracking, and awarding most activities involving the Company's physical supply portfolio. In the procurement process for physical natural gas the

Company posts an RFP to Cascade's 25+ physical supply parties to solicit offers on needed supply. The Company then collect bids from these parties over a period, depending on the number or time requirements of the packages sought, comparing the indicative pricing to each party as well as comparing the information to market intelligence available at the time. Ideally, after monitoring these indicatives and the market, CNGC awards the posted packages. Please note that posting on COMET does not obligate CNGC to execute any proposal made by physical suppliers.

Naturally, price is the principal factor; however, CNGC also considers reliability, financial health, past performance, and the party's share of the overall portfolio as to ensure party diversity. It should be noted that there is always the possibility the lowest market price may be during period when the Company is initially gathering the price indicatives; in that situation there is a risk that a sudden price run-up may lead to filling the transaction at the higher end of the bids over time or delay the acquisition to another time. However, the reverse is also true—the initial price indicatives may start high and drop over time, allowing CNGC to capture the transaction on the downward swing. In the end, timing is always a factor as the market cannot be perfectly predicted. As discussed beginning at page 4-7, compliance with applicable laws is a primary factor for RNG rather than price.

Occasionally, an operational situation may occur where time is of essence, such as a need to acquire spot gas to meet sudden swings in load demand or in response to an upstream pipeline operational event. In such situations, CNGC may make a short procurement purchase within a narrow time window to procure and schedule the supply. The Company contacts one to three reliable physical parties to meet these short-term supply needs. Again, price is the principle but not the only driver for the awarding of these supply needs. Also, please note the Company always encourages physical suppliers to propose other transactions or packages that they feel may be of interest in helping CNGC secure cost effective and operationally flexible transactions to meet CNGC's needs. In addition to analysis using Excel, CNGC also uses the PLEXOS® resource optimization model, which is a useful tool for examining logical, operationally and financially feasible physical packages that best utilizes CNGC's various transportation, storage and operational capabilities.

Financial Derivatives

For financial derivatives, CNGC contacts Company-approved financial counterparties ("counterparties") to request bids consistent with the GSOC approved hedge execution plan (HEP). Naturally, this process requires additional analysis regarding financial reasonableness, timing, hedging strategy, and volumes. The Monthly Guidance and CNG Book Model are the primary tools used to identify and analyze potential financial derivatives possibilities. Price comparisons may also become more complicated since pricing could be tiered; part of a structure deal may be tied to an index or contain floors, caps, etc. Bids are received from the counterparties and, similar to the physical portfolio, the Company then collect bids from these parties over a period, depending on the number or time requirements of the packages sought, comparing the indicative pricing to each party as well as applying the information from market intelligence available at the time. Furthermore, G&A uses MarketView and CNGC has limited access to ICE. Both deliver real-time market pricing information for hedging transactions. Ideally, after monitoring these indicatives and the market, CNGC will award the specific packages to individual parties. Again, please note that CNGC is not obligated to execute any offer received. Further information regarding Cascade's evolving hedge program can be found in the Company's 2020 Annual Hedge Plan in Appendix E.

Conclusion

Cascade's 20-year supply side resource goal is to continue to meet the energy needs of its core market customers and compliance requirements for emission reductions. This is accomplished through a package of services that combines adequate gas supplies, renewable natural gas, and cost-effective winter peaking services with long-term pipeline transportation contracts and sufficient distribution system capacity at the lowest possible cost. The Company has identified several transport, storage, and other alternative resources which may be modeled to join the Company's existing demand and supply side resources to address the load demand needs over the planning horizon.

Chapter 5

Avoided Costs

Overview

The avoided cost is the estimated cost to serve the next unit of demand with a supply side resource option at a point in time. This incremental cost to serve represents the cost that could be avoided through energy efficiency. The avoided cost forecast can be used as a guideline for comparing energy efficiency with the cost of acquiring and transporting natural gas to meet demand.

This chapter presents Cascade's avoided cost forecast and explains how it was derived. While the IRP planning horizon is 28 years, avoided costs are forecasted for 45 years to account for the full measure life of some energy efficiency measures, such as insulation, which has a 30-year life. The avoided cost forecast is based on the performance of Cascade's resource portfolio under expected conditions.

Key Points

- Avoided cost forecasting serves as a primary input for determining energy efficiency targets.
- Cascade's avoided costs include fixed transportation costs, variable transportation costs, commodity costs, carbon compliance costs, distribution system costs, a risk premium, and a 10% adder.
- For consistency between the OR and WA IRPs, Cascade is using the Social Cost of Carbon with a 2.5% discount rate as its base carbon compliance costs
- The total avoided cost ranges between $1.00 and $6.52/therm over the 28-year planning horizon.

Costs Incorporated

The components that go into Cascade's avoided cost calculation are as follows:

$$AC_{nominal} = (TC_f + TC_v + SC_v + CC + E_{Comp} + DSC + RP) * E_{adder}$$

Where:

- $AC_{nominal}$ = The nominal avoided cost for a given year. To put this into real dollars apply the following: Avoided Cost/ (1+Discount Rate)^Years from the reference year.
- TC_f = Incremental Fixed Transportation Costs
- TC_v = Variable Transportation Costs
- SC_v = Variable Storage Costs
- CC = Commodity Costs
- E_{Comp} = Environmental Compliance Costs
- DSC = Distribution System Costs
- RP = Risk Premium

- E_{adder} = Environmental Adder, as recommended by the Northwest Power and Conservation Council

The following parameters are also used in the calculation of the avoided cost:

- The most recent load forecast (March 2022);
- The inflation rate used to scale the Social Cost of Carbon (SCC) from Real $2007 to Real $2021 uses the chain type price index for the Gross Domestic Product from the Bureau of Economic Analysis (BEA)[1]
- The discount rate of 7.27% (CNGC WACC from 2021 Results of Operations and Orders in place on 12/31/2021).

Understanding Each Component

- **Incremental Fixed Transportation Costs**

  In the 2023 IRP, Cascade has not included any additional upstream capacity in its preferred portfolio for the 28-year planning horizon. If such a need were to be identified, fixed transportation costs would represent the average reservation rate of all incremental contracts that would be used to solve shortfalls. Importantly, in some cases, these costs are an estimate based on information from the pipeline companies, and furthermore, are treated as confidential as any incremental fixed transportation costs could ultimately be a negotiated rate.

- **Variable Transportation Costs**

  Variable transportation costs are the cost per therm that Cascade pays only if the Company moves gas along a pipeline. This rate is set by the various pipeline companies and can be changed if one of the pipeline companies files a rate case. The final rates filed at the conclusion of a rate case (whether reached through a settlement or a hearing) must be approved by the Federal Energy Regulatory Commission (FERC) for U.S. pipelines and the Canadian Energy Regulator (CER) for Canadian pipelines. To model rate changes in its forecast, Cascade multiplies its transportation costs by the CPI escalator every four years. Four years is a proxy, since rate cases may not be filed each year.

[1] *See* https://officeofbudget.od.nih.gov/gbiPriceIndexes.html

- **Storage Costs**

  Storage costs are the cost per therm that Cascade would pay for a storage contract that solved some or all of Cascade's peak day shortfalls. This would include an on-system storage facility, or a satellite LNG facility connected to Cascade's distribution system. Cascade does not project a need for this resource in its 2023 IRP.

- **Commodity Costs**

  Commodity costs are the costs of acquiring one therm of gas. Cascade first uses PLEXOS® to calculate the monthly percentage of gas that the optimizer would purchase from each of the three basins to serve that climate zone. These weights are then used to derive a single price for the acquisition of that therm. The source for the price that is used for each month's calculation is the monthly price from each year of Cascade's 28-year price forecast.

- **Environmental Compliance Costs**

  Once the Company has calculated its average cost of gas, a price for expected carbon compliance costs must be added. Cascade converts the cost of carbon in dollars per metric ton to dollars per dekatherm, accounting for the upstream natural gas value chain emissions in this calculation. Further information about this calculation can be found in Chapter 6, Environmental Policy. Accurate modeling of these costs has been challenging in years past due to uncertainty surrounding how these costs will ultimately be quantified. For this IRP, Cascade will continue to use the SCC with a 2.5% discount rate as its carbon compliance cost, adjusting the values of the SCC from Real $2007 to Real $2021 by using GDP data published by the BEA. The Company believes this accurately captures avoided environmental compliance costs and is consistent with the methodology used in the 2023 WA IRP, where use of the SCC with a 2.5% discount rate is required. For future iterations of the avoided cost, Cascade is exploring using the marginal abatement cost for emissions compliance in a given year, as opposed to the SCC, as this value may more accurately represent the Company's practical and specific cost for compliance, as reflected by the cost of the next most expensive resource for emissions reduction (RNG, Hydrogen, projection allowance price in auction.)

  Cascade calculates the inflation adjusted SCC to start at $83.13/Metric Ton CO_2e in 2023, rising to $104.18/Metric Ton CO_2e in 2042. In Cascade's initial avoided cost calculation, these values were equivalent to $4.49/dth in 2023, rising to $5.94/dth in 2042. Overall, carbon compliance costs related to the SCC are a significant factor in Cascade's avoided cost calculation, accounting for as much as 49.22% of the total system avoided cost in a given year.

- **Environmental Adder**

  Cascade includes a 10% adder for non-quantifiable environmental benefits as recommended by the Northwest Power and Conservation Council. As a result of conversations with various stakeholders during the IRP process, Cascade is modifying its methodology for applying the 10% adder. In the Company's 2023 IRP the adder will be applied to all elements of the avoided cost. For reference, this adder was only applied to the Commodity and Environmental Compliance Costs in prior IRPs.

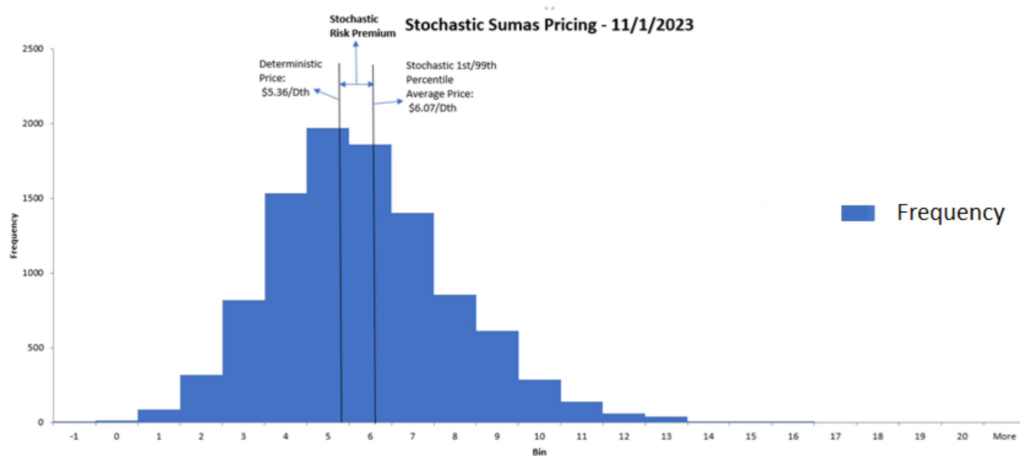
- **Distribution System Costs**

  Distribution system costs capture the costs of sending gas from the citygate to Cascade's customers. For this IRP cycle, Cascade has moved away from defining these costs as a function of margin and towards a capacity deferral valuation calculation. It is important to recognize that while energy efficiency may not be able to fully eliminate the need for a distribution system enhancement, it can defer the need for these enhancements to a later year. Because of the economic principle of the time value of money, this deferral has value, and that value is the avoided distribution system cost for the 2023 IRP. To calculate these costs, the Company projects what investments it may need to make related to growth of the distribution system, and divides that by the projected peak day load growth from Cascade's load forecast. Cascade calculates distribution system costs for both peak day and peak hour, as distribution system analysis is most concerned about system capabilities during a peak hour scenario.

- **Risk Premium**

  Cascade defines risk premium as the difference between the impacts of a potential extreme upward price movement versus that of an extreme downward price movement. Due to the lognormal nature of gas prices, the risk presented from rising prices will typically exceed that of falling prices. This is presented visually in Figure 5-1, which shows the frequency of Sumas pricing over 10,000 stochastic draws for a given month. By identifying the average of the 1st and 99th percentile of these draws, and comparing that to the deterministic or expected pricing, the Company can identify a Stochastic Risk Premium.

Figure 5-1: Stochastic Sumas Pricing 11/1/2023



The Stochastic Risk Premium is then entered into the company's Risk-Adjusted Risk Premium Final Calculation, which is defined as:

Deterministic Price * .75 + (((99th Percentile Stochastic Price + 1st Percentile Stochastic Price) /2) * .25)) - Deterministic Price

The result of this calculation is the Company's risk premium input to its avoided cost calculation.

Application

The 2023 IRP makes several enhancements in calculating and applying the avoided costs, specifically related to its application of the environmental adder, and enhancements to the distribution system cost calculation methodology. This cost metric becomes the foundation for prudency determinations regarding energy efficiency, both operationally and from a resource planning perspective. It may be helpful to think of the final avoided cost figure as something of a cutoff point. Any action that would save a therm of gas could be evaluated based on the cost per therm saved of that measure. If that number is lower than the avoided cost, it may make sense to implement that measure. If not, such a measure may not be optimal to engage in.

Avoided Cost Sensitivity Analysis

The 2023 IRP is Cascade's first Plan to incorporate emissions reduction goals related to the Climate Protection Program in Oregon and the Climate Commitment Act in Washington. To mitigate risks from the uncertainty around these regulations, the Company is performing scenario analyses around a number of variables that may impact Cascade's compliance options. One sensitivity that the Company is evaluating is around the amount of energy efficiency that Cascade may need to acquire. In scenarios where the Company may need more energy efficiency, Cascade models its avoided commodity cost as the projected cost of RNG/Green Hydrogen. In these scenarios, it is assumed the energy efficiency would not be competing with traditional natural gas, but rather emissions reducing resources, hence the use of these resources as the pricing counterpoint. The impact of this sensitivity adjustment can be found in Appendix H.

Results

Figure 5-2 displays a comparison of the average nominal avoided cost over the planning horizon for the current and past IRPs. Figure 5-3 displays the total avoided cost by each conservation zone over the 28-year IRP horizon, while Figure 5-4 provides the net present value of avoided costs over the planning period. Conservation Zone 1 covers the west side of Cascade's service territory, with load centers such as Bellingham, Stanwood, and the Sedro/Wooley area. Conservation Zone 2 refers to the central Washington service area, with load centers such as Bremerton, Longview, and Castle Rock. Conservation Zone 3 covers the eastern Washington service area, including Yakima, Walla Walla, and the Tri Cities. Finally, Zone 4 refers to Oregon citygates. A map of the Conservation Zones can be found in Figure 12-14 in Chapter 12, Glossary and Maps. For the 2023 IRP, nominal system avoided costs range between $1.00/therm and $6.52/therm, with the average avoided cost of $1.78/therm.

As mentioned earlier, the avoided cost is based on the performance of the portfolio under expected conditions for the entire 28-year planning horizon. Overall, avoided costs for the 2023 IRP are higher than in the 2020 IRP. The main driver of this is the new distribution system cost methodology, which projects a higher avoided cost, particularly when peak day load growth is lower, with distribution system investments still to be expected. The 45-year avoided costs and other detailed tables of avoided costs are found in the Excel version of Appendix H.

Figure 5-2: Avoided Cost Comparison to Previous IRPs

	2010 IRP	2012 IRP	2014 IRP	2016 IRP	2018 IRP	2020 IRP	2023 IRP
Nominal $/Therm	$ 0.810	$ 0.528	$ 0.610	$ 0.571	$ 0.673	$ 0.936	$ 1.779

Figure 5-3: Nominal Avoided Costs by Zone (Cost per Therm)

Nominal Avoided Cost (By Zone) - $/Therm							
	Zone 1	Zone 2	Zone 3	Zone 4	Oregon	Washington	System
2023	$1.218	$1.471	$1.355	$1.387	$1.387	$ 1.315	$1.358
2024	$0.921	$1.264	$1.159	$1.665	$1.665	$ 1.250	$1.460
2025	$2.393	$1.220	$1.063	$1.068	$1.068	$ 1.079	$1.078
2026	$1.507	$1.022	$0.952	$1.126	$1.126	$ 0.953	$1.042
2027	$2.442	$1.149	$1.001	$1.047	$1.047	$ 1.030	$1.040
2028	$2.385	$1.100	$0.986	$1.012	$1.012	$ 1.013	$1.014
2029	$2.607	$1.250	$1.051	$1.022	$1.022	$ 1.085	$1.056
2030	$0.895	$3.708	$1.954	$1.066	$1.066	$ 2.690	$1.887
2031	$2.672	$1.239	$1.074	$1.133	$1.133	$ 1.107	$1.121
2032	$1.717	$1.109	$1.031	$1.148	$1.148	$ 1.039	$1.094
2033	$2.811	$1.415	$1.160	$1.096	$1.096	$ 1.197	$1.148
2034	$3.073	$1.327	$1.114	$1.063	$1.063	$ 1.161	$1.113
2035	$2.902	$1.322	$1.141	$1.073	$1.073	$ 1.179	$1.127
2036	$0.993	$1.931	$1.340	$1.118	$1.118	$ 1.577	$1.350
2037	$1.859	$1.230	$1.126	$1.168	$1.168	$ 1.130	$1.149
2038	$3.343	$1.413	$1.208	$1.121	$1.121	$ 1.253	$1.187
2039	$3.304	$1.413	$1.212	$1.138	$1.138	$ 1.257	$1.198
2040	$3.662	$1.386	$1.214	$1.126	$1.126	$ 1.262	$1.195
2041	$1.064	$1.072	$5.998	$1.163	$1.163	$ 11.790	$6.527
2042	$4.016	$1.529	$1.291	$1.223	$1.223	$ 1.352	$1.289
2043	$4.117	$1.567	$1.323	$1.253	$1.253	$ 1.386	$1.321
2044	$4.226	$1.608	$1.358	$1.287	$1.287	$ 1.422	$1.356
2045	$4.344	$1.653	$1.396	$1.323	$1.323	$ 1.462	$1.394
2046	$4.472	$1.702	$1.437	$1.362	$1.362	$ 1.505	$1.435
2047	$4.608	$1.754	$1.481	$1.403	$1.403	$ 1.551	$1.479
2048	$4.752	$1.809	$1.528	$1.447	$1.447	$ 1.599	$1.525
2049	$4.905	$1.867	$1.577	$1.494	$1.494	$ 1.651	$1.574
2050	$5.065	$1.928	$1.628	$1.542	$1.542	$ 1.705	$1.625

Figure 5-4: Real $2021 Avoided Costs by Zone (Cost per Therm)

Real 2021$ Avoided Cost (By Zone)							
	Zone 1	Zone 2	Zone 3	Zone 4	Oregon	Washington	System
2023	$1.218	$1.471	$1.355	$1.387	$1.387	$ 1.315	$1.358
2024	$0.877	$1.203	$1.103	$1.585	$1.585	$ 1.190	$1.390
2025	$2.168	$1.105	$0.963	$0.968	$0.968	$ 0.978	$0.976
2026	$1.300	$0.882	$0.821	$0.971	$0.971	$ 0.822	$0.898
2027	$2.004	$0.943	$0.822	$0.859	$0.859	$ 0.845	$0.854
2028	$1.863	$0.860	$0.771	$0.791	$0.791	$ 0.791	$0.793
2029	$1.939	$0.929	$0.782	$0.760	$0.760	$ 0.807	$0.785
2030	$0.633	$2.625	$1.383	$0.754	$0.754	$ 1.904	$1.336
2031	$1.801	$0.835	$0.724	$0.763	$0.763	$ 0.746	$0.755
2032	$1.101	$0.711	$0.661	$0.736	$0.736	$ 0.666	$0.702
2033	$1.716	$0.864	$0.708	$0.669	$0.669	$ 0.731	$0.701
2034	$1.785	$0.771	$0.647	$0.618	$0.618	$ 0.674	$0.647
2035	$1.605	$0.731	$0.631	$0.593	$0.593	$ 0.652	$0.623
2036	$0.523	$1.016	$0.705	$0.589	$0.589	$ 0.830	$0.711
2037	$0.932	$0.616	$0.564	$0.585	$0.585	$ 0.566	$0.576
2038	$1.594	$0.674	$0.576	$0.535	$0.535	$ 0.598	$0.566
2039	$1.500	$0.642	$0.550	$0.516	$0.516	$ 0.571	$0.544
2040	$1.582	$0.599	$0.525	$0.486	$0.486	$ 0.545	$0.516
2041	$0.438	$0.441	$2.467	$0.478	$0.478	$ 4.849	$2.684
2042	$1.572	$0.598	$0.505	$0.479	$0.479	$ 0.529	$0.504
2043	$1.534	$0.584	$0.493	$0.467	$0.467	$ 0.516	$0.492
2044	$1.499	$0.570	$0.482	$0.456	$0.456	$ 0.504	$0.481
2045	$1.466	$0.558	$0.471	$0.447	$0.447	$ 0.494	$0.471
2046	$1.437	$0.547	$0.462	$0.437	$0.437	$ 0.484	$0.461
2047	$1.409	$0.536	$0.453	$0.429	$0.429	$ 0.474	$0.452
2048	$1.383	$0.527	$0.445	$0.421	$0.421	$ 0.466	$0.444
2049	$1.359	$0.517	$0.437	$0.414	$0.414	$ 0.457	$0.436
2050	$1.336	$0.508	$0.429	$0.407	$0.407	$ 0.450	$0.429

Chapter 6

Environmental Policy

Purpose

This chapter considers Greenhouse Gas (GHG) emission reduction policies and regulations that impact or have the potential to impact natural gas distribution companies and Cascade's methodologies for applying a cost of carbon to natural gas distribution. This discussion also includes the assumptions made in determining a 45-year avoided cost of natural gas and pairs these costs with associated two- to four-year action items.

Key Points

- State and federal agencies have issued GHG emission reduction regulations and are considered in the 2023 IRP.
- On March 20, 2020, Oregon Governor Brown issued EO 20-04 directing state agencies to reduce GHG emission under their existing authority. DEQ released the final Climate Protection Program rule on December 16, 2021.
- Cascade models carbon compliance costs as the SCC with a 2.5% discount rate, updated to real $2021.
- On July 21, 2021, the Washington legislature passed the Climate Commitment Act directing the Department of Ecology (Ecology) to develop and enforce a rule for implementing a GHG cap and trade program. Ecology released the final Climate Commitment Act rule on September 29, 2022.
- Washington state building code revisions effective late October 2023, limiting natural gas use for space and water heating in new and retrofitted commercial and residential.
- Cascade continues to monitor and engage in state, local, and federal regulatory and legislative actions.

Since the last IRP, the Oregon Department of Environmental Quality issued the Climate Protection Program (CPP) rule, OAR 340-271-0100, in late 2021 per Governor Brown's executive order directing state agencies to pursue GHG emission reductions under their authority.[1] Oregon's rule establishes a cap on GHG emissions for certain sectors, including natural gas distribution customer emissions, and requires significant reductions between 2022 and 2050.

Also, policymakers in Washington passed the Climate Commitment Act (CCA), RCW 70A.45.020, giving the Department of Ecology (Ecology) authority to regulate GHG emissions from natural gas distribution utilities, including customer emissions.[2] The Federal Government has been re-evaluating GHG emissions rulemaking for electric generating units that is expected to be re-proposed in 2023, and laws have passed which incentivize development of lower or zero-carbon energy resources.

[1] *See:* https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=6597
[2] *See:* https://apps.leg.wa.gov/rcw/default.aspx?cite=70A.45.020

Company Environmental Policy

Cascade's policy states:

"The Company will operate efficiently to meet the needs of the present without compromising the ability of future generations to meet their own needs. The environmental goals are:

> *To minimize waste and maximize resources;*
> *To be a good steward of the environment while providing high quality and reasonably priced products and services; and*
> *To comply with or surpass all applicable environmental laws, regulations, and permit requirements."*

Cascade is committed to maintaining compliance with all laws and regulations and strives to operate in a sustainable manner, while taking into consideration the cost to customers. Cascade actively engages in public proceedings related to federal and state legislative and regulatory activities. This includes offering comments on environmental policy, including air emissions and other environmental requirements. The Company has also established memberships in relevant trade organizations to assist in monitoring the potential impact of proposed legislation and regulation to the Company's operations. Cascade's goal is to ensure safe, affordable, reliable energy for Cascade's customers while serving as stewards of the Company's natural resources.

Overview

Cascade monitors environmental regulatory requirements in progress nationally, regionally, and locally that have the impacts to natural gas distribution companies. As of November 21, 2022, there are no regulations at the federal level that would require the Company to reduce GHG emissions. However, the Climate Protection Program (CPP) was finalized in Oregon on December 16, 2021, and requires GHG emissions reductions from natural gas distribution companies' customers use of natural gas. Also, the Climate Commitment Act (CCA) rule was finalized in Washington on September 29, 2022, requiring similar emissions reductions as the CPP, but through a cap and trade-type program. Cascade's compliance with the CPP is modeled within this IRP.

There have been no congressional bills or federal agencies proposing GHG reductions that would significantly impact natural gas distribution. Rather, on a federal level, there have been programs established to provide platforms to encourage the natural gas distribution segment to make voluntary commitments in reducing GHG emissions. One of the voluntary platforms is EPA's Natural Gas

Star Methane Challenge Program. The Methane Challenge Program was established by EPA in collaboration with oil and natural gas companies with Cascade participating as a founding partner of the program in March 2016 along with about 50 other companies. Partners in the program demonstrate their commitment and concern for the environment through voluntary methane emissions reductions.

Cascade used the Social Cost of Carbon (SCC) with a two and one-half percent discount rate that was established by the Interagency Working Group (IWG) on Social Cost of Greenhouse Gases to model societal costs of GHG emissions resulting from customers' combustion of natural gas. The SCC is estimated using different discount rates to develop a range of costs in dollars per ton of CO_2 that would represent the avoided cost of long-term damage from climate change caused by a ton of CO_2 emitted in a given year. Agencies, such as the EPA, have used the SCC in determining the cost of climate impacts from rulemakings. For this IRP, Cascade will use the same discount rate as the main CO_2 adder in modeling.

The Company has been involved in state-focused evaluation of renewable natural gas (RNG) opportunities in Oregon and Washington, and regionally. Cascade also monitors federal and regional RNG policy development through the Company's membership in trade organizations. Cascade provides discussion of RNG projects and additional procurement opportunities in Chapter 4, as RNG will be important to consider for Oregon and Washington GHG emission rule compliance.

There are community-driven efforts to achieve GHG emission reduction targets within, and adjacent to, Cascade's service areas. The City of Bend, Oregon has adopted GHG reduction measures. Cascade continues to meet with the city ongoing regarding potential future partnership on RNG development and community-wide carbon offset programs and will soon be piloting energy assessments for Cascade's transportation customers in the Bend region to determine energy savings potential and compliance pathways consistent with CPP compliance. Cascade will continue engaging with these communities and working with them to support GHG emission reduction targets and goals while supporting the triple bottom line of economics, equity, and sustainability. Also, in Washington a significant measure impacting natural gas use was adopted in Bellingham this year. On February 7, 2022, the Bellingham City Council passed an ordinance on requiring electric space and water heating equipment for new commercial and large (4-plus story) multifamily buildings. The electric-only mandate for space and water heating does not apply to single family construction, detached houses, duplexes, townhomes, or row houses. The ordinance rook effect on August 7, 2022. The City of Bellingham continues to explore electrification measures for residential buildings within Bellingham.

Cascade examines the policies and regulatory activities mentioned above in determining GHG emissions compliance or carbon costs for the IRP analyses. The Company considers both proposed and final regulations and legislation in this process. The following subsections provide discussion of the policy and regulatory development that has been most informative in evaluating carbon impacts on Cascade's operations and customers. Cascade also includes discussion on the Company's GHG emissions and actions and commitments the Company has taken to reduce GHG emissions.

Federal Regulation and Policy

1. Congressional Actions

Cascade monitors congressional actions on clean energy and decarbonization matters and discusses them below.

a. Infrastructure, Investment and Jobs Act (IIJA)

President Biden signed the Infrastructure, Investment and Jobs Act (IIJA), also known as the Bipartisan Infrastructure Law (BIL), into law in November 2021. The law provides infrastructure funding opportunities, including direction to EPA in making investments in communities to improve water quality, promote cleanup of contaminated sites and recycling and waste management of batteries, decarbonizing school buses, and overall pollution prevention. Also, per the IIJA, DOE has launched a notice of intent for funding opportunities for Clean eek Programs, including demonstration of regional clean hydrogen hubs. The IIJA hydrogen programs work in combination with the Hydrogen Energy Earthshot (Hydrogen Shot) which DOE launched in June 2021 which aims to accelerate a breakthrough in hydrogen as an abundant, affordable, and reliable clean energy solution and reduce the cost of clean hydrogen by 80% to $1 per 1 kilogram of hydrogen in 1 decade (1 1 1).

In addition, and in consideration of the Hydrogen Shot, IIJA and the Inflation Reduction Act (IRA), DOE posted a draft National Clean Hydrogen Strategy and Roadmap in September 2022. The draft roadmap proposes a clean hydrogen strategy and roadmap focusing on a goal of achieving use of 10 million metric tons of clean hydrogen annually by 2030, 20 million metric tons annually by 2040, and 50 million metric tons annually by 2050. By 2050, DOE projects this hydrogen implementation would reduce U.S. GHG emissions by 10% relative to 2005 levels, with a main focus on developing cost-effective hydrogen for specific sectors having limited decarbonization alternatives, such as industrial facilities. Three key strategies noted by DOE for clean hydrogen include targeting strategic high impact uses, focus on regional networks (hydrogen hubs), and reduce its cost.

Most of the funding opportunities in the IIJA are directed to communities and do not appear to be directly available to utilities. However, there may be opportunities for utilities to participate or partner with other organizations in the regional clean hydrogen programs. Cascade will continue to monitor these decarbonization programs for opportunities where the Company can best participate and/or provide support.

b. Inflation Reduction Act (IRA) of 2022

The Inflation Reduction Act was signed into law by President Biden on August 16, 2022. The law aims to address inflation through a number of measures including investment in domestic energy production and clean energy infrastructure for decarbonizing the economy.

The law includes a Methane Emissions Reduction Program[3] that applies fees to methane releases for certain oil and gas facilities that emit beyond 25,000 metric tons of carbon dioxide equivalent (CO_2e) and incentivizes investments in reducing methane leaks from oil and gas infrastructure. These requirements do not apply to distribution systems in general, and Cascade does not have facilities within the other regulated sector categories in the Program that emit above the 25,000 CO_2e metric ton emissions threshold requiring fees. However, the cost of natural gas could increase as fees and other emission reduction costs may be passed through to distribution utilities from emissions subject to this Program from upstream oil and gas segments in the natural gas value chain.

The IRA also incentivizes RNG development projects which could benefit Cascade and customers. Cascade will continue to evaluate the IRA for potential opportunities in developing RNG projects, as well as other elements that may impact natural gas distribution.

The IRA includes a Home Energy Performance-Based, Whole House Rebate program that awards grants to State energy offices to develop and implement a Home Owner Managing Energy Savings (HOMES)

[3] Text - H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022 | Congress.gov | Library of Congress, Section 60113

rebate program.[4] The HOMES rebate program will allow homeowners to utilize rebates from this program to upgrade and improve the efficiency of their home.

The IRA includes a High-Efficiency Electric Home Rebate program that awards grants to State energy offices ($4.275 Billion) and Indian Tribes ($225 million) to develop and implement a high-efficiency electric home rebate program.[5]

Other aspects of the IRA that may impact Cascade include:

- An extended residential tax credit for qualified energy efficiency home improvements;
- Tax provisions that gas utilities, or industrial customers, may use to reduce GHG emissions; and
- A new tax credit for the qualified production of clean hydrogen and extension and modification of credit for carbon oxide sequestration.

Cascade has included a summary of the parts of the IRA that may impact the Company. Since the IRA was not signed into law until August 16, 2022, after the demand forecast, avoided cost, energy efficiency, and much of the carbon compliance modeling was complete, the IRA is not incorporated in this IRP, but will be included in future IRPs.

2. Federal Agency Actions

Cascade monitors federal agency actions on clean energy and decarbonization matters and describes them below.

a. US Department of Energy (DOE)

The Department of Energy (DOE) establishes energy efficiency standards for many products used in residential, commercial, and industrial buildings and applications and is required to review and update these standards periodically. DOE considers in its rulemaking what is technically feasible and economically justified. In 2022, DOE began holding public meetings to gain input from stakeholders on

[4] Text - H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022 | Congress.gov | Library of Congress, Section 50121
[5] Text - H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022 | Congress.gov | Library of Congress, Section 50122

rulemaking for commercial water heating equipment energy conservation standards. Cascade is monitoring this rulemaking as it may result in impacts to baseline equipment used to determine the Cascade's Energy Efficiency portfolio.

b. Environmental Protection Agency (EPA)

The Environmental Protection Agency (EPA) released rulemaking on June 21, 2022, proposing amendments to 40 CFR Part 98 Subpart W (oil and gas segment) operational GHG emissions reporting. EPA has proposed emission factor updates and additional reporting of "other large release events" which are defined as unplanned, unexpected, and uncontrolled releases to the atmosphere of gas, liquids, or mixture thereof, from wells and/or other equipment that result in emissions for which there are no methodologies in the rule [§98.233] to appropriately estimate these emissions. A final rule is expected in 2023. Once the rule is final, Cascade will incorporate the amended requirements into the Company's emissions reporting.

EPA is promulgating new rule rulemaking for fossil fuel-fired electric generating units (EGUs) considering a U.S. Supreme Court decision this year. On June 30, 2022, the U.S. Supreme Court issued an opinion in West Virginia v. EPA, regarding the scope of EPA's authority under section 111(d) of the CAA for regulating EGUs. The Court did not call into question EPA's authority to regulate GHGs under the CAA. The Court concluded that EPA could not regulate under that section in a way that would force the power grid to shift from one type of generation to another. The Court also brought the "major questions doctrine" into the discussion, by observing that the Constitution does not authorize agencies to use regulations as substitutes for laws passed by Congress.

Throughout the summer of 2022, EPA held stakeholder meetings to solicit input on how to structure standards for new and existing fossil fuel EGUs. EPA also sought input on the appropriateness of different control strategies for different subsectors of the fossil-fired EGU fleet, issues surrounding public health and environmental justice, and whether the agency should build the upcoming rules around a rate-based standard that places limits on the amount of pollution an EGU can release per unit of energy produced, among other rulemaking considerations.

On September 7, 2022, EPA announced the opening of a non-rulemaking docket for additional public input from stakeholders on the Agency's efforts to reduce emissions of greenhouse gases from new and existing fossil fuel-fired EGUs. The docket will be open for public comment until March 27, 2023, and the agency is expected to release rule proposals shortly after the docket closes.

On May 23, 2023, EPA released in the Federal Register the proposed Clean Air Act (CAA) section 111 regulations to address GHG emissions from new and existing fossil-fired EGUs. Comments are due by June 24, 2023. The proposal is complex, with different best system of emission reduction (BSER) methods and technologies specified for fossil-fired EGUs depending on which subcategory an EGU falls under. Different timelines would apply for meeting a standard depending on the EGU subcategory and chosen BSER. Cascade is reviewing the rule. It is unknown at this time how the rule would impact Cascade and natural gas customers regulated under this rule.

c. Securities and Exchange Commission GHG and Climate-related Risk Disclosure Rulemaking

On March 21, 2022, the Securities and Exchange Commission (SEC) proposed rulemaking to enhance climate-related disclosures from publicly traded companies and is applicable to Cascade through Cascade's parent company MDU Resources Group, Inc. The rule proposes to require disclosure of climate-related impacts to the company, applying methodologies based on the Taskforce on Climate-related Financial Disclosures (TCFD) framework which provides guidance on disclosing material climate-related risks and opportunities pertinent to business activities. The rule also proposes using methodologies from the GHG Protocol for measuring and reporting of scope 1 and 2 GHG emissions related to company operations and energy use and may also include scope 3 emissions related to value chains, as well as emissions mitigation actions.

Certain portions of these disclosures would require third-party auditing or attestation. There are also proposed disclosure requirements for companies that develop publicly established GHG reduction targets or goals, requiring a detailed description of the included emissions or operations, how a company intends to meet those goals, a plan for tracking progress, and the time horizon for achieving the goals.

Rulemaking public comment initially closed on June 17. However, the SEC reopened comment on October 7, 2022, for an additional

14 days to provide comment to those whose comments may not have been received due to a technological error where some comments were not being received through the SEC's web form. The rule is expected to be finalized by end of 2023.

3. Social Cost of Carbon (SCC)

The SCC is estimated using different discount rates to develop a range of costs in dollars per ton of CO_2 that would represent the avoided cost of long-term damage from climate change caused by a ton of CO_2 emitted in a given year. Agencies, such as the EPA, have used the SCC in determining the cost of climate impacts within rulemakings. Other agencies, such as FERC, continue to consider whether and/or how to incorporate the SCC into their permitting and rulemaking processes.

In this IRP, Cascade is applying the SCC with a two and one-half percent discount rate from the IWG's August 2016 SCC report, but now updated to real $2021, as the carbon compliance adder in modeling impacts of a potential price that could be placed on CO_2 emissions from customers' usage of natural gas.

State Regulation and Policy

New and revised environmental regulations and policies have been enacted in Oregon and Washington. The purpose of these policies and rules is to address GHG emissions resulting from the use of fossil fuels. Some of these regulations result in increases to Cascade operating costs and reduce the sale and usage of natural gas.

1. Oregon

Since the last IRP, no GHG cap and trade program legislation has passed. In early 2020, Governor Brown released an Executive Order (EO) for state agencies to implement GHG reductions within their authority. Discussion of this EO and the Depart of Environmental Quality's subsequent Climate Protection Program (CPP) rulemaking is provided below. Cascade has modeled the compliance pathways and costs of the CPP compliance in this IRP.

a. Executive Order (EO) No. 20-04

In early 2020 Oregon Governor Kate Brown issued Executive Order 20-04, directing state commissions and agencies to facilitate achievement of new GHG emissions goals of at least 45% below 1990 levels by 2035, and at least 80% below 1990 levels by 2050. The order specifically directed the Environmental Quality Council (EQC) and Department of Environmental Quality (DEQ) to take actions necessary to cap and reduce GHG emissions. EO 20-04 is also intended to build on EO 17-20, Accelerating Efficiency in Oregon's Built Environment to Reduce Greenhouse Gas Emissions and Address Climate Change.

EO-20-04 included 13 directives to multiple state agencies establishing reporting requirements and deadlines for implementing GHG reductions. Specifically, the EO directed the EQC and DEQ to take actions necessary to cap and reduce GHG emissions, consistent with the new GHG emissions goals from large stationary sources, transportation fuels, and other liquid and gaseous fuels, including natural gas. Since the EQC and DEQ do not have the authority to implement a market-based cap and trade type system, it was anticipated that a rule would be developed to cap emissions at a baseline emissions value with a limited number of allowances distributed to regulated entities and reduce allowance allocations over time. The EO directed DEQ to commence cap and reduce program options no later than January 1, 2022.

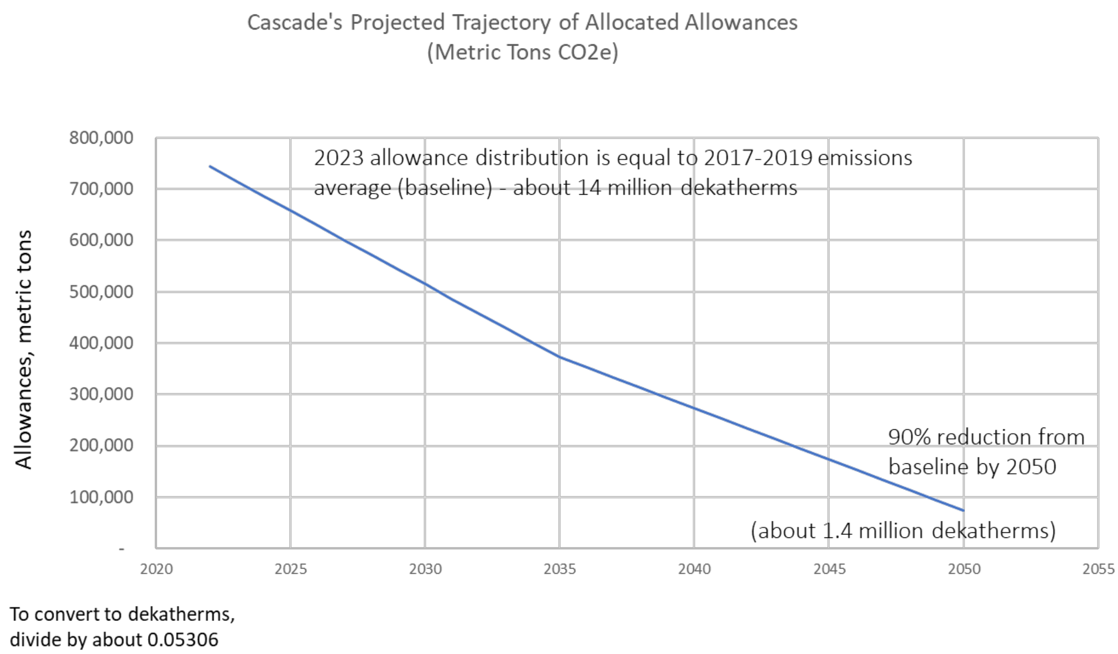
DEQ published a report describing the EQC's legal authority to cap and reduce GHG emissions and proposed a process for rulemaking. In 2020, DEQ was directed by the EO to propose rulemaking and sought input from the public to inform the agency's rulemaking approach and design. DEQ published a report describing the EQC's legal authority to cap and reduce GHG emissions and proposed a process for rulemaking. Throughout DEQ's process, Cascade engaged in the public meetings and provided input.

b. Climate Protection Program (CPP)

DEQ released the draft Climate Protection Program (CPP) rule for public comment on August 5, 2021, and issued the final CPP rule on December 16, 2021. The rule regulates GHG emissions from covered entities, including carbon dioxide (CO_2), methane (CH4), and nitrous oxide (N2O) starting in 2022. Covered entities include fuel suppliers, such as petroleum fuel suppliers and natural gas distribution utilities, as well as large stationary emission sources that emit more than 25,000 metric tons of CO_2e per year. GHG emissions resulting from natural gas use within the state reside with the natural gas distribution utility delivering the natural gas and are not the responsibility of the consumers of natural gas, such as large industrial facilities. Large industrial facilities are regulated under the CPP if their GHG process emissions and fuel combustion not otherwise regulated from a covered fuel supplier meet or exceed 25,000 metric tons of CO_2e per year. Therefore, natural gas suppliers, such as Cascade, are regulated for the GHG emissions in Oregon associated with the Company's aggregated customers' combustion or oxidation of natural gas for all core and non-core customers. Further, the CPP does not regulate GHG emissions from electric generation facilities, and natural gas usage at electric generating plants with total nominal electric generating capacity of less than 25 megawatts would fall under the responsibility of a natural gas distribution utility delivering the natural gas.

The CPP emissions are capped starting in 2022 at a baseline emissions level equivalent to the average of 2017-2019 emissions from covered entities. The cap declines overtime to meet rule reduction targets of 50% below baseline emissions by 2035 and 90% below baseline emissions by 2050. DEQ allocates no-cost emissions allowances to covered entities starting in 2022, with that year's allocation equivalent to an entity's baseline emissions. DEQ reduces allowance allocation each year proportionate to that years' emissions cap and DEQ will distribute no-cost allowances to covered entities annually by March 31. Allowances can be banked indefinitely. Cascade's 2022 allowance allocation is 743,707 metric tons CO_2e, equivalent to the Company's baseline of 2017-2019 average emissions and Cascade projects the Company's 2022 emissions to be in the range of about 800,000 metric tons CO_2e. Cascade's allowance allocations are shown in Figure 6-1.

Figure 6-1: Cascade's Projected Trajectory of OR CPP Allowance Allocations



Excluded emissions for natural gas distribution companies include CO_2 from the combustion of biomethane or RNG purchased for natural gas customers and GHG emissions from natural gas delivered to electric generating plants with a total nominal electric generating capacity of greater than or equal to 25 megawatts. Cascade delivers natural gas to electric generating plants having total electric generating capacities greater than 25 megawatts and does not currently deliver to plants with total nominal capacity lower than 25 megawatts.

The CPP requires compliance to be demonstrated by November 28 of the year following each three-year compliance period. The first three-year compliance period is from 2022 to 2024 and compliance must be demonstrated for this period by November 28, 2025. There are no interim period emissions compliance obligations as in the WA CCA. Compliance is demonstrated by surrendering no-cost emissions allowances to DEQ for retirement, purchasing and retiring allowances that may potentially be offered for trade by other covered entities, and a limited amount of Community Climate Investment (CCI) credits (described further below). Emission reductions for natural gas distribution utilities can also be achieved by replacing conventional natural gas supply with RNG and hydrogen, as well as and through implementing energy efficiency and conservation programs to reduce customer use of natural gas.

At this time, Oregon CCP compliance is expected to be predominantly met with no-cost allowances and RNG purchases, as well as through energy efficiency and conservation measures and possibly some CCIs. The role of energy efficiency and conservation programs is essential in achieving emissions reductions for CPP compliance as illustrated in Figure 9-14 in Chapter 9, Resource Integration. More information on Energy Efficiency can be found in Chapter 7, Demand Side Management.

A CCI can be used to offset one metric ton of CO_2e emissions and provide a limited mechanism for demonstrating compliance beyond no-cost allowances. CCIs can be used to meet up to 10% of a covered entity's compliance obligation in the first compliance period, 15% in the second compliance period and 20% in the third compliance period and thereafter. Cascade provides charts and additional discussion of the compliance instruments and proposed compliance pathways modeled in Chapter 9, Resource Integration.

CCIs are generated and obtained by a covered entity when DEQ approves payments from covered entities to DEQ-approved CCI entities. DEQ expects CCI entities to achieve GHG emissions reductions through funding from the payments from covered entities. The cost of each CCI credit is equal to the carbon dioxide social cost of carbon and is adjusted for inflation annually. Covered entities can bank CCIs for two compliance periods only and cannot be traded or transferred to another covered entity. There are currently no CCI entities approved by DEQ but could be in future. If no CCI entities are approved, no CCIs can be generated.

In early spring 2023, DEQ announced the agency will be amending the GHG emissions reporting rule OAR 340-215, including amendments to biomethane reporting by natural gas suppliers. The rule amendments relate to compliance demonstrations under the CPP. DEQ initiated a Regulatory Advisory Committee (RAC) in April to obtain input for the rulemaking and is hosting monthly RAC meetings from April through June. Cascade was not selected to be a member of the RAC and will submit comments where DEQ provides public comment opportunities within the RAC process and when a proposed rule is ultimately released. DEQ plans to release a notice of proposed rulemaking for public comment in August and publish a final rule for EQC approval by November 2023.

Cascade has hired a consultant, Guidehouse, to provide assistance and advice in setting up internal company processes for ongoing compliance demonstration for the CPP, as well as with WA CCA rule compliance discussed further below. Cascade will consider both the OR CPP and WA CCA in compliance planning to achieve any potential compliance planning efficiencies. At the outset, Cascade has been utilizing Resource Planning modeling tools for compliance planning and will be working with Guidehouse to develop any additional near-term planning tools for CPP compliance planning.

c. Rebuild Task Force

Per the provisions of Senate Bill 1518, the Resilient Efficient Buildings Task Force was convened to identify and evaluate policies related to building codes and building decarbonization for new and existing buildings that would enable the state to meet greenhouse gas emissions reduction goals while maximizing additional benefits. The Task Force was charged with developing recommendations with consideration for the costs, savings, and benefits of policies that relate to residential, commercial, and industrial buildings. The group met twice a month between April and December of 2022. A final report was adopted on December 13, which will be used to inform conversations around environmental policy in the 2023 legislative session.

The final report issued by the Resilient Efficient Buildings Task Force details a series of recommendations, and the overall support for each recommendation by Task Force members. The top three ranked considerations by importance for Task Force members were:

- Avoided GHG Emissions
- Energy Efficiency
- Public Health and Air Quality

Considerations ranked further down the list by Task Force members (excluding the “other” category) were:

- Household Cost Impact
- Abatement Cost Impact
- Resiliency
- Employment Impact

Recommendations included:

- Promoting, incentivizing, and/or subsidizing energy efficiency and heating/cooling. This may include weatherization and energy efficiency upgrades and retrofits as well as programmable thermostats, air sealing, equipment maintenance, minimizing duct losses, installation of energy-efficient windows and doors, daylighting, shading, and ventilation (25 support, 2 do not support).

- Promoting, incentivizing, and/or subsidizing heat pumps. The majority of the Task Force appeared to favor supporting policies that led to 100% heat pump use in covered buildings by 2035 (24 support, 2 do not support).

- Decarbonizing institutional and public buildings (23 support, 4 do not support).

- promoting, incentivizing, and/or subsidizing air purification systems (23 support, 4 do not support).

- Assessing and disclosing material-related emissions (21 support, 6 do not support).

- Modifying Energy Trust of Oregon's mission from energy efficiency to decarbonization and equity (21 support, 6 do not support).

- Building performance standards (19 support, 8 do not support).

- Aligning energy efficiency programs with the state's climate goals. This may include ensuring energy efficiency programs align with other policies such as House Bill 2021 and the Climate Protection Program; ensuring demand response programs delivery; and enabling GHG emissions reductions through energy efficiency (19 support, 8 do not support).

- Enacting energy-efficient building codes with substantiative reductions in building energy consumption by 2035 (18 support, 9 do not support).

  Cascade will monitor how these recommendations shape policy discussion in the coming legislative session and will consider how potential impacts could shape overall customer gas usage.

Several bills have emerged in the 2023 Legislation Session to build upon and implement the ReBuild Task Force recommendations. A summary of the suite of proposed laws knows as the ReBuild Package has been outlined below:

- SB 868: Healthy Heating and Cooling for All
  - Aligns energy efficiency programs with state climate goals, sets a heat pump target for the state, supports workforce development, and improves navigation of federal and state incentives for energy efficiency and retrofits of homes and businesses.

- SB 869: Build Smart from the Start
  - Ensures new buildings in Oregon are constructed energy efficiently and are more resilient to climate impacts.

- SB 870: Building Performance Standard
  - Establishes a Building Performance Standard for large commercial buildings to reduce their energy use and climate emissions over time.

- SB 871: Smart State Buildings
  - Removes barriers to accelerate energy retrofits and upgrades in state buildings.

- HB 3166: Navigation
  - Encourage interagency collaboration to simplify and streamline the ability of Oregonians to access incentives for energy efficiency and home health and safety projects

Cascade has actively monitored these bills and looks forward to continued productive discussion as part of associated workshops and hearings as these policies continue to progress.

2. Washington

In July 2021, the Washington legislature passed the Climate Commitment Act (Act), codified at Chapter 70A.65 RCW. The Act provides the Department of Ecology (Ecology) the authority to regulate GHG emissions from natural gas distribution companies, of which Ecology's former Clean Air Rule (CAR) could not. The Act gives direction to Ecology to implement a cap on greenhouse gas emissions from covered entities and a program to track, verify, and enforce compliance through the purchase of auction allowances and other compliance instruments.

The majority of the Act's requirements are promulgated within Ecology's WAC 173-446 rulemaking, establishing a program to cap greenhouse gas emissions and implement an allowance trading market. Ecology also completed WAC 173-446A rulemaking which establishes criteria to identify emissions-intensive, trade-exposed (EITE) industries for allowance allocation purposes and amended WAC 173-441, the emissions reporting rule associated with determining WAC 173-446 compliance obligations. Cascade provides discussion on the main WAC 173-446 rulemaking below.

A few other important actions in Washington this year include State Building Code Council building code revisions impacting natural gas usage in new and retrofitted commercial building and new residential buildings, a UTC study examining natural gas utility decarbonization pathways per SB 5092, and Ecology's amended schedule for the GHG Assessment for Projects (GAP) rulemaking. Cascade provides some brief discussion of these state actions further below although they are not expected to have a direct impact on the OR IRP and are provided for general understanding of regulatory activities occurring in Cascade service areas in the neighboring state of Washington. However, Cascade will consider both the OR CPP and WA CCA in compliance planning to achieve any potential compliance planning efficiencies.

a. Washington Climate Commitment Act WAC 173-446 (CCA)

On September 29, 2022, the Washington Department of Ecology released a final Climate Commitment Act rule, WAC 173-446 (CCA), a Washington state GHG emissions cap and trade rule. The rule became effective on October 30, 2022, and the emissions cap applies to 2023 emissions and onward.

The rule regulates most GHG emissions, including carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) from covered entities emitting 25,000 metric tons or more of CO_2e per year Covered entities include large stationary emission sources (e.g., manufacturing and industrial facilities), petroleum fuel suppliers, natural gas suppliers, suppliers of carbon dioxide, and electric utilities.

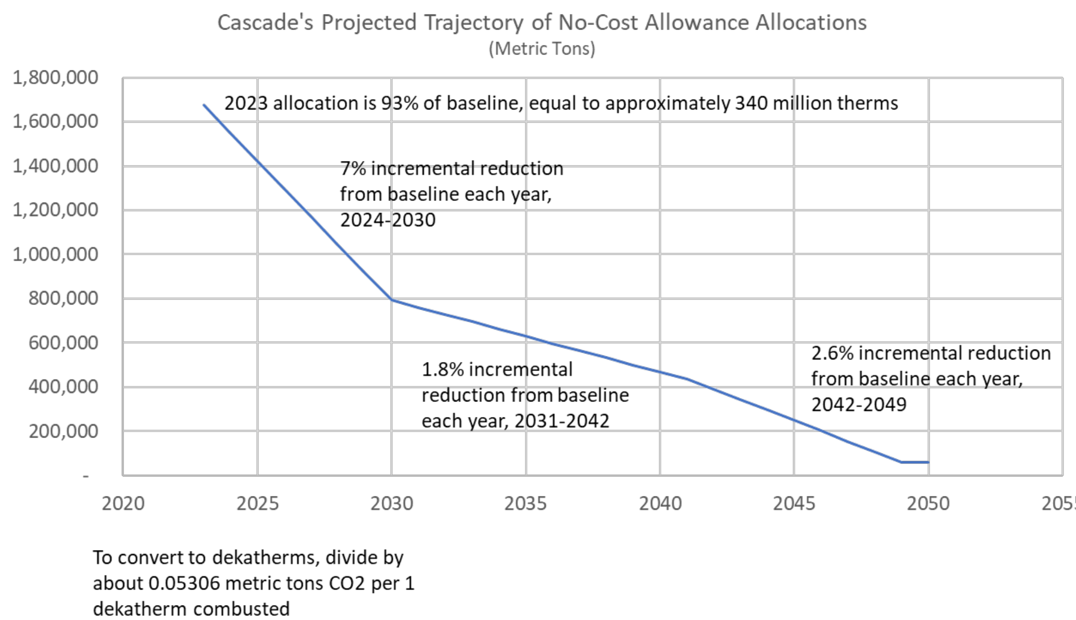
The emissions cap, or emissions allowance budget, is based on an average of 2015-2019 baseline emissions levels and declines overtime to meet rule targets of 45% below 1990 levels by 2030 and 95% below 1990 levels by 2050. Natural gas suppliers are regulated for the GHG emissions in Washington associated with a company's aggregated customers' combustion or oxidation of natural gas where customers report less than 25,000 metric tons CO_2e to Ecology and are not covered entities themselves. For Cascade, regulated customer emissions are predominantly from core customers, but also include some non-core customer emissions from facilities that do not emit 25,000 metric ton CO_2e per year. Cascade's baseline customer emissions are projected to be about 1.8 million metric tons CO_2e. Cascade's operational combustion and methane leakage emissions (e.g., Mt. Vernon compressor station combustion emissions and pipeline infrastructure) are also regulated under the CCA as those emissions have been reported at slightly higher than 25,000 CO_2e per year.

Excluded emissions for natural gas distribution companies include emissions from larger industrial customers who are covered entities themselves or customers who choose to opt-in to Ecology's program. Other excluded emissions are CO_2 from the combustion of biomethane or RNG purchased for natural gas customers. Ecology placed some geographic limitations for qualifying RNG outside of Washington for this exclusion within the WAC 173-441 GHG reporting rule and Cascade has placed limits on RNG accordingly as a compliance option in IRP modeling. Ecology received comment from natural gas distribution companies and other stakeholders on the geographic limitation during the CCA and reporting rule comment periods. When the final CCA rule was released, Ecology stated the agency's commitment to further dialogue with natural gas suppliers on this topic in the Ecology's Concise Explanatory Statement for Chapter 173-446 WAC Climate Commitment Act Program, Summary of Rulemaking and Response to Comments. Cascade will remain engaged with Ecology on this matter as RNG is important option in achieving emissions reductions and CCA compliance.

Compliance can be demonstrated through a combination of methods, such as purchasing and retiring emissions allowances and carbon offsets. Allowances can be banked indefinitely and used for future years of compliance. Emission reductions can also be achieved by replacing conventional natural gas supply with some limited RNG, hydrogen and through implementing energy efficiency and conservation programs to reduce customer use of natural gas.

Ecology will distribute an amount of no-cost allowances to natural gas utilities that decline over time with the CCA program allowance budget cap. Cascade's no-cost allowances in 2023 are equivalent to 93% of the company's baseline of 2015-2019 average emissions which is estimated to be in the range of 1.8 million metric tons of CO_2e. Ecology is expected to release natural gas distribution company baseline values in late November 2022. The no-cost allowances decline annually by 7% of Cascade's baseline, incrementally each year from 2024 to 2031, 1.8% annually from 2032 to 2041, and 2.6% annually from 2042 to 2049. Cascade's projected no-cost allowance distributions over time are shown in Figure 6-2.

Figure 6-2: Cascade's Projected Trajectory of WA CCA No-Cost Allowance Allocations



No-cost allowances will be distributed to natural gas utilities for 2023 in two tranches; 35% will be distributed by July 1, 2023, and the remaining balance of no-cost allowances will be distributed on September 1, 2023. Annually thereafter, Ecology will distribute no-cost allowances by October 24 of the prior year. For example, 2024 no-cost allowances will be distributed by October 24, 2023.

Full compliance demonstrations must be made by November 1 of the year following each four-year compliance period, with the first period from 2023 to 2026. Therefore, the first full compliance period deadline is November 1, 2027. There are also compliance demonstrations within the four-year period required by November 1 annually, where covered entities must demonstrate compliance with 30% of the prior years' emissions compliance obligation. For example, the first annual compliance demonstration will be

November 1, 2024, to comply with 30% of the 2023 compliance obligation.

Ecology joined the Western Climate Initiative (WCI) in late 2021 and is utilizing WCI's allowance auction platform to administer the allowance auctions and manage covered entity and auction participant holding and compliance accounts, as well as the limited use accounts for electric and natural gas utilities to receive no-cost allowance allocations. WCI's system is referred to as the Compliance Instrument and Tracking System Services (CITSS). Covered entity account representatives are required to register in CITSS by early December in order to complete the registration process for covered entity facilities and establish accounts in preparation of receiving allowance allocations and quarterly auction participation beginning in 2023. Cascade registered account representatives within CITSS in December and has submitted the Company's entity registration in CITSS.

Covered entities will be assigned a holding account where purchased allowances are distributed to covered entities by Ecology after each quarterly auction and a compliance account where a covered entity holds allowances it has requested Ecology transfer from the entity's holding account for compliance demonstrations. Natural gas and electric utilities are also provided limited use accounts where no-cost allowances, required to be consigned at auction, have been transferred from holding accounts. Ecology places limits on the number of allowances that can be held within compliance account and holding accounts. There is no holding limit placed on a limited use account. Also, except for the holding limits here, an allowance can be banked indefinitely.

Cascade is required to consign some of the Company's no-cost allowances. In 2023, 65% of Cascade's no-cost allowances must be consigned to auction. No-cost allowance consignment increases annually by five percent and by 2030 and thereafter, all no-cost allowances Cascade receives must be consigned to auction.

Revenues from allowance consignment must be managed and used for the benefit of customers with oversight from the UTC. The rule states, "All proceeds from the auction of allowances consigned by natural gas utilities shall be used for the benefit of customers, as determined by the utilities and transportation commission for investor-owned natural gas utilities, including at a minimum eliminating any additional cost burden to low-income customers from the implementation of the Climate Commitment Act." Remaining revenue can be used under the oversight of the UTC for the benefit customers in other ways, such as, investing in additional emissions reductions and/or providing bill credits to reduce customer cost impacts.

Cascade envisions utilizing no-cost allowances that are not consigned at auction for compliance demonstrations up until 2030 when all no-cost allowances would need to be consigned. Depending on many factors, including Ecology's budgeted allowances offered at quarterly auctions, other auction participant bidding, and allowance and other compliance instrument prices, Cascade expects to purchase additional allowances at auction for compliance. Compliance demonstrations can also include a limited amount of carbon offsets, such as forestry carbon sequestration offsets. Offsets are limited for use of up to eight percent of a covered entity's compliance obligation in the first compliance period and six percent thereafter. Ecology will make reductions to the program's annual allowance budgets commensurate with the number of offsets covered entities use for compliance. The need for allowance and offset purchases at the outset of the program will be informed by Cascade's projected demand, demand-side management and conservation programs, and RNG acquisitions. In the future, potential hydrogen acquisition would be considered.

If a covered entity would reach the end of a four-year compliance period and was not able to purchase sufficient instruments for compliance, the rule allows for covered entities to request Ecology to issue higher priced "price ceiling units" to address the shortfall. There are penalties that would apply for noncompliance with requirements of the rule, including not meeting an emissions compliance obligation demonstration.

Four general allowance auctions will be held each year on a quarterly basis commencing in 2023. Allowances offered at auction decline over time with the cap. Auction floor allowance prices, Allowance Price Containment Reserve (APCR) allowance prices, and "price ceiling unit" prices are set by Ecology per the rule in 2023 and increase annually by five percent plus inflation. These prices are published by the first business day of December of the year prior to the auctions where the prices will apply. For example, Ecology set the allowance floor price for 2023 at $19.70 per ton, and 2024 prices will be released by Ecology in early December 2023.

There are detailed processes around auction allowance bidding, accepting/rejecting bids, awarding allowance bids, and determining the auction settlement price. At the close of the quarterly auctions, Ecology awards allowances from the highest bidder on down until no allowances in the auction are left. The settlement price for all participants in the auction is the bid price where the last allowance from the auction is awarded. Also, there are two auctions each year, in parallel with two of the annual general auctions, where a limited amount of future vintage allowances will be offered for sale to market participants.

In Spring 2023, Ecology announced the agency was starting the process of exploring linkage of Washington's carbon market with California and Québec and requested public comment on linking with these jurisdictions. Cascade submitted joint comments with the other LDCs to Ecology supporting linkage. A main benefit would be having a larger and liquid allowance market which in turn would result in lower compliance costs and impacts to customers compared with a Washington-only market. Ecology plans to issue a decision in summer 2023 or later. If Ecology determines to pursue linkage, California and Québec would need to undergo their own processes to decide whether to link with Washington. Ecology acknowledges that all three programs might need to revise some regulations, so finalizing linkage would not happen until 2025 at the soonest.

As with the OR CPP rule compliance planning, Cascade is currently setting up processes to comply with the CCA and has hired a consultant, Guidehouse, to aid and advice in setting up internal company processes for ongoing compliance demonstration and participation in allowance auctions.

b. Washington State Building Code Changes

The Washington State Building Code Council (SBCC) approved new building and energy code this past year, impacting usage of natural gas for space and water heating in new and retrofitted commercial and residential buildings. On April 22, 2022, the SBCC approved changes significantly limiting the use of natural gas in new and retrofitted commercial buildings through the revised Washington State Energy Code-Commercial (WSEC-C). The revised WSEC-C is effective July 1, 2023, and stipulates new commercial construction may not include natural gas equipment for space or water heat, with a few exceptions. The use of natural gas equipment other than natural gas space and water heating equipment in commercial buildings has not been restricted as part of the revised WSEC-C. However, electric receptacles must also be installed next to certain natural gas appliances in dwelling units within new multifamily buildings.

On November 4, 2022, the SBCC voted 9-to-5 to approve two new residential code provisions for space and water heating which become effective on July 1, 2023. The adopted provisions stipulate that mechanical systems for space heating and domestic water heating utilize heat pumps (electric or gas) as the primary heating source, with few exceptions. The use of natural gas equipment, other than the prohibition of conventional non-heat pump natural gas fueled equipment for space and water heating, has not been restricted in residential buildings. However, as natural gas usage in residential uses has conventionally been primarily used for space and water heating, secondary uses such as decorative fireplaces and cooking appliances are likely to be impacted.

There are potential concerns for the codes revisions considering they result in significant changes for new residential and commercial construction statewide that becomes effective in an immediate timeframe. Depending on availability of supply for the heat pump technologies required to meet code requirements, especially as natural gas heat pump technology has not yet reached market availability, there is uncertainty in feasible implementation of the new code with electric heat pumps alone by the July 1, 2023, effective date.

In February 2023, a coalition of trade associations, union representatives, businesses and homeowners filed a lawsuit to challenge the State Building Code Council's restrictions to the use of natural gas and propane in new residential and commercial construction.

On May 24, 2023, the SBCC council members voted to delay the implementation of new codes by 120 days to late October.[6]

c. SB 5092 – WUTC Natural Gas Decarbonization Study

The legislature passed SB 5092 in 2021 which directs the WUTC to conduct a study examining feasible and practical pathways for investor-owned electric and natural gas utilities to contribute their

[6] See https://www.biaw.com/delay-the-implementation-of-new-codes/

share to greenhouse gas emissions reductions for Washington to achieve emissions reduction targets in RCW 70A.45.020, and the impacts of energy decarbonization on residential and commercial customers and the electrical and natural gas utilities that serve them. The WUTC contracted with Sustainability Solutions Group (SSG) to support the UTC with examining decarbonization pathways with privately owned energy utilities in Washington and created Docket U-210553 to manage information about the study and keep stakeholders informed. The UTC can utilize $251,000 of funding in 2022 and $199,000 in 2023 to complete this study, with a final report due to the legislature by June 1, 2023.

Since May 27, 2022, the UTC has held approximately monthly public workshops and decarbonization advisory group meetings to obtain and share information on the study and Cascade has participated in this process as a member of the advisory group.

When published, the study will discuss how natural gas distribution utilities can decarbonize, impacts of increased electrification on the ability of electric utilities to deliver services to current natural gas customers reliably and affordably, the ability of electric utilities to procure and deliver electric power to reliably meet the load of increased electrification, impacts on regional electric system resource adequacy, and the transmission and distribution infrastructure requirements for such a transition, the costs and benefits to residential and commercial customers, including environmental, health, and economic benefits, equity considerations and impacts to low-income customers and highly impacted communities, and the potential regulatory policy changes to facilitate decarbonization of the services that gas companies provide while ensuring customer rates are fair, just, reasonable, and sufficient.

d. Washington Department of Ecology (Ecology) - GHG Assessment for Projects (GAP)

At the end of 2019, Governor Inslee directed Ecology to adopt a rule by Sept 1, 2021, to consider GHG emissions in environmental assessments for major industrial projects and major fossil fuel projects with significant environmental impacts. Ecology announced rulemaking commencement on April 30, 2020, and began receiving input from stakeholders to obtain input for drafting a proposed rule planned for late 2020. In 2021, Ecology decided to pause this rulemaking as the agency is implementing the Climate Commitment Act and Clean Fuel Standard. Ecology will consider public input received on these rules and evaluate any potential intersections with the new rules and the GAP rule before proceeding. Ecology expects a draft GAP rule to be released for public review and comment sometime in 2023. Cascade will continue to monitor this regulatory action as it may impact future IRPs.

e. Other Washington Legislative Activity

Cascade is keeping apprised of additional legislation in Washington State with the intent to reduce GHG emissions. It is anticipated that several bills will emerge in the 2023 legislative session with potential impacts to the use of gaseous fuels. Such proposals may include support for innovations in the gas sector such as tools to support Climate Commitment Act compliance, and to empower renewable natural gas, hydrogen, and other decarbonization technologies that can be paired with pipeline infrastructure. It is also anticipated that proposals to further restrict the use of natural gas and all gaseous fuels may be seen in the coming session.

Local Policy

In the past few years, Cascade has observed a heightened interest by local jurisdictions and municipalities in committing to the reduction of GHG emissions within a municipality, as well as some applying commitments community-wide. Those cities or counties establishing commitments are focusing on goals and aspirations in the range of 80% GHG reductions relative to 1990 levels by 2050, consistent with the Paris Climate Agreement.

For background, the Paris Climate Agreement was a pact made by many countries across the globe, responding to concerns regarding climate change. In the pact, countries committed to GHG reductions to limit increasing global temperatures and fund response to impacts of climate change. The U.S. had been a party to the pact in 2015. In 2017, the U.S. withdrew from the Paris Climate Agreement under President Trump and in 2021, the U.S. rejoined the pact under President Biden.

Within Cascade's service areas, the City of Bend, Oregon and the City of Bellingham and Whatcom County in Washington have developed GHG reduction goals. A summary of those commitments is provided below. Also, Snohomish County, which overlaps Cascade's service area in Washington, created an ad hoc Climate Advisory Committee in 2019 to provide recommendations in the next few years that encourage adoption of policies, programs, and practices in order to reduce GHGs, address climate change, protect public health, and preserve the natural environment within the county.

There are other areas adjacent to Cascade's service areas adopting similar commitments, such as Portland, Oregon, Tacoma, Seattle, Edmonds, and Multnomah County, Washington, and Vancouver, British Columbia. Cascade has also observed adoption of energy action plans to switch from gas to electric in the Cities of Ashland and Eugene.

1. **City of Bend, Oregon**

   The City Council of Bend, Oregon passed Resolution 3044 in 2016 establishing voluntary GHG emission reduction goals for City facilities and operations of 40% reduction of 2010 baseline year emissions by 2030 and 70% reduction of 2010 baseline year emissions by 2050. The City Council passed another resolution, Resolution 3099, which created a Climate Action Steering Committee (CASC). The CASC provided recommended actions to the City Council that encourage and incentivize businesses and residents, through voluntary efforts, to reduce GHG emissions and fossil fuel use considering the voluntary goals.

   Cascade was appointed to the CASC, and actively engaged in supporting the development of a viable pathway forward that considers the essential balance between the City's economic vitality, reliability of its energy supply, and environmental goals. The CASC authored a plan recommending a set of strategies to guide both the city and the surrounding community in achieving its goals.

   On December 4, 2019, the Bend City Council approved the Climate Action Steering Committee's (CASC) recommendations concerning a pathway to reducing its fossil fuel use by 40% by 2030, and by 70% by 2050. Cascade publicly supported the recommendations presented to the city. Cascade was engaged with Bend City staff and other members of the community to identify ways to help the city meet its targets. Possible pathways identified at that time included partnerships on the integration of biogas (e.g., biodigester) and possible carbon offset programs.

   The City has determined to focus on four areas to meet their 2030 goal: energy supply, transportation, energy in buildings, and waste and materials. The City's current Environment and Climate Committee (ECC) is also having preliminary discussions about the role of gaseous fuels as part of a decarbonized future. Cascade has held regular meetings with committee staff to discuss decarbonization pathways for natural gas distribution. Cascade has also held several meetings with members of the Bend City Council.

The ECC released a memo on April 28, 2023 describing a series of natural gas policy options. In anticipation of interest in including policy options to reduce reliance on natural gas as part of the next Community Climate Action Plan Update, staff plan to hold a short term research, analysis, and public input process to better understand various options to reduce reliance on and/or decarbonize natural gas in Bend beginning in winter 2023/2024. Potential policy pathways include restricting gas in city-owned facilities, incentivizing electrification in residential and commercial buildings, encouragement of RNG, restriction of natural gas in new construction, requirements for existing buildings that would restrict NG. The City Council will be convening an ad-hoc committee on this topic.

In late 2021, Deschutes County invited interested parties to submit bids for developing a RNG project at the Knott Landfill. Cascade, in partnership with an engineering firm, submitted a proposal to the County and were awarded the project. Cascade and Deschutes County executed the contract on May 1, 2023. The project is expected to commence in 2023 and begin producing RNG by end of 2024 or early 2025. This presents an opportunity for Cascade to actively assist with regional decarbonization of natural gas. Cascade is exploring other RNG opportunities for the City, including the development of a voluntary renewables purchase program to offset emissions through the purchase of renewable energy attributes. In addition, the Company has begun piloting energy assessments for Cascade's transportation customers in the Bend region to determine energy savings potential and compliance pathways consistent with CPP requirements. This may lead to additional services and offerings in future in partnership with the Energy Trust.

2. City of Bellingham, Washington

The City of Bellingham passed a GHG Reduction and Renewables Energy Targets resolution in March 2018 updating emission reduction targets for municipal facilities and operations to reduce emissions 85% below 2000 levels by 2030, and 100% below 2000 levels by 2050, making the city facilities and operations carbon-neutral. Bellingham also included in the resolution a target to reduce community-wide emissions 70% below 2000 levels by 2030, and 85% below 2000 levels by 2050. Specifically, the goals are to obtain energy from all renewable resources and remove use of fossil fuels by 2030 and 2035 within the city, including transportation.

The city created the Climate Action Task Force (CATF) to explore and recommend how the city and community can meet these new targets, taking into account technology, feasibility, possible accelerated targets, funding mechanisms, as well as costs and other impacts. The CATF included community members that have experience in renewable energy, energy conservation, land use, energy/resource economics, community engagement, transportation, and finance. Energy utility representation and public transportation representatives were identified. However, the city did not allow more than one utility representative at the table and Puget Sound Energy (PSE) was chosen by the city to represent utilities on the task force. Cascade worked together with PSE to include Cascade's input. Minimal input was accepted from Cascade, and efforts seemed primarily focused on electrification to the exclusion of other decarbonization strategies that utilize offsets and RNG as pathways to carbon reduction.

The CATF first met on September 5, 2018, and continued to meet regularly through late 2019. On December 2, 2019, the task force finalized a report of GHG reduction recommendations. City staff reviewed the CATF's recommendations and narrowed them down to those most likely to be integrated successfully and discussed the results with the City Council. City staff used a tiered ranking system for this evaluation, considering such factors as whether the measure has already been implemented, needed further research and analysis, or tabled for future review. The measures then went through a triple bottom line "plus" assessment before adding to the City's Climate Action Plan (CAP) and the City determined which of the CATF's recommendations should be integrated into the CAP. Ten recommendations were vetted, including encouraging the State to ban internal combustion engine vehicles, expanding weatherization efforts, and disallowing the use of natural gas in new homes and buildings.

On February 7, 2022, the Bellingham City Council passed an ordinance on requiring electric space and water heating equipment for new commercial and large (4-plus story multifamily buildings). The ordinance also requires incremental improvements in energy efficiency (building envelope, lighting, insulation) and solar installation or readiness in new buildings. The electric-only mandate for space and water heating does not apply to single family construction, detached houses, duplexes, townhomes, or row houses. The ordinance rook effect on August 7, 2022.

3. Whatcom County, Washington

Whatcom County, in which the City of Bellingham is situated, has committed to the "Ready for 100" campaign that the Sierra Club is advocating and has established goals through a county ordinance. The "Ready for 100" campaign website recommends a goal of 100% renewable electricity by 2035 and 100% renewable for all other energy sectors by 2050, but participants can target less stringent goals. Whatcom County has chosen to commit to 100% renewable electricity for county operations by 2035 and has also applied the goal within the larger Whatcom County community.

Whatcom County established a Climate Impact Advisory Committee which provides review and recommendations to the Whatcom County Council and Executive on issues related to the preparation and adaptation for, and the prevention and mitigation of, impacts of climate change. On July 27, 2021, Whatcom County voted to ban the construction of new refineries, coal-fired power plants and other fossil fuel-related infrastructure. These new requirements do not constitute a gas ban but may potentially impact Cascade's plans for distribution system enhancement projects in Whatcom County. The Climate Impact Advisory committee continues to meet about monthly on climate and energy policy.

Natural Gas Industry Emissions

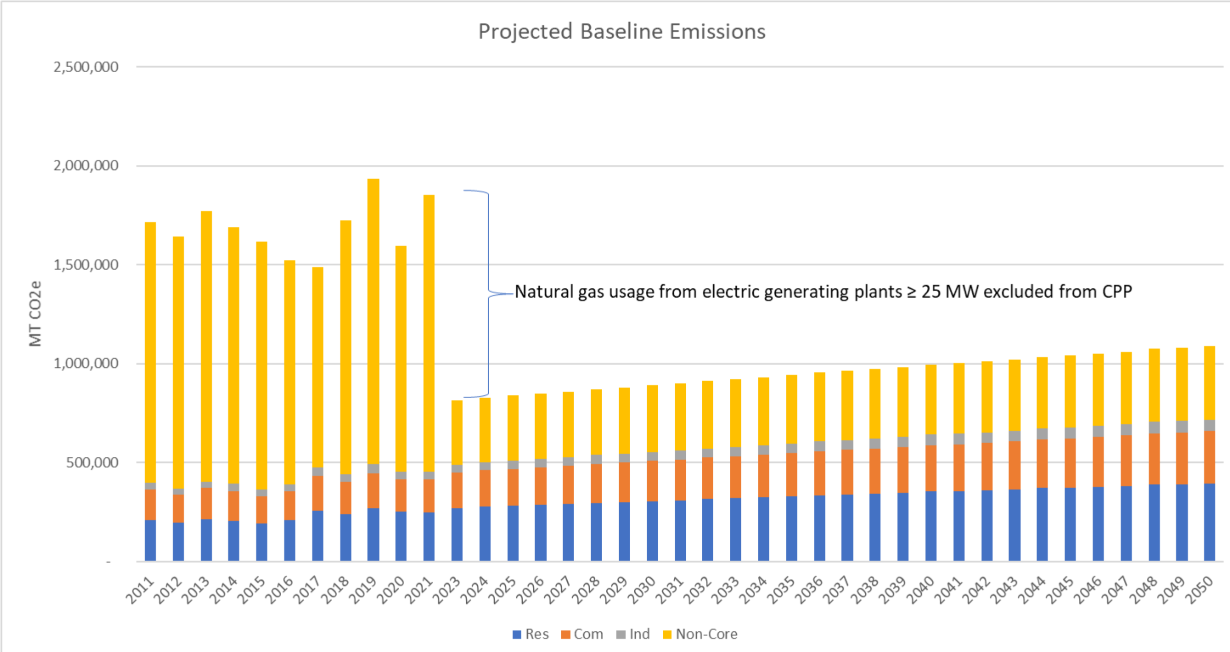
From review of EPA EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2020, in 2020 the oil and gas sector were estimated to emit about 12.1% of the total GHG emissions from all industries. Natural gas distribution facilities and operations contribute to GHG emissions generally through fugitive methane emissions and leaks from pipeline infrastructure, as well as from combustion of fuel used in compressors. EPA's emissions estimates indicate approximately four percent of oil and gas sector emissions are from distribution infrastructure.

Cascade is required to report annual facility GHG emissions to the Oregon DEQ. However, Oregon emissions do not meet the 25,000 metric ton CO_2e threshold for annual reporting to EPA. These emissions are described further below under the discussion on Cascade Operational GHG Emissions and Emission Reductions.

Cascade Customer Emissions from Natural Gas Combustion

GHG emissions are generated by Cascade's customers due to combustion of natural gas. Over time, the Company's sales of natural gas have grown to accommodate customers' demand for natural gas, and therefore, GHG emissions have increased from customers' combustion of natural gas. Cascade provides the historical customer emissions for all customers, as well as projections for customers that the Company is responsible for under the CPP in Figure 6-3.

Figure 6-3: Historical and Projected Emissions



a. Energy Efficiency Program Greenhouse Gas Emission Reductions

Cascade's conservation programs help reduce GHG emissions by providing incentives to customers for a comprehensive set of prescriptive and custom energy efficiency upgrades designed to streamline their use of natural gas, thus reducing their overall carbon footprint. Space, water heating, and weatherization incentives drive lowered energy consumption and positive energy behavior in customers' homes and businesses. This leads to lowered demand, bill reductions, and overall GHG emission reductions in the communities. As seen in Figure 6-4, Cascade's energy efficiency and conservation programs and demand-side savings in Oregon over the past three years have resulted in about 427,060 to 525,372 therm savings annually, or about 2,266 to 2,788 metric tons of CO_2e/year.

Figure 6-4: Historical DSM Savings

Annual EE and Conservation/ DSM Savings	OR				WA					
	Residential & Energy Trust Low Income		Commercial/Industrial		Residential		Commercial/Industrial		Low-Income	
	Therms	mtCO2e	Therms	mtCO2e	Therms	mtCO2e	Therms	mtCO2e	Therms	mtCO2e
2019	182,009	967	311,534	1,655	363,364	1,930	384,176	2,041	13,416	71
2020	179,240	952	247,474	1,314	383,018	2,034	266,945	1,418	9,213	49
2021	216,825	1,152	308,547	1,639	436,103	2,316	798,874	4,243	8,245	44

Cascade has seen increasing therm savings overtime by focusing on energy efficiency and benchmarking and commercial program adoption, and more term savings and emission reductions will be realized as the Company's programs mature and continue to grow. In consideration of CPP compliance requirements for example, the Company will soon be piloting energy assessments for Cascade’s non-core customers to determine energy savings potential and compliance pathways. This may lead to additional services and offerings in future in partnership with the Energy Trust. Please see Chapter 7, Demand Side Management, for additional details.

b. Renewable Natural Gas and Hydrogen

Renewable natural gas and hydrogen supply are other methods of reducing emissions associated with the Company’s customer use of natural gas. In the past year and a half, Cascade has expanded the Company’s internal and external resources to support development of RNG options for its customers and to comply with decarbonization requirements in Washington and Oregon. Cascade has recently executed agreements with developers and marketers for RNG and RNG environmental attribute purchases and is working with Deschutes County to develop an RNG project at the Knott Landfill near Bend, OR.

Cascade also continues to explore ways the Company can support technology development and pilot project opportunities to further explore distribution of hydrogen for customers on the gas distribution system. See more information on Cascade’s RNG procurements and project involvement, as well discussion of hydrogen as a future energy resource for customers in Chapter 4.

Cascade Operational GHG Emissions and Emission Reductions

Cascade's operations and infrastructure GHG emissions reported to the DEQ include fugitive methane emissions from distribution mains and service lines, and meter-regulating stations. Cascade does not operate large combustion sources in Oregon, such as compressor stations, which result in GHG emissions from combustion sources. Reported emissions from Company operations and infrastructure sources in Oregon total approximately 8,000 metric tons of CO_2e per year. These emissions have been quantified since 2010 and have remained about the same over time as default nation-wide emissions factors are required to quantify most of the emissions.

Starting this year, the Cascade is compiling a more robust GHG emissions inventory for additional emissions tracking and is also exploring the use of company specific data and emission factors to compile emissions more accurately. Cascade plans to use this comprehensive annual emissions inventory to evaluate emissions and trends, identify additional emissions reduction opportunities, and better quantify emissions reductions.

Emissions from Cascade's operations and infrastructure in Oregon are not subject to the CPP. However, Cascade has been implementing programs and operational process changes that result in emissions reductions from distribution infrastructure and operations. Cascade has realized GHG emissions reductions in implementing operational changes and capital projects required through federal Pipeline and Hazardous Materials System Administration (PHMSA) regulatory requirements as well as through changes in field operations procedures.

Fugitive Methane Emissions Reductions

EPA has focused on reducing fugitive methane emissions from the oil and gas sector but has not applied emission reduction requirements specifically to the natural gas distribution segment. Instead, the agency has focused on sponsoring voluntary programs to encourage commitments to reduce methane emissions from gas distribution companies.

c. **EPA Natural Gas Star Methane Challenge Program.**

Cascade became a Founding Partner of the EPA's Natural Gas Star Methane Challenge Program in March 2016. As a Founding Partner, Cascade chose to participate in the program under the Best Management Practice (BMP) Commitment – Excavation Damages Prevention within the natural gas distribution sector. The BMP

Commitment entails a Partner's commitment to company-wide implementation of BMPs to reduce methane emissions. Involvement in this program also provides a forum for companies to share knowledge on successfully implementing BMPs and methane emissions reductions. During this commitment, Cascade has conducted incident analyses on excavation damages and reported the relevant data to EPA.

Specifically, Cascade demonstrates its commitment to this program through implementation of BMPs to promote leak reductions. Cascade has a public awareness and damage prevention manager and coordinators who assist in providing public outreach that focuses on damage prevention and further reducing potential releases of methane from excavation damages. The public awareness and damage prevention department and local utility management and staff also engage directly with contractors and excavators with face-to-face interactions in the field, and through meetings and training events. By proactively engaging with these third parties, Cascade aims to achieve a decreasing trend in overall excavation damages and excavation damage rates, as well as an increase line location requests.

Cascade conducts investigations when damages occur to company natural gas distribution pipeline and infrastructure. Key information, such as location, root cause, type of excavator, type of equipment used and type of work performed, is collected to analyze and trend on a quarterly basis. This data is used to assess ways to mitigate risks associated with excavation and, along with effectiveness surveys, helps utilities assess the success of their programs, outreach strategies and messaging.

Some examples of utility companies' outreach efforts include annual direct mailers to public officials, emergency response organizations, excavators, customers, schools and individuals who live along Cascade's distribution lines; participation in a variety of general public outreach events; development of materials that deliver multifaceted education campaigns, including campaigns via television, radio, online, newspapers, magazines, social media and billboards. Utility companies provide publications in up to eight languages to align with the demographics of their jurisdictions. The Companies also sponsor community events, such as golf tournaments, chamber of commerce events, county fairs and rodeos, and sporting events, where pipeline safety and Call 811 information is displayed and distributed to attendees. The utilities also provide excavation safety and emergency response training upon request.

Additionally, Cascade actively participates in 811, Common Ground Alliance, local underground utility coordinating councils, and damage complaint programs and damage complaint programs in Oregon and Washington. Cascade continues to explore other voluntary actions which could reduce methane emissions resulting from excavation damage.

Beyond Cascade's commitment to reduce methane emissions from excavation damages, Cascade has completed operational and infrastructure changes to comply with federal requirements which have resulted in lowering methane emissions, and therefore lower GHG emissions in the State of Oregon. This has mainly been realized through pipeline replacement projects where newer pipeline materials such as polyethylene and steel are used to replace older materials. Since 2012, Cascade has replaced nearly 45 miles of early vintage steel pipe in Oregon with new steel or polyethylene pipe, ranging from service lines up to 12-inch mains. Also, Cascade has no unprotected steel pipe and no leak-prone cast iron pipe in its systems.

In 2020, Washington enacted HB 2518, the Natural Gas Transmission bill, requiring natural gas distribution companies to expedite mitigation of hazardous leaks and reduce as practicable nonhazardous leaks, and providing utilities rate recovery to mitigate these leaks. Although Cascade is not subject to this requirement in Oregon, the Company has adopted the same actions within Cascade's Oregon operations. Although companies are permitted by code to monitor smaller leaks for a period of time before addressing, Cascade has instituted a policy to repair all identified leaks as quickly as possible and with a goal to eliminate even the smallest non-hazardous leaks within 15 months of discovery. By expediting leak mitigation, Cascade has reduced leak emissions within the system.

Cascade's methane emissions rate in Oregon is estimated to be in the range of 0.07 and 0.11 percent (annual volume of methane emitted per total annual methane throughput volume). Although Cascade is not a member of One Future, the Company has been evaluating its emissions intensity and implementing emissions reductions for a number of years. Cascade's emission rate is close to the reported emission rate of 0.092 percent average achieved by One Future member natural gas distribution companies and is much lower than One Future's emission rate goal for the natural gas distribution segment of less than 0.22 percent.

Cascade continues to explore additional ways to reduce methane releases that occur within normal operations, including the use of technology that could be used to capture and reinject natural gas from one section of pipe into an adjacent section during pipeline maintenance. By using this technology, Cascade would be able to isolate a section of pipe scheduled for maintenance and minimize the amount of natural gas released to atmosphere from blowdowns.

Conclusion

There are new requirements impacting Cascade since the last IRP. The predominant requirements impacting Cascade in Oregon are the Climate Protection Program which regulates customer GHG emissions and will require the Company to procure significant amounts of RNG to replace traditional natural gas supply for customer demand, as well as Community Climate Investment credit purchases to offset customer emissions and further energy efficiency and conservation program deployment. Cascade has included these requirements in resource and cost modeling in this IRP.

Cascade will continue the Company's commitment in reducing fugitive methane emissions and will also continue to engage in Cascade's service area community-driven efforts in adopting GHG emission reduction targets. In particular, Cascade is meeting ongoing with the City of Bend on how the Company can support the city in achieving emissions reduction goals.

As state and federal GHG emissions policy and regulatory activity are updated, Cascade will evaluate and incorporate these potential impacts into the Company's IRP process. Cascade will also continue reviewing the Northwest Power and Conservation Council's (NWPCC) Power Plan updates to inform the Company on regional energy and GHG emissions matters that may impact additional policy development.

Chapter 7

Demand Side Management

Overview

Demand Side Management (DSM) refers to the reduction of natural gas consumption through the installation of energy efficiency measures such as insulation or more efficient gas-fired appliances, or through other load management programs such as demand response efforts that shift gas consumption to off-peak periods. The Company's primary means for reducing load is through energy efficiency programs that provide customers with financial incentives to install energy efficiency measures or appliances. The Company's energy efficiency programs in Oregon and Washington offer incentives to homeowners, commercial customers, industrial customers, and builders to invest in energy efficiency measures. Because the customer must ultimately make the decision to invest in an energy efficiency measure, DSM is unlike other supply side resources which the Company can independently secure.

Key Points

- Oregon projected energy efficiency of 14.62 million therms through 2042.
- Energy Trust of Oregon performed the technical potential analysis (the Resource Assessment Model) that informs the savings targets in Oregon for this Plan.
- Cascade has thoroughly integrated the elements of the Company's DSM programs into the full IRP planning process by forecasting the DSM potential at the climate zone level.
- Programs are designed to achieve DSM savings targets by offering customers incentives for installing energy efficiency measures.

This chapter presents the methodology used to determine the Company's DSM supply through the planning period, the Company's annual savings targets, and a narrative about how DSM goals will be achieved.

This chapter also considers alternate commodity pricing from renewable natural gas or hydrogen in response to state and Federal policy initiatives addressing carbon mitigation that may increase the cost of natural gas service, thus increasing the amount of DSM that is cost-effective (Scenario 2).

Cascade's Oregon Energy Efficiency Program

The Energy Trust of Oregon (Energy Trust) administers the following energy efficiency programs in Oregon on Cascade's behalf:

- Residential (Existing and New Home Construction)
  - Single family, moderate income, manufactured homes
    - Weatherization, HVAC & water heating equipment

- Commercial (Existing, New and Multifamily)
  - Retail, offices, schools, groceries & other associated market segments

    - Weatherization, controls, HVAC & water heating equipment

- Industrial & Agriculture (Non Transport Sites)
    - Manufacturing facilities, greenhouses
        - Process improvements, HVAC & water heating equipment, operations and maintenance

The Energy Trust of Oregon is an independent, nonprofit organization initially established to provide energy efficiency services and renewable energy programs to customers of Oregon's investor-owned electric utilities. Over time, each independently owned local gas distribution company in Oregon has transferred control of its energy efficiency programs to Energy Trust as a condition for Commission approval of their independent decoupling mechanisms. As such, Energy Trust provides energy efficiency services to much of Oregon. The Energy Trust's program offerings can be found online at www.energytrust.org.

Cascade offers a comprehensive low-income weatherization program administered by Community Action Agencies (CAAs) who provide whole-home weatherization services to qualified customers at no direct cost to the customer. While the low-income programs are designed to meet the unique needs of qualifying customers, the therm savings acquired in these programs contribute to the total DSM savings target. The Company does not currently estimate the therm savings potential for just its low-income program as they are included in the residential program potential. The low-income program details are found in Schedule 33, Oregon Low-Income Energy Conservation Program of the Company's Oregon tariff. Further details on this program and planned program updates are provided later in this chapter.

Cascade's Washington Energy Efficiency Program[1]

Cascade administers its energy efficiency programs in Washington. The methodology for establishing Cascade's long-term planning targets as well as the savings targets are included in the Company's 2020 IRP, filed in the Washington Utilities and Transportation Commission's (WUTC's) Docket UG-190714.

The Company's program offerings are broad, including rebates to homeowners for furnaces and water heaters as well as rebates to commercial customers for gas griddles and gas convection ovens. The sectors covered through these programs include the following:

- Residential (Existing and New Home Construction)
    - Single Family & Manufactured Homes

[1] The Oregon IRP rule requires planning on a system basis, hence the inclusion of Washington energy efficiency descriptions herein.

  - Built Green & ENERGY STAR® homes, weatherization, HVAC and water heating equipment, windows, and programmable thermostats

- Commercial/Industrial (New and Existing)
  - HVAC and water heating equipment, weatherization, controls, energy savings kits, commercial kitchen, and custom measures

The Company's specific program offerings are detailed in the Company's Washington tariff found online at www.cngc.com/energy-efficiency[2] as outlined in Exhibit 1 of the 2022-2023 Biennial Conservation Plan.[3]

As in Oregon, Cascade offers a comprehensive low-income weatherization program administered by CAAs. The specific details of the Company's offering can be found in Schedule 301, Low Income Weatherization Incentive Program in the Company's Washington tariff.

20-Year Forecast for Cascade Natural Gas Corporation's DSM Potential in Oregon

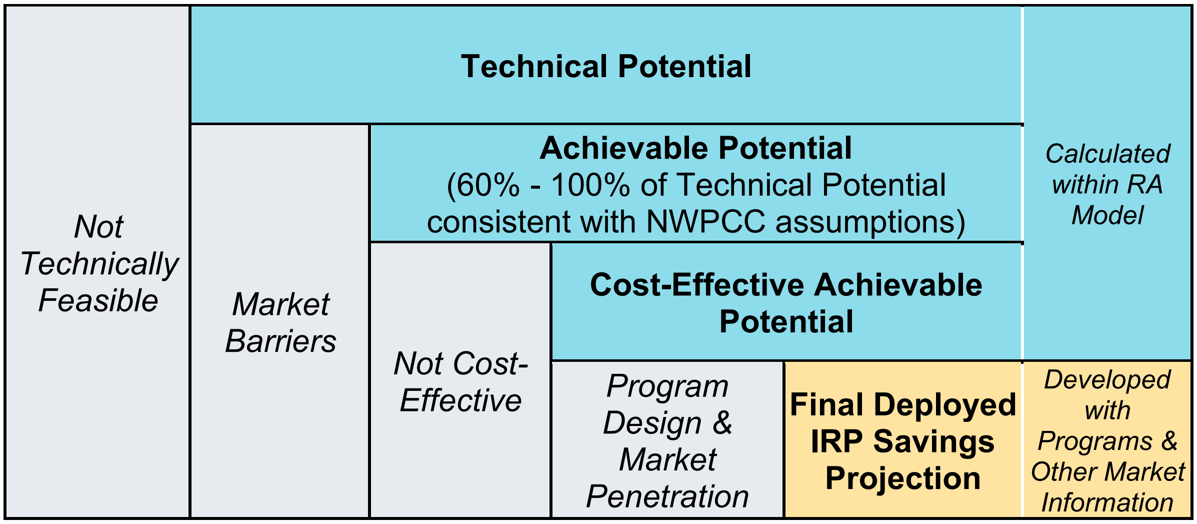
Energy Trust analyzes energy savings on a consistent and comparable basis with other supply side resources. All cost-effective energy efficiency is identified and deployed via the long-term planning process and Energy Trust is tasked with acquiring this resource on behalf of Cascade. Cascade and Energy Trust work closely to ensure Energy Trust has access to the Company's most recent forecasting data and is able to effectively integrate this information into its assessment of the Company's DSM potential. Throughout the IRP process, both entities communicated and coordinated on an ongoing basis to maximize forecast accuracy and to provide adjustments to analysis where appropriate. For this planning cycle, consistent with the previous, the Company and Energy Trust spent nearly a year engaged in constructive dialogue, beginning with an exchange of load and customer growth forecasts and Avoided Costs, as well as discount and inflation rates. From there, a series of meetings and calls were launched to ensure both parties were comfortable with the analysis as it proceeded.

As a result of this coordination, Energy Trust developed a 20-year DSM resource forecast for Cascade using Energy Trust's DSM resource assessment modeling tool (hereinafter 'RA Model') to identify the total 20-year cost-effective DSM savings potential, which is then 'deployed' exogenously of the RA model to estimate the final deployed IRP savings projection.[4] There are four types of potential that are calculated to develop the final deployed IRP savings projection. The types of potential are shown in Figure 7-1 and are discussed in greater detail in following sections.

---

[2] See Schedule 300, Energy Efficiency Incentive Program; Schedule 301, Low Income Weatherization Incentive Program; Schedule Tariffs are posted online at www.cngc.com.
[3] 2022-2023 Biennial Conservation Plan
[4] The RA Model is similar to what is called a Conservation Potential Assessment (CPA) as is performed for Cascade's Washington energy efficiency planning.

Figure 7-1: Types of Potential Calculated in 20-year Forecast Determination



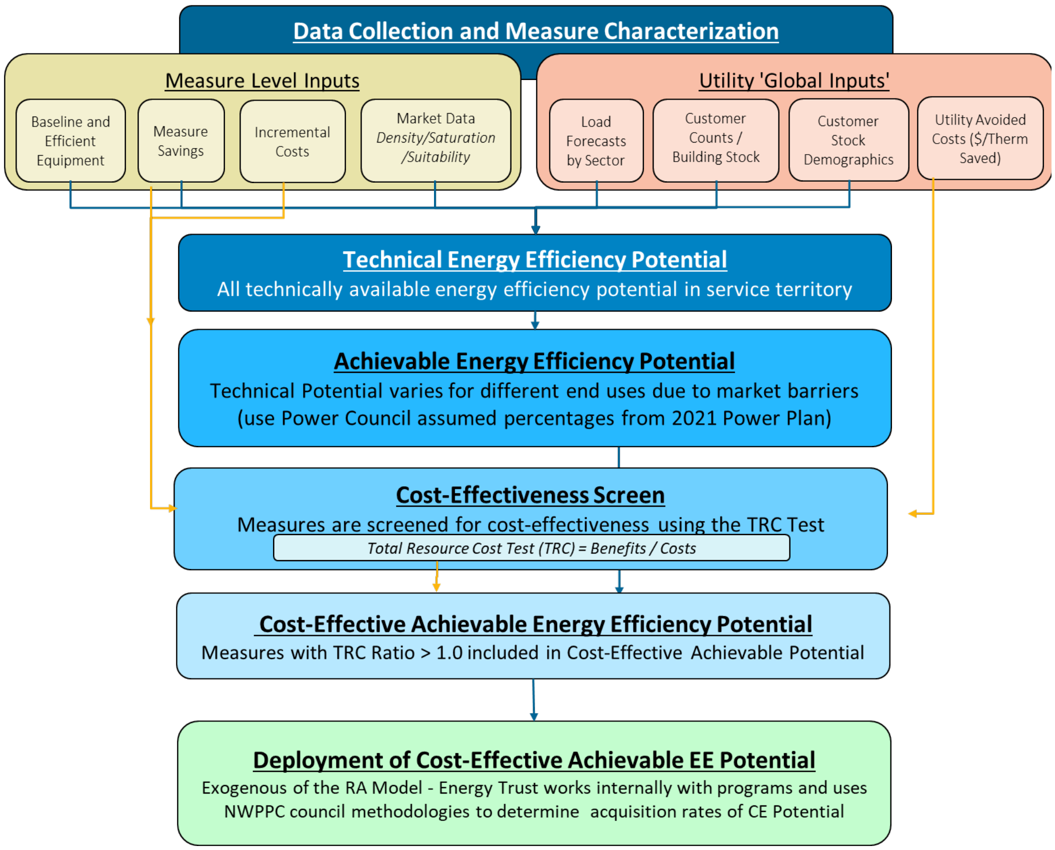
The RA Model utilizes the modeling platform Analytica®[5], an object-flow based modeling platform that is designed to visually show how different objects and parts of the RA model interrelate and flow throughout the modeling process. The RA Model utilizes multidimensional tables and arrays to compute large, complex datasets in a relatively simple user interface. Energy Trust then deploys this cost-effective potential exogenously to the RA Model into an annual savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. This final savings projection is provided to Cascade for inclusion in its PLEXOS® Model as a reduction to demand on the system.

20-Year Forecast Detailed Methodology

Energy Trust's 20-year forecast for DSM savings follows six overarching steps from initial calculations to deployed savings, as shown in the flow chart in Figure 7-2. The first five steps in the varying shades of blue nodes (*Data Collection and Measure Characterization* to *Cost-Effective Achievable Energy Efficiency Potential*) are calculated within Energy Trust's RA Model. This results in the total cost-effective potential that is achievable over the 20-year forecast. The actual deployment of these savings (the acquisition percentage of the total cost-effective potential each year, represented in the green node of the flow chart) is done outside of the RA Model. The remainder of this section provides further detail in each of the steps shown in Figure 7-2.

[5] https://lumina.com/why-analytica/what-is-analytica/

Figure 7-2: Energy Trust's 20-Year DSM Forecast Determination Flow Chart



Data Collection and Measure Characterization

The first step of the modeling process is to identify and characterize a list of measures to include in the RA Model, as well as receive and format utility 'global' inputs for use in the RA Model. Energy Trust compiled and analyzed a list of commercially available and emerging technology measures for residential, commercial, industrial and agricultural applications which can be installed in new or existing applications. The list of measures is meant to reflect the full suite of measures offered by Energy Trust, plus a spectrum of emerging technologies.[6] Simultaneous to this effort, Energy Trust collected necessary data from Cascade to run the RA Model and scale the measure level savings to a given

[6] An emerging technology is defined as technology that is not yet commercially available, but is in some stage of development with a reasonable chance of becoming commercially available within a 20-year timeframe. The Model is capable of quantifying costs, potential, and risks associated with uncertain, but high-saving emerging technology measures. The savings from emerging technology measures are reduced by a risk-adjustment factor based on what stage of development the technology is in. The working concept is that the incremental risk-adjusted savings from emerging technology measures will result in a reasonable amount of savings over standard measures for those few technologies that eventually come to market without having to try and pick winners and losers.

service territory (known as 'global inputs'). The measure level inputs and global inputs are described in more detail below.

Measure Level Inputs

Once the measures have been identified for inclusion in the RA Model, they must be characterized to determine their savings potential and screened for cost-effectiveness. The characterization inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[7], and engineering analysis. There are over 30 measure level inputs that feed into the RA Model, but on a high level, the inputs are put into the following categories:

- **Measure Definition and Equipment Identification**: This is the definition of the efficient equipment and the baseline equipment it is replacing (e.g. a 95% annual fuel use efficiency (AFUE) furnace replacing an 80% AFUE baseline furnace). A measure's replacement type is also determined in this step – Retrofit (RET), Replace on Burnout (ROB), or New Construction (NEW).

- **Measure Savings**: The therm savings associated with an efficient measure calculated by comparing the consumption of the baseline and efficient measures.

- **Incremental Costs**: The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the type of measure. If a measure is a RET measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a ROB or NEW measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline measure.

- **Market Data**: Market data of a measure includes the density, efficient saturation, and suitability of a measure. A density is the number of measure units that can be installed per scaling basis (e.g. the average number of showers per home for showerhead measures). The efficient saturation is the average saturation of the density that is already efficient (e.g. 50% of the showers already have a low flow showerhead). Suitability of a measure is a percentage input to represent the percent of the density where the efficient measure is actually suitable for installation. These data inputs are all generally derived from regional market data sources such as the Northwest Energy Efficiency Alliance's (NEEA) Residential and Commercial Building Stock Assessments (RBSA and CBSA).

[7] Secondary Regional Data sources include: The Northwest Power and Conservation Council (NWPCC), the Regional Technical Forum (the technical arm of the NWPCC), and market reports such as the Northwest Energy Efficiency Alliance's (NEEA) Residential and Commercial Building Stock Assessments (RBSA and CBSA)

Utility Global Inputs:

The RA Model requires several utility level inputs to create the DSM forecast. These inputs include:

- **Customer and Load Forecasts**: These inputs are essential to scale the measure level savings to a utility service territory. For example, residential measures are characterized on a scaling basis 'per home', so the measure densities are calculated as the number of measures per home. The RA Model then takes the number of homes that Cascade serves currently and the forecasted number of homes to scale the measure level potential to the utility's entire service territory.

- **Customer Stock Demographics**: These data points are utility specific and identify the percentage of stock that utilize different heating fuels for both space heating and water heating. The RA Model uses these inputs to segment the total stocks to the stocks that are applicable to a measure (e.g. gas storage water heaters are only applicable to customers that have gas water heat).

- **Utility Avoided Costs**: Avoided Costs are the net present value of avoided energy purchases, delivery costs, carbon compliance and risk reduction associated with energy efficiency savings represented as dollars per therm saved. These values are provided by Cascade and the components are discussed in Chapter 5, Avoided Cost. Avoided Costs are the primary 'benefit' of energy efficiency in the cost-effectiveness screen.

Calculate Technical Energy Efficiency Potential

Once measures have been characterized and utility data is loaded into the RA Model, the next step is to determine the technical potential of energy that could be saved. Technical potential is defined as the total potential of a measure in the service territory that could be achieved regardless of market barriers or cost-constraints, representing the maximum potential energy savings available. The RA Model calculates technical potential by multiplying the number of applicable units for a measure in the service territory by the measure's savings. The RA Model determines the total number of applicable units for a measure utilizing several of the measure level and utility inputs:

Total applicable units =	*Measure Density * Baseline Saturation * Suitability Factor * Heat Fuel Multipliers (if applicable) * Total Utility Stock (e.g. # of homes)*
Technical Potential =	*Total Applicable Units * Measure Savings*

The measure level technical potential is then summed to show the total technical potential across all sectors. This savings potential does <u>not</u> take into account the various market and cost barriers that will limit a 100% adoption rate.

Calculate Achievable Energy Efficiency Potential

Achievable potential is simply a reduction to the technical potential based on each measure's achievability assumption rate to account for market barriers that prevent total adoption of all cost-effective measures. Historically the achievable potential was defined as 85% of the technical potential. The Northwest Power and Conservation Council (NWPCC) updated the achievability assumption for certain measures in the most recent power plan and Energy Trust has aligned the RA model with these assumptions. Many measures still have 85% achievability while market transformation and codes and standards are assumed to be near 100% achievable while shell measures are closer to 60% achievable.

Achievable Potential =	*Technical Potential * Achievability%*

Determine Cost-effectiveness of Measure using TRC Screen

The RA Model screens all DSM measures in every year of the forecast horizon using the Total Resource Cost (TRC) test, a benefit-cost ratio (BCR) that measures the cost-effectiveness of the investment being made in an efficiency measure. This test evaluates the total present value of benefits attributable to the measure divided by the total present value of all costs. A TRC test value equal to or greater than 1.0 means the value of benefits is equal to or exceeds the costs of the measure and is therefore cost-effective and contributes to the total amount of cost-effective potential. The TRC is expressed formulaically as follows:

TRC = Present Value of Benefits / Present Value of Costs

Where the *Present Value of Benefits* includes the sum of the following two components:

- Avoided Costs: The present value of natural gas energy saved over the life of the measure, as determined by the total therms saved multiplied by Cascade's avoided cost per therm. The net present-value of these benefits is calculated based on the measure's expected lifespan using the Company's discount rate.

- Non-energy benefits are also included when present and quantifiable by a reasonable and practical method (e.g. operations and maintenance (O&M) cost reductions from advanced controls).

Where the *Present Value of Costs* includes the total incremental cost of an energy efficiency measure, which includes:

- Incentives paid to the participant; and
- The participant's remaining out-of-pocket costs for the installed cost of the measures after incentives, minus state and federal tax credits.

- Operations and maintenance costs over the life of the measure, if applicable.

The cost-effectiveness screen is a critical component for Energy Trust modeling and program planning because Energy Trust is only allowed to incentivize cost-effective measures unless an exception has been granted by the OPUC. The RA Model allows for non-cost-effective measures that have been granted OPUC exceptions to be included in the cost-effective achievable savings using an override feature.

Quantify the Cost-Effective Achievable Energy Efficiency Potential[8]

The RA Model's final output of potential is the quantified cost-effective achievable potential. If a measure passes the TRC test described above, then *achievable savings* from a measure is included in this potential. If the measure does not pass the TRC test above, the measure is not included in cost-effective achievable potential. However, the cost-effectiveness screen is overridden for some measures, detailed in Figure 7-3, under two specific conditions:

- The OPUC has granted an exception to offer non-cost-effective measures per conditions outlined in Oregon UM-551 or,
- When the measure isn't cost-effective using utility specific Avoided Costs, but the measure is cost-effective when using blended gas Avoided Costs for all of the gas utilities Energy Trust serves and is therefore offered by Energy Trust programs.

Figure 7-3: Measures with Cost-Effective Override Applied and Rationale

Measures that are Overridden	Override Applied?	Rationale
Res - Attic/Ceiling insulation	TRUE	OPUC Exception
Res – Clothes Washers (gas-only service area)	TRUE	OPUC Exception
Res - Floor insulation	TRUE	OPUC Exception
Res – Gas heated new manufactured homes	TRUE	OPUC Exception
Res - Wall insulation	TRUE	OPUC Exception

Deployment of Cost-Effective Achievable Energy Efficiency Potential

After determining the modeled 20-year cost-effective achievable potential, Energy Trust develops a savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. This is known as the deployment of savings and is a 20-year forecast of energy savings that will result in a reduction of load on Cascade's system. This savings forecast includes savings from program activity for existing measures and emerging technologies, expected savings from market transformation efforts that drive improvements in codes and standards, and a

[8] Cascade's Washington energy efficiency programs also identify a cost effective TRC potential, but primarily identifies savings potential via a modified UCT or UCT Achievable Economic Potential

forecast of what Energy Trust is describing as a 'large project adder'. The 'large project adder' is characterized as savings that account for large unidentified projects that consistently appear in Energy Trust's historic savings record and have been a source of Energy Trust overachievement against IRP targets in prior years for other utilities that Energy Trust serves.

Overview of Deploying Cost-Effective Achievable Potential

The cost-effective achievable potential output by the RA Model does not represent the forecast of savings that utilities will actually experience on their systems. Not all cost-effective achievable potential that results from the RA Model can actually be obtained by Energy Trust due to limitations in customer awareness, limitations in customer willingness to install, relative program maturity ranging from nascent offerings to mature programs with harder to reach customer segments, savings being realized through codes and standards, and other market factors. To account for these factors, Energy Trust 'deploys' the cost-effective achievable results output by the RA Model to represent the amount of savings that are forecast to be obtained either through Energy Trust programs, codes and standards or other market transformation mechanisms. This results in the 4th level of potential called 'deployed potential' outlined in Figure 7-1, using ramp rates.

There is a suite of ramp rates that Energy Trust utilizes capturing assumptions about Cascade's service territory. An individual measure's ramp rate depends on the replacement type of the measure, which is either a Lost Opportunity or Retrofit. This reflects the difference in calculating potential between different measure replacement types (ROB vs. RET vs. NEW). This method generally aligns with the NWPCC methodology for deploying potential in the NWPCC Power Plans[9] produced every five years. Below is further detail on each deployment type:

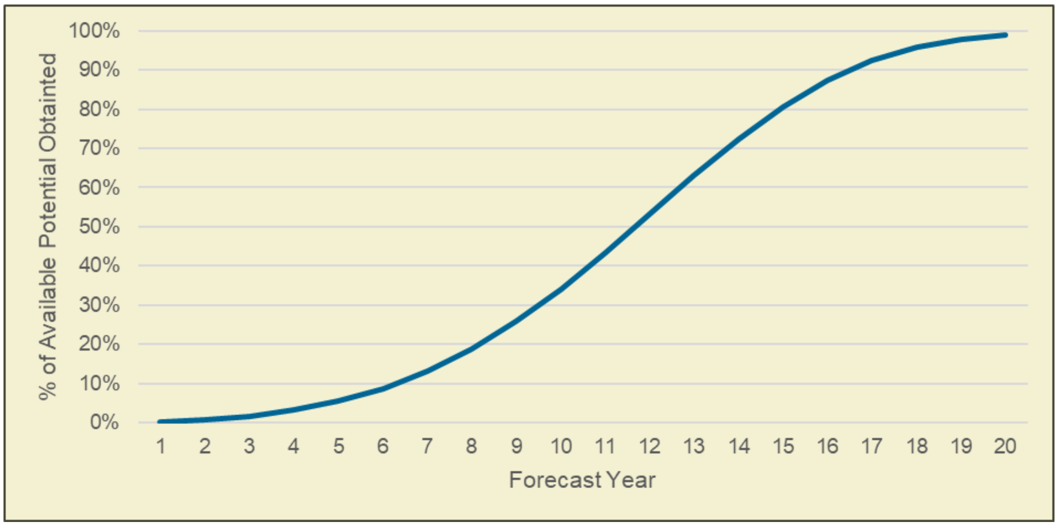
- **Lost Opportunity (LO) Measures** – LO measures are ROB and NEW measures in the RA Model. They are considered lost opportunity because the number of stocks available is limited by stock turnover for ROB measures and new construction rates for NEW measures. When a new construction project happens or a piece of equipment burns out, a one-time window of opportunity is opened to replace the old equipment with higher-efficiency equipment above code or to promote new construction equipment above code. If the opportunity is missed, it is lost until the inefficient equipment burns out again, hence the 'lost opportunity' name.

  In the early years of a forecast, it is not plausible that Energy Trust is incenting every piece of equipment that turns over, but it is possible that in the later years those replacements will be captured through either programs, codes or standards,

[9] A discussion of the ramp rate methodology applied by the Northwest Power and Conservation Council in the 2021 Power Plan can be found at:
https://www.nwcouncil.org/2021powerplan_conservation-methodologies/

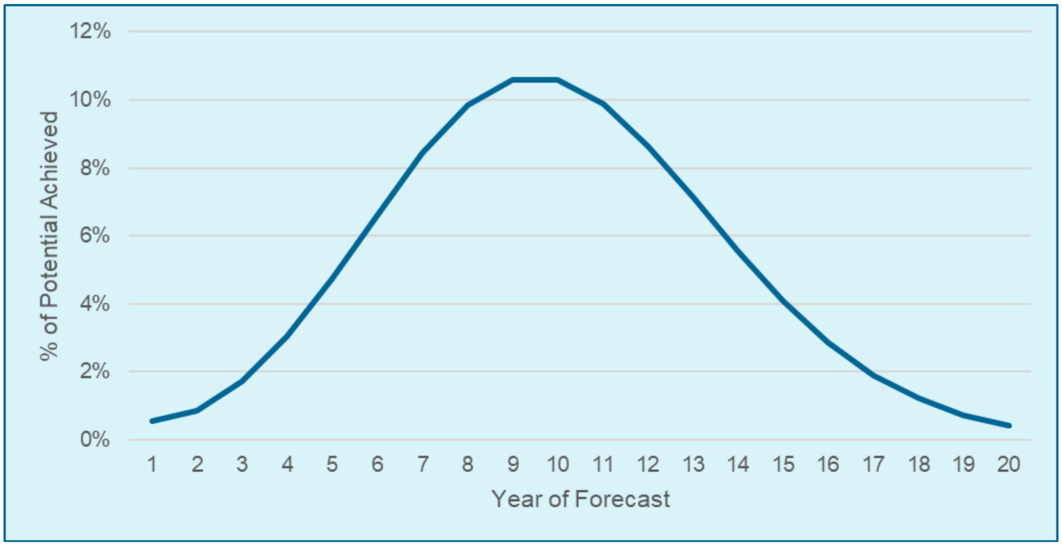
or market transformation mechanisms such as the measure becoming common practice. Therefore, ETO uses a deployment ramp rate that ramps up to capturing 100% of the available LO savings by the end of the 20-year forecast. Figure 7-4 shows a representative LO Ramp Rate:

Figure 7-4: Example of NWPCC Lost Op. Ramp rate



- **RET Measures** – The RA Model results for retrofit measures represent the total amount of potential available over the 20-year forecast period. Retrofit measure potential must be deployed differently because it is assumed that the measures can be acquired at any point within the forecast period. For retrofit measure deployments Energy Trust typically uses a bell-shaped ramp rate that adds up to 100% and distributes the potential over the 20-year forecast. Figure 7-5 shows a representative RET Ramp Rate.

Figure 7-5: Example of NWPCC Retrofit Ramp rate



Some RET measures can have ramp rates that do not add up to 100%, especially if they are hard to reach measures such as insulation or are emerging technologies

Ramp Rate Development and Calibration for Final Deployment

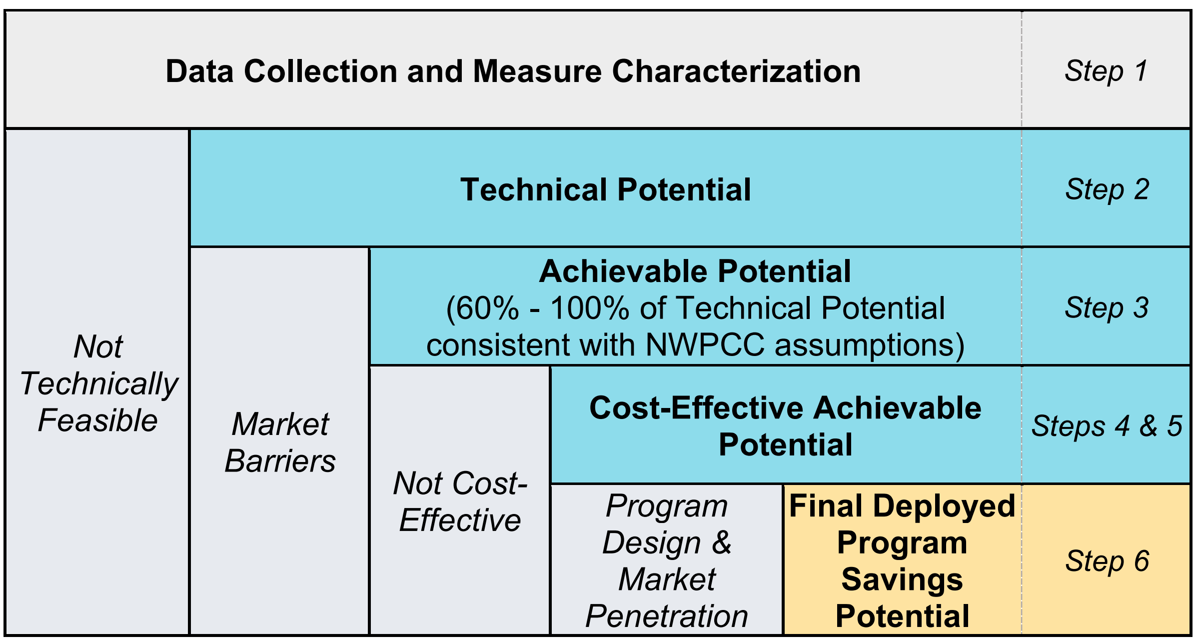
Energy Trust typically develops ramp rates at the program category level and the calibration process is divided into three time frames, as shown in Figure 7-6. The first two years of each ramp rate are calibrated to program budgeted goals to get a starting point for the curve. Years 3-5 of ramp rates are also calibrated based on collaboration between Energy Trust program intelligence and RA Model results. The remaining 15 years of the forecast are developed without program input and are based on the remaining potential available.

Some Energy Trust programs have more detailed data, and Energy Trust can develop more granular ramp rates at the end-use or measure level. Energy Trust follows the NWPCC methodology of achieving 100% of the cost-effective achievable potential by the end of the forecast, unless there is a good rationale that it is not possible to realize 100% of potential. Some reasons may include historically low uptake, installation is invasive, or it is an emerging technology. In terms of lost opportunity measures, achieving 100% means 100% turnover of the available stocks throughout that year. For retrofit measures, this means spreading 100% of the potential across the 20 years, informed by calibration in the early years.

Figure 7-6: Energy Trust Ramp Rate Calibration Process

Figure 7-6 reflects the process for how Energy Trust develops ramp rates to finalize the "Final Deployed Program Savings Potential" from the "Cost-Effective Achievable Potential" shown in step 6 and Steps 4 and 5 respectively in Figure 7-7.

Figure 7-7: The Progression to Final IRP DSM Savings Projections



Modeling Changes and Sensitives in Oregon

Energy Trust's RA Model is a 'living' model and it is continually being updated and improved. There have been a number of changes to the RA Model, methodology and measures since the 2020 IRP. These updates include:

- Refreshed measure assumptions
    - Measure inputs for measures spanning residential, commercial, and industrial program sectors were reviewed and updated using a combination of Energy Trust primary data review and analysis, regional secondary sources, and engineering analysis. The refreshed assumptions include baseline adjustments, savings and cost updates, as well as density assumptions pertaining to where measures can be installed and existing measure saturation rates.
- Emerging Technologies
    - Several emerging technologies were added to the RA Model for the 2023 IRP and these additions are described in detail in the results section below. These measures gradually add to the total potential over time as they become commercially available and gain market share against conventional efficient technologies.
- Lost Opportunity measures and unconstrained potential to replace failed equipment
    - Lost opportunity measures are constrained in each year by the assumed failed equipment burnout rate as a percentage of total stock. Energy Trust has aligned how the RA model treats lost opportunity measures to be consistent with Northwest Power and Conservation Council (NWPCC) methodology, allowing lost opportunities to recycle throughout the forecast period. I.e. if savings from these measures are not acquired when they are first available, then the potential will show up again later if the respective measure life is shorter than the forecast period.
- Updated achievability assumptions to align with NWPCC methodology
    - Energy Trust has updated achievability assumptions to be consistent with what was used in the most recent power plan. Historically achievability rates were assumed to be 85% for all measures. NWPCC has updated these rates for some measures based on market research. At a high level these changes result in greater achievability for market transformation and codes and standards, and lower achievability for shell measures.
- Scenario Runs
    - Energy Trust ran two scenarios for Cascade's 2023 IRP consisting of a base case and a high commodity scenario to reflect increases in commodity pricing from renewable natural gas or hydrogen. These scenarios are discussed in more detail in the scenario runs section. All results reflect the base case, unless noted otherwise.

Energy Trust held a stakeholder feedback meeting in September 2017 to solicit feedback on Energy Trust's forecast process. Attendees included utilities, OPUC Staff, and other regional stakeholders like the Northwest Energy Coalition. Some of the most significant themes that emerged from this process include:

- Energy Trust annual savings achievements have been consistently exceeding IRP targets.
- Utilities and stakeholders are interested in receiving a forecast based on more than just "firm" resources achieved through program activity.
- Utilities are interested in the best projection Energy Trust can provide. Achievements should fluctuate on both sides of the forecast over time.
- Forecast has been missing some estimation of future resources that Energy Trust cannot currently identify.
    - New large single loads that utilities have difficulty forecasting and associated large efficiency projects.
    - Emerging technology of the future that has not yet been developed to the point where Energy Trust includes it in its Model.
- Short-term forecasts are most important to utilities and the OPUC in the following order: 1-2 years, 3-5 years, 6-10 years, and 11-20 years.

As a result of this feedback, Energy Trust made several changes to improve its forecasting methodology which were first reflected in Cascade's 2018 and 2020 energy efficiency forecasts:

- Calibration of Measure Deployment Rates based on Program Forecasts and Trends
    - Increased coordination with program managers and a move to think about forecast in three time periods to calibrate savings potential.
        - 1-2 years (short term) - Rely on programs and align with savings goals from most recent budget
        - 3-5 years (midterm) - Programs and planning work together to extend program trends based on market intelligence
        - 6-20 years (long term) - Planning forecasts long-term acquisition rate
- Large Project Adder
    - Addition of forecast "large project adder" to account for large unidentified projects. These have previously not been forecast as increased loads or energy efficiency project opportunities and have led to results that deviated from the forecasts. The addition is based on average savings from large efficiency projects Energy Trust completed in the past.
- Alignment with NWPCC
    - Adopted deployment methodologies that better align with the NWPCC acquisition assumptions and ramping the deployment of measures to 100% of total cost-effective achievable potential for each measure.
        - Exceptions: emerging technologies and hard to reach measures such as insulation

DSM Projections in Oregon: 2023-2042

The Company foresees 14.62 million therms of its 20-year demand coming from Oregon DSM measures delivered through Energy Trust. Figure 7-8 presents the technical, achievable, and cost-effective achievable potentials as well as Energy Trust's therm savings target for the 20-year planning period.

Figure 7-8: Savings Projections for Oregon

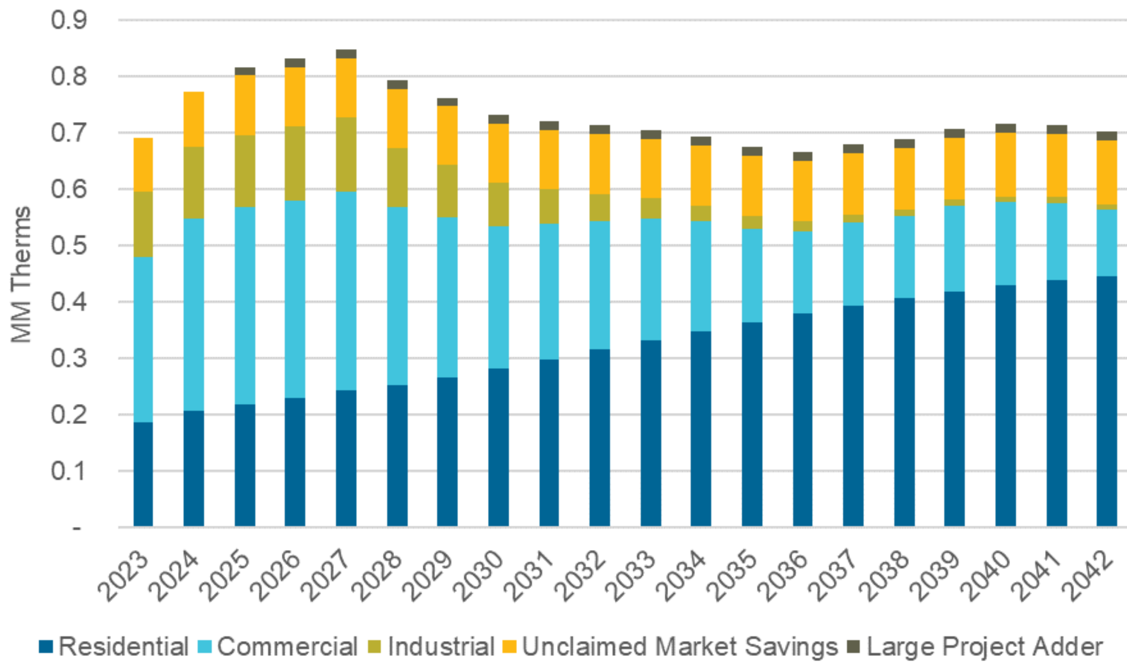
	Residential	Commercial	Industrial	All Sectors
Technical	18,333,106	8,011,512	1,486,157	27,830,775
Achievable	14,814,813	6,663,051	1,263,233	22,741,098
Cost-effective achievable	13,423,463	5,430,091	1,224,379	20,077,933
IRP Projected Savings	6,865,053	4,162,029	1,193,202	**14,624,110**[10]

The final savings projection of 14.62 million therms by 2042 in Cascade's service territory reflects the reduction to the full cost-effective achievable potential of 20.08 million therms due to additional market-related constraints on capturing savings from replacing equipment at end-of-life and measures from new homes and buildings. Such measures are known as *lost opportunity* measures. The opportunity to acquire these savings, if lost, does not reappear again until their useful life has passed. Energy Trust assumes a relatively sizable portion of these savings will be acquired over time, but Energy Trust does not expect it can leverage all these opportunities as they arise. Energy Trust's savings projection also includes therms achieved through known changes to future residential and commercial building codes where Energy Trust played a role in advancing the adoption of these codes and standards. Since energy consumption is reduced when more stringent building codes are adopted, the OPUC has agreed to allow Energy Trust to claim some of the savings since its work in transforming the market influenced the changes in code. These savings are included in the forecast associated with the New Homes and New Buildings programs.

Figure 7-9 depicts Energy Trust's annual savings projection for Cascade's service territory.

[10] The sector level IRP Projected Savings sum to 12,220,287 therms. The all sectors total of 14,624,110 includes 2,403,823 therms of savings that Energy Trust will not claim or are exogenous to the model. Unclaimed savings include NEEA's share of commercial market transformation and some commercial cooking measures becoming code. Savings exogenous to the model, but claimed by Energy Trust, are the large project adder which is included to account for unknown large projects throughout the forecast period.

Figure 7-9: 20-Year Annual Projected Savings (2023-2042)



Savings for the 2023 IRP increase in the early years and then decline in years six through fourteen. Energy Trust views 2023 and 2024 as infrastructure building years to increase savings even further through 2027 as Energy Trust works with Cascade to acquire energy savings to comply with Oregon greenhouse gas policy. This increase in energy efficiency acquisition in the near term works to pull the peak of the retrofit bell curve forward in time, and thus the tail of the curve as well, which deploys the remaining retrofit potential. This is especially evident in the commercial and industrial sectors in the trend of decreasing savings after the year 2027.

Savings in the residential sector, however, show an increasing trend through the forecast horizon. This reflects the differing composition of savings potential in the residential sector and where Cascade is on the retrofit bell curve for those measures. Residential savings include a significant amount of new and replace on burnout measures which ramp up to 100% market penetration in the later years. Additionally, residential shell and water heat end uses, as well as emerging technologies including gas fired heat pump water heat, have lower market penetrations and thus are earlier in their ramp rates. For these reasons Cascade can expect a divergence in savings trend between the commercial/industrial and residential sectors in the forecast period.

Energy Trust calibrates the first five years of the forecast to budgeted savings expectations in years one and two, and then to what programs believe they will be able to obtain for years three through five as described in Figure 7-6. In addition to Energy Trust claimed savings, the 2023 IRP savings totals include an estimate of market baseline and code changes to forecast what will come off Cascade’s system in total from energy efficiency, even if it will not be claimed and reported by Energy Trust. This is reflected in gold in the Figure 7-9 above as unclaimed market savings.

This discussion highlights that there is a divergence between forecasted savings projections and what Energy Trust will actually claim beyond the first two years of the forecast, with the first two years of savings taken from the most recent Energy Trust two-year budget. For years three through twenty it isn't clear whether the savings that Cascade will experience on its system are savings that will be claimed by Energy Trust or savings that will result from market transformation effects such as codes and standards or future changes to market baselines.

Figure 7-10 provides a 20-year view of cumulative savings projections by savings type: technical, achievable, cost-effective achievable and the deployed IRP savings projection. The orange IRP savings projection line approaches the cost-effective achievable potential but does not meet it. This is due to the earlier discussion of lost opportunity measures. Additionally, some hard-to-reach measures such as insulation or windows are not deployed to 100% of their cost-effective potential in recognition of the fact that these savings are much more difficult to achieve through programs due to various factors including being hard to reach, customer hesitation or ease of implementation.

Figure 7-10: 20-Year Cumulative Savings Projections by Savings Type

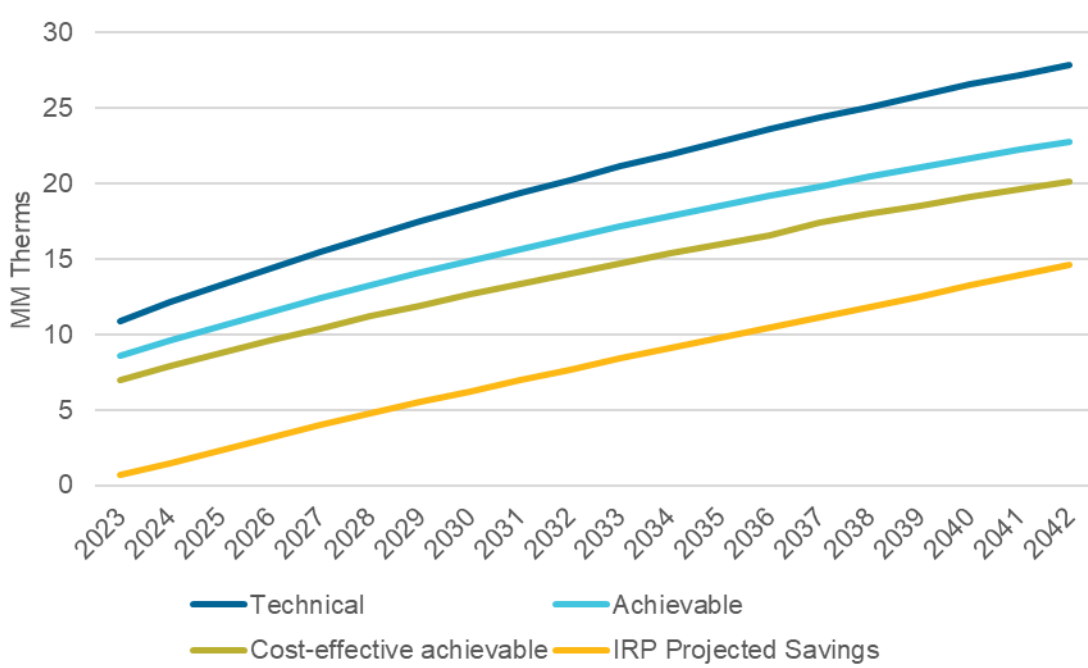


Figure 7-11 provides the cumulative savings projections by sector and savings type. The residential IRP projected savings are a smaller percentage of the total cost-effective achievable potential due to a significant amount of insulation and windows savings that are not fully deployed because they are hard to reach and have lost-opportunities with the new construction market in the early years as shown by the deployment curve in Figure 7-4.

Figure 7-11: Cumulative 20-year Savings Potential by Sector and Savings Type

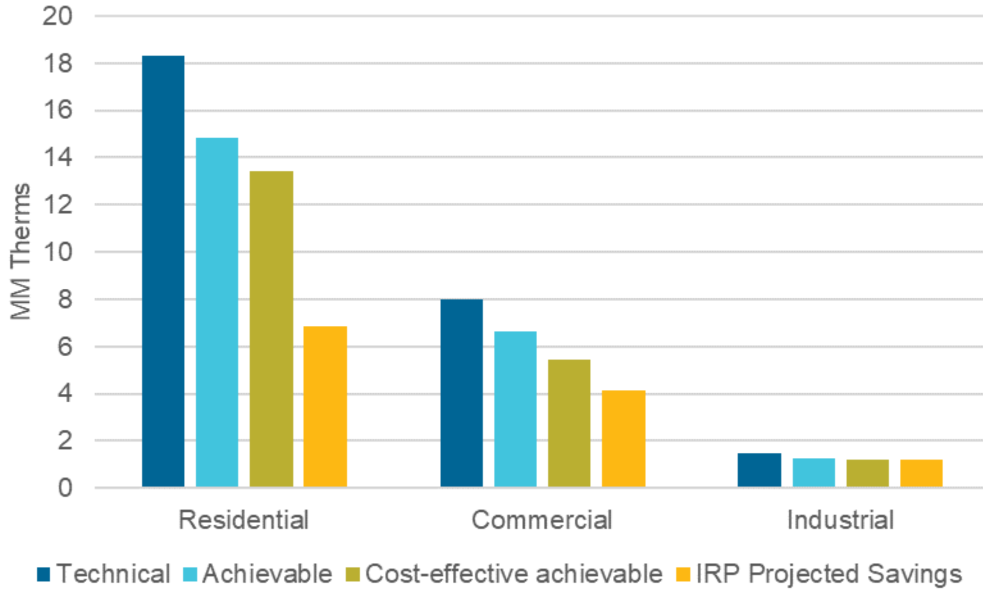


Figure 7-12 shows the potential therm savings per customer class, per measure type per previous discussion.

Figure 7-12: Savings Potential by Customer Class and Measure Type

Measure Type	Residential Therms Saved	Commercial Therms Saved	Industrial Therms Saved
New Construction	1,304,686	690,421	NA
Retrofit	1,282,554	2,028,168	1,054,952
Replacement/Burn-out	1,565,261	857,601	109,419
Strategic Energy Management	NA	751,239	28,841
New Construction Market Transformation	2,547,156	NA	NA
Unclaimed Market Savings	NA	2,122,153	NA
Large Project Adder[11]	NA	140,835	140,835
Total	**6,699,657**	**6,590,417**	**1,334,047**

Market Transformation savings are based on forecasts of units built to a code that would not have been in place had it not been for the program's efforts to accelerate both the change in code and builder's compliance with code.

Residential New Construction Market Transformation savings represent Energy Trust's best estimate of annual therm savings to be acquired for Cascade in Oregon. These savings targets include improvements in residential building codes adopted earlier due to Energy Trust's and NEEA's efforts and the estimated share of future savings that may come from codes.

Figure 7-13 provides an overview of Cascade's 20-year projected annual savings acquisition by measure end-use category showing both the total cost-effective achievable potential and the deployed IRP savings projection. A significant amount of savings is available from the heating, weatherization, and water heating[12] end-uses, which occur during peak periods.

[11] These savings can occur in either the commercial or industrial sector for a total of 281,669 therms.
[12] Water heating cost-effective potential includes savings from gas fired heat pump water heaters, an emerging technology. As shown in Figure 7-16, emerging technologies have more conservative ramp rates that do not approach 100% of available savings by the end of the forecast period to account for their market readiness. For this reason, the relative magnitude of deployed IRP savings is lower compared to the total cost-effective potential savings for the water heating end use.

Figure 7-13: 20-Year Annual Savings Projection by End Use Category

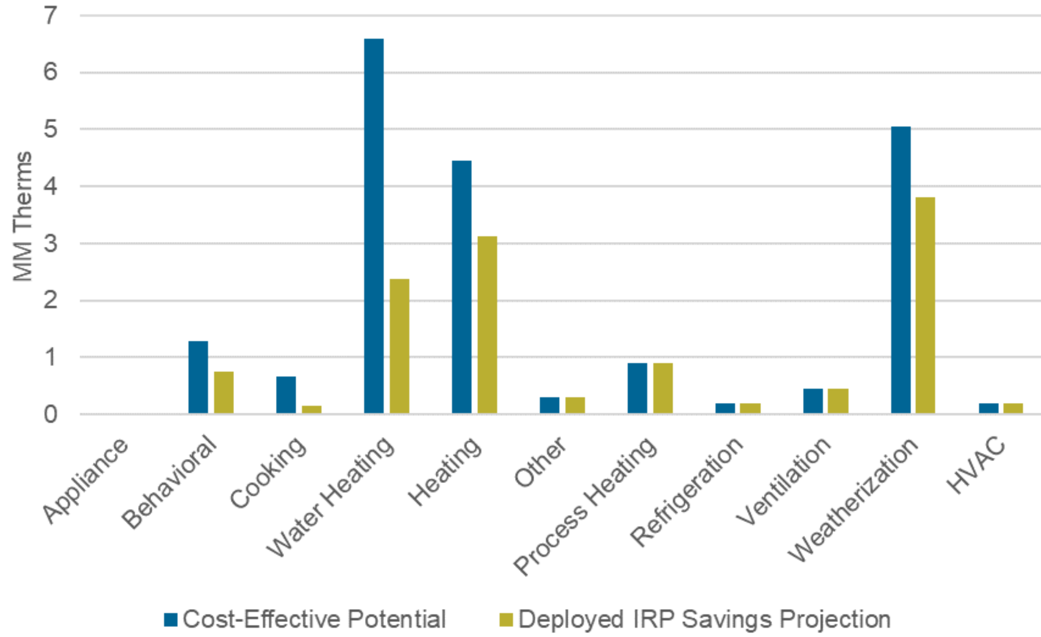
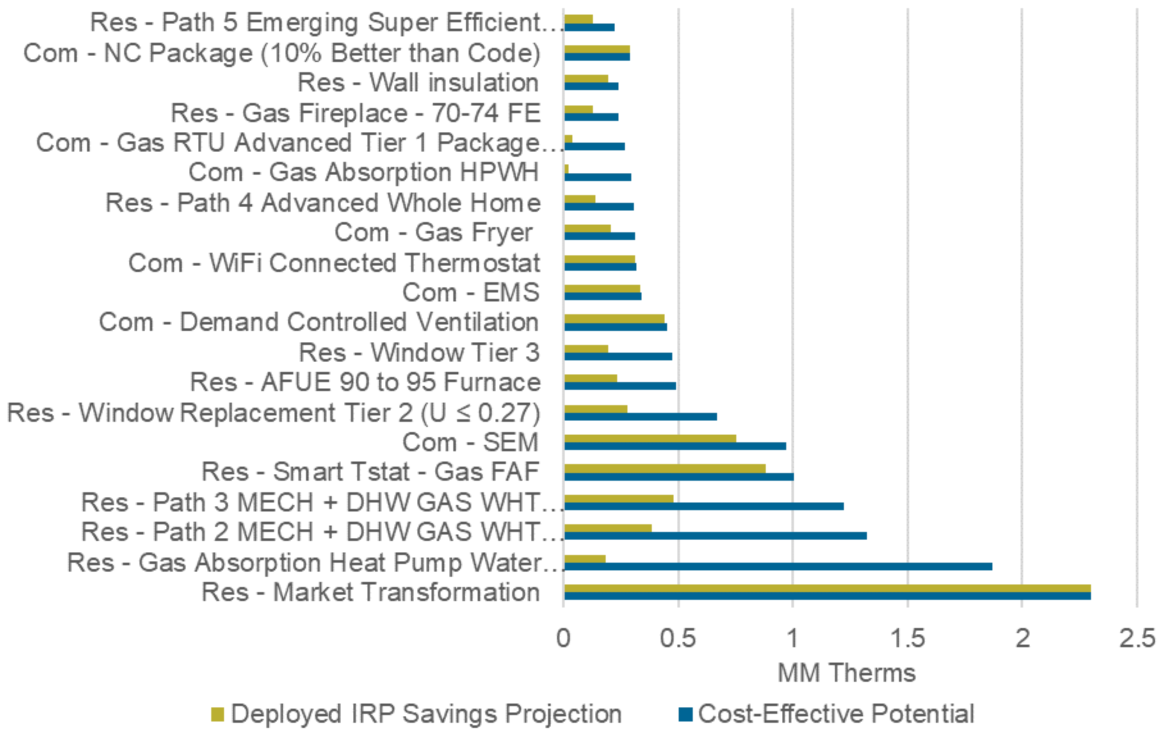


Figure 7-14 lists the top twenty measures from the Model based on their cost-effective potential. The chart also shows how much of that cost-effective potential was deployed and included in the final IRP savings projection. This illustrates the different factors that cause a measure to not achieve 100% of its cost-effective potential, for example:

- *Residential New Homes Pathways:* The reason these measures do not achieve 100% of the cost-effective potential is because of the lost opportunities in the early years, as discussed earlier in this chapter.
- *Residential – Gas Absorption Heat Pump Water Heater (HPWH):* This measure is an emerging technology and therefore is deployed at a lower rate than other measures and later in the forecast when the measure becomes cost-effective, which is why a small percentage of the cost-effective achievable potential is deployed.
- *Residential – Floor Insulation & Res – Window Replacement:* These two measures are hard to reach measures that have historically been difficult for programs to acquire. There are a lot of savings available from these measures, but Energy Trust did not deploy 100% of these savings because uptake of these measures has historically been slow. The forecast does include a small increase in savings from these measures over time but the overall deployment for these measures is more tied to historical performance than other measures.

Figure 7-14: Top 20 Measures - Cumulative Cost-Effective & Deployed IRP Savings Projections



Impact of Emerging Technologies

Energy Trust's forecast includes a suite of emerging technologies. These are technologies that are not yet commercially available and are generally high cost. The Model includes cost reduction curves for these technologies to simulate market effects as they become more mature, often resulting in the technology becoming cost effective later in the forecast period. Figure 7-15 indicates the emerging technologies that were included in this forecast.

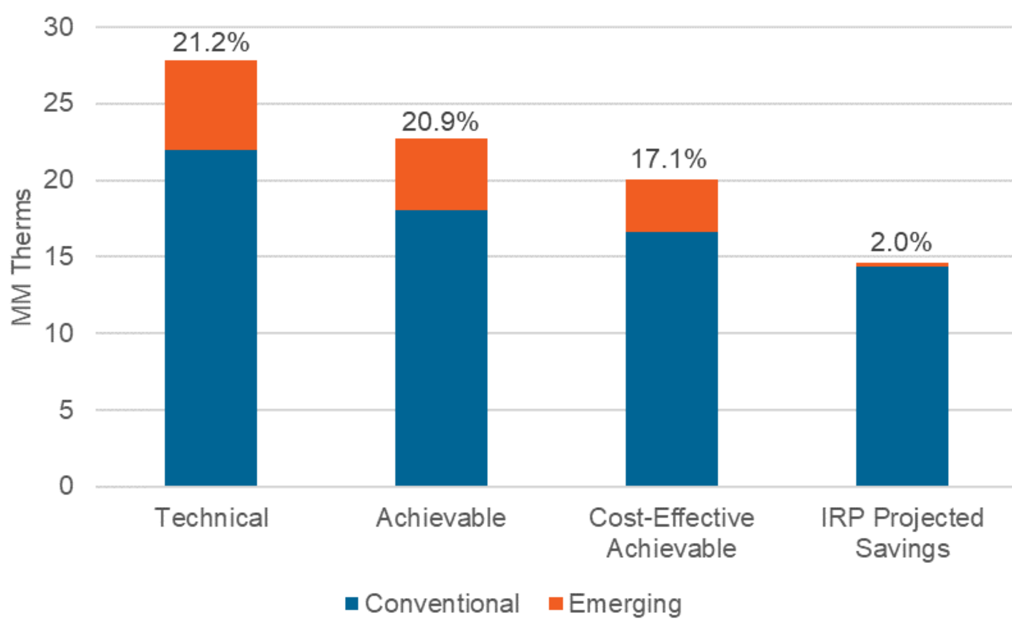
Figure 7-15: Emerging Technologies Included in the Energy Trust Forecast

Residential	Commercial	Industrial
Advanced Insulation	Condensing Gas Rooftop Unit	Advanced Wall Insulation
Cellular Shades	Gas Absorption Heat Pump Water Heater	Gas Fired Heat Pump Water Heater
Gas Absorption Heat Pump Water Heater	Gas Fired Heat Pump	
Gas Fired Heat Pump	Advanced Gas Rooftop Unit	
Thin Triple Pane Windows	Secondary Glazing	

	Thin Triple Pane Windows	
	VHE DOAS/HRV	
	Zero Net Energy	

Figure 7-16 depicts the cumulative impact of emerging technologies on the overall savings potential for each type of potential. Overall, emerging technologies account for more than 21% of the technical potential while making up 17% of cost-effective potential over the forecast. The impact on deployed IRP projected savings potential is even smaller because Energy Trust applies a different ramp rate to these technologies than existing technologies. This ramp rate places emerging technologies at the beginning of an adoption curve when they become market ready and cost effective.

Figure 7-16: Impact of Emerging Technologies on Cumulative Savings by Savings Type



Impact of Cost-Effective Override

As mentioned in the methodology discussion, Energy Trust includes some non-cost-effective measures in the forecast if they are being offered under an exception granted by the OPUC. These measures include residential and commercial insulation measures, efficient gas clothes washers and gas heated new manufactured homes. Figure 7-3 in the methodology section describes the measures in more detail. The impact of the cost-effective override is small in this IRP; only 2.9% of the cost-effective achievable potential and 3.1% of the deployed potential results from these overridden measures, as detailed in Figure 7-17.

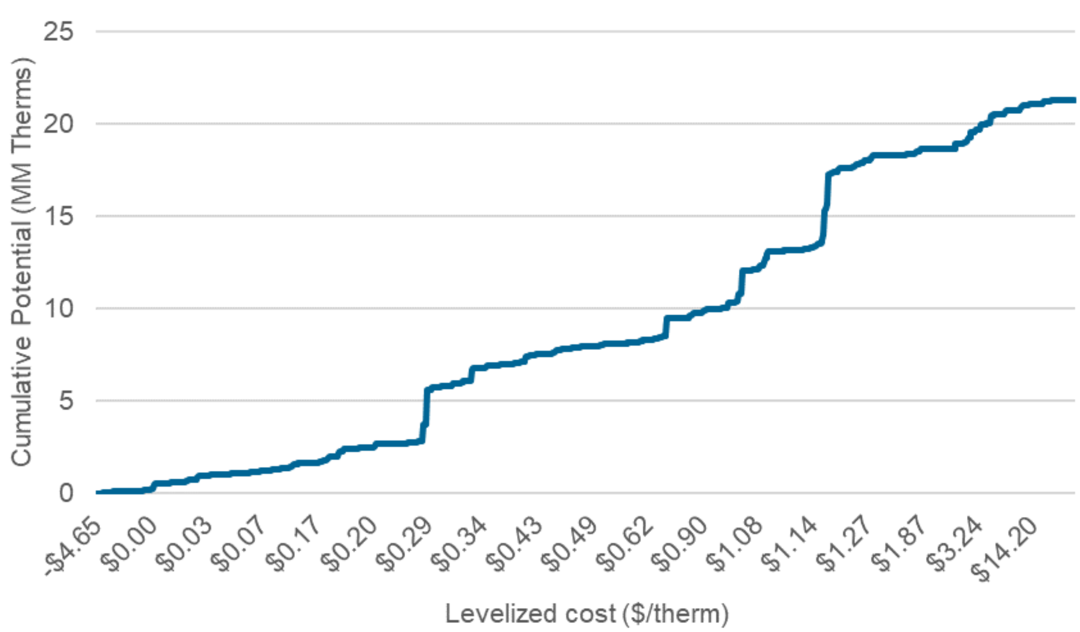
Figure 7-17: Impact of the Cost-Effective Override for Measures under OPUC Exception

Total Cumulative Potential	Cost-Effective Potential	Deployed IRP Savings Projection
Savings with CE Override (MM Therms)	20.08	14.62
Savings with NO CE Override (MM Therms)	19.50	14.16
Variance (MM Therms)	0.58	0.46
CE Overridden % of Total Potential	**2.9%**	**3.1%**

Levelized Cost Supply Curve

Figure 7-18 shows the levelized cost supply curve of energy efficiency potential. An energy efficiency supply curve plots the cumulative 20-year achievable potential on the y-axis against the associated levelized cost bin of the measure on the x-axis. The measure costs are levelized over the lifetime of the measure and can be negative if non-energy benefits exceed the cost of the measure. This provides a picture of how much potential can be obtained at different cost thresholds but should not be used to estimate the cost-effectiveness of a measure.

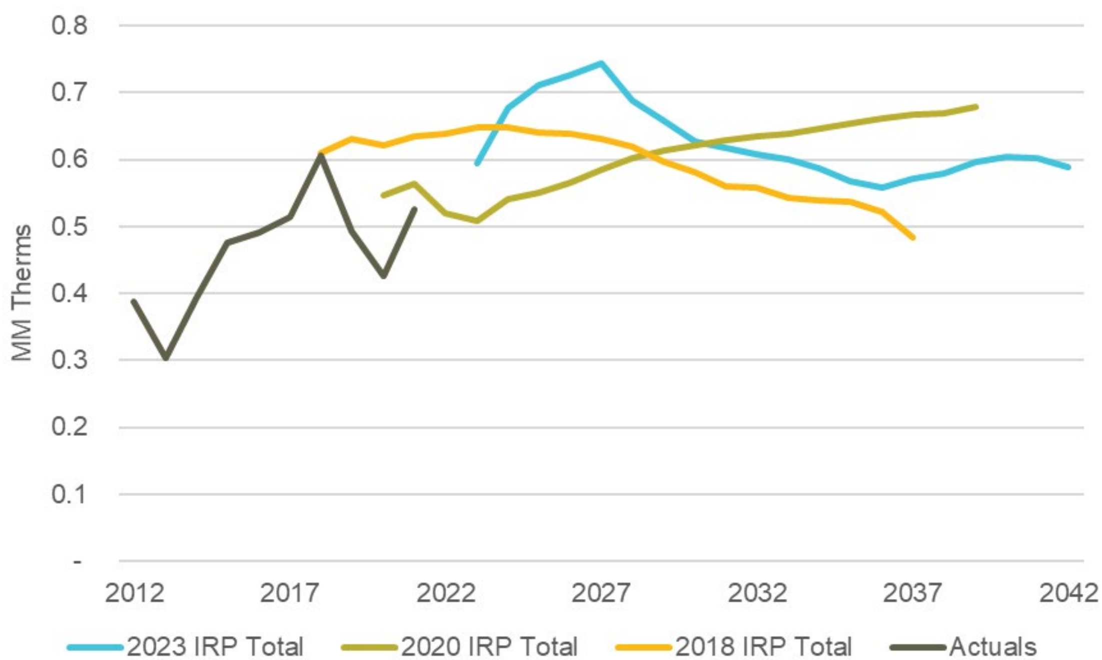
Figure 7-18: Energy Efficiency Supply Curve by Levelized Cost (20-Year Cumulative Achievable Potential)



Savings Projection Comparison to Previous IRPs

Figure 7-19 shows a comparison between the 2018 IRP, 2020 IRP, and 2023 IRP deployed savings potential, with actual savings performance shown in gray for reference. The IRP values do not include forecasted unclaimed market savings so that the forecast can be compared to Energy Trust claimed actuals. The spikey nature of the actual savings line is reflective of several factors, including the size of Cascade's Oregon service territory and the impact that large projects can have on overall annual savings achievements. Large projects can be difficult to forecast and often account for variances experienced in historical performance against goal and this is the rationale for why Energy Trust first included a 'large project adder' in the 2020 IRP forecast, and again in this IRP forecast for 2023.

Figure 7-19: Annual Actual Savings History and IRP Projection Comparison (Therms)



Savings for the 2023 IRP increase in the early years, taper, and then increase again at the end of the forecast for a variety of factors. The early year forecast generally follows the actuals trend of increasing savings year over year, and Energy Trust sees 2023 and 2024 as infrastructure building years to increase savings even further in the next five years as Energy Trust works with Cascade to acquire energy savings to comply with Oregon greenhouse gas policy. This increase in energy efficiency acquisition in the near term works to pull the peak of the retrofit bell curve forward in time. Thus, the decline in savings in years 2027 to 2037 are reflective of the deployment of the remaining retrofit potential. The increase in savings in the later years are the result of emerging technologies and lost opportunity measures in the residential sector ramping towards 100% at the end of the forecast period.

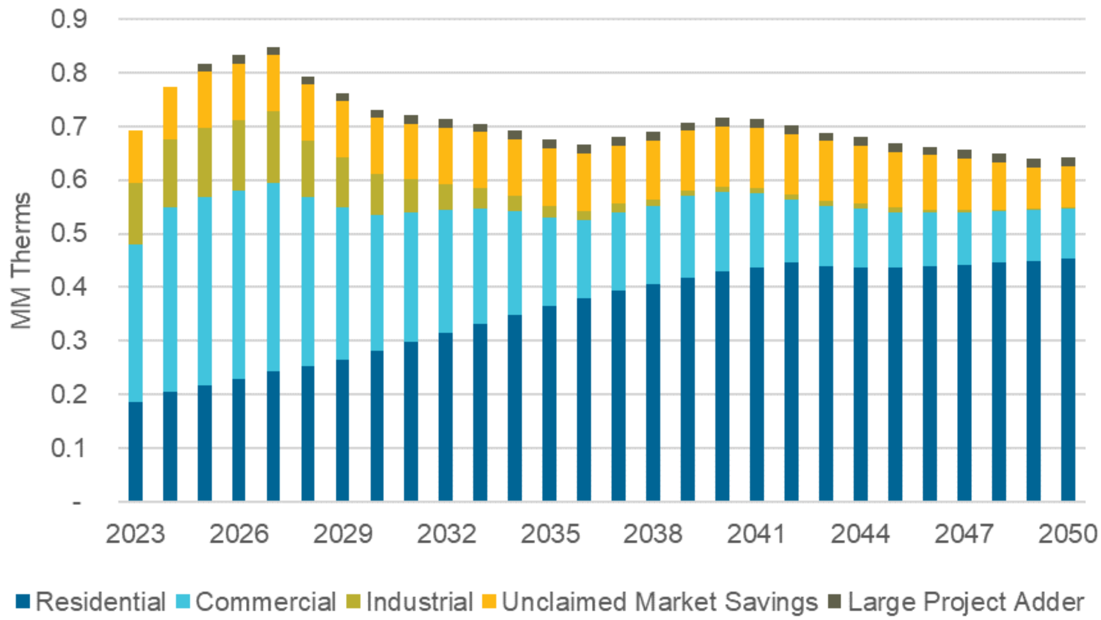
Final Savings Projection Extended to 2050

The Energy Trust RA model is configured to calculate savings potential results over a 20-year forecast horizon. Energy Trust then deploys the cost-effective achievable potential exogenously to the RA model as described above. This deployment methodology has been modified to extend the final savings projection through 2050 to better align with Cascade's planning horizon by continuing the energy efficiency acquisition curves for an additional eight years. This projection is different depending on the curve that was applied. As stated previously, Energy Trust ramp rates are based on NWPCC method and ramp rates, but calibrated to be specific to Energy Trust. Retrofit measure potential continues until 100% of the cost-effective achievable potential is acquired and savings potential is exhausted. Lost opportunity measures continue to ramp up to 100% of annual available cost-effective achievable potential at which point all savings are realized annually. Hard to reach measures or emerging technologies do not ramp to 100%.

Figure 7-20: 20-year and 29-year Final Deployed Savings Projection

	20-year Savings Projection	8-Year Savings Extension	Total Final Savings Projection through 2050
Deployed Savings	14,624,110	5,282,232	19,906,342

Figure 7-21: Annual Savings Projection by Sector through 2050



Scenario Runs

For the 2023 IRP, Energy Trust modeled two scenarios for Cascade. The two scenarios were designed to reflect differences in commodity pricing from renewable natural gas and hydrogen versus expected, conventional commodity prices. These scenarios are outlined in the bullets below and the methodologies for the scenarios are described in further detail following bullets:

- *Scenario 1:* Base Case Load and Stock Forecast / Base Case Avoided Costs
- *Scenario 2:* Base Case Load and Stock Forecast / High Avoided Costs via increased Commodity Prices

Figure 7-22 provides a graphical view of the annual savings potential for the two scenarios. Figure 7-23 provides the cumulative savings potential of each scenario.

Figure 7-22: Annual Savings Comparison of Scenarios

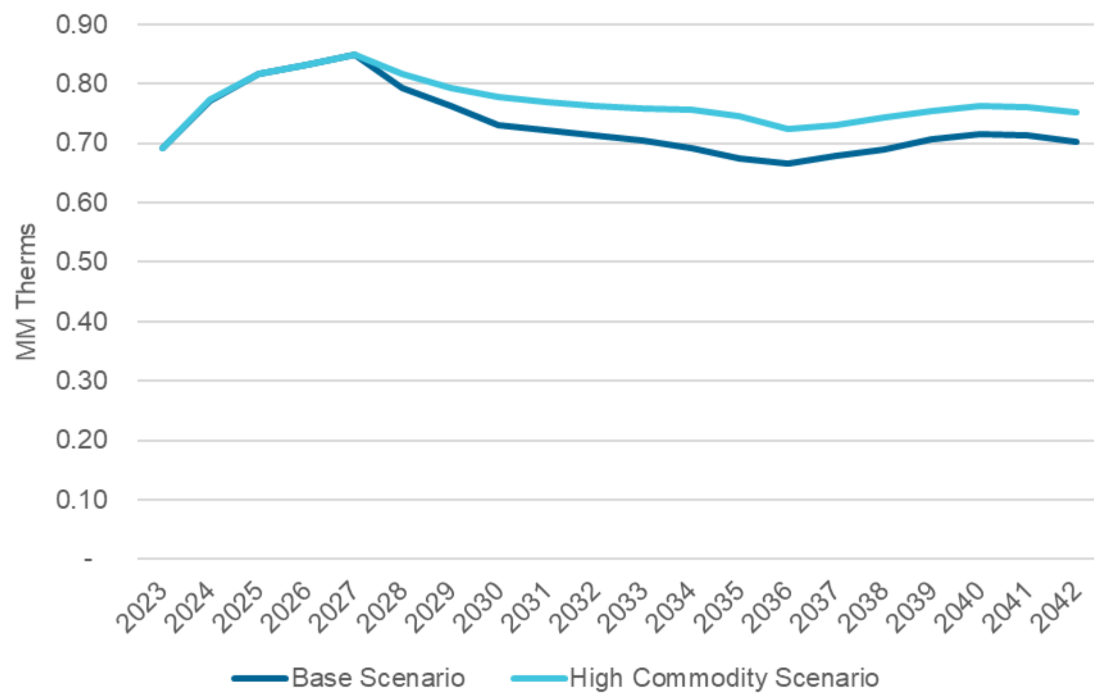


Figure 7-23: Cumulative 20-year Deployed Savings Potential by Scenario

Scenario	20 Year Cumulative Savings Potential (Therms)	% Difference from Base Case
Base Case	14,624,110	NA
High Commodity Scenario	15,372,086	5.1%

Increased commodity prices to reflect renewable natural gas or hydrogen fuel result in more of the achievable potential becoming cost-effective due to an increase in Avoided Costs in the TRC test. The high commodity scenario results in a 5.2% increase in cost-effective achievable potential over the base case for a twenty-year total of 21.1 MM therms. The deployed twenty-year savings forecast increases by 5.1% as shown in Figure 7-23. As in the base case scenario, the first five years of the forecast period are set by program budgets and expectations of market conditions, and therefore the high commodity scenario increases begin in year six of the forecast period.

Capacity Contributions of Energy Efficiency

Due to an increased focus on the refinement of targeted DSM efforts and the development of strategies for avoiding or delaying distribution system reinforcements, Cascade is assessing the capacity contribution of energy efficiency at the citygate level.

Under Cascade's current analysis, demand is reduced by the input level of energy efficiency before any optimization is calculated. However, consistent with Commission Order No. 16-054, the Company is re-examining its approach to DSM analysis and is reviewing NW Natural's capacity contribution analysis. Cascade is also monitoring the emerging conversation taking place at the regulatory level regarding Avoided Costs and will use the results of this deliberation to shape future resource planning, as appropriate.

For this planning cycle, the Company is working with Energy Trust to analyze peak day savings by load profile, with the goal of ultimately translating this into data that can be used to formulate a strategy for addressing peak day demand. A brief analysis of peak-day savings is provided in Figure 7-24:

Figure 7-24: Peak Day/Annual Usage Saving Factors and Forecasted Savings

Peak Day Factors and Forecasted Peak Day Savings (Cumulative 20-yr Therms)			
Load Profile	**Peak Day Factor**	**Total Cost-Effective Potential Peak Day Therms**	**Final IRP Savings Targets Peak Day Therms**
Cooking	0.36%	2,369	1,610
Com Heating	1.77%	75,168	66,857
Domestic Hot Water	0.33%	21,749	4,916
FLAT	0.27%	10,042	7,697
Res Heating	1.98%	151,300	120,865
Total	**NA**	**260,628**	**201,945**

Peak day savings for each load profile are calculated by multiplying the Peak Day Factor shown in Figure 7-24 against the total cumulative amount of savings for these load profiles. Figure 7-24 also provides peak day savings estimates for both total Cost-Effective Potential and Deployed IRP Savings Targets. Heating measures, which have the highest amount of annual usage coincident with peak, have the most peak savings potential. The total deployed peak savings potential from this estimate is 201,945 therms.

While reductions in peak load from all customers reduce the need for supply side resources, a full adaptation of a specifically targeted peak-management strategy would require reductions in peak load from customers connected to the portion of the distribution system that requires reinforcement. This means that for a DSM program to offer meaningful capacity contributions, the Company would need to consider a more geographically targeted, DSM strategy. Cascade will continue to coordinate both internally and with the Energy Trust to determine the optimal approach for avoiding additional capacity and the need for system reinforcements through energy efficiency.

Program Funding

In Oregon, Cascade charges customers a public purpose charge (PPC), which is a percentage applied to customers' bills. The Company's Schedule 31 PPC was adopted in 2006 with the approval of Cascade's Conservation Alliance Plan (CAP) in OPUC Docket UG 167. [13] PPC collections are used to fund Energy Trust efforts on behalf of Cascade in Oregon, and on behalf of the two Oregon low-income programs, weatherization and bill payment assistance.

In Washington, Cascade defers program costs for later collection from customers through the Schedule 596, Conservation Program Adjustment charge. Dollars collected through Schedule 596 fund the Company's residential, commercial, and industrial energy efficiency programs and the Company's low-income, weatherization program.

Targeted Load Management

As part of the IRP process the Company will identify load constrained areas within the Company's service territory in Oregon. As an IRP action item, the Company will iterate with Energy Trust to identify and target specific areas where Energy Trust programs can alleviate load constraints in order to defer supply side investments in expanding the Company's system. Energy Trust and the Company will work together to set load reduction targets in these areas. Energy Trust will coordinate with the Company to design marketing and program implementation solutions to achieve these targets. The Company will coordinate with Energy Trust to report results and related progress toward achieving these targets to the Oregon Public Utility Commission on an annual basis.

To do so, Cascade and Energy Trust will work together on a Target Load Management (TLM) project. Since 2016, Energy Trust has worked with Pacific Power and NW Natural to design and implement multi-year TLM pilot projects. These targeted programs are Non-Wires Solutions (NWS) that provide services to reduce peak demand. The projects resulted in valuable findings on how increased incentives, focused marketing, and community outreach can increase program participation in these locations. Through these projects, Energy Trust has had opportunities to advance Diversity Equity and Inclusion (DEI) objectives due to the significant presence of targeted DEI populations, including rural and low-income customers in areas selected due to the opportunity to defer grid investments there. Some of the methodologies developed via TLM efforts may also prove useful in working with local community projects built around carbon reduction or other community goals and in supporting distribution system planning. Through this work,

[13] CAP is a decoupling mechanism.

Energy Trust and the utilities collaborated in new ways across multiple groups including resource planners, marketing, communications, program delivery teams, and evaluation.

To date, Energy Trust has completed two 18-month long pilot projects with Pacific Power where they supplied a short list of potential sites, and Energy Trust estimated the potential peak reduction impacts based on customer groups present combined with historical participation in ETO's programs in these areas. In the area with the most significant potential peak reductions impacts Energy Trust refined the potential analysis by conducting localized potential studies, creating program implementation plans and deploying targeted outreach and localized marketing. In one project area, Energy Trust offered greater incentives than were available statewide, but were still cost-effective as determined by OPUC appointed cost effectiveness tests.

Energy Trust has also implemented a three phase Geographically Targeted Energy Efficiency (GeoTEE) project with NW Natural. This project was developed with three, year-long phases, each designed to test methods to incrementally increase awareness of, and participation in, Energy Trust offers.

- During the first phase, Energy Trust increased impressions and reach of existing advertising and marketing in an effort to build brand awareness.
- In the second phase, Energy Trust provided increased incentives within state-wide cost-effectiveness parameters and created new marketing tactics to reach potential customers with these increased incentives.
- The third phase offered further increased incentives based on applying an increased localized avoided cost value (compared to state-wide Avoided Costs) which reflects the value of potentially deferring gas distribution system investments to see if this drives additional participation.
    - This phase of the work is being conducted under a funding agreement between Energy Trust and NW Natural that covers the incremental delivery work and incentives as compared to what Energy trust would otherwise provide through public purpose charge funds. These funds are collected through a special tariff filed by NW Natural with the OPUC.

The tools developed through these pilots can help Cascade evaluate options to address future capacity constraints. Some of the processes Energy Trust put in place to track the efforts can also be used when providing targeted efforts to meet different objectives.

Ideally, the TLM approach can be applied to efficiently serve additional targeted geographical areas identified by Cascade, and Energy Trust and Cascade will work together to identify potential geographies and geographically specific energy efficiency potential savings and peak demand reductions associated with those locations.

The Company also manages load by offering interruptible service, Schedule 170 in Oregon and Schedule 570 in Washington. Customers receiving interruptible service are subject to service curtailment orders during peak usage events. During curtailment events, interruptible customers reduce their consumption, thus reducing the system peak demand. Service for interruptible customers is curtailed during extreme events. The Company does not plan for interruptions or decrement its load forecast for curtailment events.

Oregon Low-Income Energy Conservation Program

Cascade partners with the five Community Action Agencies (CAA) that serve low-income households in Central and Eastern Oregon to administer and deliver the Oregon Low-Income Energy Conservation Program (OLIEC) and its associated Conservation Achievement Tariff (CAT) program, which was made permanent on December 1, 2016.

The OLIEC program was designed to increase energy efficiency in low-income households within Cascade's Oregon service area by providing incentives for the installation of certain weatherization and energy efficiency measures following the completion of a home energy evaluation performed by a qualifying Low-Income, 501c3 organization or a CAA. The OLIEC program currently provides incentives for ten specific measures. The incentives are determined on the basis of the first-year dollar value of the conserved natural gas as reflected by the Company's most recently acknowledged avoided cost of natural gas.

The OLIEC program provides incentives for ceiling, floor, wall and duct insulation; duct sealing; infiltration system upgrades (weather stripping and caulking); high efficiency furnace installations; furnace tune-up and filter replacement; and high-efficiency space or water heaters. Rebates are also available for new low-income residential construction and custom energy efficiency measures on an individual basis with preference for measures that would qualify for rebate in similar projects offered through the Energy Trust.

In addition to the OLIEC rebates, agencies receive an additional $225 for administrative and direct program costs incurred by them.

CAT operates alongside of, and in conjunction, with the OLIEC Program. The CAT program is intended to bridge the gap between the portion of weatherization funding available through OLIEC (the avoided cost of natural gas) and the full cost of work performed for qualified measures. The funds are available to Agencies on a first-come, first-served basis for the purpose of providing total installed costs for weatherization measures approved under Schedule No. 33, OLIEC program. The CAT also provides each agency with a flat fee of $550 for an audit and $300 for an inspection fee. The Total Installed Costs reimbursed under CAT for a single dwelling may not exceed $10,000. Total Installed Costs are defined as all costs incurred for materials and contractor labor necessary to perform tariff-eligible natural gas weatherization work at a qualified customer premise.

The Company began piloting CAT on January 1, 2014, with a termination date of December 31, 2015. Towards the end of the pilot period, Staff offered a series of program recommendations including guidance on the collection of OLIEC/CAT funds. These recommendations limited program funding to no more than 0.625% of gross revenues for the Company's low-income weatherization programs. This amount is a close equivalent to electric utilities' collections for low income weatherization plus a .025% premium for the higher costs of serving rural areas. It was at this time that Cascade simultaneously filed Advice No. O16-10-02 which established CAT as a permanent program, added performance parameters, and addressed Staff's questions.

From 2006 through 2019, 640 homes were weatherized through the OLIEC program saving an estimated total of 97,224 therms. Resulting payments to partner CAP agencies totaled $1,891,474 for weatherization measures with payments for agency administration totaling $143,775; CAT program delivery of $183,310; and CNGC admin in the amount of $86,107 with a $3,950 adjustment to factor for the $10,000 per project cost cap. The program has seen little activity since 2019 with one home completing weatherization.

As a follow up to the poor program performance since 2019 and the analysis performed by Applied Energy Group, Inc. in 2021 on the Company's low and near low-income customer saturation within the Oregon service territory, Cascade engaged in multiple discussions with OPUC Staff, Agencies and regional stakeholders on current barriers to participation and opportunities to revise the program moving forward.

Beginning in the Spring of 2022, Cascade has held a series of preliminary meetings with OPUC Staff and Community Action Partnership of Oregon (CAPO) who represents the low-income Agencies. These discussions have progressed throughout 2022 and have included discussions on tariff revisions that would bolster the program through more flexible delivery of energy efficiency services to economically vulnerable households. In November 2022, Cascade filed a 2022 OLIEC Annual Report for proposed next steps to improve program uptake in the near term and totally revise the program in the following years.

Oregon Non-Core Customer Carbon Compliance Assessment Pilot

In response to increasing carbon compliance needs the Company partnered with Frontier Energy Inc., to bring a pilot project focused on carbon compliance assessments. The pilot project will focus on interested Eastern Oregon non-core customers and will come at no cost to the customers, the project will expand as need increases.

Frontier Energy will conduct all assessments for CNGC non-core customers. Frontier holds over 30 years of experience conducting custom energy assessments, retro commissioning recommendations, technical support, utility rebate application facilitation for both commercial and industrial sites across the country. These assessments include analyzing historic facility usage of electric, natural gas, water and review of facility operations.

Beginning fall of 2022, the Company led efforts to facilitate meetings with potential non-core customers and Frontier Energy. During this process Frontier Energy will provide an overview of assessment to be completed and non-core customers will share brief operational processes and individual carbon compliance goals to properly identify areas of concern or current improvements. Once preliminary meetings are completed, the Company will coordinate dates with non-core customers and Frontier Energy for onsite assessment. Through these onsite assessments, Frontier Energy will compile a report of energy-savings calculations and identify associated non-energy benefits for each recommended energy efficiency measure to be reviewed by the company and the non-core customer.

The Company is set to begin the first round of onsite assessments in eastern Oregon in January 2023.

Chapter 8

Distribution System Planning

Overview

Cascade strives to provide safe and reliable service to its customers. As part of Cascade's distribution planning process Cascade reviews it's systems for predicted growth and will identify and address capacity deficits. If a capacity deficit is identified reinforcement alternatives are compared and final reinforcement is selected and budgeted within Cascade's five year budget with consideration to cost, system benefits and long term planning.

This section will cover how Cascade models it's distribution systems, identifies deficits, proposes reinforcement alternatives to address deficits, reviews and selects reinforcement alternatives and how projects are put into the capital budget.

System Dynamics

Cascade operates a diverse system through Oregon and Washington over a range of pipeline diameters and operating pressures. Cascade's natural gas distribution system consists of approximately 4,893 miles of distribution and 170 miles of transmission in Washington and 1,710 miles of distribution and 107 miles of transmission in Oregon. Cascade system is also composed of facilities including regulator stations, valve stations, odorizers, heaters and compressors.

In general Cascade's distribution systems begin at a citygate station connected to an interstate pipeline. At gate stations Cascade takes custody of the gas and regulates and odorizers the gas to serve its distribution and transmission pipelines. Typically, high pressure or transmission pipelines are downstream of the gate to transport gas to regulator stations or large volume industrial customers. Regulator station reduce pressure to serve residential or commercial customers.

Network Design Fundamentals

A natural gas pipeline is constrained by the laws of fluid mechanics which dictate that a pressure differential must exist to move gas from a source to any other location on a system. Equal pressures throughout a closed pipeline system indicate that neither gas flow nor demand exist within that system. When gas is removed from some point on a pipeline system, typically during the operation of natural gas equipment, then the pressure in the system at that point becomes lower than the supply pressure in the system. This pressure differential causes gas to flow from the supply pressure to the point of gas removal in an attempt to equalize the pressure throughout the distribution system. The same principle keeps gas moving from interstate pipelines to Cascade's distribution systems. It is important that engineers design a distribution system in which the beginning pressure sources, which could be from interstate pipelines, compressor stations or regulator stations, have adequately high pressure, and the transportation pipe specifications are designed appropriately to create a feasible and practical pressure differential when gas consumption occurs on the system. The goal is to maintain a system design where load demands do not exceed the system capacity; which is constrained by minimum pressure allowances at a determined point or points along the distribution system, and maximum flow velocities at which the gas is allowed to travel through the pipeline and related equipment.

Due to the nature of fluid mechanics there is a finite amount of natural gas that can flow through a pipe of a certain size and length within specified operating pressures; the laws of fluid mechanics are used to approximate this gas flow rate under these specific and ever changing conditions. This process is known as "pipeline system modeling." Ultimately, gas flow dynamics on any given pipeline lateral and distribution system can be ascertained for any set of known gas demand data. The maximum system capacity is determined through the same methodology while calculating customer usage during a peak heating degree day. In order to evaluate intricate pipeline structures a system model is created to assist Cascade's engineering team in determining the flow capacity and dynamics of those pipeline structures. For example, before a large usage customer is incorporated into an existing distribution system the engineer must evaluate the existing system and then determine whether or not there is adequate capacity to maintain that potential new customer along with the existing customers, or if a capacity enhancement is required to serve the new customer. Modeling is also important when planning new distribution systems. The correct diameter of pipe must be designed to meet the requirements of current customers and reasonably anticipated future customer growth.

Modeling Methodology

Cascade utilizes a hydraulic gas network modeling and analysis software program called Synergi Gas, distributed and supported by DNV GL, to model all distribution systems and pipeline flow scenarios. The software program was chosen because it is reliable, versatile, continually improving and able to simultaneously analyze very large and diverse pipeline networks. Within the software program individual models have been created for each of Cascade's various distribution systems including transmission and high pressure laterals, regulator stations and compressor stations and distribution system networks and large diameter service connections.

Each system's model is constructed as a group of nodes and facilities. Cascade defines a node as a point where gas either enters or leaves the system, a beginning and/or ending location of pipe and/or non-pipe components, a change in pipe diameter or an interconnection with another pipe. A facility is defined in the system as a pipe, valve, regulator station, or compressor station; each with a user-defined set of specifications. Cascade's distribution systems are broken into 12 models for ease of use and to reduce the time requirements during a model run analysis.

Synergi can analyze a pipeline system at a single point in time or the model can be specifically designed to simulate the flow of gas over a specified period of time; which more closely simulates real life operation utilizing gas stored in pipelines as line pack. While modeling over time an engineer can write operations that will input and/or manipulate the gas loads, time of gas usage, valve operation and compressor simulations within a model, and by incorporating the forecasted customer growth and usage provided within this integrated resource plan Cascade can determine the most likely points where future constraints may occur. Once these high priority areas are identified, research and model testing are conducted to determine the most practical and cost-effective methods of enhancing the constrained location.

Model Building Process

Cascade's models are completely rebuilt every three years and are maintained between rebuilds. To rebuild the models, Cascade exports current GIS data to create the spatial models and exports historical billing data from CC&B to bring into the Customer Management Module (CMM) to create an updated demands file. Cascade's models were rebuilt in 2020 and are scheduled for rebuild in 2023.

Usage Per Customer

The IRP planning process utilizes customer usage as an essential calculation to translate current and future customer counts into estimated demands on the distribution system and total demand for gas supply and interstate transportation planning. The calculated usage per customer is dependent upon weather and geographic location.

Cascade utilizes a Customer Management Module (CMM) software product, provided by DNV GL as part of their Synergi Gas product line, to analyze natural gas usage data and to predict usage patterns on the individual customer level.
The first step in operating CMM is extensive data gathering from the Company's Customer Information System (CIS), CC&B. CC&B houses historical monthly meter read data for each of Cascade's customers, along with daily historical weather and the physical location of each customer. The weather data is associated with each customer based on location, and then related to each customer's monthly meter read according to the date range of usage.

After the correct weather information has been correlated to each meter read, a base load and weather dependent load are calculated for each customer through regression analysis over the historical usage period. DNV GL states that it uses a "standard least-squares-fit on ordered pairs of usage and degree day" regression. The result is a customer specific base load that is weather independent, and a heat load that is multiplied by a weather variable, to create a custom regression equation.

Should insufficient data exist to adequately predict a customer's usage factors, then CMM will perform factor substitution. Typically, the average usage of customers in the same geographical location and in the same customer rate class can be used to substitute load factor data for a customer which lacks sufficient information for independent analysis.

With all the structural shifts in historical data, and the significantly increased quantity of data utilized for regression, Cascade has selected a five-year time series to develop the usage per customer equations for model rebuilds. The selected time series is aligned with the recommended time study from DNV GL.
The Company recognizes that there could be significant differences in the way its customers use natural gas throughout its geographically and economically diverse service territory. Being sensitive to areas that may require capital improvements to keep pace with demand growth, Cascade separates customers by districts and then determined specific usages per customer for each.

Model Validation

To check the usage per customer Cascade validates the models for a specific temperature event. To validate the model Cascade will gather all pressures and flow data available on its system for a specific time and day, and will then set the model to the temperature experienced to see how the model is performing to determine if the usage per custom is reasonable. During model validation pressures and flows in the model are compared to actual pressure and flow data. Comparing the model results to actuals pressures and flows allow Cascade to validate the model and have confidence that the usage per customer from CMM is accurate when compared to temperature and flow data in each geographic area.

Once a model is validated it is then ramped up to its peak degree day, based on 30 years of historical weather data, to create a design day model. Cascade's peak heating degree days by district are shown in figure 8-1.

Figure 8-1: Peak Heating Degree Day

District	HDD	Avg Daily Temperature (ºF)
Aberdeen	46	14
Bellingham	47	13
Bend	71	-11
Bremerton	46	14
Eastern Oregon	73	-13
Kennewick	65	-5
Longview	46	14
Mt Vernon	47	13
Pendleton	67	-7
Walla Walla	66	-6
Wenatchee	65	-5
Yakima	65	-5

As you can see from Figure 8-1, Cascade operates in diverse regions that range from coastal to desert, which is why the models are broken down by district. Cascade heating degree day calculations are based on customers turning on their heat when temperatures drop below 60 degrees Fahrenheit. The heating degree day is calculated by subtracting the average daily temperature from 60 degrees Fahrenheit.

Distribution System Planning

Cascade spends significant time and resources on building and maintaining its design day models. Cascade uses its design day models to review large customer requests, model renewable natural gas injection onto Cascade's systems, design and sizing of pipe and facilities, long term planning, model growth predictions, identify system deficits, determine system reliability, optimize enhancement options and support cold weather action plans.

A system deficit is defined as a critical system that has reached or exceeded the capacity to serve customer demands. Critical system examples that are limiting capacity include pipeline bottleneck, minimum inlet pressure to a regulator station or high pressure system to meet a downstream operating pressure, not meeting a required customer delivery pressure, or a physical component that is limiting capacity like a regulator which has a rated flow capacity for the specific conditions that the regulator is operating under as published by the manufacturer.

As part of the IRP process, Cascade completes a comprehensive review of the Company's distribution system models every two years to ensure that Cascade can maintain reliable service to customers during design day events. Cascade also completes annual reviews of its distribution system models as part of an annual budgeting process and will update the five-year budget as needed based upon new information that impacts the five-year planning. If a deficit is predicted the system is evaluated and a reinforcement will be proposed and selected based on alternative analysis criteria. The selected reinforcement will then be placed into the capital budget based on the timing needs of the predicted deficit.

The Engineering services department works closely with Field Operations coordinators, Energy Services representatives, and district management to assure the system is safe and reliable. As towns develop, the need for pipeline expansions and reinforcements increases. The expansions are historically driven by new city developments or new housing plats. Before expansions and installation can be constructed to serve these new customers, engineering analysis is performed. As new groups of customers seek natural gas service, the models help engineers determine how best to serve them reliably.

Distribution System Enhancements

Once a deficit has been identified on a system Engineering will propose enhancement solutions to address the deficit. Distribution enhancements can include:

- pipeline reinforcement such as replacements
- pipeline loops and back feeds
- pressure increases
- uprates
- facility upgrades,
- additional regulator station feeds,
- compressor stations
- demand side management strategies

Each of Cascade's systems are unique in pipeline dynamics and will be optimized using different enhancement solutions.
Pipeline solutions consist of looping, upsizing, and uprating. Pipeline looping is the most common method of increasing capacity in an existing distribution system. It

involves installing new pipe parallel to an existing pipeline that has, or may become, a constraint point. Constraint points inhibit flow capacities downstream of the constraint creating inadequate pressures loss down the pipeline during periods of high demand. When the parallel line connects to the system, this alternative path allows natural gas flow to bypass the original constraint and bolsters downstream pressures. Looping can also involve connecting previously unconnected mains. The feasibility of looping a pipeline depends upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt, environmentally sensitive areas, and steep or rocky terrain can increase the cost to a point where alternative solutions are more cost effective.

Pipeline upsizing involves replacing existing pipe with a larger size pipe. The increased pipe capacity relative to surface area results in less friction, larger flow capacity, and therefore, a lower pressure drop. This option is usually pursued when a pipe is damaged or has integrity issues. If the existing pipe is otherwise in satisfactory condition, looping augments existing pipe, which remains in use.

Pipeline uprating increases the maximum allowable operating pressure of an existing pipeline. This enhancement can be a quick and relatively inexpensive method of increasing capacity in the existing distribution system instead of constructing more costly additional facilities. However, safety considerations and pipe regulations may prohibit the feasibility or lengthen the time before completion of this option. Also, increasing line pressure may produce leaks and other pipeline damage creating costly repairs and or may not reach the proposed uprate pressure. A thorough facility review is conducted to ensure pipeline integrity before an uprate is conducted.

Pressure regulators or regulator stations reduce pipeline pressure at various stages in the distribution system. Regulation provides a specified and constant outlet pressure before natural gas continues its downstream travel to a city's distribution system, a customer's property, or a natural gas appliance. Regulators also ensure that flow requirements are met at a desired pressure regardless of pressure fluctuations upstream of the regulator. Regulators are at citygate stations, district regulator stations, farm taps, and customer services. Regulator station provide additional capacity to an area since regulator stations are fed by high pressure laterals than can deliver more gas to the distribution system. Utilization and strategic positioning of new stations can be very helpful in increasing system reliability and capacity

Compressor stations present a capacity enhancing option for pipelines with significant natural gas flow and the ability to operate at higher pressures. For pipelines experiencing a relatively high and constant flow of natural gas, a large volume compressor installation along the pipeline will boosts downstream pressure which will increase the downstream capacity of the pipeline.

A second option is the installation of smaller compressors located close together or strategically placed along a pipeline. Multiple compressors accommodate a large flow range and use smaller and very reliable compressors. These smaller compressor stations are well suited for areas where gas demand is growing at a relatively slow and steady pace, so that purchasing and installing these less expensive compressors over time allow a pipeline to serve growing customer demand into the future.

Compressors can be a cost-effective option to resolving system constraints; however, land constraints, regulatory and environmental approvals to install a station, along with engineering and construction time, can be a significant deterrent. Adding compressor stations typically involves considerable capital expenditure and long-term operations and maintenance costs for the life of the facility.

Targeted demand side management is another approach to address distribution system deficits. Cascade is currently pursuing a pilot program to see if demand side management can delay or eliminate a distribution system enhancement that has been identified. For targeted demand side management to be considered the deficit predicted must be reasonable obtained through demand side management goals and must have time for the program to be effective. Per Energy Trust of Oregon, they recommend that a project has 3 to 5 years to be implemented and be able to see if the results of the demand side management is effective at addressing the distribution system deficit. If demand side management is not effective in the timeline predicted Cascade will move forward with completing the distribution system enhancement to avoid the predicted deficit.

Distribution System Enhancement Considerations

Each distribution system enhancement option is analyzed during the alternative selection process with consideration to scope, cost, timing, system benefits/long term planning and feasibility. For any project over 1 million dollars there is a more robust analysis for the project and supporting documentation, and engineers work collaboratively with management and directors to examine pipeline alternatives to ensure all alternatives were considered.

Distribution System Enhancement Selection Guidelines

Engineers work collaboratively with manager and directors to select the most favorable enhancement solution to address the deficit. Engineering uses the following criteria to select distribution system enhancements:

- Non pipe alternatives including:
    - Pressure Increases/Uprates if feasible;
    - Demand side management; and
    - Compressor Stations if permitting (emission/zoning, etc.) is favorable and land is available and cost effective for project.

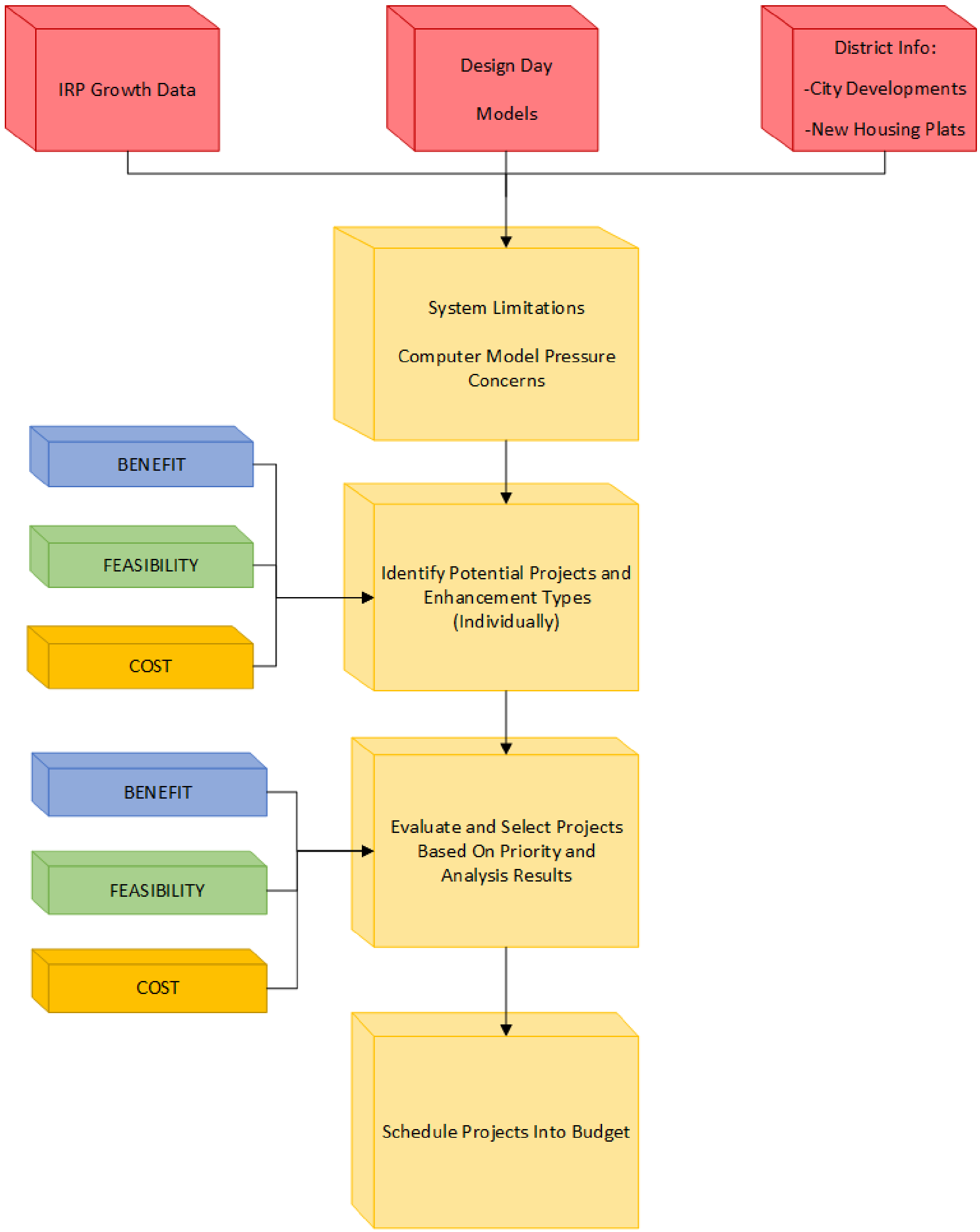
- The shortest segment(s) of pipe that addresses the deficit.
- The segment of pipe with the most favorable construction conditions that supports long term operations and maintenance activities, i.e. access, existing easements or traffic issues.
- Minimizes environmental concerns, i.e. avoid water crossings, wetlands and environmental sensitive areas.
- Minimizes impacts to the community., i.e. road closures or city road moratoriums.
- The segment of pipe that provides opportunity to add additional customers.
- Total construction costs including restoration.

Once a project/reinforcement is identified, engineering, field operations, or energy services representative begins a more thorough investigation by surveying the route and filing for permits. This process may uncover additional impacts such as moratoriums on road excavation, underground hazards, discontent among landowners, permitting concerns, etc., resulting in another iteration of the above project/reinforcement selection criteria.

Capital Budget Process

Cascade annually goes through the capital budget process to approve a five-year capital budget. Cascade's annual budget process begins in June and will typically go through three to five revisions before it is accepted and approved in late November by the board of directors. Engineers support the capital budgeting process by submitting distribution system enhancement projects to the budget. Engineers will work collaboratively with managers and directors to prioritize projects in the budget based on predicted timings needs with the goal of minimizing risk to ensure that Cascade can continue to provide safe and reliable service to Cascade's customers. Figure 8-2 provides a schematic representation of the distribution system selection process to the capital budget.

Figure 8-2: Distribution System Planning Process Flow



Cascade's budget goes through several revisions and reviews at all levels in the organization to make sure that projects are properly justified and necessary. Every year as part of the capital budget procress Cascade projects are re-reviewed and revisions will be made to the projects as needed as new information becomes available as part of the iterative IRP process.

Conclusion

Cascade's goal is to maintain a reliable natural gas distribution system in order to cost-effectively deliver natural gas to every core customer. This goal relies on Cascade being proactive in addressing current and future system deficits. Cascade's five year capital budgeting process allows time for projects to go through alternative analysis considerations and allows time for projects to be designed and constructed to address deficits in time. The iterative process of Cascade's IRP and capital budgeting process will allow Cascade the ability to adapt to the changing dynamics of the natural gas industry. These dynamics include renewable natural gas coming onto Cascade's systems, targeted demand side management, electrifican, building code changes, energy efficiency programs and hydrogen blending.

Chapter 9

Resource Integration

Overview

Resource integration is the last step in Cascade's IRP process. It involves finding the reasonable least cost and least risk mix of reliable demand and supply side resources to hit emissions targets while serving the forecasted load requirements of the core customers. The tool used to accomplish this task is a computer optimization model known as PLEXOS®.

PLEXOS® is very powerful and complex. It operates by combining a series of existing and potential demand side and supply side resources and optimizing their utilization at the lowest net present cost over the entire planning period for a given demand forecast. PLEXOS® permits the Company to develop and analyze a variety of resource portfolios quickly, to determine the type, size, and timing of resources best matched to forecast requirements.

Key Points

- Cascade utilizes PLEXOS® to find the optimal solve for forecasted resource deficiencies, as well as alternative portfolios.
- Once a solution is found under expected conditions, the candidate portfolio is stress-tested through stochastic and deterministic scenarios.
- The Top-Ranked Candidate portfolio includes all existing resources, acquisition of RNG, Hydrogen, Compliance Instruments, plus incremental DSM.
- Cascade forecasts shortfalls beginning in 2034 in Oregon and 2038 in Washington without DSM, and 2046 in Oregon and 2049 in Washington with DSM, with On-System RNG being identified as the resource to solve these shortfalls.
- For the 2023 IRP, Cascade evaluates five scenarios plus a base case scenario, with robust qualitative and quantitative analysis of the results of these scenarios.
- The Preferred Portfolio is Cascade's least cost, least risk solution to how to serve its customers over the planning horizon.

Supply Resource Optimization Process

The process for optimizing supply resources is summarized in the following six steps and is shown graphically in Figure 9-2 on page 9-4.

- **Step 1: As-Is Analysis**
  - Cascade began its optimization process by running a deterministic analysis of its existing resources with a three-day peak event. This allowed the Company to uncover the timing and quantity of resource deficiencies, both in terms of inability to serve customers and inability to hit emissions reductions targets. Once the resource need was identified, Cascade utilized its market intelligence to identify all potential options to solve for the projected shortfall.

- **Step 2: Identify Portfolios**
  - Once shortfalls were identified, Cascade utilized PLEXOS® to derive a diverse selection of potential portfolios to eliminate the deficiency. This was done through a deterministic analysis of the alternative resources. For the 2023 IRP, Cascade tested seven potential portfolios. Figure 9-1 groups these portfolios by the source of each resource. Further details regarding the components of each candidate portfolio can be found in Appendix G.

Figure 9-1: Breakdown of Candidate Portfolios

	Incremental Renewable Natural Gas	No Incremental Renewable Natural Gas
Incremental Natural Gas	-All-In -All-In Less DSM	-Incremental Transport
No Incremental Natural Gas	-RNG Only -Hydrogen Only -Renewables only	-Offsets Only

- **Step 3: Analysis of All Portfolios**
  - Once Cascade selected its portfolios, each portfolio will be run through the PLEXOS® optimizer under expected conditions. The portfolios will be evaluated with deterministic and stochastic analyses, and the timing and quantity, if applicable, of unserved demand and emissions reductions shortfalls will be recorded. Cascade will also record the risk-adjusted total system cost of each portfolio.

- **Step 4: Ranking of Portfolios**
  - The Top Ranking Candidate Portfolio will be the portfolio that is able to serve all forecasted demand over the planning horizon while hitting all emissions reductions goals. In the case of multiple portfolios accomplishing this, the portfolio that does it with the lowest risk-adjusted total system cost will be the Top-Ranking Candidate Portfolio. Portfolios were ranked based on a risk-adjusted total system cost metric, which gives 75% weight to the total system cost under deterministic conditions for a given portfolio, and 25% weight to the costs under stochastic conditions. Cascade believes the top ranked portfolio is the one with the most reasonable least cost and least risk mix of reliable energy supply resources, emissions reduction resources, and energy efficiency for Cascade and its customers. This is now deemed to be the Top Ranked Candidate Portfolio, a term that Cascade will use often in this chapter to represent the portfolio that appears to be optimal under expected conditions. It is important to note that it is still just a Candidate Portfolio until it has passed a rigorous scenario analysis, after which point it will become the Preferred Portfolio for Cascade over the 28-year planning horizon.

- **Step 5: Scenario Analysis of Candidate Portfolio**
  - The Top Ranking Candidate Portfolio is re-run through the PLEXOS® optimizer under five scenarios. These scenarios, which are explained further in Figure 9-3, will provide sensitivity testing of customer growth, energy efficiency, RNG, hydrogen, Natural Gas bans, and Natural Gas pricing. The timing/quantity if applicable of unserved demand and emissions reductions shortfalls will be recorded. Cascade will also record the risk-adjusted total system cost of each portfolio.

- **Step 6: Evaluation of Candidate Portfolio**
  - Cascade performs a qualitative and quantitative review of Top-Ranking Candidate Portfolio's ability to serve demand, hit emissions targets, and the risk-adjusted total system cost of the portfolio under the scenarios evaluated. The results of this review are presented later in this chapter. If there are concerns about the portfolio's ability to hit these metrics, or the cost of hitting these metrics, the Company may loop back to Step 5 with a new portfolio that might be more insulated against identified risks. Otherwise, the portfolio is named Cascade's Preferred Portfolio. Figure 9-2 displays this process as a flowchart.

Figure 9-2: Supply Resource Optimization Process Flow Chart

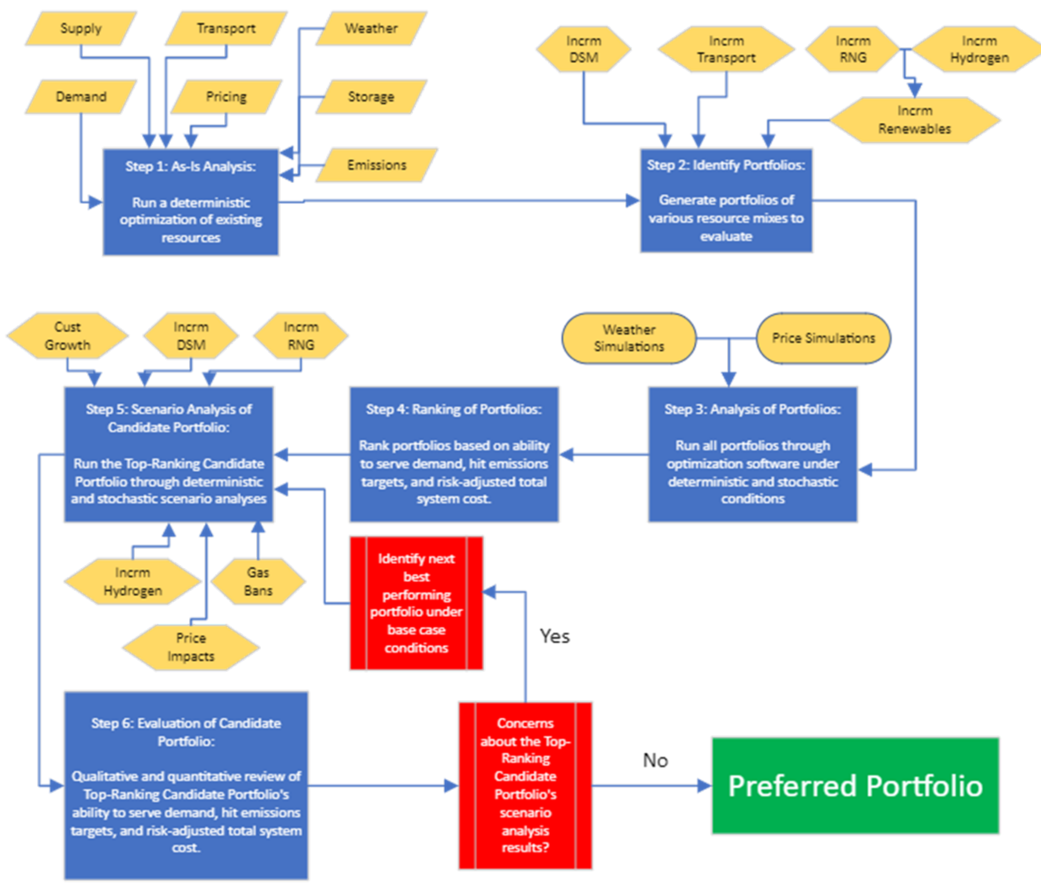


Figure 9-3: Breakdown of Scenarios Modeled

	Scenario					
2023 IRP Finalized Scenarios	**Base Case - OR-CPP and WA-CCA**	**Carbon Neutral by 2050**	**Limited RNG availability**	**Electrification**	**High Customer Case**	**High Price - Interrupted Supply**
Customer Growth	Current Expectations			No new customers after 2030	High Customer Counts	Current Expectations
Energy Efficiency	CPA Projections	Scenario 2 CPA Projections				CPA Projections
Renewable Natural Gas	Expected Availability	Expected - High Avail.	Low Availability	Expected - High Avail.		Expected Availability
Hydrogen	Expected Availability	Expected - High Avail.	Low Availability	Expected - High Avail.		Expected Availability
Natural Gas Bans	Current Bans			Additional Bans	Current Bans	
Natural Gas Price	Expected Price	Adjusted Price	Expected Price	Adjusted Price		High Price

While Chapter 13 includes a full glossary, terms related to Figure 9-3 are shown below for convenience.

Terms Used in Figure 9-3

Customer Growth: Current Expectations – Customer growth is modeled to follow base-case customer growth forecast as discussed in Chapter 3, Demand Forecast.

Customer Growth: No new customers after 2030 – Customer growth in Cascade's residential and commercial rate classes gradually slows to zero growth in 2025 and afterwards, residential and commercial customer count reduced to 10% by 2050.

Customer Growth: High Customer Counts – Customer growth is modeled to follow high customer growth forecast as discussed in Chapter 3, Demand Forecast.

Energy Efficiency: CPA Projections – Savings from demand side management programs modeled to follow the base-case projections from Cascade's internal conservation potential assessment in Washington, and from projections provide by the Energy Trust of Oregon in Oregon.

Energy Efficiency: Scenario 2 CPA Projections – Savings from demand side management programs modeled to follow a high commodity cost projection in the avoided cost as discussed in Chapter 5, Avoided Cost. Results come from Cascade's internal conservation potential assessment in Washington, and from projections provide by the Energy Trust of Oregon in Oregon.

Renewable Natural Gas: Expected Availability – Maximum available RNG used as the upper constraint of the PLEXOS® model is derived from a Cascade weighted share of a blend of the high and technical RNG potential as outlined in a 2019 ACF/ICF study. This calculation is discussed further in Chapter 4, Supply Side Resources.

Renewable Natural Gas: High Availability– Maximum available RNG used as the upper constraint of the PLEXOS® model is derived from a Cascade weighted share of a blend of the technical RNG potential as outlined in a 2019 ACF/ICF study. This calculation is discussed further in Chapter 4, Supply Side Resources.

Renewable Natural Gas: Low Availability Maximum available RNG used as the upper constraint of the PLEXOS® model is derived from a Cascade weighted share of a blend of the low RNG potential as outlined in a 2019 ACF/ICF study. This calculation is discussed further in Chapter 4, Supply Side Resources.

Hydrogen: Expected Availability – Maximum Hydrogen blending constraint of the PLEXOS® model in this scenario is 20% of delivered gas by volume.

Hydrogen: High Availability – Maximum Hydrogen blending constraint of the PLEXOS® model in this scenario is 30% of delivered gas by volume.

Hydrogen: Low Availability - Maximum Hydrogen blending constraint of the PLEXOS® model in this scenario is 5% of delivered gas by volume.

Natural Gas Bans: Current Bans – This scenario accounts for all current gas bans in Cascade's service territory as discussed in Chapter 6, Environmental Policy.

Natural Gas Bans: Additional Bans – This scenario accounts for all current and proposed gas bans in Cascade's service territory as discussed in Chapter 6, Environmental Policy.

Natural Gas Price: Expected Price – Price of natural gas is modeled to follow the base-case price forecast as discussed in Chapter 4, Supply Side Resources.

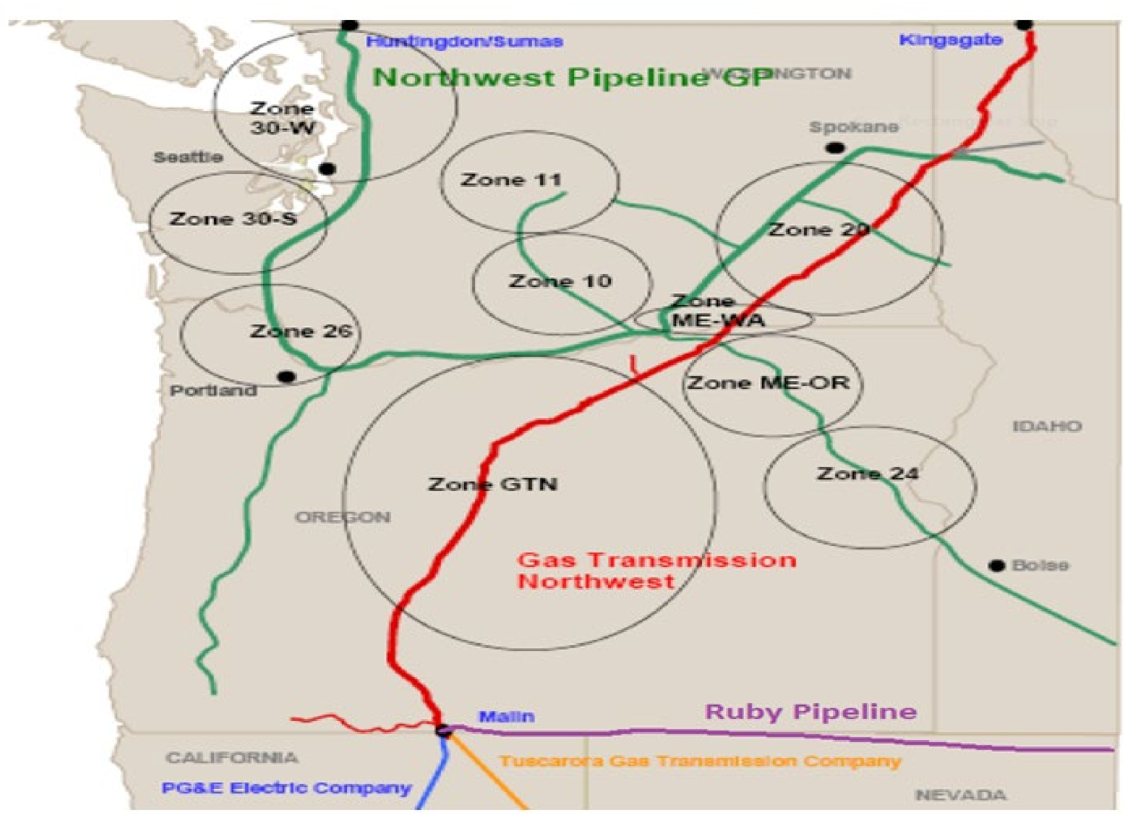
Natural Gas Price: Adjusted Price – Price of natural gas is modeled to follow to include an adjusted of 10% either higher or lower as appropriate. Lower price is used in Scenarios 2 and 4 while higher price is used in scenario 5. Scenarios 2 and 5 also include a higher priced tranche of RNG for volumes above the expected availability, prices at $26/dth.

Natural Gas Price: High Price – Price of natural gas is modeled to follow the base-case price forecast as discussed in Chapter 4, Supply Side Resources, except during a stochastic incident. When an incident occurs, prices at all basins spike to the 99th percentile results of pricing at the impacted basin, regressing back to the price forecast linearly over a two-year period.

Planning and Modeling

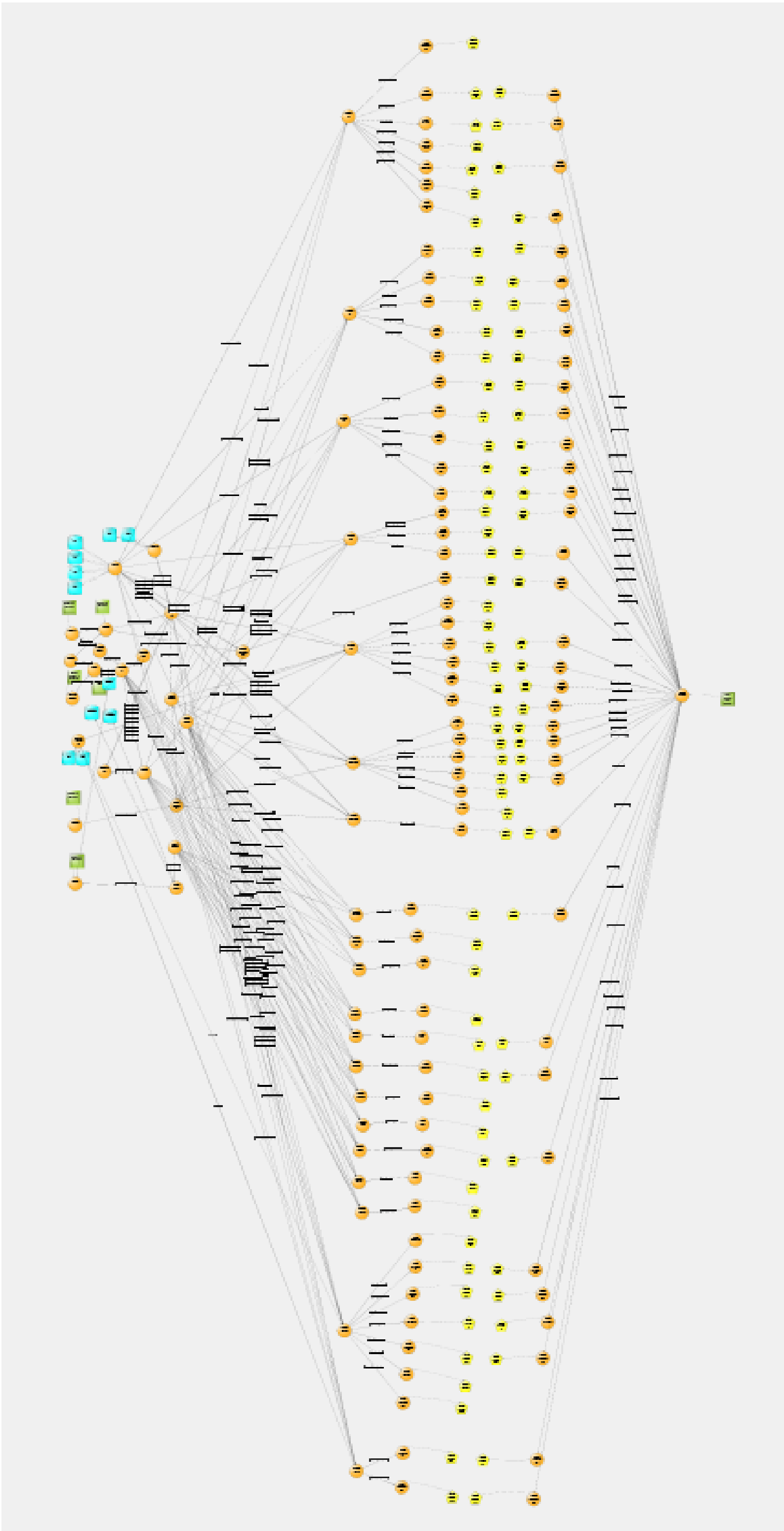
PLEXOS® has broad capabilities that allow the Company to develop supply and demand relationships that closely mirror Cascade's existing operations. Figure 9-4 shows the location of these pipeline zones. These pipeline zones reflect Cascade's customers being served from either Northwest Pipeline LLC (NWP) or Gas Transmission Northwest (GTN) interstate pipeline facilities.

Figure 9-4: Pipeline Zones Used in this IRP



With the in-house load forecast model (LFM) application, which is discussed in detail in Chapter 3, Demand Forecast, modeling dives into an even more granular level. This IRP takes more of a citygate and rate schedule view, which allows Cascade to take a deeper view of capacity shortfalls and potential constraints. A copy of the network diagram is shown in Figure 9-5. The network diagram is provided for illustrative purposes to emphasize the difficulties in configuring the model to best replicate Cascade's complex system rather than being provided for its readability.

Figure 9-5: Network Diagram of Cascade's System



Stochastic Methodology Discussion

Cascade runs its Monte Carlo simulations on all candidate portfolios, which are used to create the risk-adjusted metrics discussed in Step 4 of Cascade's supply resource optimization process. The rationale behind this is to use the deterministic results to capture the intrinsic value of each portfolio, while the stochastic results capture the extrinsic value of the portfolios. Cascade chose to weight these with a 75/25 split, as the Company believes this mix properly assigns value to results under expected conditions versus results under unexpected conditions. Additionally, this follows the regional best practices.

The Company is continuing to use its own Monte Carlo simulation engine, built in R, to generate stochastic results. This tool allows Cascade to be more detailed by running Monte Carlo simulations on daily data and creating multiple weather patterns. Utilizing R to run stochastic analysis allows Cascade to be transparent on each step of the stochastic analysis process. Using historical data for weather and gas prices, along with Cholesky decomposition matrices, Cascade runs a 200 draw Monte Carlo simulation on price and weather. This is a change from the Company's process in the 2020 IRP process, where Cascade ran 10,000 draw Monte Carlo simulations. While there are valid concerns about the validity of sample size of a 200-draw simulation, the Company is now running portfolios through all draws of the simulation as opposed to just identifying the nth percentile draw and analyzing that one draw. This allows Cascade to analyze stochastic long term success probabilities and identify when shortfalls may occur under extreme conditions.

The Cholesky decomposition matrix is a positive-definite covariance matrix. This matrix is used to draw or sample random vectors from the N-dimensional multivariate normal distribution that follow a desired distribution. In Cascade's case, this allows for correlations between weather zones to be included when drawing or sampling data distributions for Monte Carlo runs. Figure 9-6 shows Cascade's historical correlations between weather stations for the month of January. A realistic Monte Carlo draw would show similar correlations between weather stations, which Cascade manages to accomplish with the Cholesky Decomposition Matrix. By correlating random variables, there is always the potential issue of overfitting and not allowing for enough randomness between each draw. Also, Cascade is aware of the possibility of introducing bias into its models. Cascade is monitoring this by constantly evaluating and cross-validating the results.

Figure 9-6: January Historical Correlations between Weather Stations

City	Baker City	Bellingham	Bremerton	Pendleton	Redmond	Walla Walla	Yakima
Baker City	1.00000						
Bellingham	0.63383	1.00000					
Bremerton	0.65848	0.86889	1.00000				
Pendleton	0.70245	0.73001	0.69979	1.00000			
Redmond	0.71736	0.76293	0.76183	0.79743	1.00000		
Walla Walla	0.71051	0.72579	0.69180	0.95952	0.78995	1.00000	
Yakima	0.66974	0.69391	0.68315	0.79445	0.70062	0.81950	1.00000

Stochastic analysis of price presents a different set of challenges. Cascade performs its Monte Carlo simulation on each of its basins, correlating the simulation results to each other similar to how weather is correlated. Prices also follow a different distribution from weather, which adds a layer of complexity. HDDs have historically shown to be distributed normally, which allows for the use of Gaussian distributions in weather stochastic analysis, and while the month to month percentage changes in gas prices are shown to be normally distributed, gas prices tend to follow a more lognormal distribution. Practically speaking, prices appear to be just as likely to move up or down month over month, but the dollar impact of these movements is greater for price increases. For example, with a starting price of $2/dth, five straight months of 10% gains result in an increase of $1.22/dth, while five straight months of 10% losses result in a loss of $0.82/dth.

Cascade models these price movements with a Geometric Brownian motion stochastic process. For each of its 200 draws, the month over month price change is determined by two elements: a drift term and a shock term. The drift term is the expected movement of the basin pricing, derived from the Company's price forecast. The shock term is the main stochastic element, which takes the month over month return variance and multiplies it by a random normal variable to create a normal distribution of price movements for a given month, and a lognormal distribution of prices as illustrated above.

A more in-depth breakdown of the data justifying this new methodology, including the monthly present value revenue requirement (PVRR) calculations of a sampling of stochastic draws, can be found in Appendix G.

Key Inputs

Individual transportation segments, storage, supply and demand side resources, both existing and potential, are targeted to demand segments representing the citygates connected to the system and the various classes of core customers behind those gates. This level of precision allows PLEXOS® to consider each resource on an individual basis within the portfolio while also recognizing where physical system limitations exist. Resource characteristics such as a supply contract's daily delivery capability, minimum take requirements, maximum daily transport capability by individual segment, storage inventory limitations and withdrawal, and injection curve characteristics are part of each resource's basic model inputs. The ability to model resources in this fashion allows PLEXOS® to tailor the optimization within envisioned constraints and ensures that the model's optimal solution can work under anticipated operating conditions.

The optimization process compares a portfolio of resources against a specific demand requirement. PLEXOS® generates a daily demand forecast by combining base load and temperature sensitive usage factor inputs with a specified daily temperature pattern input. For IRP purposes usage factor inputs were specifically developed under high, medium, or low demand profiles culled from Cascade's in-house LFM. Daily temperature patterns are available as either design or average weather. Due to the complexity of the PLEXOS® application, the model has some combined demand areas compared to the LFM. Therefore, both usage factor and temperature pattern inputs from the LFM may be slightly adjusted within PLEXOS® on an area specific basis without creating any material difference in the load demand.

In PLEXOS®, each supply contract requires a Maximum Daily Quantity (MDQ) input to establish its specific delivery capabilities. Review of the daily, annual, monthly, or seasonal minimum utilization of the contract is required. Maximum take quantities can also be established on either an annual, monthly, or seasonal basis. The commodity rate input can reflect either a known price, in the case of a fixed cost contract, or index prices, if the user has established a representative index as a separate input item. Several fixed and variable cost rate inputs are also available for establishing separate contract cost items, if necessary. Most of the gas supply options discussed above are also available as transportation inputs.

Penalty rates on an annual, seasonal, monthly, or daily basis are needed if either minimum or maximum utilization requirements are required or desired. The penalty rate can be any amount desired or a specific amount if known. The intent of the penalty option is to direct PLEXOS® to adhere to whatever minimum or maximum characteristic is specified.

Resource mix is one of the more powerful and highly desirable input tools available in the model. By toggling on resource mix and providing an MDQ maximum and minimum, the analyst directs PLEXOS® to appraise the supply contract, on a total cost basis, against all other supply resources available within the portfolio. Under resource mix, PLEXOS® will determine whether the resource is desirable within the portfolio and at what MDQ size, within the MDQ maximum and minimum, the resource should be made available within the portfolio. This aspect of PLEXOS® is crucial to the evaluation of potential resources, as the Company conducts its resource planning, appraisal, and acquisition activities.

In addition to most of the items discussed above, storage resources have additional input considerations. Instead of MDQ inputs, the analyst establishes inventory maximums and/or minimums. If monthly inventory levels are to change over the years or within a year, PLEXOS® allows the analyst to establish that target. Injection and withdrawal capability, as well as the period within the year that each is available, are also input decisions.

A unique feature of PLEXOS® storage input is the Storage Volume - Dependent Deliverability (SVDD) Tables. This input item allows the analyst to tailor injection and withdrawal rates as either a line or step function based upon whether the facility has varying operating pressure constraints as the injection or withdrawal activity is conducted. The analyst can also establish whether inventory exists at the beginning of the planning period, and whether various prices and specific quantities exist at that time. PLEXOS® provides the analyst with five separate volume and price levels to reflect existing inventories.

Finally, PLEXOS® allows for input of a penalty rate for unserved demand. Cascade uses this functionality to give PLEXOS® a way to prioritize which rate tariff to serve when demand is higher than the resources available to serve that demand. These penalties are always higher than the cost of any incremental resources, as PLEXOS® configured to always elect to purchase these resources versus leaving demand unserved. Residential customers are always assigned the highest penalty. This tells PLEXOS® to prioritize serving these customers above all others. Commercial customers have the next highest penalty, followed by commercial/industrial customers, and finally industrial customers. It is important to note the customers on an interruptible tariff do not have a penalty assigned to leaving their demand unserved. This allows PLEXOS® the flexibility to serve the demand of these customers when possible, while making sure not to purchase additional resources if they will only be used to serve interruptible demand.

Decision Making Tool

Analysis of optimization model results and other operational and contractual constraints allows Cascade to make more informed resource decisions. The IRP optimization model output and Monte Carlo simulation analysis provide the quantifiable output from numerous model inputs. The model does not prescribe the ultimate resource portfolio. It can only calculate the least cost set of resources given their specific pricing and quantifiable constraint characteristics. However, many other resource combinations may be available over the planning horizon. Therefore, Cascade must include subjective risk judgments about unquantifiable and intangible issues related to resource selections. These include future flexibility, supplier deliverability risk, pipeline(s) risk, financial risk to the utility and its customers, operational constraints, regulatory risk, etc. The risk judgments are combined with the quantitative IRP analyses to form the actual resource decisions.

Resource Integration

The following subchapters summarize the preceding chapters bringing together the demand forecast, existing supply and demand side resources and potential alternative resources to develop the 28-year, most reasonably priced reliable portfolio.

Demand Forecast

Load growth across Cascade's system through 2050 is expected to fluctuate between 0.41% and 2.16% annually, accounting for leap years. Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow annually at an average rate of 1.21% and 0.94%, while industrial expects a growth rate of approximately 1.14%. Load across Cascade's two-state service territory is expected to increase at an average annual rate of 1.10% over the planning horizon, with the Oregon portion outpacing Washington, 1.43% versus 0.98%.

Long-Term Price Forecast

In Chapter 4, Supply Side Resources, Cascade discusses how the 28-year price forecast is based on a blend of current market pricing along with long-term fundamental price forecasts. Since pricing on the market is heavily influenced by Henry Hub prices, the Company closely monitors this market trend. The fundamental forecasts of Wood Mackenzie, the Energy Information Administration, the Northwest Power and Conservation Council, and trading partners are resources for the development of Cascade's blended long-range price forecast. Since the Company's physical supply-receiving areas (Sumas, AECO, and Rockies) are usually at a discount to Henry Hub, the Company utilizes the basis differential from Wood Mackenzie's most recently available update and compares that to the future markets' basis trading as reported in the public market.

Natural gas prices had stabilized for a period after dramatic fluctuations over the course of the last fifteen years. Figure 9-7 shows the history of regional and Henry Hub prices over the past ten years. The shale boom, environmental concerns around carbon, conservation efforts, and improvements in renewable energy had led to a market with prices as low as they have been in recent history. Recently, volatility has reentered the markets, starting at the end of 2018 with the Enbridge pipeline explosion. The inability to move gas from British Columbia to the U.S. Pacific Northwest created extreme upward pricing pressure across the region, and specifically at the Sumas basin. Once the pipeline was repaired, pricing stabilized by the summer of 2019 for a period. Recently, uncertainty regarding recovery from the COVID-19 pandemic, geopolitical threats, and an increase in exports from the U.S. have created a period of short-term high volatility, through Cascade does not expect these bullish forces to be sustained in the long term.

Figure 9-7: Historical Regional Pricing for Past Ten Years

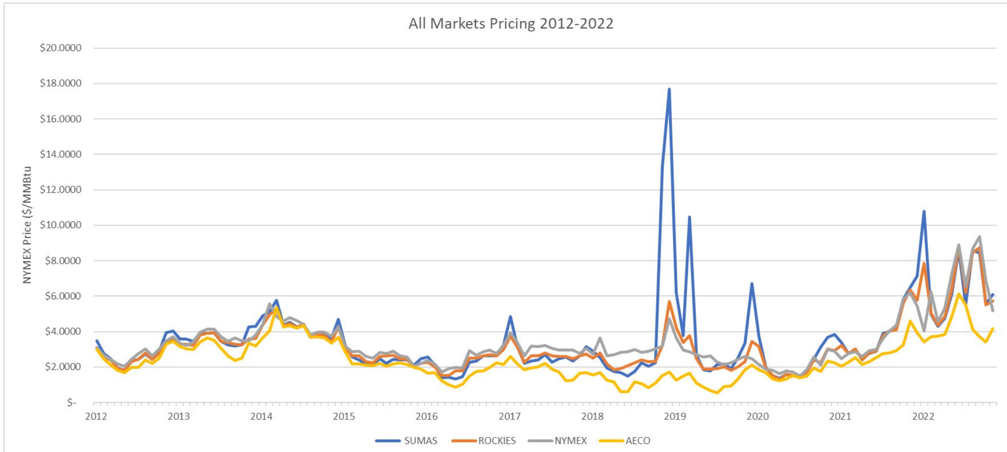
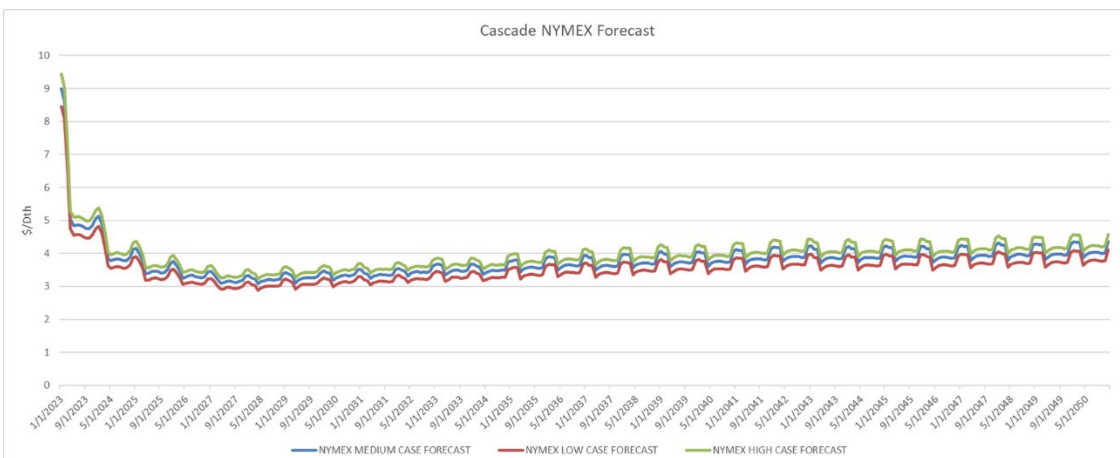


Figure 9-8 shows the comparison of ranges of NYMEX pricing for the planning horizon, including the expected low, medium, and high price.

Figure 9-8: NYMEX Annual Price Comparison



Environmental Adder

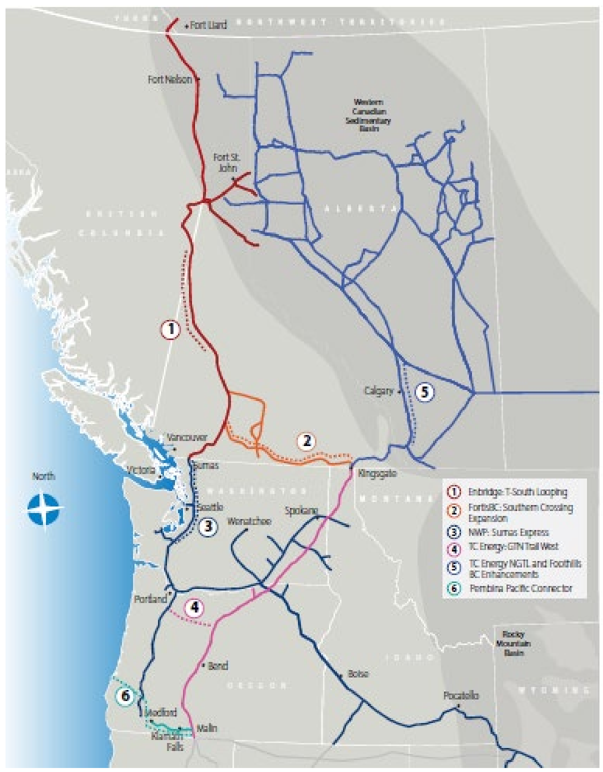
As discussed in Chapter 5, Avoided Cost, Cascade included a 10% environmental adder in its 2023 IRP's 28-year price forecast.

Transportation/Storage

Chapter 4, Supply Side Resources, describes the range of current upstream pipeline transportation capacity and storage services under contract to serve core customers.

Additionally, the Company identified several proposed transportation resources, as seen in Figure 9-9, such as a potential expansion of NWP along the I-5 corridor and acquiring currently unsubscribed GTN capacity that can be used to meet customer growth and address potential capacity shortfalls. The Company also continues to work with NWP to look at re-aligning Cascade's contracted delivery rights (Maximum Daily Delivery Obligations, or MDDOs) to citygates with potential peak day capacity shortfalls. The Company also uses segmenting pipeline capacity as a way to maximize the utilization of Cascade's capacity. These resources, plus leasing incremental storage at several regional facilities, were all considered as a resource mix of possibilities to form the Company's 28-year integrated resource portfolio.

Figure 9-9: Alternative Transportation Resources[1]



Demand Side Management

Chapter 7, Demand Side Management, describes the methodology used to identify energy efficiency potential and the interactive process that utilizes avoided cost thresholds for determining the cost effectiveness of energy efficiency measures on an equivalent basis with supply side resources. For the 2023 IRP the nominal system avoided costs ranges between $1.00/therm and $6.52/therm over the 28-year planning horizon. Through the cost-effective use of conservation programs, the Company is able to reduce the load and

[1] Northwest Gas Association (NWGA) 2020 Pacific Northwest Gas Market Outlook 2020

emissions that otherwise must be met by more costly resources, such as a pipeline capacity expansion or RNG.

Cascade's DSM forecast is incorporated into its optimization modeling by converting the heat and base load forecasts into a peak and non-peak DSM factor. The peak day factor is the ratio of forecasted peak day demand to annual demand, while the non-peak factor is equal to one divided by the number of days in that year. These values are then allocated to the pipeline zonal level and loaded into PLEXOS® to model the impact of conservation on resource acquisition needs. From a technical standpoint this is done by creating a must-take resource that acts like a supply at the zonal level equal to the peak and non-peak DSM values. While it is not actually a supply, this methodology tells PLEXOS® to use DSM to decrement demand by the forecasted energy efficiency quantities before any resource acquisition decisions are made.

Results

After incorporating these inputs into the PLEXOS® model, Cascade began its analysis by running an "As-Is" portfolio. For the purpose of the 2023 IRP, this modeling exercise assumed no RNG, no Hydrogen, and no utilization of compliance instruments like allowances in Washington and CCIs and Oregon, as Cascade does not have any of these resources at the time that modeling has been finalized for this IRP cycle. This portfolio was also evaluated with and without incremental DSM resources, to evaluate the impact of DSM on reducing demand shortfalls. With no DSM, Cascade first forecasts shortfalls in Oregon in 2038, and Washington in 2034, with the largest projected shortfall being 20,390 dth in Oregon and 7,570 dth in Washington. Adding DSM to the model delays the shortfalls to 2049 in Oregon and 2046 in Washington, with the largest projected shortfalls being 3,600 dth in Oregon and 1,430 dth in Washington. There are no significant results to discuss regarding emissions compliance with this portfolio, as Cascade will not be able to meet its emissions reduction requirements without the resources discussed earlier in this subsection.

Portfolios Evaluated

For the 2023 IRP, Cascade elected to evaluate seven potential portfolios. These portfolios represent a wide variety of potential solutions for meeting the Company's obligation to serve in a least cost, least risk manner while complying with emissions reduction requirements. Similar to electric utilities, who have a variety of options for power generation (hydro, wind, solar, etc.) Cascade is evaluating a mix of various traditional and renewable-based resources to serve its customers. The Company selected these seven portfolios after discussions with various stakeholders throughout its technical advisory group process. In future IRPs, Cascade will consider evaluating additional portfolios.

Figure 9-10 outlines the key components of each portfolio identified in Figure 9-1. PLEXOS® deterministically selects the optimal quantity of each resource based on its Resource Mix functionality. These quantities, which are provided in Appendix E, are then tested stochastically, and ultimately ranked on their ability to serve load and meet emissions goals in a least cost, least risk manner.

Figure 9-10: Resource Composition of All Evaluated Portfolios

	All-In	*All-In Less DSM*	*Incremental Transport*	*RNG Only*	*Hydrogen Only*	*Renewables Only*	*Offsets Only*
Incremental NGTL	Yellow	Yellow	Yellow	Red	Red	Red	Red
Incremental GTN N-S	Yellow	Yellow	Yellow	Red	Red	Red	Red
NWP I-5 Mainline EXP	Yellow	Yellow	Yellow	Red	Red	Red	Red
Incremental Ruby	Yellow	Yellow	Yellow	Red	Red	Red	Red
NWP Wen lateral EXP	Yellow	Yellow	Yellow	Red	Red	Red	Red
Incremental Foothills	Yellow	Yellow	Yellow	Red	Red	Red	Red
NWP Z20 lateral EXP	Yellow	Yellow	Yellow	Red	Red	Red	Red
T-South-So Crossing	Yellow	Yellow	Yellow	Red	Red	Red	Red
Trails West (Palomar)	Yellow	Yellow	Yellow	Red	Red	Red	Red
Spire Storage	Yellow	Yellow	Yellow	Red	Red	Red	Red
Gill Ranch Storage	Yellow	Yellow	Yellow	Red	Red	Red	Red
Wild Goose Storage	Yellow	Yellow	Yellow	Red	Red	Red	Red
Aeco Hub Storage	Yellow	Yellow	Yellow	Red	Red	Red	Red
Magnum Storage	Yellow	Yellow	Yellow	Red	Red	Red	Red
Clay Basin Storage	Yellow	Yellow	Yellow	Red	Red	Red	Red
DSM	Green	Yellow	Yellow	Green	Green	Green	Green
Renewable Natural Gas	Green	Green	Red	Green	Red	Green	Red
Hydrogen	Green	Green	Red	Red	Green	Green	Red
Offsets	Green	Green	Red	Red	Red	Red	Green
Allowances	Green	Green	Red	Red	Red	Red	Green
Community Climate Investments	Green	Green	Red	Red	Red	Red	Green

Legend	
Green	Selected resource for the portfolio
Yellow	Considered but not selected resource
Red	Not considered for the portfolio

Figure 9-11 ranks the candidate portfolios based on the earliest shortfall, total system costs, and stochastic probability of long-term success in serving all of Cascade's customers while complying with emissions reduction requirements. The Top-Ranking Candidate Portfolio is the one that serves all customers at the lowest cost with the lowest risk of failure. Additionally, a portfolio must be able to serve all customers and meet emissions reductions goals under deterministic conditions to be eligible to become the Preferred Portfolio. For the 2023 IRP, the Company is combining stochastic loss of load probability and emissions reduction compliance into one metric: Long-Term Success Probability. This value represents the likelihood that Cascade will be able to meet both its demand and emissions reduction requirements. In future IRPs the Company will break these two values out into separate metrics.

Figure 9-11: Final Ranking of Portfolios – Mean and VaR

	Deterministic		Stochastic			Risk Adjusted Results
Portfolio	Year of First Shortfall	Total System Cost ($000)	Long-Term Success Probability	First Compliance Period Failure	99th Percentile Total System Cost	Risk Adjusted Total System Cost
All-In	N/A	12,928,647	98.50%	2049-2051	13,071,203	12,964,285.63
All-In Less DSM	N/A	14,132,960	82%	2049-2051	14,311,565	14,177,611.45
Offsets Only	2027	9,474,555	0%	2023-2026	9,645,876	9,517,384.90
Incremental Transport	2023	3,728,934	0%	2023-2026	3,778,886	3,741,422.09
Hydrogen Only	2023	4,839,885	0%	2023-2026	4,866,004	4,846,414.49
RNG Only	2023	8,434,560	0%	2023-2026	8,502,091	8,451,442.41
Renewables Only	2023	8,940,046	0%	2023-2026	9,011,442	8,957,895.21

Top-Ranking Candidate Portfolio

Using input from the alternative resources selected, the All-In portfolio was selected as the least cost, least risk solution for Cascade's system over the planning horizon. This portfolio is now defined as the Top-Ranking Candidate Portfolio. This portfolio provides guidance as to what resources should be considered to eliminate unserved demand and meet emissions reduction targets with the least cost mix of all the alternatives that the Company has considered. Furthermore, this portfolio was derived deterministically assuming average weather with a peak day event, Cascade's average price forecast, and expected growth system-wide. The projected impact of these resources on total system costs, bill impacts to the residential 101 rate schedule, and the Company's projected resource stacks are shown in Figures 9-12 through 9-15. Full bill impact analysis can be found in Appendix K.

Figure 9-12: Top-Ranking Candidate Portfolio -Totally System Cost by Year

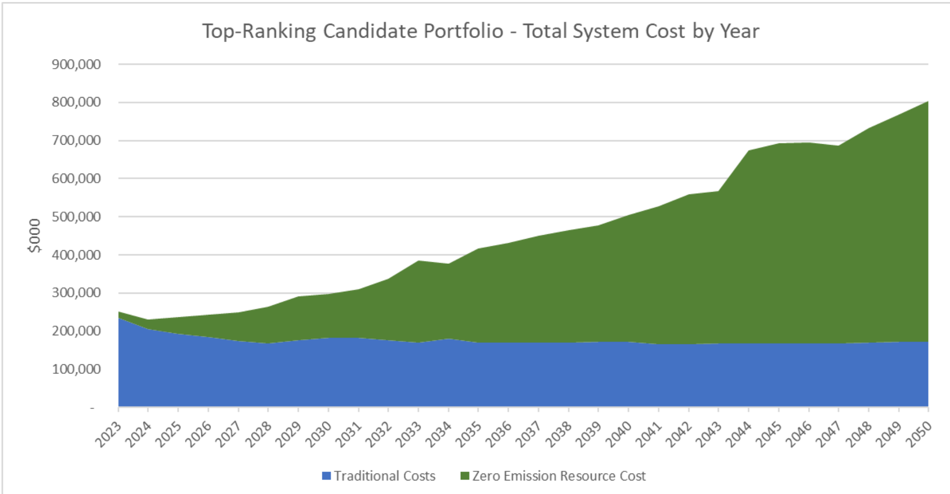


Figure 9-13: OR 101 Rate Class Bill Impact Analysis

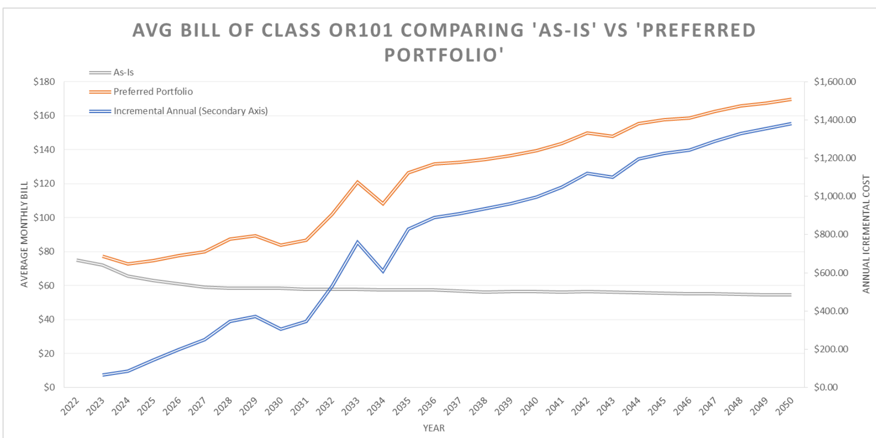


Figure 9-14: OR Projected Resource Stack for CPP Compliance

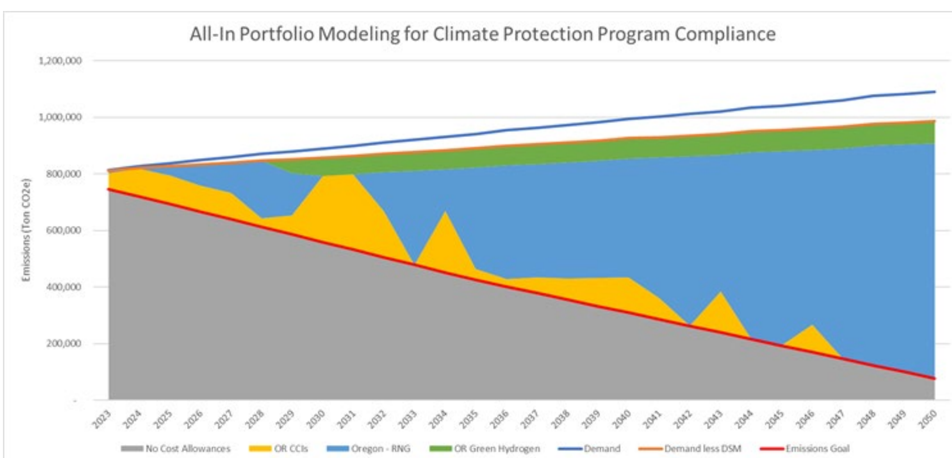
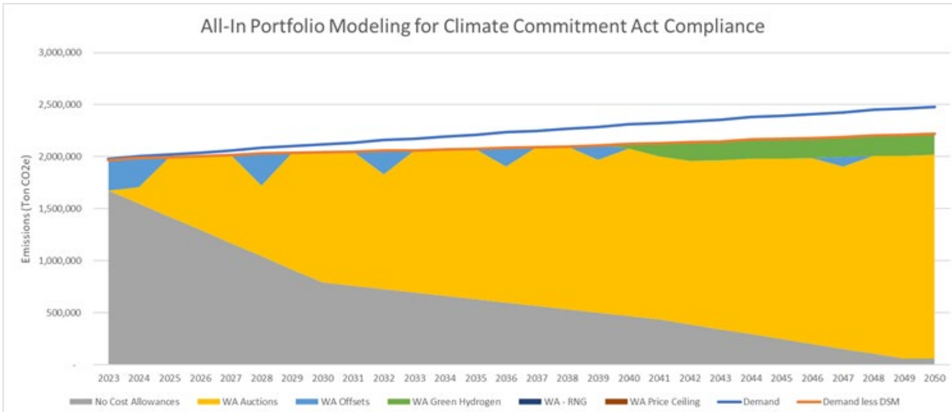


Figure 9-15: WA Projected Resource Stack for CCA Compliance



Alternative Resources Selected

The primary resources in the Top-Ranking Candidate Portfolio were RNG in OR and allowances from auction in WA. RNG is a particularly important resource because it solves for both shortfalls identified in as-is modeling. It has already been discussed how RNG reduces Cascade's emissions, but on-system RNG projects that be injected directly into the Company's distribution system are able to eliminate the need for incremental upstream transportation that would otherwise have solved Cascade's upstream capacity shortfalls in 2046 in Washington and 2049 in Oregon.

OR CCIs

Oregon has a mechanism in place where, through investment in the communities of Oregon, Cascade can reduce its emissions towards compliance with the CCA. CCIs can be used to meet up to 10% of a covered entity's compliance obligation in the first compliance period, 15% in the second compliance period and 20% in the third compliance period and thereafter. CCIs are a significant part of Cascade's early compliance strategy in Oregon as they are a cost-effective tool to hit compliance goals while RNG and green Hydrogen technologies are still developing. In later years, as CCIs become significantly more expensive, this resource is eventually phased out for the most part, to be replaced by RNG and Hydrogen in the resource stack. More information about CCIs can be found in Chapter 6, Environmental Compliance.

WA Auction Allowances

As discussed earlier, a successful auction participation strategy will be pivotal to the Company's success in complying with the Climate Commitment Act in Washington. Even at the higher end of projected allowance prices, this resource is expected to be more cost-effective than other options, particularly in early year while technology around resources like green hydrogen are still in a nascent stage. That being said, there will be many challenges that Company in its endeavor to successfully navigate the auction marketplace, including but not limited to predicting the behaviors of other participants, securing funding to meet the bid guarantee levels required to participate in the auction, and training Company staff to accurately utilize the Compliance Instrument Tracking System Service (CITSS) to execute planned strategies. To this end, Cascade has hired Guidehouse, a consulting firm with experience working with entities in other North American Cap and Trade/Invest programs implementing new regulations, including in California, Ontario, and Quebec. The Company is excited for this partnership, as it believes Guidehouse will give Cascade the tools to acquire these allowance resources in a least cost, least risk manner. More information about allowances can be found in Chapter 6, Environmental Compliance.

WA Offsets

Offsets present Cascade with an additional tool to reduce emissions by investing in Washington communities performing actions related to carbon sequestration. While it has not yet been finalized what amount of investment will equate to an offset of 1 MTCO2e, the Company does believe that it will be an attractive resource to include in its resource stack. There are limitations to the number of offsets that can be used to demonstrate CCA compliance, up to eight percent of a covered entity's compliance obligation in the first compliance period and six percent thereafter. More information about offsets can be found in Chapter 6, Environmental Compliance.

Green Hydrogen

As discussed in Chapter 4, Supply Side Resources, Cascade is excited by the opportunity to utilize green Hydrogen as a long-term part of the Company's emissions compliance strategy in both WA and OR. Hydrogen is a bountiful and clean resource that has potential to be very cost-effective in the long term if investment in its use continues. Hydrogen is a smaller molecule than Methane and does not have the same heating value as traditional natural gas, which does present challenges related to safety and quality that must be addressed before it can be part of Cascade's resource stack. From a modeling perspective, this is addressed by constraining the volume of hydrogen that can be blended with traditional natural gas and renewable natural gas to 20% of the volume. As mentioned in Chapter 4, Supply Resource Planning, this number comes from a 2013 NREL study, where it was concluded that "If less than 20% hydrogen is introduced into distribution system, the overall risk is not significant for both distribution mains and service lines." While this works for theoretical modeling, Cascade recognizes that it will have to perform its own research before implementing Hydrogen in practice. The Top-Ranking Candidate Portfolio does come within one percent of this constraint until 2046 in Washington, and 2030 in Oregon.

RNG

As discussed in Chapter 6, Environmental Policy, there are challenges to using RNG as a compliance resource in Washington. Ecology placed some geographic limitations for qualifying RNG outside of Washington for this exclusion within the WAC 173-441 GHG reporting rule and Cascade has placed limits on RNG accordingly as a compliance option in IRP modeling. In Oregon, DEQ has taken a more favorable perspective towards the utilization of RNG produced outside of the pacific northwest, leading to RNG being the most significant mid-to-long-term resource in compliance with the CPP. One challenge with modeling RNG is trying to derive constraints for the maximum amount of RNG that the Company believes it can acquire over the planning horizon that is both aggressive to reflect Cascade's position that it needs to be competitive in RNG markets, while also plausible to keep modeling results prudent. To do this, Cascade used a 50/50 split of the high and technical RNG potential identified in a 2019 ACF/ICF study to establish the potential amount of total RNG available for acquisition. From there, the Company calculated the ratio of its 2020 total sales to the EIA published figures for total 2020 U.S. natural gas consumption (the most current information available at the time of calculation) and multiplied this ratio by the potential volumes identified in the ACF/ICF study to set the upper limit for RNG constraints in the PLEXOS® model. It is important to note that, similar to with green Hydrogen, just because the model has these upper limits does not mean that it will maximize the utilization of RNG if it is not cost effective. In fact, in the short-term (pre-2030) the highest RNG saturation is about 30.20% of the maximum constraint, while in later years the highest saturation is 44.86%, aligning with the Company's goal of aggressive but also prudent planning.

Incremental DSM

As discussed early in this chapter, incremental DSM is vital resource for delaying the need for incremental upstream capacity. DSM is also a key cost-effective resource for mitigating Cascade's emissions, reducing the need for the most expensive supply side measures discussed above. The most powerful element of DSM is its cumulative impact, as measured installed in year one will have impacts far into the rest of the planning horizon, while measures installed in the next year will see their impacts added to those already installed in year one. This can be visually in the widening gap between the blue and orange lines in Figures 9-14 and 9-15. Quantitatively, DSM reduces emissions in Washington by only .5% in 2023, but as high as 10.50% in 2050. More information about DSM can be found in Chapter 7, Demand Side Management.

Marginal Abatement Cost Curves

Marginal abatement cost curves (MACC) are a valuable tool for visualizing the relationship between the resources selected in the Top-Ranking Candidate Portfolio under a common metric: The cost to remove 1 MTCO2e from the Company's emissions. Figure 9-15 shows how the curves change every five years of the planning horizon to illustrate how some resources like Hydrogen become more cost effective over time, while others like price ceiling allowances become cost prohibitive. Figure 9-16 is a more traditional MACC, showing the relationship between resources selected in 2050 to meet emissions reduction requirements, including the cost as represented by the Y-axis and the volumes utilized as represented by the width of the various columns. Additional MACCs can be found in Appendix J.

Figure 9-16: Marginal Abatement Cost Curves – By Resource

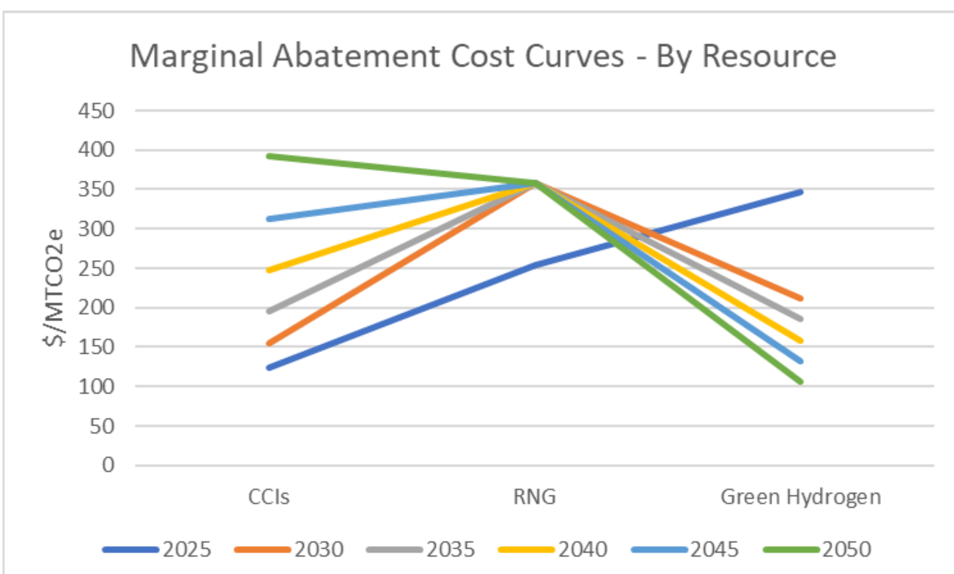
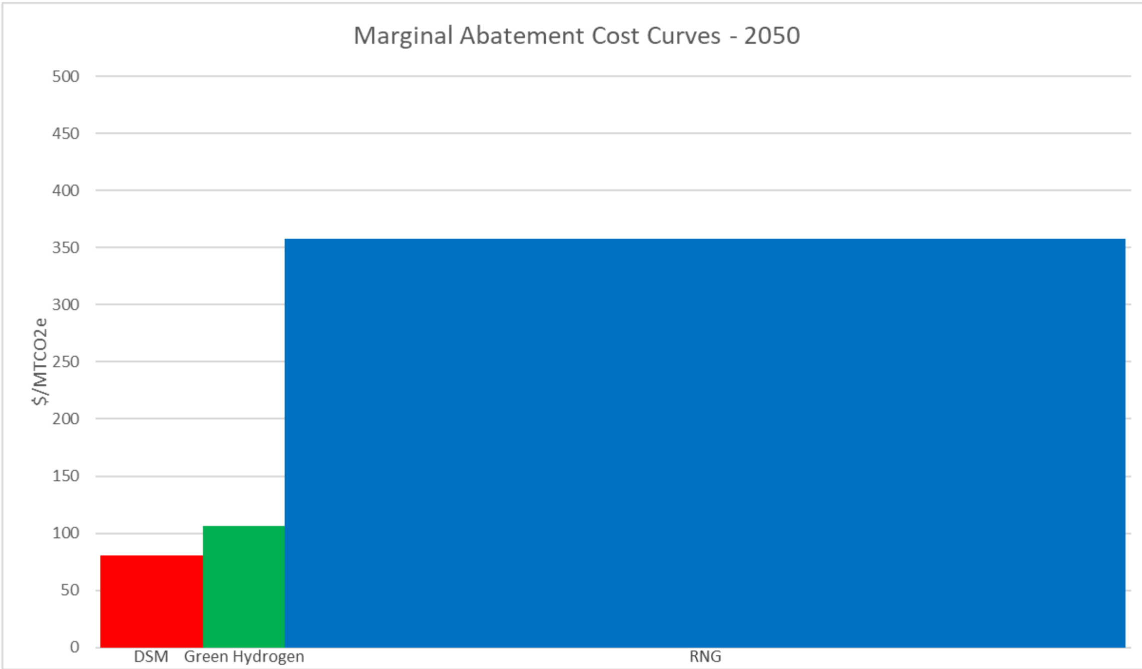


Figure 9-17: Marginal Abatement Cost Curves – 2050



Alternative Resources Not Selected

The PLEXOS® model did not select the following resources for the Top-Ranking Candidate Portfolio:

Upstream Transport

Typically, additional upstream transportation will be identified as an optimal element of the Top-Ranking Candidate Portfolio when it is able to either solve for a forecasted shortfall or lower the Total System Cost of the portfolio by enabling access to a more cost-effective supply at a cost that is lower than the cost of acquiring said transportation. For the 2023 IRP transportation contracts were not an optimal means of solving for the shortfalls identified in the As-Is analysis because they do not provide a means for lowering emissions in the same way that on system RNG is able to. Additionally, PLEXOS® did not identify any cost arbitrage opportunities for accessing lower cost supplies, so no incremental upstream transportation was selected as part of this IRP's Top-Ranking Candidate Portfolio.

Supply

- Opal Incremental – Since PLEXOS® determined there was no need for incremental Ruby capacity, there is no need to purchase additional gas to move along Ruby.
- Pacific Connector - Cascade's market intelligence determined that at this time, the Pacific Connector would not create a significant enough impact on liquidity at Malin to impact Cascade's modeling.

Storage

Gill Ranch, Clay Basin, Wild Goose, AECO Hub, Spire Storage– No incremental storage was selected. None of these storage facilities modeled were cost effective or led to an increase in served demand or lowered emissions. The primary reason appears to be that each storage facility modeled required long-term incremental transportation.

Portfolio Evaluation: Scenario Analyses

As discussed earlier in this Chapter, Cascade modeled five scenarios in addition to its base case scenario. The objective of these scenarios is capturing a wide range of externalities related to the availability and cost of supply and demand side resources, growth, and environmental policy compliance. For each scenario, Cascade will present the impact to total system cost over the planning horizon, bill impacts for Oregon residential customers, and projected emissions reduction compliance resource stacks for Oregon and Washington. A qualitative analysis will follow with key takeaways from review of the results.

Scenario 2: Carbon Neutral by 2050

This scenario models Cascade theoretically adopting a policy of going carbon neutral by 2050. As a caveat, this means the Company would be considered carbon neutral under the framework of the CCA in Washington and CPP in Oregon, so tools like auction-based allowances and CCIs are allowed to be utilized towards the objective of zero emissions by 2050. In this scenario, growth is assumed to follow the base 2023 IRP Load Forecast, including all expected regional gas bans, while DSM inputs come from the high CPAs discussed earlier in this chapter. The constraint for RNG availability is calculated the same way as discussed earlier in the Top-Ranking Candidate Portfolio Alternative Resources Selected, except the ratio of Cascade's load to nationwide consumption multiplied by only the technical potential in the ACF/ICF Study. That being said, any volumes selected above and beyond the base case availability are priced at a higher tranche of $26/dth. The constraint on Hydrogen is also increased to 30% of supply by volume to test if additional Hydrogen would be desirable in conjunction with a carbon neutral strategy. If so, such a volume would have to be heavily tested before it could be implemented in practice. Finally, the price of traditional natural gas is modeled to be 10% lower than base case modeling, as it is assumed Cascade would be joining a regional effort toward carbon neutrality in this scenario, which could result in bearish pressure towards gas prices as demand would be lower across the board.

Figure 9-18: Base Case Vs. Scenario 2 -Total System Cost by Year

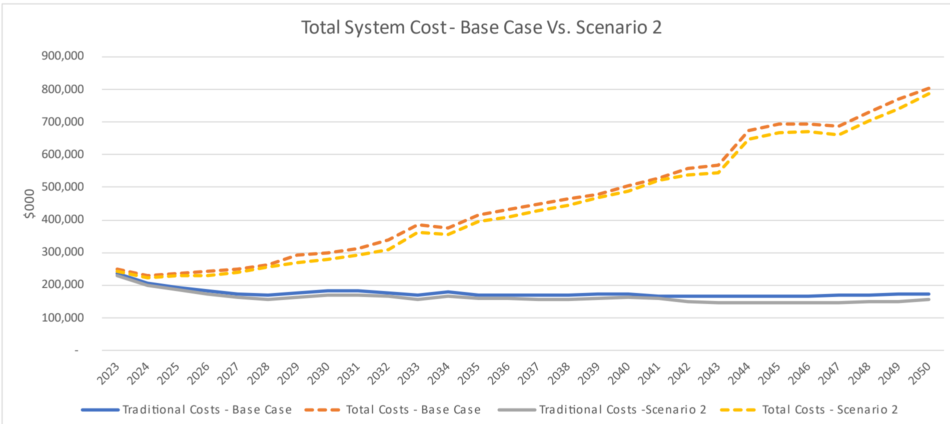


Figure 9-19: Scenario 2 OR 101 Rate Class Bill Impact Analysis

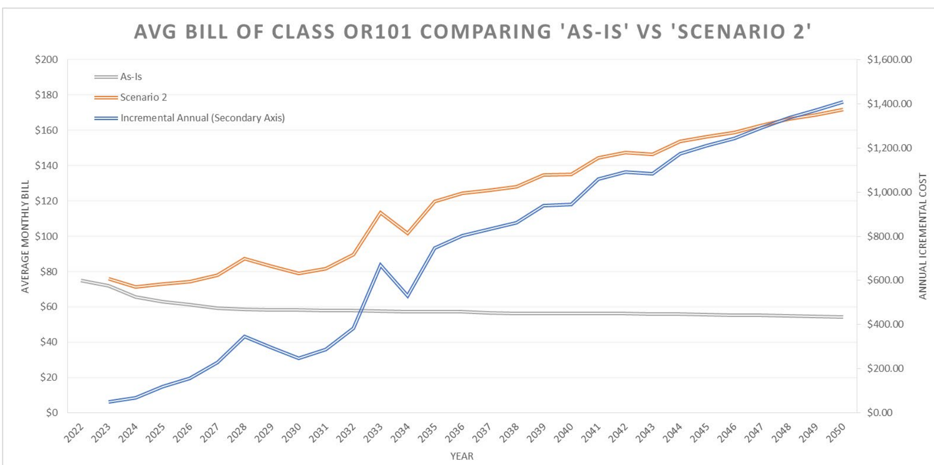


Figure 9-20: Scenario 2 OR Projected Resource Stack for CPP Compliance

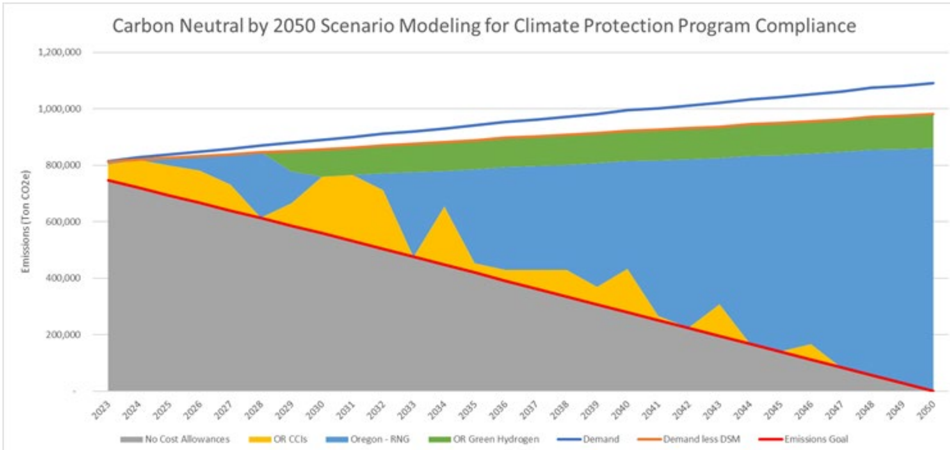
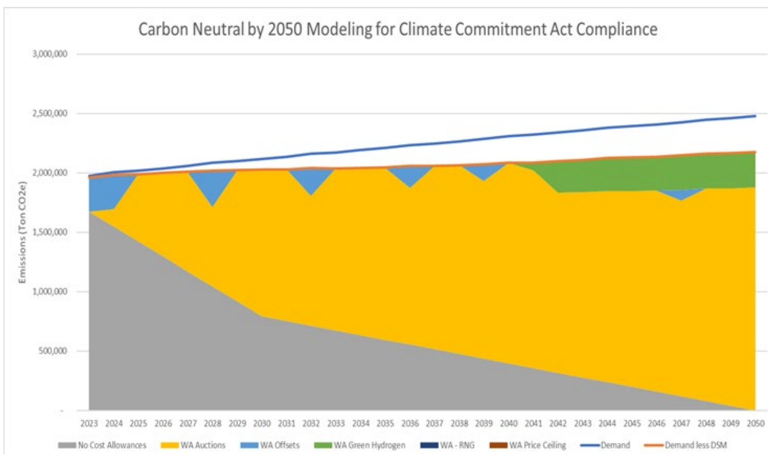


Figure 9-21: Scenario 2 WA Projected Resource Stack for CCA Compliance



Scenario 2: Key Takeaways

The primary takeaway from this scenario is that the Company is confident it would be able to serve its customers and meet carbon reduction goals under deterministic conditions even with an aspirational goal of being carbon neutral by 2050. That being said, an important resource in achieving this goal in a cost-effective manner is the increased utilization of green Hydrogen. Similar to the Company's base case modeling, Hydrogen is within 1% of maximum utilization in Washington by 2046, and in Oregon by 2030. This would put the Company well over the currently theorized safe threshold of a 20% blend by volume. This does not mean that Cascade would be engaging in unsafe practices, but rather emphasizes that research into ways to effectively utilize hydrogen in safe manner, including the potential need for investing in future technologies to facilitate higher blending limits, or potentially even independent Hydrogen distribution systems, are expected to be needed as part of a cost-effective strategy to hit carbon neutrality. Finally, an encouraging result of this modeling was the fact that total costs fluctuate between approximately 1.29% and 8.90% lower in this carbon neutral scenario when compared to base case costs. This reduction is driven by two assumptions: Access to more green Hydrogen, which is a significantly more cost-effective resource in later years, and the general 10% reduction to the price of traditional natural gas modeled in these scenarios. While it would not be prudent to conclude that going carbon neutral would automatically be a more cost-effective pathway, it is fair to say that if market conditions were to lead to the realization of those two assumptions, cost would not be a significant barrier to carbon neutrality.

Scenario 3: Limited RNG Availability

This scenario models a world where higher than expected competition for RNG, coupled with stagnation in technological developments related to RNG and Hydrogen, leads to a constraint of a limited amount of RNG and Hydrogen available for acquisition. In this scenario, growth is assumed to follow the base 2023 IRP Load Forecast, including all expected regional gas bans, while DSM inputs come from the high CPAs discussed earlier in this chapter. The constraint for RNG availability is calculated the same way as discussed earlier in the Top-Ranking Candidate Portfolio Alternative Resources Selected, except the ratio of Cascade's load to nationwide consumption multiplied by only the low potential in the ACF/ICF Study. The constraint on Hydrogen is also decreased to 5% of supply by volume to model the impact of a need to be more conservative in Hydrogen blending limits due to technological limitations. Finally, the price of traditional natural gas is modeled to be the same as in the base case.

Figure 9-22: Base Case Vs. Scenario 3 -Total System Cost by Year

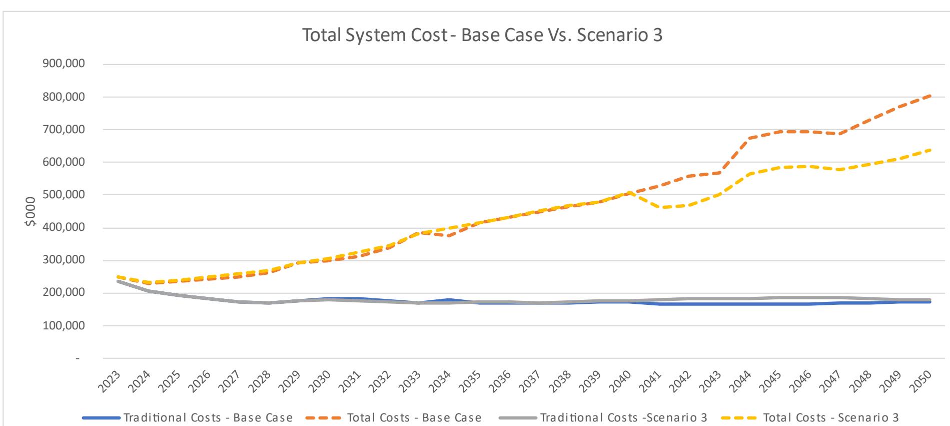


Figure 9-23: Scenario 3 OR 101 Rate Class Bill Impact Analysis

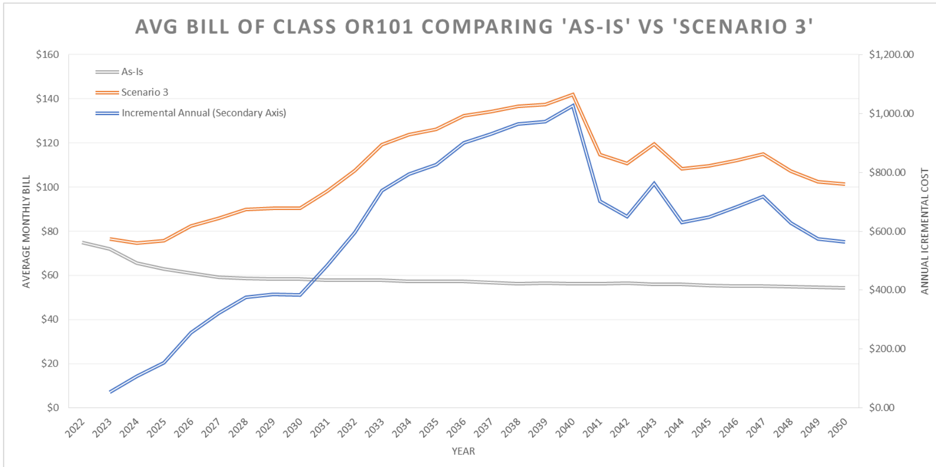


Figure 9-24: Scenario 3 OR Projected Resource Stack for CPP Compliance

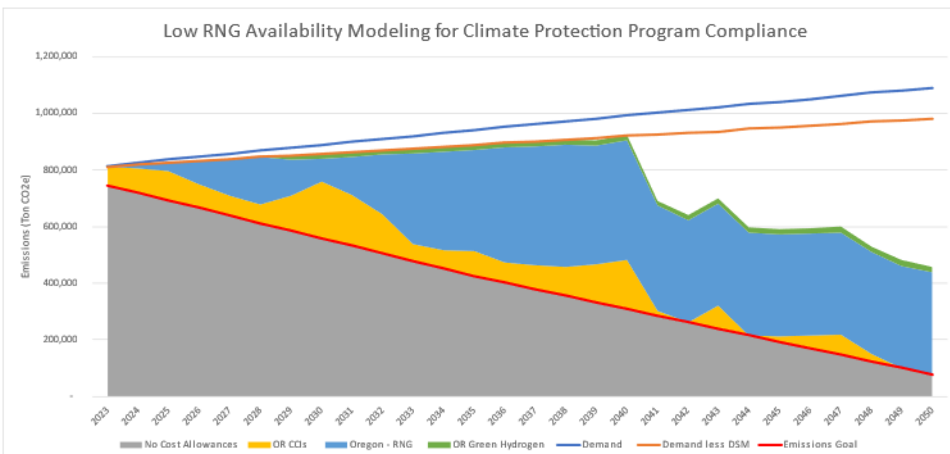
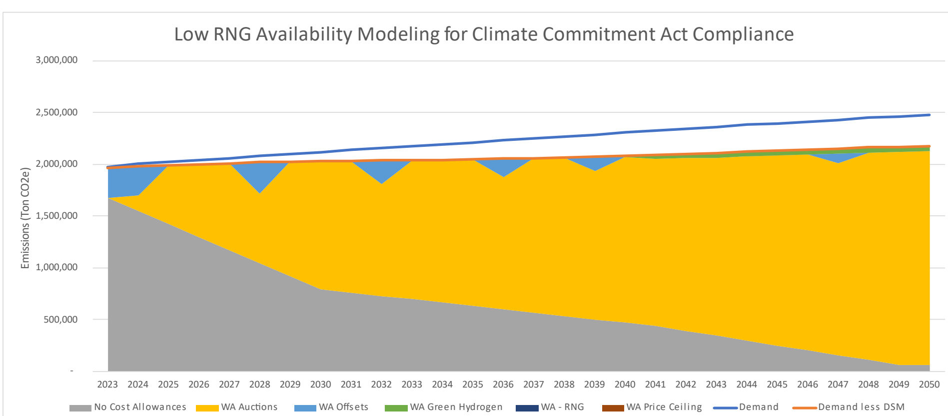


Figure 9-25: Scenario 3 WA Projected Resource Stack for CCA Compliance



Scenario 3: Key Takeaways

The primary takeaway from this scenario is that, while the Company is confident in its ability to meet emissions reduction goals with reduced availability of RNG and Hydrogen, Cascade will have difficulty reaching its goals in Oregon. These results forced the Company to reevaluate the Top-Ranking Candidate Portfolio (Step 6 of the Supply Resource Optimization Process) to consider alternative portfolios and restart the Scenario evaluation process. Ultimately it was determined that no other portfolio would have more success meeting emissions reduction goals under a limited RNG/Hydrogen scenario, so rather than reject the Top-Ranking Candidate Portfolio, the Company has elected to use these results to reaffirm its position that aggressive pursuit of RNG will be vital to Cascade's successful compliance with the CPP in Oregon. Additionally, while costs were higher while Cascade was in compliance in this low RNG scenario, costs were never more than six percent higher than base case projected costs, which the Company deems a tolerable level of variance.

Scenario 4: Increased Electrification

This scenario models lower than expected load growth projections due to both discretionary electrification and increased regional bans on natural gas. In this scenario, customer growth in Cascade's residential, and commercial rate classes gradually slows to zero growth in 2025 and afterwards, residential and commercial customer count reduced to 10% by 2050. This incorporates all expected and proposed regional gas bans. DSM inputs come from the high CPAs discussed earlier in this chapter, as aggressive energy efficiency efforts would be complimentary to any electrification efforts. The constraints for RNG and Hydrogen availability are calculated the same way as discussed earlier in the Top-Ranking Candidate Portfolio Alternative Resources Selected. Finally, the price of traditional natural gas is modeled to be 10% lower than base case modeling, as it is assumed that electrification efforts would impact all regional utilities, which could result in bearish pressure towards gas prices as demand would be lower across the board.

Figure 9-26: Base Case Vs. Scenario 4 -Total System Cost by Year

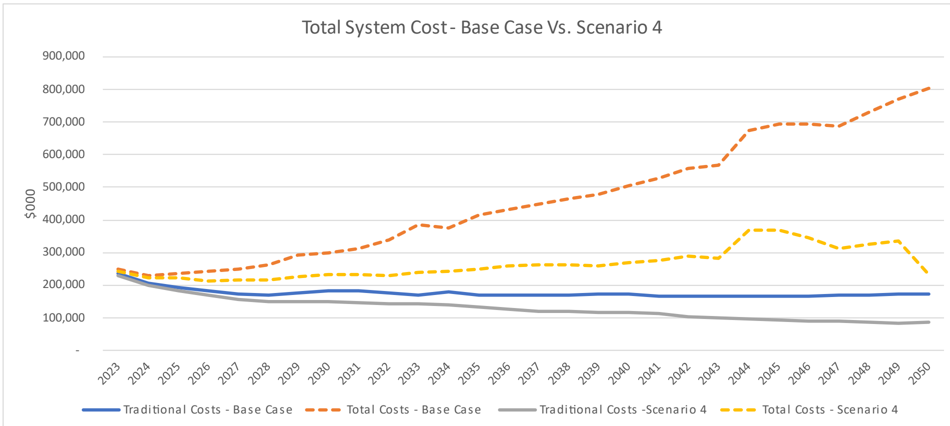


Figure 9-27: Scenario 4 OR 101 Rate Class Bill Impact Analysis

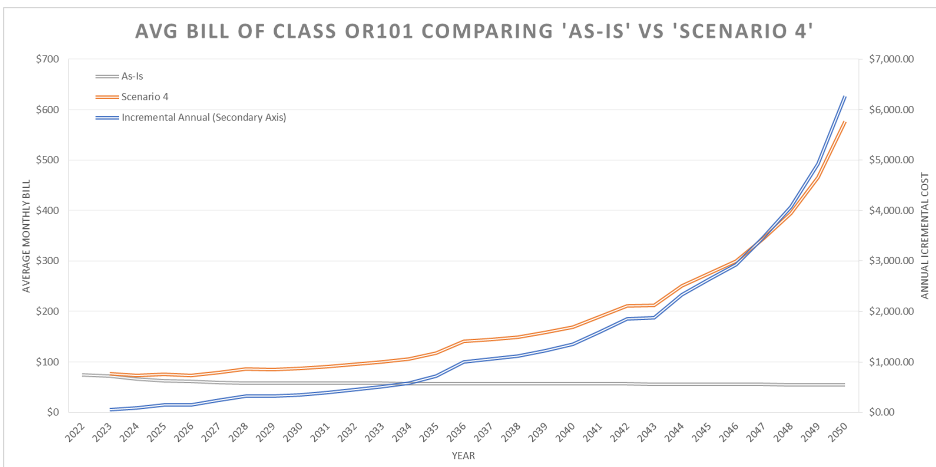


Figure 9-28: Scenario 4 OR Projected Resource Stack for CPP Compliance

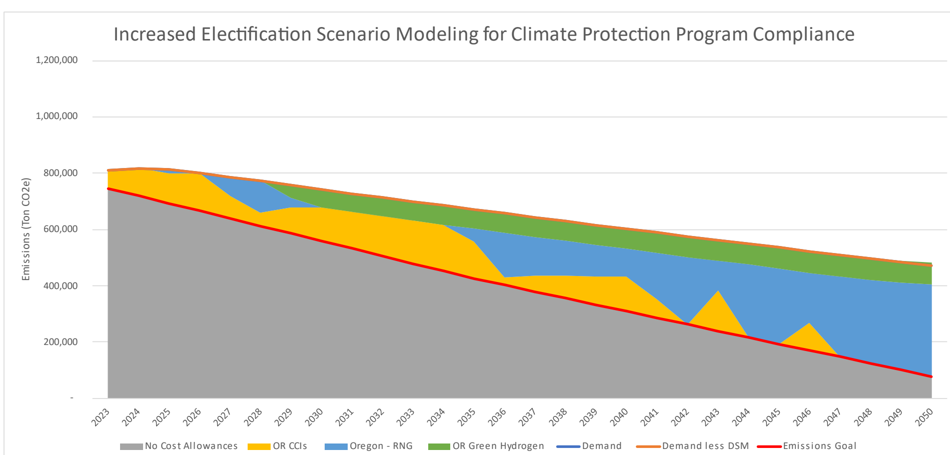
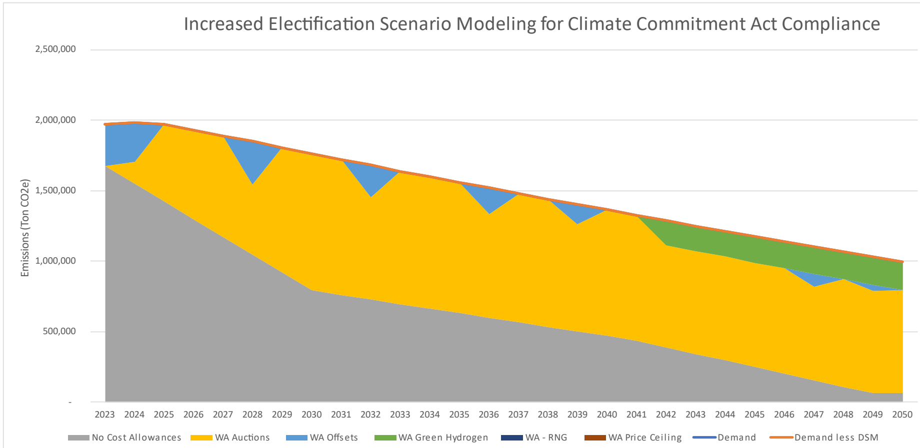


Figure 9-29: Scenario 4 WA Projected Resource Stack for CCA Compliance



Scenario 4: Key Takeaways

The primary takeaway from this scenario is that while Total System Costs for Cascade appear to be significantly lower in an electrification scenario, the impact to residential customer bills is alarming. At its peak, residential bills in this scenario will go up by approximately 960%, while the average annual increase in the electrification scenario is approximately 225%. This alarming increase reaffirms the Company's position that any efforts to undertake a dramatic move toward electrification must not be done without a detailed understanding of the regional impact of such a shift of load. While Cascade's cost may be lower, this comes at the consequence of a significant load increase to regional electric utilities, with all of the risks associated with the ability to serve such a dramatic influx of customers. Additionally, those utilities are presumably already utilizing their lowest cost, lowest risk resources to serve their existing customers. The costs to add these new customers may force those utilities to explore higher cost resource for electricity generation and their own emission mitigation. This does not even account for the significant cost to customers to replace existing gas units with their electric counterparts, a cost that will need to be accounted for in a regional electrification analysis before any action should be undertaken.

Scenario 5: High Customer Growth

This scenario models a world when customer growth is higher than Cascade's forecasts, leading to higher-than-expected emissions that will need to be accounted for in compliance with the CCA and CPP. In this scenario, growth is assumed to follow the high growth 2023 IRP Load Forecast, including all expected regional gas bans, while DSM inputs come from the high CPAs discussed earlier in this chapter. The constraint for RNG availability is calculated the same way as discussed earlier in the Top-Ranking Candidate Portfolio

Alternative Resources Selected, except the ratio of Cascade's load to nationwide consumption multiplied by only the technical potential in the ACF/ICF Study. That being said, any volumes selected above and beyond the base case availability are priced at a higher tranche of $26/dth. The constraint on Hydrogen is also increased to 30% of supply by volume to test if additional Hydrogen would be desirable to supply higher than expected growth. If so, such a volume would have to be heavily tested before it could be implemented in practice. Finally, the price of traditional natural gas is modeled to be 10% higher than base case modeling, as it is assumed that high growth would not be isolated to Cascade's service territory but rather a regional phenomenon, which could result in bullish pressure towards gas prices as demand would be higher across the board.

Figure 9-30: Base Case Vs. Scenario 5 -Total System Cost by Year

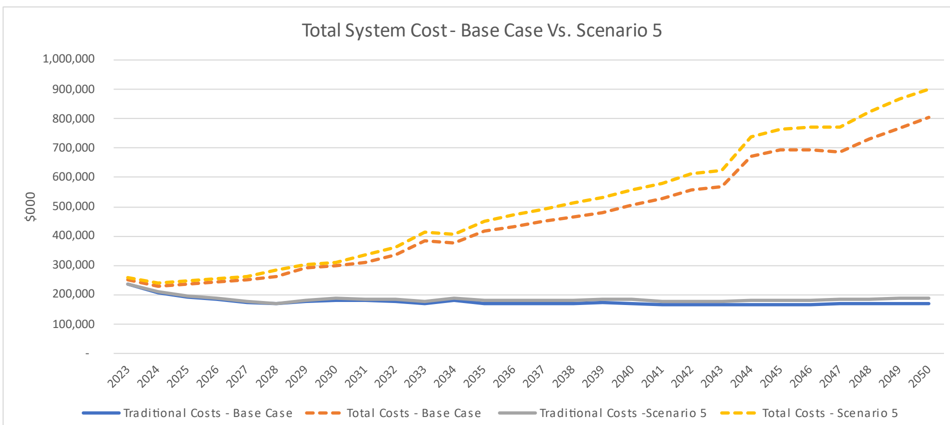


Figure 9-31: Scenario 5 OR 101 Rate Class Bill Impact Analysis

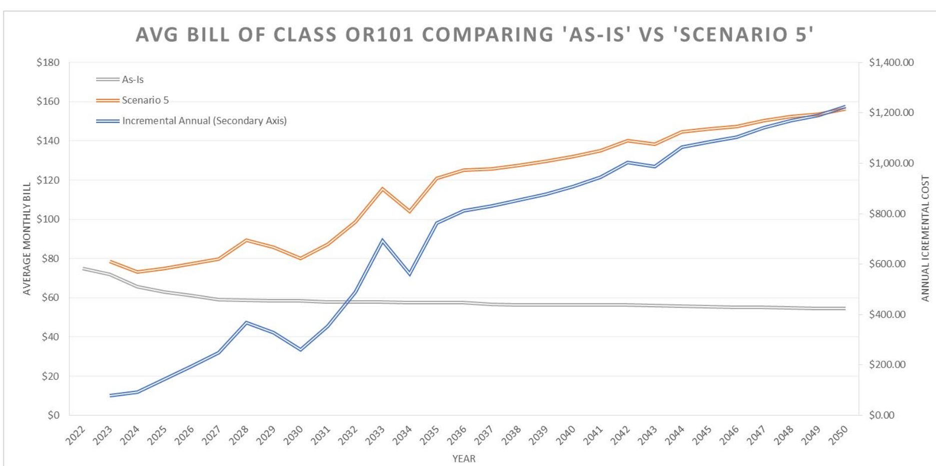


Figure 9-32: Scenario 5 OR Projected Resource Stack for CPP Compliance

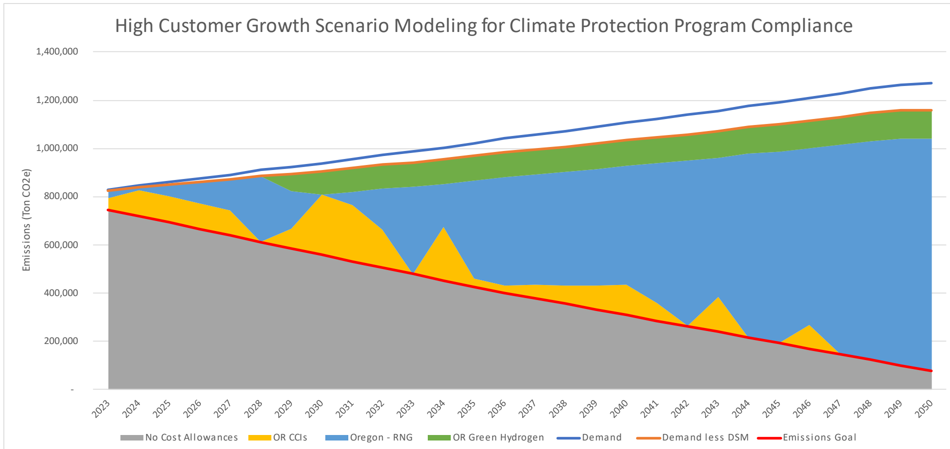
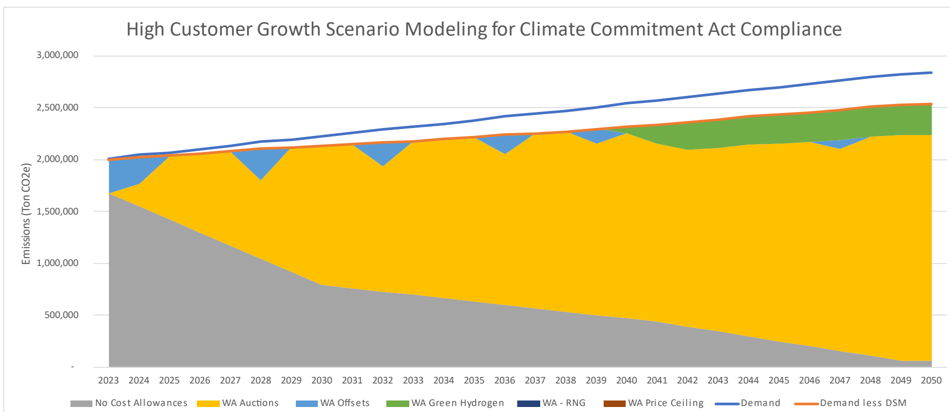


Figure 9-33: Scenario 5 WA Projected Resource Stack for CCA Compliance



Scenario 5: Key Takeaways

The primary takeaway from this scenario is that the Company is confident it would be able to serve its customers and meet carbon reduction goals under a high customer growth scenario. That being said, an important resource in achieving this goal in a cost-effective manner is the increased utilization of green Hydrogen. Similar to the Company's base case modeling, Hydrogen is within 1% of maximum utilization in Oregon by 2030, and Washington by 2046. This would put the Company well over the currently theorized safe threshold of a 20% blend by volume. This does not mean that Cascade would be engaging in unsafe practices, but rather emphasizes that research into ways to effectively utilize hydrogen in safe manner, including the potential need for investing in future technologies to facilitate higher blending limits, or potentially even independent Hydrogen distribution systems, are expected to be needed as part of a cost-effective strategy to hit carbon neutrality. This scenario also sees an increased utilization of auction allowances in Washington and CCIs in Oregon, which emphasizes the importance of Cascade working with a consultant like Guidehouse for assistance in with participating in these programs. Guidehouse is currently working with Cascade on developing internal strategies related to variance in customer growth, along with other externalities, so the Company will be prepared to optimally acquire these resources even if actual market conditions manifest differently from deterministic planning. Finally, this scenario presents the highest increase in total system cost relative to base case planning, with a forecasted increase of 12.87% at the highest point. This is largely driven by the modeled increase in natural gas pricing resulting from higher regional demand, as well as the need to acquire more compliance instruments and higher priced RNG to meet emissions reduction goals. Cascade is confident that it will be able to mitigate the impact of traditional natural gas pricing to some extent through its hedging strategies discussed in Chapter 4, Supply Side Resources, while the remaining increase, while significant, is not large enough to consider rejecting the Top-Ranking Candidate portfolio under these conditions.

Scenario 6: High Price – Interrupted Supply

This scenario models Cascade having to navigate three unique partial interruptions to its traditional natural gas supply basins. While the Company is not attempting to predict how these interrupts may manifest, it may be helpful to think of these incidents in terms of recent events that have impacts supply, such as the Enbridge explosion that limited Sumas supplies in 2018 or the recent Freeport LNG explosion that impact importers of U.S. LNG. Theoretically, these incidents could also be related to geopolitical strife, where an international conflict could potentially impact Cascade's ability to access a basin that Company expects to utilize to serve demand. In this scenario, growth is assumed to follow the base 2023 IRP Load Forecast, including all expected regional gas bans, while DSM inputs come from the Company's base case CPAs. The constraint for RNG and Hydrogen availability is calculated the same way as discussed earlier in the Top-Ranking Candidate Portfolio Alternative Resources Selected. Finally, the price of traditional natural gas is modeled to be follow the Company's base case modeling until an incident occurs, at which point prices spike to the 99th percentile of stochastic pricing of the basin where the incident occurs, with other basins experiencing correlated increases. For this scenario, it is modeled that an incident occurs at the Rockies basin on 10/1/2028, where supply is reduced to seventeen percent of expected availability, at the Sumas basin on 4/1/2034, where supply is also reduced to seventeen percent of expected availability, and at the AECO basin on 9/1/2046, where supply is reduced to 33% of expected availability. For incidents, supply comes back on line linearly over the course of two years until it returns to 100% capacity.

Figure 9-34: Base Case Vs. Scenario 6 -Total System Cost by Year

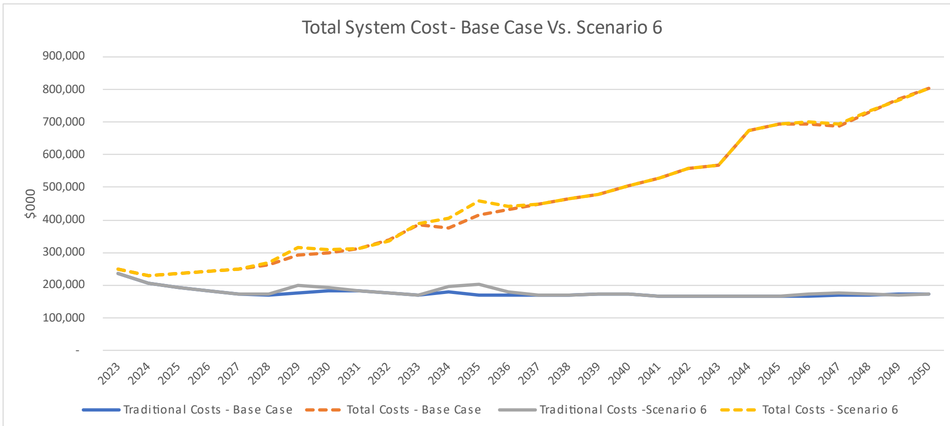


Figure 9-35: Scenario 6 OR 101 Rate Class Bill Impact Analysis

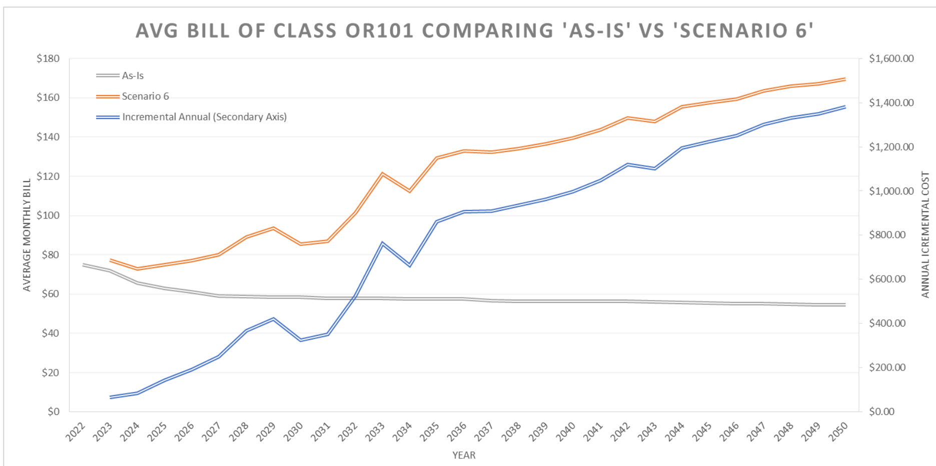


Figure 9-36: Scenario 6 OR Projected Resource Stack for CPP Compliance

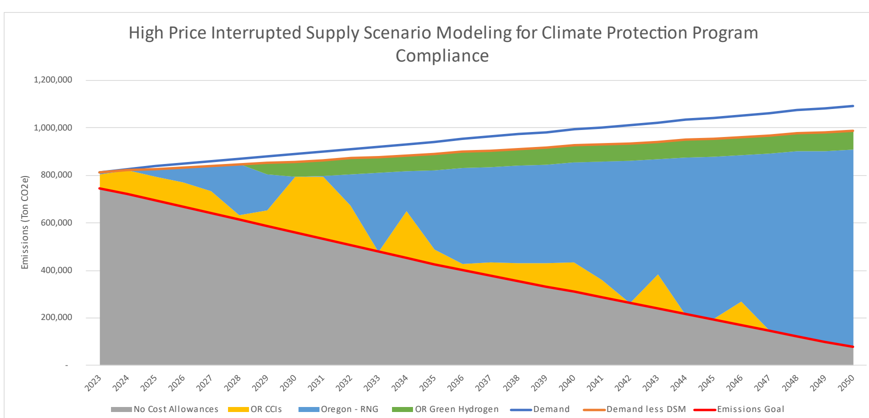
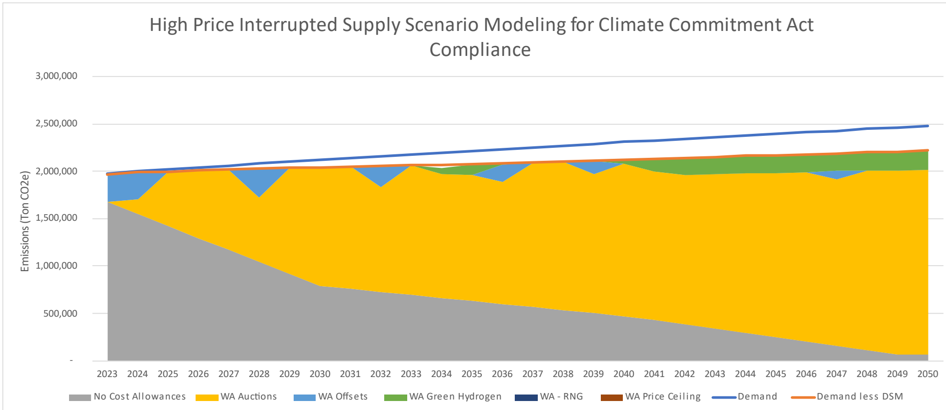


Figure 9-37: Scenario 6 WA Projected Resource Stack for CCA Compliance



Scenario 6: Key Takeaways

The primary takeaway from this scenario is that the Company is confident it would be able to serve its customers and meet carbon reduction goals under deterministic conditions even with intermittent shocks to supply basin availability. Even though Cascade's PLEXOS® modeling identifies that the Company would not be able to fully serve demand during the modeled Sumas incident in 2034, Cascade can draw on the actual Sumas incident of 2018 as an example of how human interactions can sometimes override modeled conclusions that cannot account for said human elements. Another interesting conclusion is that the timing of Cascade's entrance into Hydrogen markets could be impacted by incidents like the ones modeled in this scenario. In base case modeling, Cascade does not forecast utilization of green Hydrogen to start until 2040, but in this scenario, the model identifies Hydrogen as a cost-effective resource starting in 2034, with utilization of the 20% maximum getting as high in the mid-term as approximately 67% utilization by 2035. This introduces an additional benefit of exploring Hydrogen as a long-term resource: Insulation against potential price and availability shocks in the traditional natural gas marketplace.

Conclusion

Cascade's All-In portfolio includes all existing supply side resources as discussed in Chapter 4, all projected DSM savings discussed in Chapter 7, and all incremental resources discussed in this chapter. The All-In portfolio passed extensive scrutiny in the scenario analysis portion of the Supply Resource Optimization Process. This allows Cascade to deem this to be the Preferred Portfolio, which is the lowest cost and risk mix of resources to serve demand and meet emissions reductions goals when considering all alternate supply and demand side resources. This is primarily due to Cascade's geographical spread across the region. The Company's existing long-term transportation contracts, coupled with robust supply basins, provide a base foundation to meet the load needs of Cascade's core customers. However, Cascade's unique geographical reach also creates particular challenges as the system is non-contiguous, often requiring the Company to hold transportation capacity on multiple upstream pipelines to feed the single upstream pipeline that is connected to a particular citygate.

Scenario analyses allowed Cascade to identify a number of threats to its ability to successfully meet customer demand over the 28-year planning horizon, including the need to identify safe blending limits for hydrogen, aggressively acquire RNG when cost effective, prepare strategies for participation in Oregon's CCI program and Washington's auction marketplace, and continue to advocate for robust analysis of the regional costs and impacts of electrification. Cascade has determined that this portfolio solves for resource deficiencies at an acceptable cost. Many events could occur between now and when resource needs materialize, so Cascade will employ adaptive management to be prepared. The Company will continue to monitor and analyze system demand through reconciling and comparing forecast to actual customer counts and will continually update and evaluate all demand side and supply-side alternatives.

CHAPTER 10

STAKEHOLDER ENGAGEMENT

Overview

Input and feedback from Cascade's Technical Advisory Group (TAG) are an important resource for ensuring the IRP includes perspectives beyond the Company's and is responsive to stake-holders' concerns. After listing attending stakeholders, this section covers three distinct areas: public participation outreach, stakeholder engagement during this IRP cycle, and meetings and workshops.

Key Points

- Five TAG meetings were held. Cascade continued COVID-19 protocols with all TAG meetings held virtually.
- Multiple opportunities for public participation and stakeholder engagement were available, including access to the Company's Resource Planning Team through phone discussions and email.
- TAG meeting agendas, minutes, and presentations are available at www.cngc.com.

Stakeholders

The Company encourages public participation in the IRP process. Participants invited to these public meetings include customers, regional upstream pipelines, Pacific Northwest Local Distribution Companies and other utilities, Commission Staff, stakeholder representatives such as the Northwest Gas Association, Oregon Department of Ecology, Washington Public Counsel, Oregon Citizens' Utility Board, the Alliance of Western Energy Consumers, the Northwest Energy Coalition, the League of Women Voters, and the Green Energy Institute. Attendees for each meeting are shown in Appendix A.

Internally, the Cascade IRP stakeholders and participants are from the following departments:

- Resource Planning;
- Gas Supply/Gas Control;
- Regulatory Affairs;
- Operations/Engineering;
- Business Development
- Energy Efficiency;
- Finance/Accounting;
- Information Technology; and
- Executive group.

Additionally, Cascade contracted the services of an IRP consultant, Bruce W Folsom Consulting LLC, to assist the Company with meeting the 2023 IRP schedule.

In its IRP, Cascade presents policy and technical information in a variety of formats ranging from thumbnail overviews in each chapter to an Executive Summary to descriptive narratives in each chapter with accompanying charts, graphs, and tables to highly technical information in the appendices of the IRP. This presentation style is intended to cover the broad range, and meet each unique needs, of stakeholders.

Opportunity for Public Participation

Cascade is fully committed to ensuring the public is invited to participate in its IRP process. The Company notifies five general segments of stakeholders through a variety of means. The five segments are: Commission Staffs, Customer representatives, Community-based organizations, the Expert public, and the General public.[1,2,]

Cascade notifies these segments in several ways, including:[3]

- Social media
- Meetings throughout service territory[4]
- Invite to docket distribution lists relevant to the IRP
- Web page
- Commission web page

Cascade has a dedicated Internet webpage where customers and interested parties can view the IRP timeline, TAG presentations and minutes, as well as current and past IRPs.[5,6]

The Company believes that customers and interested parties were made aware of Cascade's IRP meetings, opportunity to participate, as well as availability of CNGC

[1] Solid participation has come from Commission Staffs, customer representatives, and some community-based organizations (depending on their staffing and adjacency to their core mission). The General Public has been represented by all three.
[2] Utilities have attempted a multitude of efforts to attract the Expert and General Public to the IRP process, including media advertisements, newspaper articles, and town hall meetings. Over the past 30 years, these by themselves, have resulted in negligible turnout.
[3] Moreover, customers know how to gain information for energy efficiency and other customer-specific utility options. Additionally, utilities host ongoing advisory groups for specific issues (e.g., energy efficiency), town hall meetings (e.g., by electric utilities for transmission siting), and other options for specific issues.
[4] On August 14, 2019, Cascade held a TAG meeting in Bend, Oregon. Despite notification to the community, no customer attended.
[5] *See:* https://www.cngc.com/rates-services/rates-tariffs/oregon-integrated-resource-plan
[6] *See:* https://www.cngc.com/rates-services/rates-tariffs/washington-integrated-resource-plan

personnel to address any related issues. Additionally, Cascade hosts the Conservation Advisory Group (CAG) to receive regular input on energy efficiency issues.

Company Commitments for Stakeholder Engagement

For attendance at meetings, in an effort to further clarify roles and responsibilities for the Company as well as stakeholders, Cascade follows a Stakeholder Engagement Design Document, which can be found in Appendix A. Cascade recognizes that involvement in the Company's TAG represents a material time commitment. As stated in the Design Document at page 1: "Cascade seeks to employ best industry practices and recognizes external participation can add incremental improvements. … Cascade recognizes stakeholders have a multitude of projects before them. This Design Document is intended to assist in optimizing participation by interested parties to yield a solid IRP to the benefit of customers and the Company."

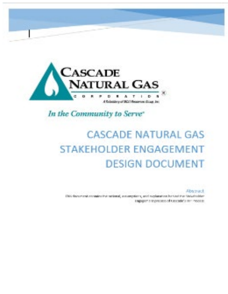
In the past decades, "rules of the road" for participation in utility advisory groups and collaboratives have ranged from full informality to specific charters. The latter has taken significant time for crafting and agreement by all parties. Cascade's Stakeholder Design Document attempts to capture the best from each approach.

The Company appreciates the investment of time attendees provide to this process by reviewing multiple documents and making subsequent suggestions. This IRP has benefited from the focus of the engaged stakeholders.

TAG Meetings and Workshops

Cascade held five public TAG meetings with internal and external stakeholders. Due to the COVID-19 pandemic, all meetings were held as virtual meetings only. In previous cycles, the Company held in-person meetings at various locations in its service territory to be more easily accessible, recognizing its IRP stakeholders are widely spread geographically.

Information about each meeting date and major agenda items are provided below as well as in Appendix A.



2023 IRP TAG 1 Meeting – Wednesday, March 30, 2022
Microsoft Teams Only from 9 am to 2 pm
• IRP Timeline
• Process
• Regional Market Outlook
• Plan for dealing with issues raised in 2020 IRP

2023 IRP TAG 2 Meeting – Wednesday, May 18, 2022
Microsoft Teams Only from 9 am to noon
• Demand and Customer Forecast
• Forecast Results
• Pipeline Presentations

2023 IRP TAG 3 Meeting – Thursday, July 28, 2022
Microsoft Teams Only from 1 pm to 4 pm
• Distribution System Planning
• Planned Scenarios and Sensitivities
• Price Forecast
• Avoided Cost

2023 IRP TAG 4 Meeting – Tuesday, September 20, 2022
Microsoft Teams Only from 9 am to 3 pm
• Carbon Impacts
• Energy Efficiency
• Renewable Natural Gas
• Preliminary Resource Integration

2023 IRP TAG 5 Meeting – Wednesday, November 9, 2022
Microsoft Teams Only from 9 am to noon
• Final Integration Results
• Finalization of plan components
• Proposed new 4-year Action Plan

Conclusion

Cascade submits it has adequately sought public participation for its IRP process and has implemented best practices for stakeholder engagement. The Company has assertively sought, at all junctures, to fully and efficiently work with stakeholders to optimize their input while being cognizant of busy workloads.

Chapter 11

Four-Year Action Plan

2023 Action Plan

The IRP Action Plan demonstrates Cascade's commitment to implementing the Company's Integrated Resource Plan and creating a portfolio of resources with the reasonable least cost mix of energy supply resources and conservation.

Key Points
Cascade's 2023 Action Plan focuses on:
- Resource Planning
- Environmental Policy
- Avoided Cost
- Demand Side Management
- Renewable Natural Gas
- Distribution System Planning
- IRP Process

Resource Planning and Environmental Policy

Cascade recognizes the importance of gathering best practices from other jurisdictional LDCs. To that end, the Company will continue to participate in the IRP process of at least three regional utilities over the course of the next two to four years with the objective of incorporating aspects that may enhance Cascade's IRP. Cascade will also attempt to get additional stakeholder involvement through convening the IRP TAG meetings in various locations within Cascade's territory, updates to Company website, and/or other means.

Cascade will also:
- 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.

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.

Demand

Cascade will look into incorporating end use forecasting into the load forecast model. With the increase in building code changes, Cascade will need to gain a better understanding on usage by end use and how the building code changes will impact future demand. Cascade will also look into incorporating income as an explanatory variable.

Demand Side Management (Energy Efficiency)

Cascade will continue to work with Energy Trust of Oregon (ETO) in an effort to create a DSM program for non-core customers. In coordination with ETO, Cascade will strive to acquire the projected cost-effective gas savings over the next two to four years. Cascade will coordinate with ETO in 2023 to include targeted load management for Baker City and Ontario distribution system projects.

Distribution System Planning

The Company will address the following Action Items for Distribution System Planning.

- Implement various stages or review of the of the list of projects that require an increase in capacity as shown in Appendix I.

Figure 11-1 on the following page highlights specific activities of the 2023 Action Plan.

Figure 11-1: Highlights of 2023 Action Plan

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: o Prineville Gate Upgrade. o Baker City Reinforcement (Targeted Load Management Candidate). o Ontario Reinforcement (Targeted Load Management Candidate).	Ongoing over the next four to five years.

Chapter 12

Glossary and Maps

Glossary of Definitions and Acronyms

The glossary is provided to allow the reader to maintain a location of definitions and acronyms for the content provided in this Integrated Resource Plan. Definitions and Acronyms can be found on pages 12-2 through 12-16. Cascade's citygates and the zone and pipeline each gate is associated with are listed on pages 12-17 through 12-18. Pipeline maps of gas systems that Cascade utilizes are provided on pages 12-19 through 12-33.

ABB™
Add-in product to the SENDOUT® model that facilitates the ability to model gas price and load uncertainty (driven by weather) into the future. ABB™ brings a Monte Carlo approach into the linear programming approach utilized in SENDOUT®.

ACEEE
American Council for an Energy-Efficient Economy.

ACHIEVABLE POTENTIAL
Represents a realistic assessment of expected energy savings, recognizing and accounting for economic and other constraints that preclude full installation of every identified conservation measure.

AECO INDEX
Alberta Canada natural gas trading price.

AKAIKE INFORMATION CRITERION (AIC)
A measure of the relative quality of statistical models for a given set of data. Given a collection of models for the data, AIC estimates the quality of each model, relative to each of the other models. Hence, AIC provides a means for model selection.

ALLOWANCES
An authorization to emit up to one metric ton of carbon dioxide equivalent.

ANNUAL FUEL UTILIZATION EFFICIENCY (AFUE)
Thermal efficiency measure of combustion equipment like furnaces, boilers, and water heaters.

ANNUAL MEASURES
Conservation measures that achieve generally uniform year-round energy savings independent of weather temperature changes. Annual measures are also often called base load measures.

ARIMA MODELING
Autoregressive integrated moving average. A time series analysis technique employed by Cascade in its demand and customer forecast.

ASSET MANAGEMENT AGREEMENT (AMA)
An arrangement that an LDC may enter into with a marketing company to assist with transportation and storage assistance.

AVOIDED COST
Marginal cost of serving the next unit of demand, which is saved through conservation efforts.

BASE LOAD
As applied to natural gas, a given demand for natural gas that remains fairly constant over a period of time, usually not temperature sensitive.

BASE LOAD MEASURES
Conservation measures that achieve generally uniform year-round energy savings independent of weather temperature changes. Base load measures are also often called annual measures.

BIO NATURAL GAS (BNG)
Typically refers to a gas produced by the biological breakdown of organic matter in the absence of oxygen.

BRITISH THERMAL UNIT (BTU)
The amount of heat required to raise the temperature of one pound of pure water one-degree Fahrenheit under stated conditions of pressure and temperature; a therm of natural gas has an energy value of 100,000 BTUs and is approximately equivalent to 100 cubic feet of natural gas.

CANADIAN ENERGY REGULATOR (CER)
The Canadian equivalent to the Federal Energy Regulatory Commission (FERC). The CER replaced the National Energy Board (NEB) on August 14, 2019.

CHOLESKY DECOMPOSITION
A positive-definite covariance matrix. This matrix is used to draw or sample random vectors from the N-dimensional multivariate normal distribution that follow a desired distribution. This allows for correlations between weather zones to be included when drawing or sampling data distributions for Monte Carlo runs.

CITYGATE (ALSO KNOWN AS GATE STATION OR PIPELINE DELIVERY POINT)
The point at which natural gas deliveries transfer from the interstate pipelines to Cascade's distribution system.

CITYGATE LOOP
Two or more citygates that transfer natural gas from the interstate pipeline to the same distribution system. Citygates are combined into a loop for modeling purposes because it is difficult to distinguish which citygate feeds a certain distribution system.

CLEAN AIR RULE (CAR)
Greenhouse gas emissions standards codified in WAC 173-442. Invalidated Dec. 15, 2017.

COEFFICIENT OF PERFORMANCE (COP)
The coefficient of performance or COP of a heat pump, refrigerator or air conditioning system is a ratio of useful heating or cooling provided to work required. Higher COPs equate to lower operating costs.

COMPRESSION
Increasing the pressure of natural gas in a pipeline by means of a mechanically driven compressor station to increase flow capacity.

COMPRESSOR
Equipment which pressurizes gas to keep it moving through the pipelines.

CONSERVATION MEASURES
Installations of appliances, products, or facility upgrades that result in energy savings.

CONSUMER PRICE INDEX (CPI)
As calculated and published by the U.S. Department of Labor, Bureau of Labor Statistics.

CONTRACT DEMAND (CD)
The maximum daily, monthly, seasonal, or annual quantities of natural gas, which the supplier agrees to furnish, or the pipeline agrees to transport, and for which the buyer or shipper agrees to pay a demand charge.

CORE CUSTOMERS
Residential, firm industrial and commercial gas customers who require utility gas service.

COST EFFECTIVENESS
The determination of whether the present value of the therm savings for any given conservation measure is greater than the cost to achieve the savings.

CUSTOMER CARE & BILLING (CC&B)
Internal billing data system for Cascade Natural Gas.

DAY GAS
Gas that can be purchased as needed to cover demand in excess of the base load.

DEKATHERM (DTH)
Unit of measurement for natural gas; a dekatherm is 10 therms, which is 1000 cubic feet (volume) or 1,000,000 BTUs (energy).

DEMAND SIDE MANAGEMENT (DSM)
The activity pursued by an energy utility to influence its customers to reduce their energy consumption or change their patterns of energy use away from peak consumption periods.

DEMAND SIDE RESOURCES
Energy resources obtained through assisting customers to reduce their demand or use of natural gas. Also represents the aggregate energy savings attained from installation of conservation measures.

ELECTRONIC BULLETIN BOARD (EBB)
Online communication systems where one can share, request, or discuss information on just about any subject.

ENERGY INFORMATION ADMINISTRATION (EIA)
The U.S. Energy Information Administration (EIA) is a principal agency of the U.S. Federal Statistical System responsible for collecting, analyzing, and disseminating energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. EIA programs cover data on coal, petroleum, natural gas, electric, renewable and nuclear energy. EIA is part of the U.S. Department of Energy.

ENTITLEMENTS
Flow management tool used by upstream pipelines, in conjunction with operational flow orders.

EXTERNALITIES
Costs and benefits that are not reflected in the price paid for goods or services.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)
The government agency charged with the regulation and oversight of interstate natural gas pipelines, wholesale electric rates and hydroelectric licensing; the FERC regulates the interstate pipelines with which Cascade does business and determines rates charged in interstate transactions.

FIRM SERVICE OR FIRM TRANSPORTATION
Service offered to customers under schedules or contracts that anticipate no interruptions; the highest quality of service offered to customers.

FIRST OF THE MONTH PRICE (FOM)
Supply contracts entered into on a short-term basis to cover expected demand for that month.

FORCE MAJEURE
An unexpected event or occurrence not within the control of the parties to a contract, which alters the application of the terms of a contract; sometimes referred to as "an act of God;" examples include severe weather, war, strikes, pipeline failure, and other similar events.

FOURIER TERMS
An alternative to using seasonal dummy variables, especially for long seasonal periods, is to use Fourier terms. Fourier terms consist of a series of sine and cosine terms of frequencies that can approximate any periodic function. These terms can be used for seasonal patterns with great advantage over seasonal dummy variables.

FUEL-IN-KIND (FUEL LOSS)
A statutory percent of gas based on the tariff from the pipeline that is lost and unaccounted for from the point where the gas was purchased to the citygate.

FUGITIVE METHANE EMISSIONS
Natural gas that escapes the system during drilling, extraction, and/or transportation and distribution of gas.

GAS MANAGEMENT SYSTEM (GMS)
A transactional and reporting system to consolidate natural gas nominations, contracts, balancing and pricing data.

GAS SUPPLY OVERSIGHT COMMITTEE (GSOC)
Oversees the Company's gas supply purchasing and hedging strategy. Members of GSOC include Company senior management from Gas Supply, Regulatory, Accounting & Finance, Engineering, and Operations.

GAS TRANSMISSION NORTHWEST (GTN)
A subsidiary of TransCanada Pipeline which owns and operates a natural gas pipeline that runs from the Canada/U.S. border to the Oregon/California border. One of the six natural gas pipelines Cascade transacts with directly.

GAUSSIAN (NORMAL) DISTRIBUTION
A distribution of many random variables that form a symmetrical bell-shaped graph.

GEOMETRIC BROWNIAN MOTION (GBM)
A continuous-time stochastic process in which the log of the randomly varying quantity follows a random shock combined with a drift element.

GREENHOUSE GAS (GHG)
A greenhouse gas is a gas that absorbs and emits radiant energy within the thermal infrared range. Increasing greenhouse gas emissions cause the greenhouse effect. The primary greenhouse gases in Earth's atmosphere are water vapor, carbon dioxide, methane, nitrous oxide and ozone.

HEATING DEGREE DAY (HDD)
A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below 60 degrees Fahrenheit; a daily average temperature representing the sum of the high and low readings divided by two.

HENRY HUB (NYMEX)
The physical location found in Louisiana that is widely recognized as the most important pricing point in the United States. It is also the trading hub for the New York Mercantile Exchange (NYMEX).

INJECTION
The process of putting natural gas into a storage facility or biomethane into the distribution system.

INTEGRATED RESOURCE PLAN (IRP)
The document that explains Cascade's long-range plans and preparations to maintain sufficient resources to meet customer needs at a reasonable price.

INTERRUPTIBLE SERVICE
A service of lower priority than firm service, offered to customers under schedules or contracts that anticipate and permit interruptions on short notice; interruption occurs when the demand of all firm customers exceeds the capability of the system to continue deliveries to all firm customers.

INTERSTATE PIPELINE
A federally regulated company that transports and/or sells natural gas across state lines.

JACKSON PRAIRIE
An underground storage facility jointly owned by Avista Corp., Puget Sound Energy, and NWP. The facility is a naturally occurring aquifer near Chehalis, Washington, which is located some 1,800 feet beneath the surface and capped with a very thick layer of dense shale.

LINEAR PROGRAMMING
A mathematical method of solving problems by means of linear functions where the multiple variables involved are subject to constraints; this method is utilized in the SENDOUT® Gas Model.

LIQUEFIED NATURAL GAS (LNG)
Natural gas that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure. It is liquefied to reduce its volume and thereby facilitate bulk storage and transport.

LOAD FACTOR
The average load of a customer, a group of customers, or an entire system, divided by the maximum load factor that can be calculated over any time period.

LOAD FORECAST
A forecast, an estimate, or a prediction of how much gas will be needed for residences, companies, and other institutions.

LOAD MANAGEMENT
The reduction of peak demand during specific, limited time periods by temporarily curtailing usage or shifting usage to other time periods. Load management reduces system peak demand very well, but can have little or no effect on total energy use. Its effects are temporary and of short duration.

LOAD PROFILE
The pattern of a customer's gas usage, hour to hour, day to day, or month to month.

LOADMAP
Microsoft Excel-based modeling tool developed by AEG to determine the Technical/Economic/Achievable Potential savings of various proposed DSM programs

LOCAL DISTRIBUTION COMPANY (LDC)
LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area.

LOOPING
The construction of a second pipeline parallel to an existing pipeline over the whole or any part of its length, thus increasing the capacity of that section of the system.

LOWEST REASONABLE COST (LRC)
LRC methodology is used when evaluating alternatives to determine the optimal solution to a given problem.

MCF
A unit of volume equal to 1,000 cubic feet.

MDDO
Maximum daily delivery obligation.

MDQ
Maximum daily quantity.

MDT
Thousands of dekatherms.

MEMORANDUM OF UNDERSTANDING (MOU)
A memorandum of understanding (MOU) is a nonbinding agreement between two or more parties outlining the terms and details of an understanding, including each parties' requirements and responsibilities. An MOU is often the first stage in the formation of a formal contract.

MONTE CARLO ANALYSIS
A type of stochastic mathematical simulation which randomly and repeatedly samples input distributions (e.g. reservoir properties) to generate a results distribution.

NATIONAL ENVIRONMENTAL POLICY ACT (NEPA)
A United States environmental law that promotes the enhancement of the environment and established the President's Council on Environmental Quality (CEQ). The law was enacted on January 1, 1970.

NATURAL GAS
A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geologic formations beneath the earth's surface, often in association with petroleum; the principal constituent is methane, and it is lighter than air.

NEEDLE PEAKING RESOURCE
Utilized during severe or “arctic” cold weather.

NEW YORK MERCANTILE EXCHANGE (NYMEX)
An organization that facilitates the trading of several commodities including natural gas.

NGV
Natural gas vehicles.

NOMINAL
Discounting method that does not adjust for inflation.

NOMINATION
The scheduling of daily natural gas requirements.

NON-COINCIDENT PEAK
The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than one year.

NON-CORE CUSTOMER
Large customers who contract with a third party for supply and upstream pipeline capacity. Cascade provides distribution services only. Typical customers include large commercial, industrial, cogeneration, wholesale, and electric generation customers.

NORTH AMERICAN ENERGY STANDARDS BOARD (NAESB)
Serves as an industry forum for the development and promotion of standards which will lead to a seamless marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities.

NORTHWEST BUILDER OPTION PACKAGES (NWBOP)
A prescriptive method for labeling new homes as ENERGY STAR. BOPs specify levels and limitations for the thermal envelope (insulation and windows), HVAC and water heating equipment efficiencies for the Pacific Northwest. BOPs require a third-party verification, including testing the leakage of the envelope and duct system, to ensure the requirements have been met.

NORTHWEST GAS ASSOCIATION (NWGA)
A trade organization of the Pacific Northwest natural gas industry. The NWGA's members include six natural gas utilities serving communities throughout Idaho, Oregon, Washington and British Columbia; and three natural gas transmission pipelines that transport natural gas from supply basins into and through the region.

NORTHWEST PIPELINE CORPORATION (NWP)
A principal interstate pipeline serving the Pacific Northwest and one of six natural gas pipelines Cascade transacts with directly. NWP is a subsidiary of The Williams Companies and is headquartered in Salt Lake City, Utah.

NORTHWEST POWER AND CONSERVATION COUNCIL (NWPCC)
NWPCC consists of two members from each of the four Northwest states- Oregon, Washington, Idaho and Montana- who develop a plan for meeting the region's electric demand.

NOVA GAS TRANSMISSION (NOVA or NGTL)
See TransCanada Alberta System.

OFF-SYSTEM
Any point not on or directly interconnected with a transportation, storage, and/or distribution system operated by a natural gas company within a state.

OPAL (OPAL HUB)
Natural gas trading hub in Lincoln County, Wyoming.

OPERATIONAL FLOW ORDER (OFO)
A mechanism to protect the operational integrity of the pipeline. Upstream pipelines may issue and implement System-Wide or Customer-Specific OFOs in the event of high or low pipeline inventory. OFOs require shippers to take action to balance their supply with their customers' usage on a daily basis within a specified tolerance band. Shippers may deliver additional supply or limit supply delivered to match usage. Violations or failure to comply with an OFO can result in the pipeline assessing penalties to offending shippers.

OREGON PUBLIC UTILITY COMMISSION (OPUC)
The chief electric, gas and telephone utility regulatory agency of the government of the U.S. state of Oregon. It sets rates and establishes rules of operation for the state's investor-owned utility companies. The OPUC's official name is Public Utility Commission of Oregon.

PACIFIC CONNECTOR GAS PIPELINE PROJECT (PCGP)
A proposed 232-mile, 36-inch diameter pipeline designed to transport up to 1 billion cubic feet of natural gas per day from interconnects near Malin, Oregon, to the Jordan Cove LNG terminal in Coos Bay, Oregon, where the natural gas will be liquefied for transport to international markets

PEAK DAY
The greatest total natural gas demand forecasted in a 24-hour period used as a basis for planning peak capacity requirements.

PEAK DAY GAS
Gas that is purchased in a peak day situation to serve demand that cannot be satisfied by base or day gas.

PERFORMANCE TESTED COMFORT SYSTEMS (PTCS)
Northwest regional programs with a focus on improving HVAC system comfort and increasing savings. They promote contractor training for properly sealing ducts and installing high-efficiency heat pumps, with a focus on sizing, commissioning, and setting controls. Technicians must complete a BPA-approved training to be certified to perform work in this program. These programs are supported by BPA and Northwest Public Utilities.

POUNDS PER SQUARE INCH (PSI)
The standard unit of measure when determining how much pressure is being applied when gas is flowing through a pipe.

PREFERRED PORTFOLIO
Cascade's term of art for the optimal mix of resources to solve for forecasted shortfalls in the 20-year planning horizon.

PRESENT VALUE OF REVENUE REQUIREMENT (PVRR)
The annual revenues required by the firm to cover both its expenses and have the opportunity to earn a fair rate of return. The annual costs to provide safe and reliable service to the company's customers that the company is allowed to recover through rates. The present value a future sum of money or stream of cash flows given a specified rate of return. Future cash flows are discounted at the discount rate, and the higher the discount rate, the lower the present value of the future cash flows.

PRICE ELASTICITY
Economic concept which recognizes that customer consumption changes as prices rise or fall.

R
A programming language and free software environment for statistical computing and graphics supported by the R Foundation for Statistical Computing.

REAL
Discounting method that adjusts for inflation.

RECOURSE RATE
Cost-of-service based rate for natural gas pipeline service that is on file in a pipeline's tariff and is available to customers who do not negotiate a rate with the pipeline company. Also see negotiated rate. (Source: FERC https://www.ferc.gov/resources/glossary.asp#R)

REFERENCE CASE
Average annual demand from the forecast results without peak day.

REGASIFICATION RESOURCE
Process by which LNG is heated, converting it to a gaseous state. Designed for vaporizing LNG where and when it will be used.

REGULATOR STATION
A point on a distribution system responsible for controlling the flow of gas from higher to lower pressures.

RENEWABLE FUEL
A power source that is continuously or cyclically renewed by nature, i.e. solar, wind, hydroelectric, geothermal, biomass, or similar sources of energy.

ROCKIES INDEX
Natural gas trading price near the Rocky Mountains.

SATELLITE LNG FACILITIES
A facility for storing and vaporizing LNG to meet relatively modest demands at remote locations or to meet short-term peak demands. LNG is usually trucked to such facilities.

SEASONAL PEAKING SERVICE
The delivery of gas, firm or interruptible, sold only during certain times of the year, generally when system demands are not high.

SENDOUT®
Natural gas planning system from ABB™; a linear programming model used to solve gas supply and transportation optimization questions.

SERVICE TERRITORY
Territory in which a utility system is required or has the right to provide natural gas service to ultimate customers.

SPOT MARKET GAS
Natural gas purchased under short-term agreements as available on the open market; prices are set by market pressure of supply and demand.

STANDBY
Support service that is available, as needed, to supplement a consumer, a utility system, or to another utility to replace normally scheduled energy that becomes unavailable.

STORAGE
The utilization of facilities for storing natural gas which has been transferred from its original location for the purposes of serving peak loads, load balancing, and the optimization of basis differentials. The facilities are usually natural geological reservoirs such as depleted oil or natural gas fields or water-bearing sands sealed on the top by an impermeable cap rock. The facilities may be man-made or natural caverns. LNG storage facilities generally utilize above ground insulated tanks.

SUMAS INDEX
Natural gas trading price near the city of Sumas, which is on the Washington/Canadian border approximately 25 miles from the Pacific Ocean.

SWAP
A financial instrument where parties agree to exchange an index price for a fixed price over a defined period.

SYNERGI®
Engineering software used to model piping and facilities to represent current pressure and flow conditions, while also predicting future events and growth.

TARIFF
A published volume of regulated rate schedules plus general terms and conditions under which a product or service will be supplied.

TECHNICAL ADVISORY GROUP (TAG)
Industry, customer, and regulatory representatives that advise Cascade during the IRP planning process.

TECHNICAL POTENTIAL
An estimate of all energy savings that could theoretically be accomplished if every customer that could potentially install a conservation measure did so without consideration of market barriers such as cost and customer awareness.

THERM
A unit of heating value used with natural gas that is equivalent to 100,000 British thermal units (BTU); also, approximately equivalent to 100 cubic feet of natural gas.

THROUGHPUT
The total of all natural gas volume moved through a pipeline system, including sales, company use, storage, transportation, and exchange.

TOTAL RESOURCE COST (TRC)
Measures the net costs of a demand side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The test is applicable to conservation, load management, and fuel substitution programs.

TRANSCANADA ALBERTA SYSTEM
Previously known as NOVA Gas Transmission (NGTL); a natural gas gathering and transmission corporation in Alberta that delivers natural gas into the TransCanada BC System pipeline at the Alberta/British Columbia border; one of six natural gas pipelines Cascade transacts with directly.

TRANSCANADA BC SYSTEM
Also known as Foothills Pipeline. Previously known as Alberta Natural Gas; a natural gas transmission corporation of British Columbia that delivers natural gas between the TransCanada-Alberta System and GTN pipelines that runs from the Alberta/British Columbia border to the United States border; one of six natural gas pipelines Cascade transacts with directly.

TRANSPORTATION GAS
Natural gas purchased either directly from the producer or through a broker, and used for either system supply or for specific end-use customers, depending on the transportation arrangements; NWP and GTN transportation may be firm or interruptible.

TRANSPORTATION SERVICE AGREEMENT (TSA)
A transportation services agreement is a contract made between goods providers and those who offer transportation for those goods. In the context of the IRP, this refers to shippers and upstream pipelines.

TURN-BACK CAPACITY
When natural gas shippers, upon expiration of their contract(s) for pipeline capacity do not renew capacity rights, in whole or in part, with the original pipeline, return said capacity rights back to the pipeline.

UPSTREAM PIPELINE CAPACITY
The pipeline delivering natural gas to another pipeline at an interconnection point where the second pipeline is closer to the consumer. In the context of the IRP this refers to any transmission pipeline that is upstream of the Cascade distribution system.

VALUE AT RISK (VaR)
A metric used to quantify uncertainty into a tangible number.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION (WUTC)
A three-member commission appointed by the governor and confirmed by the state senate. The Commission's mission is to protect the people of Washington by ensuring that investor-owned utility and transportation services are safe, available, reliable and fairly priced.

WINTER GAS SUPPLIES
Gas supply purchased for all (base gas) or part (day gas) of the heating season.

WITHDRAWAL
The process of removing natural gas from a storage facility, making it available for delivery into the connected pipelines; vaporization is necessary to make withdrawals from an LNG plant.

WOODS & POOLE (W&P)
An independent firm that specializes in long-term county economic and demographic projections.

ZONE
A geographical area. A geological zone means an interval of strata of the geologic column that has distinguishing characteristics from surrounding strata.

ZONE - IRP
For modeling purposes, Cascade's distribution system is divided into several zones. These zones are generally organized by the location of compressor stations on upstream pipelines or by specific weather areas. Where appropriate, the Zone-IRP is separated by state. Please see the chart on the next page that references the citygate/location to the appropriate IRP zone.

DESCRIPTION	METER	ZONEID	PIPELINE
7TH DAY ADVENTIST FARM TAP	ADVENSCH	ZONE 10	NWP
A & M RENDERING	AMRENDER	ZONE 30-W	NWP
A & W FEED LOT FARM TAP	AWFEED	ZONE 20	NWP
ABERDEEN/HOQUIAM/MCCLEARY	ABRNDHOQ	ZONE 30-S	NWP
ACME	ACME	ZONE 30-W	NWP
ALCOA, WENATCHEE	ALCOA	ZONE 11	NWP
ARLINGTON	ARLINGTN	ZONE 30-W	NWP
ATHENA/WESTON	ATHENA	ZONE ME-OR	NWP
BAKER	BAKER	ZONE 24	NWP
BELLINGHAM II	BLLINGII	ZONE 30-W	NWP
BELLINGHAM/FERNDALE	BLHAM	ZONE 30-W	NWP
BEND TAP	BEND	ZONE GTN	GTN
BREMERTON (SHELTON)	BREMERTON	ZONE 30-S	NWP
BRULOTTE HOP RANCH	BRULOTTE	ZONE 10	NWP
BURBANK HEIGHTS	BURBANKH	ZONE 20	NWP
CASTLE ROCK	CASTLERK	ZONE 26	NWP
CHEMICAL LIME	CHEMLIME	ZONE 24	NWP
CHEMULT	CHEM	ZONE GTN	GTN
DEHANNS DAIRY FARM TAP	DEHANDRY	ZONE 10	NWP
DEMING	DEMING	ZONE 30-W	NWP
EAST STANWOOD	EAST STANWOOD	ZONE 30-W	NWP
FINLEY	FINLEY	ZONE 20	NWP
GILCHRIST TAP	GILC	ZONE GTN	GTN
GRANDVIEW	GRDVEW	ZONE 10	NWP
GREEN CIRCLE FARM TAP	GRENCIRL	ZONE 26	NWP
HERMISTON	HERMSTON	ZONE ME-OR	NWP
HUNTINGTON	HTINGTON	ZONE 24	NWP
KALAMA FARM TAP	KALAMA	ZONE 26	NWP
KALAMA NO. 2	KALAMA2	ZONE 26	NWP
KAWECKI, WENATCHEE	KAWECKI	ZONE 11	NWP
KENNEWICK	KENEWICK	ZONE 20	NWP
KOMOS FARMS TAP	KOMO	ZONE GTN	GTN
LA PINE TAP	LAPI	ZONE GTN	GTN
LAMBERT'S HORTICULTURE	LAMBERTS	ZONE 10	NWP
LAWRENCE	LAWRENCE	ZONE 30-W	NWP
LDS CHURCH FARM TAP	LDSCHURC	ZONE 30-W	NWP
LONGVIEW-KELSO	LONGVIEW	ZONE 26	NWP
LYNDEN	LYNDEN	ZONE 30-W	NWP
MADRAS TAP	MADR	ZONE GTN	GTN
MENAN STARCH	MEMANSTR	ZONE 20	NWP
MILTON FREEWATER	MILFREE	ZONE ME-OR	NWP
MISSION TAP	MISSION	ZONE ME-OR	NWP
MOSES LAKE	MOS LAKE	ZONE 20	NWP
MOUNT VERNON	MTVERNON	ZONE 30-W	NWP
MOXEE CITY	MOXEE	ZONE 11	NWP
NORTH BEND	NBEND	ZONE GTN	GTN
NORTH PASCO METER STATION	NPASCO	ZONE 20	NWP
NYSSA-ONTARIO	NYSSA	ZONE 24	NWP
OAK HARBOR/STANWOOD	OAKHAR	ZONE 30-W	NWP
OTHELLO	OTHELLO	ZONE 20	NWP
PASCO	PASCO	ZONE 20	NWP

PATERSON	PATERSON	ZONE 26	NWP
PENDLETON	PENDLETN	ZONE ME-OR	NWP
PLYMOUTH	PLYMTH	ZONE 20	NWP
PRINEVILLE TAP	PRVL	ZONE GTN	GTN
PRONGHORN TAP	PRONGHORN	ZONE GTN	GTN
PROSSER	PROSSER	ZONE 10	NWP
QUINCY	QUINCY	ZONE 11	NWP
REDMOND TAP	REDM	ZONE GTN	GTN
RICHLAND	RICHLAND	ZONE 20	NWP
SANDVIK, KENNEWICK	SANDVIK	ZONE 20	NWP
SEDRO/WOOLLEY ET AL.	SEDRO	ZONE 30-W	NWP
SELAH	SELAH	ZONE 11	NWP
SOUTHRIDGE	STHRDG	ZONE 20	NWP
SOUTH BEND	S BEND	ZONE GTN	GTN
SOUTH HERMISTON TAP	SHRM	ZONE GTN	GTN
SOUTH LONGVIEW FIBRE	SOLONG	ZONE 26	NWP
STANFIELD CITY TAP	STTAP	ZONE GTN	GTN
STEARNS TAP	STEA	ZONE GTN	GTN
SUMAS, CITY OF	SUMASC	ZONE 30-W	NWP
SUNNYSIDE	SUNSIDE	ZONE 10	NWP
TOPPENISH ET AL. (ZILLAH)	TOPENISH	ZONE 10	NWP
U & I SUGAR, MOSES LAKE	UI SUGAR	ZONE 20	NWP
UMATILLA	UMATILLA	ZONE ME-WA	NWP
WALLA WALLA	WALLA	ZONE ME-WA	NWP
WALULA	WALULA	ZONE ME-WA	GTN
WENATCHEE	WENATCHE	ZONE 11	NWP
WOODLAND WA	WOODLAND	ZONE 26	NWP
YAKIMA CHIEF FARMS	YAKCHFRM	ZONE 11	NWP
YAKIMA FIRING CENTER	YAKFIRCR	ZONE 11	NWP
YAKIMA/UNION GAP	YAKIMA	ZONE 11	NWP

Maps of System Infrastructure

Figure 12-1: Map – AECO Hub Storage

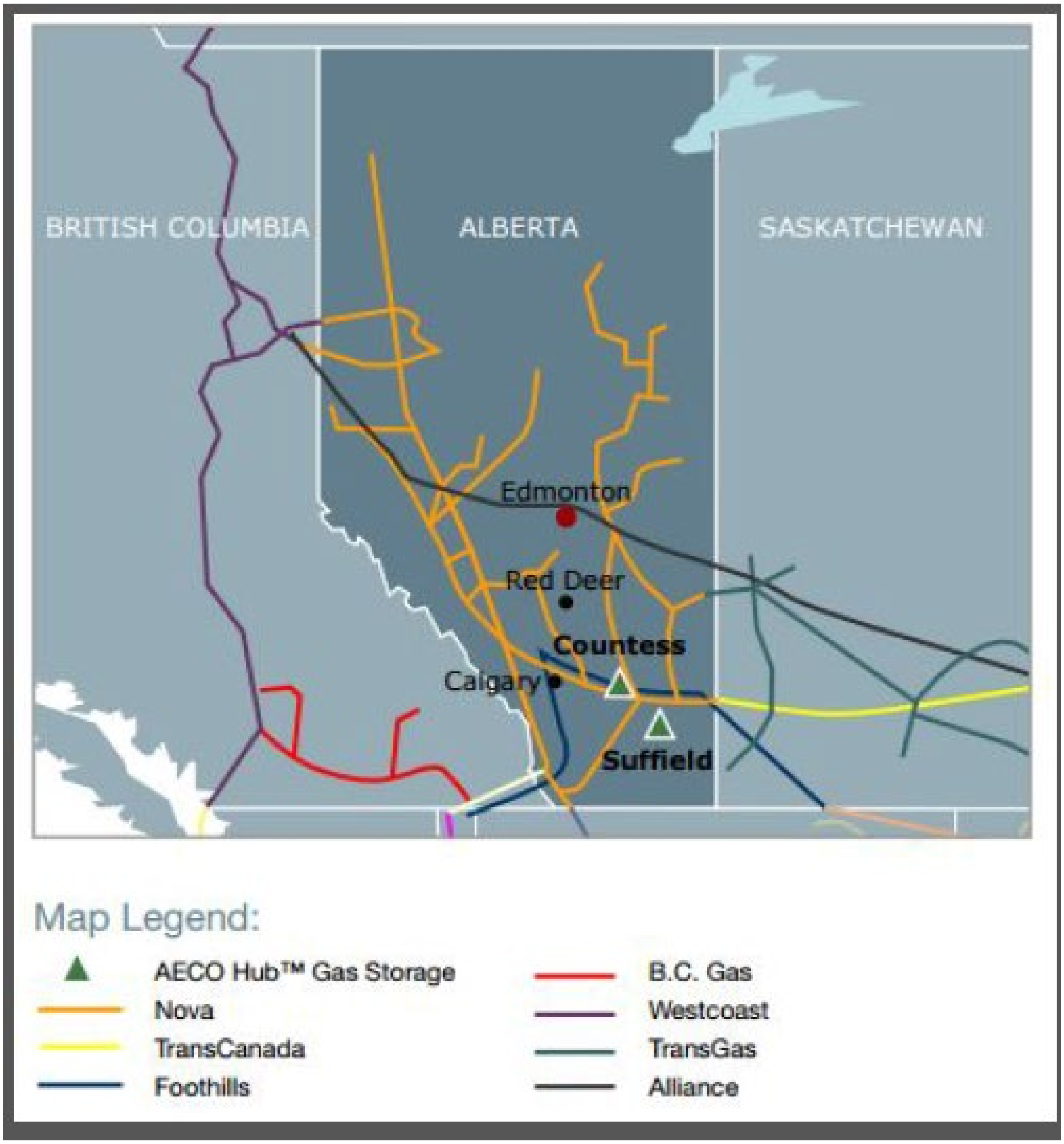


Figure 12-2: Map – California Storage Map

Figure 12-3: Map – Cascade Natural Gas Pipeline System

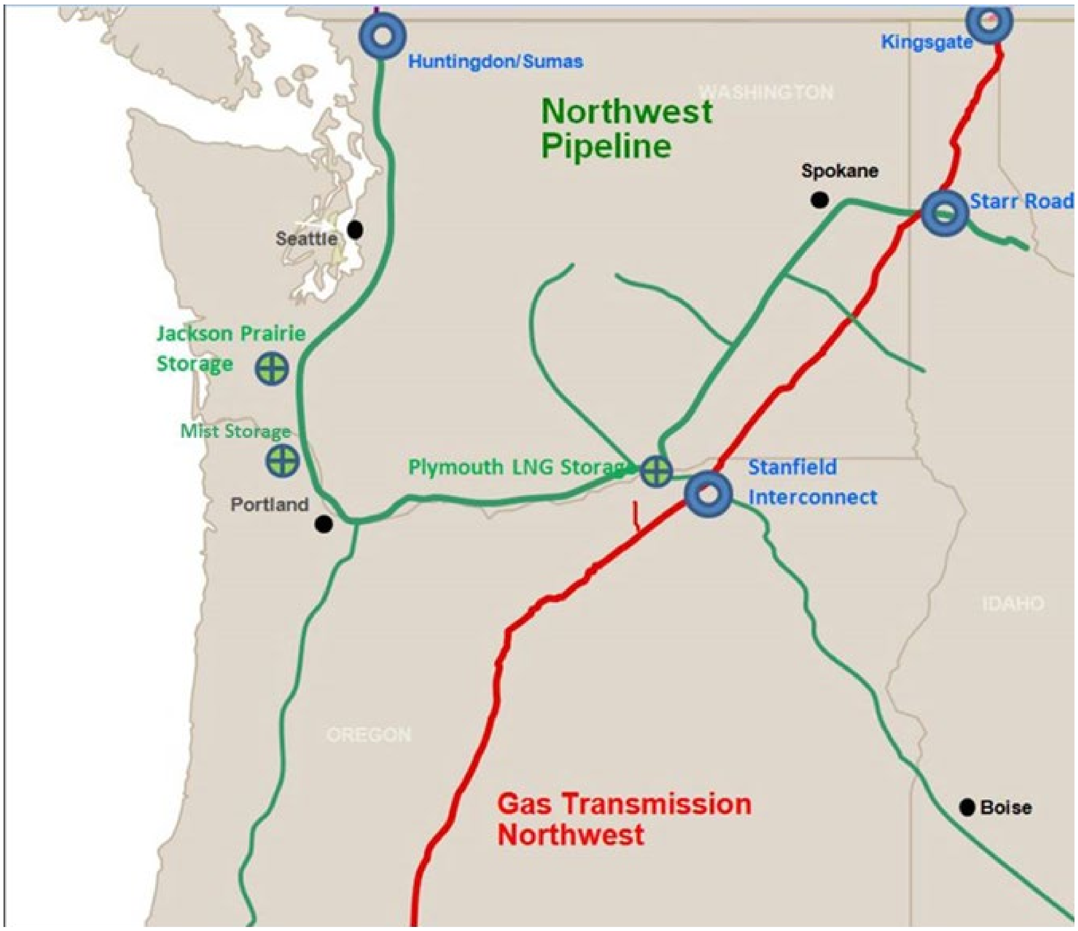


Figure 12-4: Map – Foothills-British Columbia Map

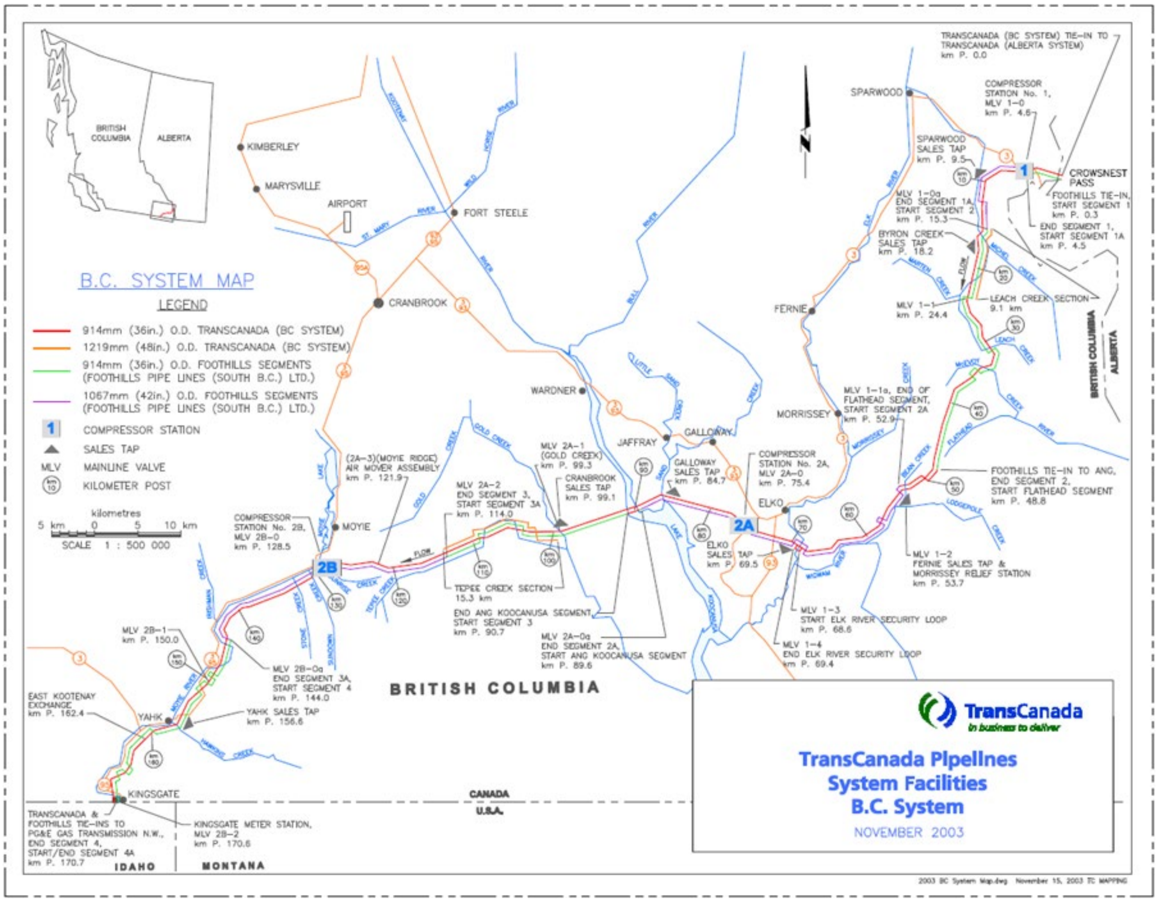


Figure 12-5: Map – Foothills-Full System

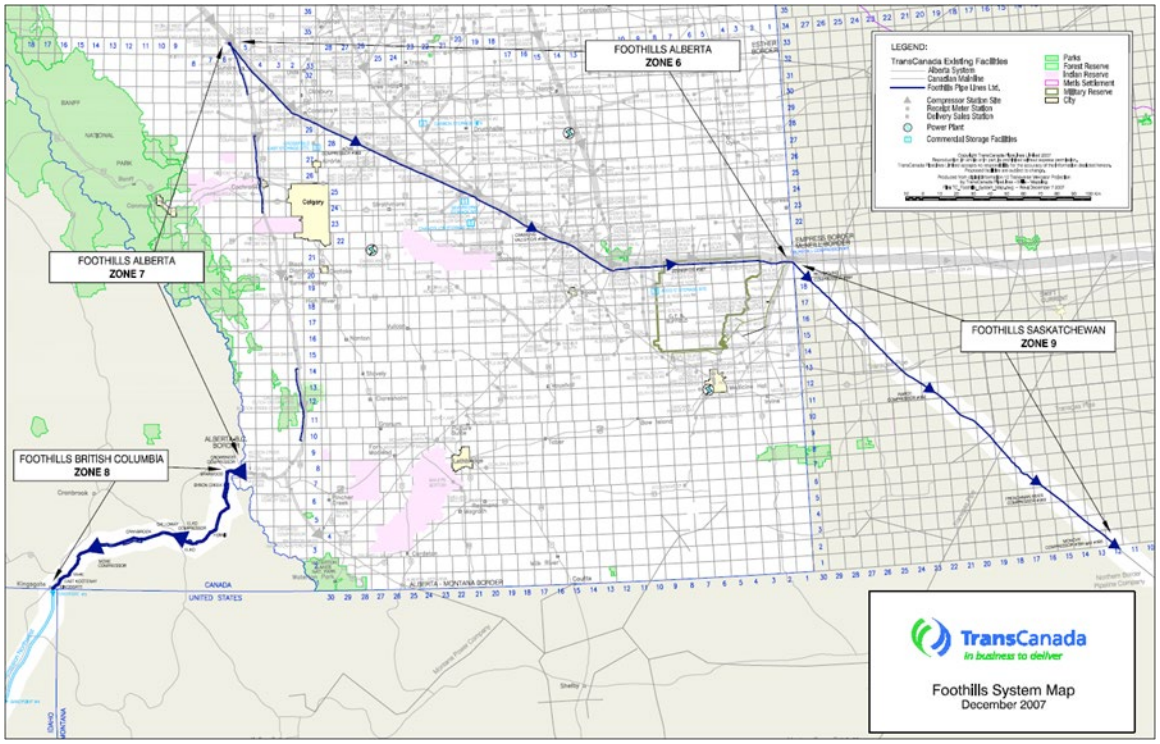


Figure 12-6: Map – GTN System Map

Location	DRN	Mile Post
Kingsgate	3498	0.00
Moyle Springs	198186	22.00
Bonners Ferry	3503	27.04
Schweitzer	159304	55.50
Sandpoint	3496	59.26
Dover Bay	634335	61.14
Sagle Sales	769368	65.22
Athol	160164	84.77
Rathdrum City	3539	97.64
Rathdrum Gen Tap	160138	97.64
Lancaster	314085	99.78
Chase Road Delivery	1389605	102.50
Spokane City	28203	108.29
Spokane Summary	28201	108.29
Mica	28204	121.15
Spangle	28205	134.18
Rosalia	28245	145.71
St. John	28246	158.89
Palouse	217745	172.07
Lacrosse	28247	182.79
Kosmos Farm	159305	271.66
Stanfield	18503	277.37
Stanfield City	18505	282.76
Calpine H.P.P.	314578	282.88
South Hermiston	217744	289.83
CSBRR	198185	304.22
Coyote Springs	198184	304.23
Coyote Springs 2	314579	304.24
Carty	140177	319.50
Carty Generating Station	1401645	319.60
ThreeMile Road Dairy D	21748	319.70
ThreeMile Road Dairy R	21749	319.70
Logan International	217723	304.25
Carty	1401645	324.30
Madras	18430	410.16
Prineville	18432	426.80
Redmond	18402	438.30
Pronghorn Tap	360889	445.80
North Bend	233740	450.28
Bend	18403	454.51
South Bend	217724	457.50
Stearns	18404	469.19
Lapine	159307	483.90
Gilchrist	18437	500.97
Chemult	18440	519.44
Harpold Sales	1402105	599.23
Kingsley Field Tap	473654	599.26
Klamath CoGen	288499	599.27
West Klamath Tap	198183	599.28
Klamath Expansion	311972	599.29
Phoenix Medford	198182	599.30
Turquoise Flats	1049174	609.80
Tuscarora/GTN Interconnect	190094	609.80
Malin	1820	612.46

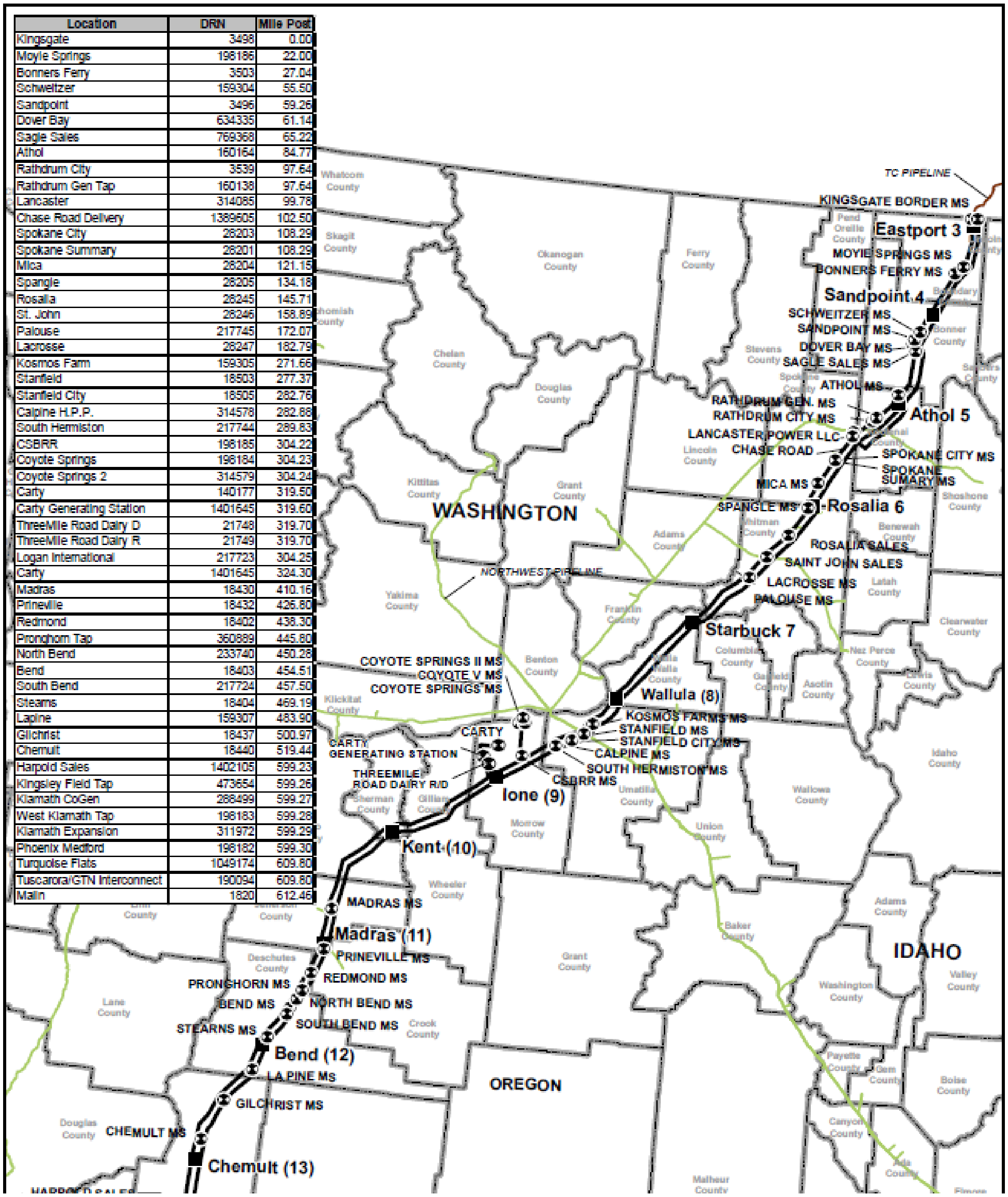
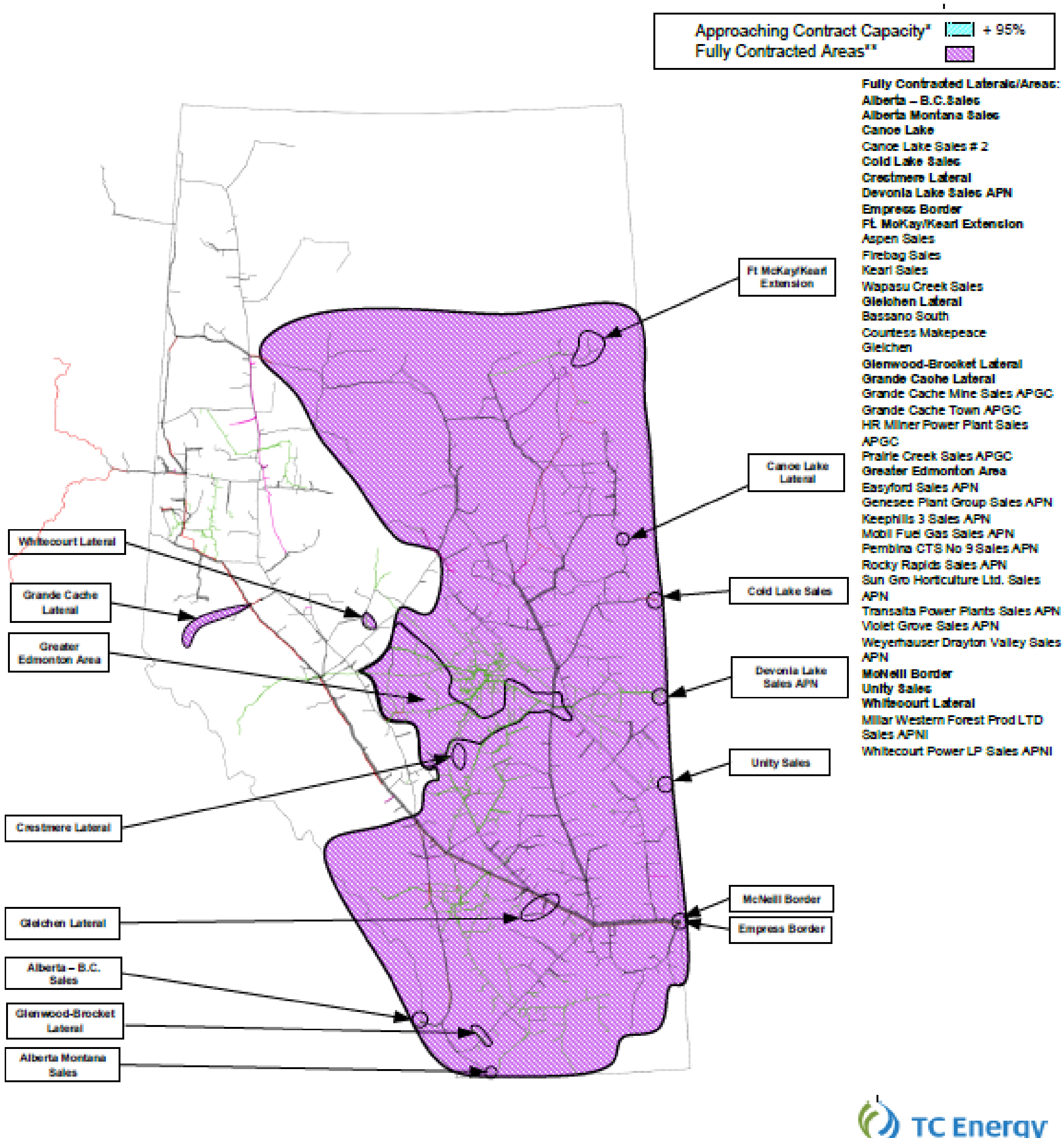


Figure 12-7: Map – NGTL Delivery System Map

TC Energy's NGTL System FT-R Availability Map
for May 2020

Note: The areas identified on this map are either Approaching Contract Capacity or Fully Contracted (see definitions below). This information is a snap shot as of May 4 2020 and is subject to change. Please contact your Customer Account Manager for clarification or additional information.



Approaching Contract Capacity*	Contracts are greater than 95% of the area or facility capability. It is recommended that Firm Transfers or New Firm Contracts be confirmed with TCPL Customer Sales.
Fully Contracted**	Area is fully contracted. Firm Transfers allowed within restricted area; upstream at 1 to 1 ratio and downstream at determined hydraulic equivalence. New requests for Firm Transportation service will be held pending availability of Area capacity. For additional information refer to the Informational Postings on Customer Express, Project Area Receipt and Delivery Capacity Update. Last Updated: May 4 2020
Capacity within any portion of the NGTL System can become fully contracted at any time and without prior notice. NGTL encouages customers to review their FT-D requirements to ensure that their FT-D levels align with their expected flow requirements.	

Figure 12-8: Map – NGTL Receipt System Map

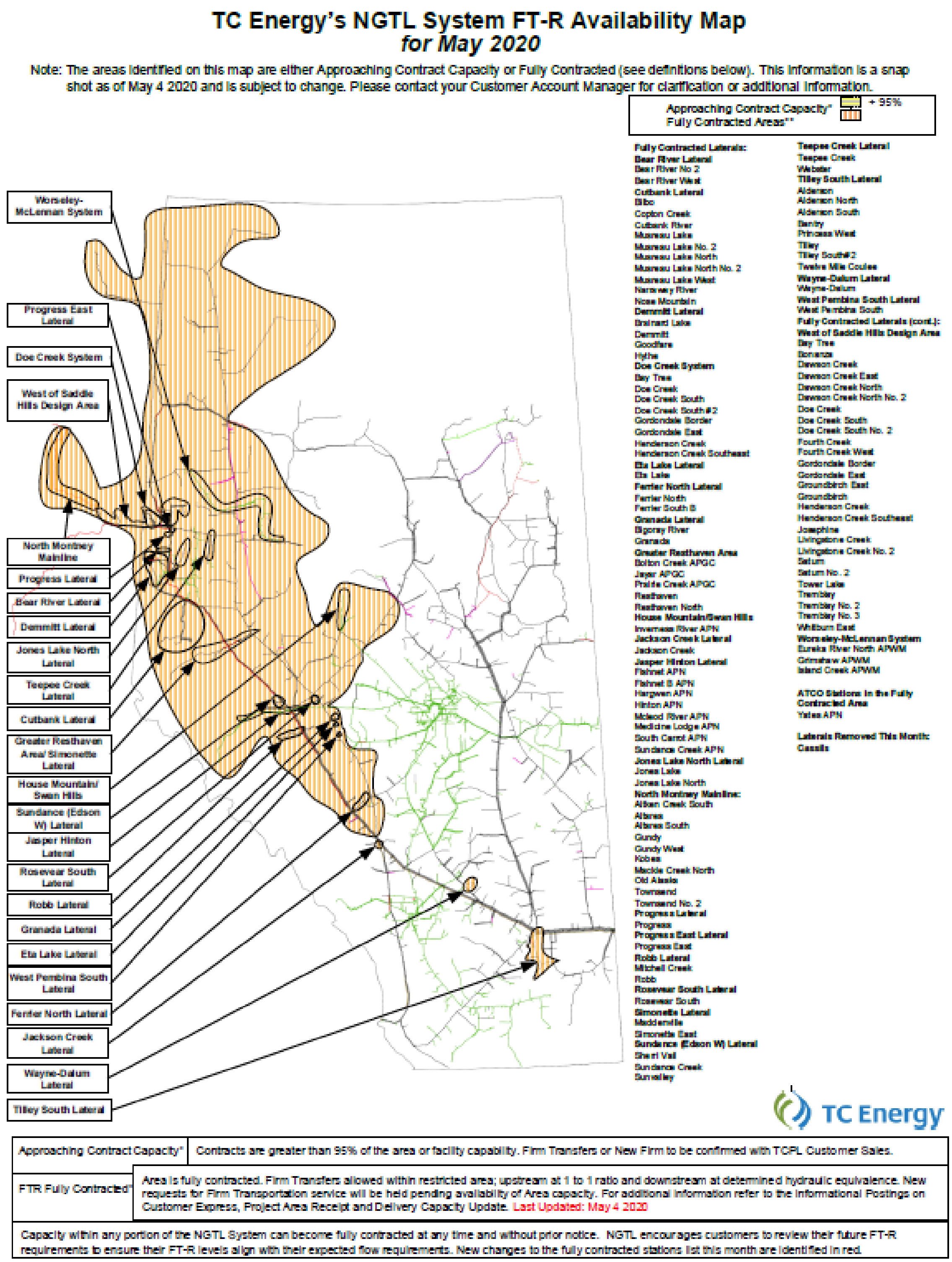


Figure 12-9: Map – NWP North System Map

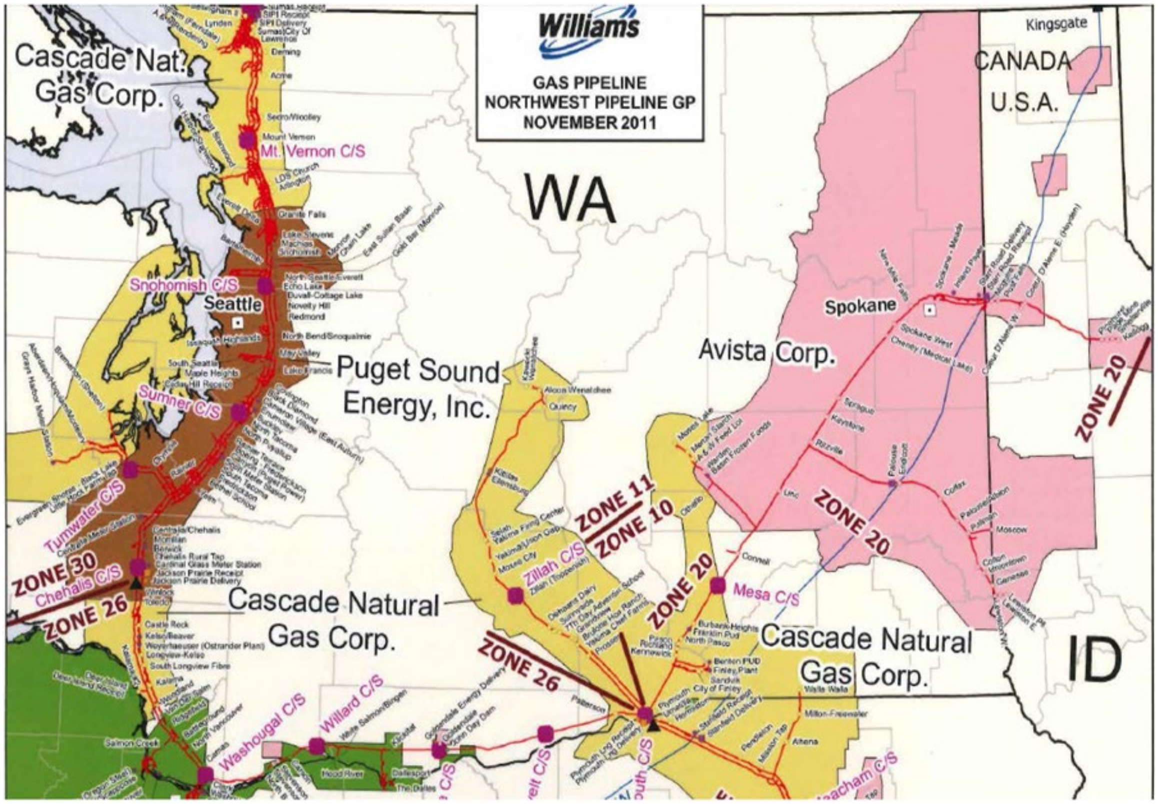


Figure 12-10: Map – NWP South System Map

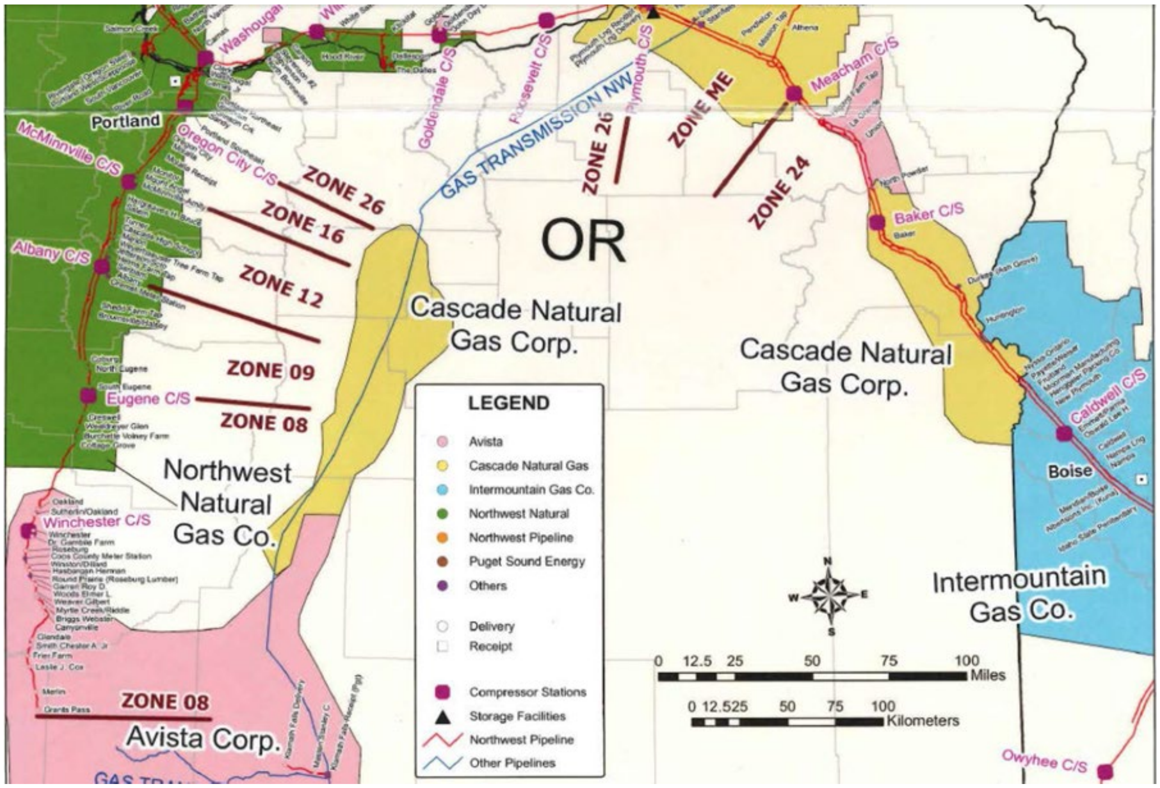


Figure 12-11: Map – Westcoast Sectional Map

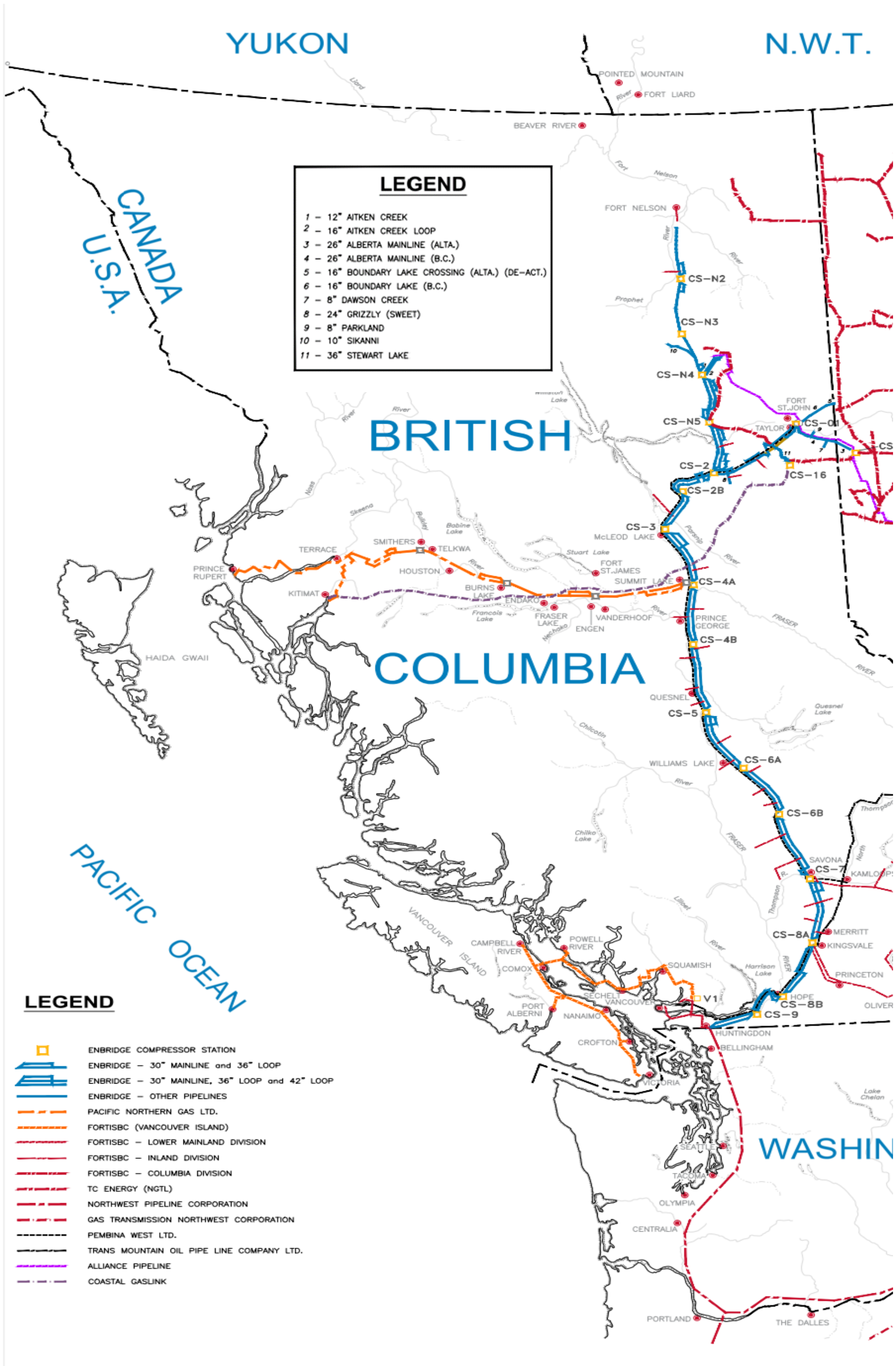


Figure 12-12: Map – Western U.S. and Canadian Pipeline Map

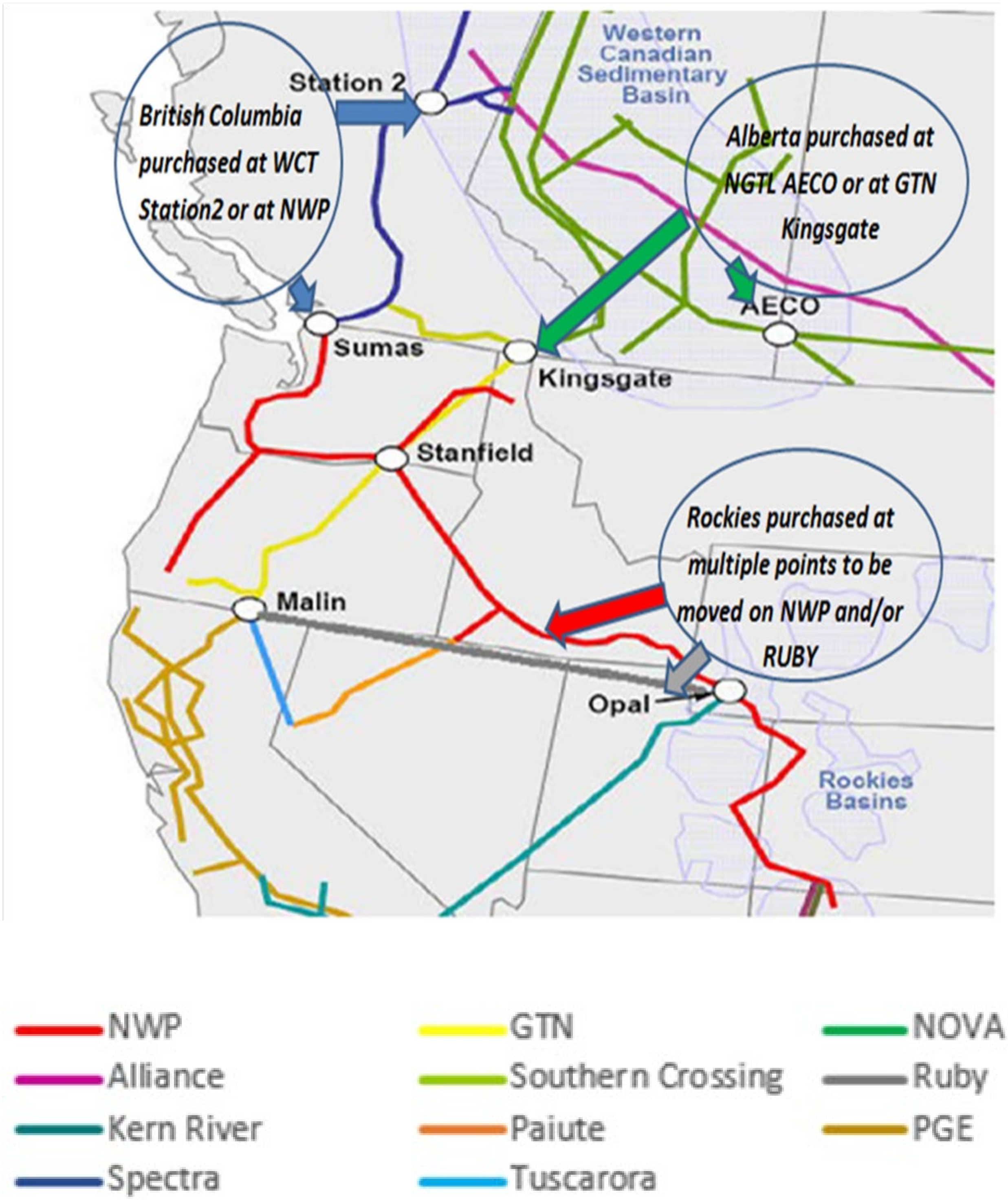


Figure 12-13: Map – Certificated Service Areas as Specified in RCW 80.28.190

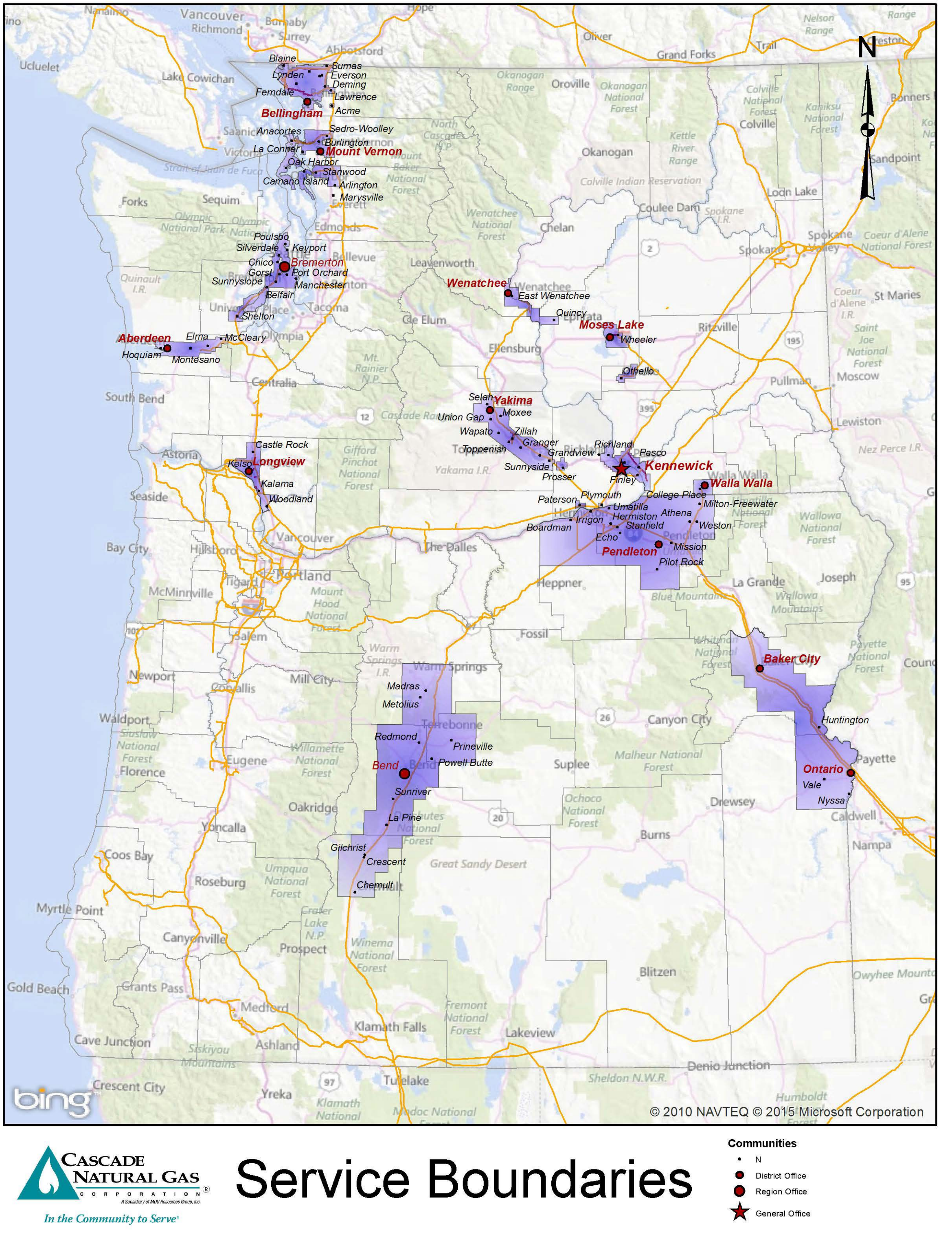


Figure 12-14: Map – Pipeline Transportation Capacity Usage

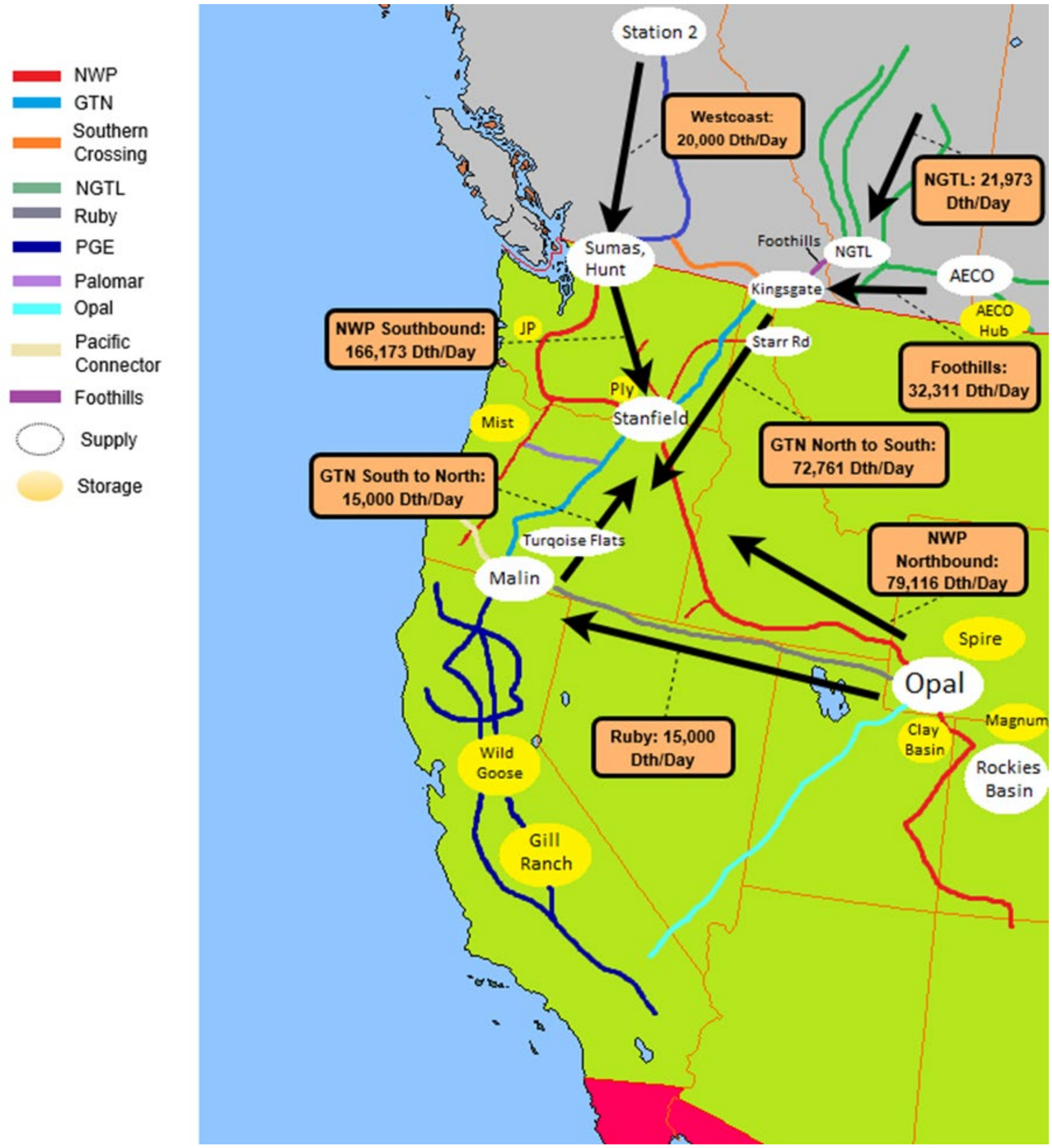


Figure 12-14: Map – Washington Conservation Zones

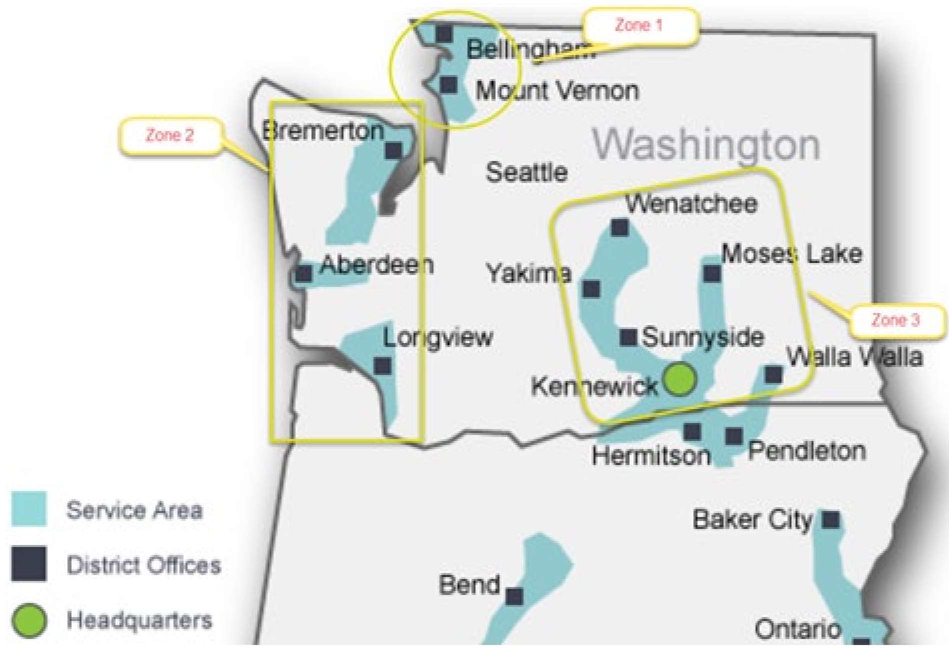


Figure 12-15: Locations of Faster Growing Citygates