CASCADE NATURAL GAS CORPORATION

A Subsidiary of MDU Resources Group, Inc.

In the Community to Serve®

2020
Integrated Resource Plan

July 31, 2020

CASCADE NATURAL GAS CORPORATION
2020 INTEGRATED RESOURCE PLAN
TABLE OF CONTENTS

CHAPTER 1

EXECUTIVE SUMMARY

Introduction

Key Points

- Cascade's first material deficiency occurs in 2023.
- The Company's four-year action plan provides the road map for resource acquisition.
- Load growth is forecasted average 1.26% per year over the 20-year planning horizon.
- Cascade modeled Cap and Trade as its main carbon forecast.
- The total avoided cost ranges between $0.26/therm and $1.11/therm over the 20-year planning horizon.
- Cascade projects 12.09 million therms of energy efficiency in Oregon over the 20-year planning horizon.
- This plan was informed by five Technical Advisory Group meetings, with active engagement by stakeholders.
- Cascade continues to be fully committed to the IRP process.
- Each chapter provides an *at-a-glance* summary of the key points.

Cascade Natural Gas Corporation's (Cascade, CNGC, or the Company) Integrated Resource Plan (IRP or Plan) forecasts 20 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 2020 through 2039. While the Plan cannot predict the future, it is a useful guide. Below is 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.

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 299,000 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 useful for both long- and short-term planning. The Company initiates 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.

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.

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

Load growth across Cascade's system through 2039 is expected to fluctuate between 0.78% and 1.80% 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 1.66% and 0.91%, respectively, while industrial expects a growth rate of around 0.51%.

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 exceed 434 million therms in 2039. Residential customers are expected to grow from 54.5% of the total core load to 57% of the total core load by 2039.

Load across Cascade's two-state service territory is expected to increase 1.26% annually over the planning horizon, with the Oregon portion outpacing Washington at 1.58% versus 1.15%.

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 areas of North America: British Columbia, Alberta, and the Rockies. The Company secures its gas through firm gas supply contracts and open market purchases.

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 and Plymouth 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 facilities and the Plymouth facility are located directly on NWP's transmission system. In addition, Cascade has leased Mist storage from NW Natural. The Mist facility located in Columbia County, near Mist, OR. 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.

Thereafter, to determine the low case and high case, the Company utilized the EIA economic growth factors which are 1.5 for the Low Case, 2.0 for the Reference Case, and 2.6 for the High Case.[1]

Besides currently used resources, Cascade considered alternative resources. Other potential incremental capacity options evaluated included: NWP Proposed Bremerton-Shelton Realignment, 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), Wild Goose Storage.

Cascade also considered unconventional supplies such as satellite LNG, renewable natural gas, and the realignment of its Maximum Daily Delivery Obligations (MDDOs) on NWP.

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

[1] EIA 2018 Annual Energy Outlook

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 Hedging Plan, 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, 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 $21.13/metric ton in 2020 and capping at $61.50/metric ton from 2030 onward. 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 commodity portion of the avoided cost to account for nonquantifiable, environmental benefits. This 10% adder was first recommended by the Northwest Power and Conservation Council (NWPCC) based on Federal legislation.

New to the 2020 IRP, Cascade has included distribution system costs in its avoided cost calculation. Distribution system costs capture the costs of sending gas from the citygate to Cascade's customers. For this IRP cycle, Cascade calculated distribution system costs as the Company's system weighted average of its authorized margins, as approved in UM-1893. These costs are inflated by the Consumer Price Index (CPI) escalator every year.

For the 2020 IRP, the nominal system avoided costs ranges between $0.26/therm and $1.11/therm over the 20-year planning horizon. The increase over time is largely driven by the escalating cost of carbon.

Chapter 6: Demand Side Management & Environmental Policy

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 62 million therms system-wide over the 20-year planning horizon; 12.09 million therms in Oregon and 50 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. The levelized costs per measures in the 2020 IRP's cost-effective achievable potential are slightly higher than they were in the 2018 IRP for two reasons: 1) The therm savings targets in this IRP include savings from non-cost-effective measures that the Commission is allowing the Energy Trust to incent; and 2) The price of gas has decreased over the last two years.

The program savings projections included in this IRP are also slightly higher than those presented in the Company's 2018 IRP for the following reasons: 1) New measures were considered in the analysis; 2) Measure assumptions were updated based on more current data; 3) Emerging technologies were included in the analysis; and 4) Updated measure saturation rates from third-party research and survey work were used.

Chapter 6 also considers environmental policies being both enacted and considered in Oregon, Washington, and nationally. A number of initiatives intended to reduce, eliminate, or mitigate the effects of greenhouse gases on the atmosphere are in play. Carbon legislation is a reality, as both Oregon and Washington have begun adopting carbon regulations.

The Company follows all carbon related initiatives closely as policy changes will impact the natural gas retail business in some way. A carbon tax will raise customers' prices: initiatives such as Portland's goal of being 100% renewable by 2050, or Ashland's and Eugene's plans to reduce carbon emissions, and may reduce natural gas usage. Carbon policies will also increase the Company's avoided costs thus increasing cost-effective energy savings potential. Policies addressing climate change are likely to impact all factors in integrated resource planning (e.g., demand forecasts, pricing, and DSM potential) and, therefore, must be closely monitored.

Chapter 7: Renewable Natural Gas

Renewable Natural Gas (RNG) has been introduced as its own chapter for the first time in this 2020 IRP. With there being a strong desire to mitigate the carbon footprint of the natural gas industry, the amount of information covered on RNG warranted a separate chapter. Cascade has been involved and committed to developing programs that follow RNG guidelines and rules stated in SB 98 and HB-

1257.

The Company has met with several individuals and companies within the RNG industry such as producers, municipals, wastewater treatment plants, biodigesters, and landfills. Currently, none of the projects have a timeline to implement putting RNG on the system in the near future. The Company will file an update in the 2021 Annual IRP Update.

Cascade has developed a potential RNG cost effectiveness methodology. Cascade is also utilizing SENDOUT® as another model for analyzing RNG. Cascade will continue to monitor RNG guidelines and rules and incorporate any necessary changes to these models.

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 conservation. 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 three sample projects and Appendix I lists all known distribution projects.

Chapter 9: Resource Integration

Cascade utilizes SENDOUT® for resource optimization. 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 SENDOUT® provides helpful but not perfect information to guide decisions.

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. 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.

Even after the savings from energy efficiency programs are realized, Cascade will need to acquire additional capacity resources or enter into other supply arrangements to meet anticipated peak day requirements, primarily due to continued growth in the Company’s residential and commercial customer base. Utilizing the SENDOUT® resource optimization model, several portfolios were run to test the viability of acquiring incremental storage and transportation resources based on existing recourse rates and discounted rates, and via capacity release through a third party. Basin prices in the model over the 20-year planning horizon have AECO trading at a discount to Rockies, Malin, and Sumas. The acquisition of additional traditional pipeline capacity is the most reasonable resource to address most capacity shortfalls on a peak day.

Using input from these alternative resources, SENDOUT® derives a portfolio of existing and incremental resources that Cascade defines as the Preferred Portfolio. This provides guidance as to what resources should be considered to reduce unserved demand with a reasonable least cost and least risk mix of demand and supply side resources under expected pricing, weather, and growth environments.

Twenty-year portfolio costs under a multitude of scenarios/sensitivities are expected to range between $4,067,388,000 to $4,627,197,000 for the planning period, with an average cost per therm ranging between $0.5232 and $0.5478.

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. One meeting was held in Bend. Participants invited to these public meetings include interested customers, regional upstream pipelines, Pacific Northwest Local Distribution Companies, Commission Staff, stakeholder representatives such as the Northwest Gas Association, Public Counsel, Citizens' Utility Board, Oregon Department of Ecology, and the Alliance of Western Energy Consumers. Cascade has a dedicated internet webpage where customers and parties can view the IRP timeline, TAG presentations and minutes, 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 Four-Year Action Plan. Further descriptions can be found in Chapter 11, Four-Year Action Plan.

Figure 1-1: Highlights of 2020 Action Plan

Functional Area	Anticipated Action	Timing
Resource Planning	Cascade will: • attend other regional LDC IRP meetings; • work with NWP on realigning MDDOs; • determine if the temporary Jackson Prairie contract should be made permanent; • develop modeling scenarios that represent Pipeline OFOs; • improve the alignment of resource/costs between the PGA and the IRP; • develop more scenarios that address changing Canadian Markets; • add RNG as a candidate portfolio; and • work with Staff and Stakeholders to develop a more effective presentation for the severity of negative outcomes. Cascade will report on the status of this action item when filing the 2021 OR IRP Update.	Ongoing, for inclusion in 2022 IRP.
Demand	Cascade will look into making adjustments to a few methodologies on the demand forecast and scenarios. Those adjustments include: • Adding wind in the stochastic weather analysis; and • A new methodology for peak day.	Ongoing, for inclusion in 2022 IRP.
Environmental Policy	Cascade will either begin or continue to participate/monitor the following items: • Continue to support the City of Bend's Climate Action Plan; • Participate in City of Bellingham Climate Action Plan discussions; • Monitor service areas for potential GHG reduction goal development relating to energy delivery and supply; • Monitor carbon pricing and policy developments nationally and statewide; • Monitor federal and state GHG regulation development for energy industry; and • Continuation of current emission reduction and monitoring endeavors.	Ongoing, for inclusion in 2022 IRP.
DSM (Energy Efficiency)	The Company will execute the Demand Side Management action items as described on page 11-3 and 11-4.	Ongoing, for inclusion in 2022 IRP.
Renewable Natural Gas	Cascade will continue to develop and update the cost-effective evaluation tool.	Ongoing, for inclusion in 2022 IRP.
Distribution System Planning	These projects are budgeted over the next five years: • FP-306990 - PENDLETON 4" IP REINFORCEMENT • FP-306991 - PENDLETON 4" HP REINFORCEMENT • FP-306992 - PENDLETON KORVOLA ROAD 4" • FP-316851 - South Hermiston to Feedville • FP-316854 - BEND GATE REBUILD • FP-316863 - Prineville Gate Rebuild • FP-317586 - RF-REDM-6"S-4,750'-VETERANS WY • FP-318466 - RF-Baker-GT-NW Baker Gate • FP-318468 - RF-Baker-GT-NW Baker Regulation • FP-318469 - RF-Baker-GT-NW Baker Gate Odorizer • FP-318475 - RF-Baker-GT-NW Baker GT Line • FP-318682 - RF-BEND-6"S-1100'-SHEVLIN PK • FP-318733 - RF-BEND-6"S-2MI-SHEVLIN PK • FP-318737 - RF-BEND-R-SHEVLIN PK RD 2" • FP-318741 - RF-BEND-6"PE-1200'-PONDEROSA ST • FP-318744 - RP-PRINEVILLE-GT-TRANSCANADA • FP-318745 - RP-BEND-GT-TRANSCANADA • FP-318770 - RF-REDM-R-VETERANS WAY-2" STD	Ongoing over the next five years.

Chapter 2

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 represent 25% of total throughput, while non-core customers represent 75% of total throughput.
- Cascade is a subsidiary of MDU Resources Inc., based in Bismarck, North Dakota.

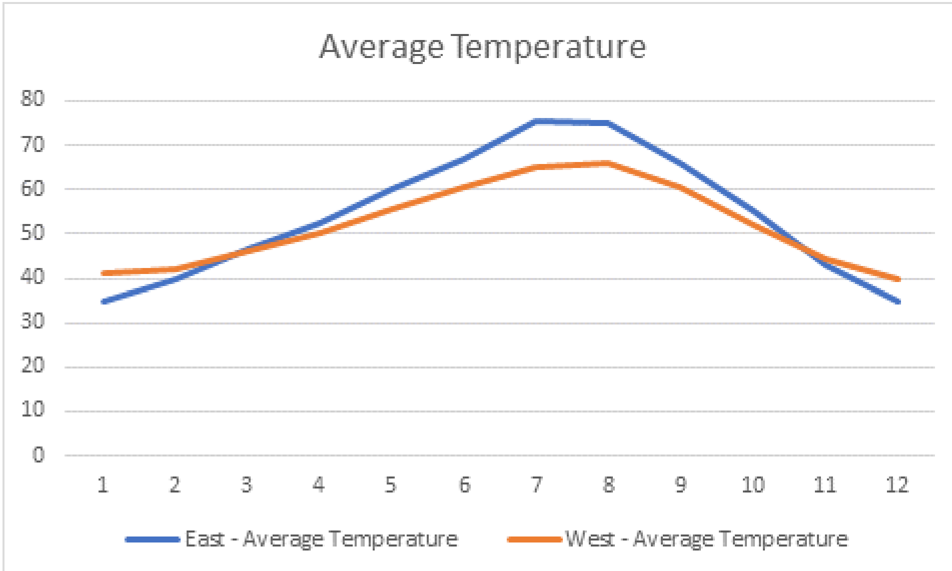
Company Overview

Cascade Natural Gas Corporation (CNGC or Cascade or Company) has a rich history that began 67 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 purchasing other utility 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. 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 299,000 customers with approximately 77,000 customers in Oregon and 222,000 customers in Washington. The Company's customers reside in 96 communities--28 in Oregon and 68 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 the service territory is almost as diverse as its geographical extension. Oregon's service territory is in rural areas throughout northern central and central Oregon as well as eastern Oregon. All regions or Oregon have semi-arid climates with periods of arctic cold in the winter and heat waves in the summer. 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.

Figure 2-1: Average Temperature by Region

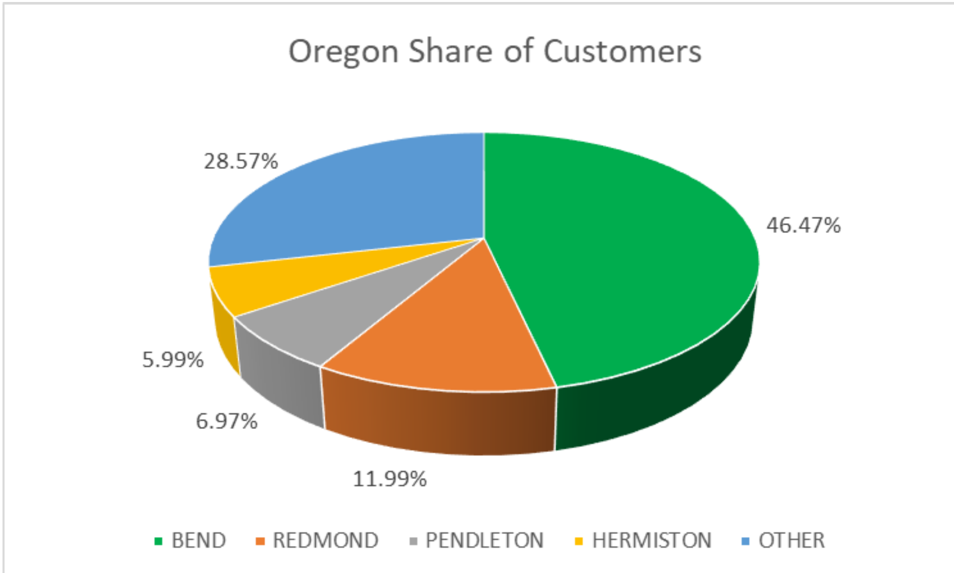


Below are some of the more populated towns within the regions Cascade provides distribution service:

- **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 Oregon customer density by town. A map of Cascade's certificated service territory is provided as Figure 12-13 in Chapter 12, Glossary and Maps.

Figure 2-2: Customer Density by Town



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 (WCT) provides British Columbia gas directly into the Company's distribution system. Cascade also holds upstream 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 12.

Core vs Non-Core Service

Cascade offers core service, which is the procurement of gas supply from an upstream basin, 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.[1] These customers, referred to as large volume transportation or non-core customers, procure the distribution of their gas supply from Cascade from citygate to the point of delivery at the customer's site. The Company currently has approximately 245 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 upstream resource analysis of its Integrated Resource Plan (IRP). Non-core demand is a consideration in distribution planning. While it is not the core substance of the IRP, it is included in Chapter 8, Distribution System Planning.

As of fourth quarter 2019, Cascade's residential customers represent approximately 13% of the total natural gas delivered on Cascade's system, while commercial customers represent roughly 10%, and the approximately 500 core industrial customers consumed around 2% of total gas throughput. The remaining non-core industrial customers represent the balance of the 75% 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 serve more than one 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.

[1]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

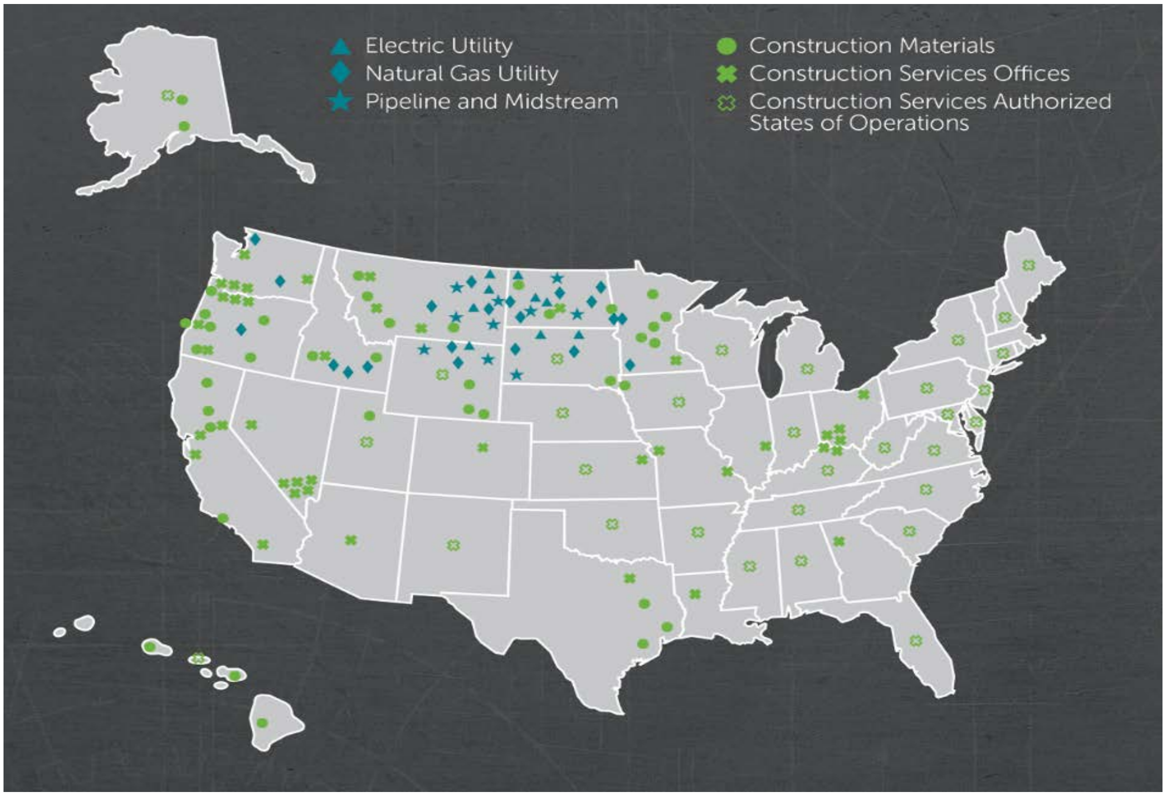
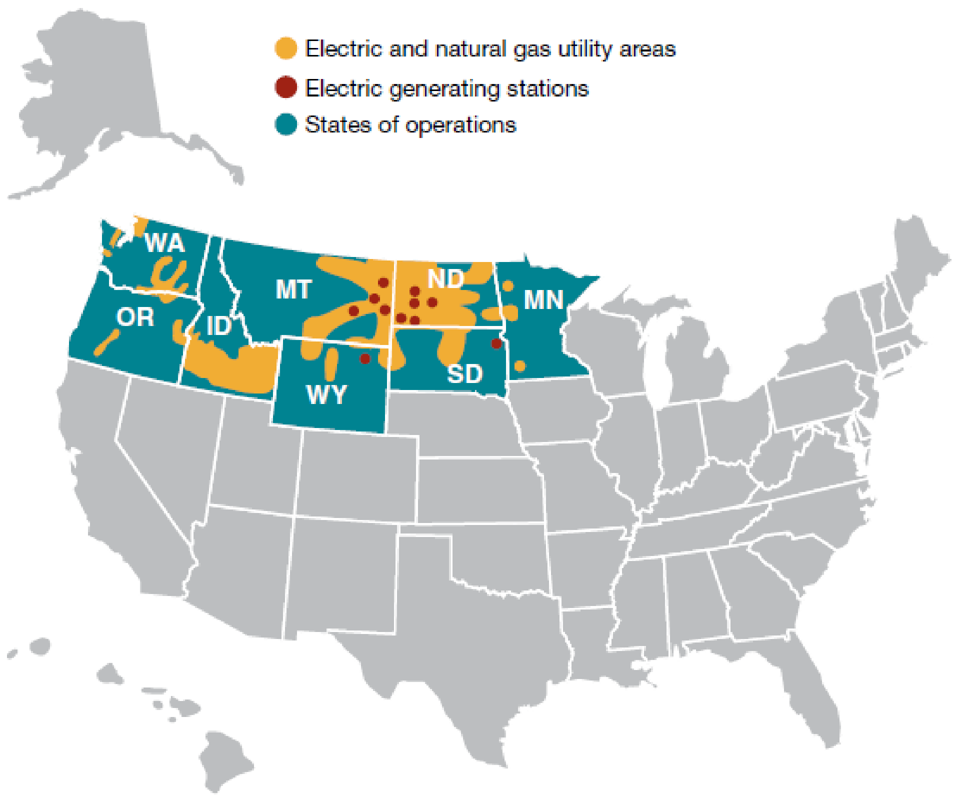


Figure 2-4: MDU Resources Electric and Natural Gas Services and Territory



CHAPTER 3

DEMAND FORECAST

Overview

Key Points

- Cascade initiates its forecast with analyses of demand area, weather, and HDDs.
- Peak day is analyzed deterministically with coldest day in 30 years, and stochastically using 10,000 Monte Carlo simulated draws.
- Cascade uses a 60 °F reference temperature to calculate HDDs.
- 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 1.26% per year over the 20-year planning horizon.
- Uncertainties in the future may cause differences from the Company's forecast.

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. Sources of this forecast include historic data, market intelligence, 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 Demand Side Management (DSM) resources, revenue budgeting, and load forecasts associated with the purchased gas cost process.

Demand Areas

For the 2020-2039 planning horizon, Cascade forecasted at both the citygate and rate class levels. This is a change of methodology from previous years when certain models were built from the district or zonal level. 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, twenty are grouped into eight different citygate loops. Therefore, Cascade forecasts a total of 55 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		Redmond	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		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

Historical weather data is provided by a contractor, Schneider Electric. Historically, Cascade has accessed data from NOAA (National Oceanic and Atmospheric Administration), but found many months/locations with missing data. The current forecast uses 30 years of recent history as the normal or expected weather. The forecast model takes the 30 previous years, converts the data to heating degree days (HDDs), then averages the HDDs into average days to create a normal or expected year. Cascade has seven weather locations with four located in Washington and three in Oregon. The three locations in Oregon are Baker City, Pendleton, and Redmond.

Heating Degree Days

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. The historical threshold for calculating HDD has been 65 °F. However, when modeling gas demand based on weather, Cascade has determined that lowering the threshold to 60 °F produces more accurate results for the Company's service area. Figures 3-2 and 3-3 illustrate why the lower threshold is preferable. These figures show that heating demand does not begin to increase significantly until an HDD of five (65 °F minus 60 °F) is reached, if the traditional HDD threshold of 65 °F is utilized. Lowering the HDD threshold improves the R^2 statistic, thus giving a better measure of the relation between HDD and therms (measurement of heat usage). Cascade ran a cross-validation analysis to compare the forecast with actual weather and customer counts in the regressions (e.g. 2011 customers, with 2011 weather, to cross-validate 2011). When comparing, using a 65 °F reference temperature, the cross-validation analysis had a mean absolute percentage error (MAPE) of 14.9%. When using a 60 °F reference temperature, the MAPE improved to 7.62%.

Figure 3-2: Acme Therm/HDD with 65°F Reference Temperature

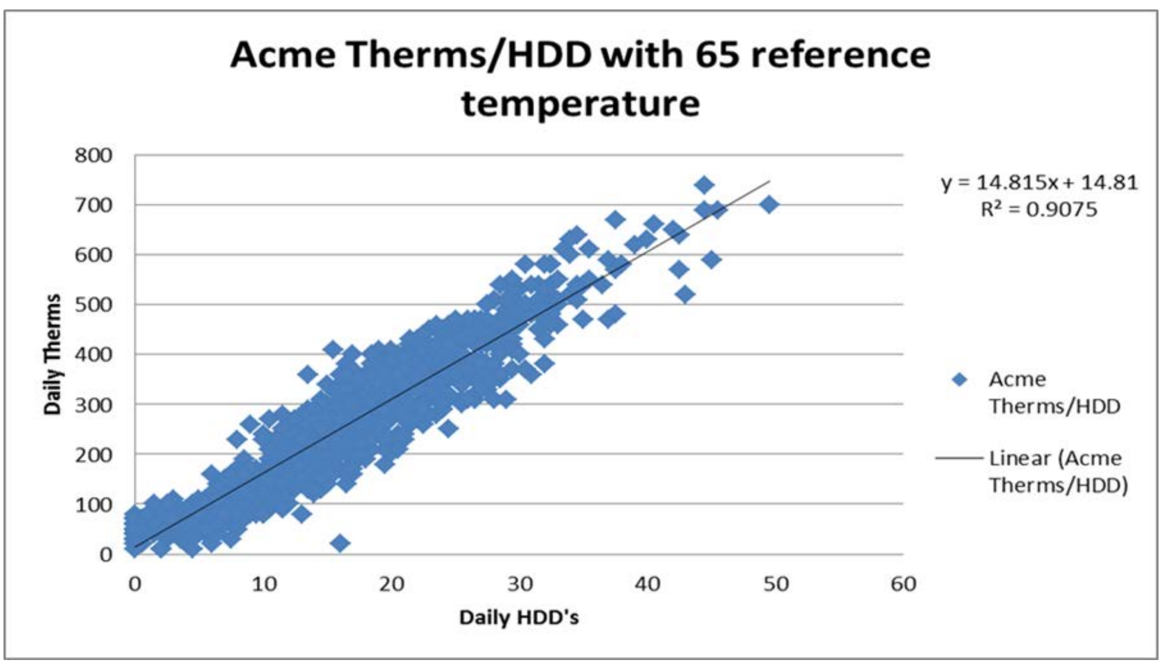
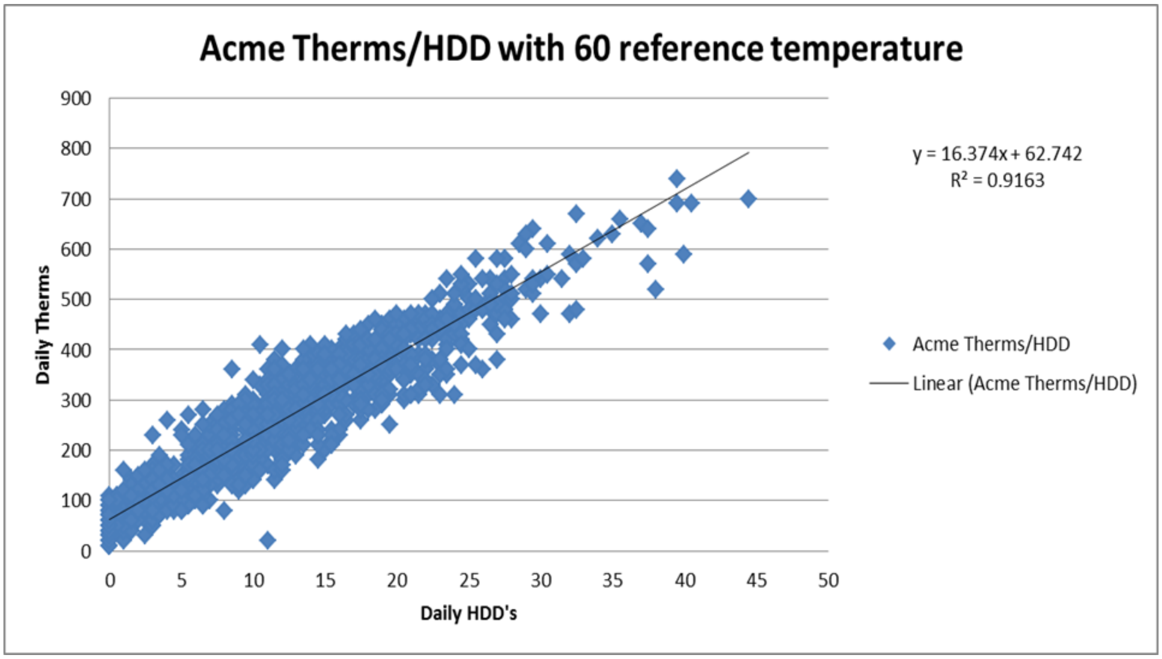


Figure 3-3: Acme Therm/HDD with 60°F Reference Temperature



Peak Day HDDs

In order to ensure satisfaction of core customer demand on the coldest days, Cascade develops a deterministic and a stochastic peak day usage forecast in conjunction with annual base load forecasts. 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 deterministic peak day that was analyzed in the forecast model is a system-wide weighted HDD coldest in 30 years value.

This peak day will give Cascade the deterministic outcome with varying amounts of demand. The deterministic peak HDD methodology allows Gas Supply to plan for the highest peak event during a heating season.

System-wide maximum peak HDDs are determined by first selecting the system-wide single coldest day recorded in the past 30 years. To determine the system-wide single coldest day, HDDs from all seven weather stations are considered, giving appropriate weight to the weather stations. The weights are determined by the increase in demand experienced with an increase in one HDD. Cascade has found December 21, 1990, to have the highest, system-weighted HDD, at 56 HDDs for this period.

For SENDOUT®, Cascade uses the system-wide maximum peak HDDs method. Cascade applies the HDDs experienced on December 21, 1990, to each of the regressions in the forecast model. For example, all citygates associated with the Yakima weather station use the HDD for Yakima on December 21, 1990, and similarly for all the other weather stations and citygates. This provides a highest demand scenario for peak demand load based on 30 years of weather history for each citygate. Applying December 21, 1990, weather temperatures to today's forecast methodology gives Cascade an accurate representation of the demand the Company could expect to experience if this weather happened during the planning horizon.

Cascade is actively expanding its peak day methodology to include stochastic elements such as Monte Carlo analysis. More on this peak day analysis can be found on page 3-11. Cascade will also continue to investigate how various peak day standards affects the core demand load areas which are short of capacity. This investigation will include (but not be limited to) analysis of how other regional utilities look at peak day, discussions with the various weather services, and continued dialogue with Commission Staff and other interested parties.

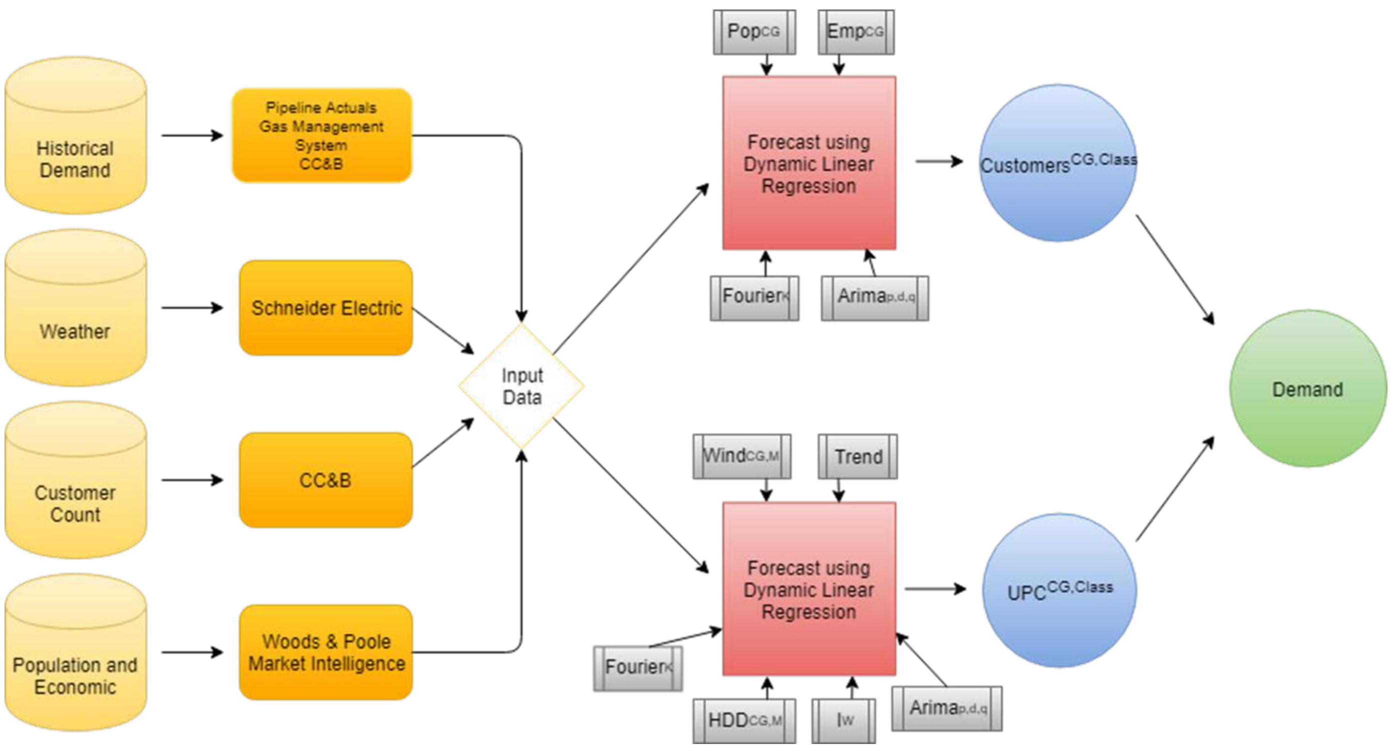
Wind

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.

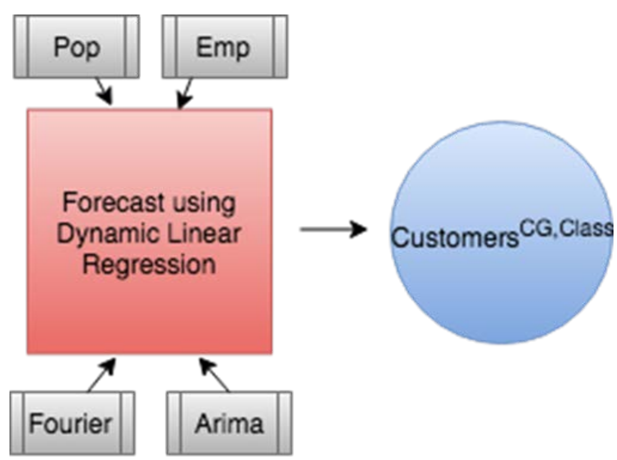
Demand Overview

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). 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 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:

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

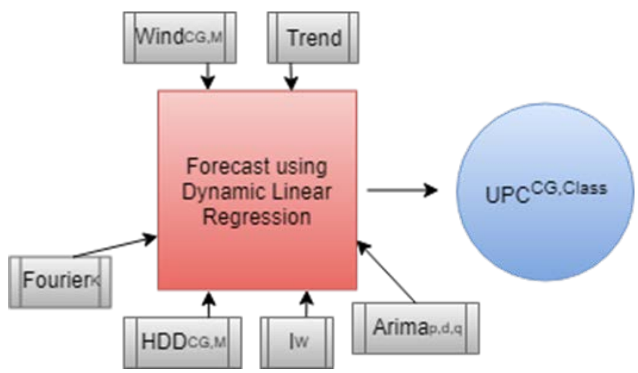
Cascade runs this model approximately 200 times to account for each customer class by citygate. The Company begins by testing seven different combinations of the regressors in both dynamic regression models and one Autoregressive Integrated Moving Average (ARIMA) model. The dynamic regression models 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 0.85% between 2020 and 2039 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.

Among other reasons, the Company believes that growth in the following regions will be a major factor in any forecasted system-wide deficiency:

- Bend, Oregon – According to Portland State University's (PSU) Population Research Center, the city of Bend is estimated to have an average annual growth rate of 10.22%. This is credited to factors such as job growth, increases in ratios of full-time to part-time jobs, poverty rates decreasing, and others. A study by a personal finance website called WalletHub found Bend to be the 3rd fastest growing city in the U.S. [1]
- Redmond, Oregon - The city of Redmond seems to be absorbing much of Bend's rapid growth. With a lower cost of living and a strong job market, Redmond is boasting an annual average growth rate of 10.14%, according to PSU's Population Research Center. [2]
- Tri-Cities, Washington – According to Washington's Office of Financial Management's data released in June 2019, Benton and Franklin counties were the fastest growing counties in the state between 2018 and 2019. These counties are growing at an impressive 2.2% and 2.3%, respectively, between 2018 and 2019. This rapid growth is credited primarily to net migration (people moving in versus people moving out). [3]

Use-Per-Customer (UPC) Forecast Methodology



As previously mentioned, Cascade utilizes regression models for the UPC part of the demand forecast as well. Sources for the inputs into this model are pipeline actuals, Cascade's gas management system, and Cascade's Customer Care and Billing System (CC&B). Cascade developed the UPC coefficient by 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 daily core usage data. The daily data is then allocated to a rate schedule for each citygate by using CC&B. This data is then 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:

$$\frac{Therms}{C_{Class}^{CG}} = \alpha_0 + \alpha_1 HDD^{CG,M} + \alpha_2 I_w + \alpha_3 T + \alpha_4 WIND^{CG,M} + Fourier(k) + ARIMA(p,d,q)$$

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[1] https://wallethub.com/edu/fastest-growing-cities/7010/
[2] https://www.oregonlive.com/news/erry-2018/05/3772ef0a5e1889/how_fast_is_each_oregon_city_g.html
[3] https://www.tricitiesbusinessnews.com/2019/06/2019-population-growth/

Model Notes:

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

Cascade runs this model for each of the 55 citygates and citygate loops by customer class where applicable, resulting in approximately 200 models. Cascade starts with the above model for Residential, Commercial, and Industrial customer classes. A change in methodology from previous IRPs involves keeping variables in the model that may appear non-significant on a statistical level but relevant on an economic level. This could be a shoulder month, i.e. September, showing insignificance in a model but economically known to affect the annual load shape of residential customers. Also, Cascade now runs the UPC forecast with Fourier and ARIMA terms.

Peak Day Forecast Methodology

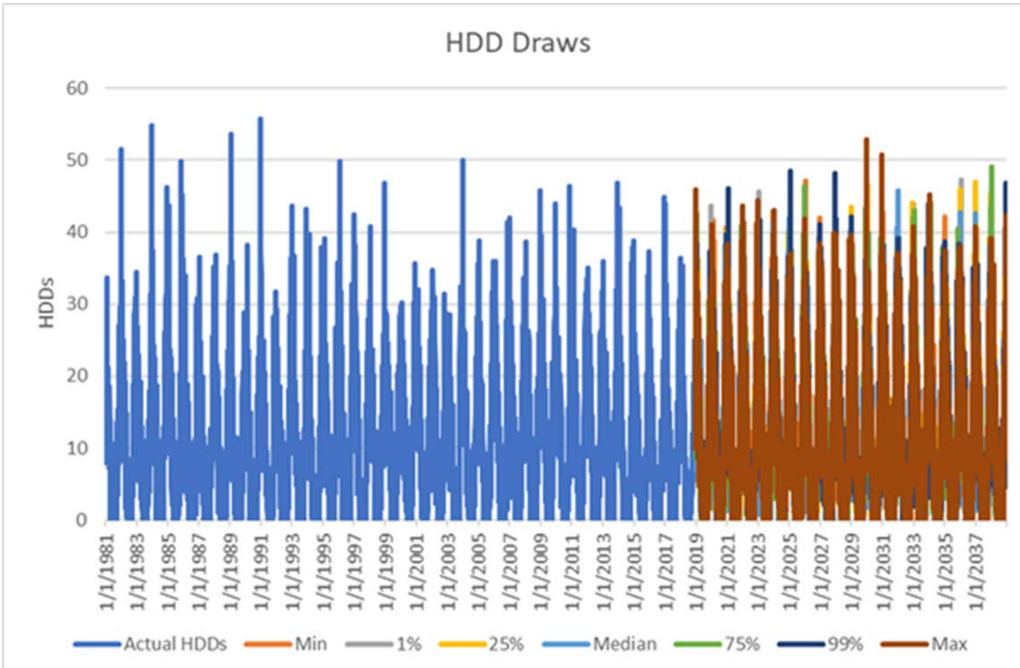
Cascade's methodology for peak day forecasting is similar to its forecast of demand. For a deterministic forecast, Cascade utilizes the same dynamic regressions as before but with a peak day HDD inserted. This peak day HDD comes from the coldest on record in the last 30 years. Once this peak day is inserted for every year of the forecast, Cascade deterministically derives a peak day usage forecast.

The Company also utilizes Monte Carlo simulation to stochastically analyze the peak day behavior. Through the statistical program R, Cascade runs 10,000 Monte Carlo draws in each weather zone, making sure to correlate the draws based on historical correlations between each weather zone. This results in 10,000 draws of various weather behavior based on historical averages, standard deviations, and correlations between weather zones. Further discussion regarding the Monte Carlo methodology can be found in Chapter 9, Resource Integration.

In this stochastic analysis, Cascade analyzed many attributes, including the minimum, the maximum, and percentiles such as the 1st, 25th, 75th, and the 99th. The 99th percentile is then used to calculate the Value-at-Risk (VaR) metric to compare with the VaR limits discussed in Chapter 9.

Figure 3-5 displays the historical weather data along with the Monte Carlo simulated weather forecast. The historical weather data represents actual HDDs. The 10,000-draw simulation includes the following draws: Minimum, 1%, 25%, median, 75%, 99%, and maximum.

Figure 3-5: Historical vs. Monte Carlo Simulated Weather



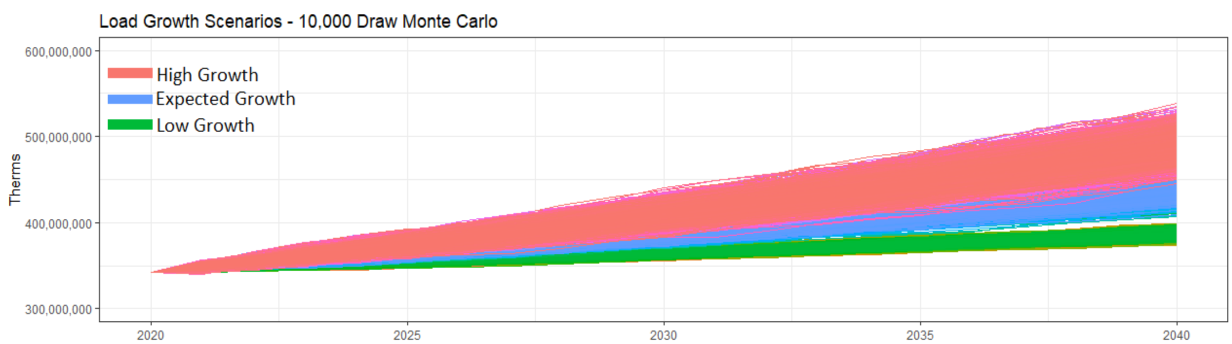
Scenario Analysis

Cascade stress tests the load forecast in SENDOUT® 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. Figure 3-6 identifies the list of scenarios. Figure 3-7 displays the scenario analysis over the planning horizon.

Figure 3-6: Growth and Weather Scenarios

Scenario	Weather	Growth	UPC
Base Case	Expected	Expected	Expected
Low Growth	Expected	Low	Expected
Low Growth Stochastic	Monte Carlo Weather	Low	Expected
High Growth	Expected	High	Expected
High Growth Stochastic	Monte Carlo Weather	High	Expected

Figure 3-7: Scenario Analysis Demand Forecast (Volumes in Therms)



The base case contains expected weather, customer growth, and use per customer. The base case also has one max peak day event for each weather zone. Expected weather is the average weather over the past 30 years. High and low growth scenarios, discussed more on page 3-17, explain that Cascade uses modifiers to represent higher than expected growth and lower than expected growth. The high and low growth stochastic scenarios are represented by the 10,000 red and green lines above in Figure 3-7. This provides a stochastic stress test of Cascade's growth scenarios. Stochastic tests such as these on demand are only to show how weather and/or growth can impact demand over the 20-year planning horizon. 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 9.

Forecast Results

Load across Cascade's two-state service territory is expected to increase at an average annual rate of 1.26% over the planning horizon, with the Oregon portion outpacing Washington, 1.58% versus 1.15%. Figure 3-8 shows the expected core load volumes by state.

Figure 3-8: Expected Core Load by State (Volumes in Therms)

Year	Washington	Oregon	System
2020	256,632,337	86,191,685	342,824,022
2025	272,364,811	93,774,368	366,139,180
2030	289,075,933	101,716,374	390,792,307
2035	305,787,078	109,658,358	415,445,436
2039	319,102,685	115,997,548	435,100,233
Average Annual Growth	**1.15%**	**1.58%**	**1.26%**

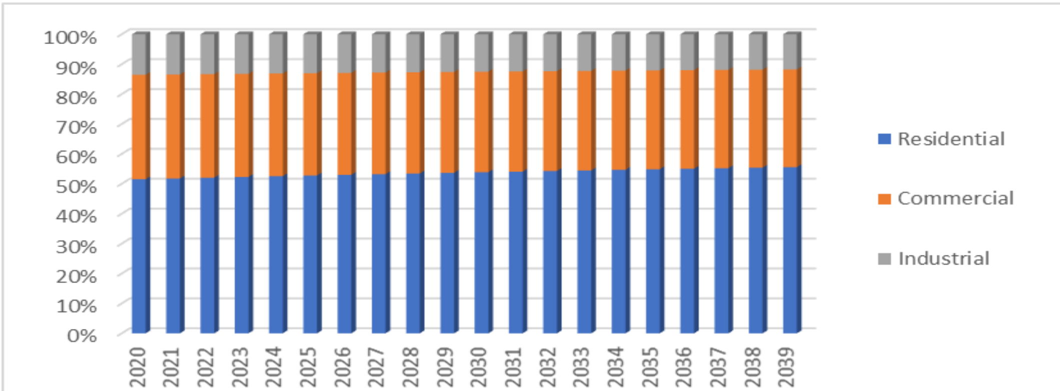
Load growth across Cascade's system through 2039 is expected to fluctuate between 0.78% and 1.80% annually, accounting for leap years. Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow annually at an average rate of 1.66% and 0.91%, while industrial expects a growth rate of approximately 0.51%. Figure 3-9 shows the percentage of core growth by class over the planning horizon.

Figure 3-9: Expected Core Load Growth by Class

Average Growth	Residential	Commercial	Industrial	System
2020-2024	1.91%	1.00%	0.55%	1.41%
2025-2029	1.68%	0.88%	0.47%	1.25%
2030-2034	1.62%	0.91%	0.52%	1.24%
2035-2039	1.50%	0.87%	0.51%	1.17%
Average Annual Change	**1.66%**	**0.91%**	**0.51%**	**1.26%**

In absolute numbers, system load under normal weather conditions is expected to grow annually at an average of 4.9 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 54.5% of the total core load to 57% of the total core load by 2039. Figure 3-10 displays the relative percentage relationship of expected loads by class.

Figure 3-10: Expected Load Stack by Class



Cascade expects residential customers to increase load at an annual average growth of approximately 3.4 million therms and commercial core customers to increase load at an annual average growth of approximately 1.2 million therms over the 20-year planning horizon. Industrial customers are expected to increase load at an annual average growth of approximately 247,000 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)

Year	Residential	Commercial	Industrial
2020	176,668,996	119,706,359	46,448,668
2025	193,278,462	125,290,909	47,569,808
2030	210,595,205	131,345,978	48,851,124
2035	227,911,914	137,401,072	50,132,450
2039	241,732,639	142,220,037	51,147,557
Average Annual Change	**1.65%**	**0.91%**	**0.51%**

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

Figure 3-12: Expected Customer Counts by Class

Year	Residential	Commercial	Industrial
2020	3,152,556	445,063	9,047
2025	3,464,692	467,980	9,687
2030	3,776,826	490,896	10,326
2035	4,088,960	513,812	10,966
2039	4,338,669	532,146	11,477
Average Annual Change	**1.65%**	**0.93%**	**1.22%**

Geography

Bend, Oregon is a major driver in the growth rate. The central part of the state is expected to see a large increase in growth. Figure 3-13 shows the percentage growth of load by each of Cascade's weather locations. Figure 3-14 shows the percentage growth of load by each pipeline zone over the planning horizon. Lastly, Figure 3-15 displays a range of core peak day growth over the planning horizon along with a sampling of peak day therms. Peak day average annual growth is expected to be approximately 1.38%.

Figure 3-13: Oregon 20-Year Load Growth by Weather Location (Volumes in Therms)

Weather	Average Annual Growth	2020 Load	2039 Load
Baker City	0.70%	9,984,100	11,380,900
Pendleton	0.90%	14,607,900	17,306,000
Redmond	1.83%	61,166,000	86,878,800
Oregon	**1.56%**	**85,758,000**	**115,565,700**

Figure 3-14: System 20-Year Load Growth by Pipeline Zone

Zone	Load Growth
Zone 10	-0.51%
Zone 11	23.74%
Zone 20	51.36%
Zone 24	15.04%
Zone 26	10.60%
Zone 30-S	18.58%
Zone 30-W	24.77%
Zone GTN	43.72%
Zone ME-OR	18.96%
Zone ME-WA	19.56%

Figure 3-15: Expected Peak Day Growth (Volumes in Therms)

Period	Peak Day Growth	Year	Peak Day Therms
2020 – 2024	1.56%	2021	3,612,900
2025 – 2029	3.04%	2026	3,890,000
2030 – 2034	2.90%	2032	4,222,500
2035 – 2039	2.80%	2037	4,499,600
Average Annual Growth	**1.38%**		

High and Low Growth Scenarios

High and low growth scenarios were created by examining the confidence intervals resulting from the customer forecast model. Cascade derived from these intervals a high growth modifier of 1.5 times the expected growth, and a low growth modifier of 0.5 times the expected growth. Cascade projects an average annual growth rate of 1.26% in load growth on the expected case, 0.63% on the low band and 1.88% on the high band. Figure 3-16 displays the expected total system load growth across various scenarios.

Figure 3-16: Expected Total System Load Growth (By Percentage) Across Scenarios

Range	Low	Expected	High
2020-2024	0.71%	1.41%	2.12%
2025-2029	0.63%	1.25%	1.88%
2030-2034	0.62%	1.24%	1.87%
2035-2039	0.59%	1.17%	1.76%
2020-2039	**12.70%**	**26.92%**	**42.81%**
Average Annual Change	**0.63%**	**1.26%**	**1.88%**

Load growth under poor economic conditions is expected to average 0.63% annually over the forecast period, while load growth under good economic conditions is expected to average 1.88% annually. The cumulative effect of high growth over 20 years could result in an additional load of 54 million therms, while low growth could result in a load of 48 million therms less than the expected scenario predicts. Figure 3-17 shows the expected total system load across these scenarios.

Figure 3-17: Expected Total System Load Growth Across Scenarios (Volumes in Therms)

Year	Low	Expected	High
2020	342,824,000	342,824,000	342,824,000
2025	354,330,108	366,139,200	378,257,147
2030	366,104,897	390,792,300	416,960,879
2035	377,513,053	415,445,400	456,899,827
2039	386,367,323	435,100,200	489,601,247
2020-2039	**43,543,323**	**92,276,200**	**146,777,247**
Average Annual Load Increase	**2,291,754**	**4,856,642**	**7,725,118**

Alternative Forecasting Methodologies

Cascade has expanded its forecasting methodologies used in the customer forecast into the use-per-customer (UPC) forecast. Cascade now uses Fourier terms and ARIMA terms in its UPC 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.

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 – continued economic growth, carbon legislation, building code changes, direct use campaigns, conservation, and long-term weather patterns. The range of scenarios presented here and in Chapter 9 encompass the full range of possibilities through econometric analysis. These forecasts were created after running through 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 that 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.

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, the Company 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, storage delivery services from Jackson Prairie, Mist and Plymouth liquified natural gas (LNG) service, and transportation resource options available to the Company.

Key Points

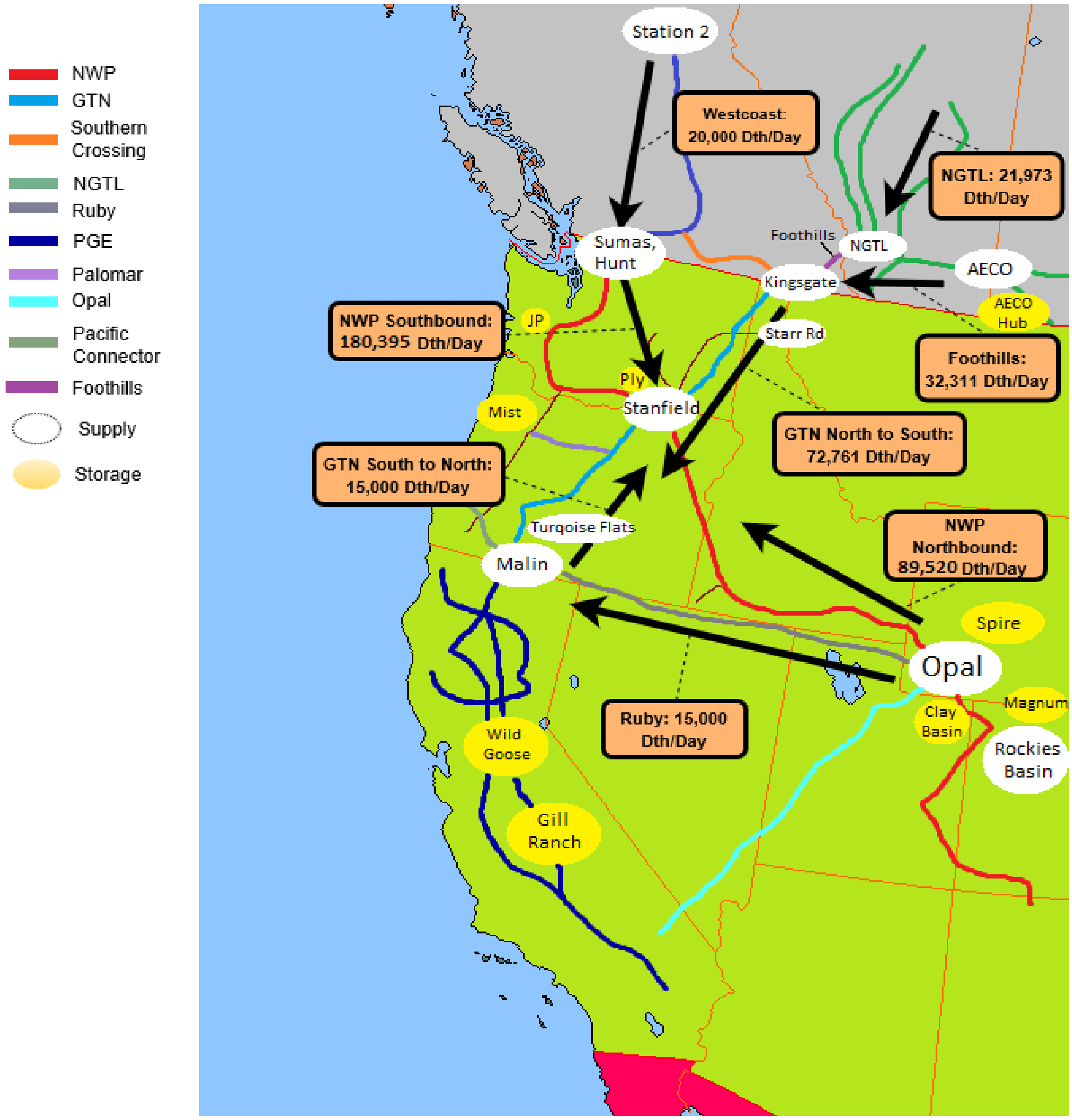
- To meet the Company's core market demand, Cascade accesses firm gas supplies and short-term gas supplies purchased on the open market, in addition to utilizing storage.
- Cascade purchases gas from the Rockies, British Columbia (Sumas), and Alberta (AECO). Gas is transported to the Company's system via pipelines by either bundled or unbundled contracts.
- 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 2020 IRP.
- Risk management policies are implemented to promote price stability.
- Cascade's 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 for a particular month for one or more days. A separate and important source of gas supply is natural gas storage service, which is used to load balance, provide pricing arbitrage, and assist in needle peak events during the heating season.

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.

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



Firm 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 needle 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.

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 requests it, but the Company is not required to take gas unless it is needed to meet customer load demand. Peaking resources typically allow the Company to take between fifteen and twenty days of service during the winter period. These resources are usually more expensive than base load or winter supplies and typically include fixed charges to cover the costs for the sellers to stand by to deliver the supplies.

Needle peaking resources are utilized during severe or arctic cold experiences when demand can increase sharply. These resources are very expensive and are available for a very short period. One source of needle peaking gas supply is a form of demand side management that may be obtained from Cascade's core interruptible customer base. These customers are required to maintain standby or alternate fuel capability so that Cascade can request the customer switch to its alternate fuel source so Cascade can utilize (divert) the gas supply and transportation capacity to meet the Company's core firm market requirements. The benefits associated with this type of resource include lowering the demand of the industrial facility and providing a like amount of additional gas supply with pipeline capacity to meet core demand. Needle peaking requirements can also be met using on-site LNG facilities.

Currently, Cascade does not own or operate any LNG facilities along the distribution system.

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 according to 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 (1 to 30 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.

Due to the potential for interruption of the spot market, these supplies are not considered a reliable source of gas supply for the winter peaking requirements of Cascade's core market. As identified earlier, part of the reason these supplies are considered less reliable is that these volumes are made available after longer-term firm commitments have been contracted for delivery by upstream suppliers. The available volumes are likely to vary daily, depending on production or the suppliers' ability to store un-marketed supply. Under a NAESB contract, parties can identify firm, variable, or interruptible quantities for these supplies. Buyers and sellers use this standard contract when entering into short-term supply transactions. Therefore, these spot volumes are more susceptible to daily operational constraints on the upstream pipelines. This is particularly true in the case of Northwest Pipeline (NWP), which is a displacement pipeline with bi-directional flow. Depending on how gas is scheduled versus how it physically flows between compressor stations, constraints can possibly occur. These constraints are identified in the timely cycle and must be adjusted according to a propriety model run by NWP. This can be done by NWP through an Operational Flow Order in which NWP directs Cascade to deliver to specific zones or move supply from one zone to another to assist with the constraint.

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.

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 vessels or tanks cooled to a liquid state, known as 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 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 in Lewis County, Washington, approximately ten miles south of Chehalis. The following extract explaining the Jackson Prairie facility is found on Puget Sound Energy's website. 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 in Benton County, Washington approximately 30 miles south of Kennewick. According to NWP's website, the total facility has storage capacity of 2.4 BCF. Cascade has leased approximately 28% of this storage capacity.

In addition to the above, the Company has also added storage capacity at the storage facility. This 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.

All of the above facilities are located directly on NWP's transmission system. Therefore, storage withdrawal rates can be changed several times during an individual gas day to accommodate weather-driven changes in core customer requirements. Withdrawal capabilities should also be accompanied by firm capacity on the transporting pipeline(s) to be of value as a reliable source of gas supply. Cascade's Jackson Prairie storage and Plymouth LNG service require TF-2 firm transportation service 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 4-2.

Figure 4-2: 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
Facility	**Storage Capacity**		**Withdrawal Rights**
Plymouth LNG (Principle)	5,622,000		600,000
Plymouth LNG (2016)	1,000,000		181,250
Mist	6,000,000		300,000

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 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 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.

A complete listing of Cascade's current transportation agreements is provided in Appendix E.

At a minimum, in order to ensure a diversified physical portfolio, the basic design of Cascade's transportation portfolio considers incorporating these general physical products or elements:

- Annual supply package;
- November through March (the whole heating season);
- December through February (peak of the heating season);
- Spring Seasonal (Apr-Jun);
- Spring/Summer Seasonal (April through October);
- Day Gas; and
- No more than 25% of the overall portfolio can be supplied by a single party.

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, 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 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 vs a monthly level. In order to capture the potential seasonality as well as the variances of monthly price within the producing basins, the Company blended the pricing data from these various forecast sources.

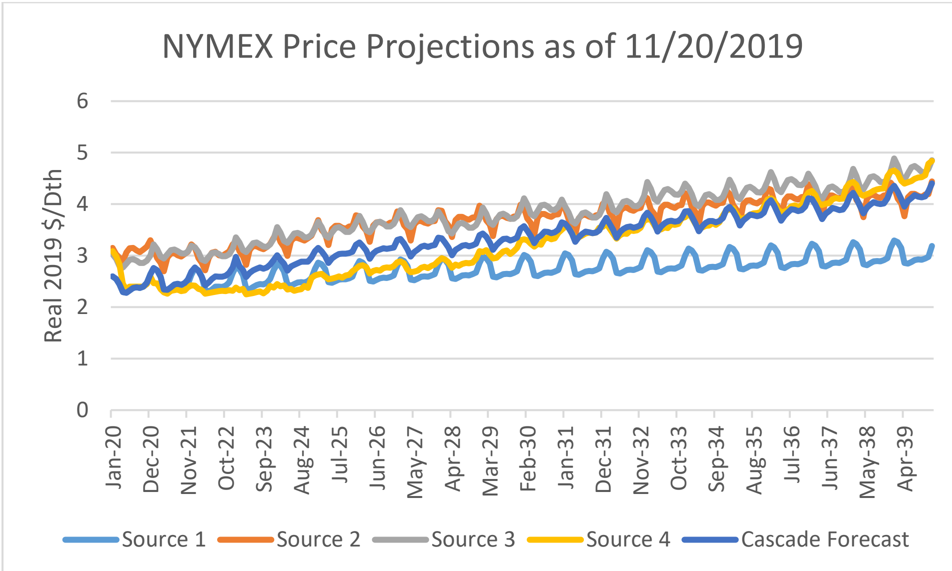
The fundamental forecasts of Wood Mackenzie, the EIA, NWPCC, Platts, S&P Global, Bentek, and Cascade's trading partners are resources for the development of a blended long-range price forecast. Wood Mackenzie publishes a long-term price forecast twice a year to subscribing customers. This forecast was broken down by month through the planning horizon and includes Henry Hub as well as basis differentials 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 4-3. A comparison of the sources Cascade uses in its forecast and the actual blended forecast is provided in Figure 4-4.

Figure 4-3: Sample of Cascade's Henry Hub Price Forecast Weights

Date	Source 1	Source 2	Source 3	Source 4
T+1	9.115%	47.371%	29.499%	14.015%
T+2	10.772%	44.692%	29.580%	14.955%
T+3	9.570%	49.212%	28.405%	12.812%
T+4	12.002%	43.537%	30.386%	14.075%
T+5	11.523%	43.476%	32.206%	12.796%
T+6	14.850%	32.243%	37.449%	15.458%
T+7	13.972%	35.110%	36.448%	14.470%
T+8	15.837%	31.029%	37.275%	15.859%
T+9	15.074%	35.022%	34.192%	15.712%
T+10	16.913%	31.090%	34.166%	17.831%
T+11	16.168%	34.193%	31.641%	17.999%
T+12	17.183%	29.466%	32.449%	20.902%

Figure 4-4: Henry Hub Price Forecast by Source ($US/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.

Also new to the 2020 OR IRP, Cascade has decided to weight 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 somewhat independently from Henry Hub. Correspondingly, the Company applied a weighted average to determine the individual basis differential in the price forecast.

In order to determine the low case and high case, the Company utilized the EIA economic growth factors which are 1.5 for the Low Case, 2.0 for the Reference Case, and 2.6 for the High Case.[1]

Pros and Cons of New Methodology

The changes made to the 2018 price forecast represent a significant 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 is pleased with this forecast, 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 does have 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 9, some of the load growth over the planning horizon will require Cascade to secure incremental supply side resources.

[1] EIA 2018 Annual Energy Outlook

The purpose of this chapter is to identify the potential incremental supply resources the Company considered for the 2020 IRP.

Cascade models its incremental resources simultaneously through SENDOUT®. This allows the Company to evaluate each resource as a potential solution relative to all other resources, without any bias towards any particular option. Cascade utilizes functionality within SENDOUT® 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 SENDOUT® to be either not cost effective or not optimal in comparison with other resource options.

Pipeline Capacity

- **Bremerton-Shelton Realignment:** During the 2018 IRP, NWP presented Cascade with a proposal to realign a portion of its capacity that runs from Sumas to Plymouth. This capacity gave the Company lateral rights along the Shelton lateral. Additionally, Cascade took the option to acquire a storage redelivery contract from Jackson Prairie to Stanfield Delivery. Cascade will continue to monitor the Bremerton-Shelton lateral during the resource integration analyses to ensure there are no constraints.

- **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.

- **GTN/NGTL Capacity Acquisition:** Cascade recently acquired 20,000 dth of GTN, 20,000 of NGTL, and 10,000 of Foothills capacity that will begin in 2023. Cascade will continue to monitor GTN capacity through the resource integration analyses. If a constraint is determined, Cascade would acquire currently unsubscribed capacity on GTN in order to secure its gas supplies at liquid trading points to serve Central Oregon.

- **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.

- **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.

- **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.

- **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.

- **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 starts 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 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 and special interest advocates. Incremental transport involving GTN might be necessary to ensure transport from Malin to Cascade's GTN receipt point at Turquoise Flats.

- **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.

Storage Opportunities

- **AECO Hub Storage:** This is Niska'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. Currently, no open season is planned. 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 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 (North Mist II):** According to NW Natural's 2016 IRP (LC 64), Chapter 3, pages 3.34 and 3.35,

  > NW Natural is in the midst of developing a project called North Mist that would combine new underground storage at Mist and a new

transmission pipeline to serve Portland General Electric (PGE) at Port Westward called North Mist. The storage reservoirs currently in service at Mist and those that would be developed as North Mist for PGE do not collectively exhaust Mist's storage potential; other Mist production reservoirs that theoretically could be developed by NW Natural into additional storage resources. The primary impediment in doing so is not geological, but the challenges associated with developing new pipeline capacity to move the gas from Mist to the Company's load centers.

NW Natural identifies a prospective Mist expansion project for core customer use in this IRP as 'North Mist II.' North Mist II involves 100 MMcf/day of maximum delivery capacity coupled with a maximum storage capacity of 2.0 billion cubic feet (Bcf), and includes a new compressor station and associated appurtenances. These capabilities would be exclusively for utility use. Should a third party want to subscribe to a North Mist II expansion, total deliverability and storage capacity would increase to match those additional subscribed amounts.

New to the 2020 IRP, Cascade contacted the operators of Mist to gather updated data to properly model this storage facility in SENDOUT®. The results of this can be found in Chapter 9.

- **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. Cascade met with Spire in mid-2019 to discuss any potential storage opportunities between Spire and Cascade. Currently, Spire is expanding their contracts but won't have any availability until early-2021.

- **Wild Goose Storage:** Wild Goose is located north of Sacramento in northern California and was 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 Magnum Gas Storage 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 4 solution mined storage caverns capable of storing 54 billion cubic feet (Bcf) of natural gas.[2] Magnum would be connected to the Kern River Gas Transmission and Questar 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 would be connected to 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. Instead, its usefulness revolves around the availability of another (no doubt larger) facility with the ability to supply the LNG to fill its tank(s). 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 contemplated 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.

- **Renewable Natural Gas (RNG):**
  Cascade is committed to the acquisition of cost-effective RNG under the current regulatory guidance provided by the OPUC and WUTC. An in-depth discussion of Cascade's RNG philosophy and analysis techniques can be found in Chapter 7, Renewable Natural Gas.

- **Realignment of Maximum Daily Delivery Obligations (MDDO):** Cascade has long held more delivery rights than receipt rights on NWP under its principle 100002 agreement. This was a result of FERC Order

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

636, when NWP was required to assign upstream capacity directly on GTN (formerly known as Pacific Gas Transmission) to the shippers that were using that capacity. NWP allowed the direct assignment as part of the conversion from their merchant role to an open access pipeline. However, NWP did not lower its capacity contract to reflect the direct assignment. In effect, this increased Cascade's system capacity by the amount GTN would directly be providing to Cascade. On the plus side, this gives Cascade great flexibility to utilize 315,994 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 speculative supply side resources at this point in time. Ultimately these unconventional 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, infrastructure risks, and price risks. Regulatory risks include the unknown impacts of future Federal Energy Regulatory Commission (FERC) or Canada's Energy Regulator (CER)[3] rulings that may impact the availability and cost of interstate pipeline transportation.

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.

[3] 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.

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, natural gas is seen as a fuel that could significantly contribute to lessening American dependency on foreign oil. It should be noted that several proposals being discussed or that are in process involve a number of Canadian upstream pipelines which could have a direct impact on the availability of supply or at least may pose potential risks to increases in the price of supplies sourced from British Columbia and Alberta. This new service may impact the amount of Alberta gas available for companies such as Cascade. The Company will continue to monitor and be actively involved in the various pipeline forums as these initiatives develop.

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 eliminating 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 because they have no up-front cost.

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 Swaps

- Year one up to 60% of annual requirements
- Year two set at up to 40%
- Up to 20% hedged volumes for year three

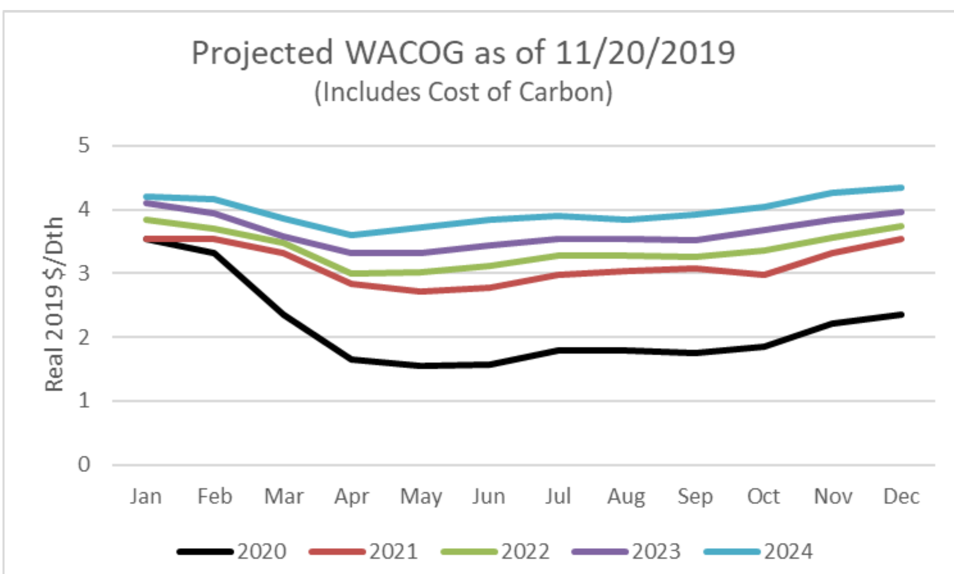
Depending on market conditions, the strategy allows for the ratchets to increase to 75%, 50%, and 30%, respectively, provided current market information supports moving to a different level.

Cascade may employ 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 effect. 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 less than 50%. For the 2018 procurement design, GSOC felt that with Cascade's unique load and wide geographical profile, the lack of price volatility would potentially expose the Company to unreasonable premiums on derivatives. Therefore, GSOC chose to hedge using fixed priced physicals. Currently, Cascade hedges approximately 40% of the portfolio using fixed priced physicals.

The Company entered into fixed price physical transactions and one financial swap for the current programmed buying period. Fixed prices consist of locked-in prices for physical supplies. As will be further described in this chapter, the Company utilizes a programmed buying approach for locking in or hedging gas supply prices. In light of the relative lack of volatility in current prices, abundant supply, concerns regarding the administrative impacts of the Dodd-Frank Wall Street Reform Act, and an evolving hedging policy in Washington, Cascade has only executed one new financial derivative for the 2020 IRP. The Company still monitors the outer years and stands ready to execute financial swaps when market and pricing conditions are more favorable. 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 4-5 provides a graph showing the Company's projected weighted average cost of gas (WACOG), including the base case carbon adder, for the 2020 IRP.

Figure 4-5: Projected Cascade WACOG as of November, 2019



On March 13, 2017, the Washington Utilities and Transportation Commission (WUTC) issued its Policy and Interpretative Statement on Local Distribution Companies' (LDCs) Natural Gas Hedging Practices in Docket UG-132019.[4] This statement provided guidance on how LDCs should develop and implement more robust risk management strategies, analyses and reporting related to hedging activities. Many of the techniques employed as a result of the WUTC docket will benefit Oregon customers as well, so a discussion of these best practices is prudent for this IRP.

In Docket UG-132019, the WUTC reviewed hedging practices by utilities in the State of Washington and found that local LDCs experienced opportunity costs associated with price risk mitigation techniques upwards of $1.1 billion over a ten-year period. The WUTC discovered that many of these costs were caused by adherence to programmatic "set-it-and-forget-it" price risk mitigation techniques (herein called hedging or hedging strategies) that did not respond well to the downward trending market which prevailed in recent years. The WUTC concluded that, while hedging is necessary to limit upside price risk, an effective program should also give flexibility that can mitigate downside hedge losses by adjusting to changing market conditions. To achieve this goal, the Commission identified a need for a risk-responsive hedge plan with a robust analytical framework.

GSOC oversees the Company's gas supply purchasing and hedging strategy. Members of GSOC include Company senior management from Gas Supply, Regulatory, Finance and Operations. In preparing the Company's hedge execution plan, Cascade has relied on the following points when interpreting the WUTC hedging policy statement:

- WUTC affirmed its preference that natural gas LDCs utilize risk responsive hedging practices.
- Hedging practices should not be speculative in nature. Hedging is an activity designed to reduce price uncertainty, not an attempt to realize profits based on predictions of anticipated market movements.
- The Commission believes that while there is no right mix of methods that may be applied unilaterally due to utility specific operations, LDCs must reasonably plan for market volatility and appropriately react to balance ratepayer exposure to hedging losses. This includes recognizing dual protection from upside price risk and downside hedging loss, along with annual validation of acceptable hedging outcomes.
- Based on the WUTC hedging policy statement the Company is aware that the WUTC views the Gettings White Paper as a resource in helping LDCs develop more robust risk management programs. While

[4] https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=132019

> Cascade has considered portions of the White Paper to inform the Company's enhanced risk management strategies, analysis and reporting, Cascade has hired a consultant, Gelber & Associates, to assist the Company in developing the proper risk responsive process and analyses.

With the assistance of Gelber & Associates (G&A or Gelber), an energy consulting firm with 30 years of experience in utility hedging, CNGC has reexamined 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 & Associates 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 are the appropriate design criteria to satisfy Commission requirements.

An update of Cascade's work with Gelber on a more risk-responsive hedge design can be found in the Company's WUTC acknowledged 2019 Annual Hedge Plan in Appendix E.

Portfolio Purchasing Strategy

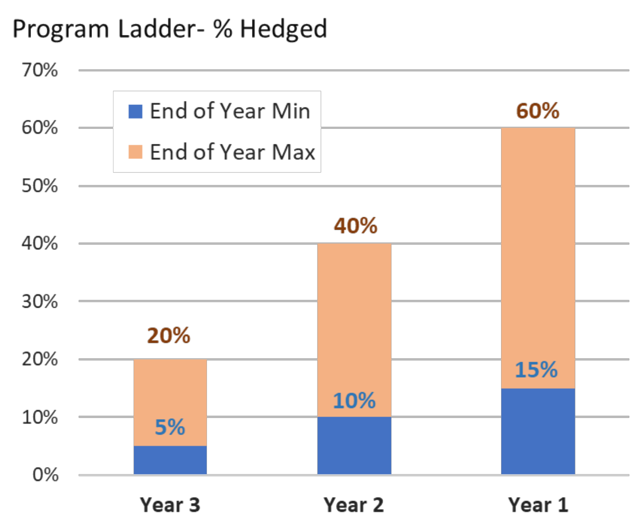
As stated earlier, GSOC oversees the Company's gas supply purchasing strategy. Based on current stable prices and a robust supply picture, the Company considers contracting physical supplies for up to five years (based on a warmer-than-normal weather pattern). The Company's current gas procurement strategy 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.

The current hedging plan for CNGC, approved by GSOC in the spring of 2019, is comprised of 99% physical purchases in a ladder design in which hedges are added and accumulated every year prior to the final consumption of the gas. The natural gas is considered hedged when its price is locked-in and scheduled for delivery in the physical market using a fixed-price physical purchase. The program currently allows up to 20% of expected purchases to be hedged three years prior to delivery, up to 40% hedged two years prior, and up to 60% hedged the year prior to the final consumption of the gas. The portfolio percentage of fixed priced purchases is defined in the Cascade Natural Gas NOV19-OCT20 PGA.

The gas supply portfolio design is overseen by GSOC, which 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 (under the proposed plan they will retain this function), 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. This team is overseen by the Director, Gas Supply—Utility Group.

As depicted on Figure 4-6, the structure of the current plan is as follows: Year 1 is currently hedged at 25% (blue bars) which leaves 15% (orange bar) of additional hedges that can be added for Year 1. Year 2 is currently hedged at 20% which leaves 5% of additional hedges that can be added for Year 2. (For clarity, when Year 2 becomes Year 1, the hedge percentage will increase from a maximum of 25% to a maximum of 40% unless overridden by the GSOC portfolio design discussed previously). Year 3 is currently unhedged which leaves 20% of additional hedges that can be added for Year 3.

Figure 4-6: Current Hedge Ladder



Additional characteristics of the current strategy are described below:

- Stay the course. Portfolio procurement for 2020 should continue with same guidance as 2019's plan. This is the most reasonable action while the Company works with Gelber & Associates to identify modifications to future portfolio and hedging designs for GSOC to consider.
- Annual load expectation (Nov-Oct) is approximately 30,000,000 dekatherms, consistent with recent load history.
- Portfolio procurement design based on a declining percentage each year, accordingly: Year 1: approximately 80% of annual load expectation; Year 2: 40%, Year 3: 20%.
- Portfolio must contain a variety of parties, locations, contract volume and terms.
- Considerations of structured products, caps, floors, derivatives, etc. are not to exceed 5% of overall contract supply target. These items are principally used as a potential offset to fixed priced physicals being "out of the money".
- GSOC can always modify the plan to include additional years if a significant discount price materializes.
- GSOC may make further modifications to this portfolio plan based on the results of the Company's hedging initiative to be in compliance with WUTC docket UG-132019.

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. Cascade employs a bidding process when procuring fixed priced physical, indexed spot physical, as well as financial swaps used to hedge the price of underlying index based physical supplies. In the bidding process, the Company alerts a minimum of three suppliers and/or financial counterparties of the specific gas supply transactions Cascade plans to fill. Cascade then collects bids from these parties over a period of time for 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, Cascade awards the specific packages to individual parties. Naturally, price is the principle factor; however, Cascade also considers reliability, financial health, past performance, and the party's share of the overall portfolio so that the Company ensures party diversity. It should be noted that the lowest market price may occur during a 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 indicators may start high and drop over time allowing Cascade to capture the transaction on the downward swing. In the end, timing is always a factor as the market cannot be predicted with any certainty.

Cascade follows a similar process when it submits a formal request for proposals (RFP) to the various suppliers. Parties are asked to provide offers on specific packages, but are also encouraged to propose other transactions or packages that they feel may be of interest in helping Cascade secure financially attractive and flexible transactions to meet the Company's needs. This process requires additional analysis regarding operational reasonableness, timing, and volumes. Price comparisons also become more complicated since pricing could be tiered; part of a structure deal may be tied to an index or contains floors, caps, etc. Cascade utilizes TruMarx's COMET transaction bulletin board system to assist in communicating, tracking, and analyzing these RFP activities.

Conclusion

Cascade's 20-year supply side resource goal is to continue to meet the energy needs of its core market customers. This is accomplished through a package of services that combines adequate gas supplies 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 conservation. The avoided cost forecast can be used as a guideline for comparing energy conservation 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 is only a 20-year plan, avoided costs are forecasted for 45 years to account for the full measure life of some conservation measures, such as insulation, which has a 30-year life. The avoided cost forecast is based on the performance of Cascade's portfolio under expected conditions.

Key Points

- Avoided cost forecasting serves as a guideline for determining energy conservation targets.
- Cascade's avoided costs include fixed transportation costs, variable transportation costs, commodity costs, a carbon tax, distribution system costs, a risk premium, and a 10% adder.
- New to the 2020 IRP, the Company has included a value for avoided or delayed distribution investment, and a methodology to calculate risk premium.
- The total avoided cost ranges between \$0.26 and \$1.11/therm over the 20-year planning horizon.

Costs Incorporated

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

$$AC_{nominal} = TC_f + TC_v + SC + ((CC + C_{tax}) * E_{adder}) + DSC + RP$$

Where:

- $AC_{nominal}$ = The nominal avoided cost for a given year. To put this into real dollars apply the following: Avoided Cost/ (1+inflation rate)^Years from the reference year.
- TC_f = Incremental Fixed Transportation Costs
- TC_v = Variable Transportation Costs
- SC = Storage Costs
- CC = Commodity Costs
- C_{tax} = Carbon Tax
- E_{adder} = Environmental Adder, as recommended by the Northwest Power and Conservation Council
- DSC = Distribution System Costs

- RP = Risk Premium

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

- The most recent load forecast (9/27/2019);
- The inflation rate used is tied to the Consumer Price Index (CPI) from Woods & Poole's 2019 projections and
- The discount rate of 7.33% (Cascade's real after-tax weighted average cost of capital).

Understanding Each Component

- **Incremental Fixed Transportation Costs**

  For the 2020 IRP, prior to the acquisition of incremental demand-side management resources, Cascade identifies the year 2032 as the start of potential capacity shortfalls. To this end, fixed transportation costs after 2032 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). 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.

  For its 2020 IRP, Cascade projects shortfalls will begin in 2032. Once these shortfalls begin, the next therm saved would no longer apply to existing contracts, but rather to prevent the need to acquire additional transportation. To this end, variable transportation costs after 2032 represent the average demand charge of all incremental contracts that would be used to solve shortfalls. It is worth noting that these costs are estimated based on information from the pipelines and should be treated as confidential as any incremental variable transportation costs could ultimately be a negotiated rate. These costs are inflated by the CPI escalator every four years to mimic the occurrence of potential rate cases.

- **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 into Cascade's distribution system. Cascade does not forecast a need to acquire additional storage, so this value is zero for the 2020 IRP.

- **Commodity Costs**

  Commodity costs are the costs of acquiring one therm of gas. Cascade first uses SENDOUT® 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 20-year price forecast.

- **Carbon Tax**

  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. Accurate modeling of these costs can be challenging due to uncertainty surrounding how these costs will ultimately be quantified. When Cascade locked in its avoided cost for the 2020 Oregon IRP in late 2019, the Oregon legislature was attempting to pass a Cap and Trade bill that, if passed, would not contain explicit costs for carbon emissions, but rather emissions reduction targets. If utilities cannot meet these targets through emissions reductions efforts, they will presumably be required to purchase carbon offsets through a marketplace that does not yet exist in Oregon. Although this legislation ultimately did not pass, on March 10th, 2020, Governor Brown issued Executive Order No. 20-04. This order establishes emissions reductions targets for Oregon but no explicit costs tied to emissions in excess of the targets set. With some type of Cap and Trade system being the most probable carbon compliance future in Oregon, Cascade has elected to use market driven carbon compliance cost as its primary carbon forecast, with California's Energy Assessment Division's 2019 IEPR Preliminary GHG Allowance Price Projections being the closest analog available to a future Oregon carbon marketplace.

Currently, Cascade projects a scaling carbon tax, starting at $21.13/metric ton in 2021 and capping at $61.50/metric ton from 2030 onward. These prices are pulled directly from the real mid-price forecast of the IEPR price projections. The Company assumes that compliance costs begin in 2021 to provide a year of implementation time from the beginning of the planning horizon, and caps prices at $61.50 based on guidance in the cover page of the IEPR projections. 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. That being said, Cascade recognizes the uncertainty surrounding the cost of carbon compliance as discussed earlier, so the Company performs significant analysis around the variance of carbon compliance costs and the impact of this variance on DSM potential. This is discussed further in Chapter 9, Resource Integration.

- **Environmental Adder**

Cascade includes a 10% adder for non-quantifiable environmental benefits as recommended by the Northwest Power and Conservation Council. The 10% adder is added after the cost of gas and taxes are applied.

- **Distribution System Costs**

Distribution system costs capture the costs of sending gas from the citygate to Cascade's customers. For this IRP cycle, Cascade calculates distribution system costs as its system weighted average of its authorized margins, as posted in the Company's tariffs. Distribution system projects that are not related to growth are then backed out of the weighed margin figure to capture only the costs that can be deemed avoidable. 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 views a risk premium as a cost associated with uncertainty around the other avoided cost factors, versus relative certainty of the costs around energy efficiency programs. For the 2020 IRP, the Company worked closely with its stakeholders to create a methodology to quantify this premium. Cascade requested a hypothetical 20-year fixed price quote from its Asset Management Agreement (AMA) partner, Tenaska Marketing Ventures. The Company then compared the prices offered at each of its basins to its 20-year price forecast. Surprisingly, the 20-year fixed prices offered by

Tenaska were lower than projected floating market prices, which would lead to a negative risk premium. Cascade is following the regional best practice established during the UM1893 avoided cost docket and recording a value of zero for risk premium instead of the negative values that were calculated

Peak Hour Calculation Methodology

As discussed earlier, to properly quantify the impact of distribution system enhancement costs, Cascade analyzes what the projected costs would be to increase flow by one therm on peak hour. To do this, Cascade analyzed a representative sample of the actual hourly flow through a few large citygates in its service territory on a particularly cold week in recent years. The Company then analyzed the ratio of peak hour demand to daily demand and applied this ratio to its projected peak day capacity costs. The result of this calculation can be found in Appendix H.

Application

The 2020 IRP makes several enhancements in calculating and applying the avoided costs. This cost figure becomes the foundation for many prudency determinations 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.

Results

Figure 5-1 displays the total avoided cost by each conservation zone over the 20-year IRP horizon, while Figure 5-2 provides the net present value of avoided costs over the planning period. For the 2020 IRP, the system avoided costs range between $0.26/therm and $1.11/therm.

As mentioned earlier, the avoided cost is based on the performance of the portfolio under expected conditions for the entire 20-year planning horizon. Overall, avoided costs for the 2020 IRP are lower than in the 2018 IRP. The main driver of this is falling gas prices, and the continued low volatility of prices keeps Cascade’s price forecast low throughout the planning horizon. This effect is mitigated somewhat what by changes in methodology, including the addition of distribution system costs to the calculation. The 45-year avoided costs and other detailed tables of avoided costs, including various carbon scenarios, are found in the Excel version of Appendix H.

Figure 5-1: Total Oregon Avoided Costs by End Use (Cost per Therm)

TOTAL AVOIDED COSTS - *Annual Values*					
Lifetime	**DHW**	**FLAT**	**Res Heating**	**Com Heating**	**Clotheswasher**
2020	$0.26	$0.26	$0.28	$0.28	$0.26
2021	$0.39	$0.39	$0.40	$0.41	$0.39
2022	$0.43	$0.43	$0.45	$0.45	$0.43
2023	$0.45	$0.45	$0.46	$0.47	$0.45
2024	$0.50	$0.50	$0.52	$0.52	$0.50
2025	$0.54	$0.54	$0.56	$0.56	$0.54
2026	$0.58	$0.57	$0.60	$0.60	$0.57
2027	$0.61	$0.61	$0.63	$0.64	$0.61
2028	$0.67	$0.66	$0.68	$0.69	$0.66
2029	$0.73	$0.72	$0.75	$0.75	$0.72
2030	$0.78	$0.78	$0.80	$0.81	$0.78
2031	$0.79	$0.78	$0.81	$0.81	$0.78
2032	$0.83	$0.82	$1.02	$1.00	$0.81
2033	$0.83	$0.83	$1.02	$1.00	$0.81
2034	$0.84	$0.83	$1.03	$1.01	$0.82
2035	$0.84	$0.84	$1.03	$1.01	$0.82
2036	$0.85	$0.85	$1.04	$1.02	$0.83
2037	$0.89	$0.88	$1.08	$1.06	$0.87
2038	$0.90	$0.89	$1.09	$1.07	$0.88
2039	$0.92	$0.91	$1.11	$1.09	$0.90

Figure 5-2: Total Oregon Avoided Costs Net Present Value (Cost per Therm)

TOTAL AVOIDED COSTS - *Net Present Value*					
Lifetime	**DHW**	**FLAT**	**Res Heating**	**Com Heating**	**Clotheswasher**
2020	$0.25	$0.25	$0.26	$0.27	$0.25
2021	$0.61	$0.60	$0.63	$0.64	$0.60
2022	$0.99	$0.98	$1.03	$1.03	$0.98
2023	$1.36	$1.36	$1.42	$1.42	$1.35
2024	$1.76	$1.76	$1.83	$1.84	$1.75
2025	$2.18	$2.17	$2.26	$2.27	$2.16
2026	$2.60	$2.59	$2.70	$2.71	$2.58
2027	$3.03	$3.02	$3.14	$3.16	$3.01
2028	$3.48	$3.47	$3.60	$3.62	$3.46
2029	$3.95	$3.93	$4.08	$4.10	$3.92
2030	$4.43	$4.42	$4.58	$4.60	$4.40
2031	$4.90	$4.88	$5.06	$5.07	$4.86
2032	$5.36	$5.34	$5.63	$5.64	$5.32
2033	$5.81	$5.79	$6.18	$6.18	$5.76
2034	$6.25	$6.22	$6.71	$6.70	$6.18
2035	$6.66	$6.63	$7.22	$7.20	$6.59
2036	$7.07	$7.03	$7.71	$7.68	$6.98
2037	$7.47	$7.43	$8.20	$8.17	$7.37
2038	$7.86	$7.81	$8.68	$8.63	$7.75
2039	$8.24	$8.19	$9.14	$9.08	$8.13

CHAPTER 6

DEMAND SIDE MANAGEMENT AND ENVIRONMENTAL POLICY

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 rebates/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

- Cascade targets saving approximately 62 million therms system-wide over the 20-year planning horizon; 12.09 million therms in Oregon and 50 million therms in Washington.
- 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 incen-tives for installing energy

This chapter presents the methodology used to determine the Company's DSM supply curve for the 20-year planning period, the Company's annual savings targets, and a narrative about how DSM goals will be achieved.

This chapter also considers 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.

Cascade's Oregon Energy Efficiency Program

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

- 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 have income data for its customers and, therefore, cannot separately estimate the therm savings potential for just its low-income program. The program details are found in Schedule 33, Oregon Low-Income Energy Conservation Program of the Company's Oregon tariff. Further details on this program 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 2018 IRP, filed in the Washington Utilities and Transportation Commission's (WUTC's) Docket UG-171186. A recapitulation of the Company's short-term goals and initiatives for achieving these goals is available in the Company's Conservation Plan filed in WUTC Docket UG-190957 and is included in Appendix D of the 2018 WA IRP.

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

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

fryers and gas convection ovens. The sectors covered through these programs include the following:

- Residential (Existing and New Home Construction)
    - Single Family & Manufactured
        - Built Green & Energy Star homes, weatherization, HVAC and water heating equipment, Energy Savings Kits, exterior doors, and programmable thermostats

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

The Company's specific program offerings are detailed in the Company's Washington tariff found online at www.cngconserve.com.[2]

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 Corporations' DSM Potential in Oregon

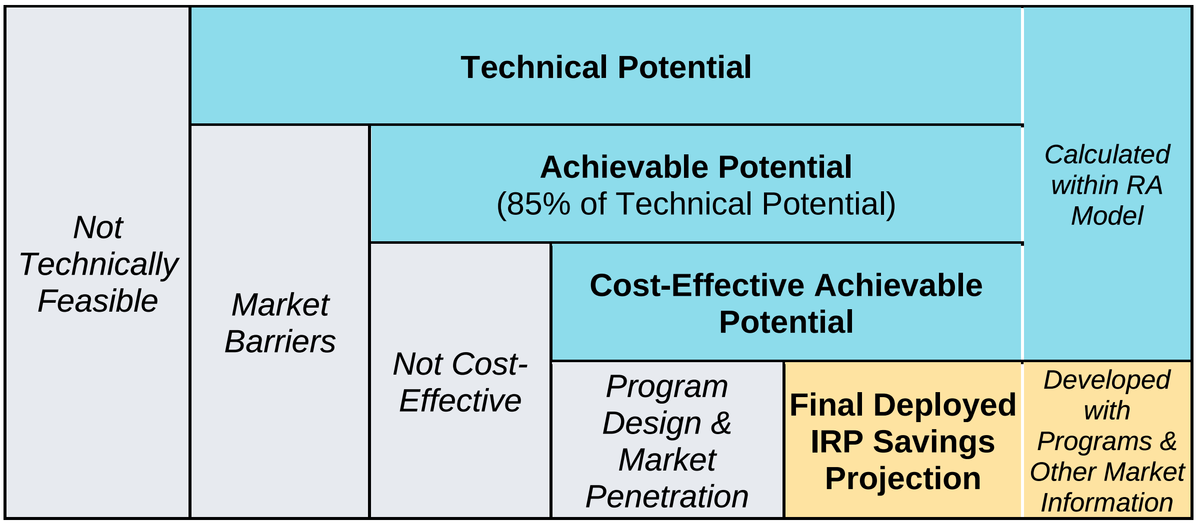
Energy Trust analyzes energy savings on a consistent and comparable basis with other supply side resources. All cost-effective energy efficiency is identified and deployed via the long-term planning process and Energy Trust is tasked with acquiring this resource on behalf of Cascade. Cascade and Energy Trust work closely together to ensure that 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 forecasting and avoided costs, as well as discount and inflation rates. From there, a series of meetings and calls were launched to ensure that 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

[2] See Schedule 300, Residential Conservation Incentive Program; Schedule 301, Low Income Weatherization Incentive Program; Schedule 302, Commercial/Industrial Conservation Program. Tariffs are posted online at www.cngc.com.

savings potential, which is then 'deployed' exogenously of the RA model to estimate the final deployed IRP savings projection.[3] 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 6-1 and are discussed in greater detail in the sections.

Figure 6-1: Types of Potential Calculated in 20-year Forecast Determination



The RA Model utilizes the modeling platform Analytica®[4], 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 20-year savings projection is provided to Cascade for inclusion in its SENDOUT® Model as a reduction to demand on the system.

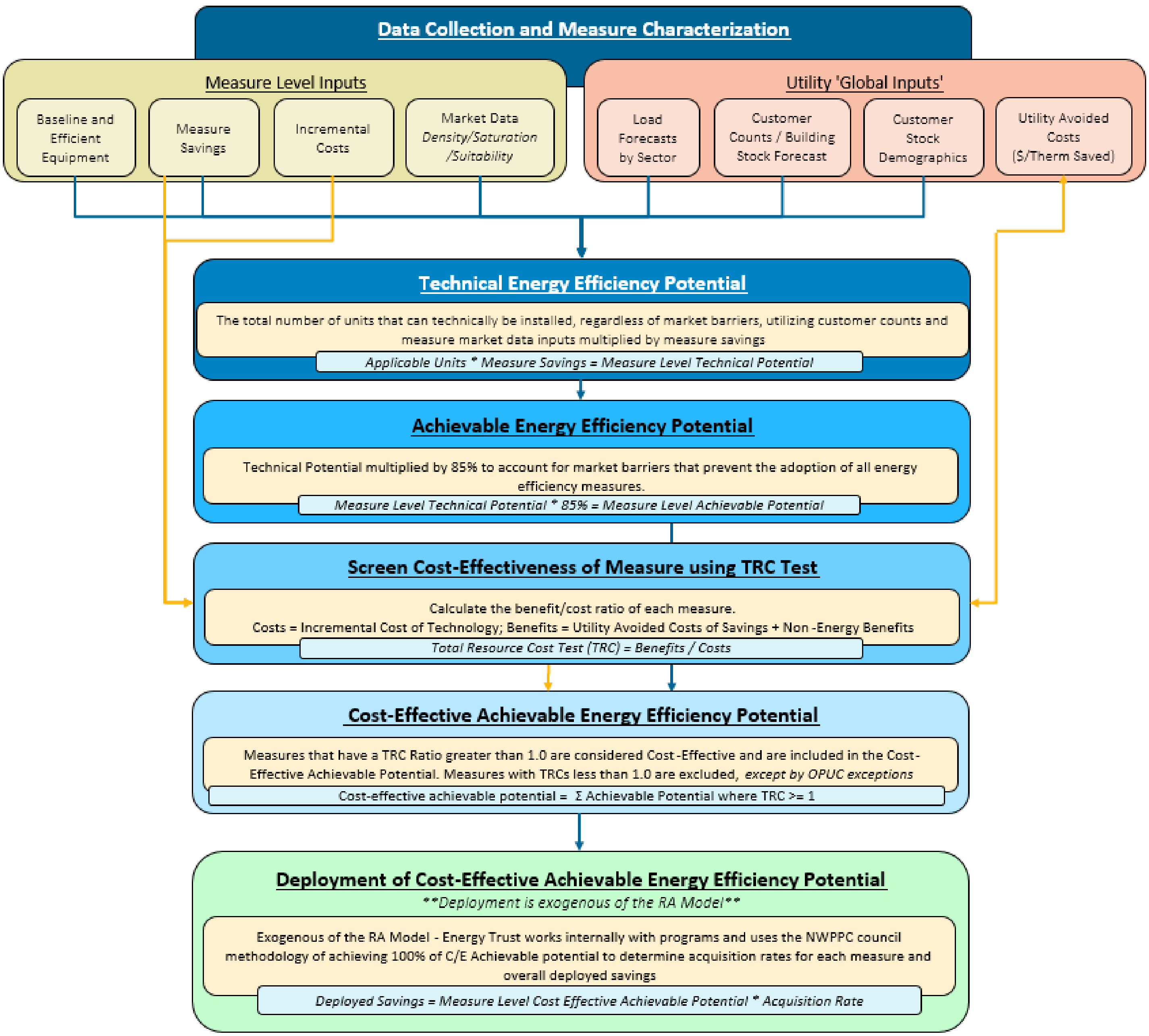
20-Year Forecast Detailed Methodology

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 6-2. 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

[3] The RA Model is similar to what is called a Conservation Potential Assessment (CPA) as is performed for Cascade's Washington energy efficiency planning.
[4] https://lumina.com/why-analytica/what-is-analytica/

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 exogenously of the RA Model. The remainder of this section provides further detail in each of the steps shown in Figure 6-2.

Figure 6-2: 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.[5] 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 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 cost-effectiveness. The characterization inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[6], 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% EF furnace replacing an 80% EF 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 kWh or therms savings associated with an efficient measure calculated by comparing the consumption of the baseline and efficient measures.

[5] 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.

[6] 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)

- **Incremental Costs**: The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the type of the 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).

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 and delivery costs associated with energy efficiency savings represented as $'s 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 referenced above:

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 by 15%, to account for market barriers that prevent total adoption of all cost-effective measures. Defining the achievable potential as 85% of the technical potential is the generally accepted method employed by many industry experts, including the Northwest Power and Conservation Council (NWPCC) and National Renewable Energy Lab (NREL).

Achievable Potential =	*Technical Potential * 85%*

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. water savings from low-flow showerheads, 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 in the RA Model.

Quantify the Cost-Effective Achievable Energy Efficiency Potential

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* (85% of technical potential) 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 6-3, 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 6-3: Measures with Cost-Effective Override Applied and Rationale

Measures that are Overridden	Override Applied?	Rationale
Res - Attic/Ceiling insulation	TRUE	OPUC Exception
Res - Floor insulation	TRUE	OPUC Exception
Res - Wall insulation	TRUE	OPUC Exception
Res - 0.67/0.69 EF Gas Tank Water Heater	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 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

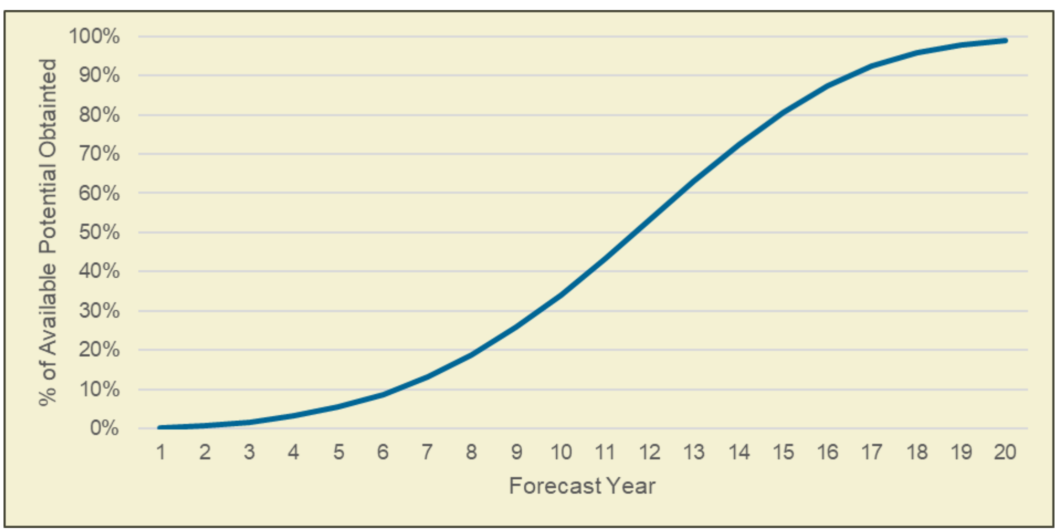
The cost-effective achievable potential output by the RA Model does not represent the forecast of savings that utilities will actually experience on their systems. Not all cost-effective achievable potential that results from the RA Model can actually be obtained by Energy Trust due to customer awareness, customer willingness to install, program maturity, codes and standards, and other market factors. To account for all of 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' outline in Figure 6-1, using ramp rates.

There is a suite of ramp rates that Energy Trust utilizes, and 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[7], produced every five years although Energy Trust applies ramp rates that reflect assumptions about specific market conditions in Cascade's Oregon territory. 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 market transformation. 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 6-4 shows a representative LO Ramp Rate:

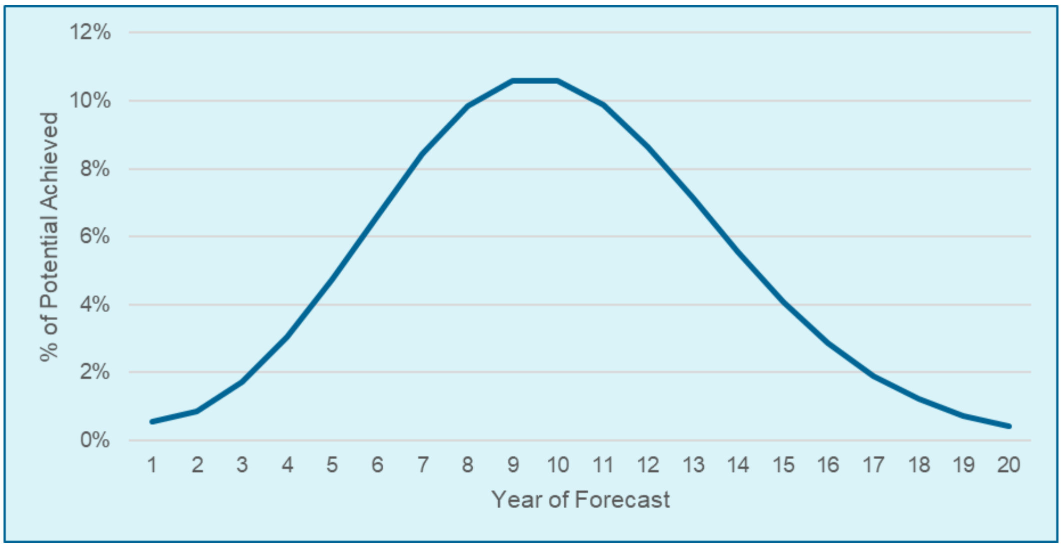
Figure 6-4: Example of NWPCC Lost Op. Ramp rate



[7] A discussion of the ramp rate methodology applied by the Northwest Power and Conservation Council in the 7th Power Plan can be found in Chapter 12 of the 7th Power Plan: https://www.nwcouncil.org/sites/default/files/7thplanfinal_chap12_conservationres_2.pdf

- **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 6-5 shows a representative RET Ramp Rate.

Figure 6-5: 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

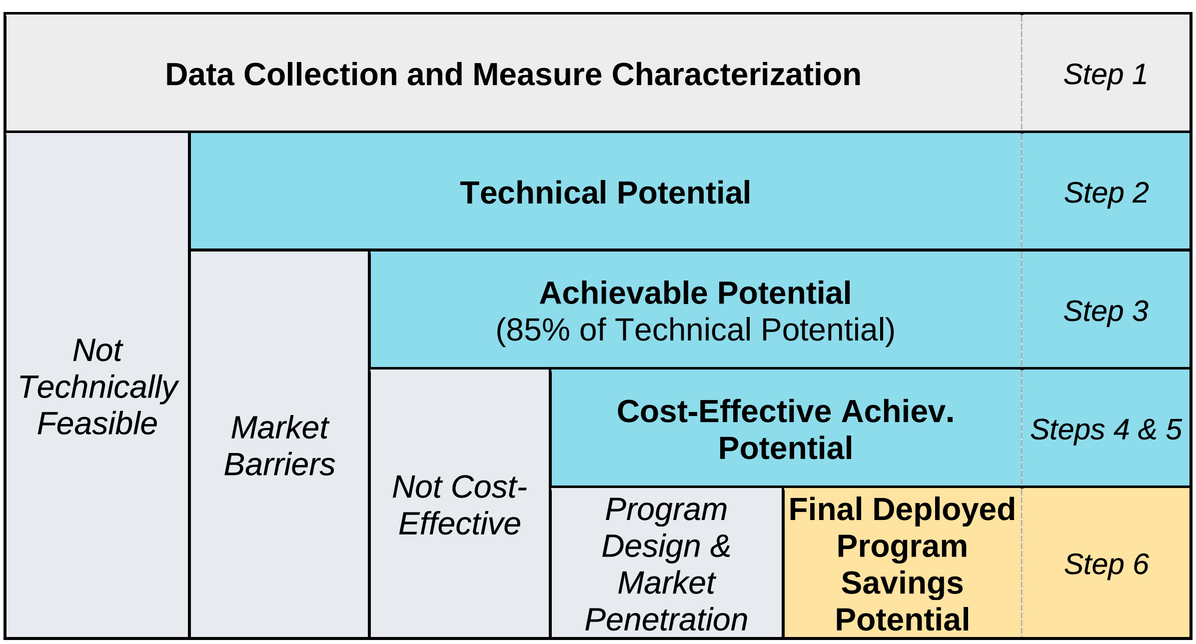
Energy Trust typically develops ramp rates at the program category level and the calibration process is divided into three time frames, as shown in Figure 6-6. The first two years of each ramp rate are calibrated to program budgeted goals to get a starting point for the curve. Years 3-5 of ramp rates 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.

Figure 6-6: Energy Trust Ramp Rate Calibration Process

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 be that measures have had historically low uptake, installation is invasive, or it is an emerging technology. In terms of lost opportunity measures, achieving 100% means achieving 100% of the available stocks turning over in that year. For retrofit measures, this means spreading 100% of the potential across the 20 years, informed by calibration in the early years.

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

Figure 6-7: 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 2018 IRP, which are a result of a stakeholder workshop that Energy Trust held in 2017 and other more recent internal improvement updates.

The purpose of the stakeholder meeting in September 2017 was 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 'mega-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 are reflected in Cascade's energy efficiency forecast:

- New Measures
    - Inclusion of additional behavioral savings and near net-zero homes and buildings
- 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 loads or opportunities and have led to results that deviated from the forecasts. The addition is based on average savings from large projects 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

Other updates since the 2018 IRP include:

- Refreshed measure assumptions
  - Energy Trust has completely overhauled the measures in the RA Model to better reflect the savings and cost estimates utilized by Energy Trust programs. Additionally, market data has been updated significantly to include the most recent iterations of RBSA II and CBSA.
- Emerging Technologies
  - Several emerging technologies were added to the RA Model in the Fall of 2017 and these additions are described in detail in the results section below. These measures add to the total potential in the later years of the forecast but they do not show up in the earlier years because they are not yet commercially available.
- Load Forecast Alignment
  - Energy Trust worked with Cascade to better understand what is included in Cascade's load forecast to better align modeling efforts.
- Scenario Runs
  - Energy Trust ran five scenario runs for Cascade's 2020 IRP to show changes in potential based on different carbon prices and measure adoption ramp speed. These scenarios are discussed in more detail in the results section.

DSM Projections in Oregon: 2020-2039

The Company foresees 12.09 million therms of its 20-year demand coming from Oregon demand side management measures delivered through Energy Trust. Figure 6-8 presents the technical, achievable, and cost-effective achievable potentials as well as Energy Trust's therm savings target for the 20-year planning period.

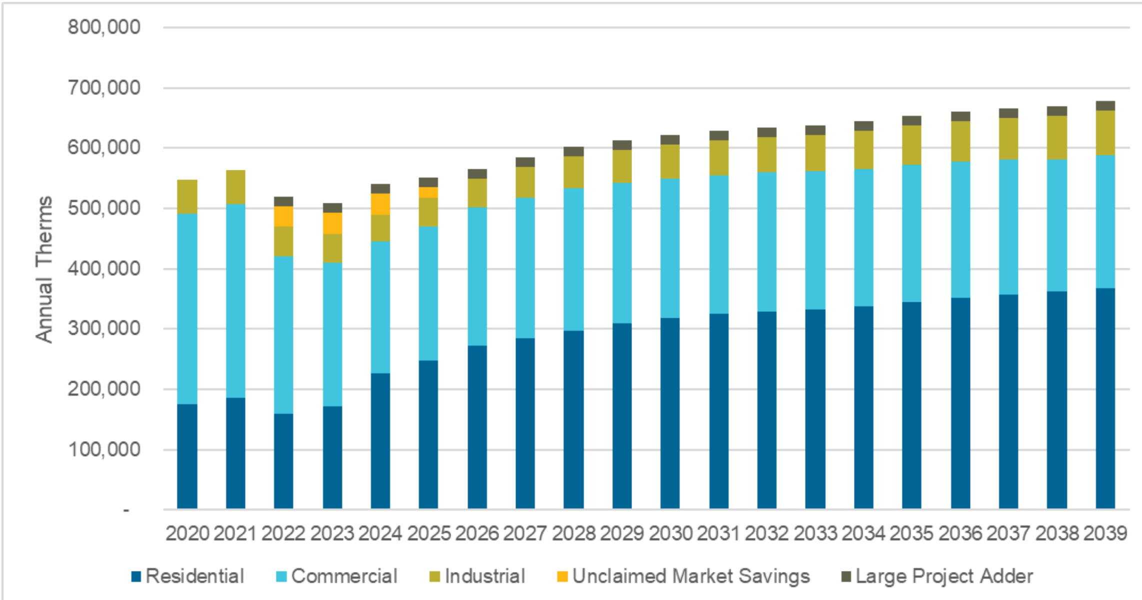
Figure 6-8: Savings Projections for Oregon

	Residential	Commercial	Industrial	All Sectors
Technical	15,330,968	10,907,894	1,495,547	27,734,409
Achievable	13,031,322	9,271,710	1,271,215	23,574,247
Cost-effective achievable	10,567,961	6,259,466	1,229,985	18,057,412
IRP Projected Savings	5,823,039	5,121,593	1,148,116	**12,092,748**

The final savings projection of 12.09 million therms by 2039 in Cascade's service territory reflects the reduction to the full cost-effective achievable potential of 18.06 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. This was done for the New Homes and New Buildings programs.

Figure 6-9 depicts Energy Trust's annual savings projection for Cascade's service territory.

Figure 6-9: 20-Year Annual Projected Savings (2020-2039)



The decline in savings from 2021 to 2023 is due to the expiration of savings from the New Homes programs for past work that contributed to building code changes (otherwise known as market transformation savings) as discussed above[8]. Additionally, some of the forecasted decline in savings is due to changes to measure level savings assumptions due to the use of market baselines. Market baselines are used to develop savings estimates for replacement measures and the baseline assumption is a representation of what the market is currently purchasing, resulting in a weighted average baseline of non-efficient and efficient equipment. As the market matures over time, the market baseline tends to become more efficient, resulting in lower projected savings per measure. Cascade does not include anticipated future savings resulting from market baselines in their load forecast. Therefore, Energy Trust assumes fixed baselines for measures affected by evolving market baselines for the purpose of projecting future savings potential.

Energy Trust calibrates the first five years of the forecast to what programs believe they will be able to obtain and for the first time, programs began to forecast the decline of savings due to market baselines. As a result, for the 2020 IRP, Energy Trust estimated the amount of the program forecasts that are attributed to market baseline and code changes in the first five years of the forecast. Energy Trust included a forecast of these market changes impacts called 'Unclaimable Market

[8]Consistent with practices employed by Northwest Energy Efficiency Alliance, Energy Trust assumes that market transformation savings resulting from Oregon residential codes will persist for homes built for 10 years after the code cycle takes effect. In this case, Energy Trust began claiming savings from the 2011 code in 2012 and these savings will fall off significantly in 2022 and will no longer be claimed at all in 2023.

Savings' in order 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 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 6-10 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 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.

Figure 6-10: 20-Year Cumulative Savings Projections by Savings Type

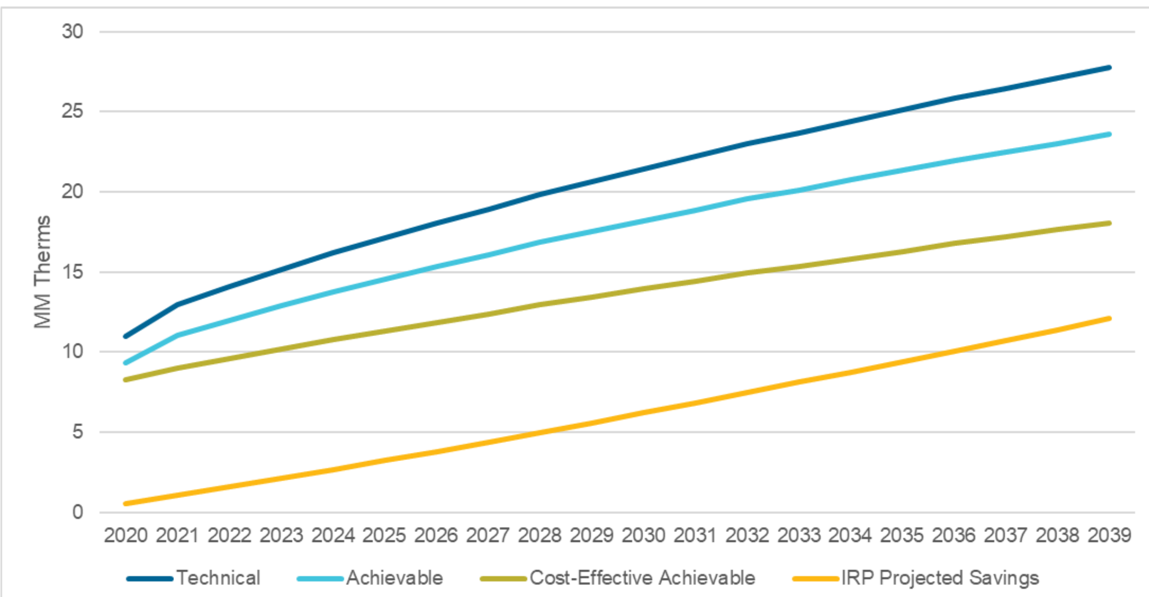


Figure 6-11 provides the cumulative savings projections by sector and savings type. The residential IRP projected savings are a smaller percentage of the total cost-effective achievable potential due to a significant amount of insulation and windows savings that are not fully deployed because they are hard to reach and have lost-opportunities with the new construction market in the early years.

Figure 6-11: Cumulative 20-year Savings Potential by Sector and Savings Type

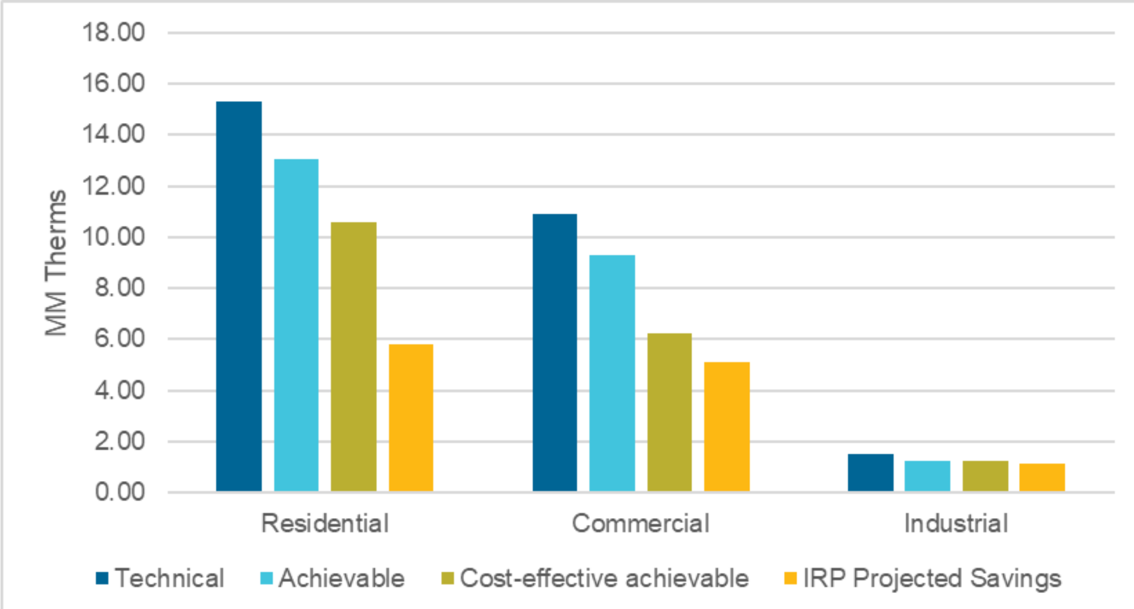


Figure 6-12 shows the potential therm savings per customer class, per measure type per previous discussion.

Figure 6-12: Savings by Customer Class and Measure Type

Measure Type	Residential Therms Saved	Commercial Therms Saved	Industrial Therms Saved
New Construction	1,346,437	913,018	NA
Retrofit	1,694,650	2,119,303	1,070,386
Replacement/Burn-out	1,050,276	936,046	77,730
Strategic Energy Management	NA	811,875	NA
New Construction Market Transformation	1,662,781	NA	NA
Unclaimed Market Savings	NA	122,424	NA
Large Project Adder	NA	287,823	NA
Total	5,754,144	5,190,488	1,148,116

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.

Energy Trust's analysis of the market transformation savings that will result from energy system requirements written into the 2019 commercial code[9] was not complete by the time this forecast took place, therefore commercial market transformation savings are zero. However, the unclaimed savings adder includes a forecast of some of the commercial market transformation savings likely to come from the 2020 commercial code.

Figure 6-13 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 and weatherization end-uses, which occur during peak periods.

[9] For information on the 2019 Oregon Structural Specialty Code visit the Oregon Building and Codes Division Website: https://codes.iccsafe.org/content/OSSC2019P1

Figure 6-13: 20-Year Annual Savings Projection by End Use Category

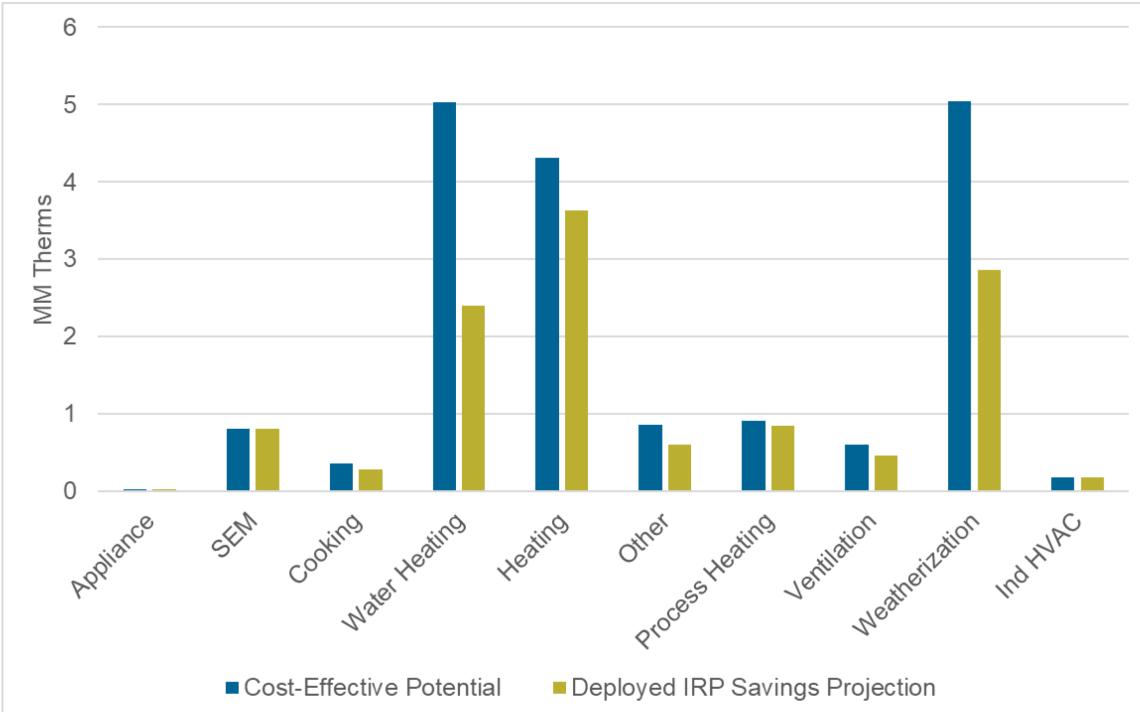
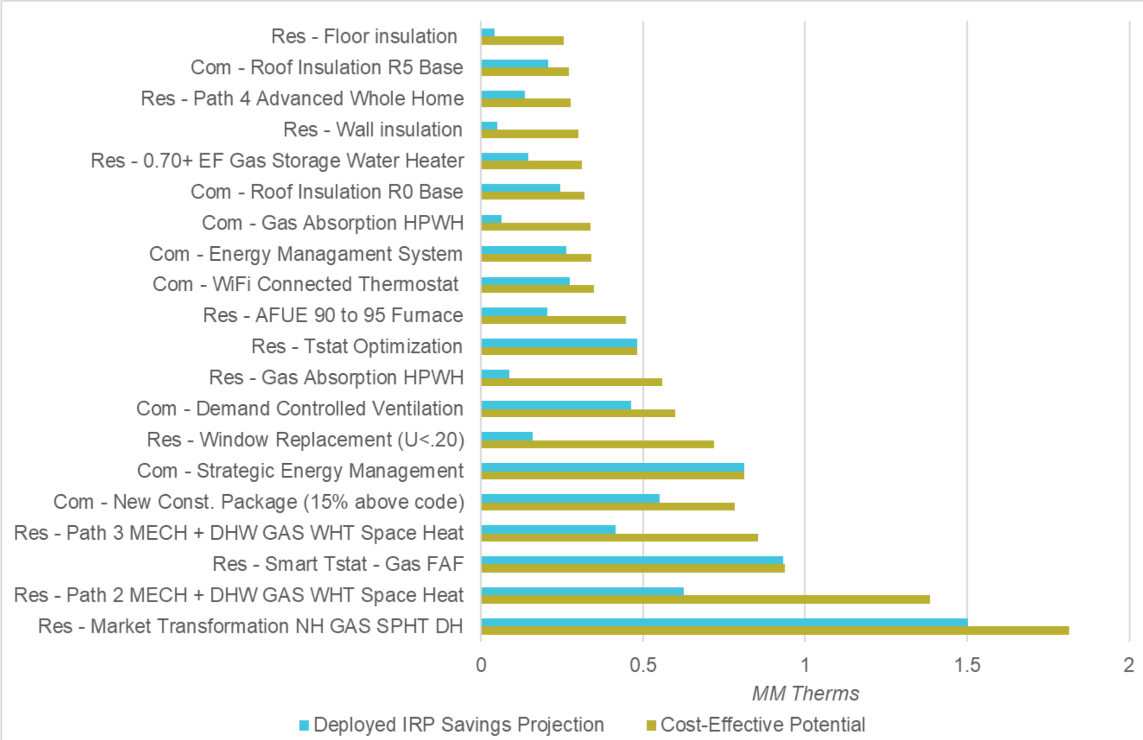


Figure 6-14 lists the top twenty measures from the Model based on their cost-effective potential. The chart also shows how much of that cost-effective potential was deployed and included in the final IRP savings projection. This illustrates the different factors that cause a measure to not achieve 100% of its cost-effective potential, for example:

- *Residential – Floor Insulation & Res – Window Replacement:* These two measures are hard to reach measures that have historically shown low program performance. 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 been slow. The forecast does include a small increase in savings from these measures over time but is more tied to historical performance than other measures.
- *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 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.

Figure 6-14: Top 20 Measures - Cumulative Cost-Effective & Deployed IRP Savings Projections



Impact of Emerging Technologies

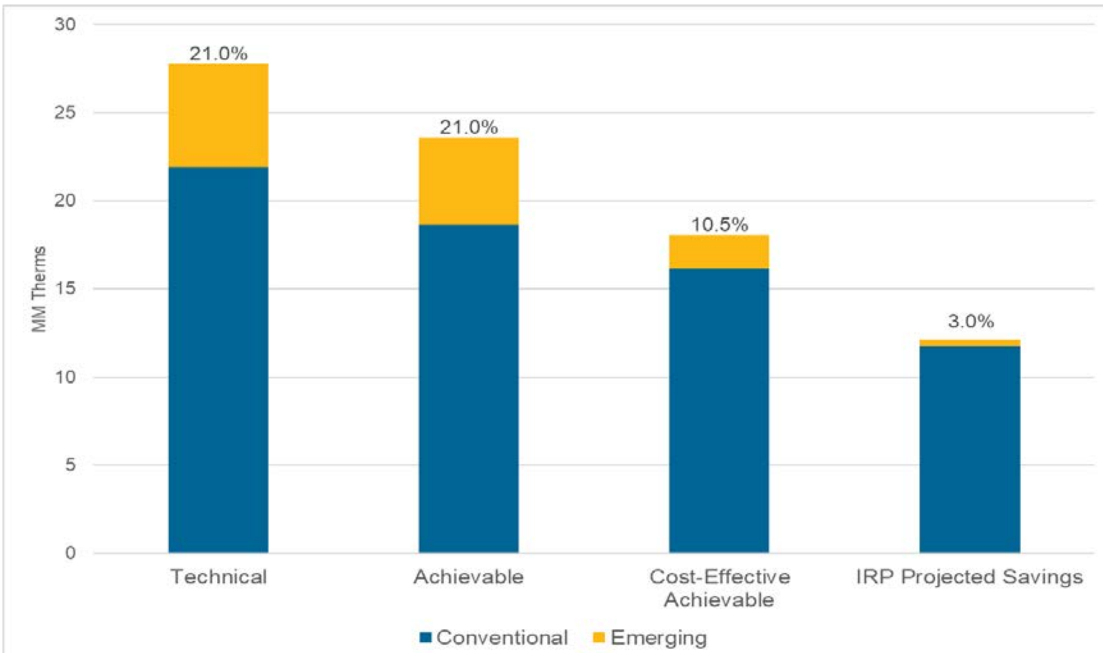
Energy Trust's forecast includes a suite of emerging technologies. These are technologies that are not yet commercially available and are generally high cost. The Model includes cost reduction curves for these technologies to simulate market effects as they become more mature, often resulting in the technology becoming cost effective later in the program. Figure 6-15 indicates the emerging technologies that were included in this forecast.

Figure 6-15: Emerging Technologies Included in the Energy Trust Forecast

Residential	Commercial	Industrial
Path 5 Emerging Super Efficient Whole Home	Advanced Ventilation Controls	Gas-fired HP Water Heater
Window Replacement (U<.20), Gas SH	DOAS/HRV - GAS Space Heat	Wall Insulation- VIP, R0-R35
Absorption Gas Heat Pump Water Heaters	DHW Circulation Pump	
Advanced Insulation	Gas-fired HP HW	
	Gas-fired HP, Heating	
	Zero Net Energy Path	

Figure 6-16 depicts the cumulative impact of emerging technologies on the overall savings potential for each type of potential. Overall, emerging technologies account for over 20% of the technical potential, but only about half of that potential becomes cost-effective 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 cost effective.

Figure 6-16: 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 insulation measures and gas water heaters. Figure 6-3 in the methodology section describes the measures in more detail. The impact of the cost-effective override is small in this IRP; only 5% of the cost-effective achievable of potential is overridden on 1.4% of the deployed potential results from these overridden measures, as detailed in Figure 6-17.

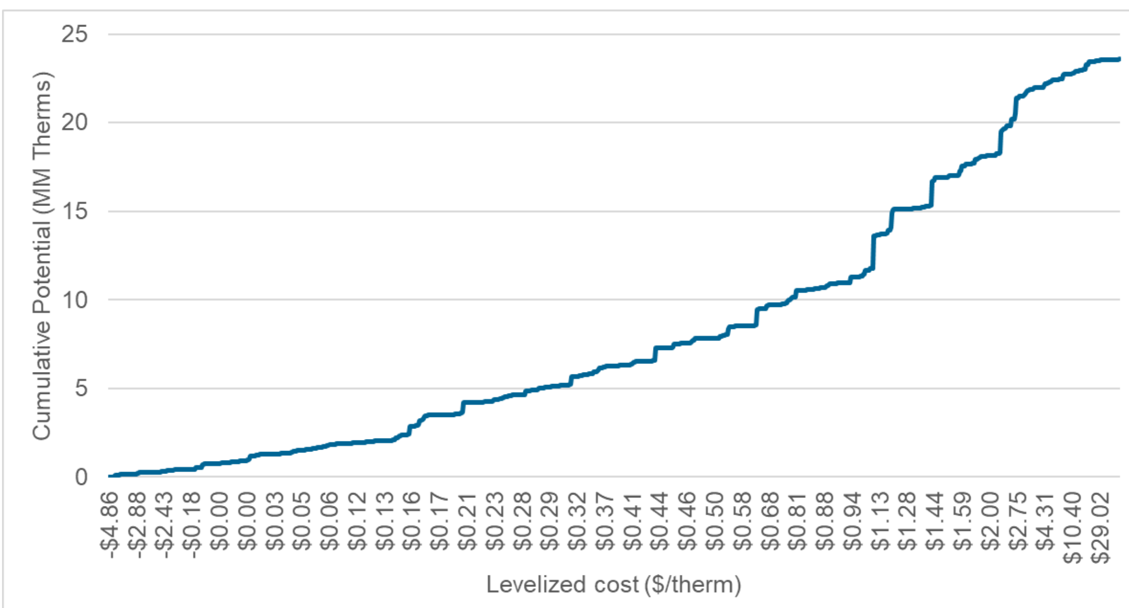
Figure 6-17: Impact of the Cost-Effective Override for Measures under OPUC Exception

Total Cumulative Potential	Cost-Effective Potential	Deployed IRP Savings Projection
Savings with CE Override (MM Therms)	18.06	12.09
Savings with NO CE Override (MM Therms)	17.08	11.93
Variance (MM Therms)	0.98	0.17
CE Overridden % of Total Potential	**5.4%**	**1.4%**

Levelized Cost Supply Curve

Figure 6-18 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.

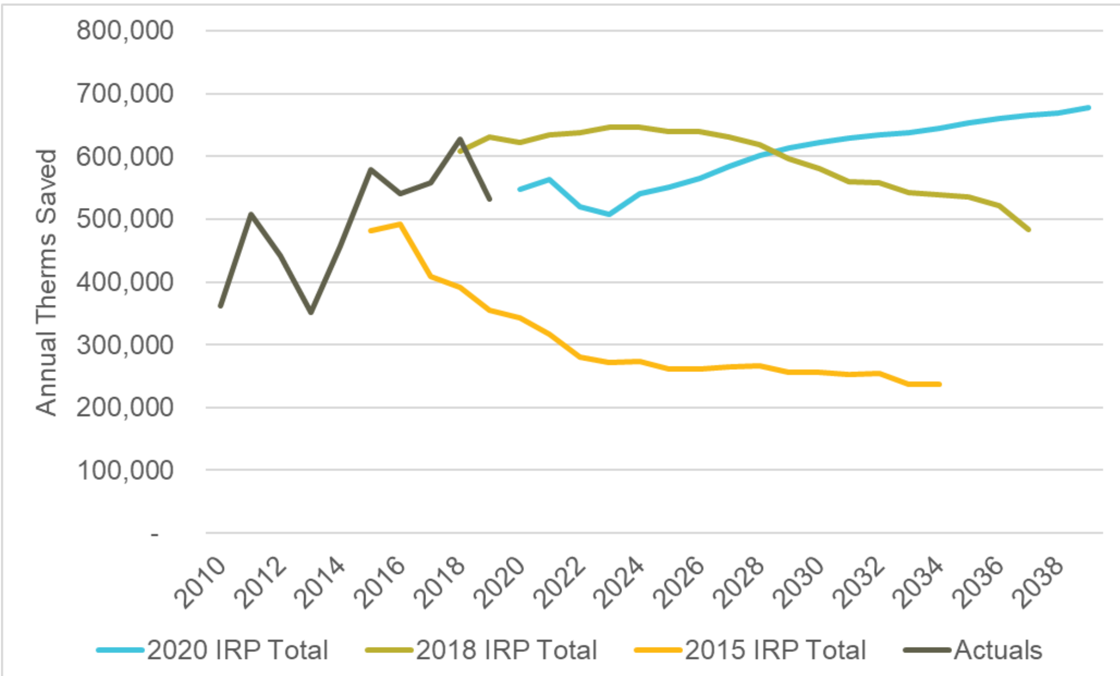
Figure 6-18: Energy Efficiency Supply Curve by Levelized Cost (20-Year Cumulative Achievable Potential)



Savings Projection Comparison to Previous IRPs

Figure 6-19 shows a comparison between the 2015 IRP, 2018 IRP, and 2020 IRP deployed savings potential, with actual savings performance shown in gray for reference. The spikey nature of the actual savings line is reflective of several factors, including the small size of Cascade's Oregon service territory and the potential of overachieving or underachieving due to 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 included a 'large project adder' in the 2020 IRP forecast.

Figure 6-19: Annual Actual Savings History and IRP Projection Comparison (Therms)



Savings for the 2020 IRP increase in the later years, which is a product of the methodology change to align with NWPCC deployment assumptions. Previous forecast vintages were more reflective of what Energy Trust will be able to claim, but the 2020 IRP deploys all the cost-effective savings over the forecast. The later years of the forecast are savings that could come through Energy Trust programs, codes and standards, or market transformation. In the 2020 IRP Energy Trust does not attempt to delineate what portion of the forecasted savings will come from Energy Trust programs after year five of the forecast. The current method should provide a better representation of the loads that will actually come off of Cascade's system due to energy efficiency of all types.

Scenario Runs

For the 2020 IRP, Energy Trust modeled five scenarios for Cascade. This was the first time that Energy Trust provided scenario runs for Cascade's IRP work. The five scenarios were based upon two different levers: carbon prices embedded in the avoided costs and increased/decreased deployment ramp rates. 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 Ramp Rates / Social Cost of Carbon Avoided Costs (higher than Reference Case Avoided Costs)
- *Scenario 2:* Base Case Ramp Rates / Market Price of Carbon Avoided Costs (lower than Reference Case Avoided Costs)
- *Scenario 3:* Base Case Ramp Rates / NO Carbon Price included in Avoided Costs
- *Scenario 4:* Low (Slow) Ramp Rates / Reference Case Avoided Costs
- *Scenario 5:* High (Fast) Ramp Rates / Reference Case Avoided Costs

The first three scenarios utilized different carbon price forecasts; carbon price was chosen as a lever because of the potential for carbon legislation in Oregon in the near term. Note that the base case avoided costs provided by Cascade already include a carbon price forecast that begins in 2021. This carbon price accounts for about 25%-40% of the avoided cost value of a measure, depending on the measure life and load profile. The purpose of these scenarios is to test the sensitivity of different carbon price scenarios, such as the social cost of carbon, or the impact of taking a carbon price out of the avoided costs completely. Energy Trust input these different carbon prices into the avoided cost calculations for each scenario and re-ran the Model to see what might become cost effective or not cost-effective based on these changes to avoided costs. Energy Trust utilized the same ramp rates developed for the base case deployed savings to get the final scenario savings projections.

The final two scenarios were based on speeding up or slowing down the ramp rates in terms of deploying savings potential. This depended on the measure replacement type and whether or not the measure is an emerging technology. For measures that are retrofit replacements, the spread of the savings over the 20-year horizon was either front loaded or only reached 85% of the total potential rather than 100% in the base case. For lost opportunity measures (replacement/new construction), the year in which 100% of the available stocks captured shifted up or down in time. The base case assumption was 100% of turned over stocks will be acquired by year 20. Both of these scenarios utilize the base case avoided costs, including base case carbon price forecasts. Assumptions for each scenario are detailed below:

- Scenario 4: High (Fast) Ramp Methodology:
    - *Lost Opportunity Measures (Replacement/New Construction):* Achieve 100% of available turned-over measures earlier in the forecast (about 5 years)
    - *Retrofit Measures:* Savings are front loaded for measures
    - *Emerging Technologies:* Applied a faster ramp rate ramp rate than base case

- Scenario 5: Low Ramp Methodology:
  - *Lost Opportunity Measures (Replacement/New Construction):* Achieve only 85% of available turned-over measures in the forecast instead of 100% like the base case
  - *Retrofit Measures:* Achieve only 85% of available retrofit potential
  - *Emerging Technologies:* Applied a slower ramp rate ramp rate than base case

Figure 6-20 provides a graphical view of the annual savings potential for each scenario. Each scenario is labeled with an S and a number representing the scenario number it is associated with from the descriptions above, with S0 as the base case. Figure 6-21 provides the cumulative savings potential of each scenario.

Figure 6-20: Annual Savings Comparison of Scenarios

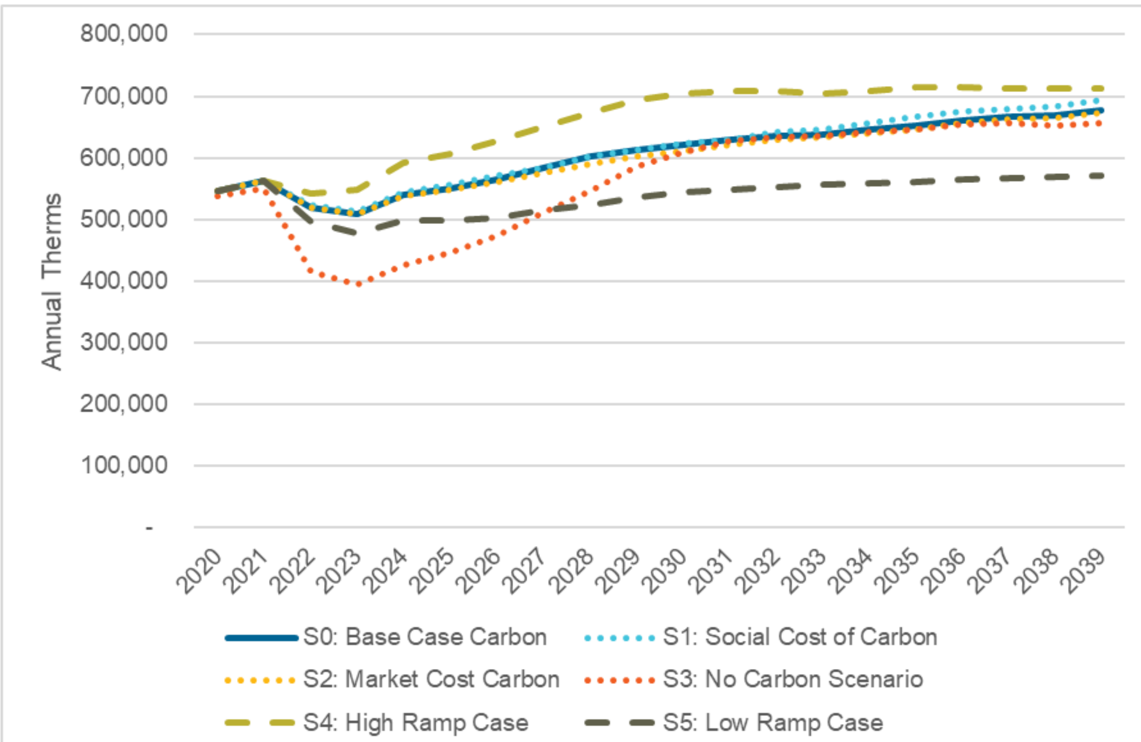


Figure 6-21: Cumulative 20-year Deployed Savings Potential by Scenario

Scenario	20 Year Cumulative Savings Potential (Therms)	% Difference from Base Case
S0: Base Case Carbon	12,092,748	NA
S1: Social Cost of Carbon	12,213,602	1.0%
S2: Market Cost Carbon	11,988,015	-0.9%
S3: No Carbon Scenario	11,299,643	-6.6%
S4: High (Fast) Ramp Case	13,145,690	8.7%
S5: Low (Slow) Ramp Case	10,752,512	-11.1%

The carbon scenarios have minimal impact on the overall potential (+ or – 1%) except for the no carbon scenario, which is about 6.6% lower cumulatively than the base case. This is because Cascade already includes a carbon price forecast in their base case scenario that makes more measures cost effective earlier in the forecast when compared with the no carbon scenario. Therefore, changes to that price forecast are relatively insensitive. Some additional key notes and takeaways from the three carbon scenarios:

- Carbon price has a minimal effect on overall deployed cost-effective potential, unless no carbon is considered at all.
- Measures are tested for cost-effectiveness each year in the Model, so the carbon scenarios most often shift the year when a measure becomes cost-effective, rather than moving measures fully in or out of the whole forecast period.
- The no carbon scenario catches up to the base case over the forecast in terms of annual savings for the same reason as outlined in the last bullet. Avoided costs increase over time, so many of the measures that were not cost effective without a carbon assumption still became cost-effective by the end of the forecast.
- There are relatively few measures that are on the margin (just below a TRC of 1.0).
- These scenarios do not account for customer adoption elasticity.

The high and low ramp scenarios have a much larger impact on overall deployed savings, with the high ramp scenario resulting in about 8.7% more cumulative savings potential than the base case and the low ramp scenario resulting in at about 11% lower savings potential than the base case. These high and low ramp scenarios are meant to represent faster or slower savings acquisition that could be the result of one or a combination of factors, which may include circumstances outlined below. Energy Trust's influence on outcomes is subject to uncertainty associated with how customers will respond to Energy Trust offerings in the midst of other circumstances that are beyond Energy Trust control. Some of the potential reasons that one of the scenarios may occur are:

- Increased incentives from higher avoided costs due to carbon
- Economic booms or slowdowns
- Increased awareness of carbon and therefore increased interest in energy efficiency adoption (or the opposite)
- Increased or decreased funding of energy efficiency in Oregon
- Carbon legislation or other legislation.
- Customer behavior or interest in certain technologies

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 inputted 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 6-22:

Figure 6-22: 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	0.30%	1,099	863
Com Heating	1.80%	89,959	73,216
Domestic Hot Water	0.40%	10,249	4,791
FLAT	0.30%	2,545	2,344
Res Heating	2.10%	192,531	110,512
Res Clothes Washer	0.20%	6	3
Total	**NA**	**296,389**	**191,728**

Peak day savings for each load profile are calculated by multiplying the Peak Day Factor shown in Figure 6-22 against the total cumulative amount of savings for these load profiles. Figure 6-22 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 191,728 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. [10] 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.

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 rebates for the installation of certain weatherization and conservation measures following the completion of a home energy evaluation performed by a qualifying Low-Income, 501c3 organization or a CAA. The rebates 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 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

[10] CAP is a decoupling mechanism.

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 bridges 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-serve 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.

Over the life of the OLIEC program, from 2006 through 2019, 640 homes have been weatherized saving an estimated total of 97,224 therms. Resulting payments to partner CAP agencies have 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.

Cascade staff met with the low-income agencies delivering the OLIEC/CAT program in September of 2019. The agencies expressed challenges associated with their ability to fund the administrative costs associated with rural travel and other work necessary to serve the needs of the Company's service area. They also made several recommendations including:

- Removal of the <R12 starting insulation requirement as baseline insulation standards and codes have changed since the time this was developed;
- Provide administrative funds that cover agency travel. Some agencies must drive 2 ½ hours each way to reach customers in Cascade's service area and this can require an overnight stay; and
- Help with identifying eligible clients.

Cascade is currently exploring the feasibility of these program improvements and will engage with OPUC Staff to determine the best pathway forward. Without program changes, Cascade anticipates that a similar number of homes (3) will be served in 2019-20 as was the previous program year.

It is important to note that based on pilot activities, it is likely the agencies would be able to serve around 100 homes each year, if administrative and funding allowances were adjusted to match other ratepayer funded natural gas weatherization programs in Oregon.

Load Management Programs

The Company also manages load by offering interruptible service, Schedule 177 in Oregon and Schedule 577 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.

Environmental Policy and Legislation

Cascade evaluates the impact of a range of externalities, including CO_2 emissions prices, cost adders, and supply costs. The Company also examines other influences with potential impacts to the delivery of cost-effective DSM efforts such as energy code changes, cost-effectiveness exemptions, and changes in avoided cost and valuation methodologies.

Currently, several regulatory and legislative developments have potential impacts on the demand-side management portion of the IRP. To the best extent possible, these potential impacts have been incorporated into the Oregon DSM projections.

Since the last planning cycle, Cascade has monitored the following legislation, community-driven efforts, and other external actions with the potential to influence natural gas use, and DSM projections, in the states of Washington and Oregon:

Oregon

- Cap and Invest

The Oregon State Legislature did not reach consensus on a direction this year regarding cap and invest legislation. As a result, 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 directs the Environmental Quality Council and Department of Environmental Quality to take actions necessary to cap and reduce GHG emissions. The implications of the Governor's directive can be found below.

- Executive Order 20-04
  - At the end of the 2020 legislative session, Governor Brown issued Executive Order 20-04, which is intended to build on Executive Order 17-20, Accelerating Efficiency in Oregon's Built Environment to Reduce Greenhouse Gas Emissions and Address Climate Change, and to further Oregon's goal of reducing greenhouse gas emissions. The EO provides 13 directives to multiple state agencies, with reporting requirements and deadlines. Specifically, the EO directs the Environmental Quality Council (EQC) and Department of Environmental Quality (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. The EO directs DEQ to commence cap and reduce program options no later than January 1, 2022.

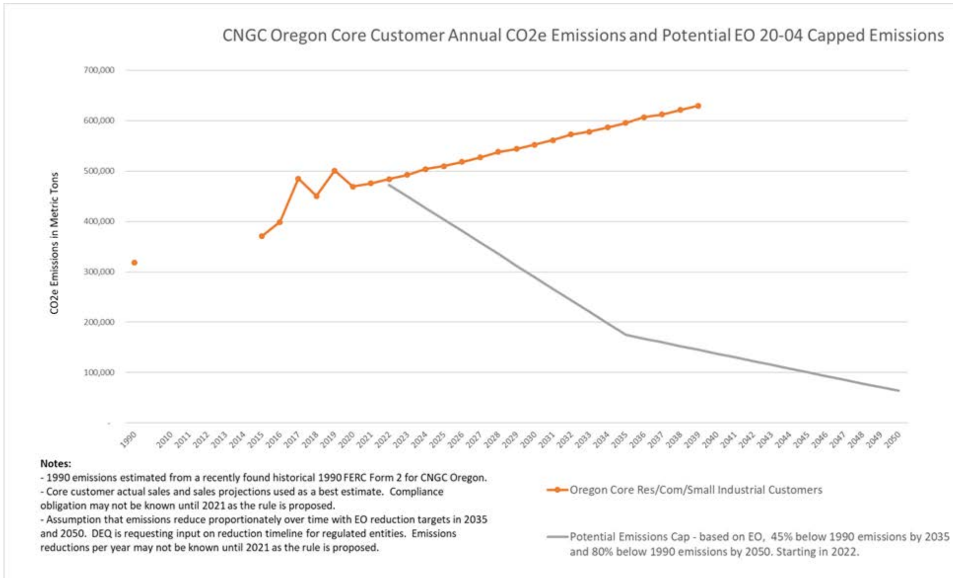
  - The first reporting deadline associated with EO 20-04 was on May 15, 2020. The Governor designated state agencies to report on proposed actions within their statutory authority to reduce greenhouse gases and mitigate climate change impacts. DEQ offered a preliminary report which describes the EQC's legal authority to cap and reduce GHG emissions, proposes a process to engage the public and stakeholders in gathering input into program design options, provides a preview of policy considerations and initial core program design elements, and describes the public comment process on the preliminary report. DEQ also sought public input on a list of questions designed to inform DEQ's final work plan and a final report was submitted to Governor Brown by June 30, 2020.

  - On June 15, 2020, Cascade submitted comments in response to the DEQ's report and associated questions. The Company identified areas of potential impact to Cascade's 75,000 customers in Oregon. As part of its planning efforts, Cascade intends to coordinate with other state agencies, specifically the OPUC and the Oregon Department of Energy (ODOE) to further understand existing program and compliance obligations that may interplay with the Department's cap and reduce efforts. Cascade will work closely with all relevant agencies to consider and manage the fiscal impacts of GHG reductions to natural gas consumers and businesses. Additional considerations may be needed if reduction requirements are difficult to achieve and compliance flexibility is limited.

- The GHG reductions for natural gas suppliers are likely to have substantive impacts to Cascade's customers. The Company has previously estimated cost increases to the company's natural gas customers under the legislative approaches from 2019 to 2020, which incorporated the same GHG reduction goals as published in EO 20-04. Although we expect DEQ's rulemaking could be different, the same goals are stated. If the same reduction goals are applied to natural gas distribution utilities, Cascade's residential and commercial customers may see rate increases in their bills starting in the first year the reductions are to be implemented and would be projected to spike to a 46 percent increase by 2035 and would be expected to increase further as the cap reduces beyond 2035. This projection was anticipated under a legislative approach which included flexibility in the form of allowances, offset purchases and trading. If DEQ's authority is constrained and cannot legally provide compliance flexibility and alternative compliance options, costs will be even higher for natural gas distribution utilities and customers. Emissions reductions required within the strict goal timelines as identified in the EO could result in noticeable increases in energy costs to customers without sufficient compliance flexibility. Cascade will continue to monitor these potential impacts as part of its resource planning.

- DEQ plans to commence formal rulemaking work with the appointment of a rules advisory committee (RAC) in late 2020. DEQ plans to host RAC meetings and any additional public or invited stakeholder meetings in early 2021 and to release a notice of rulemaking packet for public comment in Summer/Fall 2021. The rulemaking packet is expected to be provided to the EQC in Fall 2021. DEQ has not determined a final cap and reduce timeline/trajectory or compliance obligation for regulated entities. However, Cascade has developed a preliminary graph showing past and projected core customer emissions, using the preferred portfolio forecast, representing the combustion of natural gas sold to customers that may potentially be regulated by DEQ under Cascade's compliance requirement. The chart also has a projected emissions reduction trajectory that was estimated by applying a proportionate amount of reduction over time considering the EO's goal of 45 percent reduction of 1990 emissions by 2035 and 80% reduction of 1990 emissions by 2050. Absent a baseline and final trajectory provided by DEQ, Cascade has used an estimate of 1990 emissions from core customer sales volumes provided on a recently located 1990 FERC Form 2 schedule and applies a baseline in 2022 of a three-year average of core customer actual emissions from 2017-2019. Depending on DEQ's approach to rulemaking and designation of a specific emissions baseline, Cascade's compliance obligations may be very different from what is presented here. As DEQ's rulemaking process commences, Cascade is expected to have a clearer picture of compliance obligations.

Figure 6-23: CNGC Oregon Core Customer Annual CO_{2e} Emissions



- o Cascade is also monitoring possible increases to the market price of renewable natural gas as competition for renewable natural gas as a compliance option for multiple sectors increases. Cascade understands that DEQ is planning a rulemaking to increase landfill methane capture in Oregon. The Company has encouraged DEQ to ensure regulations allow for natural gas utilities to utilize landfill gas as a compliance option to reduce GHG emissions for utility customers. The determination of whether landfill gas is allowed as part of cap and reduce compliance will have impacts on the total available RNG potential for Cascade as it increases its planning in this area.

- o In addition to its engagement with DEQ, Cascade submitted comments to ODOE in response to their implementation report submitted to Governor Brown in May 2020. Cascade understands that ODOE will launch a rulemaking process in Summer of 2020 to establish new rules for energy efficient products by September 1, 2020. In addition, ODOE plans to work with the Building Codes Division (BCD) to adopt building efficiency goals for 2030 for new residential and commercial construction. ODOE also plans to work with BCD to report on current progress toward achieving a goal of at least 60 percent reduction in new building annual site energy consumption, and to develop metrics to inform the baseline and reduction associated with code updates.

- Bend Climate Action Plan
    - 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 has actively participated on the CASC and publicly supported the recommendations presented to the City. Cascade is now engaged with Bend City staff and other members of the community to identify ways to help the City meet its targets. Possible pathways forward include partnerships on the integration of biogas, and possible carbon offset programs.

- Renewable Energy Goals
    - Portland has developed a 100% renewable goal. The city proposes to go 100% renewable energy by 2035, and 100% economy wide by 2050. Renewable energy includes energy derived from wind, solar, existing and low-impact hydro, geothermal biogas, and wave technology sources. Similar goals are also under consideration in Hillsboro, Milwaukie, and Beaverton, Oregon. While each of these communities is outside of Cascade's service area, it is important to keep apprised of such targets in the event that they are adopted in areas served by the Company.

- Gas to Electric Fuel-Switching
    - The Cities of Ashland and Eugene have adopted energy action plans to help reduce carbon emissions. As a result of the Ashland Climate and Energy Action Plan, and the Community Climate and Energy Action Plan in Eugene, the Ashland Municipal Electric Utility and Eugene Water and Electric Board are reversing course on the value of the direct use of natural gas for space and water heating, and are considering potential fuel switching from natural gas to electric heat pump technology. Ashland and Eugene plan to begin with the use of renewables for electric generation before aggressively pursuing switching to low carbon and non-carbon fuels.

- SB 98: Pertaining to Renewable Natural Gas (RNG)
    - During 2019 the Oregon State Legislature approved SB 98, which limits the costs to natural gas utilities for procuring RNG and allows for recovery of prudently incurred costs for the purchase of RNG and associated infrastructure by means of an automatic adjustment clause. The law treats small and large gas utilities separately and offers distinct guidelines for these two categories. Cascade, with fewer than 200,000 gas customers in Oregon, qualifies as the latter. The Company is actively participating in OPUC docket AR 632, initiated to develop administrative rules for the OPUC to implement

an RNG program for Oregon gas utilities. Cascade will continue to provide feedback and closely follow the development of the regulatory guidelines that will govern the implementation of this law.

Washington

- Energy Code Changes
  - On November 8, 2019, the Washington State Building Code Council ("SBCC") voted to approve the Fuel Normalization and Additional Credits tables in Section R406.2 with an electric emissions factor of 0.7 lbs/kwh instead of the previously approved carbon emissions factor of 0.8 lbs/kwh for electricity. Under this new language, a heat pump gets one credit assigned when the 0.7 lbs/kwh carbon emissions factor is used. This results in a full credit going to homes using a minimum code heat pump and will likely tilt the selection of heating systems in that direction and away from efficient gas furnaces (which do not receive similar treatment under the code).

- Clean Air Rule
  - On January 16, 2020 the Supreme Court of Washington issued a 5-4 decision vacating in-part and upholding in-part the lower court's decision to vacate the Clean Air Rule (CAR). The Court conclusively determined that the Clean Air Act's purpose section does not authorize Ecology to set emission standards for "indirect emitters" (such as natural gas utilities). The court went on to sever the portions of the rule as they applied to actual emitters (the direct emitter sources) and remanded to the superior court for further proceedings. HB 2957 was introduced to amend existing law to allow CAR to regulate "indirect emitters". A compromise between parties on certain issues in the bill was unsuccessful and the bill died when the legislature adjourned on March 12, 2020.

- HB 1257: Concerning Energy Efficiency
  - On July 28, 2019 HB 1257, the Washington bill concerning energy efficiency, went into effect. The law set new requirements for conservation planning, and energy efficiency target setting, as well as new rules governing the development of conservation potential assessments. It also included language to allow for the recovery of certain biogas investments under the guidance of the WUTC. Cascade is currently engaged in workshops and other regulatory discussions to fully understand the changes that will need to be made to energy efficiency programs, and what opportunities may arise concerning renewable natural gas.

- Other Relevant Legislation
    - Cascade is keeping apprised of additional legislation in Washington State with potential impacts to demand side management and energy usage. Examples include HB 2311, the Greenhouse Gas Emissions Bill which updated Washington's GHG emissions reduction goals to 45%below 1990 levels by 2035, 75% below 1990 levels by 2040, and 95% below 1990 levels by 2050, and HB 2518, the Natural Gas Transmission bill which requires natural gas transmission and distribution companies to expedite mitigation of hazardous leaks, reduce as practicable non-hazardous leaks, and provides utilities rate recovery. Both of these bills were approved this session, and Cascade anticipates that the Governor will sign them into law. Further, the Company anticipates some form of carbon emissions reduction or carbon pricing legislation may be adopted in the 2021 legislative session which will have a direct impact on the use and price of natural gas.

Federal Greenhouse Gas (GHG) Emissions Reduction Policy

Cascade monitors congressional actions on reducing GHG emissions, such as through the Climate Leadership and Environmental Action for the Nation's (CLEAN) Future Act discussion draft developed in the U.S. House of Representatives Energy and Commerce Committee and the American Energy Innovation Act (AEIA) S.2657 developed in the U.S. Senate Energy and Natural Resources Committee. The CLEAN Future Act is intended to achieve a U.S. economy-wide net zero greenhouse gas (GHG) emissions goal by 2050. The House Energy and Commerce Committee will hold hearings and stakeholder meetings on this draft throughout 2020 as the Act is refined. The AEIA is a Senate Energy and Natural Resources Committee compilation of more than 50 energy-related measures proposed to strengthen the domestic economy, national security, and international competitiveness while facilitating cleaner energy that protects human health and the global environment. The AEIA would promote efficiency, renewable energy, energy storage, carbon capture, utilization, and storage (CCUS) for fossil-fired generation facilities, advanced nuclear technology, and industrial and vehicle technology, as well as facilitating energy security and workforce development.

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 has chosen to participate in the program under the Best Management Practice (BMP) Commitment – Excavation Damages 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 the initial commitment timeframe, Cascade will conduct incident analyses on all excavation damages and report the relevant data to EPA as the agency finalizes the reporting forms.

Specifically, Cascade demonstrates its commitment to this program through implementation of BMPs to promote leak reductions. Cascade created the position of Public Awareness and Damage Prevention Coordinator in 2018. This position assists in providing community education and outreach opportunities, focusing on damage prevention, and further reducing potential releases of methane from excavation damages. This position also focuses on working with contractors or third parties that are repeat offenders. By identifying and reaching out to these repeat offenders prior to work beginning on their respective project, Cascade expects to see a reduction in excavation damages throughout the Company's service areas.

Additionally, Cascade actively participates in 811, Common Ground Alliance, 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 lower 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 25 miles of early vintage steel pipe in Oregon, ranging from service lines up to 12-inch mains, with new steel or polyethylene pipe. Also, Cascade has no unprotected steel pipe and no leak-prone cast iron pipe in its systems.

Further, Cascade is better positioned than most U.S. utilities as the Company has no unprotected steel pipeline and none of the potentially leak-prone cast iron pipe seen elsewhere. There are many LDCs who still have cast iron pipe in their systems and are focusing on replacement of that infrastructure.

CHAPTER 7

RENEWABLE NATURAL GAS

Overview

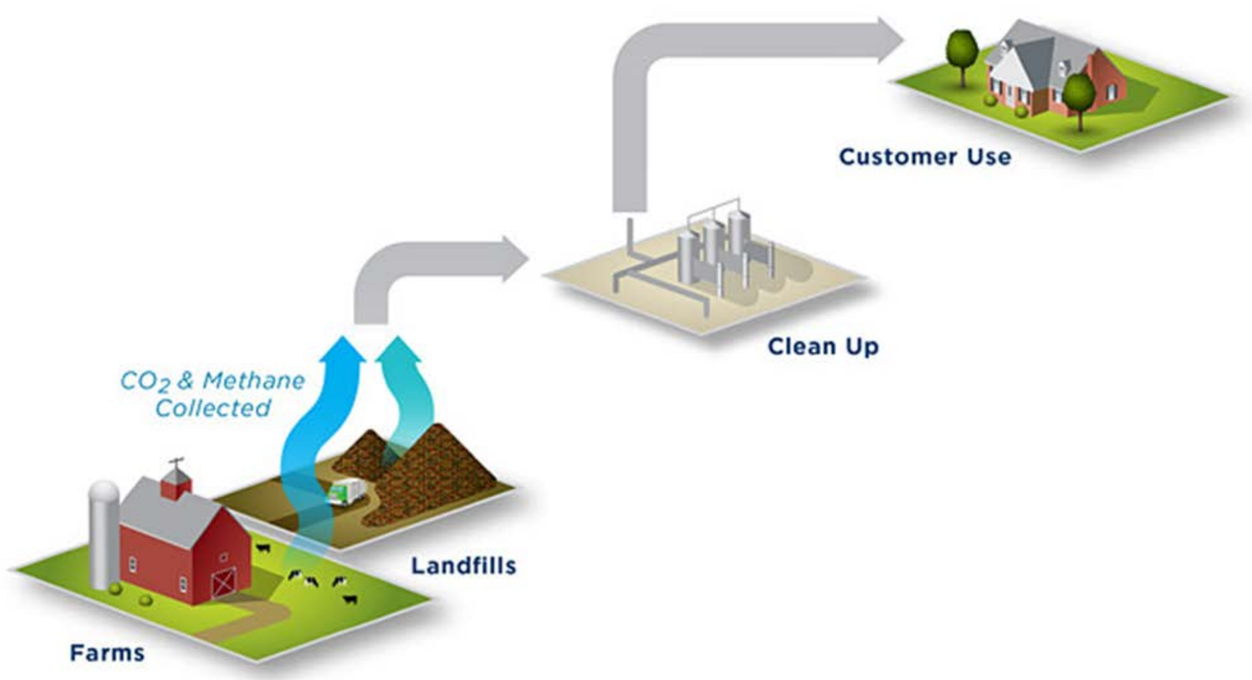
Renewable Natural Gas (RNG), as defined in Senate Bill 98 (SB 98[1]), is any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements:

- Biogas
- Hydrogen gas derived from renewable energy sources; or
- Methane gas derived from a combination of biogas and hydrogen gas derived from renewable energy sources; or
- Natural gas that has been bundled with the necessary environmental attributes so as to represent the full environmental benefits of renewable natural gas.

Key Points

- Cascade is committed to developing programs that allow Cascade to acquire RNG under guidelines and rules stated in Oregon SB 98 and Washington HB-1257.
- The Company has met with several individuals, companies, and producers, potentially sponsoring RNG projects such as municipals, wastewater treatment plans, biodigesters, and landfills.
- On December 4, 2019, the Bend City Council approved its citywide Community Climate Action Plan.
- Taking best practices from other regional LDCs, Cascade has developed a potential RNG cost effectiveness methodology.

Figure 7-1: Example of RNG process from landfill to end user

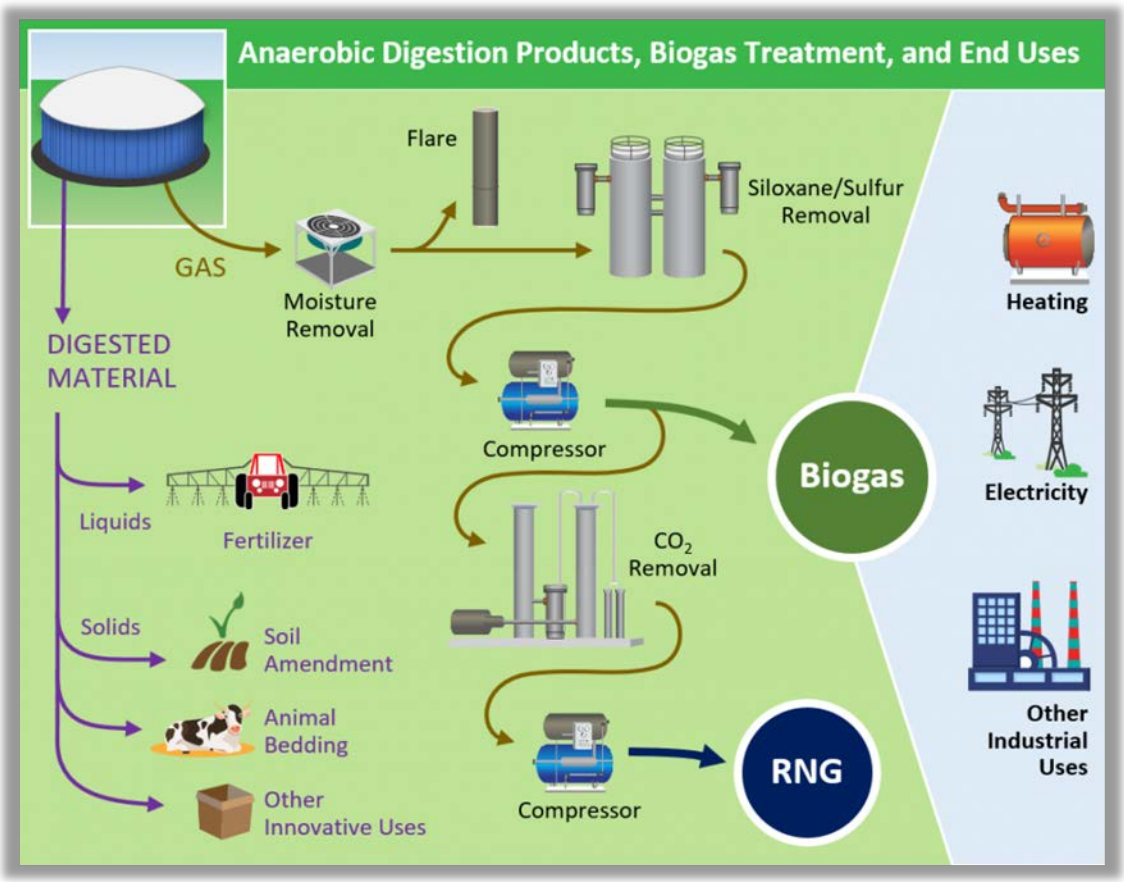


[1] https://olis.leg.state.or.us/liz/2019R1/Downloads/MeasureDocument/SB98/Introduced

Examples of RNG are:

- Biogas from Landfills
    - o Collect waste from residential, industrial, and commercial entities.
    - o Digestion process takes place in the ground, rather than in a digester.
- Biogas from Livestock Operations
    - o Collects animal manure and delivers to anaerobic digester.
- Biogas from Wastewater Treatment
    - o 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.[2]

Figure 7-1: Anaerobic Digestion Products, Biogas Treatment, and End Uses

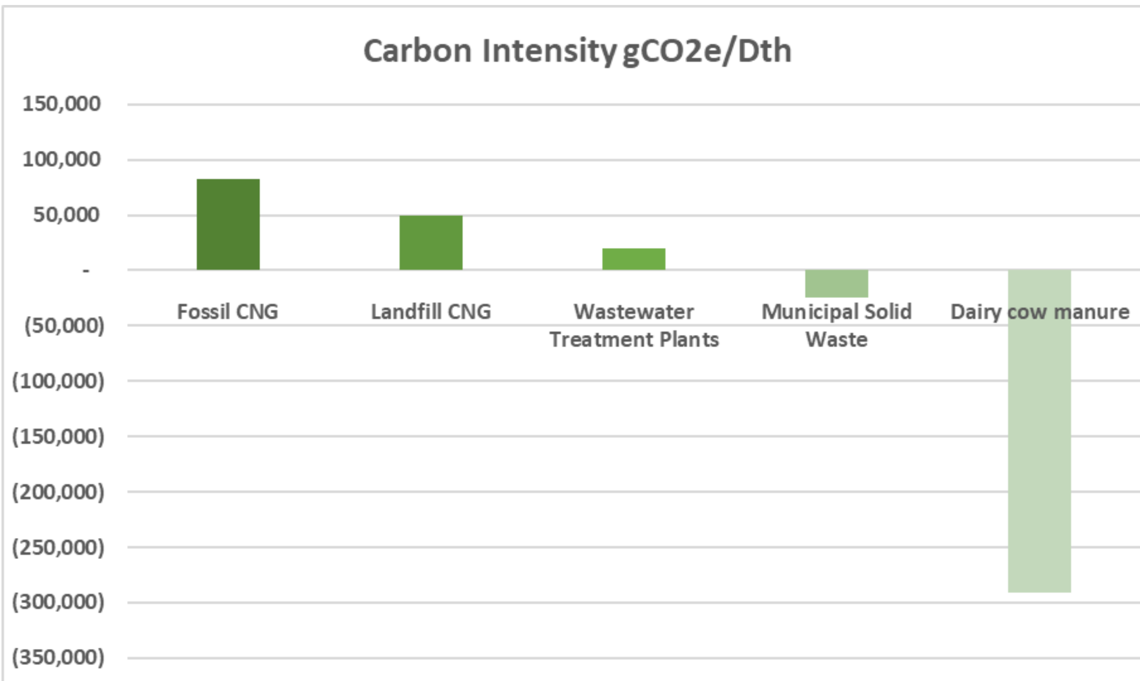


[2] U.S. Department of Energy, Alternative Fuels Data Center, Renewable Natural Gas

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 7-2 highlights the different impact of five different types of natural gas[3].

Figure 7-2: Carbon Intensity of Natural Gas by Source



From a regulatory perspective, there is some debate in both Oregon and Washington as to how these differences should be treated with regards to the valuation of renewable natural gas as a carbon neutralizing resource. Some parties believe it is best to treat all RNG the same to encourage investment in any projects available to produce RNG, while others argue it is critical to capture the exact impact of each RNG project. Cascade will closely monitor the legislative efforts in both states to ensure that the Company properly valuates all future RNG projects.

[3] https://ww2.arb.ca.gov/sites/default/files/classic//research/apr/past/13-307.pdf

Regulatory Matters Regarding RNG

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 section.

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.

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

(1) According to preliminary 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 under the Cascade Market Research subsection later on in the chapter.

(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 has been in discussions with several RNG producers. Currently, none of the projects have a timeline to implement putting RNG on the system. The Company will file an update in the next Annual IRP Update.

(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

Cascade has listed information about opportunities, challenges, and perceived barriers in the Cascade Market Research section. Cascade's current strategy is to gather all market intelligence regarding RNG by meeting with RNG producers and other regional LDCs, as well as following RNG legislation. Gathering as much information as possible will give Cascade the opportunity to make prudent decisions when the Company begins participation in RNG programs.

(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

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

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

Where

$\boldsymbol{C_{RNG}}$ = The all-inclusive annual cost of a proposed RNG project
$\boldsymbol{I_{RNG}}$ = 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.
$\boldsymbol{AC_U}$ = Avoided upstream costs
AC_D = Avoided distribution system costs
$\mathbf{P}$ = Daily price of gas being evaluated
$\mathbf{Q}$ = Daily quantity of gas being evaluated
$\mathbf{VC}$ = 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.
$\mathbf{CIF}$ = Carbon Intensity Factor. This is calculated by multiplying the Company's expected carbon compliance cost by 1 minus the ratio of a proposed projects carbon intensity to conventional gas' carbon intensity.
$\boldsymbol{C_{Conventional}}$ = The all-inclusive annual cost of conventional natural gas.
If $\boldsymbol{C_{Conventional}} \geq \boldsymbol{C_{RNG}}$, 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.

Cascade Market Research

The Company has met with several individuals and companies within the RNG industry such as producers, municipals, 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.
- Digester 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/wastewater treatment projects seen as an ideal option for utilities as they have low RINs and Low Carbon Fuel Standards (LCFS) potential.
- $13-$30/dth long-term off-take deals.

City of Bend Climate Action Plan

On December 4, 2019, the Bend, OR city council approved its citywide Community Climate Action Plan. The plan, which was developed with the guidance of the Climate Action Steering Committee (CASC), was designed to guide the City and the community in pursuit of reducing fossil fuel use by 40% by 2030 and by 70% by 2050.

The Climate Action Plan is comprised of voluntary efforts to encourage greater energy efficiency, use of renewable energy, and resource management in the Bend community. Cascade served as an active participant on Bend's CASC, and continues to support the City's carbon reduction planning efforts.

Cascade and the City share a mutual desire to identify areas of partnership on RNG development. Cascade is currently in discussion with Bend on the exploration of renewable natural gas through the City's wastewater treatment plant, or similar facilities. The Company is also considering the development of a voluntary program to offset fossil gas usage.

Cascade will continue to work with Bend in exploration of RNG and other low carbon opportunities in support of its climate ambitions. The Company will also keep apprised of other communities interested in placing RNG in the distribution system and will coordinate as appropriate.

RNG Projects

As mentioned earlier, the Company has met with several individuals and companies within the RNG industry such as producers, municipals, wastewater treatment plants, biodigesters, and landfills. Location, type of project, and other details are discussed throughout this process to evaluate specific resources. Due to the sensitivite nature regarding the detailed information of actual RNG projects, Cascade will provide those sensitive details in Appendix J under confidential treatment.

RNG Goals

An internal committee composed of Business Development, Gas Supply Operations, Resource Planning, Engineering, and Regulatory personnel has been working with senior management with the goal of developing Cascade's long-term strategy for RNG. As part of these discussions the Company is considering the development of a unique staff position for RNG policy, practice, and direction within the corporate structure. This RNG specific function would likely have overall responsibility for coordinating among various corporate departments and activities (such as the IRP) that are affected by RNG activities.

Additionally, the Company has a goal of continued participation in various RNG rulemakings across the region. Cascade is actively engaged with other LDCs and industry groups to respond to RNG-related legislation in Oregon and Washington (e.g. Oregon SB-98 and Washington HB-1257). Cascade is working towards ensuring compliance RNG rules and regulations identified in dockets such as OPUC dockets AR632, UM2030 and WUTC docket U-190818.

Cascade recognizes that RNG related rules includes the development of potential programs to make RNG available to customers. The Company will work to develop programs that allow Cascade to acquire RNG, while ensuring that related costs to rate base don't result in rate increases of over 5% of the Company's authorized revenue requirement. As implied earlier, resources will ultimately be required to implement rules and create required programs.

Please see Chapter 11, Four-Year Action Plan*,* for more information about future RNG action items.

RNG Scenarios

For the 2020 IRP, Cascade is introducing two new scenarios related to RNG modeling. Both scenarios are purely hypothetical and do not reflect any current negotiations with actual RNG producers, but rather allow the company to model the financial impacts of adding either off-system or on-system RNG to its portfolio. An on-system project would be a project that connects directly to Cascade's distribution system. An off-system project would require upstream capacity to get the RNG to Cascade's distribution system. Additionally, it is important to note that while the information from these scenarios is valuable, SENDOUT® modeling is only one tool that will be used in the RNG evaluation process. Qualitative review of these results, along with other elements that cannot be captured in SENDOUT® but are discussed in Cascade's Project Cost Effectiveness Evaluation Methodology, will be key to the final decisions regarding the acquisition of RNG.

Figure 7-3 compares the annual costs of the Company's portfolio to the costs when an on-system RNG project is added, while figure 7-4 shows the impacts of an off-system RNG project. For both scenarios, Cascade models 300 dekatherms per day of must take supply at $13.50 per dekatherm before environmental attributes.

Figure 7-3: RNG Cost Comparison – On-System RNG

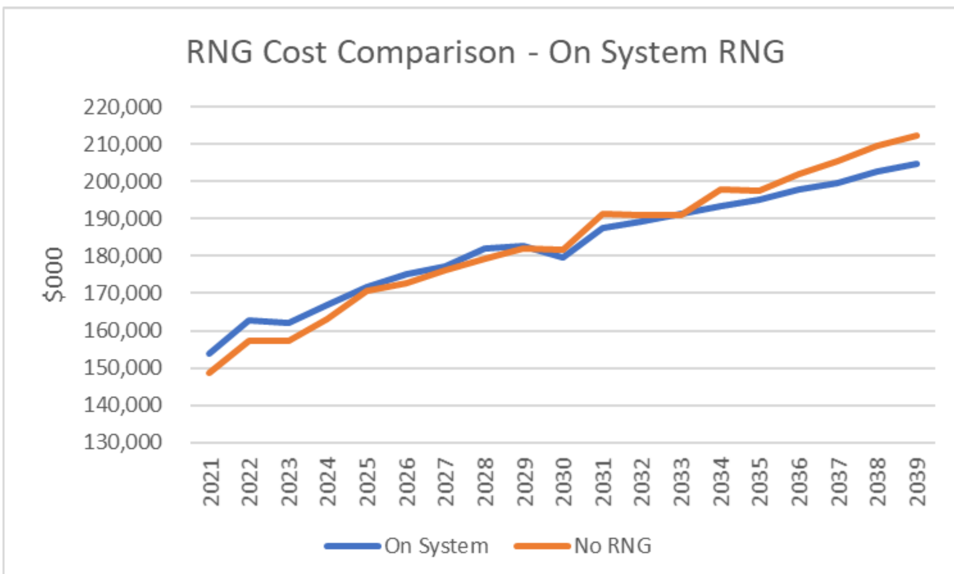
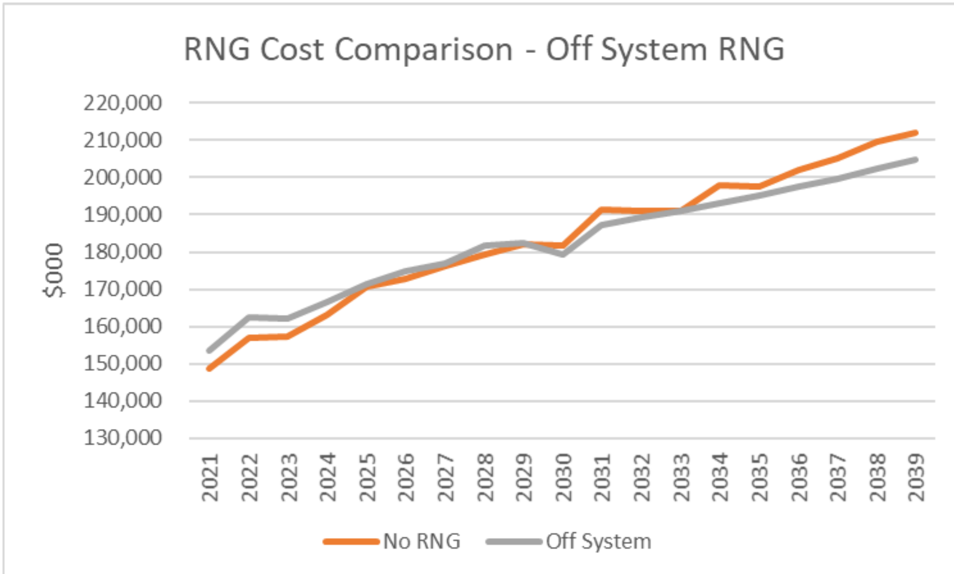


Figure 7-4: RNG Cost Comparison – Off-System RNG



Although not initially cost effective, one noteworthy result of this analysis is that both types of RNG projects do present cost savings opportunities in the later years of the scenarios. The major driver of this inversion is avoided carbon compliance costs, as discussed in Chapter 5, Avoided Costs. If the cost of carbon does ultimately follow a cap and trade marketplace as the Company has modeled, RNG programs may potentially become cost effective starting in 2030 under these scenarios.

Conclusion

RNG presents Cascade with an exciting opportunity to introduce a new resource into the Company's integrated resource plan. Cascade echoes the sentiment of both regulatory bodies and the general public for the Company to use RNG in its system, but decisions to purchase RNG must still follow the regulatory principles of reasonable and reliable least cost, least risk resource acquisition.

Because of the uncertainty surrounding what will ultimately be the value of environmental attributes, Cascade cannot yet definitively conclude what types of RNG programs will prove to be cost effective during the 2020 IRP planning horizon. As more information become available, the Company will update its models and analysis in future IRPs.

CHAPTER 8

DISTRIBUTION SYSTEM PLANNING

Overview

Key Points

- Distribution system network design fundamentals anticipate demand requirements and identify potential constraints.
- Cascade utilizes its internal GIS environment and other input data to create system models through the use of Synergi® software.
- Distribution system enhancements include analyses of pipelines, regulators, and compressor stations.
- Impacts of proposed conservation resources on anticipated distribution constraints are reviewed.
- Analyses are performed on every system at design day conditions to identify areas where potential outages may occur.
- Cascade has identified enhancement projects over the next four years.

Cascade's IRP includes the evaluation of safe, economical, and reliable full-path delivery of natural gas from basin to the customer meter. Securing adequate natural gas supply and ensuring sufficient pipeline transportation capacity to Cascade's citygates are necessary elements for providing gas to the customer. The other essential element is ensuring the distribution system growth behind the citygates are not constrained. Important parts of the planning process include forecasting local demand growth, determining potential distribution system constraints, analyzing possible solutions, and estimating costs for distribution system enhancements.

Analyzing resource needs in the IRP ensures adequate upstream capacity is available to the citygates, especially during a peak event. Distribution planning focuses on determining if adequate pressure will be available during a peak hour. Given this nuance, distribution planning supplements the goals, objectives, risks, and solutions as resource planning.

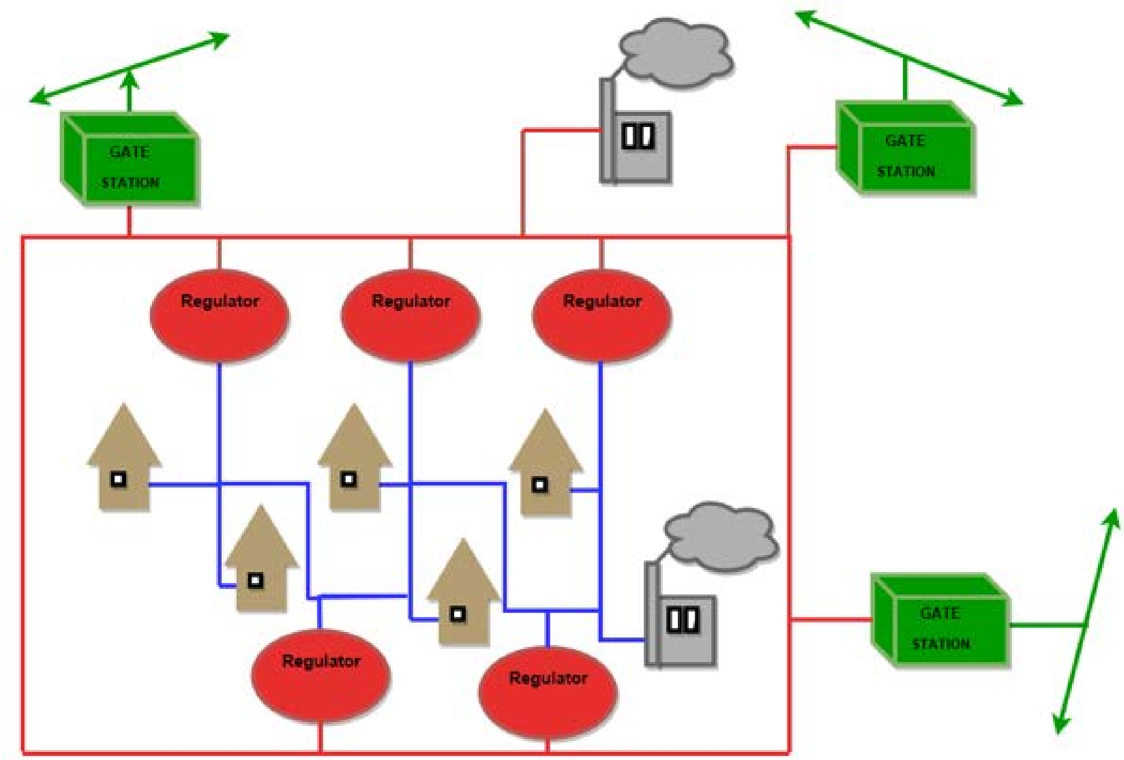
Cascade's natural gas distribution system consists of approximately 1,604 miles of distribution main pipelines in Oregon, and 4,744 miles in Washington, as well as numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment. Cascade operates one compressor station located within Cascade's distribution system near Fredonia, Washington. The vast majority of the distribution network pipelines and regulating stations operate and maintain system pressure solely from the pressure provided by the interstate transportation pipelines.

Network Design Fundamentals

Gas distribution networks rely on pressure differentials to move gas from one location to another. If the pressure is exactly the same on both ends of a pipe, the gas will not flow. Therefore, it is important that gas engineers design the distribution network such that the pressure in the pipe will always be high enough that a differential can be created when gas leaves the system. As gas flow increases, pressure is lost due to friction. Using the laws of fluid mechanics, engineers, informed by flow modeling data, determine the maximum flow of gas through a pipe of a certain diameter and length that will not cause pressure drops that are too great.

Not all natural gas flows equally throughout a network. Certain points within the network constrain flow and restrict overall network capacity. Network constraints can occur as demand requirements evolve. Anticipating these demand requirements, identifying potential constraints, and forming cost-effective solutions with sufficient lead time without overbuilding infrastructure, are the key challenges in network design. Figure 8-1 provides an example of a network diagram.

Figure 8-1: Network Design Fundamentals

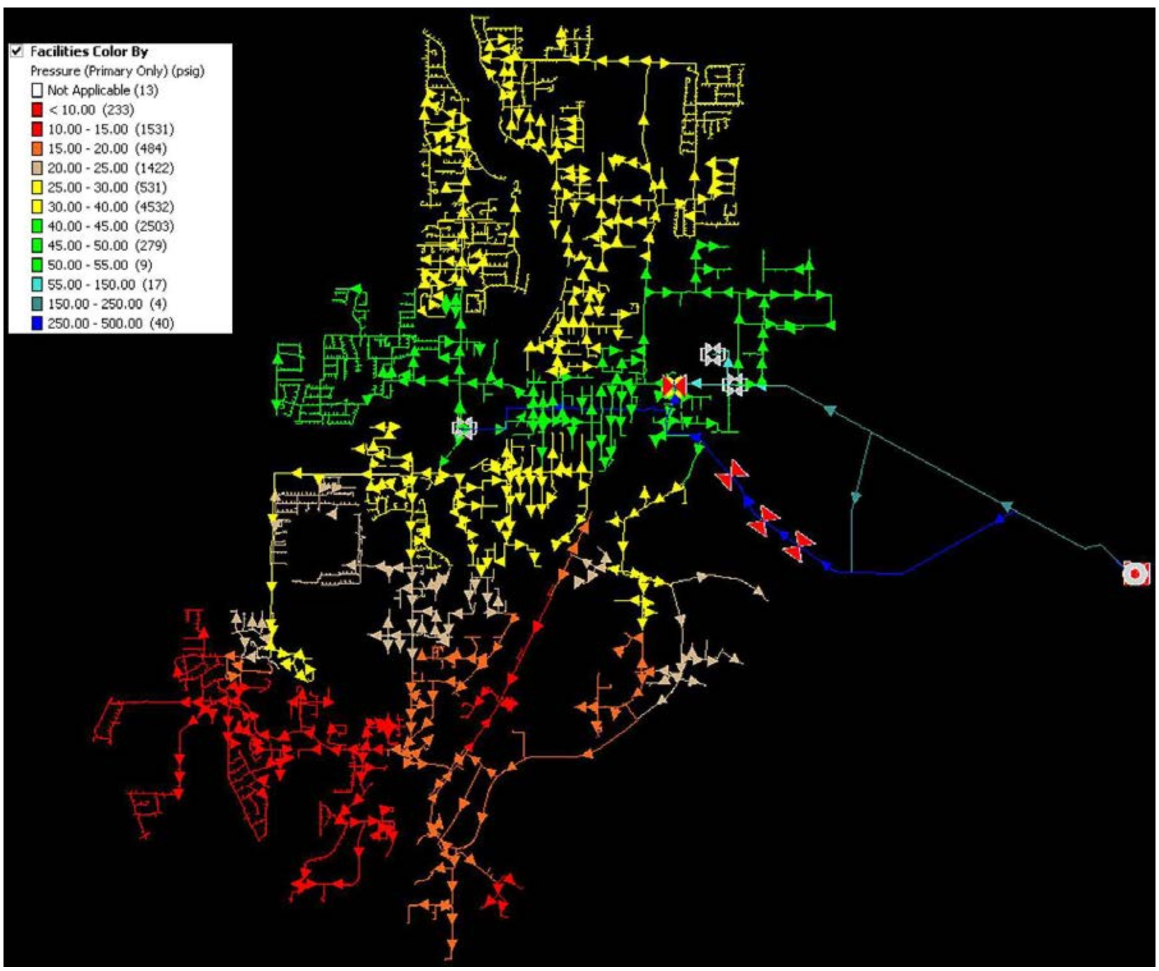


Computer Modeling

Developing and maintaining effective network design is aided by computer modeling for network demand studies. Demand studies have evolved with technology in the past decade to become a highly technical and powerful means of analyzing distribution system performance. Utilizing computer software, individual models are created for each of Cascade's different systems. These models include both high-pressure lines and distribution system networks. As gas loads are simulated to increase according to the demand forecasts, the pressures within each system are checked. When the simulation shows the pressure dropping to an unacceptable level, that system and the surrounding area are determined to be a constraint area. When constraint areas are found, an engineer determines the most cost-effective way of solving the problem.

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 installation and operating pressure. Using the internal GIS environment and other input data, Cascade creates system models through the use of Synergi® software. The software provides the means to model piping and facilities to represent current pressure and flow conditions while predicting future events and growth. Combining these models with historical weather data provides a design day model that can predict a worst-case scenario. Design day models predicting a constraint area are identified and remedied before a real problem is encountered. Figure 8-2 is an example of a low-pressure scenario (constraint area) identified using Synergi®. Ultimately, the planned projects can be funneled through the Distribution Project Process Flow (Figure 8-4 on Page 8-9) to be prioritized and slotted into the budget.

Figure 8-2: Constraint Area Example



Synergi® is used in conjunction with the GasWorks models that were built years ago and have been upgraded as needed. Cascade's philosophy is that models should be reviewed for significant changes annually and recalibrated to represent the system more accurately. Synergi® is more advanced than GasWorks and is much more user-friendly. Synergi® is also the modeling software of choice for many other local distribution companies (LDCs).

Distribution System Planning

Many LDCs conduct two primary types of evaluations in their distribution system planning efforts to determine the need for resource additions such as distribution system reinforcements and expansions. A reinforcement is an upgrade to existing infrastructure or new system additions, which increases system capacity, reliability, and safety. An expansion is a new system addition to accommodate an increase in demand. Collectively, these are known as distribution enhancements.

The engineering department works closely with field operations coordinators and 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. Using system modeling software to represent cold weather scenarios, predictions can be made about the capacity of the system. As new groups of customers seek natural gas service, the models provide feedback on how best to serve them reliably.

Another aspect of system planning involves gate capacity analysis and forecasting. Over time each gate station will take on more and more demand and it is Cascade's goal to get out in front with predictions. The IRP growth data received, along with design day modeling, allows for forecasting of necessary gate upgrades. SCADA technology utilized by Cascade allows verification of numbers with real time and historic gate flow and pressure data. The data proves reliable in verifying models and forecasting projects.

Distribution System Enhancements

Demand studies facilitate modeling multiple demand forecasting scenarios, constraint identification, and corresponding optimum combinations of pipe modification, and pressure modification solutions to maintain adequate pressures throughout the network. Distribution system enhancements increase the overall capacity of a distribution pipeline system while utilizing existing gate station supply points. The purpose of this is to get in front of potential constraints on the distribution system. Distribution system enhancements do not reduce demand nor do they create additional supply. The two broad categories of distribution enhancement solutions are pipelines and regulators.

Pipelines

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 laying 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 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, 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, 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 before 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. A thorough review is conducted to ensure pipeline integrity before pressure is increased. Figure 8-3 provides a snapshot of some of the major components of Cascade’s pipeline system.

Figure 8-3: Cascade System Pipeline Overview

Pipeline:

- Diameter – ½" to 20"
- Material – Polyethylene and Steel
- Operating Pressure - 20 psi to 900 psi
- Washington – approx. 4,744 miles of distribution main
- Oregon – approx. 1,604 miles of distribution main

Regulators

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. Utilization and strategic positioning of new stations can be very helpful in increasing system reliability and capacity. Cascade has over 700 regulator stations along its system.

Compression

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 boosts downstream pressure.

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, 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. Based on Cascade's detailed knowledge of the distribution system, there are no foreseeable plans to add compressors to the distribution network.

Conservation Resources

Reviewing the impacts of proposed conservation resources on anticipated distribution constraints is equally important. Although Cascade historically provides utility-sponsored energy efficiency programs throughout a particular jurisdiction (i.e. all of Cascade's Washington or Oregon service territory), there may be instances where a more targeted approach could reduce or delay the estimated reinforcement for a specific area. As discussed in Chapter 6, Demand Side Management, the acquisition of conservation resources is entirely dependent upon the individual consumer's day-to-day purchasing and behavior decisions. While Cascade attempts to influence these decisions through its energy efficiency programs, the consumer is still the ultimate decision maker regarding the purchase of a conservation measure. Therefore, Cascade does not anticipate that the peak day load reductions resulting from incremental energy efficiency measures will be adequate to eliminate distribution system constraint areas at this time. However, over the longer term (through 2027), the opportunity for targeted energy efficiency programs to provide a cumulative benefit that offsets potential constraint areas may be an effective strategy.

Distribution Project Process Flow

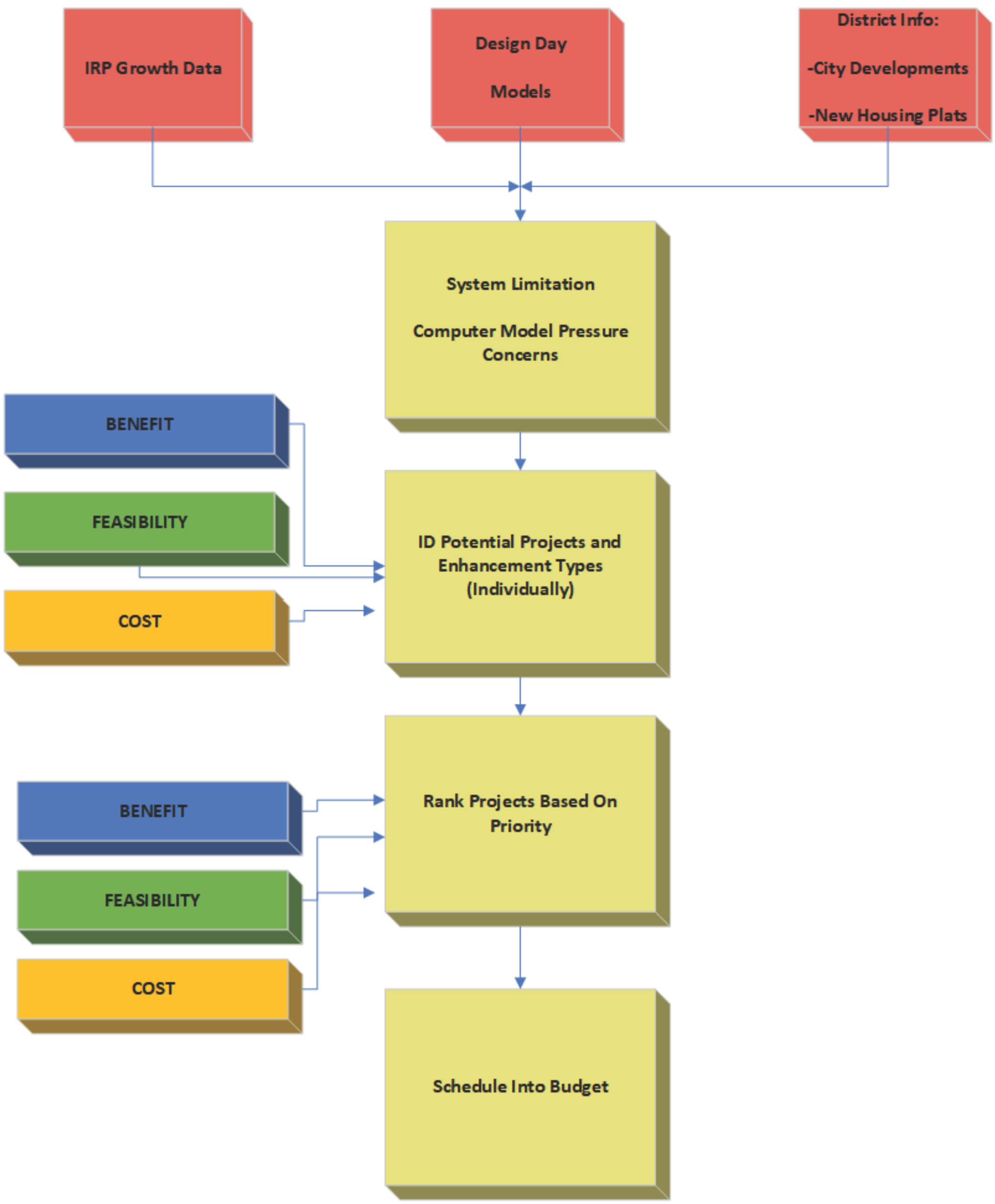
After developing a working demand study, analyses are performed on every system at design day conditions to identify areas where potential outages may occur. These constraint areas are then risk-ranked against each other to ensure the highest risk areas are corrected first and that others are properly addressed. Within a given area, projects/reinforcements are selected using the following criteria:

- The shortest segment(s) of pipe that improves the deficient part of the distribution system.
- The segment of pipe with the most favorable construction conditions, such as ease of access or rights or traffic issues.
- Minimal to no water, railroad, major highway crossings, etc.
- The segment of pipe that minimizes environmental concerns including minimal to no wetland involvement, and the minimization of impacts to local communities and neighborhoods.
- The segment of pipe that provides opportunity to add additional customers.

- Total construction costs including restoration.

Once a project/reinforcement is identified, the design engineer, field operations coordinator, 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, etc., resulting in another iteration of the above project/reinforcement selection criteria. Figure 8-4 provides a schematic representation of the distribution project process flow.

Figure 8-4: Distribution Project Process Flow



Distribution System Planning Results

Figure 8-5 summarizes the estimated costs and timing of distribution system enhancements in Cascade's three Oregon Districts. The summary of these enhancements provides preliminary estimates of timing and costs of major reinforcement solutions addressing growth-related system constraints. The scope and needs of distribution system enhancement projects generally evolve with new information requiring ongoing reassessment. Actual solutions may differ due to changes in growth patterns and/or construction conditions that diverge from the initial assessment.

The following discussion provides a summary of the planned distribution enhancements in Cascade's Oregon Districts:

- Bend District: The Bend area is experiencing rapid growth. The projected customer growth over the next five years will result in constraints in Cascade's distribution system in the cities of Bend, Redmond, and Prineville. Several distribution enhancements have been planned in these cities over the next four years to mitigate the potential constraints. These enhancements include gate station upgrades, extending distribution pipe, installing new regulator stations, and upsizing existing pipe.

- Eastern Oregon District: Baker City is served by one gate station to the south and customer growth results in constrained areas during design day events. The proposed distribution enhancement is to install a new gate station to the north to remediate the low pressure areas and improve reliability by providing a second feed to Baker City.

- Pendleton District: Steady growth in the cities of Pendleton and Hermiston and isolation of the distribution systems due to minimal highway and stream crossings, results in areas of the system requiring enhancement to alleviate potential constraints. The enhancements proposed involve looping the pipeline systems in the constrained areas to provide additional capacity and reliability.

Figure 8-5 provides a summary of Cascade's upcoming growth projects. The specific engineering projects can be found in Appendix I. With the use of the computer modeling software and Cascade's Distribution Project Process Flow, Cascade can identify projects for the longer term. As projects are completed they are integrated into the system to assure the model is current.

Figure 8-5: Distribution Planning Project Summary

Location	2020	2021	2022	2023
Bend District	$ 2,433,788	$ 2,665,856	$ 3,052,484	$ 2,562,402
Eastern Oregon District	$ -	$ 1,229,692	$ -	$ -
Pendleton District	$ -	$ 486,118	$ 377,393	$ 830,765

Conclusion

Cascade's goal is to maintain its natural gas distribution system's reliablity and to cost-effectively deliver natural gas to every core customer. This goal relies on modeling to increase the capacity and reliability of the distribution system by identifying specific areas that may require changes. The ability to meet the goal of reliable and cost-effective natural gas delivery is enhanced through localized distribution planning, which enables coordinated targeting of distribution projects responsive to customers' growth patterns.

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 serve the forecasted load requirements of the core customers. The tool used to accomplish this task is a computer optimization model known as SENDOUT®.

SENDOUT® 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. SENDOUT® 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 SENDOUT® 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 using Value at Risk (VaR) analysis.
- The optimal portfolio includes all existing resources plus incremental DSM.
- Cascade's first material long-term As-Is deficiency occurs in 2033 around Bend, Oregon. Shortfalls are projected across the Company's entire service area by the end of the planning period.
- With incremental resources, all forecasted deficiencies are eliminated, at costs that are within Cascade's VaR limit.

Supply Resource Optimization Process

The process for optimizing supply resources is summarized in the following eight steps and shown graphically in Figure 9-2 on page 9-5.

- **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. Once the resource need was identified, Cascade utilized its market intelligence to identify all potential options to solve for the projected shortfall.

- **Step 2: Introduce Additional Resources**
  - Once shortfalls were identified, Cascade utilized SENDOUT® 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 2020 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.

Figure 9-1: Breakdown of Candidate Portfolios

	GTN	No GTN
NWP	- All-In - All-In Less DSM	- NWP Only - NWP Only w/ Storage
No NWP	- GTN Only - GTN Only w/ Storage	- Storage Only

- **Step 3: Stochastic Analysis of All Portfolios Under Existing Conditions**
  - Once Cascade selected its portfolios, each one was tested stochastically. Each portfolio was run through a 10,000 draw Monte Carlo weather simulation under normal growth, pricing, and storage/supply accessibility. The Company recorded the total system cost and unserved demand of each draw, as these are the metrics used to rank the portfolios.

- **Step 4: Ranking of Portfolios**
  - Cascade took the unserved demand and total system cost of all draws in each portfolio and calculated the mean and VaR of the portfolios. For its modeling purposes, the Company defines VaR as the 99th percentile of unserved demand and total system cost. This is a generally-accepted methodology for determining a reasonable worst-case scenario for risk analysis. Cascade ranked its portfolios by first giving preference to any portfolio that fully solved for unserved demand in both stochastic and deterministic analysis. After that, 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 and energy efficiency for Cascade and its customers. This is now deemed to be the Top Ranked Candidate Portfolio, but it is still just a Candidate Portfolio until it has passed a rigorous scenario and sensitivity analysis.

- **Step 5: Stochastic Scenarios of Candidate Portfolio**
  - Cascade created nineteen different scenarios to stochastically test its candidate portfolio. These scenarios, which are detailed in Figure 9-3, measure how the portfolio performed in high and low growth environments, as well as various restrictions related to storage availability. In each scenario, the portfolio was run through a 10,000 draw Monte Carlo weather simulation, and the total system cost at the 99th percentile was recorded as the VaR for the Candidate Portfolio in that scenario.

- **Step 6: Scenario Analysis of Candidate Portfolio**
  - The VaR of the Candidate Portfolio in each scenario was compared to the Company's VaR limit, which was set by Cascade's Gas Supply Oversight

Committee (GSOC) and was equal to 1.25 times the mean total system cost of the portfolio under expected conditions. If the VaR in any scenario exceeded this limit, that portfolio may be rejected, and the next highest ranked portfolio would become the new Top Ranked Candidate Portfolio for scenario analysis. If the VaR of all scenarios did not exceed this limit, the portfolio passed scenario testing and moved to sensitivity testing.

- **Step 7: Sensitivity Testing of Candidate Portfolio**
  - Cascade created eight different pricing environments to stochastically test its candidate portfolio. These sensitivities, which are detailed in Figure 9-3, measure how the portfolio performed in high and low price situations, as well as with a range of adders related to carbon legislation. In each sensitivity, the portfolio was run through a 10,000 draw Monte Carlo NYMEX price simulation, and the total system cost at the 99th percentile was recorded as the VaR for the Candidate Portfolio in that sensitivity.

- **Step 8: Sensitivity Analysis of Candidate Portfolio**
  - Similar to comparing the scenarios in Step 6, the VaR of the Candidate Portfolio in each sensitivity was compared to the Company's VaR limit, which was set by Cascade's GSOC and was equal to 1.25 times the mean total system cost of the portfolio under expected conditions. If the VaR in any sensitivity exceeded this limit, that portfolio may be rejected, and the next highest ranked portfolio would become the new Top Ranked Candidate Portfolio for scenario analysis. If the VaR of all sensitivities did not exceed this limit, the portfolio passed sensitivity testing and could be confirmed as Cascade's Preferred Portfolio. Figure 9-2 displays this process as a flowchart.

Figure 9-2: Supply Resource Optimization Process Flow Chart

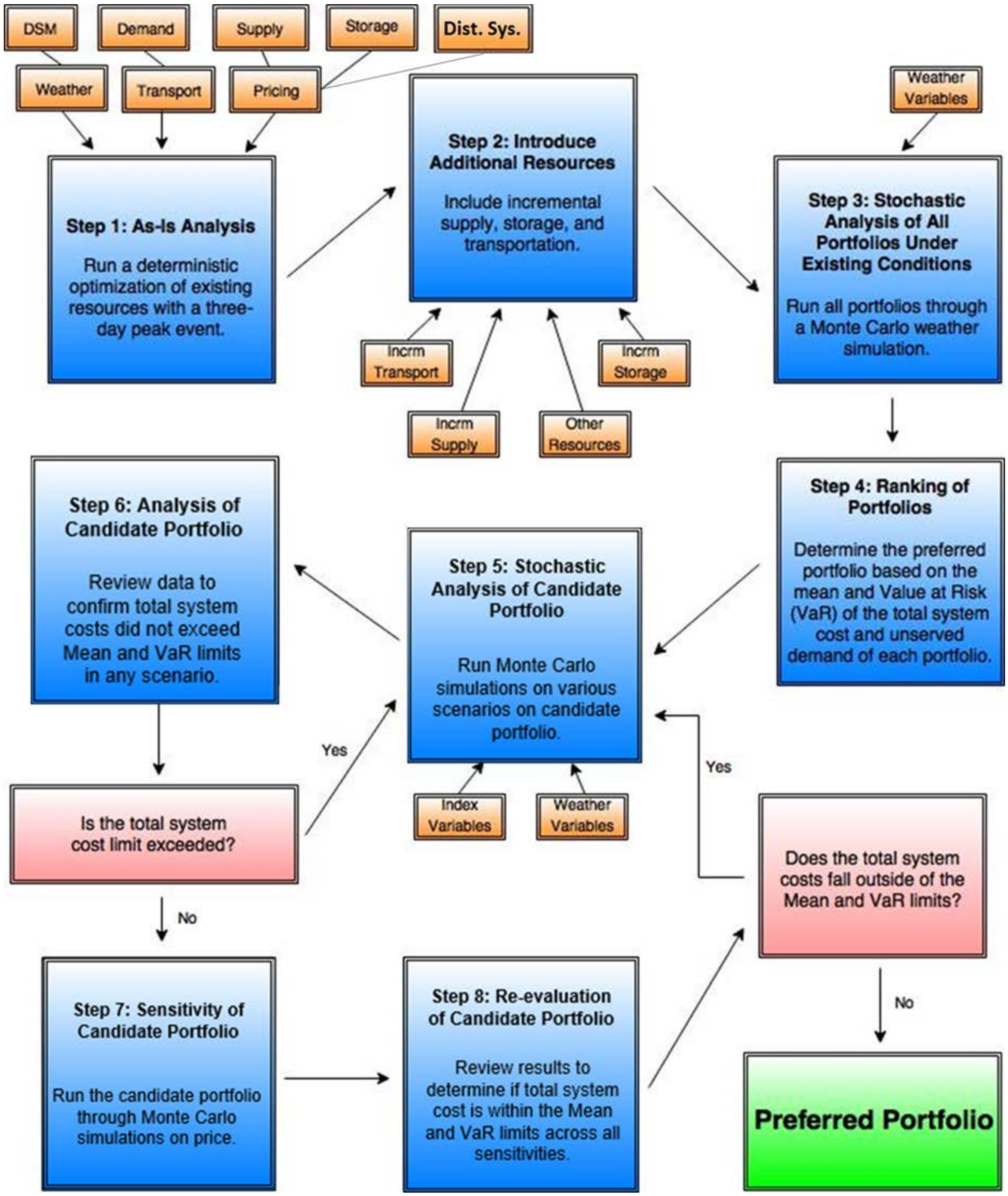


Figure 9-3: Breakdown of Scenarios & Sensitivities Modeled

Scenarios and Sensitivities		Assumptions: Growth	Weather	Price	Carbon Forecast	Constraints	First Year Unserved
Expected Conditions		Medium Load Growth	Stochastic Weather	Stochastic Pricing	Cap and Trade	None	N/A
Transportation	**No Evergreen**	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No Current Contracts Evergreen	2024
Growth	**High Growth**	High Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	None	2035
	Low Growth	Low Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	None	N/A
Environmental Adder	**0%**	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing with a 0% Environmental Adder	Cap and Trade	None	N/A
	20%	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing with a 20% Environmental Adder	Cap and Trade	None	N/A
	30%	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing with a 30% Environmental Adder	Cap and Trade	None	N/A
No Supply	**No Alberta Supply**	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No gas from Alberta	2020
	No BC Supply	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No gas from British Columbia	2020
	No Rockies Supply	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No gas from Rockies	2021
	No Canada Supply	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No gas from Canada	2020
Limit Supply	**Limit Alberta**	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No day gas from Alberta	N/A
	Limit BC	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No day gas from British Columbia	N/A
	Limit Rockies	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No day gas from Rockies	N/A
	Limit Canada	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No day gas from Canada	N/A
No Storage	**No JP**	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No access to Jackson Prairie	N/A
	No Plymouth	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No access to Plymouth storage	N/A
	No Mist	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	No access to Mist storage	N/A
Limit Storage	**Limit JP**	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	25% access to Jackson Prairie	N/A
	Limit Plymouth	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	25% access to Plymouth storage	N/A
	Limit Mist	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	Cap and Trade	25% access to Mist storage	N/A
Carbon Forecasts	**No Carbon**	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing	No Carbon Forecast	None	N/A
	Social Cost of Carbon	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing	SCC w/ 3% Discount Rate	None	N/A
	Market Choice	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing	House of Representatives' Market Choice Proposal	None	N/A
	Stochastic Carbon	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing	95th percentile of potential Carbon Forecasts	None	N/A
Price Forecast	**High Price Forecast**	Medium Load Growth	Average Weather with Peak Event	High Pricing Environment	Cap and Trade	None	N/A
RNG	**RNG #1**	Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	Cap and Trade	Must Take On-System RNG Added	N/A
	RNG #2	Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	Cap and Trade	Must Take Off-System RNG Added	N/A

While Chapter 12 includes a full glossary, terms related to Figure 9-3 are shown below for convenience.

Terms Used in Figure 9-3

Average Weather with Peak Event – The weather pattern was modeled using historical weather data in each of Cascade's climate zones for the past 30 years. In addition, a design peak day was inserted on December 21st of each year to allow for conservative forecasting to model the coldest day in Cascade's system over the past 30 years.

Stochastic Weather – The weather pattern was modeled using historical weather data in each of Cascade's climate zones. This data is run through a Monte Carlo simulation, which allows the Company to derive the 99th percentile of potential system weighted heating degree days (HDDs).

No Evergreen – A transportation constraint where Cascade models the impact of not renewing any contracts with a termination date before the end of the 20-year planning horizon.

Low Customer Growth – Low customer growth scenarios were created by examining the low end of the confidence intervals of Cascade's customer forecast, as mentioned on page 3-17.

Medium Customer Growth. Cascade used its expected customer forecast, as mentioned on page 3-17 for the expected growth scenario

High Customer Growth – High customer growth scenarios were created by examining the high end of the confidence intervals of Cascade's customer forecast, as mentioned on page 3-17.

Medium Pricing Environment – Price was modeled using Cascade's price forecast, which was derived by weighting the forecasts from multiple sources over the 20-year planning horizon.

High Pricing Environment – Price was modeled using Cascade's price forecast, which was derived by weighting the forecast of a number of sources over the 20-year planning horizon. Prices were then increased by 5% at all markets to simulate a high pricing environment over the 20-year period.

Stochastic Pricing – NYMEX Pricing was modeled by running Cascade's price forecast through a Monte Carlo simulation, which allows the Company to identify the 99th percentile of potential NYMEX pricing based on the deterministic projections.

Stochastic Pricing with 0% Adder – Price was modeled using Cascade's price forecast, which was derived by weighting the forecasts from its sources over the 20-year planning horizon. Cascade then removed the 10%

environmental adder, originally in place to simulate the impact of unforeseen environmental conditions.

Stochastic Pricing with 20% Adder – Price was modeled using Cascade's price forecast, which was derived by weighting the forecast of its sources over the 20-year planning horizon. Prices were then increased by 20% at all markets to simulate the impact of unforeseen environmental conditions.

Stochastic Pricing with 30% Adder – Price was modeled using Cascade's price forecast, which was derived by weighting the forecast of its sources over the 20-year planning horizon. Prices were then increased by 30% at all markets to simulate the impact of unforeseen environmental conditions.

Cap and Trade – This is modeled as Cascade's base carbon forecast for the 2020 IRP as an adder to Cascade 20-year price forecast and avoided cost starting in 2021. The Company uses the California Energy Commission's Integrated Energy Policy Report (IERP) 2019 Preliminary GHG Allowance Price Projection as a proxy for the projected pricing of an Oregon Marketplace.

SCC w/ 3% Discount Rate – This is modeled as an adder to Cascade 20-year price forecast and avoided cost starting in 2021. The source of this forecast is the Interagency Working Group on Social Cost of Greenhouse Gases' Technical Support Document: Technical Update of the Social Cost of Carbon (SCC) for Regulatory Impact Analysis Under Executive Order 12866.

House of Representatives' Market Choice Proposal – A carbon sensitivity based on the proposed carbon tax that was introduced to the US House of Representative on January 24, 2019 (H.R. 763)[1]. The proposal is not expected to pass but is a good proxy for a potential national tax. This is modeled as an adder to Cascade 20-year price forecast and avoided cost starting in 2020.

Must Take On-System RNG – This is a hypothetical renewable natural gas resource that is inserted into the scenario at the zonal level, meaning no additional upstream capacity is needed to inject the supply at a citygate. Pricing, quantity, and timing of the resource, as well as the impact of this resource, is discussed further in Chapter 7, Renewable Natural Gas.

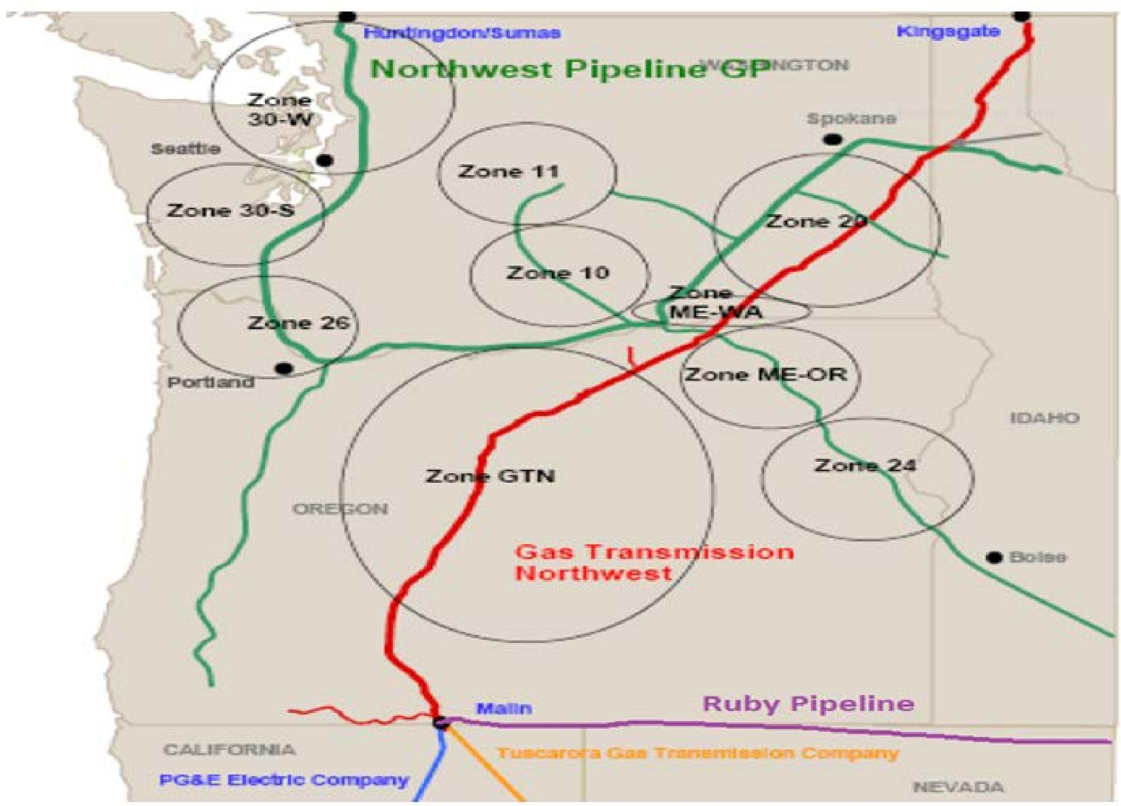
Must Take Off-System RNG – This is a hypothetical renewable natural gas resource that is inserted into the scenario at the supply basin level, meaning additional upstream capacity is needed to inject the supply at a citygate. Pricing, quantity, and timing of the resource, as well as the impact of this resource, is discussed further in Chapter 7, Renewable Natural Gas.

[1] H.R.763 - Energy Innovation and Carbon Dividend Act of 2019 (https://www.congress.gov/bill/116th-congress/house-bill/763/text)

Planning and Modeling

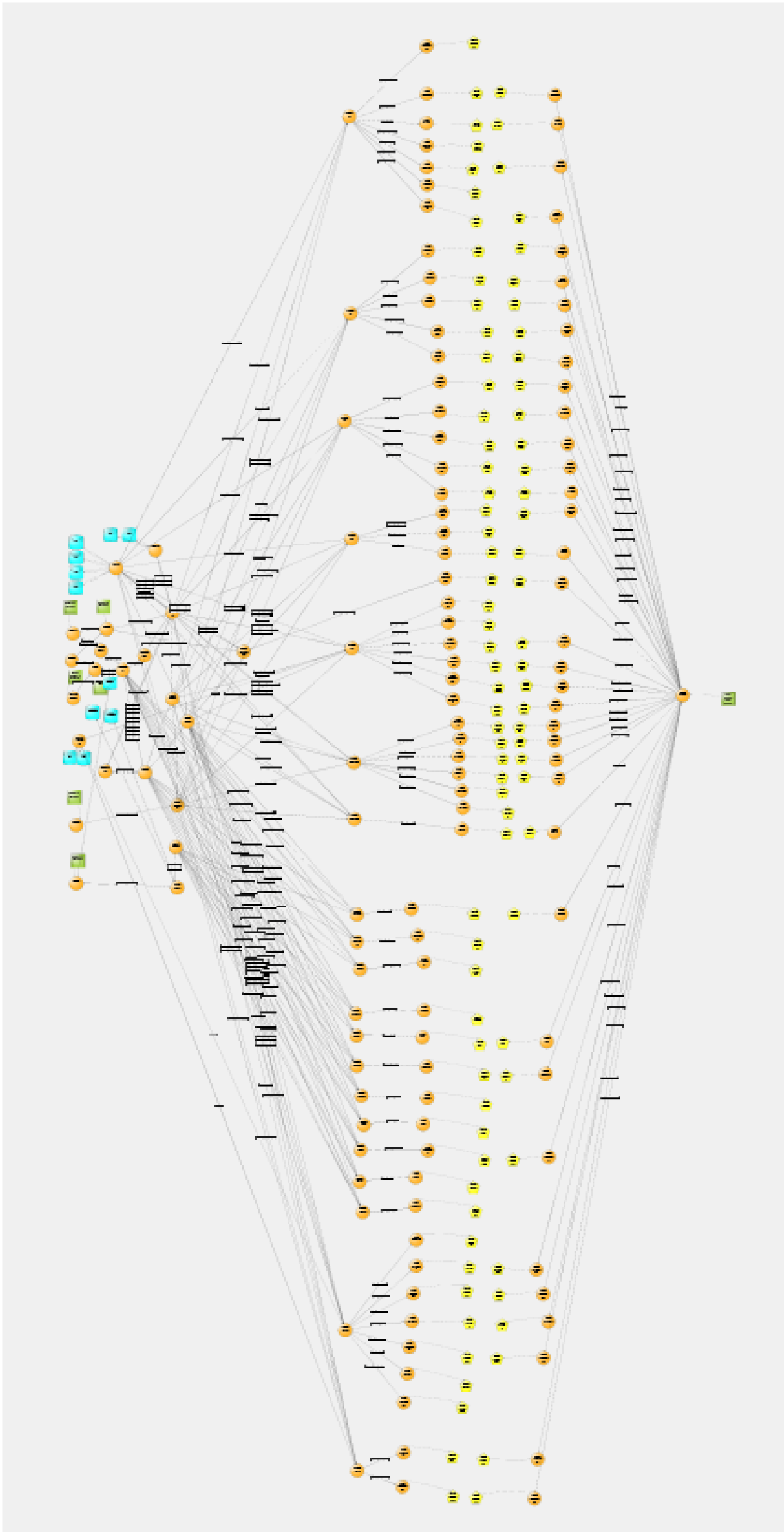
SENDOUT® has broad capabilities that allow the Company to develop supply and demand relationships that closely mirror Cascade's existing operations. Beginning with the 2008 IRP, Cascade expanded its modeling from the district level to modeling the system grouped by the various pipeline zones. Figure 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: SENDOUT® Network Diagram of Cascade's System



Stochastic Methodology Discussion

Cascade has implemented two major changes to its stochastic process. First, the Company now runs its Monte Carlo simulations on all candidate portfolios, which is 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.

Second, Cascade has moved from using the Monte Carlo functionality within SENDOUT® to building its own simulation engine in Excel and R. While SENDOUT® was able to generate adequate results in the past, the Company wanted to run a more robust simulation to supplement the functionality of SENDOUT®. SENDOUT® ran Monte Carlo simulations on monthly data and then used historical patterns to create weather patterns. The new methodology allows Cascade to be more detailed by running Monte Carlo simulations on daily data and creating multiple weather patterns. The new methodology of utilizing R to run stochastic analysis allows Cascade to be transparent on each step of the stochastic analysis process. Using historical data for weather, along with Cholesky decomposition matrices, Cascade can now run a 10,000 draw Monte Carlo simulation on price and weather, which will allow for a more accurate distribution when identifying what is the 99th percentile of price and weather for stochastic analysis. The negative aspect of running stochastic analysis outside of SENDOUT® is that Cascade needs to manually insert the weather data of a specific stochastic analysis draw to run the linear optimization of that weather profile. The Monte Carlo functionality embedded within SENDOUT® allows the program to read and optimize the stochastic weather results from all generated draws automatically.

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 only performs its Monte Carlo simulation on NYMEX, as the basins are ultimately calculated as a function of the NYMEX price plus or minus a basis differential. This eliminates the need to correlate multiple variables, while simplifying the process. 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 months, 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 10,000 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 NYMEX, 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.

Resource Optimization Output and Analysis Reports

After the model run is performed and SENDOUT® selects the optimal set of resources from the available portfolio, output reports are generated. SENDOUT® provides an assortment of input and output reports that it can generate, provided they are selected prior to the optimization run. SENDOUT® offers dozens of separate input reports that summarize various items such as demand inputs, the resulting forecast, temperature patterns as well as supply, storage, and transportation resource inputs. These reports verify that the information supplied to SENDOUT® is being accurately interpreted by the model.

The results of the optimization process are provided in the dozens of output summary reports. These reports summarize various aspects of the optimal portfolio resource size and selection as well as cost and utilization over the planning period. For purposes of this discussion, certain key output reports will be summarized below.

Key Output Report - Cost and Flow Summary

The Cost and Flow Summary Report consolidates a myriad of informative aspects of the optimization run. The report provides a breakdown of portfolio costs on a yearly basis, unit cost detail, as well as a total planning period basis, in several different formats. For example, an aggregate portfolio cost total is provided for comparison between years, as well as between various optimization runs, if the analyst is attempting to compare the impact that one or more resources can have on the portfolio. This total portfolio cost figure is also broken down into supply, storage and transportation cost summaries on both a yearly and planning period basis.

The report also contains the Resource Mix summary. This summarizes SENDOUT® decisions regarding the sizing and optimal mix of incremental resources, which determines whether one or many different types of resources should be considered for inclusion in the total resource portfolio.

Key Output Report - Month to Month Summary

While the Cost and Flow summary provides an indication of individual resource utilization, the Month to Month summary allows greater examination of how SENDOUT® utilizes each resource. The user can determine if the particular type of resources presented to SENDOUT® are being utilized as envisioned or whether other types of resources would more closely match requirements. For example, as has been done by Cascade, the analyst may offer annual supply contracts to SENDOUT® to address load growth over the planning period. The analyst can examine this report to determine if SENDOUT® uses these supplies throughout the year or only occasionally. If SENDOUT® utilizes this resource on a short-term basis during the winter, the analyst can introduce seasonal resources to SENDOUT® to determine whether it would choose them over the annual supplies already available in the portfolio.

SENDOUT® also presents monthly information in other specific reports. For example, the supply information provided in this Month to Month report is also available in greater detail in the Supply Summary Report. The same is true with the Transportation Summary Report and the Storage Summary Report. SENDOUT® also offers monthly supply utilization information in the Load Factor Summary Report, which some analysts may prefer to use in their approach to analyze the SENDOUT® results.

Key Output Report - Supply vs. Requirements

The Supply vs. Requirements report compares a particular forecast's monthly demand requirement quantity against the optimal portfolio's various supply quantities. This shows supply utilization as well as determines whether the supply portfolio quantities are sufficient to meet demand. If an insufficiency exists, the report isolates the shortfall by month as well as the location of the Company's demand requirement. With this information, the Daily Unserved Demand report determines if a pattern exists with respect to the shortfall. For example, if the daily report indicates that the shortfall occurs on the peak day the analyst could turn to the Peak Day Report to determine if the shortfall is supply or transportation related. If the shortfall occurs on any number of days surrounding the peak or at other times during the year, the analyst can turn to the Daily Supply Take and Daily Transport Flow reports to determine whether the portfolio is constrained by supply availability or transport capacity on those particular days.

Key Output Reports - Custom Report Writer

Ultimately, the availability and interpretation of information gained through SENDOUT® output reports contribute to developing better resource portfolios. SENDOUT® output report(s) contains vast amounts of information, which may overwhelm the casual observer. Therefore, SENDOUT® offers the user a Custom Report Writer (or Report Agent) module, which can isolate certain information contained in the various output reports and improve the analysis activity. Report Agent provides the user a menu of report information sources from which to choose specific items. The user has the option of viewing or downloading the information into spreadsheets or databases. Provided the information is available, the analyst can readily access specific items, which simplifies the data acquisition process if further analysis is desired. While the report writer is a useful tool in this regard, not all SENDOUT® output information can be accessed through this module.

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 SENDOUT® 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 SENDOUT® 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. SENDOUT® 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 SENDOUT® 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 SENDOUT® on an area specific basis without creating any material difference in the load demand.

In SENDOUT®, 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 SENDOUT® 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 user directs SENDOUT® to appraise the supply contract, on a total cost basis, against all other supply resources available within the portfolio. Under resource mix, SENDOUT® 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 SENDOUT® 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, SENDOUT® 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 SENDOUT® storage input is the Storage Volume - Dependent Deliverability (SVDD) Tables. This input item allows the user 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. SENDOUT® provides the analyst with five separate volume and price levels to reflect existing inventories.

Finally, SENDOUT® allows for input of a penalty rate for unserved demand. Cascade uses this functionality to give SENDOUT® 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 SENDOUT® should always elect to purchase these resources versus leaving demand unserved. Residential customers are always assigned the highest penalty. This tells SENDOUT® 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 SENDOUT® 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 20-year, most reasonably priced reliable portfolio.

Demand Forecast

Load growth across Cascade's system through 2039 is expected to fluctuate between 0.78% and 1.80% 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 1.66% and 0.91%, while industrial expects a growth rate of approximately 0.51%. Load across Cascade's two-state service territory is expected to increase at an average annual rate of 1.26% over the planning horizon, with the Oregon portion outpacing Washington, 1.58% versus 1.15%.

Long-Term Price Forecast

In Chapter 4, Supply Side Resources, Cascade discusses how the 20-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 have stabilized after dramatic fluctuations over the course of the last ten 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 have led to a market with prices as low as they have been in recent history. Recently, prices have remained relatively stable due to abundant supply, with one noticeable exception occurring at the end of 2018 with the Enbridge pipeline explosion. The inability to move gas from British Columbia to the US Pacific Northwest created extreme upward pricing pressure across the region, and specifically at the Sumas basin. Fortunately, the pipeline was repaired swiftly, and pricing stabilized by the summer of 2019.

Figure 9-7: Historical Regional Pricing for Past Ten Years

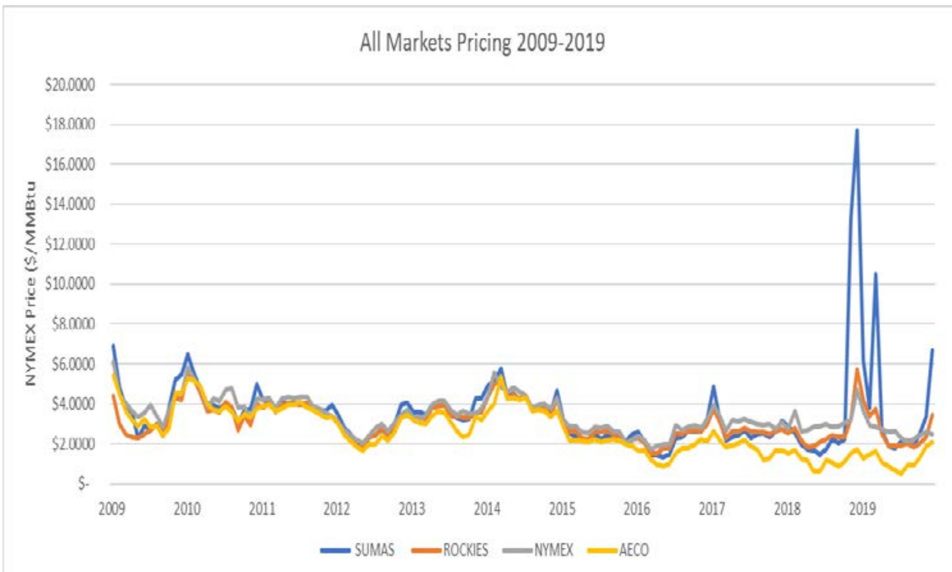
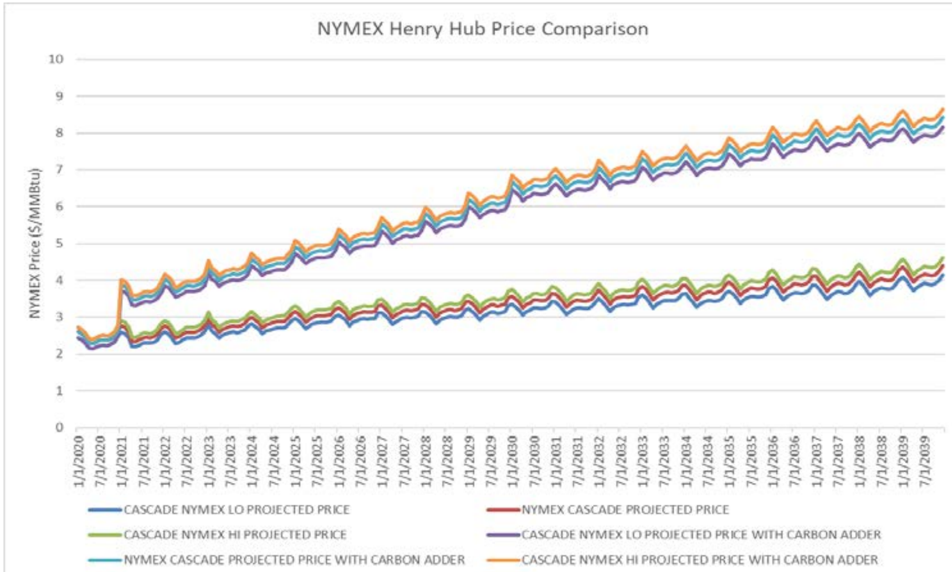


Figure 9-8 shows the comparison of ranges of pricing for the planning horizon, including the expected low, medium and high price, with and without a carbon adder for the impact of a potential cap and trade marketplace. The large jump starting in 2021 is a result of Cascade modeling that year as the start of the carbon tax.

Figure 9-8: NYMEX Annual Price Comparison



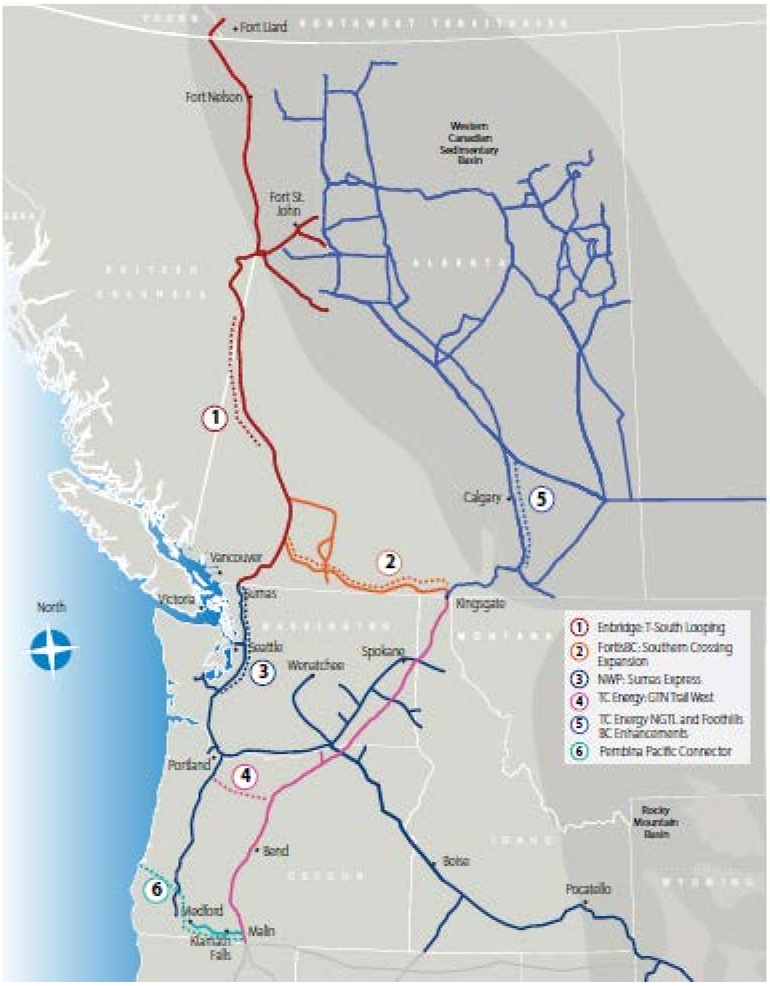
Environmental Adder

As discussed in Chapter 5, Avoided Cost, Cascade included a 10% environmental adder in its 2020 IRP's 20-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 20-year integrated resource portfolio.

Figure 9-9: Alternative Transportation Resources[2]



Demand Side Management

Chapter 6, Demand Side Management and Environmental Policy, 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 2020 IRP the nominal system avoided costs ranges between \$0.26/therm and \$1.11/therm over the 20-year planning horizon. Through the cost-effective use of conservation programs, the Company is able to reduce the load demand that must be met by more costly supply resources, such as a pipeline capacity expansion.

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. These values are then allocated to the pipeline zonal level and loaded into SENDOUT® to model

[2] Northwest Gas Association (NWGA) 2020 Pacific Northwest Gas Market Outlook 2020

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 SENDOUT® 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 SENDOUT® model, Cascade analyzed the demand compared to the existing resources as well as the demand against various portfolios of available resources. This served as the foundation for the Company to see what resources are taken to meet system demand with the least cost, lowest risk mix of natural gas supply and conservation. Figure 9-10 provides a snapshot of the potential peak day unserved demand across Cascade's system prior to applying any realignment of delivery rights, transportation contract segmentation or other alternative resources. Figure 9-11 displays the same information as Figure 9-10, but for Oregon citygates only.

Figure 9-10: Load Centers with Potential Peak Day Unserved Demand in Dekatherms– As-Is Modeling

Demand Group	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Bend Loop	-	1,154	2,769	-	-	-	-	-	-	-

Demand Group	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Sunnyside	-	-	-	-	-	-	-	399	1,427	910
Yakima Loop	-	-	-	-	-	-	-	197	2,870	-
Kennewick Loop	-	-	-	-	-	-	-	600	240	3,726
Nyssa Ontario	-	-	-	-	-	947	792	1,084	997	1,133
Longview South Loop	-	-	-	-	-	-	-	82	82	82
Bremerton Shelton	-	-	-	-	-	1,603	528	4,939	4,302	4,774
Sumas Loop	-	-	-	-	-	-	-	1,306	1,553	4,603
Bend Loop	-	-	-	542	2,158	3,773	4,290	7,005	8,620	10,236
Walla Walla	-	-	-	-	-	-	-	1,464	2,524	2,690

Figure 9-11: Oregon Load Centers with Potential Peak Day Unserved Demand in Dekatherms – As-Is Modeling

Demand Group	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Bend Loop	-	1,154	2,769	-	-	-	-	-	-	-

Demand Group	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Bend Loop	-	-	-	542	2,158	3,773	4,290	7,005	8,620	10,236

Because Cascade has more delivery rights than receipt rights, the Company must allocate the delivery rights to match up with receipt capability. First, the Company allocates capacity on transportation contracts that have a single receipt point. Next, Cascade allocates capacity on conjunctive contracts that provide corridor and delivery point flexibility (re-allocation of MDDOs). The Company also gives consideration to critical delivery areas, constrained laterals and maximizing corridor flexibility—longest haul contractual rights. Cascade illustrates reallocation of MDDOs in Appendix F.

Analysis of Unserved Demand

As discussed in Chapter 3, the Pacific Northwest will experience significant growth over the 20-year planning horizon. Cascade will need to acquire additional resources to solve for the deficiency caused by this growth. Of note, growth at one of the Company's citygates may cause unexpected shortfalls at other, seemingly unrelated citygates. For example, Cascade's Bremerton-Shelton citygate serves a significant number of residential customers. If that area were to experience rapid growth, existing resources for customers on an interruptible tariff, in Yakima for example, may be realigned to Bremerton-Shelton to serve this increased demand using a transportation contract with a broadly defined receipt point. This would make it appear as though Yakima had experienced the rapid growth, since that is where the shortfall would be appearing, even though this would not be the case in this hypothetical example. Page 3-10 goes into further detail regarding some of the major growth drivers.

Shortfalls in the citygates Cascade serves off the GTN pipeline are consistent with the Company's significant growth projections for its service areas in Oregon, particularly the city of Bend. The initial shortfalls are temporarily solved by incremental capacity that has been acquired starting in 2023, but long-term growth will still outpace this capacity by 2033. Potential unserved demand in NWP's Zone 30-S is a result of the pipeline's contractual philosophy of mainline versus lateral rights. Cascade has enough mainline rights to serve these citygates, but additional lateral rights may be required to reach the areas in Zone 30-S. This is not strictly enforced in a non-peak day situation, but such flexibility cannot be relied upon on peak day. Figure 12-9 and Figure 12-10, in Chapter 12, shows a map that illustrates the difference between the mainline and a lateral.

Portfolios Evaluated

For the 2020 IRP, Cascade has elected to evaluate seven potential portfolios. These portfolios represent a wide variety of potential solutions for Cascade's resource deficiency, with an evaluation of all available resources in the Pacific Northwest for natural gas. Unlike electric utilities, who have a variety of options for power generation (hydro, wind, solar, etc.), Cascade is limited to a single resource, natural gas, which hinders the scope of potential portfolio analysis. 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 9-12 outlines the key components of each portfolio identified in Figure 9-1. SENDOUT® 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 ranked in order of unserved demand and total system cost.

Figure 9-12: Resource Composition of All Evaluated Portfolios

Figure 9-13 uses the mean and VaR of the total system cost and unserved demand of the portfolios considered to calculate the risk adjusted value of each portfolio. Given Cascade's mission to serve its customers, portfolios are first evaluated on unserved demand, and then mean total system cost.

Figure 9-13: Final Ranking of Portfolios – Mean and VaR

	Deterministic		Stochastic		Risk Adjusted Results	
Portfolio	Unserved Demand (DT)	Total System Cost ($000)	Unserved Demand (DT)	Total System Cost ($000)	Risk Adjusted Unserved Demand (DT)	Risk Adjusted Total System Cost ($000)
All-In	-	4,279,132	0	4,398,492	-	4,308,972
All-In Less DSM	-	4,282,291	0	4,422,989	-	4,317,466
NWP + Storage	13,686	4,299,105	0	4,422,992	10,264.50	4,330,076
NWP	13,686	4,301,075	0	4,424,828	10,264.50	4,332,013
GTN + Storage	18,179	4,294,023	0	4,437,641	13,634.25	4,329,928
GTN	18,179	4,295,876	0	4,439,678	13,634.25	4,331,827
Storage Only	28,155	4,282,291	0	4,437,522	21,116.25	4,321,099

Top-Ranking Candidate Portfolio

Using input from the alternative resources selected, the All-In portfolio was selected as the least cost, least risk solution to Cascade's forecasted unserved demand. This portfolio is now defined as the Top-Ranking Candidate Portfolio. This portfolio provides guidance as to what resources should be considered to reduce the unserved demand with the least cost mix of all of 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 impact of these resources on both unserved demand and Cascade's resource mix is shown graphically in Figures 9-14 through 9-17.

Figure 9-14: Annual Supply Take vs Demand – Candidate Portfolio

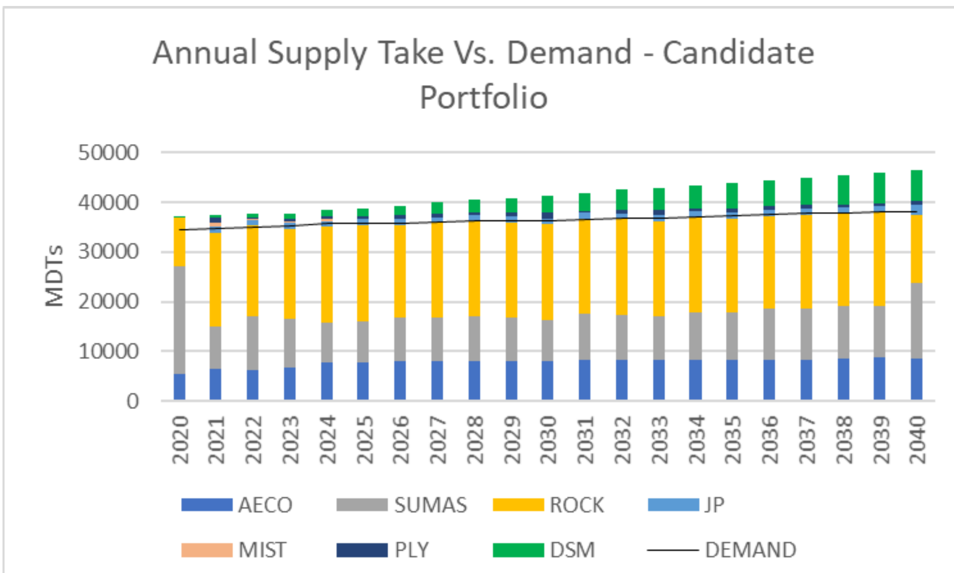


Figure 9-15: Peak Day Supply Take vs Demand – Candidate Portfolio

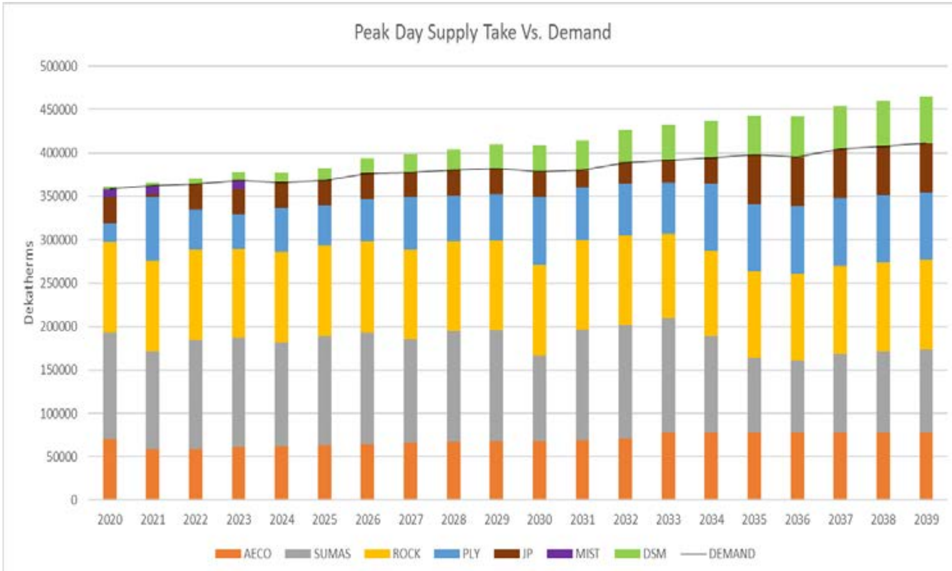


Figure 9-16: Annual Transport vs Demand – Candidate Portfolio

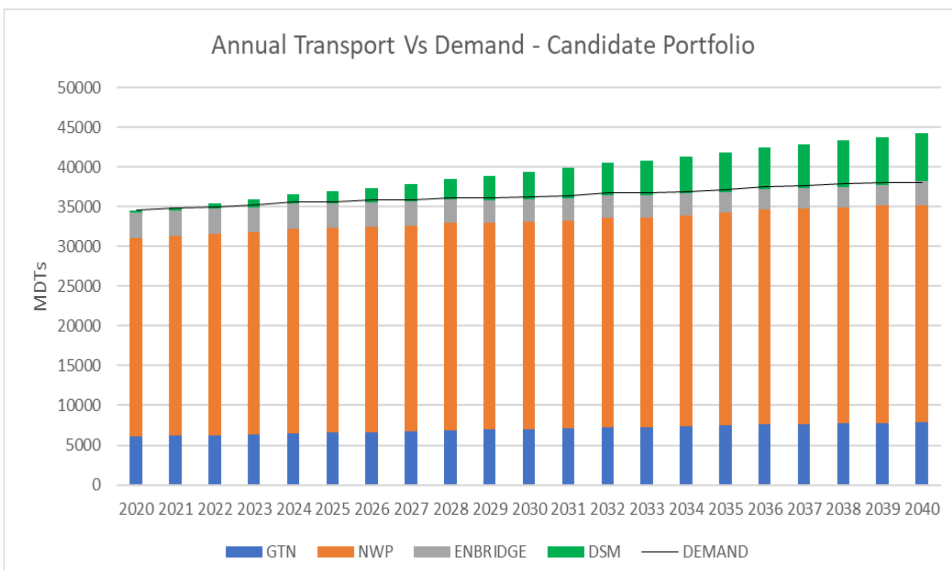
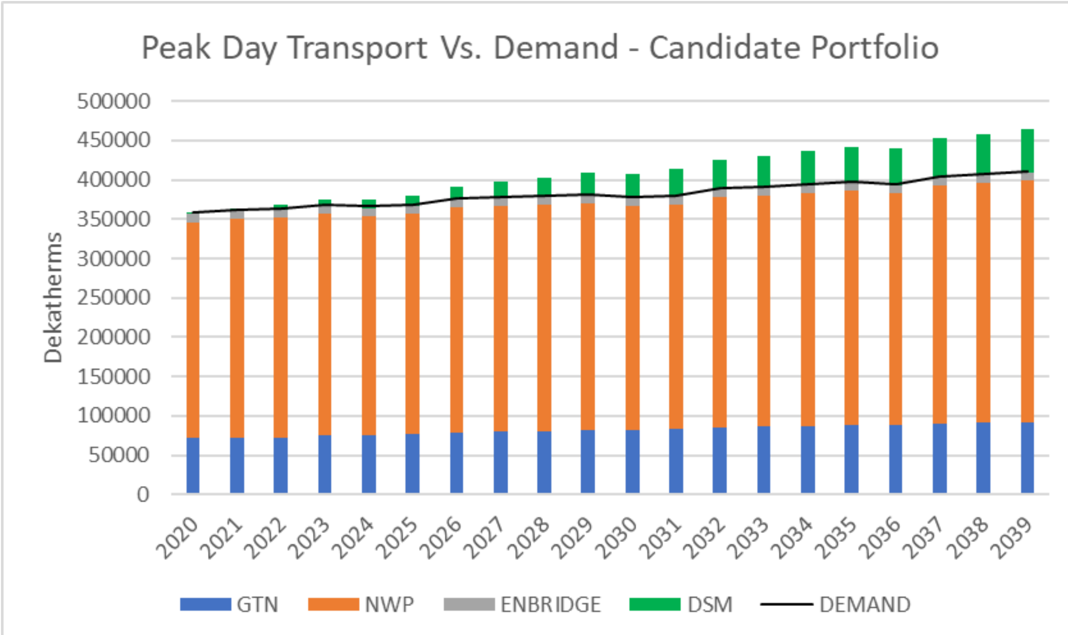


Figure 9-17: Peak Day Transport vs Demand – Candidate Portfolio



Alternative Resources Selected

For the first time in recent Cascade IRP history, the only resource selected by the SENDOUT® model for the Top-Ranking Candidate 20-year Portfolio was incremental energy efficiency. The quantity and timing of this resource is summarized in Figure 9-18.

Figure 9-18: Projected Cumulative Incremental DSM – in Therms

Sector	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential	174,898	360,431	519,687	691,837	917,913	1,165,482	1,436,906	1,721,003	2,016,653	2,322,400
Commercial	317,008	639,435	900,883	1,139,421	1,358,536	1,581,475	1,811,295	2,047,723	2,288,955	2,532,619
Industrial	55,338	110,676	159,170	205,839	250,775	297,530	346,277	396,889	449,398	503,447
Unclaimed Market Savings	-	-	34,978	69,956	104,935	104,935	104,935	104,935	104,935	104,935
Large Project Adder	-	-	15,990	31,980	47,970	63,961	79,951	95,941	111,931	127,921
Total	547,244	1,110,543	1,630,709	2,139,034	2,680,129	3,213,383	3,779,363	4,366,490	4,971,872	5,591,321

Sector	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Residential	2,636,242	2,955,897	3,279,298	3,604,742	3,934,254	4,269,108	4,609,748	4,955,437	5,305,334	5,660,658
Commercial	2,777,880	3,024,936	3,271,584	3,518,368	3,763,510	4,007,124	4,249,410	4,491,421	4,731,341	4,971,039
Industrial	559,274	616,726	675,897	736,870	800,051	865,286	932,707	1,001,849	1,073,177	1,146,565
Unclaimed Market Savings	104,935	104,935	104,935	104,935	104,935	104,935	104,935	104,935	104,935	104,935
Large Project Adder	143,911	159,901	175,892	191,882	207,872	223,862	239,852	255,842	271,832	287,823
Total	6,222,242	6,862,395	7,507,605	8,156,796	8,810,622	9,470,315	10,136,652	10,809,485	11,486,619	12,171,019

In an effort to mitigate the risk around the uncertain nature of DSM potential, particularly with the major role energy efficiency has in the Company's Top-Ranking Candidate Portfolio, Cascade worked with its partner, the Energy Trust of Oregon, to evaluate the impact of different carbon futures on DSM. The results of this analysis are presented in Figure 9-19

Figure 9-19: Analysis of Alternative Carbon Futures – in Therms

Scenario	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Base Case Carbon	547,244	1,110,543	1,630,709	2,139,034	2,680,129	3,231,012	3,796,941	4,381,099	4,982,888	5,595,764
Social Cost of Carbon	547,244	1,110,543	1,633,849	2,146,222	2,690,808	3,247,009	3,817,421	4,401,746	5,003,811	5,616,945
% Difference from Base	0.00%	0.00%	0.19%	0.34%	0.40%	0.50%	0.54%	0.47%	0.42%	0.38%
Market Choice Carbon	547,244	1,110,543	1,629,432	2,137,628	2,675,453	3,223,014	3,784,324	4,359,312	4,950,040	5,552,338
% Difference from Base	0.00%	0.00%	-0.08%	-0.07%	-0.17%	-0.25%	-0.33%	-0.50%	-0.66%	-0.78%

Scenario	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Base Case Carbon	6,217,575	6,846,458	7,481,429	8,119,908	8,765,178	9,418,231	10,079,170	10,745,481	11,415,053	12,092,748
Social Cost of Carbon	6,239,892	6,870,151	7,512,679	8,158,736	8,816,249	9,482,179	10,157,065	10,836,258	11,520,365	12,213,602
% Difference from Base	0.36%	0.35%	0.42%	0.48%	0.58%	0.68%	0.77%	0.84%	0.92%	1.00%
Market Choice Carbon	6,163,388	6,783,576	7,413,292	8,046,069	8,685,763	9,332,593	9,988,961	10,651,112	11,315,628	11,988,015
% Difference from Base	-0.87%	-0.92%	-0.91%	-0.91%	-0.91%	-0.91%	-0.90%	-0.88%	-0.87%	-0.87%

If the Social Cost of Carbon ultimately ends up being the cost of carbon compliance, DSM potential would only increase. If a lower carbon compliance cost such as the Market Choice Proposal materializes, the impact on the DSM potential would be minimal, never exceeding 10,000 dekatherms annually across all of Oregon, which translates to less than 100 dekatherms on a peak day. This sensitivity analysis reinforces the Company's confidence in the role energy efficiency will play in solving resource acquisition needs.

Alternative Resources Not Selected

The SENDOUT® model did not select the following resources for the Top-Ranking Candidate Portfolio:

Transport

- Incremental GTN – Allows Cascade to continue to serve customers as the Company's core load grows in citygates that are fed by GTN capacity, specifically around Bend, Oregon. At this time the additional Oregon capacity acquired in 2023, in conjunction with incremental energy efficiency, offsets the need for more GTN capacity.
- Bremerton-Shelton Realignment – Provides the Company with the ability to secure additional firm lateral rights along the I-5 corridor. Additionally, allows Cascade to move additional gas from its' Jackson Prairie facility to Stanfield, which can then be moved to the Company's Oregon citygates via incremental GTN capacity from Stanfield to Malin. The Company does not forecast a need for additional I-5 capacity at this time,

but will continue to monitor growth in Western Washington, as prior IRPs have identified the region as an area with potential shortfalls in the future.

- Incremental NOVA – Provides Cascade with a cost-effective opportunity to move gas from AECO to Kingsgate, versus buying gas at Kingsgate directly. No significant quantities were identified by the model, so the Company will continue to model open seasons on NOVA.
- Incremental Foothills – Since the Company has more capacity on Foothills versus NOVA, Cascade would need to identify a significant amount of additional NOVA capacity needed before its modeling would recommend additional foothills capacity.
- Incremental Ruby/Turquoise Flats – Without a need for additional capacity on GTN, Cascade does not need additional capacity on Ruby and at Turquoise Flats to move additional gas to GTN.
- Wenatchee Expansion – Cascade's market intelligence, in conjunction with its SENDOUT® modeling determined that it would be more cost-effective to acquire incremental NWP capacity via the Bremerton-Shelton realignment while redirecting existing flexible transportation to central Washington. Since no additional capacity is needed on the I-5 corridor, a Wenatchee expansion is not required as well.
- Zone 20 Expansion – Cascade's market intelligence, in conjunction with its SENDOUT® modeling, determined that it would be more cost-effective to acquire incremental NWP capacity via the Bremerton-Shelton realignment while redirecting existing flexible transportation to eastern Washington. Since no additional capacity is needed on the I-5 corridor, a zone 20 expansion is not required as well.
- Incremental Starr Road – SENDOUT® determined that with Cascade's current price forecast it did not make sense to purchase incremental capacity to move AECO gas from GTN to NWP.
- Eastern Oregon Expansion – Cascade's market intelligence, in conjunction with its SENDOUT® modeling, determined that it would be more cost effective to acquire incremental NWP capacity via the Bremerton-Shelton realignment while redirecting existing flexible transportation to eastern Oregon. Since no additional capacity is needed on the I-5 corridor, an Eastern Oregon expansion is not required as well.
- T-South Southern Crossing – SENDOUT® determined that based on Cascade's current price forecast it did not make sense to purchase incremental capacity to move in either direction along the Canadian border.
- Trails West (Palomar) – SENDOUT® determined that with Cascade's current price forecast it did not make sense to purchase incremental capacity to move in either direction across central Oregon.

Supply

- Opal Incremental – Since SENDOUT® 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, Mist Storage – No incremental storage was selected. None of these storage facilities modeled were cost effective or led to an increase in served demand. The primary reason appears to be that each storage facility modeled required long-term incremental transportation.
- Spire Storage – The Company's modeling identified this as a potentially cost-effective resource, but Cascade has concerns about the reliability of Spire Storage due to past incidents. Cascade will include an action item in this IRP to evaluate the viability of Spire further prior to the 2022 IRP.

Impact of Top-Ranking Candidate Portfolio on Unserved Demand

As discussed earlier, the primary metric that all portfolios are evaluated on is unserved demand. If at all feasible, the Top-Ranking Candidate Portfolio must solve for all forecasted shortfalls under expected conditions. Figures 9-20 and 9-21 show the forecasted Peak Day Unserved Demand under expected growth and carbon forecasts. Weather and price are modeled using the risk adjusted methodology referenced in Step 4 of the Supply Resource Optimization Process.

Figure 9-20: Load Centers w/ Deterministic Forecasted Peak Day Unserved Demand in Dekatherms – Top Ranking Candidate Portfolio

Demand Group	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Sunnyside	-	-	-	-	-	-	-	-	-	-
Yakima Loop	-	-	-	-	-	-	-	-	-	-
Kennewick Loop	-	-	-	-	-	-	-	-	-	-
Nyssa Ontario	-	-	-	-	-	-	-	-	-	-
Longview South Loop	-	-	-	-	-	-	-	-	-	-
Bremerton Shelton	-	-	-	-	-	-	-	-	-	-
Sumas Loop	-	-	-	-	-	-	-	-	-	-
Bend Loop	-	-	1,160	-	-	-	-	-	-	-
Walla Walla	-	-	-	-	-	-	-	-	-	-

Demand Group	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Sunnyside	-	-	-	-	-	-	-	-	-	-
Yakima Loop	-	-	-	-	-	-	-	-	-	-
Kennewick Loop	-	-	-	-	-	-	-	-	-	-
Nyssa Ontario	-	-	-	-	-	-	-	-	-	-
Longview South Loop	-	-	-	-	-	-	-	-	-	-
Bremerton Shelton	-	-	-	-	-	-	-	-	-	-
Sumas Loop	-	-	-	-	-	-	-	-	-	-
Bend Loop	-	-	-	-	-	-	-	-	-	-
Walla Walla	-	-	-	-	-	-	-	-	-	-

Figure 9-21: Oregon Load Centers w/ Deterministic Forecasted Peak Day Unserved Demand in Dekatherms – Top Ranking Candidate Portfolio

Demand Group	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Bend Loop	-	-	1,160	-	-	-	-	-	-	-

Demand Group	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Bend Loop	-	-	-	-	-	-	-	-	-	-

The potential shortfall identified in 2022 is a good example of the importance of pairing qualitative analysis with the quantitative results provided by SENDOUT®. From a regional evaluation of the capacity needs on GTN, the Company is confident in its ability to contract for third party citygate deliveries to serve its customers on a peak day without the need to acquire additional GTN capacity in 2022.

Portfolio Evaluation: Additional Scenario/Sensitivity Analyses

Figure 9-22 summarizes the net present value of the PVRR of all additional demand scenarios and sensitivities reviewed. After the Candidate Portfolio was selected, the Company tested it stochastically through various extreme situations, which are further explained in Appendix E. As discussed during Cascade's Supply Resource Optimization Process, the objective of this analysis is to ensure that the costs of the Candidate Portfolio do not exceed the VaR limit in any of the scenarios/sensitivities discussed in Figure 9-3. The results of all scenarios are also shown graphically in Figures 9-23 and 9-24.

Figure 9-22: Total System Cost and Average Cost/Served Therm of Additional Scenarios/Sensitives

Scenario	Total System Cost ($000)	$/Therm Served	Distance from VaR Limit
No Carbon Forecast	4,067,388	0.5232	$ 1,300,256
SCC Carbon Forecast	4,291,633	0.5521	$ 1,076,011
Market Choice Carbon Forecast	4,219,313	0.5428	$ 1,148,331
Price Forecast High	4,348,336	0.5594	$ 1,019,308
Environmental Adder 0%	4,200,421	0.5403	$ 1,167,223
Environmental Adder 20%	4,402,809	0.5664	$ 964,835
Environmental Adder 30%	4,498,902	0.5787	$ 868,742
Stochastic Carbon	4,193,098	0.5394	$ 1,174,546
No Evergreen	N/A*	N/A	N/A
Low Growth	4,094,227	0.5713	$ 1,273,417
High Growth	4,627,197	0.5478	$ 740,447
Limit BC	4,470,642	0.5760	$ 897,003
No BC	N/A*	N/A	N/A
Limit Alberta	4,234,825	0.5456	$ 1,132,820
No Alberta	4,441,634	0.5731	$ 926,010
No Rockies	4,543,428	0.5957	$ 824,216
Limit Rockies	4,259,653	0.5488	$ 1,107,991
Limit Canada	4,419,800	0.5694	$ 947,844
No Canada	N/A*	N/A	N/A
No Plymouth	4,384,592	0.5649	$ 983,053
Limit Plymouth	4,372,424	0.5633	$ 995,220
Limit JP	4,397,880	0.5666	$ 969,765
No JP	4,421,787	0.5697	$ 945,857
Limit Mist	4,338,902	0.5590	$ 1,028,742
No Mist	4,339,958	0.5591	$ 1,027,687
RNG #1	4,275,469	0.5500	$ 1,092,175
RNG #2	4,273,400	0.5497	$ 1,094,244

* Note - SENDOUT® is unable to calculate costs for infeasible Scenarios/Sensitivities

VaR Limit	**5,367,644**

Figure 9-23: Total System Cost Comparison by Scenarios/Sensitivity

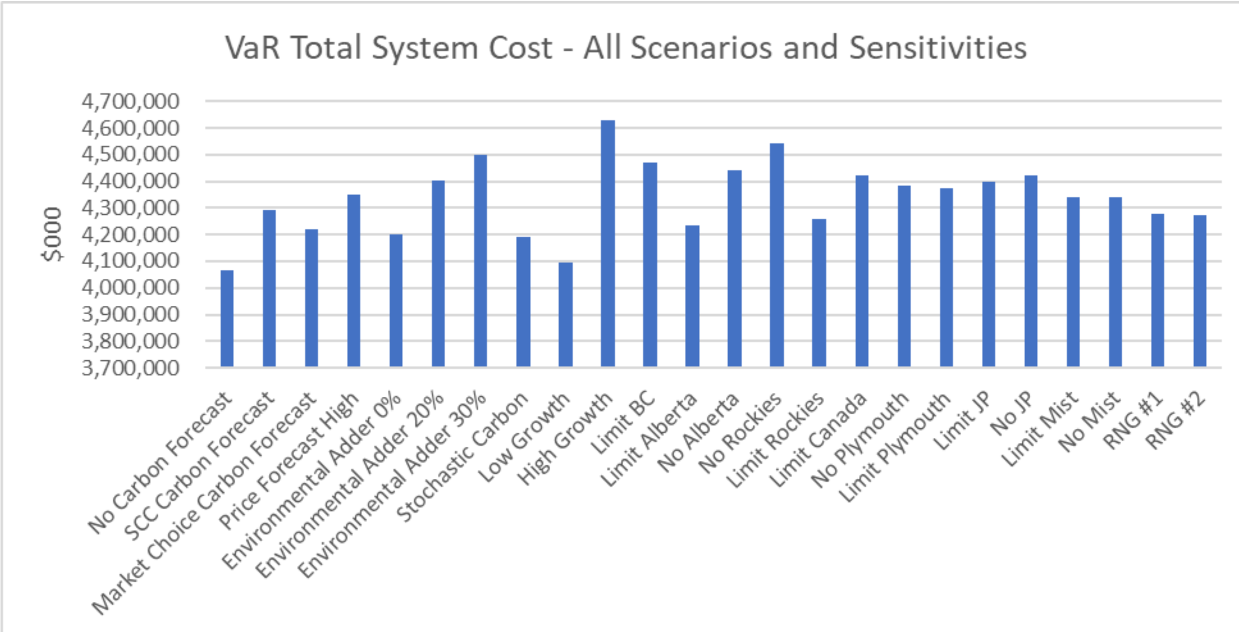
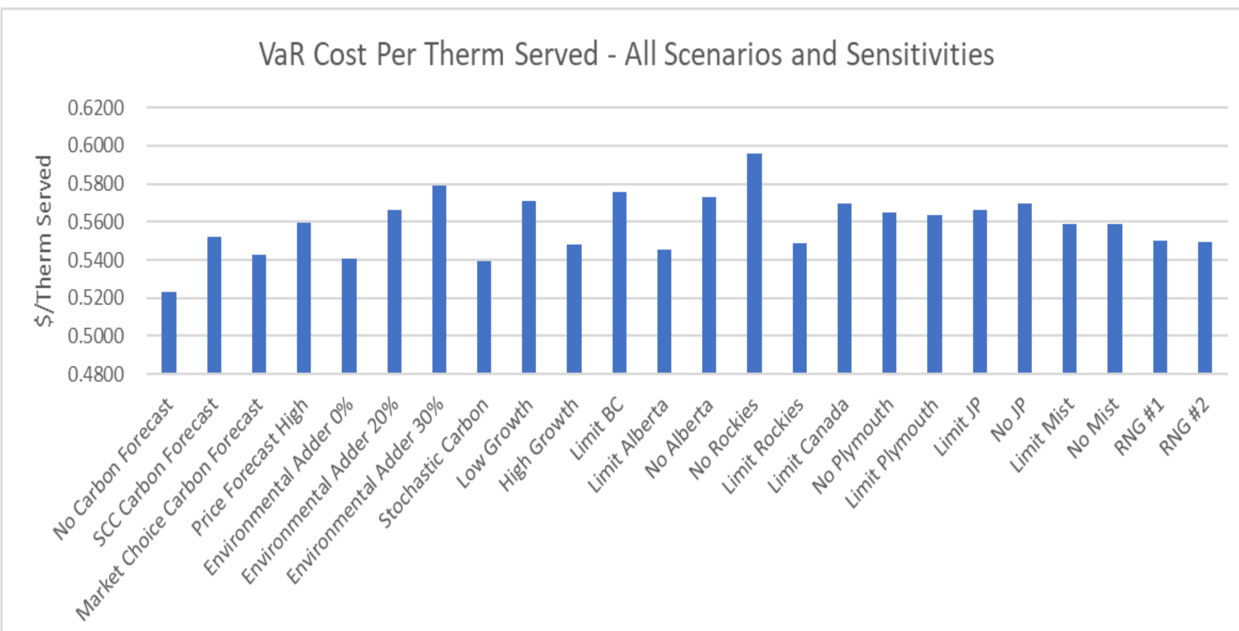


Figure 9-24: Cost per Therm Served by Scenario/Sensitivity



Three scenarios in particular provide intriguing results that merit further discussion: High Growth and Low/no BC.

In Cascade's High Growth Scenario, the Company identifies potential shortfalls systemwide starting in 2035. If these shortfalls were forecasted to occur earlier in the planning horizon, it could be cause for concern that the Top Ranking Candidate Portfolio is not robust enough to survive near-term variance in the Company's load projections. Fortunately, the projected deficiency occurs late in the planning horizon, which provides guidance that, if actual growth begins to follow the high growth trajectory, incremental resources may be needed.

While Cascade is hesitant to label scenarios as analogs to real life events, it is worth discussing the limit BC and no BC scenarios in the context of the 2018 Enbridge explosion. The Company's scenarios assume a permanent impact to supplies at Sumas, while the Enbridge incident only temporarily restricted access to gas in British Columbia. If such an explosion were to cause permanent damage, the data from this scenario analysis would seem to indicate that Cascade's system could survive restricted access to BC supplies, but would struggle to maintain the capacity to serve customers if Sumas gas were to be fully inaccessible for a sustained period of time.

Stochastic Analyses - Annual Load Requirements & Weather Uncertainty

The annual load requirements will vary dramatically based on the weather assumptions. Through the use of its new proprietary Monte Carlo functionality, the Company has the ability to analyze the impacts of stochastic weather on its load forecast. Figure 9-25 shows the daily HDD pattern at each of Cascade's seven weather stations, while Figure 9-26 compares the system weighted stochastic weather to the deterministic system weighted weather profile

Figure 9-25: Stochastic HDDs by Weather Station

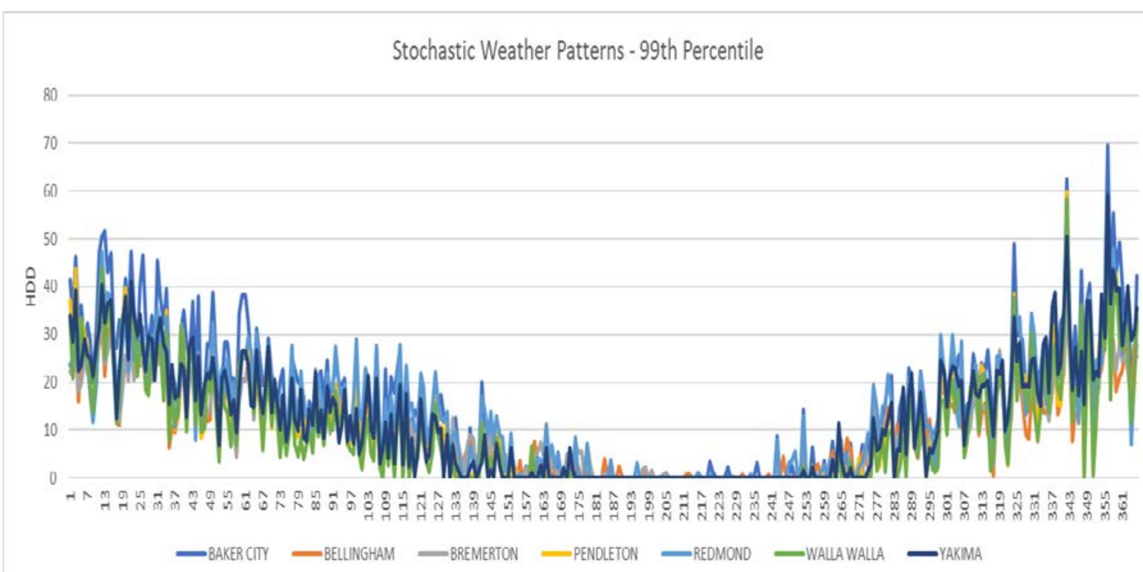
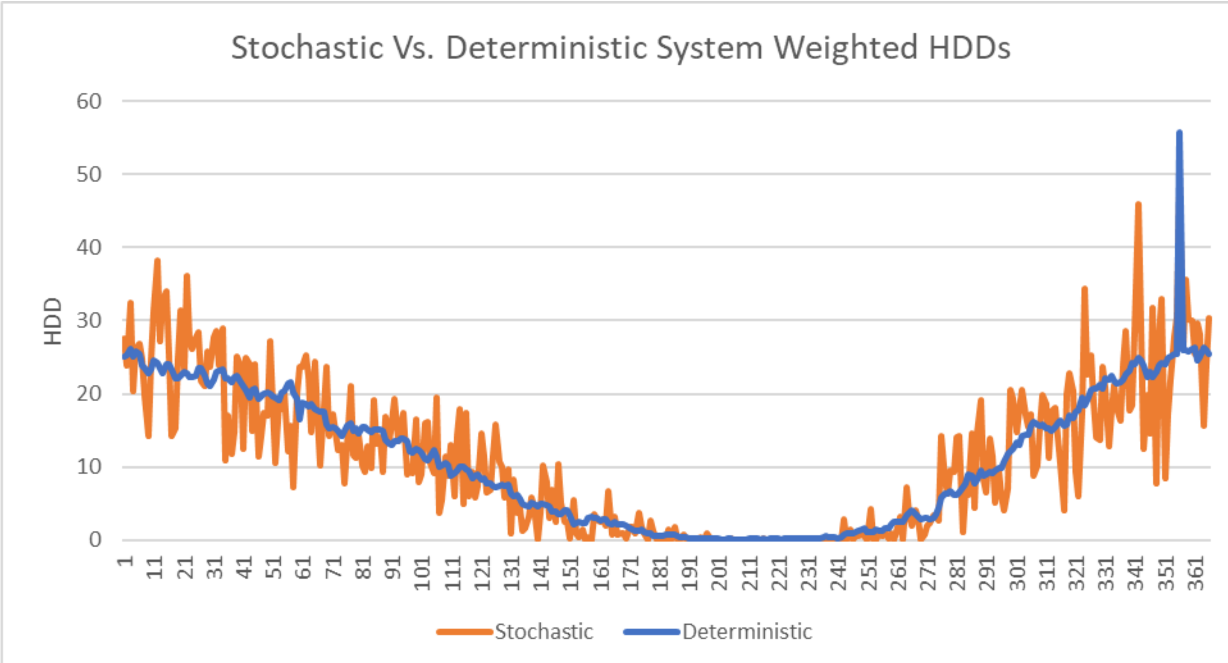


Figure 9-26: Stochastic Vs. Deterministic System Weighted HDDs



Stochastic Analyses – Price Uncertainty

Similar to weather analysis, uncertainty related to future gas prices can have a significant impact on Cascade forecasted costs over the 20-year planning horizon. The Company analyzes the risk of price projections by running the 99th percentile of monthly load weighted prices with a variety of carbon and environmental externality costs as its sensitivity analyses. Figure 9-27 provides a potential price forecast at the 99th percentile of possible pricing for each basin. Figure 9-28 compares these forecasts to their deterministic counterparts.

Figure 9-27: 99th Percentile Price Forecast by Basin – Monte Carlo Data

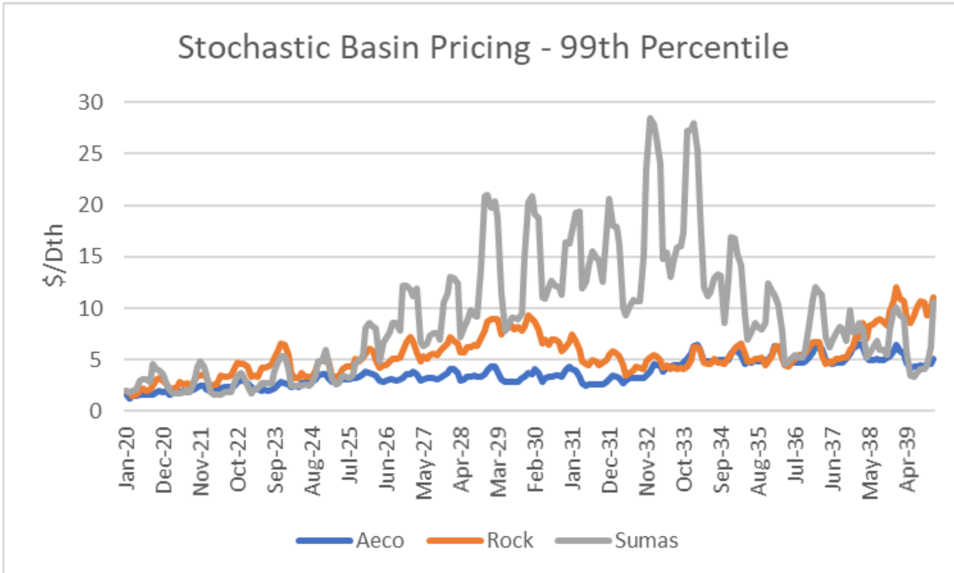
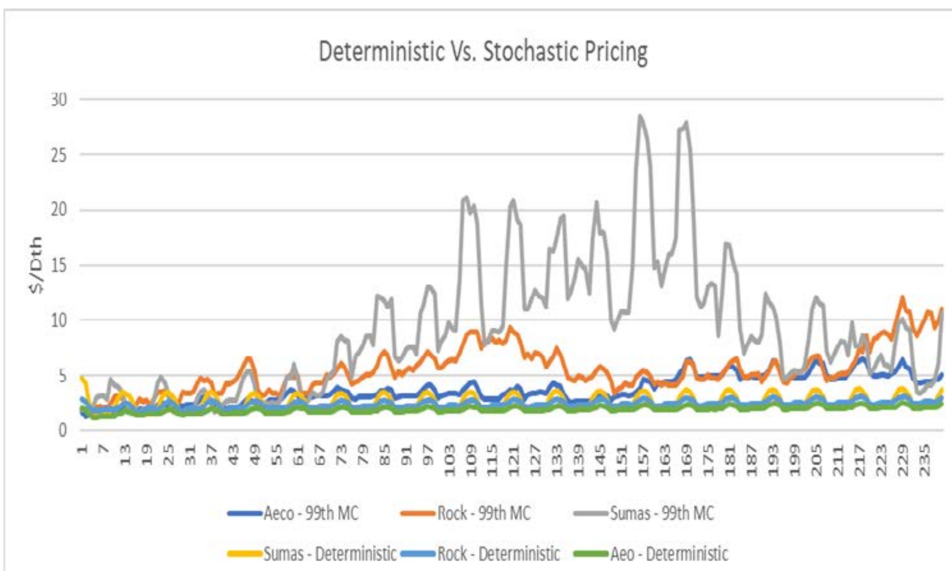


Figure 9-28: Deterministic Vs. Stochastic Pricing



Conclusion

Cascade's All-In portfolio includes all existing supply side resources as discussed in Chapter 4, all projected DSM savings discussed in Chapter 6, and all incremental resources discussed in this chapter. This portfolio did not exceed the VaR Limit in any scenarios or sensitivities run by the Company. This allows Cascade to deem this to be the Preferred Portfolio, which is the lowest cost and risk as expected 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, provides a base foundation to meet load needs of Cascade's core customers. However, Cascade's unique geographical reach 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.

The High Customer Growth demand analysis provides an opportunity for evaluating demand trajectories relative to the expected scenario. Based on this analysis sufficient time is expected to be available to plan for forecasted resource needs. Even under extreme pricing sensitivities related to the cost of carbon legislation compliance, Cascade has determined that this portfolio solves for resource deficiencies at an acceptable cost. Many events could occur between now and when the first 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.

Key Points

- Five TAG meetings were held in multiple locations.
- Multiple opportunities for public participation were available, including access to the Company's Resource Planning Team through phone discussions and email.
- TAG meeting agendas and presentations are available at www.cngc.com.

Approach to Meetings and Workshops

The Company held a series of public meetings, typically in the state of Oregon for the development of this specific IRP. Cascade's IRP stakeholders are widely spread out geographically; cities in Oregon are generally more easily accessible for individuals to attend than Kennewick for TAG meetings. For those unable to travel, all meetings were available by Skype and teleconference. Cascade scheduled five TAG meetings between August 2019 and March 2020. Cascade is offering to hold a TAG 6 after the draft IRP has been distributed and comments are returned to Cascade.

In an effort to further clarify roles and responsibilities for the Company as well as stakeholders, Cascade created a stakeholder engagement document, which can be found in Appendix A. Cascade recognizes that involvement in the Company's TAG represents a material time commitment. 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.

Stakeholders

The Company encourages public participation in the IRP process. 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, Public Counsel, Citizens' Utility Board, and the Alliance of Western Energy Consumers.

Internally, the Cascade IRP stakeholders and participants are from the following departments:

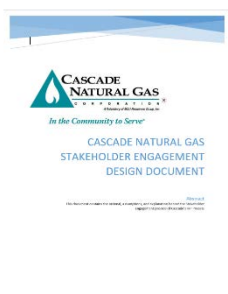
- Resource Planning;

- Gas Supply/Gas Control;
- Regulatory Affairs;
- Operations/Engineering;
- 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 2020 IRP schedule.

TAG Meetings and Workshops

Cascade held five public TAG meetings with internal and external stakeholders. In an attempt to get more public participation, Cascade held the first TAG meeting in the city of Bend, which is Cascade's largest service territory in Oregon. Prior to the meeting, Cascade also posted a Facebook campaign inviting the public to participate in the first TAG meeting. Despite those efforts, Cascade did not have anyone from the public join the first TAG meeting. Cascade did reach 3330 people, which means there were 3330 unique viewers of Cascade's Facebook campaign. Robust discussion occurred, in particular, around energy efficiency, carbon, renewable natural gas during TAG 4. This meeting is a good example of stakeholder participation and good input to the Company. Information about each meeting date and major agenda items are provided below as well as in Appendix A.



2020 IRP TAG 1 Meeting – Thursday, August 15, 2019
- Location: Bend, OR, 9 am to 12 pm
- Process
- Key Points
- IRP Team
- Timeline
- Regional Market Outlook
- Plan for dealing with issues raised in 2018 IRP

2020 IRP TAG 2 Meeting – Thursday, September 5, 2019
- Location: Salem, OR, 9 am to 12 pm
- Demand and Customer Forecast and Non-Core Outlook
- Drilling down into segments of demand forecast

2020 IRP TAG 3 Meeting – Wednesday, November 6, 2019
- Location: Kennewick, WA, 9 am to 12 pm
- Presentation from Ruby Pipeline of Kinder Morgan
- Distribution System Planning

- Planned Scenarios and Sensitivities
- Alternative Resources
- Price Forecast
- Avoided Cost
- Current Supply Resources
- Transport Issues.

2020 IRP TAG 4 Meeting – Wednesday, January 15, 2020

- Location: Portland International Airport Conference Center, 9 am to 12 pm
- Carbon Impacts
- Energy Efficiency (Energy Trust of Oregon)
- Renewable Natural Gas
- Preliminary Resource Integration Results

2020 IRP TAG 5 Meeting – Wednesday, March 11, 2020

- Location: Salem, OR, 9 am to 12 pm
- Final Integration Results
- Finalization of plan components
- Four-year Action Plan

2020 IRP TAG 6 Meeting – Tuesday, June 30, 2020

- Location: Microsoft Teams Meeting 1 pm to 1:45 pm
- Cascade's Cost-Effective Evaluation Model for Renewable Natural Gas

Opportunity for Public Participation

Cascade is fully committed to ensuring the public is invited to participate in its IRP process. Cascade has a dedicated Internet webpage where customers and parties can view the IRP timeline, TAG presentations and minutes, as well as current and past IRPs.[1]

[1] *See:* https://www.cngc.com/rates-services/rates-tariffs/oregon-integrated-resource-plan

CHAPTER 11

FOUR-YEAR ACTION PLAN

2020 Action Plan

The Four-Year 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 2020 Action Plan focuses on:
- Supply Side Resources
- Environmental Policy
- Avoided Cost
- Demand Side Management
- Renewable Natural Gas
- Distribution System Planning
- IRP Process

Resource Planning

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 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. The Company will also perform cross validation on new methodologies to ensure the accuracy of the new models.

Cascade will also:
- continue to work with Northwest Pipeline to pursue opportunities to better align Maximum Daily Delivery Obligations (MDDO) contract delivery rights at no incremental costs to customers through the use of segmentation or other proposals.
- determine if the temporary Jackson Prairie account JP3 release from Puget Sound Energy should be made permanent.
- continue to work on developing scenarios to replicate potential supply and transport impacts for pipeline operational flow orders (OFO) and consideration of other strategies to minimize OFO impacts.
- continue to develop SENDOUT® direct models for gas cost workbooks provided to commissions during PGA filings to better improve the alignment of resources/costs between the PGA and the IRP.
- develop more scenarios to specifically address potential Canadian supply market changes such as diversion of Station 2 supplies to Liquified Natural Gas and/or Nova Gas Transmission, Limited, and the impact of the Canadian federal fuel charge on the price and potential switching of supply basins utilization/needs of upstream pipeline transportation over time.
- add Renewable Natural Gas as a candidate portfolio for the supply resource optimization process.
- work with Staff and Stakeholders to develop a more effective presentation for the severity of negative outcomes. Cascade will report on the status of this action item when filing the 2021 OR IRP Update.

Demand

Cascade will look into making adjustments to a few methodologies on the demand forecast and scenarios. Those adjustments include:

- Adding wind in the stochastic weather analysis.
- A new methodology for peak day. Cascade's peak day is currently the coldest day in past 30 years. Beginning with the 2022 IRP, Cascade's current peak day will fall outside of the 30-year range.
- The 2021 Annual Update will discuss any potential impacts the COVID-19 crises may have on demand.

Environmental Policy

Cascade will either begin or continue to participate/monitor the following items:

- Continue to support the City of Bend's Climate Action Plan efforts which were approved by the City Council on December 4, 2019.
- Participate in City of Bellingham Climate Action Plan discussions.
- Monitor service areas for potential Greenhouse Gas reduction goal development relating to energy delivery and supply.
- Monitor carbon pricing and policy developments nationally and statewide (i.e., OR ballot measure, 2020 carbon tax or cap and trade bills, Social Cost of Carbon, Market Choice, The Clean Future Act, etc.).
- Monitor federal and state GHG regulation development for energy industry.
- Continuation of current emission reduction and monitoring endeavors (i.e., Methane Challenge Program, Renewable Natural Gas studies).

Demand Side Management (Energy Efficiency)

The Company will examine the impact that changes such as revised building codes, OPUC exemptions granted for non-cost-effective measures, and changes to avoided cost calculations may have on the Company's long- and short-term conservation potential. Success shall be measured by the following:

- The Company shall hold at least one meeting with the Energy Trust to discuss any changes that might affect the Company's energy efficiency therm savings targets, and, if applicable, what actions may need to be taken to comply with or adapt to the changes.
- Cascade will provide a summary of its meeting with the Energy Trust in its 2021 IRP Annual Update. In compliance with OAR 860-021-0400(9), the Company will file an update as soon as is reasonably possible if any changes result in a significant deviation from the 2020 IRP.

- The Company will work with the Energy Trust of Oregon to identify potential areas for expanded engagement in support of local communities' climate action planning goals. These discussions could include consideration of biogas engagement where cost-effective and regulatorily permitted. Findings on how to best support local climate plans will be included in the next IRP.

Cascade will strive to acquire the following amount of cost-effective gas therm savings over the next two years:

Figure 11-1: Cost-effective gas therm savings

	2020	2021	2022	2023
Oregon	547,244	563,251	520,166	508,325
Washington	726,625	853,253	2,041,847[1]	2,407,954
Total	1,273,869	1,416,504	2,562,013	2,916,279

- The Company will acquire cost-effective therm savings by partnering with Energy Trust in Oregon and by delivering programs under the oversight of the Company's Conservation Advisory Group in Washington. Short-term annual therm savings targets are refined annually in Oregon by the Energy Trust through the budgeting process and in Cascade's Conservation Plan, which the Company files each December 1st in Washington.

As an additional 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.

Renewable Natural Gas

Cascade has begun creating an RNG Project Cost Effectiveness Evaluation Methodology as seen on page 7-6. Due to uncertainty around environmental attributes, as well as other rules and guidelines for RNG, Cascade will continue to develop and update the cost-effective evaluation tool.

[1] The Washington targets for 2022 and 2023 can also be found on page 7-24 in Cascade's 2018 Integrated Resource Plan (Docket UG-171186). The Company is currently finalizing an update to its Conservation Potential Assessment via AEG which will change the Washington cost-effective gas therm savings. The OPUC will have access to the updated numbers when the next WA IRP is filed in February 2021.

Distribution System Planning

The Company has provided a list of projects that require an increase in capacity as shown in Appendix I. Over the next four years, Cascade plans to construct citygate upgrades in Bend and Prineville. A few of the other projects include pipe upgrades as well as increased pipe capacity, while continuing to maintain compliance with Maximum Allowable Operation Pressure regulations.

Figure 11-1 on the following page highlights specific activities of the 2020 Action Plan.

Figure 11-1: Highlights of 2020 Action Plan

Functional Area	Anticipated Action	Timing
Resource Planning	Cascade will: • attend other regional LDC IRP meetings; • work with NWP on realigning MDDOs; • determine if the temporary Jackson Prairie contract should be made permanent; • develop modeling scenarios that represent Pipeline OFOs; • improve the alignment of resource/costs between the PGA and the IRP; • develop more scenarios that address changing Canadian Markets; • add RNG as a candidate portfolio; and • work with Staff and Stakeholders to develop a more effective presentation for the severity of negative outcomes. Cascade will report on the status of this action item when filing the 2021 OR IRP Update.	Ongoing, for inclusion in 2022 IRP.
Demand	Cascade will look into making adjustments to a few methodologies on the demand forecast and scenarios. Those adjustments include: • Adding wind in the stochastic weather analysis; and • A new methodology for peak day.	Ongoing, for inclusion in 2022 IRP.
Environmental Policy	Cascade will either begin or continue to participate/monitor the following items: • Continue to support the City of Bend's Climate Action Plan; • Participate in City of Bellingham Climate Action Plan discussions; • Monitor service areas for potential GHG reduction goal development relating to energy delivery and supply; • Monitor carbon pricing and policy developments nationally and statewide; • Monitor federal and state GHG regulation development for energy industry; and • Continuation of current emission reduction and monitoring endeavors.	Ongoing, for inclusion in 2022 IRP.
DSM (Energy Efficiency)	The Company will execute the Demand Side Management action items as described on page 11-3 and 11-4.	Ongoing, for inclusion in 2022 IRP.
Renewable Natural Gas	Cascade will continue to develop and update the cost-effective evaluation tool.	Ongoing, for inclusion in 2022 IRP.
Distribution System Planning	These projects are budgeted over the next five years: • FP-306990 - PENDLETON 4" IP REINFORCEMENT • FP-306991 - PENDLETON 4" HP REINFORCEMENT • FP-306992 - PENDLETON KORVOLA ROAD 4" • FP-316851 - South Hermiston to Feedville • FP-316854 - BEND GATE REBUILD • FP-316863 - Prineville Gate Rebuild • FP-317586 - RF-REDM-6"S-4,750'-VETERANS WY • FP-318466 - RF-Baker-GT-NW Baker Gate • FP-318468 - RF-Baker-GT-NW Baker Regulation • FP-318469 - RF-Baker-GT-NW Baker Gate Odorizer • FP-318475 - RF-Baker-GT-NW Baker GT Line • FP-318682 - RF-BEND-6"S-1100'-SHEVLIN PK • FP-318733 - RF-BEND-6"S-2MI-SHEVLIN PK • FP-318737 - RF-BEND-R-SHEVLIN PK RD 2" • FP-318741 - RF-BEND-6"PE-1200'-PONDEROSA ST • FP-318744 - RP-PRINEVILLE-GT-TRANSCANADA • FP-318745 - RP-BEND-GT-TRANSCANADA • FP-318770 - RF-REDM-R-VETERANS WAY-2" STD	Ongoing over the next 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 12-19. Pipeline maps of gas systems that Cascade utilizes are provided on pages 12-20 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.

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

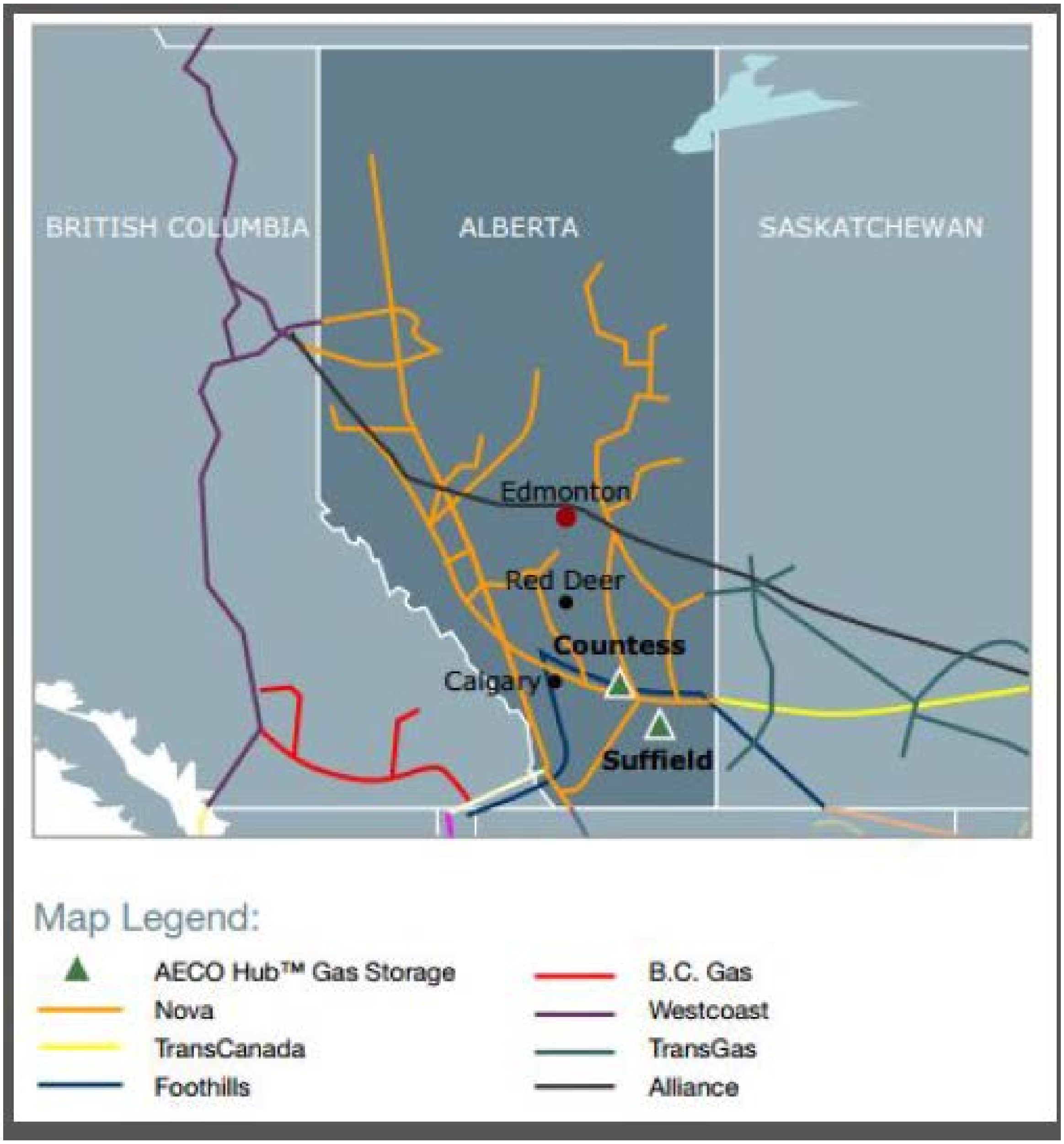


Figure 12-2: Map – California Storage Map

Figure 12-3: Map – Cascade Natural Gas Pipeline System

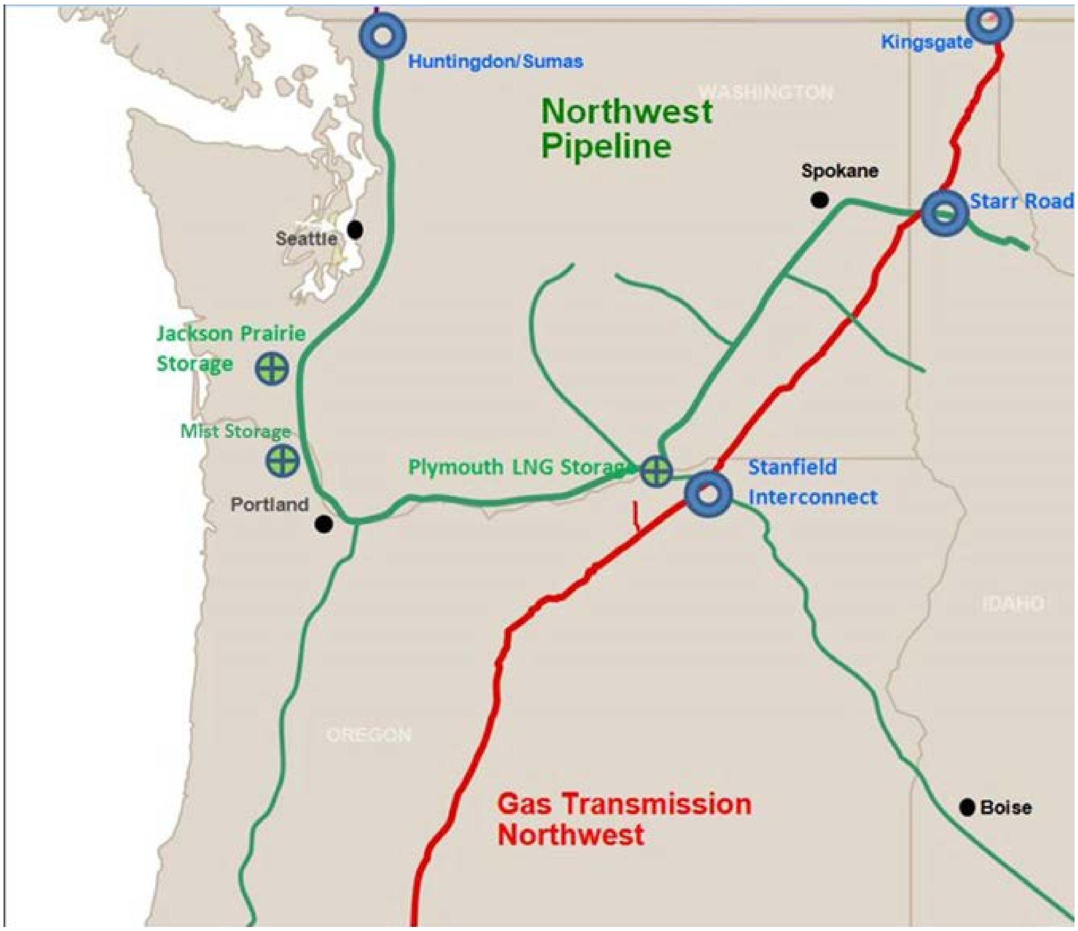


Figure 12-4: Map – Foothills-British Columbia Map

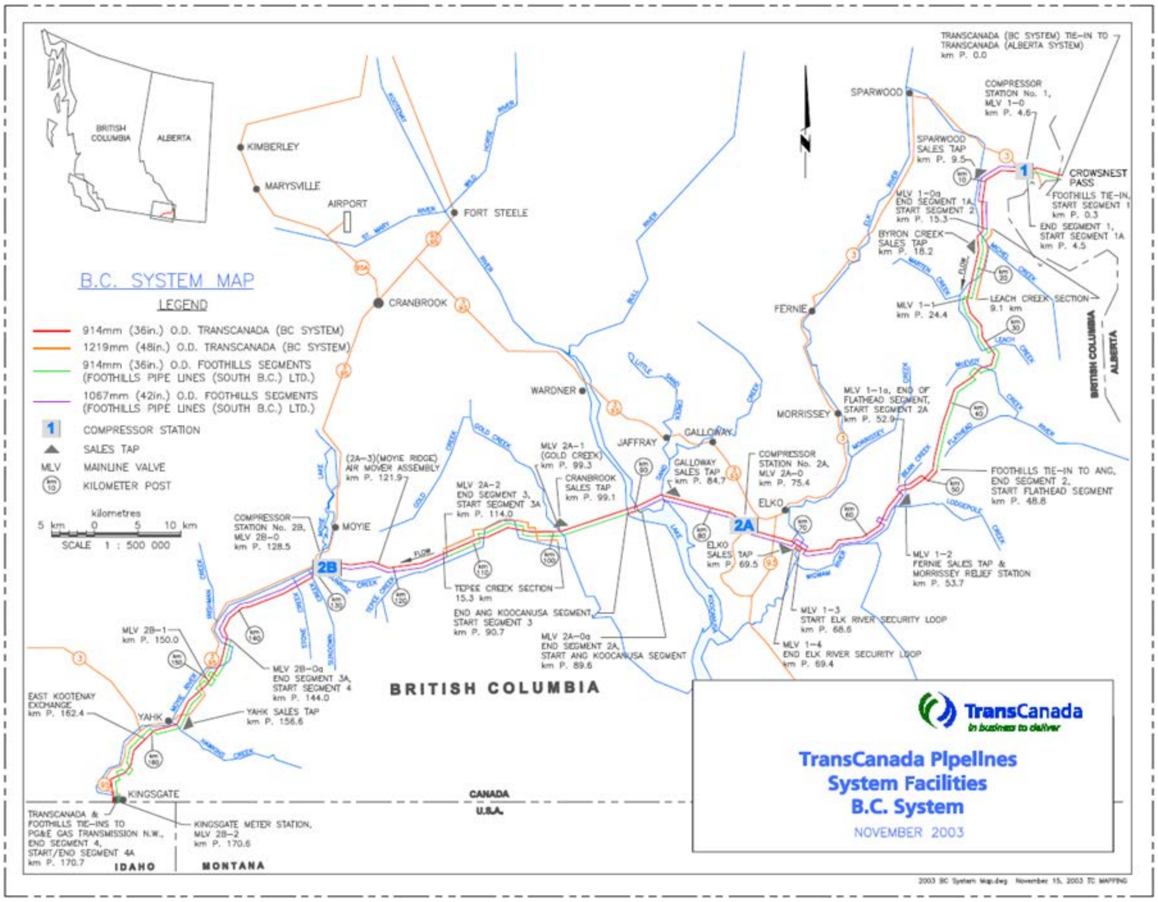


Figure 12-5: Map – Foothills-Full System

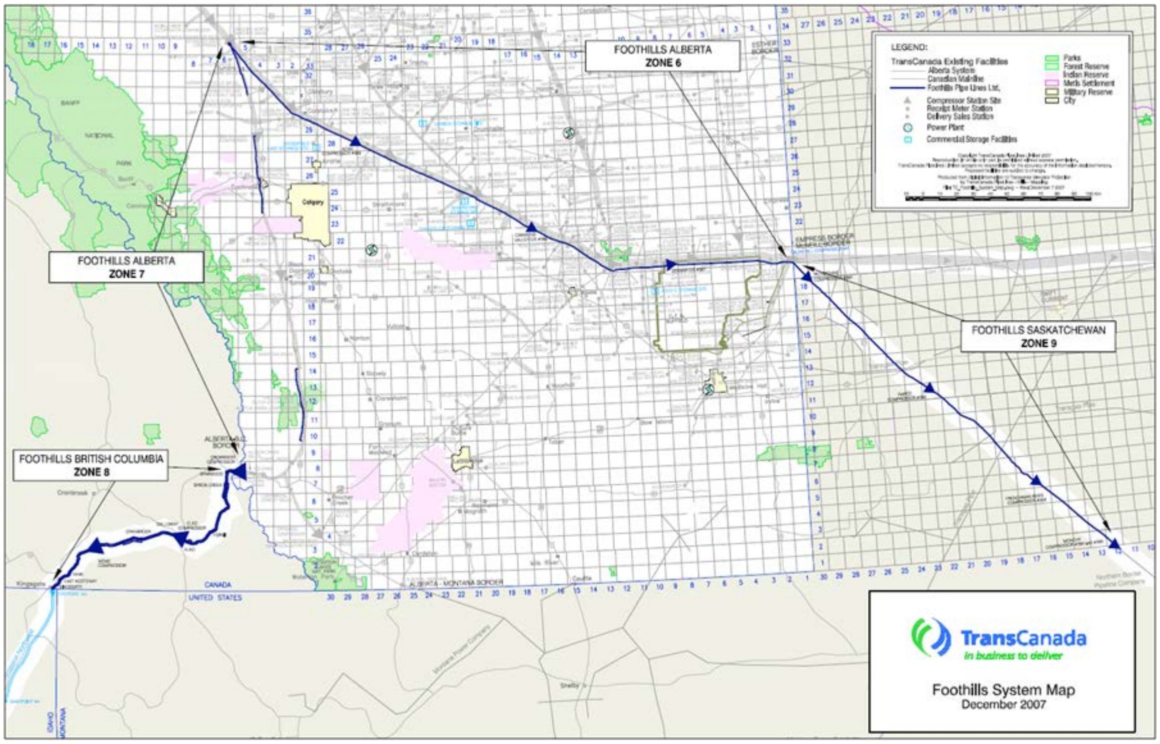
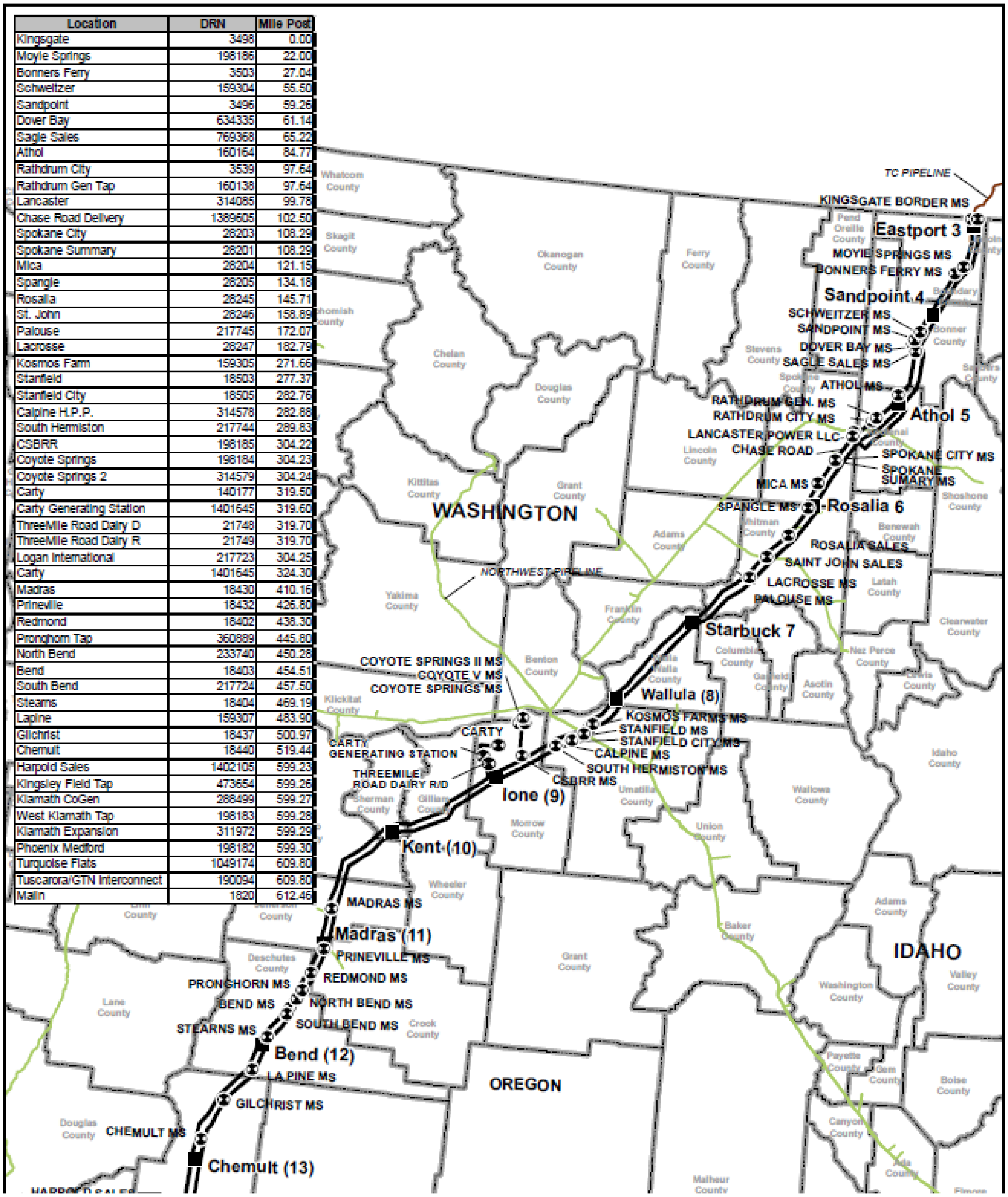


Figure 12-6: Map – GTN System Map

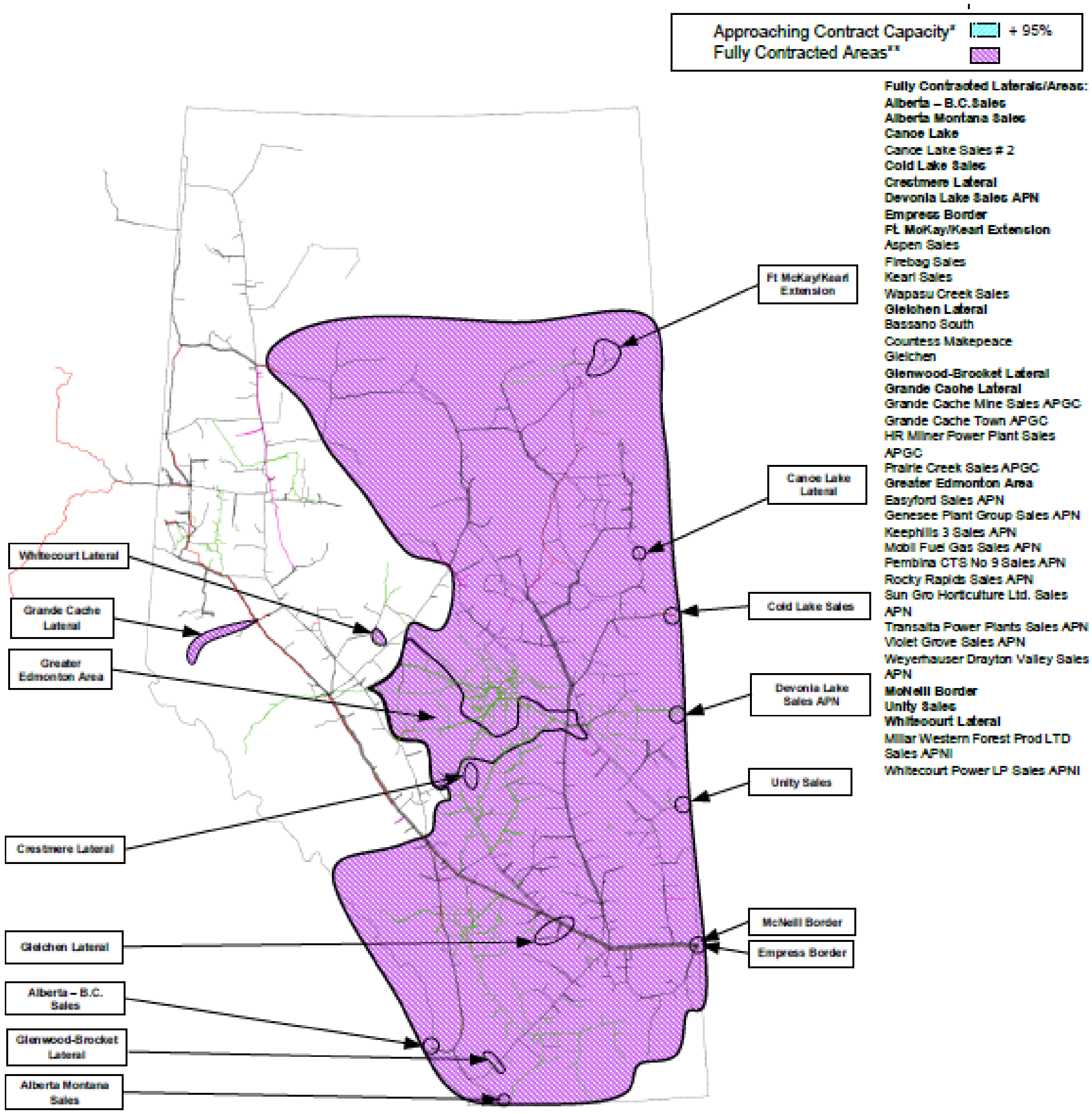


Location	DRN	Mile Post
Kingsgate	3498	0.00
Moyie Springs	198186	22.00
Bonners Ferry	3503	27.04
Schweitzer	159304	55.50
Sandpoint	3496	59.26
Dover Bay	634335	61.14
Sagle Sales	769368	65.22
Athol	160164	84.77
Rathdrum City	3539	97.64
Rathdrum Gen Tap	160138	97.64
Lancaster	314085	99.78
Chase Road Delivery	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

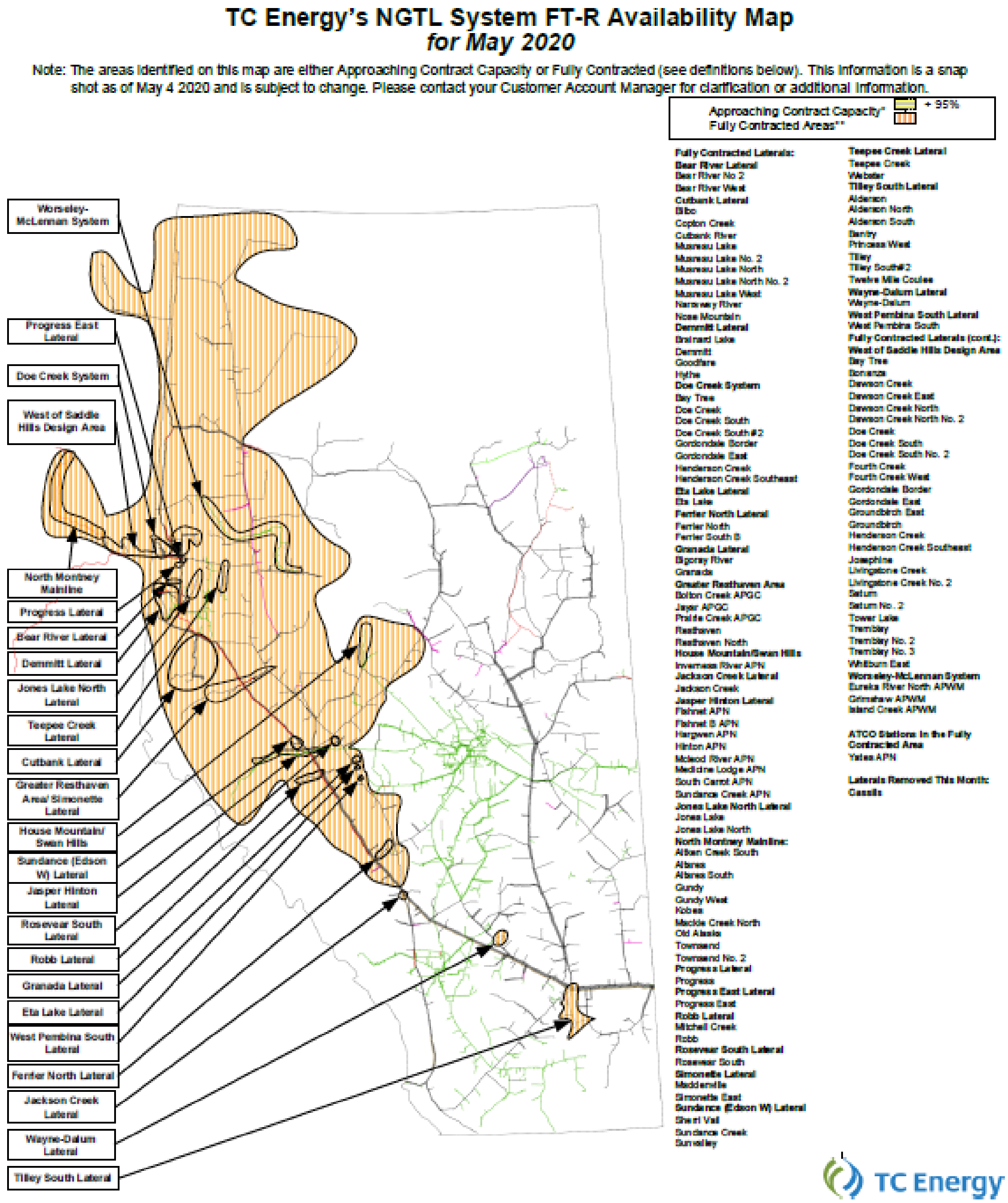
TC Energy's NGTL System FT-R Availability Map
for May 2020

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



Approaching Contract Capacity*	Contracts are greater than 95% of the area or facility capability. Firm Transfers or New Firm to be confirmed with TCPL Customer Sales.
FTR 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 encourages customers to review their future FT-R requirements to ensure their FT-R levels align with their expected flow requirements. New changes to the fully contracted stations list this month are identified in red.

Figure 12-9: Map – NWP North System Map

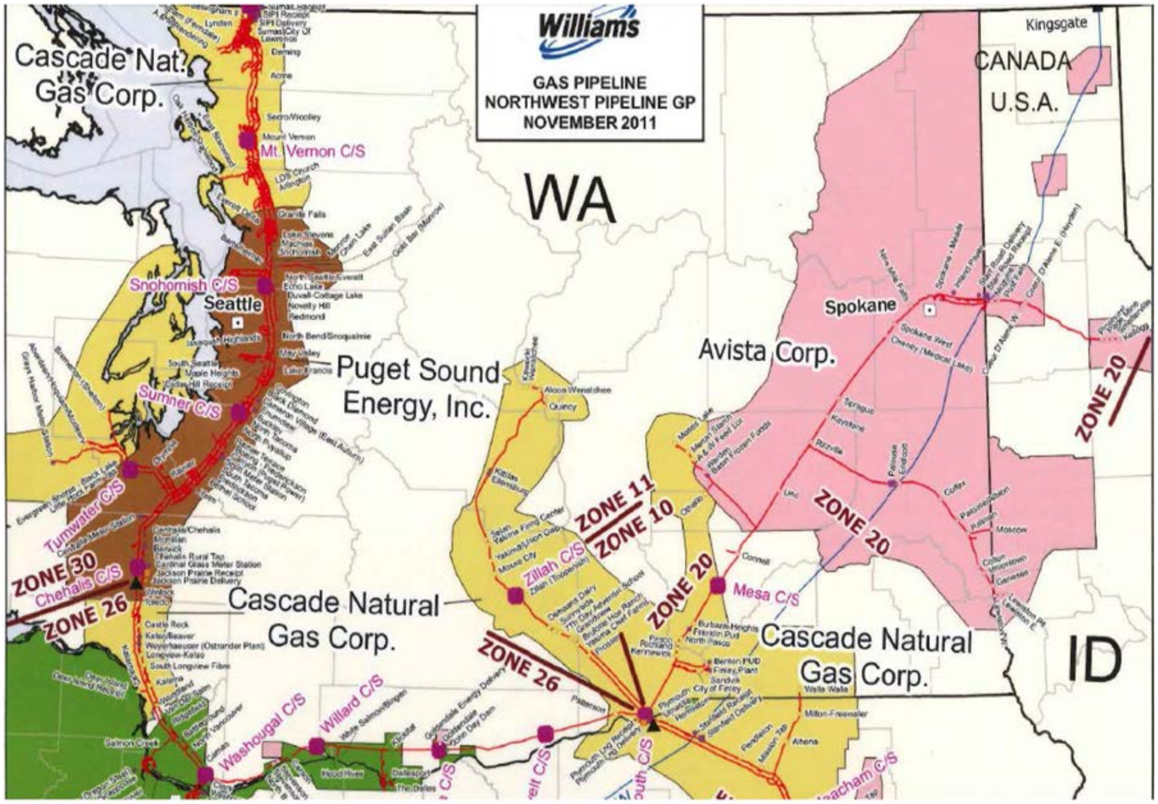


Figure 12-10: Map – NWP South System Map

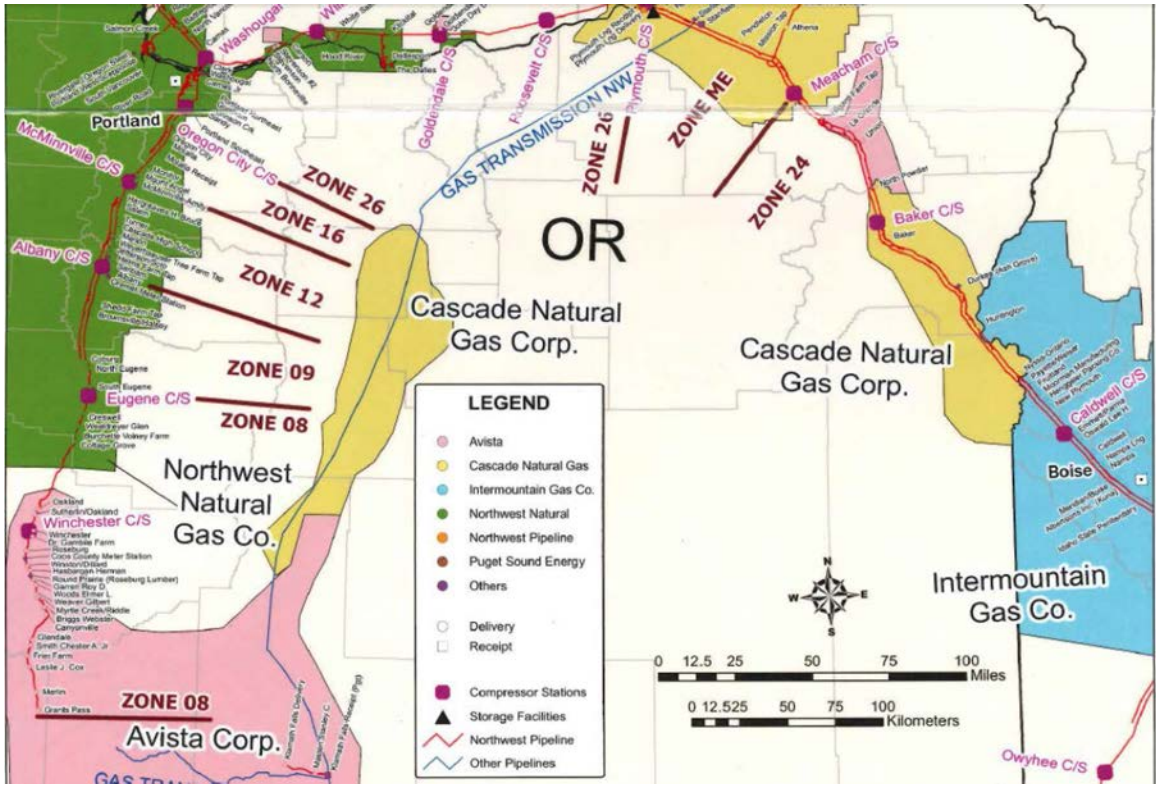


Figure 12-11: Map – Westcoast Sectional Map

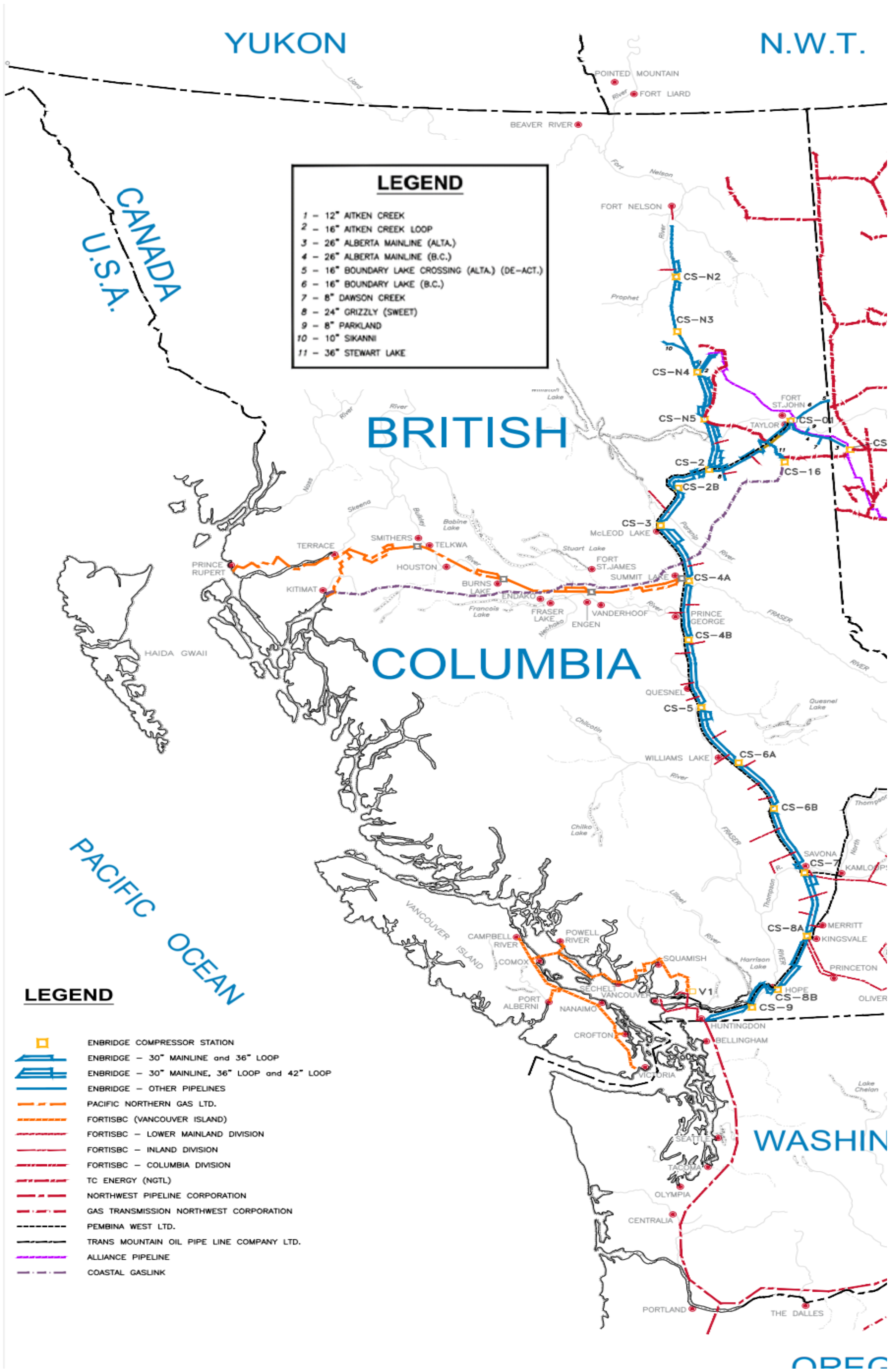


Figure 12-12: Map – Western U.S. and Canadian Pipeline Map

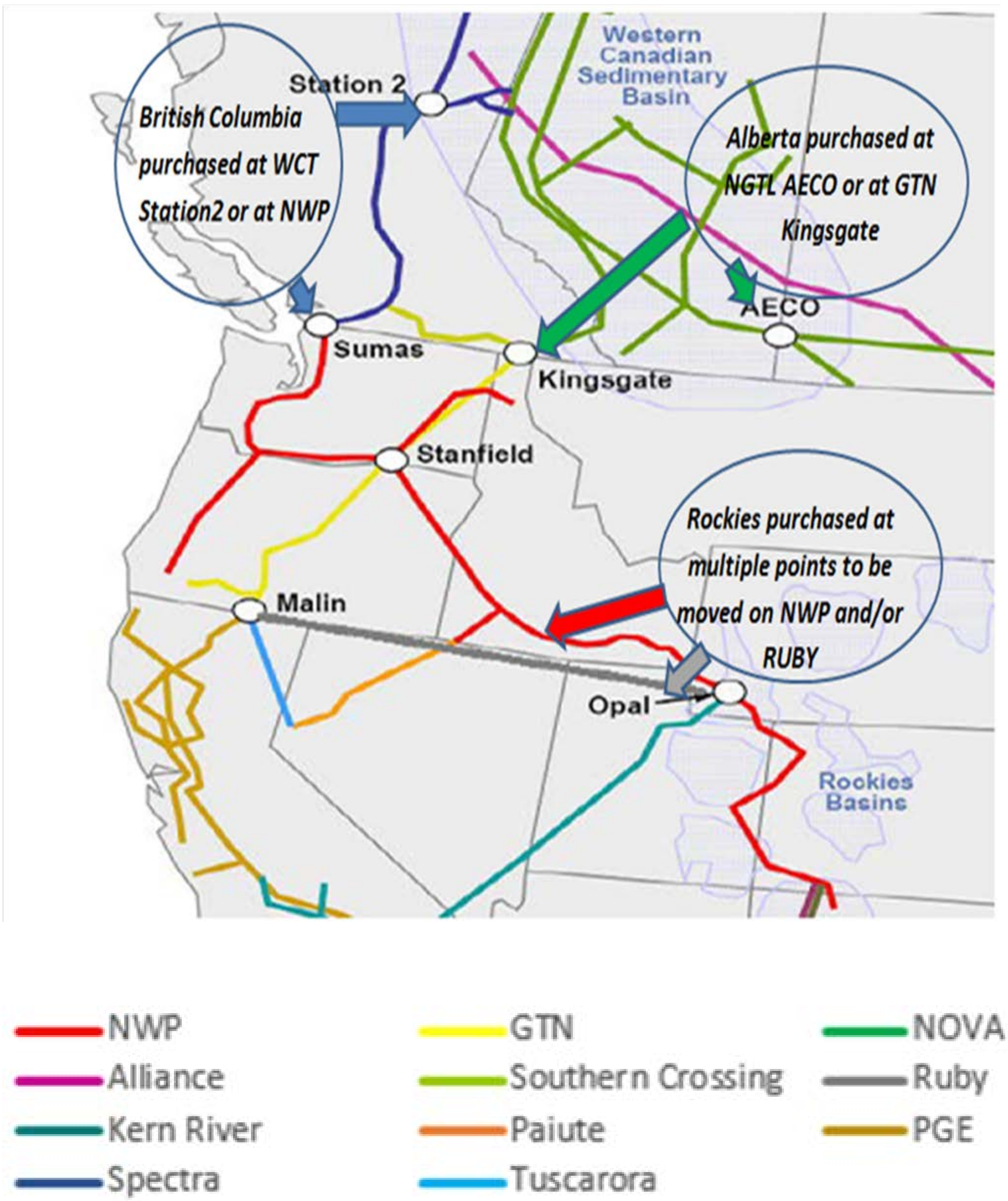
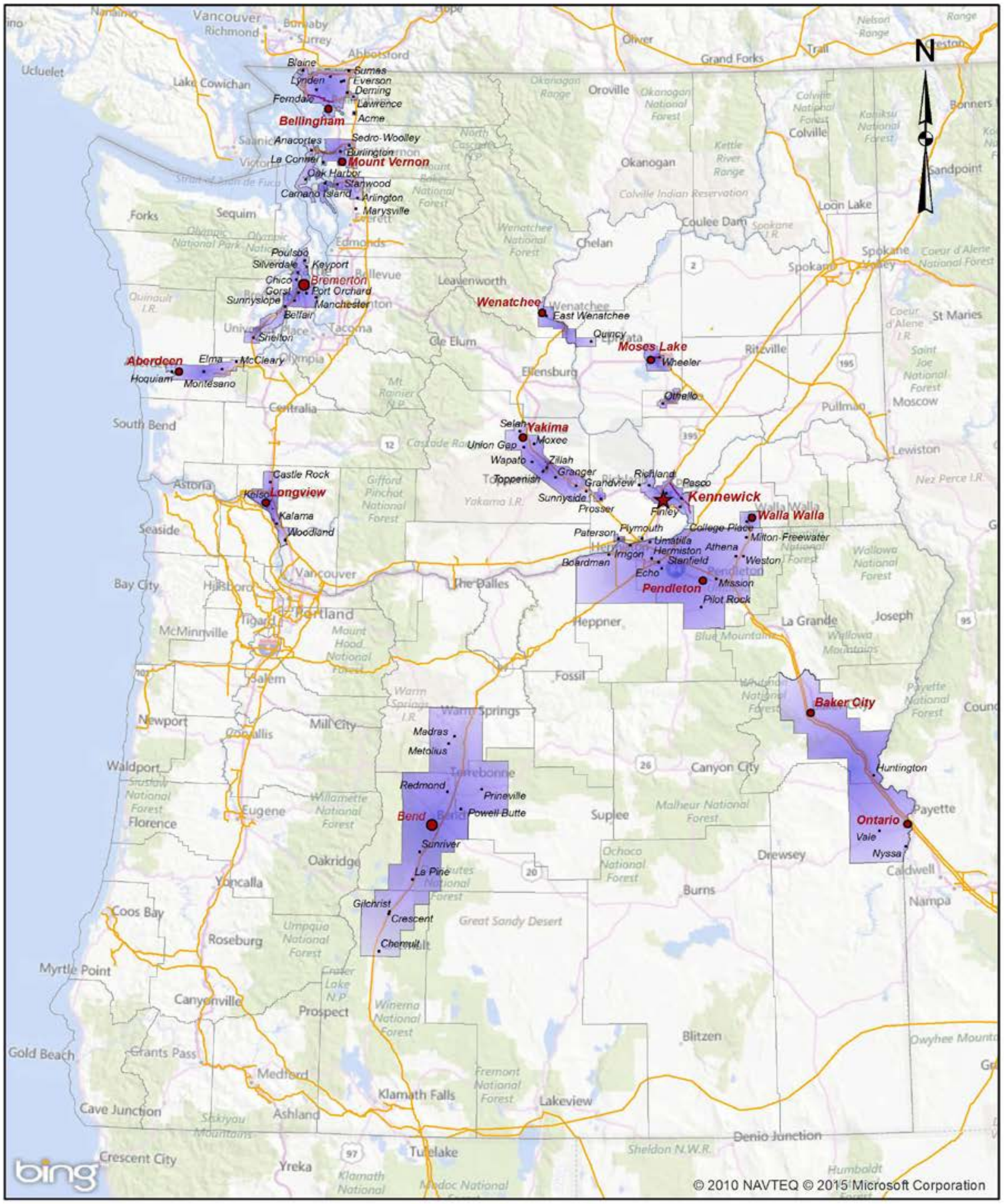


Figure 12-13: Map – Certificated Service Areas as Specified in RCW 80.28.190



Service Boundaries

Communities

- N
- District Office
- Region Office
- General Office

Document Path: G:\Dept\Mapping\SYSTEM MAP\System Map.mxd /Date: 11/13/2015

Figure 12-14: Map – Pipeline Transportation Capacity Usage