CASCADE NATURAL GAS CORPORATION

A Subsidiary of MDU Resources Group, Inc.

In the Community to Serve®

2016
Integrated Resource Plan

December 14, 2016

CASCADE NATURAL GAS CORPORATION
2016 INTEGRATED RESOURCE PLAN (UG-160453)
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SECTION 1

EXECUTIVE SUMMARY

Purpose

The primary purpose of Cascade's long-term resource planning process has been and continues to be to inform and guide the Company's resource acquisition process consistent with state regulatory requirements.

Cascade's resource planning focuses on ensuring that the Company meets the needs of firm gas sales customers in a way that minimizes costs over the long term. Although some pipeline citygates indicate potential shortfalls, in aggregate, through 2019, Cascade has sufficient upstream pipeline capacity. However, looking past the 2019-2020 winter heating season, Cascade's capacity will fall short of its design peak day demand forecast primarily as a result of growth in its residential and commercial customer base. As a result, the Company is entering a period where Cascade will need to acquire additional resources to meet the growing needs of the Company's core customers. This Executive Summary provides a broad overview of the planning process and summarizes key findings from this Plan.

Key Points

- Cascade's first resource deficiency is in 2017 with the need for incremental transportation in 2020. This is based on SENDOUT® modeling.
- The Company's two-year action plan provides the road map for implementation.
- Load growth is forecasted to be 1.25% per year, or 26% over the 20-year planning horizon.
- Avoided costs range from approximately $.5041/therm to approximately $.6659/therm, beginning with a $10/ton carbon cost adder and rising to $30/ton.
- Part of future resources are projected to include 1.7 million therms of energy efficiency over the next two years.
- Future pipeline infrastructure needs will focus on three major enhancement projects over the next three years.
- This Plan was informed by six Technical Advisory Group meetings with active engagement from stakeholders.
- Cascade has fully committed to the IRP process with significant new administrative approaches.
- Each section provides an "at-a-glance" view by inclusion of "Key Points."

IRP Process and Stakeholder Involvement

Cascade's long-term resource planning process is consistent with the Integrated Resource Plan (IRP) rule requirements found in Washington Administrative Code (WAC) 480-90-238. Input and feedback from the Company's Technical Advisory Group (TAG) is an important resource to help ensure that Cascade's IRP is developed from a broader perspective than Cascade could have done on its own. Historically, participants at these public meetings have included interested customers, regional pipelines, local distribution companies (LDCs), Commission Staff, and stakeholder representatives such as the Northwest Gas Association (NWGA), Citizens Utility Board of Oregon (CUB), Washington Public Counsel, and the Northwest Industrial Gas Users (NWIGU).

Cascade held six public TAG meetings with engaged stakeholders. Additionally, throughout the plan development stage, Cascade provided supplemental workshops at the request of WUTC Staff to cover Cascade's forecasting methodology in greater detail as well as to provide a more detailed overview of the Company's Gas Supply function.

See Section 10, Stakeholder Engagement, for a more detailed description of the list of stakeholders and specific information about the TAG meetings.

Responding to the 2014 IRP Issues

In response to the issues identified with the 2014 IRP, Cascade has strengthened its commitment to securing and supporting the appropriate internal and external resources necessary to work with all stakeholders to produce a 2016 IRP that meets all regulatory requirements. Part of the Company's commitment to the IRP includes hiring two additional resource planning analysts and an independent IRP consultant. Based on this commitment, Cascade has hired one resource planning analyst, is actively pursuing the second hiring, and contracted with a consultant during the 2016 IRP process. Additionally, an IRP Steering Committee consisting of various members of Cascade's senior management was formed to improve management oversight of the entire IRP process.

In WUTC's April 14, 2016, letter to the Company, the WUTC identified a number of issues concerning Cascade's 2014 Integrated Resource Plan. These issues are described below, along with Cascade's response to resolving the concerns.

- The lack of clear explanation of the timing of resource needs and how capacity deficits at specific citygates would be met [WAC 480-90-238(3)(g)]

    - Cascade worked with stakeholders to clearly identify by TAG 6 the specific timing, potential exceptions, and method of dealing with upstream pipeline capacity deficits at demand areas. Table 8-4 in Section 8, Resource Integration, states planned major actions by year to address shortfalls. Additionally, Appendix F, Capacity Requirements & Peak Day Planning, provides graphs showing the expected resource stack for each of the 65 citygates.

- The lack of detailed load forecast information by class and state [WAC 480-90-238 (3)(a)]

    - The Company provides a detailed description regarding the development of the load forecast by class and state in Section 3, Demand Forecast. Additionally, each individual citygate/load center's forecast demand is displayed by rate class in Appendix B, Demand Forecast.

- Insufficient analysis and explanation of conservation potential [WAC 480-90-238 (3)(b)]

  - Cascade worked with stakeholders during TAG 3 to identify Staff's specific concerns regarding the insufficient analysis and explanation of conservation potential. The Company believes the discussion in Section 7, Demand Side Management, provides the required analysis and explanation of conservation potential.

- The lack of a description of the Company's stakeholder engagement process [WAC-480-90-238(5)]

  - The 2016 IRP provides an improved description of the stakeholder participation process with the inclusion of TAG meeting presentations, minutes and responses to stakeholder comments. Section 10, Stakeholder Engagement, describes the public participation approach, list of stakeholders, number and dates of the various TAG meetings. Additionally, copies of all TAG presentation materials and minutes are provided in Appendix A, IRP Process. Lastly, to improve the public's access to IRP related information, Cascade recently established a dedicated Internet webpage where all parties can view the IRP timeline, TAG presentations and minutes, as well as current and past IRPs.

- Unclear explanation of the Company's risk management rationale and hedging strategy [WAC 480-90-238(3) (f)].

  - Cascade is currently participating in the WUTC's hedging Docket UG-132019. Throughout this process, the Company has provided comments and explanations of its risk management efforts. Cascade will continue to participate in Docket UG-132019. A more robust explanation of the Company's risk management and hedging strategy is provided in Section 4, Supply Side Resources.

- In addition to the above-listed rule requirements, the Commission also identified a general lack of organization and presentation that made the Plan difficult to read and understand.

  - Cascade provided a draft version of the expanded IRP Table of Contents for WUTC Staff's review in September 2016. This expanded table of contents reflected more discussion items and provided more detail regarding the organizational structure of the components of the 2016 IRP. This table of contents was discussed with stakeholders at TAG 4. Additionally, Cascade obtained the services of an independent IRP consulting firm, Bruce W Folsom Consulting LLC, to provide recommendations that have been incorporated to improve Cascade's IRP.

Highlights from Each Section

Demand Forecast

The Cascade demand forecast developed for the IRP is a forecast of customers, core natural gas demand, and core peak demand for the next 20 years. Cascade's core load consists of approximately 53% residential and 47% commercial and industrial for the first year 2017 projection. Cascade utilizes seven weather locations, effectively covering the entire service territory. Figure 1-1 breaks out the percentage of 2017 forecast load by class. Figure 1-2 provides this breakout for Washington.

Figure 1-1: 2017 System Forecast Load Breakout by Class

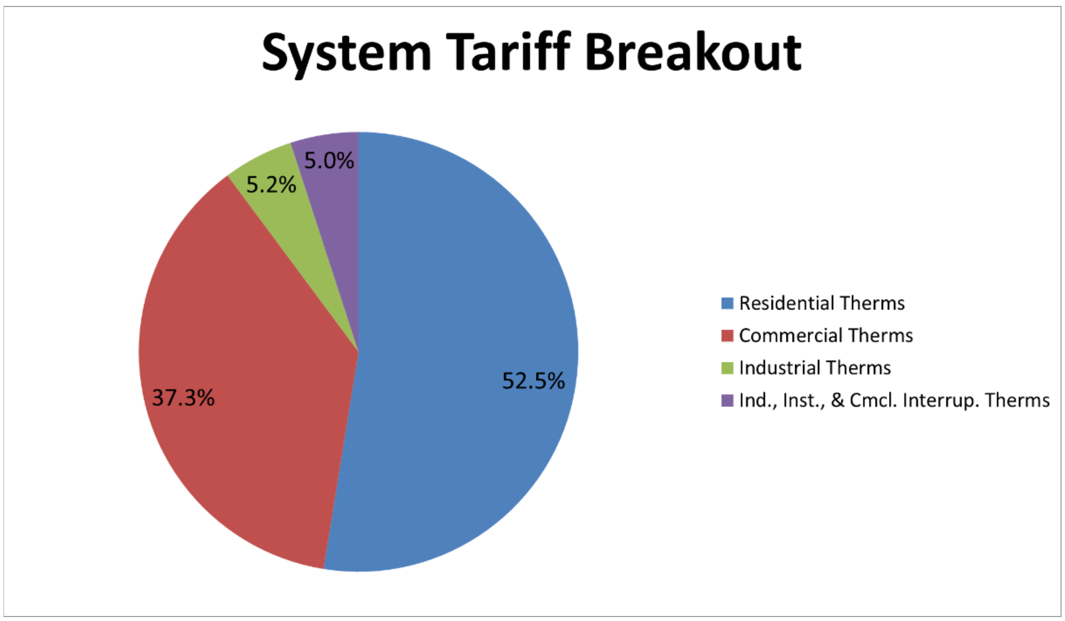
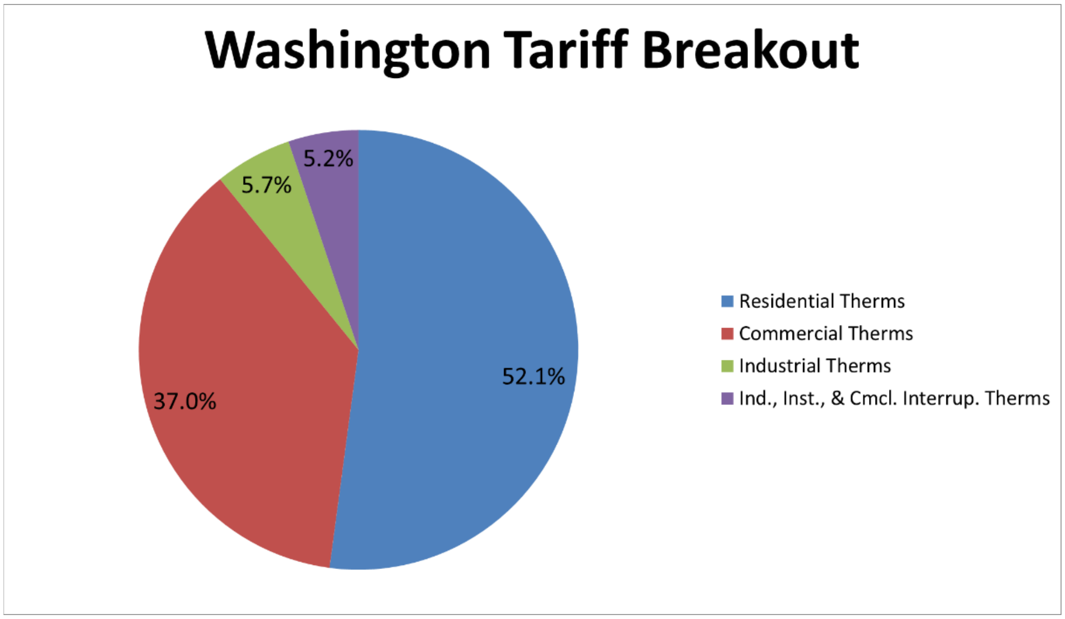


Figure 1-2: 2017 Washington Forecast Load Breakout by Class



Cascade's demand is weather and customer driven; the colder the weather or greater the customer count, the greater the demand. This current forecast uses 30 years of recent weather history as the "normal" or expected weather. It is forecasted under various weather and growth scenarios – expected annual weather, cold annual weather, warm annual weather, extreme cold day, high growth, low growth, etc. Cascade performed analysis on weather and demand for each of 65 citygates that serve core customers. Growth factors are applied to each of the 20 years in the forecast for each citygate. Since Cascade has observed that heating demand does not appreciatively start until average temperatures dip below 60 °F, a 60 °F threshold is used to calculate Heating Degree Days (HDDs).

Cascade has a portion of its load that is non-weather dependent. This is typically caused by a non-residential customer who ramps up production based on the time of season. This demand is removed prior to running the demand versus weather analysis. After the HDD and customer forecast are input into the regression to produce a usage forecast, the non-weather dependent demand is added back to reflect actual usage.

Cascade anticipates core customer base will continue growing over the planning horizon and annual throughput is anticipated to increase between 1.1% and 1.3% per year. Figure 1-3 displays the annual forecasted therms over the planning horizon.

Figure 1-3: Annual Load Forecast for 20-Year Planning Horizon

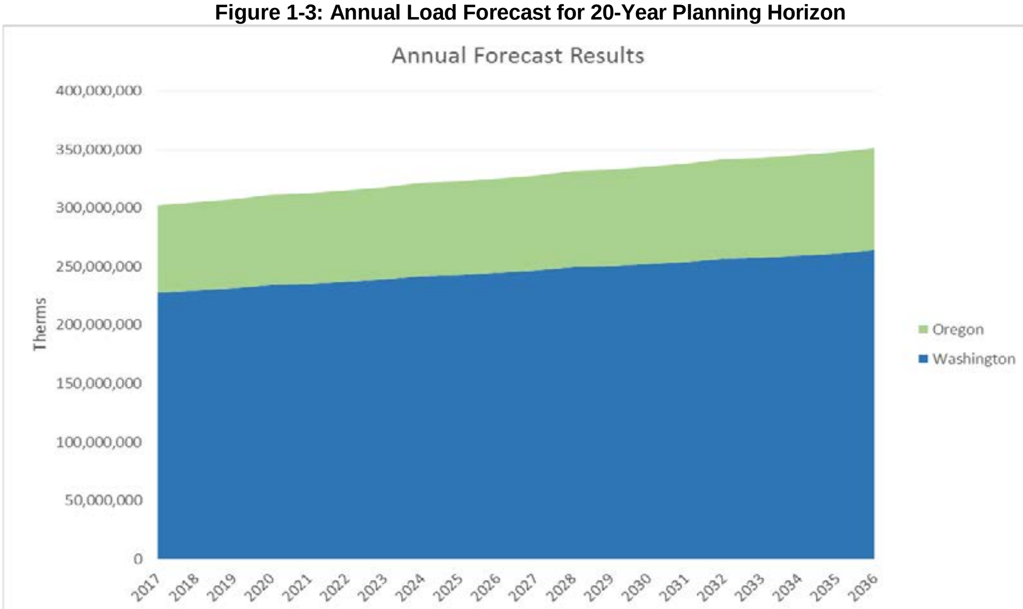


Figure 1-4: Western U.S. and Canadian Pipeline Map

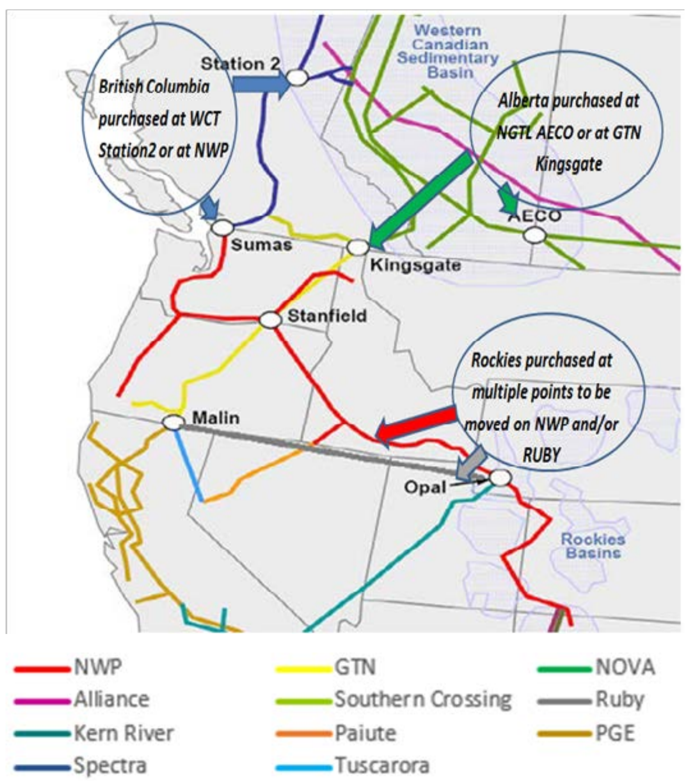
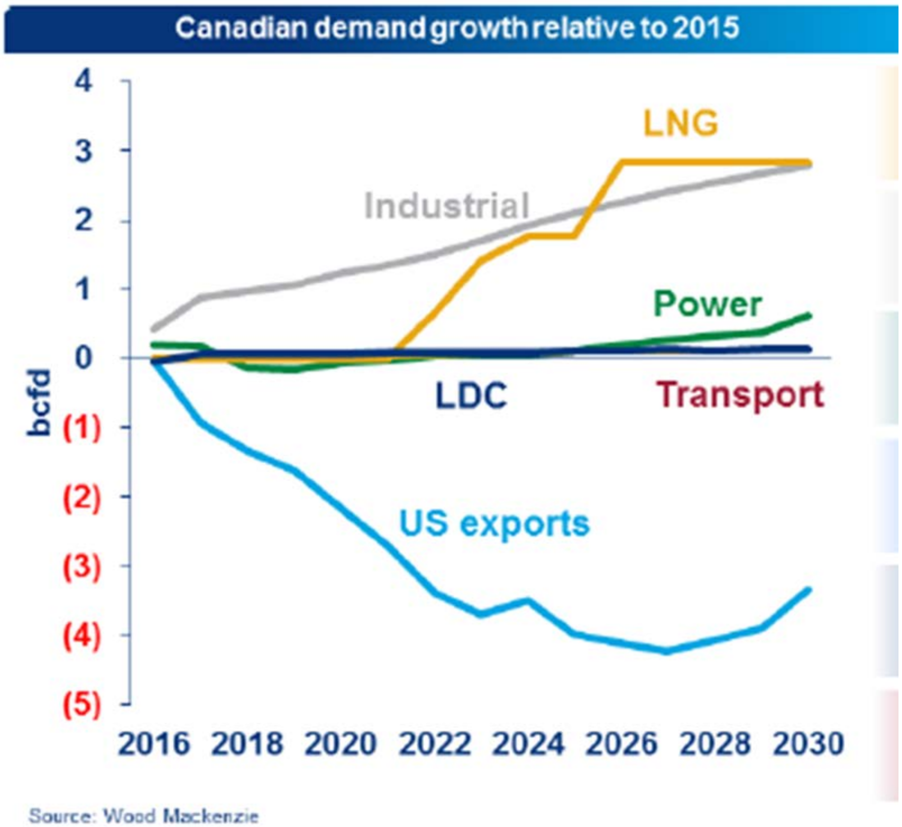


Figure 1-4 displays general flow paths for the regional supply basins. A larger map of Figure 1-4 is also provided in Section 13, Glossary and Maps, with Figure 13-12. Physical gas supply is expected to be more than sufficient to meet growing demand in the Pacific Northwest and North America. New supply development technologies continue to provide additional resources in British Columbia and the Rocky Mountain regions. Shale gas from the Horn River Basin, Montney and Marcellus is likely to keep sufficient supplies available in North America. Looking ahead, Cascade anticipates that Rockies production will slightly decline. However, some industry experts, such as Wood Mackenzie, believe that Liquefied

Natural Gas (LNG) will flow from BC in the early 2020s. The market could see AECO prices begin to rise relative to Rockies if LNG exports from the Canadian west coast pulls supplies away from AECO. Figure 1-5 shows the Canadian demand growth that demonstrates the increase in LNG export growth.[1]

Figure 1-5: Canadian Demand Showing LNG Export Growth



Experts predict U.S. production is expected to be over 90 Bcf/d in 2020 and over 110 Bcf/d in 2030 with larger amounts of low-cost gas in the Marcellus basin. Production growth in Western Canada is flat and low prices will ultimately reduce any long-term production expectations. U.S. demand is expected to exceed 90 Bcf/d in 2020 and 115 Bcf/d by 2030, about 7-10% higher than expected in the Company's 2012 IRP. Low long-term prices will likely encourage new gas-intensive industrial projects. Power-sector consumption strengthens as coal displacement continues. U.S. and Canadian LNG exports are likely to ramp up by 2022. Several projects utilizing Canadian resources continue to emerge in the U.S. Pacific NW and British Columbia; although it is likely few, if any, will make it to service due

[1] Wood Mackenzie Canada Gas Markets Long-term Outlook H1 2016

to a combination of financial, regulatory, and regional environmental concerns. Mexico's power sector is expected to continue to grow as new gas-fired power plants are built and existing fuel-oil plants are converted to burn gas.

Cascade has considered bio-natural gas (BNG) as an alternative, but as of this writing there are no viable projects available to serve Cascade's core customers. Regardless, prior to any BNG supplies being added to the portfolio, gas quality issues will need to be satisfactorily addressed. In addition to Cascade, upstream pipelines, such as Northwest Pipeline are beginning to address gas quality issues regarding BNG. Cascade will continue to monitor market intelligence sources to see if viable BNG opportunities develop.

The projected costs for natural gas have declined significantly in recent years. Long-term prices are estimated to range from $2.50 to $5 over the planning horizon compared to the $8 to $13 forecasted in the 2008 IRP.

Environmental Considerations

Cascade's 2016 Integrated Resource Plan includes an expanded discussion regarding environmental considerations compared to prior plans. The purpose of these considerations is to support policies that cost-effectively achieve state and federal carbon emission reduction targets. Included in the discussion are Cascade's carbon methodology and assumptions for calculating inputs towards a 20-year avoided cost of natural gas with an associated two-year action items.

Federal, Washington, and Oregon agencies are proposing a series of regulations and policies to address greenhouse gas (GHG) emissions with carbon dioxide CO_2 being their primary component. While focused on the Pacific Northwest electric industry, the Northwest Power and Conservation Council (NPCC or Council) exhaustively examines CO_2 in its Seventh Power Plan (Plan) released in May 2016. This Plan builds on the Council's previous work and has become the recognized standard for carbon analyses. Cascade's work on its IRP is best informed by the Council's survey of approaches, sensitivity analyses, and scenarios, with attention to Cascade's customers regarding cost-effectiveness and the results of other local distribution companies (LDC). Cascade is addressing CO_2 by promoting energy efficiency, encouraging of the direct use of natural gas, recapturing methane, and preventing gas leaks. Regarding expectations, there is less of an impact on customers as compared to the electric utility industry.

Thus the question is not whether carbon adders should be included in Washington and Oregon but, rather, how and in what amount. Of the eight approaches NPCC examined, virtually all LDCs and electric utilities—as well as the Council—have centered on the Carbon Cost Risk approach. This results in a $10/ton carbon cost adder to Cascade's avoided costs (via the 20-year price forecast) in 2018, and $30/ton in 2035.

A more detailed discussion regarding carbon assumptions for this IRP can be found in Section 5, Environmental Considerations.

<u>Long-Term Price Forecast/Avoided Costs</u>

Cascade's long-term planning price forecast is based on a blend of current market pricing along with long-term fundamental price forecasts. The fundamental forecasts used are from Wood Mackenzie, the Energy Information Administration (EIA), the NPCC, and Bentek. Market price forecasts, particularly in near term, are heavily influenced by NYMEX Henry Hub prices. While not a guarantee of where the market will ultimately finish, NYMEX Henry Hub and regional basis are the most current information that provides some direction for future market prices.

Several complicating factors call into question the accuracy and application of price elasticities. These include: regulatory mechanisms (e.g., purchased gas adjustments (PGAs) and general rate cases) which dampen price signals, or information to customers about future pricing. Historical data (embedded with effects of conservation, technology, and economic conditions) is imperfect for a precise price elasticity determination. The retail price of the most "substitutable" fuel—electricity—moves with the cost of natural gas, thereby reducing the economic value for customers to use electricity for heat when natural gas is selling at a high-price. Evolution of modeling suggests that future IRP modeling should incorporate iterative quantitative equations to allow built-in price elasticity effects.

With this 2016 IRP, Cascade has incorporated price elasticity into the plan. For Cascade's current IRP cycle, a short-run coefficient factor of -0.10 and a long-run factor of -0.12 with ranges of plus or minus 0.07 are incorporated, given regional studies and other utilities' modeling efforts.

As part of the IRP process, Cascade calculates a 20-year gas price forecast and 45 years of avoided costs. The avoided cost is an 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 evaluating energy conservation next to the cost of acquiring and transporting natural gas to meet demand. Cascade evaluates the impact that a range of environmental externalities, including CO_2 emission prices, would have on the avoided costs in terms of cost adders and supply costs. The avoided costs are produced based on system-wide peak day. Peak day is discussed more in Section 3, Demand Forecast.

The components of the avoided costs include:

- The long-term gas price forecast compiled from multiple consultants' gas price forecast (which is the majority of the cost);
- A price for carbon included in the gas price forecast, which has been provided by a consultant;
- Gas storage variable and fixed costs;
- Upstream variable and fixed transmission costs;
- Peak related on-system transmission costs; and
- A 10% adder for environmental benefits, as recommended by the Northwest Power and Conservation Council (NPCC).

For the 2016 IRP the system avoided costs ranges between $0.5041/therm and $0.6659/therm over the 20-year planning horizon. Further discussion and details regarding the avoided cost projections for the 45 years through 2060 can be found in Section 6, Avoided Costs, and further discussion regarding price elasticity can be found in Section 8, Resource Integration.

Demand Side Management (DSM)

Section 7, Demand Side Management, is an Executive Summary in accordance with the commitment made to transition toward a separate Conservation Plan provided each December where the majority of the energy-efficiency planning process will take place. The majority of the low income program elements have been pulled out of the IRP to be addressed in the annual Conservation Plan per the July 2016 Conservation Advisory Group (CAG) meeting.

Smoother assimilation into the other IRP sections is reflected by moving from statewide conservation forecasts to a climate zone granularity. Focus is also placed on how the Company incorporates its goals into the resource allocations and how the Company has the tools to ensure its achievement potential is achieved, including insights into items needing to be accomplished in the future ten-year range to meet its goals.

The DSM section discusses the Company's motivation for investing in conservation (through policy, Commission directive, etc.), what has been accomplished, and how the Company is going to move forward including what the Company will do differently to accomplish conservation goals in the near future.

Cascade Natural Gas uses Nexant Inc.'s in-house developed Microsoft Excel-based modeling tool, TEA-POT (Technical/Economic/Achievable Potential), to run multiple scenarios to establish market potential savings based on variable inputs within the Company's Washington Service territory.

TEA-POT was rerun with updated load forecast inputs for Section 7, Demand Side Management. For the first time, it was run at the climate zone level of granularity with separate unique inputs for each of the three geographic service territories.

Figure 1-6 shows location of the various climate zones.

Figure 1-6: Climate Zones

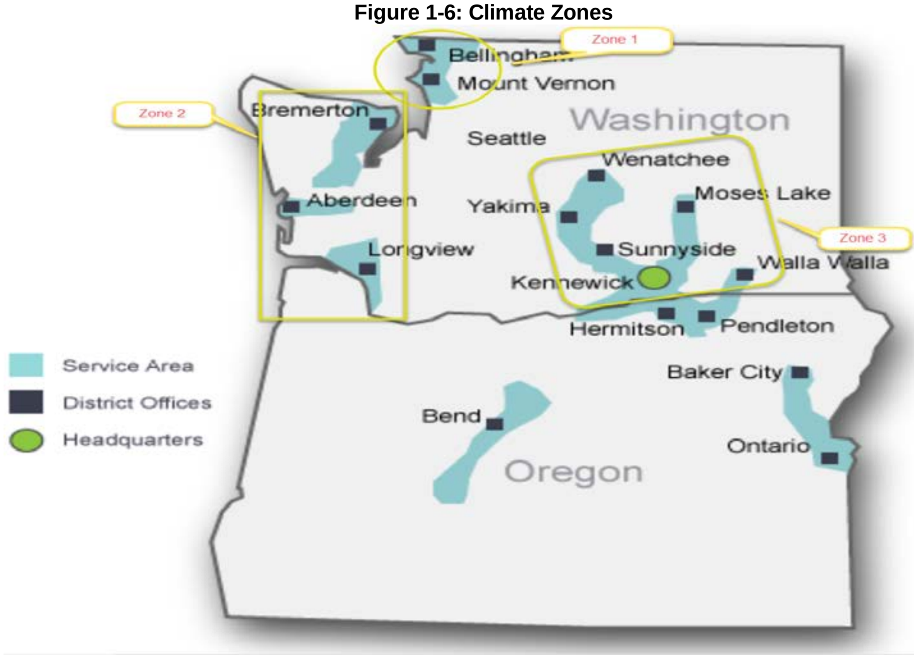


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Figure 1-7 shows how the conservation portfolio grows over the planning horizon. Figure 1-8 shows this growth by customer class.

Figure 1-7: Full Conservation Portfolio by Climate Zone

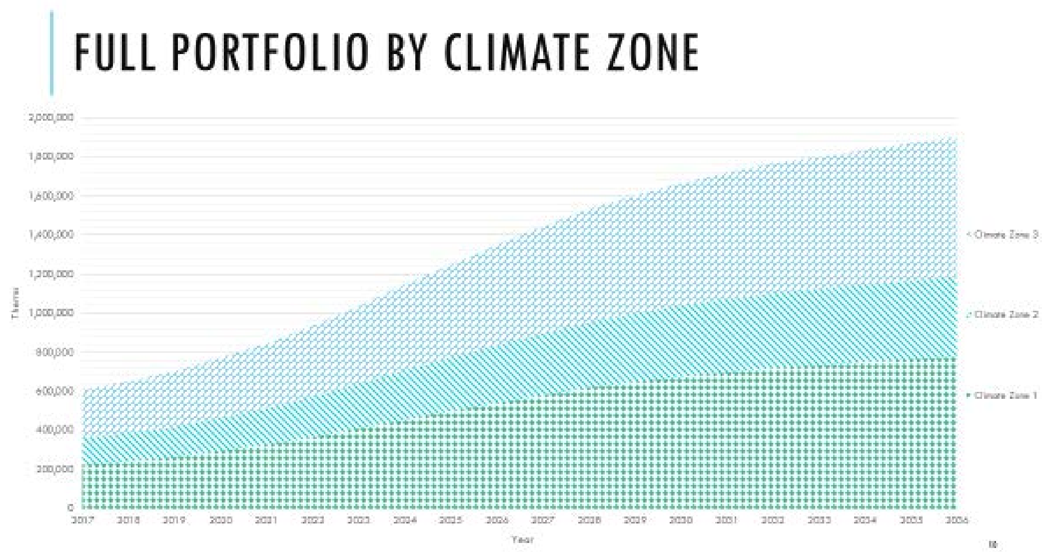
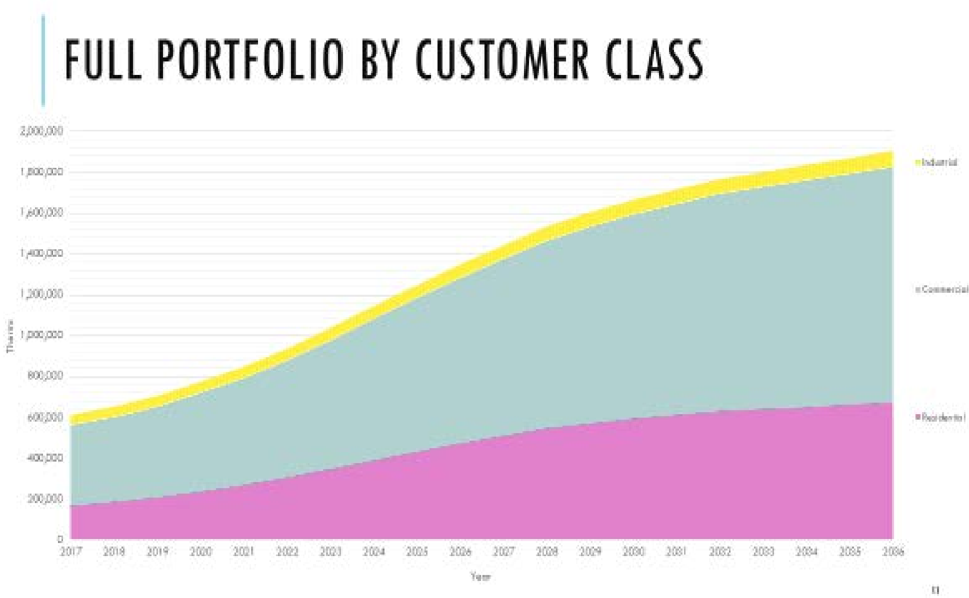


Figure 1-8: Full Conservation Portfolio by Customer Class



Resource Integration

Cascade utilizes SENDOUT® for resource optimization. This model 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. SENDOUT® is very powerful and complex. It operates by combining a series of existing and potential demand side and supply side resources and optimizes their utilization at the lowest net present cost over the entire planning period for a given demand forecast. SENDOUT® utilizes a linear programming approach. 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. Therefore, it is important to acknowledge that linear programming analysis 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 can be added to its resource portfolio, including additional conservation programs, incremental off-system storage alternatives at AECO Hub, Mist, Ryckman Creek, Wild Goose, and Gill Ranch. Additionally, incremental transportation capacity on NWP, Ruby, NGTL, Foothills and GTN pipeline systems was considered, along with on-system satellite LNG facilities, biogas, 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' worth 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 with energy efficiency programs, 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 scenarios were run to test the viability of acquiring incremental storage and transportation resources either based on existing recourse rates, discounted rates and via capacity release through a third party. Basin prices in the model over the 20-year planning horizon have AECO's trading at a discount to Rockies, Malin and Sumas. The acquisition of additional traditional pipeline capacity represents the most reasonable resource to address most capacity shortfalls on a peak day.

Satellite LNG facilities that are located within Cascade's distribution system are also attractive alternatives. Satellite LNG may alleviate the need for incremental pipeline capacity and to the extent the facility could be strategically located on a portion of the distribution system, it could provide the further benefit of eliminating or reducing distribution system constraints. Cascade's modeling indicates that should it be determined by late 2017 that a combination of realigned delivery rights and/or an NWP expansion along the Yakima-Wenatchee line is not possible by 2022, Cascade should consider securing satellite LNG directly connected to the distribution system to address potential shortfalls in the area.

Many of the proposed pipeline projects will not be viable resources until 2018 at the earliest. In the interim, incremental capacity needs can be met through the use of peaking resources and citygate gas supply deliveries which will utilize third-party (non-Cascade) upstream pipeline transportation.

Using input from these alternative resources discussed, SENDOUT® derives a portfolio of existing and incremental resources that Cascade defines as the Expected Scenario. This scenario provides guidance as to what resources should be considered to reduce unserved demand with the least cost mix of all of the alternatives that the Company has considered, under expected pricing, weather, and growth environments.

20-year portfolio costs are expected to range between $3,179,914,000 to $5,086,396,000 for the planning period, with an average cost per therm ranging between $0.449 and $0.718.

A more detailed discussion regarding the Company's resource integration and the results can be found in Section 8, Resource Integration, beginning on page 8-17.

Distribution System Planning

Distribution planning focuses on determining if the Company will have adequate pressure during a peak hour.

Cascade's natural gas distribution system consists of approximately 4,744 miles of distribution main pipelines in Washington, and 1,604 miles in Oregon; as well as numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment. Currently, one compressor station is placed within Cascade's distribution system near

Fredonia, WA. 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.

Cascade's Geographic Information System (GIS) helps engineering look at what is currently in place to meet load demand and assists them to create system models. Cascade's engineers use GIS and other input data such as customer billings to create models using a software application called Synergi. After achieving a working load study, analyses are performed on every system at design day conditions to identify areas where potential outages may occur. These areas of concern are then risk-ranked against each other to ensure the highest risk areas are addressed first.

The results of Cascade's current modeling has identified near term growth around Stanwood and Manchester which may require reinforcement work in 2017 and 2018. Gate station work may begin in 2019 to address growth in Walla Walla. The distribution planning process and more description regarding possible near term projects is provided in Section 9, Distribution System Planning.

Table 1-1 shows Cascade's Two-Year Action Plan. Further descriptions plus other anticipated action items can be found in Section 12, Two-Year Action Plan.

Table 1-1: Two-Year Action Items Highlights

Functional Area	Anticipated Action	Timing
Demand Forecast	Expanding forecasting to test non-linear regression methodology using SAS	Beginning in 2016 for 2018 IRP
Demand Forecast	Consider the new weather normalization model in the forecast	Beginning in 2016 for 2018 IRP
Demand Forecast	Cascade will work on gathering growth information from other locations to compare with Woods & Poole. Also include analysis from State Economist Report	Beginning in 2017 for inclusion in 2018 IRP
DSM	Investigate incorporating distribution system costs into the avoided cost calculation	Beginning in 2017 for inclusion in 2018 IRP
DSM	As specific carbon legislation is passed, the Company will update its avoided cost calculations, conservation potential and make modifications to its DSM incentive programs as necessary.	Consider in 2017 for possible modification in the 2018 IRP
Environmental, DSM, Demand Forecast	The Washington State Dept. of Ecology issued a new carbon rule. Cascade will need to consider IRP implications	Beginning in 2017 for inclusion in 2018 IRP
Resource Integration	Expand Monte Carlo methodology to include analyses of a variety of potential portfolio scenarios (e.g., high growth, low pricing, etc.)	Beginning in 2017 for inclusion in 2018 IRP

Functional Area	Anticipated Action	Timing
Supply Resources	Negotiate with TransCanada for the needed incremental GTN capacity for November 2017	Complete by June 2017, with a November 2018 in-service date
Supply Resources	Work with NWP to define what delivery rights can be modified to meet potential shortfalls	Complete assessment by July 2017
Supply Resources	Work with NWP and potentially other regional LDCs to determine if a combination of I-5, Wenatchee, etc. expansion or segmentation can address shortfalls and regional infrastructure concerns.	Complete assessment by July 2017
Distribution System Planning, Resource Planning, Gas Supply	Incorporate the citygate study into the IRP.	Beginning in 2016, complete in early 2017 for inclusion in IRP
Distribution System Planning, Gas Supply, Operations, Others	Use the results of the citygate study to confirm aligning of alternative resources, specifically satellite LNG	Confirm if satellite LNG is proper solution by July 2017;
Distribution System Planning, Gas Supply, Operations, Others	Subject to confirmation of a need for satellite LNG, proceed with implementation of facility	Begins no later than July 2017, for potential in service date of November 2018

Use and Relevance of the Integrated Resource Plan

Cascade's IRP provides the strategic direction guiding the Company's long-term resource acquisition process. The Plan does not commit Cascade to the acquisition of a specific resource type or facility nor does it preclude the Company from pursuing a particular resource or technology. Rather, the Plan identifies key factors related to resource decisions and provides a method for evaluating resources in terms of their cost and risk. Cascade recognizes that integrated resource planning is a dynamic process reflecting changing market forces and a changing regulatory environment.

SECTION 2

COMPANY OVERVIEW

Overview

Cascade Natural Gas Corporation delivers retail natural gas service to more than 273,000 customers with approximately 205,000 customers in Washington and 68,000 in Oregon. The Company's customers are located in 96 communities -- 68 of which are in Washington and 28 in Oregon. Cascade's service areas are concentrated in the smaller, rural communities in western and central Washington and central and eastern Oregon. The climate of the service territory is almost as diverse as its geographical extension. The western Washington portion of the service territory (nicknamed "I-5 corridor") has a marine climate similar to many coastal cities of western and southern Europe. Periodic exceptions include the occasional significant snow events, but these are rare. In general, the climate in the western part of the service territory is mild with frequent cloud cover, winter rain and warm summers.

Key Points

- Cascade serves diverse geo-graphical territories across Washington and Oregon.
- The Company began in 1953 with the unification of five local distributors.
- Cascade's primary pipelines are Northwest Pipeline (NWP), Gas Transmission Northwest (GTN), and Westcoast (WCT) with access to three other pipelines.
- Core customers represent 23% of total throughput, while non-core customers represent 77% of total throughput.
- Cascade is a subsidiary of MDU Resources Inc., based in Bismarck, North Dakota.

The climate of the eastern portion of Cascade's Washington service territory has semi-arid conditions with periods of arctic cold in the winter and heat waves in the summer.[1]

Described below are some of the major towns within specific regions where 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.
- **Southern** – Bend and surrounding communities, Ontario, Baker City and the Pendleton/Hermiston areas.

Over the sixty-six years Cascade has been in business, the Company has gone through many changes. Figure 2-1 provides a snapshot of the Company's most landmark experiences from the last six decades. Cascade has provided a map in

[1] Western Regional Climate Center, retrieved November 14, 2016.

Section 13, Figure 13-13 that shows the certified service areas as specified in RCW 80.28.190.

Figure 2-1: Historical Timeline for Cascade Natural Gas

1950s	• Business leaders and public officials in the Pacific Northwest initiated a campaign to bring natural gas to the region to replace gas and other fuels that had been steadily rising in price over the past 20 years.
1953	• Five gas companies --- Bellingham Gas Co., Bremerton Gas Co., Wenatchee Gas Co., Northwest Cities Gas Co., and Consolidated Gas Co. ---serving 15 communities in Washington, Oregon, and Idaho, merged to form Cascade Natural Gas Corporation.
1959	• Cascade merged with Oregon Natural Gas Company
1960s	• Cascade merged with Pacific Natural Gas Corporation
1965	• Cascade purchased Garfield Gas Gathering Company
1973	• Cascade's stock was first traded on the New York Stock Exchange
2007	• Cascade merged with MDU Resources Group, Inc. (MDUR). The MDUR utility group consists of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation and Intermountain Gas Company, who collectively serve natural gas to over 910,000 residential, commercial and industrial customers in 334 communities and adjacent rural areas across eight states. The natural gas utility operating sales revenues by jurisdiction is as follows: Idaho - 32%; Washington - 26%; North Dakota - 15%; Montana - 8%; Oregon - 8%; South Dakota - 6%; Minnesota - 3%; and Wyoming - 2%.
2010	• Cascade moved its headquarters from Seattle, Washington to Kennewick, Washington (see Figure 2-3.)

Pipeline and Basin Locations

Cascade purchases natural gas from a variety of suppliers and transports gas supplies to its distribution system via 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 gas, and Westcoast Transmission (WCT) provides British Columbia gas directly into the distribution system. Cascade also holds transportation contracts upstream of these systems on TransCanada Pipeline's Foothills Pipeline (formerly ANG) and NOVA Gas Transmission Ltd. (also known as NGTL), as well as on Ruby Pipeline. More information about the pipelines and the supply basins can be found in Section 4, Supply Side Resources. Maps of select pipelines can be found in Section 13, Glossary and Maps.

Core vs Non-Core/Bundled vs. Unbundled Service

Since Cascade began distributing natural gas in the Pacific Northwest, the Company has offered its customers a “bundled” natural gas distribution service. This bundled service includes the gas supply which is transported to Cascade's citygate and the distribution of that gas to the end use “bundled-service” customer. Customers receiving traditional bundled services are referred to as core customers.

In 1989, Cascade “unbundled” its rates, and, as a result, the Company currently has approximately 250 large volume customers who have elected to become "non-core" customers. These customers have made the choice to rely on alternative methods of gas service rather than take the traditional bundled gas supply and pipeline transportation services available to core customers for their gas requirements.

Providing gas supply and transportation capacity resources to non-core customers is not considered part of this Integrated Resource Plan (IRP). As such, resources for serving these customers are separate from the supply and capacity contracts for the core customers who continue to utilize Cascade's bundled system gas supplies and capacity. Although the resource needs for non-core customers are not included in either the conservation or supply side resource analysis, their contracted peak day delivery is considered in the distribution system planning analysis discussed in Section 9, Distribution System Planning.

For the calendar year ended December 2015, Cascade's residential customers represented approximately 12% of the total natural gas delivered on Cascade's system, while the commercial customers represented approximately 9% and the 500 core market industrial customers consumed approximately 2% of total gas throughput. The remaining non-core industrial customers represented about 77% of total throughput.

Company Organization

Cascade is a subsidiary of MDU Resources Group, Inc., a multidimensional natural resources enterprise traded on the New York Stock Exchange as "MDU Resources." Cascade is part of the utility group of subsidiaries. MDU Resources Group's utility companies serve more than 1 million customers. Cascade Natural Gas Corporation 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 2-2 provides a geographical representation of the various services/territories served by MDU Resources.

Figure 2-2: MDU Resources Services and Territory

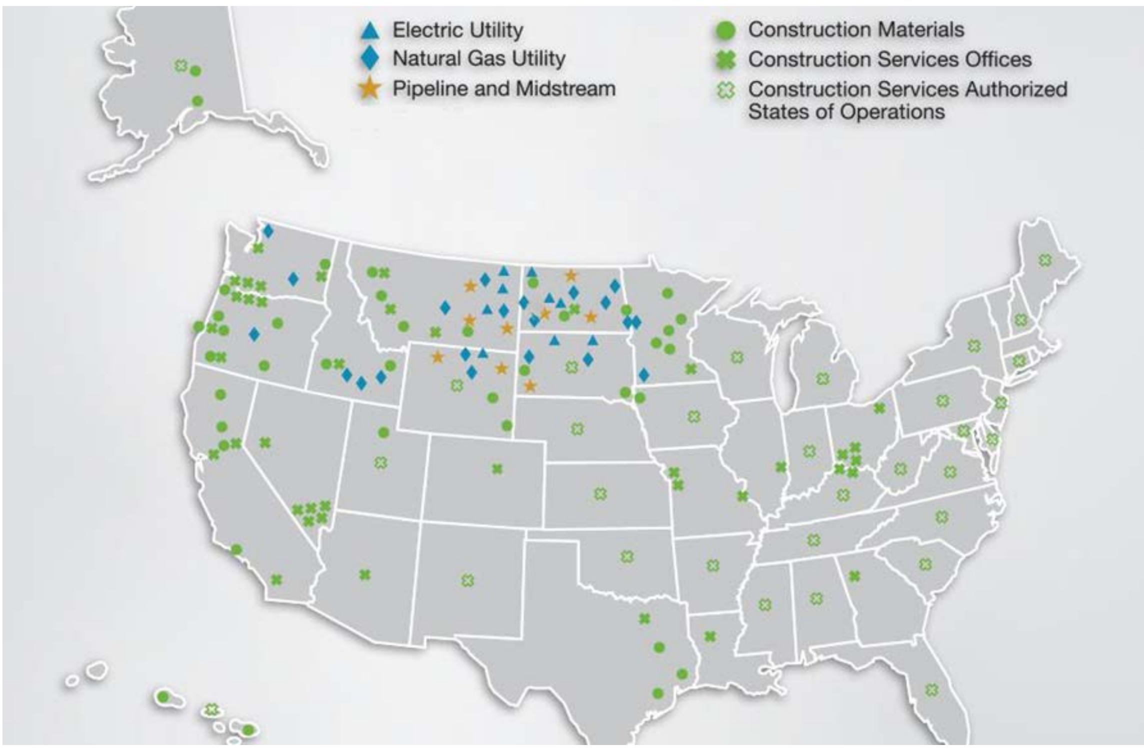


Figure 2-3 is a picture of the Company's headquarters. Cascade's headquarters is located in Kennewick, Washington. Many internal and external stakeholders have developed Cascade's 2016 IRP. Cascade's IRP Steering Committee provides oversight and guidance, ensuring the IRP meets all regulatory requirements.

Figure 2-3: Cascade's Headquarters in Kennewick, Washington

SECTION 3

DEMAND FORECAST

Overview

Each year Cascade develops a 20-year forecast of customers, therm sales and peak requirements for use in short-term (annual budgeting) and long-term (distribution and integrated resource planning) planning processes. This forecast is a robust portfolio of estimates created by enhancing a single best-estimate forecast with various potential economic, demographic and marketplace eventualities into low, medium and high growth forecast scenarios. The scenarios are used for distribution system enhancement planning and as inputs in optimization models to determine the least cost portfolio of supply and DSM resources, revenue budgeting, and load forecasts associated with the purchased gas cost process.

Key Points

- Cascade initiates its forecast with analyses of demand area, weather, and heating degree days (HDDs).
- Three peak day scenarios are examined: Average peak HDDs; System-wide max peak HDDs; and Max citygate peak HDDs.
- Cascade uses a 60 degree reference temperature to calculate HDDs.
- The Company utilizes an ordinary least squares (OLS) regression to predict customer usage.
- High and low scenarios were included and alternative forecasting methodologies were considered.
- Cascade expects system load growth to be 1.25% per year, or 26% over the 20-year planning horizon.
- Uncertainties in the future may cause differences from the Company's forecast.

Demand Areas

In 2016, Cascade is forecasting at the citygate level. This is a change of methodology from previous years where certain models were built from the district or zonal level. Cascade has a total of 74 citygates of which only nine citygates feed non-core customers and the remaining 65 serve at least one core customer. Of the 65 citygates that serve core customers, eighteen are grouped into eight different citygate loops. Each citygate is assigned to a weather location. For this IRP, the Company assigned the citygates to either the closest weather location by distance or the closest weather location by climatic simile. The citygate results are rolled up into zones and districts which segregate Cascade's system based on pipelines and weather (see Appendix B, Demand Forecast). Table 3-1 provides a cross reference for the demand areas.

Table 3-1: Demand Areas

Citygate	Loop	State	Weather Location	Zone
7TH DAY SCHOOL		WA	Yakima	10
A/M RENDERING		WA	Bellingham	30-W
ACME		WA	Bellingham	30-W

Citygate	Loop	State	Weather Location	Zone
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	Bend Loop	OR	Redmond	GTN
NORTH PASCO		WA	Walla Walla	20
NYSSA-ONTARIO		OR	Baker City	24
OAK HARBOR/STANWOOD	East Stanwood Loop	WA	Bellingham	30-W
OTHELLO		WA	Walla Walla	20
PASCO	Burbank Heights Loop	WA	Walla Walla	20
PATTERSON		WA	Yakima	26
PENDLETON		OR	Pendleton	ME-OR

Citygate	Loop	State	Weather Location	Zone
PRINEVILLE		OR	Redmond	GTN
PRONGHORN		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
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
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

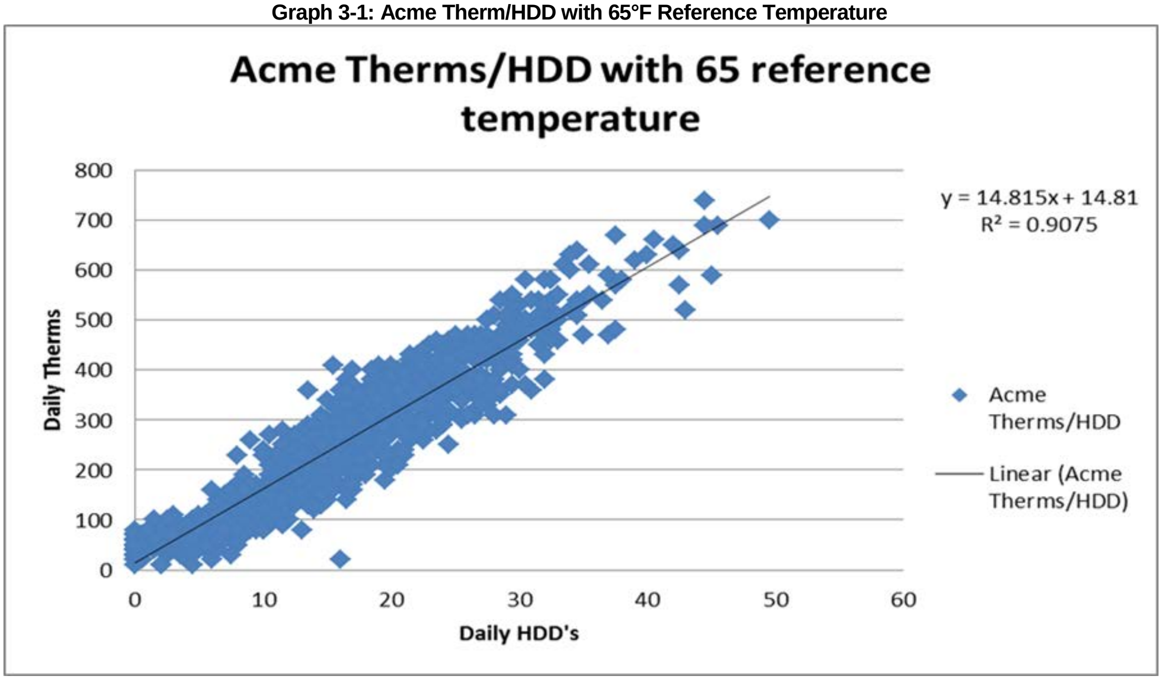
Weather

Historical weather data is provided by a contractor, Schneider Electric. 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 months to create a normal or expected year. Cascade has seven weather locations with four located in Washington and three in Oregon. The four weather locations in Washington are Bellingham, Bremerton, Yakima, and Walla Walla.

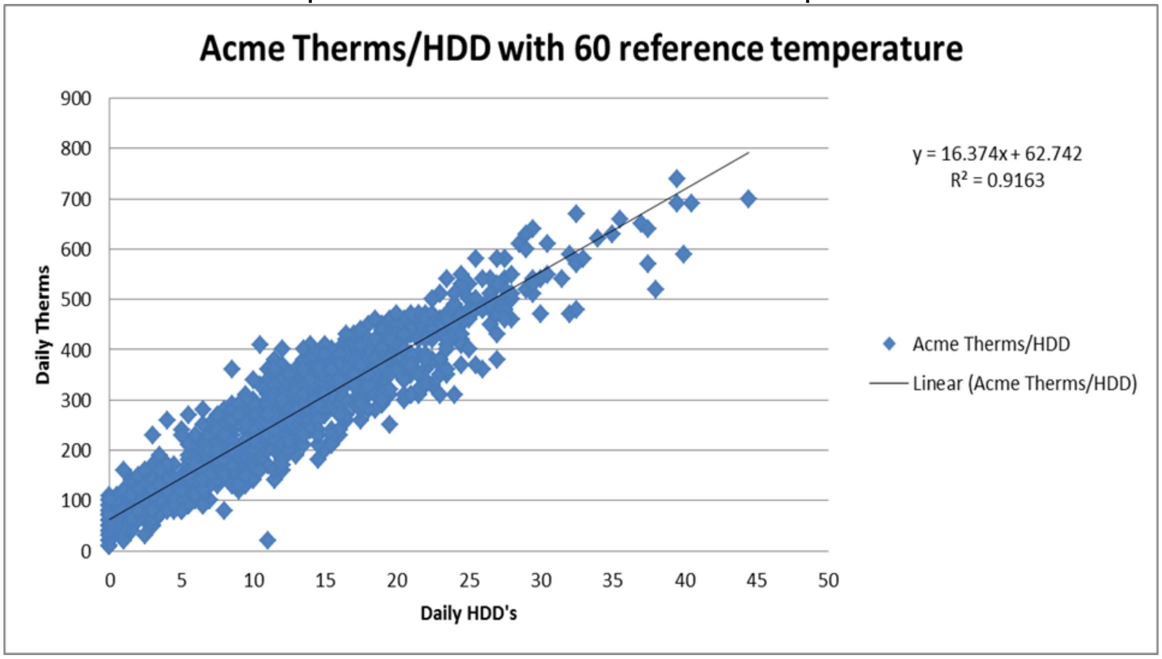
Heating Degree Days

HDD values are calculated by beginning 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 65 °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 better results. Graphs 3-1 and 3-2 show why the lower threshold is preferable. They show that heating demand does not begin to increase significantly until a HDD of five (65 °F minus 60 °F) if the traditional HDD threshold of 65 °F is utilized. Lowering the HDD threshold improves the R^2 thus giving a better measure of the relation between HDD and therms (measurement of heat usage). Cascade ran a backcast to measure how the forecast would compare to actuals when using actual weather and customer count in the regressions (ex. 2011 customers, with 2011 weather, to forecast 2011). When comparing, using a 65 degree reference temperature the backcast had a mean absolute percentage error (MAPE) of 14.9%. When using a 60 degree reference temperature the MAPE improved to 7.62%.

Graph 3-1: Acme Therm/HDD with 65°F Reference Temperature



Graph 3-2: Acme Therm/HDD with 60°F Reference Temperature



Peak Day

In order to ensure satisfaction of core customer demand on the coldest days, Cascade develops three peak day usage forecasts in conjunction with annual base load forecasts. Peak day forecasts enable Cascade to make prudent distribution system and peak 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 three scenarios that are analyzed in the forecast model:

- Average peak HDDs;
- System-wide max peak HDDs; and
- Max citygate peak HDDs.

Average peak HDDs in a given year are calculated based on the average of the coldest day for each of the last 30 years. Initially, the coldest system-weighted peak day is found for each year for the last 30 years. The actual HDD from each of those 30 peak days is averaged resulting in an average peak HDD for each weather location.

System-wide max 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 each causes with an increase in 1 HDD. Cascade has found December 21, 1990 to be the highest system weighted HDD, at 56 HDDs, for this period.

The max citygate peak HDDs is determined by finding the coldest HDD for each weather station in the 30-year history and combining those to happen in one day. The max citygate peak day is a hypothetical scenario where the coldest HDD for each weather station happened on one day.

Peak day demand is then derived by applying the HDDs from one of the three peak day scenarios to the monthly linear regression equation for each citygate.

For SENDOUT®, Cascade uses the system-wide max peak HDDs method. Cascade applies the HDDs seen on December 21, 1990, to each of the regressions in the forecast model. For example, all citygates associated with the Bellingham weather station use the HDD for Bellingham 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.

These methods rest on the assumption that core market load shape does not significantly change throughout the forecast horizon. Cascade believes that the peak day forecast conservatively overestimates peak day usage as the base forecast does not explicitly include future conservation measures implemented by customers that would act to increase energy efficiency and reduce therm day usage.

Cascade will continue to investigate how the peak day standard affects those 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.

Growth

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 derived from Woods & Poole. Woods & Poole growth forecasts are provided at the county level and are directly assigned to a citygates previous year's customer count. It should be noted that Woods & Poole forecasts are adjusted whereas the internal intelligence about a demand area indicates a significant difference from Woods & Poole with regard to observed economic trends.

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 by applying Woods & Poole's forecasts to accurately predict Cascade's service territory's strongest and weakest performance over the next 20 years (Appendix B, Demand Forecast). These scenarios, along with the original best-estimate expected scenario, encapsulate a range of most-likely possibilities given known data. The most recent Woods & Poole data indicates an average growth of 1.25% between 2017 and 2036 for Cascade's service territory. The projected customer growth can be viewed in Appendix B, Demand Forecast. Based on historical experience and given expected weather, Cascade expects system load will likely remain within a range bounded 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 forecasted system-wide deficiency:

- Bend, Oregon – The city of Bend recently approved an urban growth plan that is projected to allow for the development of 2,380 acres of land. City planners project this will add more than 17,000 homes, and 21,000 jobs. No specific timeline for the completion of this expansion is provided in their May 2016 project update.[1]
- Walla Walla, Washington – The city of Walla Walla is heavily focused on promoting small business growth, tourism, and its reputation as a leading wine producer in a competitive eastern Washington wine market. Cascade currently projects growth of approximately 30% in this area over the 20-year planning horizon.[2]
- Tri-Cities, Washington – Richland, Kennewick, and Pasco have been a hotbed for growth in recent years. As of the most recent census numbers, population grew by 10% in the past four years. Furthermore, Pasco is currently in the top ten cities for population growth in Washington State. Cascade currently projects growth of over 35% in this area over the 20-year planning horizon.[3]

Methodology

Cascade uses an ordinary least squares methodology with the goal of predicting demand based on weather and forecasted customers. Demand for each citygate and rate schedule takes on the formula:

[1] *See* City of Bend Urban Growth Boundary Project Update, issued May 2016
[2] *See* http://www.wallawallatrends.ewu.edu/
[3] *See* http://www.tri-cityherald.com/news/local/article32225670.html

$$y = [(a * x) + c] * customers$$
$$where,$$
$$y = dekatherms$$
$$a = UPC\ coefficient\ dekatherms\ per\ HDD\ per\ customer$$
$$x = HDD$$
$$c = baseload\ constant\ per\ customer\ in\ dekatherms$$
$$customers = forecasted\ customers$$

Cascade developed the Use per Customer (UPC) coefficient by gathering historical pipeline demand data by month. The pipeline demand data includes core and non-core usage. The non-core data is backed out using Cascade's non-core Aligne system which leaves monthly core usage data. The monthly data is then allocated to a rate schedule for each citygate by using Cascade's Customer Care and Billing System (CC&B). This data is then divided by customers to come up with a UPC number for each month for each rate schedule at each citygate. An ordinary least squares regression is then run using the UPC and HDD actuals to derive results.

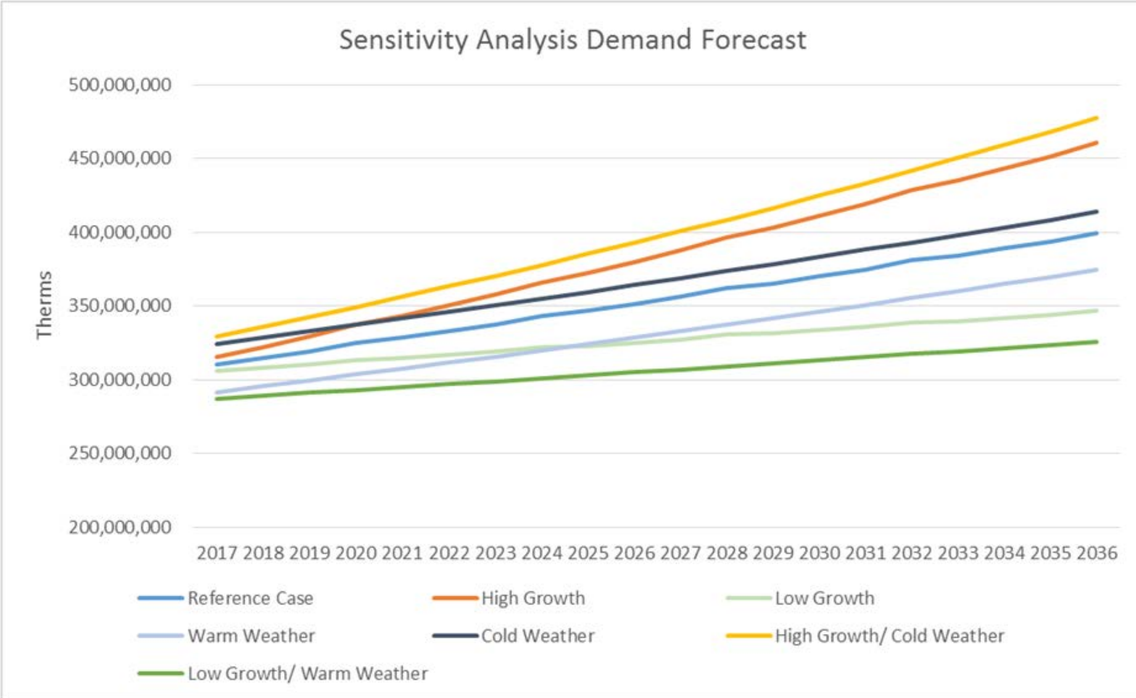
Sensitivity Analysis

Cascade stress tests the system in SENDOUT® by using alternative forecasting methodologies. These alternative forecasting methodologies refer to changing factors that influence demand. Alternative models include high and low customer growth, high and low weather patterns, or a combination thereof. The combination between alternative growth and weather is high growth/cold weather, and low growth/warm weather because these test the extremes as they complement each other when it comes to influencing demand. Table 3-2 identifies the list of scenarios. Figure 3-1 charts the sensitivity analysis over the planning horizon.

Table 3-2: Growth Scenarios

Scenario	Weather	Growth	Use per Customer
Reference Case	Expected	Expected	Expected
Expected Scenario	Expected with peak event	Expected	Expected
High Growth	Expected	High	Expected
Low Growth	Expected	Low	Expected
Warm Weather	Low HDDs	Expected	Expected
Cold Weather	High HDDs	Expected	Expected
High Growth/ Cold Weather	High HDDs	High	Expected
Low Growth/ Warm Weather	Low HDDs	Low	Expected

Figure 3-1: Sensitivity Analysis Demand Forecast (Volumes in Therms)



The reference case is the case Cascade expects to happen in regard to weather, growth, and use per customer. The expected scenario is the same as the reference case with a single system-wide max peak day event. Expected weather is the average weather over the past 30 years. For high/low HDDs Cascade used the average temperature of the six coldest/warmest years to create a high and low weather scenario. Six years is a sufficient timeframe to capture a realistic high/low scenario. Cascade applies the growth rates gathered from Woods & Poole as mentioned on pages 3-7 and 3-8 for the expected growth case. Cascade uses the expected regression results as explained on pages 3-8 and 3-9 at each citygate for all cases. High and low growth scenarios, discussed more on page 3-14, explain that Cascade uses percentage errors from previous Woods & Poole forecasts to create the scenarios.

Forecast Results

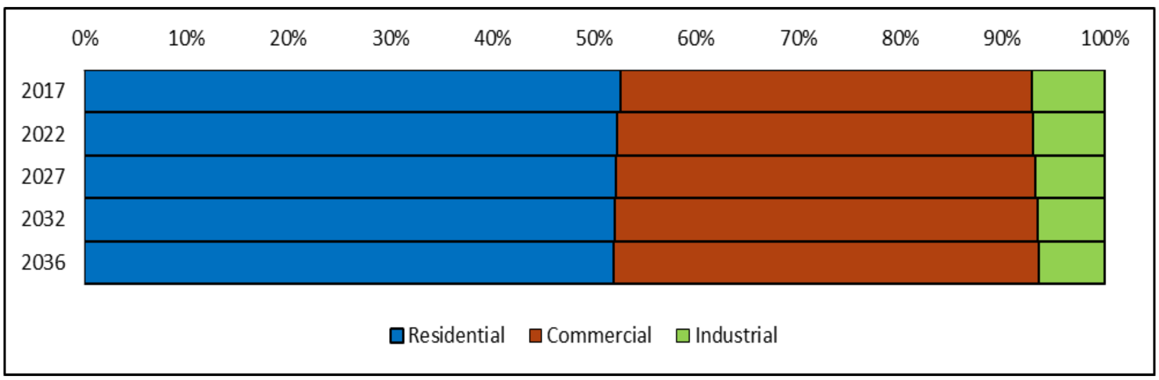
Load growth across Cascade's system through 2036 is expected to fluctuate between 1.16% and 1.31% annually after smoothing the leap year anomaly. Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow at a rate above 1% annually while industrial expects a growth rate of around 0.5%. Table 3-3 shows the percentage of core growth by class over the planning horizon.

Table 3-3: Expected Load Growth by Class

	Residential	Commercial	Industrial	System
2017 - 2021	**1.25%**	**1.69%**	**0.75%**	**1.31%**
2022 - 2026	**1.24%**	**1.56%**	**0.46%**	**1.28%**
2027 - 2031	**1.21%**	**1.48%**	**0.33%**	**1.24%**
2032 - 2036	**1.13%**	**1.39%**	**0.26%**	**1.16%**
2017 - 2036	**1.21%**	**1.53%**	**0.45%**	**1.25%**

In absolute numbers, system load under normal weather conditions is expected to exceed over 397 million therms in 2036. A majority of core load today is residential. Cascade projects the ratio between residential, commercial, and industrial to increase in favor of commercial customers. The increase in favor of commercial customers is referring to the fact that commercial customers are expected to grow from being 37.3% of the total core load to 38.7% of the total core load by 2036. Figure 3-2 displays the relative percentage relationship of expected loads by class.

Figure 3-2: Expected Load Growth by Class



Cascade expects residential and commercial core customers to increase load by around 40-42 million therms each over the 20-year planning horizon. Industrial customers are expected to increase load by approximately 4 million therms over the same time period. Cascade expects load to increase by about 89 million therms. Table 3-4 displays the expected core load volumes by class.

Table 3-4: Expected Load Growth by Class (Volumes in Therms)

	Residential	Commercial	Industrial
2017	162,191,299	124,556,975	21,888,875
2022	173,002,864	135,106,639	23,006,406
2027	184,425,511	145,676,974	23,892,422
2032	197,089,261	157,102,305	24,702,016
2036	206,484,956	165,833,234	25,233,289
2017 - 2036	27.31%	33.14%	15.28%

Load growth is primarily a result of increased customer counts. The number of commercial and industrial customers is expected to increase slightly faster than therm usage. Table 3-5 displays the expected customer counts by class.

Table 3-5: Expected Customer Counts by Class

	Residential	Commercial	Industrial
2017	244,177	36,339	598
2022	259,872	39,483	620
2027	276,412	42,640	634
2032	293,424	45,863	644
2036	306,867	48,472	651
2017 - 2036	25.67%	33.39%	8.83%

Geography

Load across Cascade's two-state service territory is expected to increase 26% over the planning horizon, with the Oregon portion outpacing Washington at 36% versus 26%. Table 3-6 shows the expected core load volumes by state.

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

	Washington	Oregon	System
2017	232,414,950	76,222,198	308,637,148
2022	248,096,580	83,019,329	331,115,909
2027	263,898,367	90,096,540	353,994,907
2032	281,006,139	97,887,443	378,893,582
2036	293,590,373	103,961,106	397,551,479

Within Washington, the western part of the state as well as Walla Walla is expected to see a large increase in growth. Yakima is expected to experience minimal growth. The 2017 load on 56 HDDs is expected to be 3.5 million therms, rising to 4.5 million by 2036. Peak day load will increase at 1.33% annually, while annual load increases by 1.25%. Table 3-7 shows the percentage growth of load by each of Cascade's weather locations. Table 3-8 shows the percentage growth of load by each pipeline zone over the planning horizon. Lastly, Table 3-9 displays a range of core peak day growth over the planning horizon along with a sampling of peak day therms.

Table 3-7: Washington 20-Year Load Growth by Weather Location

Bellingham	28.5%
Bremerton	24.2%
Walla Walla	30.5%
Yakima	18.1%
Washington	26.1%

Table 3-8: System 20-Year Load Growth by Pipeline Zone

Zone 10	15.9%
Zone 11	14.8%
Zone 20	32.8%
Zone 24	4.1%
Zone 26	23.2%
Zone 30-S	22.2%
Zone 30-W	27.0%
Zone GTN	44.4%
Zone ME-OR	14.0%
Zone ME-WA	12.1%

Table 3-9: Expected Peak Day Growth (Volumes in Therms)

Period	Peak Growth	Year	Peak Day Therms
2017 - 2021	1.43%	2021	3,776,574
2022 - 2026	1.36%	2026	4,041,751
2027 - 2031	1.30%	2031	4,313,247
2032 - 2036	1.22%	2036	4,584,628

High and Low Scenarios

High and low scenarios were created by examining the percentage errors of previous Woods & Poole forecasts. The percentage errors show the average percentage difference between a Woods & Poole forecast and actual results. The previous forecasts averaged a percentage error of 0.5% or less of the actual forecast. Since Cascade is expecting about a 1.25% growth, a reasonable high and low scenario band is 0.65% above or below that growth level. Table 3-10 displays the expected total system load growth across various scenarios.

Table 3-10: Expected Total System Load Growth (By Percentage) Across Scenarios

	Low	Mid	High
2017 - 2021	0.65%	1.31%	1.97%
2022 - 2026	0.64%	1.28%	1.94%
2027 - 2031	0.61%	1.24%	1.89%
2032 - 2036	0.57%	1.16%	1.78%
2017 - 2036	0.62%	1.25%	1.90%

Load growth under poor economic conditions is expected to be around 0.6% annually over the forecast period, while load growth under good economic conditions is expected to be around 1.9% annually. The cumulative effect of high growth over 20 years could result in additional load of 61 million therms, while low growth could result in a load with 52 million therms less than predicted in the medium growth scenario. Table 3-11 shows the expected total system load across these scenarios.

Table 3-11: Expected Total System Load Growth Across Scenarios (Volumes in Therms)

	Low	Mid	High
2017	303,968,666	308,637,148	313,346,208
2021	312,685,907	326,602,114	341,104,474
2026	323,326,756	349,373,660	377,602,786
2031	333,769,148	372,643,579	416,609,463
2036	345,227,222	397,551,479	458,654,121
Deviation	(52,324,257)		61,102,642

Alternative Forecasting Methodologies

Cascade has made a slight change to the forecast methodology this year by using customers in the coefficient for the demand forecast formula. Cascade plans to continue to look at alternative forecast methodologies and purchased SAS

Analytics, a statistical analysis software, and plans to examine non-linear forecasting methodologies.

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 increased cost of improved precision sometimes has decreasing customer benefits.
- Regulators expect continual improvement because new tools are available and they expect to see what the Washington Commission calls “adaptive management” for all of its jurisdictional energy companies.
- Major differences in accounting treatment between the states regarding “test years” must be considered since they are 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 an “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 to isolate primary factors for greater precision of long-term calculations.
- Unknown and uncertain future changes such as the assumptions for CO_2 required for carbon policy and other environmental externalities.
- 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.

This illustrates the complexity of forecasting and highlights areas of stakeholder attention. Best efforts, at the appropriate 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 there are several important factors that make predicting future demand particularly difficult – economic recovery, carbon legislation, building code changes, direct use campaigns, conservation, and long-term weather patterns. The range of scenarios presented here encompasses 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.

SECTION 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 degrees of service reliability and attain it at the lowest cost possible while maintaining infrastructure that is sufficient for customer growth. Assuming such an 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 components that constitute the "bundled services" purchased by core market customers.

This section describes the various gas supply resources, storage delivery services from Jackson Prairie and Plymouth LNG service, and transportation resource options that are available to the Company as supply side resources.

Key Points

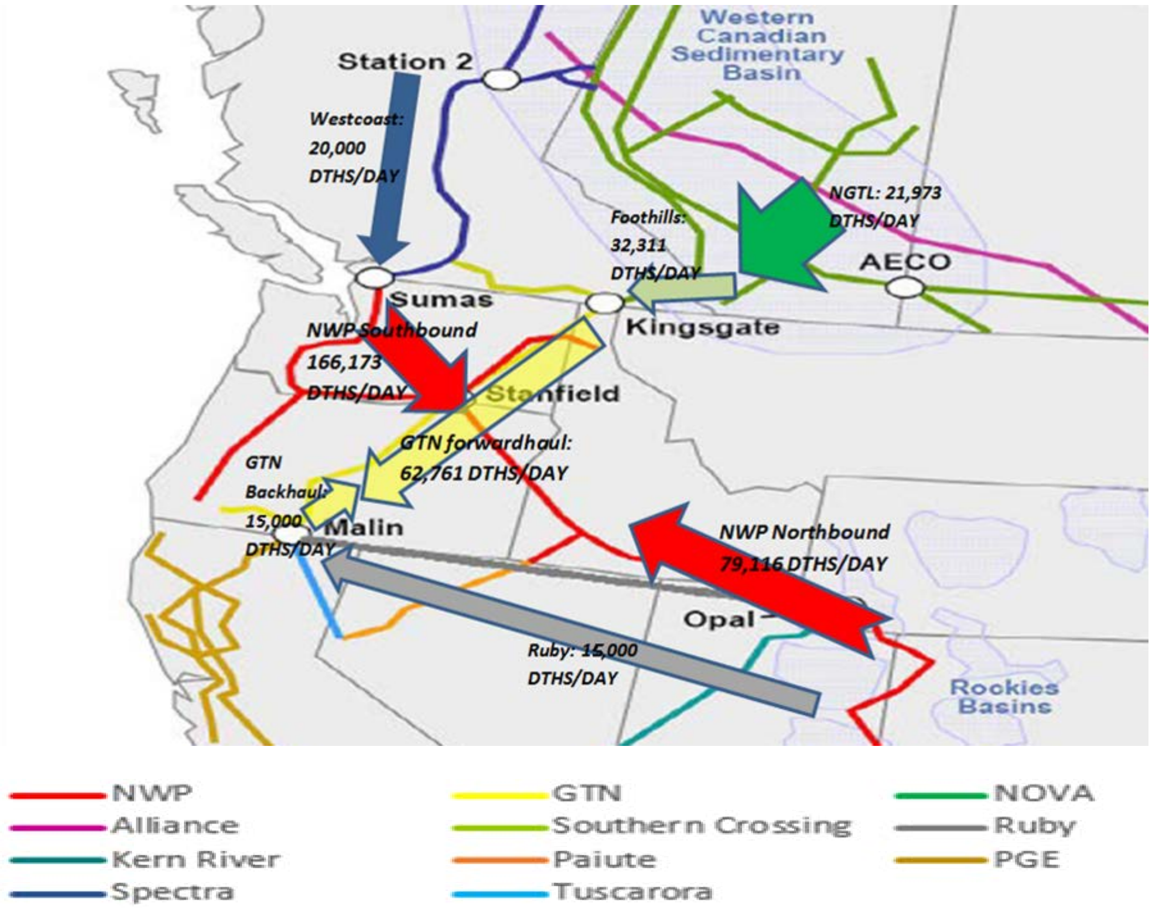
- To meet the Company's core market demand, Cascade accesses: 1) Firm gas supplies and 2) Short-term gas supplies purchased on the open market, plus storage.
- Cascade purchases gas from Rockies, British Columbia (Sumas), and Alberta (AECO). Gas is transported to the Company's system by either bundled 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 2016 IRP.
- Risk management policies are implemented to promote price stability.
- Cascade's Gas Supply Oversight Committee (GSOC) oversees the Company's gas supply purchasing strategy.
- Modeling of Cascade's available resources result 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 required to provide economical service to low load factor customers during seasonal peak and the needle peaks of 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. A larger map of Figure 4-1 is also provided in Section 13, Glossary and Maps, with Figure 13-12.

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 for 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 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 "take" 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 requires it, but the Company is not required to take gas unless it is needed to meet customer load requirements. Peaking resources typically allow the Company to take between 15 and 20 days of service during the winter period. These resources are 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 of time. One source of needle peaking gas supply that is actually a form of demand side management 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 to 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 would 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 through the use of propane air plants or on-site liquefied natural gas (LNG) facilities. Currently, Cascade does not own or operate any LNG facilities along the distribution system.

A cost comparison between propane and natural gas can be done based on their individual BTU ratings. Assuming the cost for LNG is $6.00 per 1,000 cubic feet, $6.00 will purchase approximately 1.03 million BTUs of energy. This would be equivalent to 11.26 gallons of propane. At $2.00/gallon of residential propane (as of October 2016), natural gas would be a more cost effective energy solution under these conditions. Breaking it down even further, natural gas needs to be priced at more than $22.52 per 1,000 cubic feet for propane to be a more cost effective energy solution (provided the cost for propane is $2.00/gallon).

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. Some contracts have fixed reservation charges assessed each month, while others may have minimum daily or monthly take requirements. Most contain penalty provisions for failure to take the minimum supply according to the contract terms. Contract details will also vary from year to year, depending on company and supplier needs and the general trends in the market.

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” or “just-in-time 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 until the price equates or exceeds that of alternate energy supplies (such as oil or electricity). Spot supplies can be expected to move to the markets that offer the highest price, which in turn can affect delivery reliability.

Due to the potential for interruption of the spot market, these supplies are not considered as reliable a 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 (North American Energy Standards Board) contract, parties have the ability to identify firm, variable, or interruptible quantities for these supplies. This is the standard contract used by buyers and sellers 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 the Northwest Pipeline, 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. Complicating matters is that each of the pipelines have multiple supply scheduling deadlines, allowing scheduled volumes to be adjusted. As a result, at any given point in the process, constraints can occur, leading to the potential of the scheduled spot supply volumes being reduced or not delivered to the citygate at all.

The role for spot market gas supply in the core market portfolio is based upon 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. For example, should prices in one basin drop radically compared to another basin, a supply contract may allow the flexibility to reduce takes in order to take advantage of spot supply from a lower priced basin. 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.

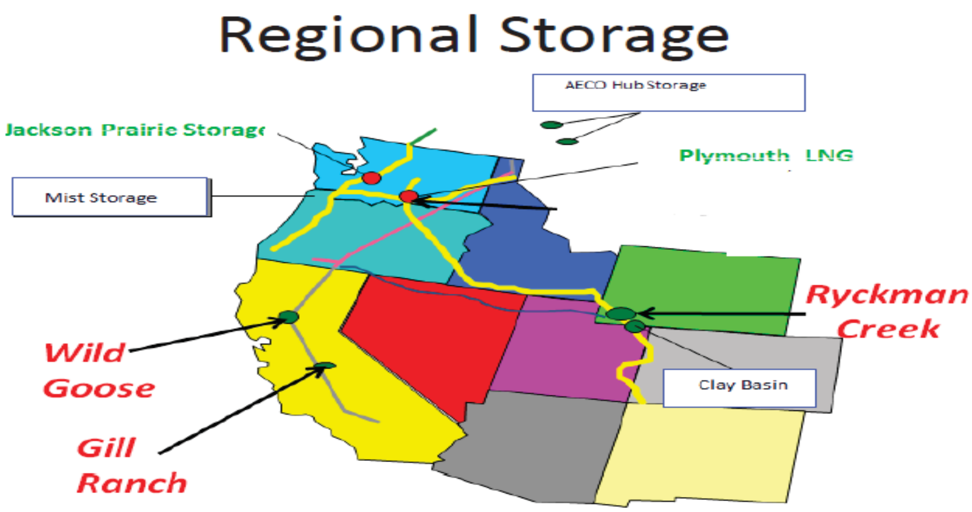
Storage Resources

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 under pressure as compressed natural gas, or cooled to a liquid state, which is liquefied natural gas (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, therefore, 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 4-2 displays the location of some of the storage facilities in the region.

Figure 4-2: Regional Map Showing Location of Various Gas Storage Facilities



Cascade has contracted for storage service directly from Northwest Pipeline since 1994. Jackson Prairie is located in Lewis County Washington approximately 10 miles south of Chehalis. The following extract explaining the Jackson Prairie facility was found on Puget Sound Energy's website. Puget is 1/3 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.[1]

The Company also has contracted for service from NWP's Plymouth, Washington LNG facility. According to NWP's website, the total facility has storage capacity of 2.4 BCF. Cascade has leased approximately 28% of this storage capacity.

[1] *See* www.pse.com

Both Jackson Prairie facilities and the Plymouth facility 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. This type of operating flexibility would not necessarily be available with off-system storage. Withdrawal capabilities must also be accompanied by firm capacity on the transporting pipeline(s) to be of any value as a reliable source of gas supply. Cascade's Jackson Prairie storage and Plymouth LNG service requires 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 Table 4-1.

Table 4-1: Cascade Leased Storage Services (Volumes in Therms)

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

Capacity Resources

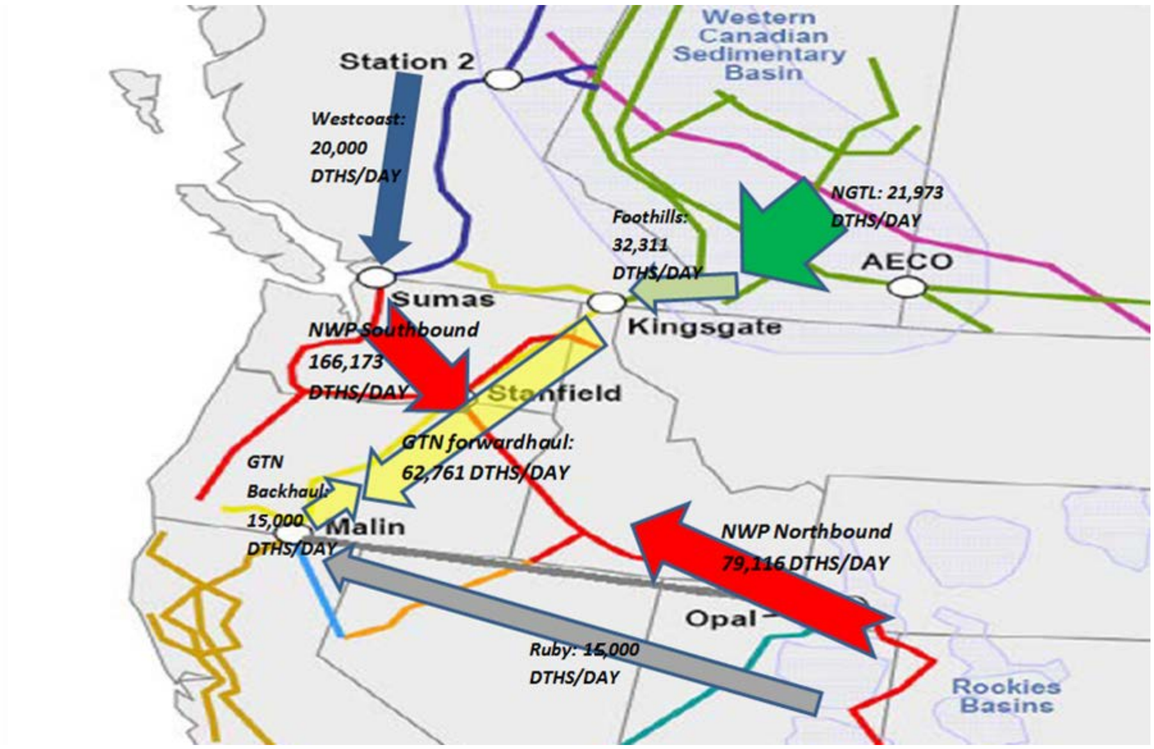
Capacity options are either interstate pipeline transportation resources or capacity on Cascade's local distribution system. Cascade's local distribution system was built to serve the entire connected load in its various distribution service areas, on a coincidental demand basis, regardless of the type of service the customer may have been receiving.

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 gas supplies have been "bundled" by the supplier (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 (twenty to thirty year) contracts.

Cascade has a few dozen 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

Spectra (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 9 to 120 days. Figure 4-3 provides a general flow of Cascade's combined contracted pipeline transportation rights.

Figure 4-3: Regional Map Showing Current Contracted Pipeline Transportation Flow



A complete listing of Cascade's current transportation agreements can be found in Appendix E, Current and Alternative Supply Resources.

At 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
- Nov-Mar (the whole heating season)
- Dec-Feb (peak of the heating season)
- Spring Seasonal (Apr-Jun)
- Spring/Summer Seasonal (Apr-Oct)
- Day Gas
- On annualized basis supplies are typically secured 1/3 British Columbia, 1/3 Alberta and 1/3 Rockies
- No more than 25% of the overall portfolio can be supplied by a single party

Natural Gas Price Forecast

For IRP planning 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 has considered price forecasts from several sources, such as Wood Mackenzie, Energy Information Administration (EIA), Bentek, Northwest Power and Conservation Council (NPCC), as well as Cascade's observations of the market to develop the low, base, and high price forecasts. For confidentiality purposes, the Company will refer 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 may not necessarily be 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 blends the pricing data from these various forecast sources. It should be noted that at the time the 2016 IRP price forecast was developed, Cascade did not have one of the Company's outside consultant's price forecast for the final years of the planning horizon. As a result, the weight in the final few years of the forecast heavily favors Source 4, as it was the only forecast available to the Company at the time. As will be noted in Section 8, Resource Integration, incremental resource decisions are anticipated to be in place before 2030; consequently, the Company does not feel using Source 4's 2034-36 price forecast would have a material impact on resource selection or the avoided costs.

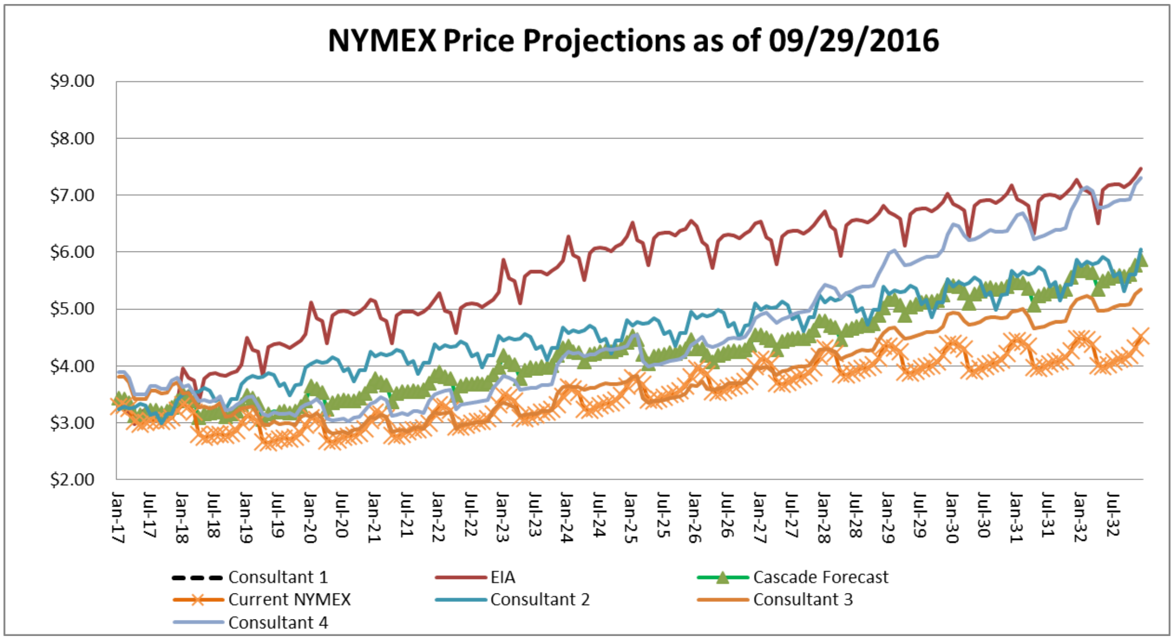
The fundamental forecasts of Wood Mackenzie, the EIA, NPCC, and Cascade's trading partners are resources for the development of a blended long-range price forecast. Wood Mackenzie publishes a long-term price forecast twice a year to subscribing customers. This forecast is broken down by month through 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 develops 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 assigns a weight to each source to develop the monthly Henry Hub price forecast for the 20-year planning horizon. The forecast weighting factors are shown in Table 4-2. The Company gives Source 1 the most weight at the start of the planning horizon based on nearness to term. In recent years, the EIA forecast has often been higher than the forecast price of the other sources; however, it is still a respected industry barometer of prices (Figure 4-4). As Cascade's forecast moves ahead, the Company starts to reduce the impact of Source 1 and gives greater weight to the other sources.

Table 4-2: Cascade's Henry Hub Price Forecast Weights

Year	Source 1	Source 2	Source 3	Source 4
2017	40%	5%	35%	20%
2018	35%	5%	35%	25%
2019	30%	5%	35%	30%
2020	25%	5%	40%	30%
2021	20%	5%	45%	30%
2022	15%	5%	55%	25%
2023	10%	5%	60%	25%
2024	10%	5%	65%	20%
2025	5%	5%	70%	20%
2026	5%	0%	75%	20%
2027	0%	0%	75%	25%
2028	0%	0%	75%	25%
2029	0%	0%	75%	25%
2030	0%	0%	75%	25%
2031	0%	0%	75%	25%
2032	0%	0%	75%	25%
2033	0%	0%	75%	25%
2034	0%	0%	0%	100%
2035	0%	0%	0%	100%
2036	0%	0%	0%	100%

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



Development of the Basis Differential for Sumas, AECO and Rockies

Since the Company's physical supply receiving areas (Sumas, AECO, and Rockies) are 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. 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 2.1 for the Low Case, 2.7 for the Reference Case, and 3.2 for the High Case.[2]

Please see Appendix G, Weather & Price Uncertainty Analyses, for the 20-year price forecasts details.

Incremental Supply Side Resource Options

As is more thoroughly described in Section 8, Resource Integration, some of the load growth over the planning horizon will require Cascade to secure incremental supply

[2] EIA 2016 Annual Energy Outlook, Appendix C

side resources. The purpose of this section is to identify the potential incremental supply resources the Company considered for the 2016 IRP.

Pipeline Capacity

- **Cross Cascades, Trail West (Palomar, NMax, Sunstone, Blue Bridge, et al):** Trail West is a 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 Capacity Acquisition:** The Company 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 have a relatively small scale and so could be expected to have a relatively high unit cost.

- **NWP I-5 Expansion (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 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. Recently, Avista, Cascade, NW Natural and Puget Sound Energy agreed to combine its efforts as a group to work with the regional pipelines (GTN, NWP) on potential expansions in the region.

- **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. Basically, this project presents an opportunity as a potential supply resource for the purposes of 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 citygate. The project was initially denied due to lack of demand. That has changed but it faces considerable opposition. 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 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 mind 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 from 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 (NGTL) system means that 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 possible interruption. Incremental transport involving Nova, 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 Section 3, pages 34-35,

> NW Natural is in the midst of a project 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 18. 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; there still remain 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 instead, the challenges are 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.' Essentially, this new pipeline is planned to be built from Mist to the Kelso- Beaver Pipeline (KB Pipeline); and from there onto NWP's system" for potential delivery to Cascade gates.

  Cascade will continue talks with the Mist parties to see if those opportunities may be cost effective.

- **Ryckman Creek Storage:** Ryckman Creek Resources, LLC, is a wholly-owned subsidiary of Peregrine Midstream Partners, LLC. Ryckman Creek Gas Storage Facility is located near the town of Evanston, Wyoming and approximately twenty-five miles southwest of the Opal Hub. Ryckman Creek 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. Ryckman Creek currently has interconnects with Questar Gas Pipeline, Kern River Transmission, Questar Overthrust Pipeline, Ruby Pipeline, and Northwest Pipeline. Incremental transport involving Questar and possibly Ruby would be necessary (Cascade's current transportation contract with Ruby is currently winter-only).

- **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.

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 such as Yakima, 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.

- **Bio-natural gas (BNG):** BNG typically refers to gas produced by the biological breakdown of organic matter in the absence of oxygen. BNG originates from biogenic material and is a type of biofuel. One type of BNG is produced by anaerobic digestion or fermentation of biodegradable materials such as biomass, manure or sewage, municipal waste, green waste, and energy crops. This type of BNG is comprised primarily of methane and carbon dioxide. The principal type of BNG is wood gas, which is created by gasification of wood or other biomass. This type of BNG is comprised primarily of nitrogen, hydrogen, and carbon monoxide, with trace amounts of methane. The gases, methane, hydrogen and carbon monoxide, can be combusted or oxidized with oxygen. Air contains 21% oxygen. This energy release allows BNG to be used as a fuel. BNG can be used as a low-cost fuel in any country for any heating purpose, such as cooking. It can also be utilized in modern waste management facilities where it can be used to run any type of heat engine to generate either mechanical or electrical power. BNG is a renewable fuel, which can be used for transport and electricity production, so it attracts renewable energy subsidies in some parts of the world. In many cases, not enough pricing and supply information is currently available for this resource to be considered in this planning cycle; however, where possible, the Company endeavored to analyze those situations where sufficient data is available. Cascade continues to monitor the BNG activities of companies such as PG&E, Intermountain Gas, Sempra Utilities, and Puget Sound Energy.

- **Re-alignment of Maximum Daily Delivery Obligations (MDDO):** Cascade has long held more delivery rights than receipt rights on NWP under its principle 100002 agreement. This came as a result of FERC Order 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 316,994 Dths/day of delivery rights vs 205,123 Dths/day of receipt rights. Cascade has the right to deliver gas to any delivery point within Washington and Oregon so long as the total MDDOs are not exceeded. Cascade and NWP have worked continuously in recent years for ways to address Cascade's potential peak day capacity shortfalls through re-alignment of the Company's contractual rights where possible, which mitigates the need to acquire incremental NWP capacity through expansions.

Cascade considers Unconventional Gas Supply Resources such as supplies from a 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. They include regulatory risks, deliverability risks, and price risks. Regulatory risks include the unknown impacts of future Federal Energy Regulatory Commission or Canada's National Energy Board 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. 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. 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 New York Mercantile Exchange (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 idea is to level the price 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 40% of annual requirements
- Year two set at up to 25%
- 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.

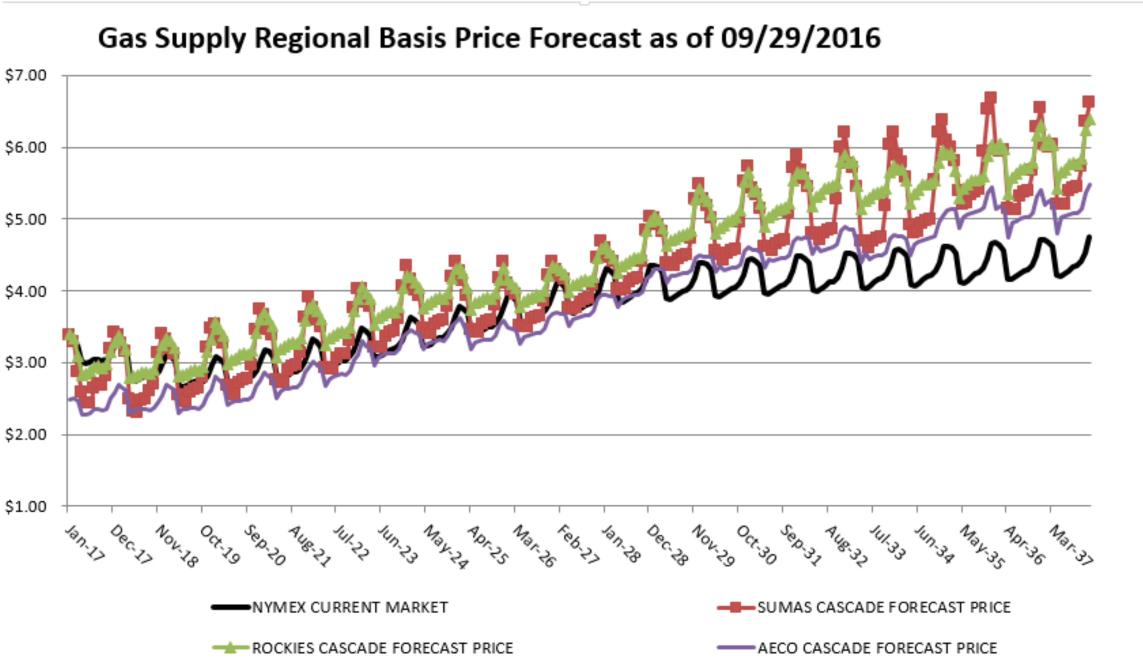
Risk is associated with business objectives and the external environment. The number of hedging strategies to deal with risk are almost infinite. To manage risk, it is categorized as to whether the risk is one to be avoided, one to be accepted and controlled, or a risk left uncontrolled. When a risk 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 requires acceptable analysis of the possible side effects on the financial position of the Company as compared to the rewards.

Because the price the Company pays for gas is subject to market conditions, 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.

The use of derivatives is permitted only after identified risks have been determined to exceed defined tolerance levels and are considered unavoidable. These decisions are made by Cascade's GSOC. 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%. Currently, Cascade hedges approximately 40% of the portfolio using fixed priced physicals.

The Company entered into fixed price physical transactions rather than executing financial swaps for the 2016 programmed buying period. Fixed prices consist of locked-in prices for physical supplies. As will be further described in this section, 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 open hedging dockets in both Oregon and Washington, Cascade has not executed any new financial derivatives or considered any for the 2016 IRP. The Company still monitors the outer years and stands ready to execute financial swaps when market and pricing conditions are more favorable. Figure 4-5 provides a graph showing the projected regional price forecast for the 2016 IRP by basin.

Figure 4-5: Regional Basis Price Forecast



Cascade is currently participating in the WUTC's hedging Docket UG-132019. Cascade is also an active participant in OPUC's hedging Docket UM-1720. Docket UG-132019 is directed at hedging no more than approximately four or five years out. It also appears that any guidelines resulting from the docket will be focused on enhancing the analysis and reporting of each of the LDCs' hedging activities. The OPUC initiated Docket UM-1720 as a result of long-term hedging guidelines proposed by NW Natural in their 2014 IRP. Throughout both processes Cascade has provided comments and explanations of its risk management efforts. As of the preparation of this IRP, no general consensus has materialized amongst the participants. The two hedging dockets are not synchronized, which is contributing to concerns on how to implement any guidelines. Cascade is hopeful that some level of consistency with the end product will develop between the two states. The Company will continue to participate actively in both Docket UG-132019 and Docket UM-1720.

Portfolio Purchasing Strategy

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.

In spring 2016, GSOC approved a portfolio design for three years as follows:[3]

- Portfolio procurement design based on a declining percentage each year accordingly: Approximately Year 1: 80% of annual requirements; Year 2: 40%, Year 3: 20%. For the current portfolio design, GSOC approved a targeted base portfolio design with 80% of the average five-year annual load in Year 1, 40% in Year 2, 20% in Year 3.
- GSOC will consider a modification from a three-year rolling portfolio if: 1) reasonable concerns exist regarding the availability of supply in a particular basin; or 2) the outer year three-year forward price is 20% higher/lower than the front month over a reasonably sustained period.
- The first portfolio year "hedged" (fixed-price physical or financial swaps) is not to exceed approximately 40% of annual requirements in year 1. Second year should be set at 25%, and 20% hedged volumes for year three.
- GSOC will consider a modification of this plan if the outer year three-year forward price is 20% higher/lower than the front month over a reasonably sustained period.
- The portfolio can always be modified with additional years if a significant discount price materializes.
- Maintain a diversity of physical supplies from Alberta, British Columbia, and Rockies.
- Maximize supplies from the regions that afford the lowest prices. Gas from AECO is currently the lowest-cost gas in the Company's supply portfolio. Station 2 is also relatively inexpensive but the Company has limited available T-South transport under contract. Sumas is often the highest-priced supply but in recent times it has been less expensive than Rockies except for certain times during the winter.
- Include a small level of annual supplies.
- Annual load expectation (Nov-Oct) is approximately 30,000,000 dths, consistent with recent load history.
- Considerations of structured products, caps, floors, etc., are not to exceed 5% of overall contract supply target.

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

[3] GSOC annually determines the number of years (0 to 5) to include in the rolling portfolio plan.

Once GSOC has approved the portfolio procurement strategy and design, the Company employs a variety of methods for securing the best possible deal 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 days or weeks depending on the number or time requirements of the packages sought, comparing the indicative pricing to each party as well as comparing the information to market intelligence available at the time. Ideally, after monitoring these indicatives and the market, 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 there is always the possibility the lowest market price may be during period when the Company is initially gathering the price indicatives; in that situation there is a risk that a sudden price run-up may lead to filling the transaction at the higher end of the bids over time, or delay the acquisition to another time. However, the reverse is also true—the initial price indicatives may start high and drop over time allowing us 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 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 will require 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.

SECTION 5

ENVIRONMENTAL CONSIDERATONS

Overview

> **Key Points**
> - State and federal agencies are proposing greenhouse gas (GHG) emission reduction regulations, which must be considered in the 2016 IRP.
> - On September 15, 2016, the Washington Department of Ecology (Ecology) issued the final Washington Clean Air Act (CAA) Clean Air Rule (CAR) WAC-173-442. Preliminary impacts are still being discussed.
> - The Northwest Power and Conservation Council analyzes eight analytical approaches for future carbon costs.
> - Of these, the Council recommends the Carbon Cost Risk approach.
> - Cascade models high and low ranges to examine carbon cost impacts on prices.

New environmental regulations and policies are being proposed at the Washington, Oregon and federal levels. The purpose of these rules is to address greenhouse gas (GHG) emissions resulting from the use of fossil fuels. Considering Cascade is a natural gas distribution company, some of these regulations could have the potential to significantly increase Cascade's operating costs.

On October 23, 2015, the EPA published the final Clean Power Plan (CPP) rule that requires existing fossil fuel-fired electric generation facilities to reduce CO_2 emissions. On February 9, 2016, however, the United States Supreme Court granted an application for a stay of the Clean Power Plan pending disposition of the applicants' petition for review in the D.C. Circuit Court and disposition of the applicants' petition for a writ of certiorari if such a writ is sought. The rule requires that states must, by September 6, 2016, either submit to the EPA a request for a two-year extension to submit a final state plan, or submit a plan demonstrating how emissions reductions will be achieved and include emission limits in the form of an annual emission cap or an emission rate that will be applied to each fossil fuel-fired electric generating facility within the state starting in 2022. Emission limits become more stringent from 2022 to 2030, with the 2030 emission limits applying thereafter. The effective date and compliance dates in the rule are expected to be addressed in a future decision made by the United States Supreme Court. However, Cascade does not own or operate any fossil-fired electric generation facilities and is not subject to the CPP.

The 2016 Oregon Legislature adopted "Coal to Clean" (SB 1547) legislation effectively removing coal in the state by 2030 (by disallowing any coal-related costs in retail electricity rates) and also adopted a standard that requires 50% of all electricity used in Oregon to be from renewable sources starting in 2040.

On September 15, 2016, the Washington Department of Ecology (Ecology) issued the final Washington Clean Air Act (CAA) Clean Air Rule (CAR) WAC-173-442 requiring greenhouse gas emission reductions from various industries in the state, including emissions from the combustion of natural gas supplied to end-use customers by natural gas distribution companies, such as Cascade. In 2017, Cascade must maintain emission of carbon dioxide equivalent (CO_2e) less than or equal to its baseline emissions. Preliminary impacts from the rule are discussed in detail further below.

It is possible that other state or federal regulations and legislation may potentially be adopted in the future that could require Cascade to address GHG emissions. Cascade will continue to monitor GHG regulations and legislation for potential impacts to its operations and costs to customers.

While focused on the Pacific Northwest electric industry, the Northwest Power and Conservation Council (NPCC or Council) exhaustively examined CO_2 in its Seventh Power Plan (The 7th Plan) released in May, 2016.[1] The 7th Plan builds on the Council's previous work and has become the recognized standard for carbon analysis in the Pacific Northwest. Cascade believes the 7th Plan contains relevant CO_2 costs for use in modeling cost impacts to natural gas distribution utilities.

The Council considered eight analytical approaches to establish future carbon costs.[2] These are:

- Social Cost of Carbon (Mid-Range and High);
- Carbon Cost Risk (e.g., $0 - $110/ton);
- Regional Renewable Portfolio Standards at 35%; and
- Five Approaches: 1) Maximum Carbon Reduction-Existing Technology, 2) Maximum Carbon reduction-Emerging Technology, 3) Coal Retirement, 4) Coal Retirement with the Social Cost of Carbon, and 5) Coal Retirement with the Social Cost of Carbon and No New Gas.

Four additional scenarios were included:

1) Planned Loss of a Major Non-GHG Emitting Resource (i.e., 1,000 aMW of hydro);
2) Unplanned Loss of a Major Non- GHG Emitting Resource;
3) Faster Conservation Deployment; and
4) Slower Conservation Deployment. Further, four sensitivity analyses were performed:
    i. No Demand Response;
    ii. Low Natural Gas and Wholesale Electricity Prices;
    iii. Increased Market Reliance; and
    iv. Lower Conservation.

[1] Seventh Northwest Power and Conservation Council Plan (aka Seventh Power Plan), Northwest Power and Conservation Council, Document 2016-02, February 25, 2016; approved and released May, 2016.
[2] Seventh Power Plan, pages 3-7 to 3-14

The Council also discusses fugitive natural gas emissions in the Plan. Some studies suggest "fugitive methane" emissions can be more impactful to the natural gas industry than CO_2 emissions from using natural gas at the end-use or to generate electricity.[3] Fugitive methane emissions may occur at all points of the extraction, gathering, transportation, storage, and distribution of natural gas. The Council notes the actual amount of fugitive natural gas emitted is uncertain and that its contribution to greenhouse gas emissions is less than that of the electric industry.

Cascade's IRP has been heavily informed by the Council's Seventh Power Plan and has carefully incorporated its survey of approaches, sensitivity analyses, and scenarios. Consideration has also been given to cost-effectiveness, customer value, and the results of other local distribution companies (LDCs).

Of the eight approaches examined by the NPCC, virtually all LDCs and electric utilities—as well as the Council—have centered on the Carbon Cost Risk approach. This approach results in a $10/ton carbon cost adder to Cascade's avoided costs in 2018 and $30/ton in 2035. Therefore, the question is not whether carbon adders should be included in Washington and Oregon but, rather, how and at what amount. This IRP models these assumptions and analyzes cost ranges for various sensitivities and several related scenarios.

In addition, Ecology's constraints on emission reduction units (ERUs) for compliance with CAR makes it difficult to project their cost. Since Cascade has not conducted an analysis of ERU costs, the Company has applied NPCC's prices to model preliminary cost impacts from CAR. Cascade expects the total cost projected in its modeling to be conservative since the model applies a price of CO_2e to emissions from natural gas delivered to all customers, whereas CAR requires ERUs to be purchased for a portion of emissions from gas delivered to customers. Cascade will further evaluate ERU costs and compliance costs in the future as Ecology establishes Cascade's baseline emissions value and emission reduction pathway, and considers the timing of a decision by the Washington Superior Court for Thurston County on the legality of CAR.

Additionally, Cascade has undertaken GHG emission reductions through its energy efficiency programs, as well as voluntary efforts, and continues to monitor other options, as described at the end of this section.

[3] Seventh Power Plan, pages 3-31 to 3-32

Purpose

This section considers mandated state and federal GHG emission reduction policies and regulations directly impacting natural gas distribution companies. In addition, this section examines methodologies for applying a cost of carbon to natural gas distribution companies and identifies the assumptions made in determining a 20-year avoided cost of natural gas, and pairs these costs with associated two-year action items.

Significant emission policies—proposed or adopted—have occurred since Cascade's last IRP. The Federal government as well as policy-makers in Washington and Oregon have actively pursued GHG emission reductions, and primarily CO_2 emission reductions.

The following summarizes the salient aspects of this at the national, regional, and state levels.

The National Focus

The EPA has applied Clean Air Act, Section 111(d) to promulgate state Clean Power Plan regulations, primarily directed towards electric generation. The rules would require GHG emissions from specified power plants to be reduced by 32% from 2005 levels by 2030. The U.S. Supreme Court stayed implementation of the proposed rules in February 2015 and oral arguments were heard on September 27, 2016 in the District of Columbia Circuit Court of Appeals. The timing of its findings is indeterminate.

Washington

On September 15, 2016, the Washington Department of Ecology (Ecology) issued the final Washington Clean Air Act (CAA) Clean Air Rule (CAR) WAC-173-442 requiring greenhouse gas emission reductions from various industries in the state, including emissions from the combustion of natural gas supplied to end-use customers by natural gas distribution companies, such as Cascade. On the same date, Ecology finalized requirements for reporting GHG emissions from natural gas distributors under WAC 173-441. In 2017, Cascade must maintain emissions of CO_2e less than or equal to its baseline emissions. Cascade's baseline emissions will be set by Ecology using the average emissions from natural gas consumption by Cascade's customers between 2012 and 2016. Beginning in 2018, Cascade must meet an emissions reduction pathway that decreases 1.7% each year from its emissions baseline or must acquire emissions offsets equal to the amount of emissions in excess of Cascade's emission reduction pathway.

Cascade plans to obtain emissions offsets to comply with CAR because natural gas delivery pipelines are not emission sources and Cascade has an obligation to meet the natural gas demand of its customers. Emission offsets consist of either in-state emission reduction units ("ERUs") or, to a limited and declining extent, out-of-state allowances from states or provinces that have established multi-sector greenhouse gas programs. Under CAR, each metric ton (MT) of CO_2e that a covered party emits that exceeds the covered party's compliance obligation and is not covered by an emission offset is a separate violation of CAR. Thus, failure to obtain sufficient emissions offsets could subject Cascade to state CAA enforcement.

Cascade has significant concerns about the legal underpinnings of the CAR. It is Cascade's position that Ecology does not have authority to implement a program to limit statewide greenhouse gas emissions, particularly a trading program based on ERUs. Cascade also maintains that Ecology does not have authority to regulate non-emitting sources for their customers' emissions. Cascade expressed these concerns in comments on the proposed rule that preceded CAR, which were submitted to Ecology on July 22, 2016. Ecology failed to address Cascade's comments in the final CAR.

On September 27, 2016 and September 30, 2016, Cascade and three other natural gas distribution utilities jointly filed complaints in the United States District Court for the Eastern District of Washington and the State of Washington Thurston County Superior Court, respectively, challenging the legal underpinnings of CAR. While a decision from the state court may possibly be issued some time in 2017, CAR is final and remains in effect, Cascade must plan accordingly for compliance while the legal issues are resolved.

1. Compliance Obligations Under CAR

CAR includes natural gas distributors in the scope of required emissions reductions under WAC 173-442-010. Cascade is a Covered Party under CAR as the Company is a natural gas distributor per WAC 173-442-020(k). WAC 173-442-020(j)(iii) then identifies CO_2 emissions that are reported to EPA under 40 CFR 98 Subpart NN as the covered emissions for natural gas distributors.

a. Baseline Emissions

First, Cascade reviewed previous GHG reporting reports it submitted to EPA according to 40 CFR 98 Subpart NN. Using the data provided for those reports, Cascade estimated the approximate gas delivered to customers (assumed to be core customers and customers that are not considered covered parties themselves) for 2012 to 2016 and provides that data in Table 5-1 below. Cascade believes this would be the quantity of natural gas delivered to customers to be used in estimating Cascade's baseline GHG emissions value according to the rule.

Table 5-1: Estimated Quantity of Gas Delivered to Customers for Determining Cascade's Baseline GHG Emissions

(pending consultation with Ecology in 2017)

Year	Total Gas Received by Cascade from Suppliers (Mscf)	Approximate Gas Delivered to Customers Considered Covered Parties Themselves (Mscf)	Approximate Gas Delivered to Customers to Establish Cascade's Baseline (Mscf)
2012	80,068,497	38,009,461	42,059,036
2013	94,336,926	52,968,305	41,368,621
2014	91,569,922	45,956,078	45,613,844
2015	90,932,690	52,301,573	38,631,117
2016 (projected)	92,069,349 (1.25% projected growth from 2015)	50,408,652 (average from 2013-2015)	41,660,697
2012-2016 Average	89,786,383	47,928,814	41,866,663

Next, Cascade estimated the CO_2 emissions resulting from Cascade's delivery of gas to customers that would not be considered covered parties themselves and includes that data in Table 5-2. Ecology states in the rule that a baseline GHG emissions value will be calculated in metric tons (MT) of CO_2 equivalent (CO_2e). Further discussion will be planned with Ecology at a future date on whether the CO_2 emissions under 40 CFR 98 Subpart NN are different than what Ecology considers for CO_2e emissions in this section of the rule for natural gas distribution companies. At this time Cascade is using CO_2 as calculated under Subpart NN for estimating CO_2/CO_2e per WAC 173-442-020(j)(iii).

According to Table 5-2, CO_2 emissions from natural gas delivery to customers are greater than 70,000 MT per year and, thus, Cascade is considered a Category 1 covered party per WAC 173-442-50(1)(a). For Category 1 covered parties, a baseline GHG emissions value is determined according to WAC 173-442-050(2)(a) and (3). From these requirements Cascade projects its approximate baseline emission value would be equivalent to the 2012 to 2016 average annual emissions from delivery of natural gas to customers that are not themselves covered parties under CAR. This value is estimated at approximately 2,277,546 MT per year of CO_2. Cascade must submit emission calculations for 2012 to 2016 to Ecology as required by March

31, 2017 and will contact Ecology to discuss emission calculations before submitting. Ecology must then establish a final baseline emissions value for Cascade through a regulatory order by January 30, 2018.

Table 5-2: Estimated Baseline GHG Emissions Value for Cascade
(pending consultation with Ecology in 2017)

Year	Approximate Gas Delivered to Customers to Establish Cascade's Baseline (Mscf)	Annual Emissions, (MT of CO_2) [Mscf x 0.0544 MT CO_2/Mscf]
2012	42,059,036	2,288,012
2013	41,368,621	2,250,453
2014	45,613,844	2,481,393
2015	38,631,117	2,101,533
2016 (projection)	41,660,697	2,266,342
2012-2016 Average Delivery to Customers and Estimated Baseline GHG Emissions Value	41,866,663	**2,277,546**

b. Compliance Pathway

In 2017, the GHG reduction pathway for Cascade is equivalent to the baseline emissions of approximately 2,277,546 metric tons (MT) of CO_2. As mentioned above, the emission reduction pathway decreases annually by an additional 1.7% of Cascade's baseline emissions value. In calendar year 2036, the emission reduction pathway remains constant at the value calculated for 2035.

Table 5-3 represents Cascade's preliminary estimated baseline emissions value and emission reduction pathway from 2017 to 2035, showing emissions allowed each year.

Table 5-3: Preliminary Baseline GHG Emission Value and Projected Emission Reduction Pathway for Cascade

Year	Cascade's Baseline Emissions Value (MT of CO_2)	Potential Emission Reduction Pathway or Emissions Allowed Each Year (MT of CO_2)
2017	2,277,546	2,277,546
2018	2,277,546	2,238,828
2019	2,277,546	2,200,110
2020	2,277,546	2,161,392
2021	2,277,546	2,122,673
2022	2,277,546	2,083,955
2023	2,277,546	2,045,237
2024	2,277,546	2,006,518
2025	2,277,546	1,967,800
2026	2,277,546	1,929,082
2027	2,277,546	1,890,364
2028	2,277,546	1,851,645
2029	2,277,546	1,812,927
2030	2,277,546	1,774,209
2031	2,277,546	1,735,490
2032	2,277,546	1,696,772
2033	2,277,546	1,658,054
2034	2,277,546	1,619,336
2035	2,277,546	1,580,617

By January 30, 2018, Ecology is required to issue a regulatory order per WAC 173-442-200(6) to Cascade which will contain the official emission reduction pathway in units of metric tons of CO_2e for each calendar year in the compliance period and the total reduction pathway for each compliance period.

Table 5-4 shows a preliminary comparison of Cascade's greenhouse gas emission reduction pathway, projected gas delivery to customers that are not covered parties themselves under CAR, and the resulting projected annual compliance emissions obligation for Cascade. The projected gas delivery to customers assumes a 1.25% annual forecasted growth in demand. Considering this growth rate and that 2016 is yet a projection of emissions, Cascade projects emissions from natural gas deliveries in 2017 to exceed its baseline emission value, as shown in Table 5-4. As such, Cascade will be required to reduce its emissions consistent with CAR beginning in 2017. Future increases in natural gas delivery coupled with Cascade's declining emission reduction pathway increase Cascade's compliance burdens under CAR.

Table 5-4: Preliminary Annual Compliance Obligation for Cascade

Year	Projected Emission Reduction Pathway or Emissions Allowed Each Year (MT of CO_2)	Projected Emissions, assuming 1.25% Annual Growth for Cascade Gas Delivered (MT of CO_2)	Compliance Obligation (MT of CO_2)
2017	2,277,546	2,294,671	17,125
2018	2,238,828	2,323,355	84,526
2019	2,200,110	2,352,396	152,287
2020	2,161,392	2,381,801	220,410
2021	2,122,673	2,411,574	288,901
2022	2,083,955	2,441,719	357,764
2023	2,045,237	2,472,240	427,003
2024	2,006,518	2,503,143	496,625
2025	1,967,800	2,534,432	566,632
2026	1,929,082	2,566,113	637,031
2027	1,890,364	2,598,189	707,826
2028	1,851,645	2,630,667	779,021
2029	1,812,927	2,663,550	850,623
2030	1,774,209	2,696,844	922,636
2031	1,735,490	2,730,555	995,064
2032	1,696,772	2,764,687	1,067,915
2033	1,658,054	2,799,245	1,141,192
2034	1,619,336	2,834,236	1,214,900
2035	1,580,617	2,869,664	1,289,047

WAC requires compliance to be demonstrated at the end of each compliance period as explained in WAC 173-442-200. Each compliance period is a three-year period with the first period from 2017 to 2019. As required by WAC 173-442-250, Cascade must submit its first compliance demonstration report by December 31, 2020, to Ecology, providing the required verification that sufficient qualifying ERUs have been purchased to cover emissions above Cascade's emission reduction pathway.

c. Emission Offsets

Cascade continues to evaluate options for purchasing ERUs and allowances to cover emissions above the projected emission reduction pathway. Per WAC 173-442-100, ERUs must originate from greenhouse gas emission reductions occurring within Washington; per WAC 173-442-170, a limited amount of allowances also may be used for compliance.

The price of ERUs is unknown at this time. Ecology's constraints on ERUs make it difficult to project their cost. Considering Cascade's modeling applies a price of CO_2 to all emissions from natural gas delivered to all customers and CAR only requires compliance with a portion of these emissions, the total carbon cost from Cascade's modeling is expected to be conservative. Cascade will further evaluate

ERU costs and compliance costs in the future as Ecology establishes Cascade's baseline emissions value and emission reduction pathway, and considers the timing of a decision by the Washington Superior Court for Thurston County on the legality of CAR.

Initiative 732 (I-732 or "Clean Energy Future") appeared on the November 2016 ballot and would have charged a carbon tax of $25/ton of carbon, lowered the sales tax by 1%, granted a tax rebate of up to $1,500 annually to 400,000 low income families, and eliminated the business and occupation (B&O) tax on manufacturing. On November 8th, Washington voters rejected this measure with the percentage vote being 59% against.

Potential other carbon initiatives are in-progress, such as one that may be introduced by environmental and labor advocates.[4] Regardless, significant other state policies with CO_2 impacts have been adopted including, but not limited to, the Energy Independence Act ("I-937") and the Washington State Electric Vehicle Action Plan. However, Cascade's operations are not directly impacted by these two policies.

Oregon

The Oregon Legislature has actively considered multiple new state laws as follows:

- "Coal to Clean" law adopted in 2016 (SB 1547).
  - Effectively eliminates coal power by 2030.
  - 50% renewable electric generation by 2040.

- Several other legislative proposals considered without adoption in 2016:
  - Replace GHG emission goal with cap and trade program (SB 1574).
  - Repeal GHG emission goal; requires Environmental Quality Commission to adopt goals and limits (HB 4068).

It is possible that other state or federal regulation and legislation may potentially be adopted in the future that could require Cascade to address GHG emissions. Cascade will continue to monitor GHG regulation and legislation for potential impacts to natural gas distribution companies.

[4] Based on discussions with environmental advocates.

The Regional Focus

The Northwest Power Planning and Conservation Council's mission is to ensure, with public participation, an affordable and reliable energy system while enhancing fish and wildlife in the Columbia River Basin. The Northwest Power Planning and Conservation Council develops electric generation system plans for the Pacific Northwest and recently approved its 7th Power Plan (May 2016). Significant discussion, analyses, and scenarios regarding CO_2 are contained in Chapters 3 and 15 of the 7th Plan. These will be addressed in the following subsection ("Types of CO_2 Adder Analyses").

Moreover, considerable prior regional collaboration has occurred regarding GHG, such as the proposed cap and trade program of the Western Climate Initiative.[5]

Types of CO_2 Adder Analyses

The Council's Seventh Power Plan summarizes applicable approaches. While directed to the electric industry, these are provided as illustrations of the potential scope of methodologies and recently-performed analyses. These are excerpted, *verbatim*, so as to illustrate the Plan's characterization of each.

> <u>Social Cost of Carbon (SCC)</u>
> "Two scenarios, the Social Cost of Carbon – Mid-Range (SCC-MidRange) and Social Cost of Carbon – High (SCC-High), use the US Interagency Working Group on Social Cost of Carbon's estimates of the damage cost of forecast global climate change. According to the Working Group, the SCC is an estimate of the economic damages associated with a small increase in carbon dioxide (CO2) emissions, conventionally one metric ton, in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e. the benefit of a CO2 reduction). Therefore, in theory, the cost and economic risk of the resource strategy that achieves carbon dioxide emissions reductions equivalent to the social cost of carbon would offset the cost of damage."
>
> <u>Carbon Cost Risk</u>
> "The carbon cost risk scenario is intended to explore what resources result in the lowest expected cost and economic risk given existing policy plus the economic risk that additional carbon dioxide reduction policies will be implemented. Each of the 800 futures imposes a carbon dioxide price from \$0 to \$110 per metric ton at a random year during the 20-year planning

[5] Cap and trade is "a system for controlling carbon emissions and other forms of atmospheric pollution by which an upper limit is set on the amount a given business or other organization may produce but which allows further capacity to be bought from other organizations that have not used their full allowance." Oxford Dictionary

period. Over time, the probability of a carbon dioxide price being imposed and the level of that price both increase. By 2035, the average price of carbon dioxide rises to $47 per metric ton across all futures. It should be noted, that the use of a carbon dioxide price does not presume that a "pricing policy" (e.g., carbon tax, cap and trade system) would be used to reduce carbon dioxide emissions. The prices imposed in this scenario could also be a proxy for the cost imposed on the power system through regulation to reduce carbon dioxide emissions (e.g., caps on emissions)."

Regional Renewable Portfolio Standard at 35 Percent (Regional RPS at 35%)

"This scenario assumes that a region wide Renewable Portfolio Standard (RPS) is established at 35 percent of regional retail electricity sales across all four Northwest states. Presently, three states in the region have RPS. Montana and Washington require that 15 percent of the retail sales of energy be served by renewable resources. Montana's RPS must be satisfied in 2015 and Washington's by 2020. Oregon requires that 20 percent of retail sales be served by renewable resources by 2020. These state level RPS generally only apply to investor owned utilities and larger public utilities, while this scenario assumes that all of the region's retail sales are covered. Since this scenario was designed to test the cost and effectiveness of this policy for reducing regional power system carbon dioxide emissions, it did not include future carbon dioxide regulatory cost risk uncertainty or estimated damage cost. The cost-effectiveness of a policy that only requires use of additional renewable generation can, therefore, be compared to other scenarios that tested alternative policy options to reduce carbon dioxide emissions, including those use a combination of strategies such as limiting the type of new resources that can be developed and imposing a carbon price."

Maximum Carbon Reduction – Existing Technology

"This scenario was designed to explore the maximum carbon dioxide emissions reductions that are feasible with current commercially available technologies. In this scenario all of the existing coal plants serving the region were assumed to be retired by 2026. In addition, the least efficient (i.e., those with heat rates exceeding 8,500 Btu/kWh) existing natural gas-fired generating facilities were assumed to be retired by 2031. No carbon dioxide cost risk or estimated damage cost was assumed, so this scenario can be compared to the cost-effectiveness of other policy options (e.g., Carbon Cost Risk, Regional RPS at 35%, Social Cost of Carbon, Retire Coal w/SCC MidRange, etc. scenarios) for reducing carbon dioxide emissions."

Maximum Carbon Reduction – Emerging Technology

"This scenario considers the role that new technologies might play in achieving carbon dioxide reduction. Due to the speculative nature of the performance and ultimate cost of technologies considered in this scenario the Council's Regional Portfolio Model (RPM) was not used to identify this scenario's least cost resource strategy. Rather, the RPM was used to define the role (e.g., capacity and energy requirements) that new and emerging technologies would need to play in order to achieve carbon dioxide reductions beyond those achievable with existing technology."

<u>Retire Coal – This scenario is identical to the Maximum Carbon Reduction</u>
"Existing Technology scenario, except that it does not retire any existing natural gas generation. This scenario was designed to establish the lowest carbon dioxide emission level achievable by retiring all of the existing coal plants serving the region while assuming the continued operation of existing gas-fired generation. Since this resource strategy relies on existing gas generation rather than investing new resource development it could potentially have lower costs than the Maximum Carbon Reduction – Existing Technology scenario, but might produce similar carbon dioxide emissions. This scenario constructed based on public comment on the draft plan, and therefore was not considered during its development."

<u>Retire Coal with Social Cost of Carbon Mid-Range (Retire Coal w/SCC MidRange)</u>
"This scenario is identical to Retire Coal scenario, except that it assumes that the US Interagency Working Group on Social Cost of Carbon's Mid-Range estimate of the damage cost of forecast global climate change are reflected in fossil fuel costs. This scenario was designed to test the cost, economic risk and carbon emissions impacts that internalizing the damage cost of climate change would have on the resource dispatch and development. It was assumed that this scenario's resource strategy would rely more on renewable resources. Therefore, this scenario assumes greater availability and lower solar PV system cost for both utility scale projects and distributed systems. This scenario was constructed based on public comment on the draft plan, and therefore was not considered during its development."

<u>Retire Coal with Social Cost of Carbon Mid-Range and No New Gas Generation (Retire Coal w/SCC MidRange & No New Gas)</u>
"This scenario is identical to Retire Coal w/SCC MidRange scenario, except that it assumes that no new natural gas-fired generation resources can be constructed to replace retiring coal plants or existing gas generation if such plants are uneconomic to operate. This scenario was designed to test the cost, economic risk and carbon emissions impacts of restricting new resource development to renewable resources when compared to the

> Retire Coal w/SCC MidRange scenario. This scenario was constructed based on public comment on the draft plan, and therefore was not considered during its development."

To account for resource uncertainty, in addition to the above approaches, four additional scenarios were analyzed. "Four scenarios explored resource uncertainties and carbon dioxide regulatory compliance cost and economic risk. Two examined the effect that the loss of a major non-greenhouse gas-emitting resource might have on the region's ability to reduce power system carbon dioxide emissions. The Unplanned Major Resource Loss scenario assumed that a significant (approximately 1000 average megawatt) non-greenhouse gas emitting generator was unexpectedly taken out of service. The Planned Major Resource Loss scenario assumed that similar magnitudes of the region's existing non-greenhouse gas emitting resources were phased out over the next 20 years. Since both of these scenarios were designed to identify resource strategies that would maintain regional compliance with federal carbon dioxide emissions limits they assumed the cost of future carbon dioxide regulatory risk used in the Carbon Cost Risk scenario.

"The Planned Major Resource Loss scenario also provides insight into the resource implications that would occur in the event of the planned removal of any specific non-carbon resource in the region, including the removal of major hydroelectric projects such as the four federal dams on the lower Snake River. The lower Snake River dams have a combined nameplate capacity of 3,033 megawatts. However, because of limited reservoir storage, their useful peaking capability (e.g. 10-hour sustained-period capacity) ranges from about 1,700 to 2,000 megawatts, which represents about 11 percent of the aggregate hydroelectric system's sustained peaking capability. Annually, on average, these four projects produce about 1,000 average megawatts of energy or about 5 percent of the region's annual average load."

Four sensitivity analyses were performed:

- No Demand Response
- Low Natural Gas and Wholesale Electricity Prices
- Increased Market Reliance
- Lower Conservation

Fugitive Methane Emissions

Electric generation fueled by natural gas has significantly less CO_2 emissions than electric generation from coal. According to a report commissioned by the Natural Gas Council, fugitive methane emissions comprise 10.6% of U.S. anthropogenic

GHG emissions. However, methane emissions from the natural gas industry comprise 2.6% of total emissions. Furthermore, emissions from natural gas system themselves represented only about 1.4% of the volume of methane in U.S. natural gas produced in 2014.[6]

The Council's Seventh Power Plan notes:

> "…there is considerable uncertainty around such issues as whether its impacts compared to carbon dioxide are over or under-stated…and whether accounting for the methane emissions from coal production would also raise that fuel's full life-cycle climate impacts…"
>
> "…will likely draw on gas production new wells which have lower fugitive emissions…"
>
> "…unless new pipeline capacity is needed, fugitive emissions from pipeline leaks remain relatively constant…"

Thus, fugitive methane emissions need to be addressed but do not offset the benefit of lower overall CO_2 emissions when compared to electric generation from natural gas.

Washington and Oregon Commission-Jurisdictional Planning Treatment

All Washington and Oregon LDCs follow the protocols of the Council's Carbon Cost Risk approach:

<u>Puget Sound Energy</u>

In its 2015 IRP, Puget Sound Energy modeled three CO_2 prices: No Federal CO_2 price ($0/ton); Mid CO_2 price ($13/ton in 2016 to $54/ton in 2035); High CO_2 price ($35/ton in 2020 to $120/ton in 2035.)

<u>NW Natural Gas</u>

In its 2016 IRP, Northwest Natural Gas includes a cost for carbon beginning in 2021 at $7/ton with $28/ton in 2035 for Oregon; for Washington; the carbon adder starts at $7/ton in 2017 with $32/ton in 2035.

[6] Finding the Facts on Methane Emissions: A Guide to the Literature, ICF International on Behalf of The Natural Gas Council, http://www.ngsa.org/download/analysis_studies/NGC-Final-Report-4-25.pdf

Avista

In its 2016 Natural Gas IRP: a carbon adder is included beginning in 2018 ($10/ton), escalating to approximately $20/ton (2035) based on cap and trade carbon policy.

Cascade's Current Efforts for Greenhouse Gas Reduction

Cascade's conservation programs help reduce CO_2 emissions by providing incentives to customers for a comprehensive set of prescriptive and custom energy efficiency upgrades designed to streamline their use of natural gas, thus reducing their overall carbon footprint. Space, water heating, and weatherization incentives drive positive energy behavior in customers' homes and businesses. This leads to lowered demand, bill reductions, and overall carbon emission reductions in the communities Cascade serves (see Section 7, Demand Side Management, for additional details).

In addition to the conservation of natural gas, the direct use of this resource can also be a significant source of carbon reduction. When natural gas is transported to electric generation facilities which, in turn, transmit electricity for customers' end-uses (e.g., space heating, water heating, cooking, etc.), 50% to 75% of the Btu content of the power is lost when compared to the same end-uses which have been supplied by natural gas. According to the American Gas Association's whitepaper, *Dispatching Direct Use: Achieving Greenhouse Gas Reductions with Natural Gas in Homes and Businesses*, a typical gas water heater uses half the energy of an electric resistance hot water heater, emits half the CO_2, and costs less than half as much to operate on an annual basis. This opportunity for carbon savings applies to space heating equipment as well.

In fact, the Environmental Protection Agency recognizes source efficiency as the method utilized when assessing the energy efficiency value of conservation equipment and measures.[7]

It is for these reasons that Cascade has encouraged the direct use of natural gas when paired with strong energy conservation measures. Accelerating this effort would be of benefit from both a demand response and a carbon reduction standpoint—a win for the community, Company, and customers.

[7] *See* https://www.energystar.gov/buildings/facility-owners-and-managers/existing-buildings/use-portfolio-manager/understand-metrics/difference).

In addition, the natural gas industry is focused on methane recapturing and leak prevention efforts. Cascade is monitoring these efforts, both nationally and regionally and has made commitments in one of these areas in particular.

Most recently, Cascade became a Founding Partner of the EPA's Natural Gas Star Methane Challenge Program. As a Founding Partner, Cascade has voluntarily 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 commitment to company-wide implementation of BMPs to reduce methane emissions. During the initial commitment timeframe, Cascade will conduct incident analyses on all excavation damages and report the relevant data to EPA. Cascade is also exploring other voluntary actions which could reduce methane emissions resulting from excavation damage. Cascade's operational and infrastructure changes have resulted in lower methane emissions, and therefore lower GHG emissions, in the State of Washington.

Proposed Direction

As mentioned above, the Council's Seventh Power Plan provides a considered rendition of carbon cost treatment for planning purposes. Cascade's specific assumptions would benefit by following the Council's Carbon Cost Risk approach yielding a $10/ton carbon adder in 2018, rising to $30/ton in 2035.

High and low ranges modeled to determine cost sensitivities and scenario planning provide alternative forecasting methodologies. As mentioned above in discussion on CAR impact, Cascade believes significant uncertainty remains regarding the cost of compliance. As ERU costs are more clearly defined, and actual offset markets develop in the state, the Company will be able to more effectively model in impacts of this rule. In the meantime, sensitivities and impacts on prices have analyzed, with expanded analysis occurring as more information becomes available.

SECTION 6

AVOIDED COSTS

Overview

As part of the IRP process, Cascade calculates a 20-year forecast and 45 years of avoided costs. Cascade provides a 45-year avoided cost because some of the insulation measures exceed 30-year lives – thus the 45-year timeframe to account for the full measure life. 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. Cascade evaluates the impact that a range of environmental externalities, including CO_2 emission prices, would have on the avoided costs in terms of cost adders and supply costs. The Company produces an avoided cost case based on the expected scenario.

Key Points

- Avoided cost forecasting serves as a guideline for determining energy conservation targets.
- Cascade incorporates nine factors in its avoided cost calculation.
- A short-run coefficient factor of -0.10 and a long-run factor of -0.12 with ranges of plus or minus 0.07 is used for price elasticity purposes.
- The Company has included a 10% carbon adder in its 2016 IRP.
- The total avoided cost ranges between $0.5041 and $0.6659/therm over the 20-year planning horizon.

As discussed in Section 7, Demand Side Management, when calculating the avoided cost figures, the Company includes an incremental cost advantage for conservation resources to recognize the non-quantifiable benefits associated with conservation such as price certainty and a hedge value against future carbon costs.

Costs Incorporated

The following costs are included in the avoided cost calculation:

- The long-term gas price forecast compiled from multiple consultants' gas price forecasts (which is the majority of the cost);
- A price for carbon included in the gas price forecast, which has been provided by a consultant;
- Gas storage variable and fixed costs;
- Upstream variable and fixed transmission costs;
- Peak related on-system transmission costs; and
- A 10% adder for environmental benefits, as recommended by the Northwest Power and Conservation Council (NPCC).

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

- The most recent load forecast (9/8/2016);
- The inflation rate used is 1% (from EIA); and
- The discount rate used is 3.52% (30-year mortgage rate at the time of calculation).

Price Elasticity

Price elasticity is an economic concept which recognizes that customer consumption changes as prices rise or fall. The amount of this change (or "elasticity") is a function of other available products (i.e., substitutes) or the ability for customers to go without or use less with no meaningful impact on their personal life or in commerce.[1,2] "Price signals" is a term used to describe how customers see or expect future pricing to affect them.[3]

Price elasticity is expressed mathematically as a coefficient describing the amount of change in consumption per change in price. For example, a price elasticity factor of -0.10 means a consumer will reduce usage by 1% if the price increases by 10%. Conversely, a 0.10 coefficient factor for a 10% price decrease would predict customers would increase consumption by 1%. For products with high substitutability, the coefficient factors are high (e.g., greater than 0.50) and vice versa.

Price elasticity can be highly temporal. Consumers may not be able to make changes with short-term price increases or decreases. Yet, several years out, that same customer may replace equipment or make behavioral changes to use significantly less or more of a product depending on whether, over the long term, the product is more or less expensive.

The importance of price elasticity to natural gas integrated resource planning lies in the 20-year period over which the demand forecasts are estimated. This forecast (or range of forecasts under scenario planning) is a key determinant of the avoided cost. Low price elasticity in a rising natural gas price environment would suggest forecasted higher load would not change customer behavior and more natural gas

[1] An example of substitutes for a commodity is transportation fuels. As gasoline prices rise, commuters may carpool more or use public transportation. Conversely, in a low-cost gasoline environment, people may take longer driving vacations rather than fly or stay closer to home. In the long-term, higher gasoline prices could steer customers to changing out their choice of their automobiles toward electric vehicles or compressed natural gas (CNG) vehicles, thereby reducing to zero their gasoline consumption. Conversely, some drivers such as taxi cab owners may have no near-term choices regarding amount of miles driven; rather, they pass the higher cost of gasoline to their customers.

[2] An example of going without or using less is movies at a cinema. Many entertainment alternatives are present, including waiting until a certain film is released to DVD or Blu-ray.

[3] "A price signal is information conveyed to consumers and producers, via the price charged for a product or service, which provides a signal to increase/decrease supply and/or that the demand for the priced item has increased/decreased." – Wikipedia.

would need to be acquired with corresponding delivery infrastructure. However, if usage materially decreases with higher prices, then less purchases and capital investment by an LDC would be necessary. Therefore, price elasticity has some effect on the avoided cost.

Because avoided costs are integral to conservation planning, among other components, the impact of price elasticity on consumer consumption is of interest to all stakeholders in the planning process.

Several attributes of the regulated utility environment cause price elasticity calculations to be difficult to calculate with precision. Within customer classes, the type of customer usage varies:

- Residential—heating and non-heating
- Commercial—heating and processing

Additionally, regulatory protocols may reduce direct signals because the annual purchased gas adjustment (PGA) may result in price increases or decreases of unknown magnitude. Further, customers assume general rate cases and price changes will occur annual or biannually. As a result, customers are more likely to be uncertain of future pricing than to have the preconception that prices will rise.

Several items reduce load growth over time, regardless of price elasticity and price signals. Changes in economic conditions, added conservation, revised building codes and appliance standards, and advances in technology can lead to historical data that includes reduction in usage irrespective of pricing. This causes difficulty for customers to receive meaningful price signals and difficulty for utilities to isolate primary factors for long-supply term price elasticity calculations (other than inflation). Regardless, customers may not return (or rebound) to historic usage after experiencing higher or lower price excursions.

A review of price elasticity leads to the following findings relevant to Cascade's current IRP process:

- Price elasticity exists, yet determining specific coefficient factors for linear modeling is inexact;
- A range of coefficient factors should be used to test sensitivities of the factors and impacts to the forecasts;
- Given Cascade's diverse geographical territory, statistical significance of price elasticity coefficients is uncertain;
- Several complicating factors call into question the accuracy and application of price elasticities. These include:
    - Regulatory mechanisms (e.g., PGAs and general rate cases) which dampen price signals or information to customers about future pricing;

    - Historical data (embedded with effects of conservation, technology advances, and changing economic conditions) renders reliance on this data imperfect for precise price elasticity determination;
- The retail price of the most "substitutable" fuel—electricity—moves with the cost of natural gas, thereby lessening the economic value of alternative fuels to customers; and
- Evolution of modeling suggests that future IRP modeling should incorporate iterative quantitative equations to allow built-in price elasticity effects.

Regardless, the Company believes price elasticity must be taken into account. For Cascade's 2016 IRP, a short-run coefficient factor of -0.10 and a long-run factor of -0.12 with ranges of plus or minus 0.07 is justifiable, given regional studies and other utilities' modeling efforts.

Several price elasticity inquiries are traditionally referenced in regional price elasticity discussions. These include:

- The American Gas Association (AGA) released a study in 2007 identifying the short-run price elasticity coefficients for the Pacific and Mountain regions to each be -0.07 with a low and high range of -0.03 and -0.13 respectively. The long-run estimates were -0.12 (Pacific) and -0.10 (Mountain), with the range being between -0.01 and -0.29.

- The geographic area of a utility's service territory can result in the statistical significance of price becoming more uncertain. This suggests that for Cascade—with its customers spread over two states in smaller sections—relatively precise price elasticity coefficient factors would either not be available or would be costly to determine with lesser benefits of doing so.[4]

- Use per customer has been decreasing over the past thirty years prompted by multiple factors, including systemic items such as conservation, building codes and appliance standards and behavioral influences such as the 2008 recession.

- In its 2014 Natural Gas IRP, Avista stated it "continues to study how to incorporate a price elastic response to demand given the complex cross commodity relationships, regulatory pricing mechanisms, flat forward price curve and changing technologies in energy efficiency that make discerning how much demand response to expect over the long term. An action item from Avista's 2014 Natural Gas IRP was to explore the possibility of a regional elasticity study facilitated by Avista in conjunction with a third-party such as the NWGA [Northwest Gas Association] or the AGA. Avista approached the NWGA and they are willing to assess regional interest and facilitate the process. Avista

[4] Bernstein, Mark A, and James Griffin. Regional Differences in the Price-Elasticity of Demand for Energy – RAND Corporation, 2005.

is developing the scope, assessing who is best to conduct a study, and determining the associated costs. Avista will assess the interest level of regional stakeholders before deciding to proceed with the study."[5] Upon further discussion, this initiative did not proceed.

A review of these studies and inquiries of price elasticity in the natural gas industry indicates no regional precise calculations are available specific to a utility. A short-run coefficient factor of -0.10 and a long-run factor of -0.12 recognizes the temperature differentials of its service territory, east and west of the Cascade Mountains with low and high ranges at plus or minus 0.07.

Incorporation of Carbon Adder

Federal, Washington, and Oregon agencies are proposing a series of regulations and policies to address greenhouse gas (GHG) emissions to regulate carbon dioxide CO_2 emissions. While focused on the Pacific Northwest electric industry, the NPCC exhaustively examines CO_2 in the 7th Plan released in May 2016. This Plan builds on the Council's previous work and has become the recognized standard for carbon analyses. Cascade's IRP is best informed by the Council's survey of approaches, sensitivity analyses, and scenarios with attention to Cascade's customers regarding cost-effectiveness and the results of other LDCs. Cascade is addressing CO_2 in its energy efficiency programs, encouragement of the direct use of natural gas and methane capturing as well as leak prevention. Regarding expectations, customers have a smaller carbon footprint from their natural gas usage than from their electric usage.

Regardless, there is a high level of uncertainty about the impact that carbon legislation will have on natural gas prices, and in turn, on the avoided cost. Therefore, the Company has included a 10% carbon adder in its 2016 IRP's 20-year price forecast as a carbon adder proxy.

More in-depth discussion regarding the impacts of carbon legislation can be found in Section 5, Environmental Considerations.

Application

The 2016 IRP makes several changes in calculating and applying the avoided costs. With the 2016 IRP, Cascade now calculates an avoided cost for each of the three Washington conservation zones. Section 7, Demand Side Management, has habitually operated as a stand-alone process wherein the Company reduces consumption in the near term through the existing programs, and the conservation

[5] Avista 2014 Natural Gas IRP at page 41.

team then forecasts its savings potential into the 20-year horizon at a state level. Once the savings potential forecasts are available at a statewide level, the savings forecasts are provided to the Resource Planning Group in the final stages of the load forecast, where they are treated as a must take supply resource, reducing the load demand that must be met by more costly supply resources. Since the Company now forecasts avoided costs by conservation zone, this provides another level of granularity to assist the Conservation Group in determining the cost-effectiveness of various programs.

Results

Table 6-1 displays the avoided cost by each conservation zone over the 20-year IRP horizon. For the 2016 IRP the system avoided costs ranges between $0.5041/therm and $0.6659/therm over the 20-year planning horizon.

As mentioned earlier, the avoided cost is based on the 20-year expected scenario. Overall, avoided costs for the 2016 IRP are lower than recent IRPs. Other than the fixed cost increases due to the inclusion of several alternative resources selected as part of the expected case portfolio, commodity costs—the biggest driver of avoided costs—are down. The 45-year avoided costs that are referenced in Section 7, Demand Side Management and other detailed tables of avoided costs, including various carbon scenarios, are found in the Excel version of Appendix H, Avoided Cost Calculations, specifically in tab “Appendix H P 1” in rows 8-15.

Table 6-1: Avoided Costs by Conservation Zone (Cost per Therm)

Year	Zone 1 Avoided Cost	Zone 2 Avoided Cost	Zone 3 Avoided Cost	Washington Avoided Cost	Oregon Avoided Cost	System Avoided Cost
2017	$ 0.542800	$ 0.494000	$ 0.522900	$ 0.524500	$ 0.512200	$ 0.521500
2018	$ 0.518900	$ 0.507000	$ 0.522100	$ 0.517600	$ 0.510900	$ 0.515900
2019	$ 0.525200	$ 0.490000	$ 0.512600	$ 0.512700	$ 0.506700	$ 0.511200
2020	$ 0.523200	$ 0.483400	$ 0.504500	$ 0.507300	$ 0.494300	$ 0.504100
2021	$ 0.536300	$ 0.494300	$ 0.511500	$ 0.517600	$ 0.500000	$ 0.513200
2022	$ 0.557300	$ 0.518800	$ 0.527300	$ 0.537300	$ 0.518200	$ 0.532500
2023	$ 0.557600	$ 0.503400	$ 0.518200	$ 0.530500	$ 0.503300	$ 0.523700
2024	$ 0.576600	$ 0.515900	$ 0.537100	$ 0.548100	$ 0.524300	$ 0.542100
2025	$ 0.580000	$ 0.523200	$ 0.537700	$ 0.551200	$ 0.523900	$ 0.544300
2026	$ 0.576600	$ 0.528400	$ 0.542700	$ 0.553000	$ 0.525600	$ 0.546000
2027	$ 0.591100	$ 0.539000	$ 0.554200	$ 0.565500	$ 0.534000	$ 0.557400
2028	$ 0.616300	$ 0.561800	$ 0.572500	$ 0.587500	$ 0.549000	$ 0.577700
2029	$ 0.628500	$ 0.551000	$ 0.571000	$ 0.589500	$ 0.547100	$ 0.578600
2030	$ 0.653400	$ 0.568700	$ 0.595700	$ 0.612800	$ 0.569000	$ 0.601500
2031	$ 0.668600	$ 0.605700	$ 0.609900	$ 0.632200	$ 0.579200	$ 0.618500
2032	$ 0.669400	$ 0.612300	$ 0.607400	$ 0.633000	$ 0.575000	$ 0.618000
2033	$ 0.694800	$ 0.641600	$ 0.635900	$ 0.660400	$ 0.599900	$ 0.644700
2034	$ 0.679800	$ 0.673500	$ 0.637600	$ 0.661900	$ 0.598400	$ 0.645300
2035	$ 0.691800	$ 0.675400	$ 0.646600	$ 0.670600	$ 0.604100	$ 0.653200
2036	$ 0.710600	$ 0.647200	$ 0.665400	$ 0.679600	$ 0.627300	$ 0.665900

SECTION 7

DEMAND SIDE MANAGEMENT

Overview

Key Points

- The 2016 IRP is the first iteration of the DSM section where the majority of the program planning has transitioned to the 2017 Washington Conservation Plan.
- This plan is informed by Cascade's stand-alone Conservation Advisory Group (CAG.)
- Cascade examines the Technical, Economical, and Achievable Potential of DSM programs through the TEA-Pot model.
- TEA-Pot generates targets as part of the Conservation Plan, based on conservation potential.
- 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 based on incentives, research, information, outreach, and engagement of key parties – and are designed and implemented to achieve DSM savings targets.

Demand Side Management (DSM) refers to resources acquired through the reduction of natural gas consumption due to increases in efficiency of energy use and/or load management. Unlike supply side resources, which are purchased directly from a supplier, demand side resources are purchased from individual customers in the form of energy that remains unused as the result of energy efficiency. The Washington Utilities and Transportation Commission (WUTC or Commission) requires gas utilities to consider cost-effective DSM resources in their energy portfolio on an equal and comparable basis with supply side resources. In the gas industry, DSM resources are conservation measures that include, but are not limited to the following: ceiling, wall, and floor insulation; higher efficiency gas appliances, insulated windows and doors, ventilation heat recovery systems and weather stripping. By prompting customers (i.e. encouraging and influencing customers through conservation related outreach efforts) to reduce their demand for gas, Cascade can displace the need to purchase additional gas supplies, displace or delay contracting for incremental pipeline capacity, and possibly displace or delay the need for reinforcements on the Company's distribution system. It's also important to acknowledge that the Company can prompt and encourage customers to reduce their use, but ultimately it's up to the end user to elect to reduce usage and recognize the values inherent in energy efficiency, ultimately resulting in reduced consumption and load management.

There are two basic types of demand side resources: base load resources and heat sensitive resources. Base load resources displace the need for base load supply side resources. They will offset gas supply requirements throughout the year, regardless of the weather and outside conditions. Base load DSM resources include high efficiency water heaters, higher efficiency cooking equipment and ozone injection laundry systems. Heat sensitive DSM resources are measures whose therm savings increase during cold weather (meaning the measure is used more often during colder weather). For example, a high efficiency furnace will lower therm usage in the winter months when the furnace is utilized the most and will provide little if any savings in the summer months when the furnace is rarely used. Examples of heat sensitive DSM measures include ceiling, floor, and wall insulation measures, high efficiency gas furnaces, and improvements to ductwork and air sealing. These types of heat sensitive measures offset more of the peaking or seasonal gas supply resources, which are typically more expensive than base load supplies.

To provide some background on how Cascade has traditionally addressed its DSM program development, it's important to recognize this 2016 IRP is the first iteration of the DSM section where the majority of the program planning has transitioned to a stand-alone Conservation Planning document released annually to the Commission in December. In December 2015, the Company provided its first dedicated report – the 2016 Washington Conservation Plan (Conservation Plan), and committed to transitioning to an executive summary of the planning process in future submissions of the IRP. Several Conservation Advisory Group (CAG) meetings have been held in the past year to clarify the elements of the Company's DSM efforts that stakeholders would like to see addressed in the IRP, and those which are more appropriately housed within the Conservation Plan.

Conservation efforts for the Company's Oregon customers are offered through the Energy Trust of Oregon.

Conservation Planning

The Conservation Plan for 2017 will include the same elements as the 2016 iteration with an elaboration on the current outreach efforts and possible avenues to increase awareness in future years. These elements include the program goals and budgets, discussions around program cost effectiveness, the existing portfolio of measures, emerging technologies, the possibility of introducing additional DSM measures into the portfolio of offerings and their associated costs, incentive levels, targets, possible updates to Washington's low income weatherization programs to increase participation, outreach communications plans and a close look at the short-term goals and actions in the next two years for implementation of the programs, as well as the longer term, ten-year outlook.

The Company's conservation program offerings are based on a carefully selected assortment of high-efficiency upgrades and envelope improvements designed to reduce natural gas consumption by residential, commercial and industrial customers on qualifying rate schedules. The portfolio of measures is chosen based on a variety of elements -- primary among them being the cost effectiveness of the upgrade, but also based upon regional market availability and administrative feasibility, just to name a few. Further elaboration on the current portfolio of offerings will be housed in the Conservation Plan, as will discussions on potential additions to the existing portfolio and options for increasing incentive levels to improve uptake, although these aspects will be touched upon in this IRP.

DSM Incorporation into the IRP

One of the elements noted as a priority for this 2016 IRP by the Company's CAG, and the Commission, was a desire to more thoroughly integrate the elements of the Company's DSM programs into the full IRP planning process. The DSM section has habitually operated as a stand-alone process wherein the Company reduces consumption in the near term through the existing programs, and the conservation team then forecasts savings potential into the 20-year horizon at a state level. Once the savings potential forecasts are available at a statewide level those inputs are provided to the supply resource planning group in the final stages of the load forecast, where they are subtracted from the long-term load forecast.

When viewing overall supply requirements for the 20-year forecast, the impact from conservation and energy-efficiency efforts appears to have a modest impact. However, when approached from the standpoint that every therm saved is one less to acquire, the conservation programs have the opportunity to impact the Company's future planning. The Company approaches DSM planning to determine how it might increase its ability to reduce consumption and demand in the long term.

Pathways to Achieve Goals for the Next Ten Years

Combining DSM efforts into the Company's resource planning processes requires incorporating the savings goals from its Conservation Programs into its resource allocation planning, including load management. Future IRPs will have an expanded plan development approach that will allow for improved collaboration and alignment of conservation goals and traditional supply resource alternatives. The Company anticipates the 2018 IRP work plan will be expanded from the current eight month period to a fifteen month timeline, further enhancing opportunities to integrate DSM into the IRP.

Calendar Year 2016 has been a transition year for the Conservation Department as the Company set the stage to increase program accomplishments commensurate with the achievable potential indicated by the Nexant TEA-Pot model.[1] Significant steps have been taken to encourage a steady increase in program related activities with the associated development of improved administrative processes and additional internal staffing to set the groundwork for expansion of program savings into the next ten years.

[1] *See* subsection Analysis of the WA territory Assessment via the Technical Economic Achievable Potential Modeling Tool for further detail into the calculated Conservation potential.

For the past two years, the residential programs were delivered through a mix of third party implementation and internal program oversight. In an attempt to pursue a long-term, sustainable, affordable and simplified delivery model the Company began exploring internal program implementation options for its residential program in the summer of 2015 knowing the existing vendor contract would expire by the end of the year. Internal delivery provides the Company with greater oversight and management of the customer rebate experience, smoother and shorter rebate processing from start to finish, and direct control over data quality and data management – meaning tailored reporting and tracking ability.

The Company recognized that administrative funding and budgets for program implementation required greater funding. Specifically, expenses for administrative costs for delivery of the Cascade residential rebate programs were not adequate to cover the vendor's costs. Transitioning to an internal delivery model necessitated adding two additional internal staff to support residential rebate processing and trade ally management. This enhanced continuity and data management security in future years with the use of an internal software solution.

Recognizing the need for technical support of an internal delivery model, the Company submitted a proposal to obtain a software package to support rebate processing and allow customer submission via an online rebate portal. In mid-2015 Cascade contacted various software implementation companies to discuss cloud-based software for internal residential program delivery.

In late summer of 2015 the Company engaged in conversations with its Conservation Advisory Group (CAG) about proposed program delivery changes and advised it would release an RFP for software support. The software package vendor was chosen in November 2015 and work started immediately to customize the Nexant Inc. iDSM Central and iTrade Ally product to Cascade's needs. The program's residential delivery vendor (EGIA) agreed to continue processing residential rebates and working with the Company through the first few months of CY 2016 as their program delivery ramped down and the new software and commensurate internal delivery processes ramped up.

As the Company has spent the first ten months of 2016 delivering the residential programs, it has become apparent that internal implementation of the programs has allowed a greater insight into areas to improve the experience for the customer. The easier the process to apply, the more likely the customer is to recall the programs positively when making future home and business energy choices, and consequently the more likely to choose higher-efficiency upgrades. Cascade has thoroughly reviewed and revised its residential applications and program requirements to remove barriers while increasing ease of submission and maintaining program integrity. Improvements to the process include removal of the “Paid in full” requirement (which allows and encourages equipment financing when appropriate for the customer) as well as increased messaging to contractors to include all relevant install data on the invoice, negating the need for repeat data entry by the customer.

One additional item the Company has taken toward reaching the increased goals in the next ten years is recognition of the improvements to the program in reviewing and processing applications with missing data – thereby reducing the amount of “Disqualified” applicants (DNQ’d). The last estimate was a reduction of nearly 66% of the previously DNQ’d projects, which could reflect the reality that two-thirds of the projects previously disqualified between May 2013 and January 2016 could have been approved if some additional follow-up had been performed. Previously, the vendor administering the residential programs did not allocate adequate resources toward project follow-up, resulting in a significant portion of the residential rebates sitting in limbo awaiting additional data from either contractors or customers to allow the program to either approve or disqualify the submissions. While it is important to acknowledge the onus is ultimately on the customer to provide all required data, it’s also important to contribute to their success and help with what can be a confusing application process (when feasible within administrative budgetary constraints).

Upon transition of the existing files to the Company it was determined that a significant portion of the pending applications could be processed and approved if additional administrative time was allocated to the process. While this effort did require a significant amount of time and effort from the internal team to resolve the missing data projects, and unfortunately caused a backlog of newer projects in the process, it has allowed the program to more accurately portray savings associated with equipment and weatherization measures that had already been installed and should be counted toward the program achievements.

During the residential program transition planning phase the Company also began to alter a few key elements of the program administration to increase the timeliness of reporting related to program accomplishments. Supporting the capacity to create a timelier snapshot of current program accomplishments would allow the Company to more nimbly pivot efforts as the need arose and better enable the Company to react to market trends in building construction and efficiency. One of the elements explored was altering the reporting methodology from tracking per paid date versus install date.

Historically the Company tracked rebate submissions by the date the measure or upgrade was installed at the premise. CAG members requested the Company pursue tracking via the date a rebate was paid rather than the previous install date method to help reduce lag-time in reporting savings. The Company agreed to transition the program reporting model to track savings based on the date the rebate was paid, which makes annual reporting more straightforward and allows Cascade to accommodate the earlier submission deadline of June 1st to the Commission each year.

The Company also altered the requirement for submission of rebates to require their submission within 90 days of install (as opposed to previous requirements to submit by March 1st of the following year after install). The combination of these two changes should help the programs avoid the standard influx of rebate applications in the following year thereby enabling greater transparency into program accomplishments throughout the year.

As the tracking method was changing for 2015, the Company's annual report released in 2016 reporting 2015 savings showed a reflection of savings by paid date in calendar year (CY) 2015. A graph was included noting the variations for the first year of reporting in this manner and how it compared to the therm savings totals if tracked by install date for 2015.

All program updates and changes have an effect on the savings the Company is able to achieve. These changes allow Cascade staff to focus more time on implementing the program and looking toward future outreach opportunities to bring in additional savings.

Outside of the significant updates to the residential program in the past year aimed at achieving increased savings goals, Cascade also increased its administrative support for the commercial and industrial conservation incentive program. While the internal staff has been increasing efforts and support, Lockheed Martin, the Commercial program delivery vendor, has significantly increased its support of the program as well by performing additional outreach to commercial and industrial trade ally contractors, and implementing a marketing and outreach campaign to notify customers of available offers while highlighting success stories in the local communities to encourage additional uptake. This is an ongoing effort and is discussed further in this section. It's also relevant to note the increased support on the residential side internally from the Company, as well as investment in the internal software package, positions the commercial program for growth into the future in a variety of ways whether through the existing vendor or through a combination of more robust internal support paired with the expertise of the external vendor's experience and known achievements.

Where does Cascade need to go from here to reach its goals? The Company is focused on continuous improvement to reach its goals. The programs are constantly evolving to meet the Company needs, Commission directives, market changes, technological improvements, policy changes and a vast array of externalities.

As has been the case for the past year, the Company will complete its work with Nexant Inc. related to the software product for the remainder of 2016 and the first quarter of 2017. Once the product is fully functional (it is currently in use for the programs, but the reporting processes and trade ally functionality are still in development, as is the low income program element and the EM&V – or evaluation, measurement and verification portion) then the Company will use the advanced reporting ability to develop further plans on key areas of the territory to concentrate additional efforts.

One of the additional steps the Company is in the process of taking involves the low income weatherization incentive program alterations required as part of the recent settlement agreement in Docket UG-152286.[2] The Company is currently working with its CAG to alter Schedule 301 to increase customer assistance and participation through the Community Action Agencies for Cascade's most vulnerable customer base, hopefully having the ability to see an impact in program participation as early as this heating season.

General messaging and outreach will be increased to the local communities above and beyond existing levels to reach those customers who have yet to engage in the Conservation Incentive Programs (CIP). Cascade will also take the opportunity to partner with other utilities, and community programs, as appropriate and available, to promote a more widely understood goal toward high-efficiency uptake and energy conservation in its service territory.

Motivators

Multiple contributing factors motivate the Company to engage in DSM efforts. The conservation programs allow the Company a chance to demonstrate its commitment to responsible environmental stewardship along with a desire to assist its customers while ensuring customer satisfaction. If the Company encourages efficient and wise use of natural gas, customers not only receive the most value from their investment, but reduce their expenses in the future, thus setting the groundwork for future conscientious choices related to energy consumption.

[2] Washington Utilities and Transportation Commission Docket UG-152286 Order 4, Final Order Approving Settlement Agreement. Pages 3-4.

Additionally, the Company needs to meet the Washington Utilities and Transportation Commission's directives and settlement agreements including Docket UG-152286 whereby "The Parties state that the conservation commitments in the Settlement solidify the conservation efforts that Cascade is already undertaking and add structure and accountability."[3]

Another contributing factor stems from state and federal policy and possible future greenhouse gas emissions parameters as discussed in Section 5, Environmental Considerations.

Lastly, the Company recently received approval to implement a decoupling mechanism in Washington. This allows the Company to "decouple" or disassociate recovery of its revenue requirement with volumetric gas sales. As gas sales fluctuate up or down due to conservation or weather, the decoupling mechanism ensures the Company will recover the costs it needs to do business, making it indifferent to conservation. The Company was already committed to its conservation programs prior to the approval of the decoupling mechanism (and previously had decoupling in Washington), but it further cements the Company's ability to support and grow its Conservation Incentive Programs.

Progress Report – Where Cascade is Going and Where Cascade has Been

As mentioned earlier in the section, this IRP and its relation to the Company's DSM efforts represents a slightly altered approach to resource planning with a concerted effort made toward incorporation of the conservation efforts as a true resource toward planning to meet future demand. From a pragmatic perspective, the format of the DSM section in this document is different from past submissions in that it represents a transition to an executive summary versus the full conservation planning document. This IRP also attempts to add a level of transparency and granularity to the Company's planning process since the conservation potential for this IRP is calculated through the Nexant TEA-Pot model separated into three different areas and savings assumptions (heat-sensitive resources have different savings potential by area) by reviewing them at the climate zone level. Further elaboration is provided below on this process. These inputs at the zonal level are provided by resource planning and are integrated into the forecast model.

Company therm savings achievements for the past two years compared to the 2012 IRP and the 2014 IRP goals are in Table 7-1 inclusive of the next two years' worth of goals (2017 and 2018) to demonstrate what the Company is striving toward in the near future. Totals for 2016 accomplishments will not be available until the annual report is filed in June 2017.

[3] IBID.

Table 7-1: Recent IRP Goal to Actual Therm Accomplishments

	Year	Goal	Actual	Difference
2012 IRP	2013	510,511	471,431	**-8%**
	2014	566,150	641,615	**13%**
2014 IRP	2015	584,449	831,501	**42%**
	2016	620,020	Not yet available	Not yet available
2016 IRP	2017	839,876		
	2018	891,574		

See Table 7-2 for the goals and budgets for 2017 & 2018 for reference. These were used in development of the 2017 Conservation Plan.

Table 7-2: Program Goals & Budgets at a Glance 2017 & 2018

	Calendar Year 2017				Calendar Year 2018			
	Residential	Commercial Industrial	Low Income[3]	Total	Residential	Commercial Industrial	Low Income[3]	Total
Admin Budget[1]	$550,000	$1,000,000	$8,911	$1,558,911	$566,500	$1,030,000	$8,911	$1,605,411
Therm Targets[2]	323,878	515,998	15,000	854,876	331,357	545,217	15,000	891,574
NEEA Natural Gas Market Transformation				$313,174				$452,285

The Nexant study estimated energy efficiency savings developed into three types of potential: technical potential, economic potential, and achievable potential. Market penetration rates associated with each potential were estimated and included in this assessment. Nexant analyzed this potential via a customized tool based from a Microsoft Excel-based modeling tool, TEA-Pot for the Cascade conservation potential assessment. This modeling tool was built on a platform that provides the ability to run multiple scenarios and re-calculate potential savings based on variable inputs such as sales/load forecasts, natural gas prices, discount rates, and actual program savings. This model provides transparent assumptions and calculations for estimating market potential.

While technical and economic potential are both theoretical limits to efficiency savings, achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase. Cascade’s conservation program adopted the Achievable Potential to set goals under an array of possible future conditions.

The Company maintains the Achievable potential (with administrative costs included) will still be an *aspirational* goal (especially as it relates to the residential program) and believes it does not provide the same level of refinement to goal setting as can be performed at a program implementer level.

The following subsection elaborates on the methods used by the TEA-Pot model to develop the three levels of Potential for the programs and subsequent creation of the Company's two-year short-term plan.

Industry standard cost effectiveness tests were performed to gauge the economic merits of the portfolio. Each test compared the benefits of the energy efficiency metric to their costs defined in terms of net present value of future cash flows.

Cascade applies the Utility Cost Test (UCT). The benefits of the UCT are the avoided energy costs and avoided capacity costs for the lifetime of the measure. The costs in this test are the program administrator's incentive costs and administrative costs.

Market Segmentation Findings

An important first step in calculating Cascade's energy efficiency potential estimates is to establish baseline energy usage characteristics and disaggregate the market by sector, segment, and end use.

It is important to recognize the Technical, Economic, and Achievable potential represented within Cascade's Washington service territory does not represent the "on-the-ground" conservation potential. Furthermore, the high-level screens provided in the Nexant report represent the savings potential available if <u>every cost-effective measure</u> identified under the Achievable screen could be integrated into the Company's conservation program portfolio. In other words, the summary pages of the study provide a high-level view into what would be *theoretically* possible.

It is not uncommon for a utility to set programmatic goals below achievable potential findings. Many utilities utilize potential studies to inform the direction of goals and help design programs to capture untapped end use/technology potential. In the most recent IRP the Company established a separate programmatic level of potential for a variety of reasons as referenced earlier, but primarily because administrative costs were not calculated into the program at the Achievable level through the TEA-Pot model. The Achievable potential also assumes savings are captured in all end uses in all market segments. It's rare for utilities to develop DSM programs that address all segments simultaneously as they tend to be more strategic in where they focus their resources.

As recognized by Nexant, a more nuanced approach is required in order for the Company to create a realistic portfolio of conservation measures that pass programmatic screening and offer realistic conservation benefits to customers.

Therefore, the Company treated the Base Case findings as a high-level assessment of potential, and then utilized the TEA-Pot model to create dynamic, focused portfolios and subsequent targets for use in the IRP and for program planning.

A summary of the program planning and TEA-Pot modeling scenarios used by the Company for its Conservation Incentive Program portfolio in the 2016 IRP is included here. Figure 7-1 provides a visual representation of the process of narrowing down potential from the Technical potential level to the Achievable level employed by the Company.

Figure 7-1: Savings Potential Process

Technical Potential
Technical Potential represents a substitution by the end user of all *technically* feasible measures at the end use level.

Economic Potential
Economic considers the most efficient measures that pass *economic* screening tests and is a subset of Technical Potential.

Achievable Potential
Achievable embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase to simulate a realistic estimate of real-life conditions.

TEA-Pot provides the Company with a much more nuanced and manageable method to developing its portfolio than was used in the past.

The Company's objectives in developing its rebate offerings center on the desire to:

1. Maximize the inclusiveness of viable, industry-acknowledged conservation measures.
2. Maintain incentive levels that send meaningful price signals to consumers to upgrade to high-efficiency natural gas equipment and energy saving measures.

3. Remain cost effective at the Company's most recently acknowledged avoided costs.

Cascade set an administrative budget in order to plan and operate programs. This budget must ensure an acceptable ratio of costs balanced with therm savings achievements. Since therm savings offset the costs of administrative investment, the greater the achievement, the more cost-effective the programs. If the budget or therm savings upon which the portfolio is built are unrealistic, the Company risks developing a scale-dependent portfolio unable to maintain cost effectiveness.

Target Development

TEA-Pot generated targets will be acknowledged in the conservation plan as *aspirational* targets and those Cascade will aggressively strive towards throughout the year. However, the programs will be built in a way that ensures cost-effectiveness can be maintained even if the Company falls short of that target.

Below is a brief list of what has been altered in this iteration of the conservation forecast from previous IRP submissions:

- Divided Demand Side Management forecast into Climate Zones instead of Statewide;
- Incorporated Administrative Costs into the model so that the Achievable forecast yields more realistic results;
- Aligned the long-term discount rate across the IRP;
- Updated all model inputs, which are discussed in depth below, under the Technical Economic Achievable Potential Modeling tool subsection;
- Included all measures over the full forecast, as noted in the 2014 IRP (page 57 of the DSM section) reviewed in Nexant's 2014 Conservation Potential Study in both the Residential and Commercial/Industrial modeling. Commercial/Industrial program's prescriptive measures and custom projects would fully be recognized, while allowing for a first quarter of 2017 comprehensive discussion with the CAG to explore changes to the residential conservation incentive program's offerings; and
- Split all measures for each customer class between the 30% and 50% of incremental costs rebate levels in order to maximize uptake and thereby increase therm savings potential over the forecast.

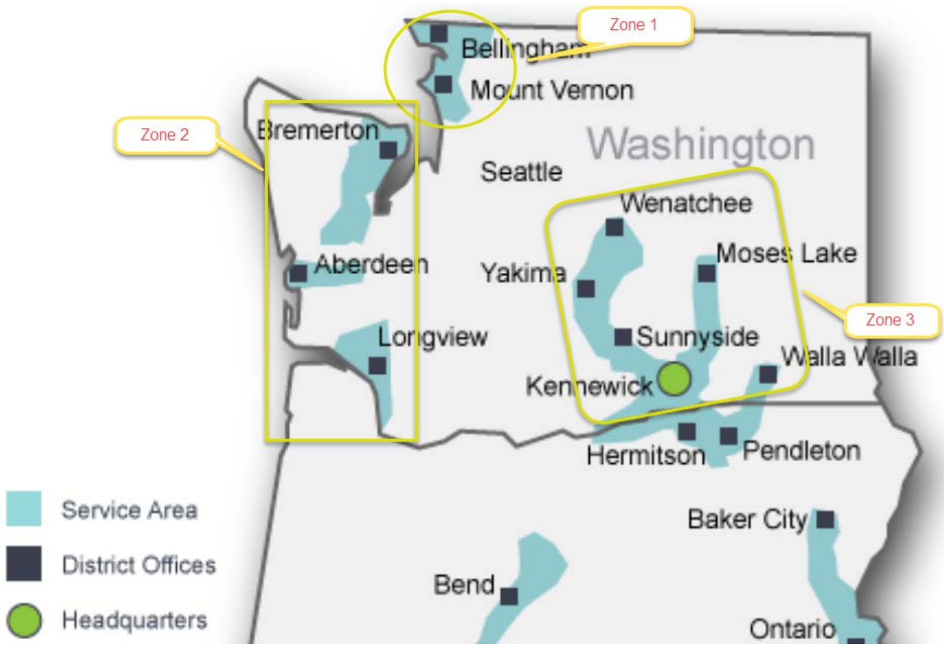
Conservation Potential

In the following subsections, the Company will elaborate on its modeling processes, modeling tool and provide an analysis of the future potential as well as opportunities for increased participation and briefly discuss some of the steps to aim for the achievable goals.

Climate Zone Centered Modeling

For the first time, the Conservation Forecast was run at the Climate Zone level of granularity instead of statewide. See Figure 7-2 for a visual representation of the CIP Climate Zones. By tailoring the inputs, each of the three Climate Zones was able to reflect its technical, economic and achievable potential individually. This will allow program administrators to tailor outreach to specific, potentially underperforming areas and mimic other areas' successful marketing campaigns that have surpassed their potential.

Figure 7-2: Cascade Conservation Climate Zones



The unique inputs used were customer count and volume growth rate forecasts by customer class, Residential, Commercial, and Industrial, and the avoided costs. These are shown in Table 7-3. All other factors were held constant across each Climate Zone's scenario, such as the inflation rate, long-term discount rate, load profile, transmission loss rate, cost effectiveness threshold, which measures were left at the 30% of incremental costs incentive level or bumped to the 50% level, and the administrative levelized costs per therm. All factors of the model, as well as other changes introduced for the first time in this year's IRP, are discussed further in-depth in the following TEA-Pot Modeling tool subsection.

Table 7-3: Unique Inputs per Climate Zone

Unique Climate Zone Scenario Inputs			
Factors	**CZ1**	**CZ2**	**CZ3**
Avoided Costs	\$0.5428 to \$0.784944	\$0.4940 to \$0.714911	\$0.5229 to \$0.735016
Residential Volume Forecast	57M-72M therms	26M-31M therms	39M-47M therms
Residential Customer Forecast	81,754-103,021	38,136-46,337	63,495-76,345
Commercial Volume Forecast	31M-42M therms	20M-26M therms	43M-56M therms
Commercial Customer Forecast	10,037-13,565	5,000-6,406	11,173-14,431
Industrial Volume Forecast	2.9M-3.2M therms	3.2M-3.9M therms	11M-13M therms
Industrial Customer Forecast	176-191	66-69	224-245
Note: See Appendix D, Demand Side Management, for full list of measures by Climate Zone and by market segment included as unique inputs.			

The results of both the Residential and Commercial/Industrial Incentive Programs' Climate Zone level potential are summarized in Figures 7-3 through 7-6.

Figure 7-3: Zone 1 Achievable Conservation Forecast Potential by Customer Class

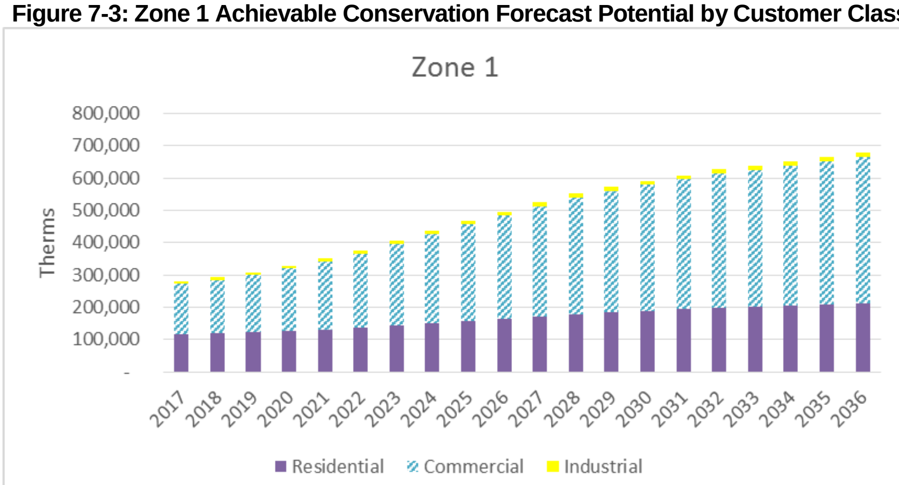


Figure 7-4: Zone 2 Achievable Conservation Forecast Potential by Customer Class

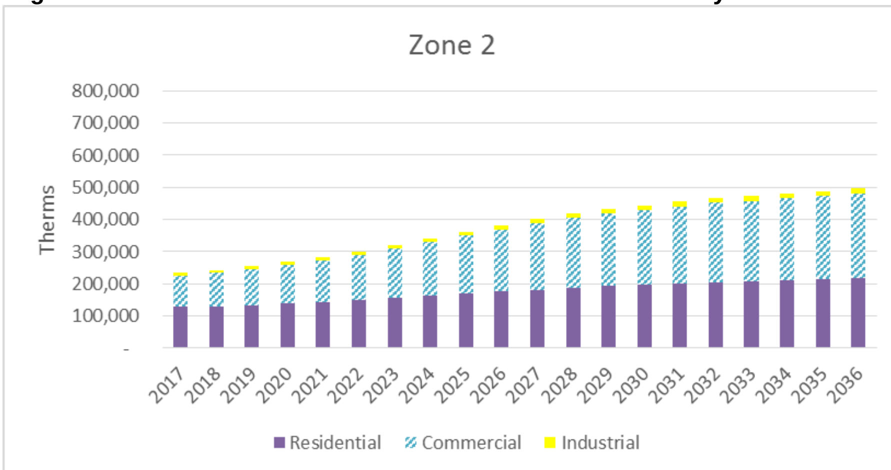
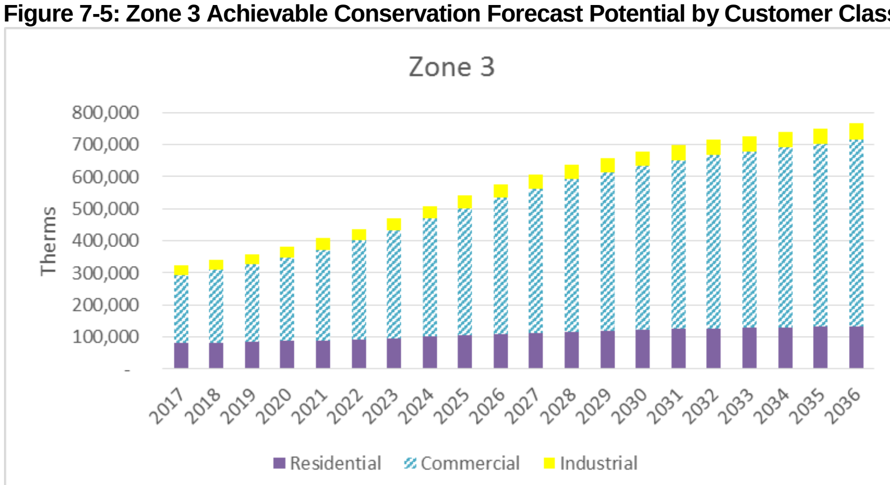


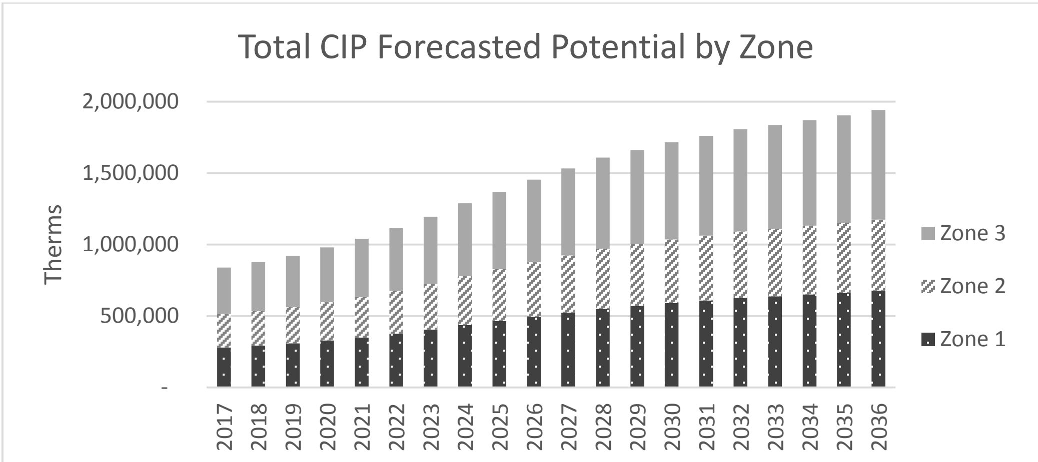
Figure 7-5: Zone 3 Achievable Conservation Forecast Potential by Customer Class



One interesting piece about Climate Zone 3's forecast is the Industrial customer class' highest potential. Large Industrial customers' projects are not available every year, but when they are, they have a large impact on the Commercial & Industrial programs' annual achievements and full program portfolio's cost effectiveness.

The Total CIP Forecasted Potential by Zone Figure 7-6 demonstrates Climate Zone 2's lower potential compared to Climate Zones 1 and 3. The reason is its significantly lower customer counts and volume inputs, which are partially offset by the lowest avoided costs in both the near and long-term time horizons.

Figure 7-6: Total CIP Forecasted Potential by Zone



Assessing Future Potential: Analysis of the WA Territory Assessment via the Technical Economic Achievable Potential Modeling Tool

Cascade hired Nexant to produce a Conservation Potential Study and TEA-Pot model in 2013. Nexant also performed a selection of EM&V in the final report released at the beginning of 2014. The study's analysis was based on the calendar year 2012 and was tailored to Cascade's distinct service territory.

Since then, Cascade has returned to Nexant to update the TEA-Pot model. Most noteworthy was the unlocking of administrative costs for incorporation into the model in order to allow the forecasted achievable level to more accurately reflect the programs' realistic therm savings potential.

Cascade utilizes the UCT screen to measure the program's cost effectiveness. The UCT Test is the optimal vehicle for valuation of these measures since it is a straightforward and clean calculation of the utility's investment in DSM and does not penalize customers for making independent determinations regarding the cost-benefit of an energy efficiency upgrade. The UCT instead treats the rebate from utility run natural gas efficiency programs as a leveraged partnership that drives positive market change and the installation of measures with the potential for long-lived and deeper energy savings.

Cascade's methodology has also changed in two key ways. First, on the Commercial and Industrial side of the program, all measures from the study are used for all years of the time horizon instead of prescriptive only measures offered under the current tariff in place at the time of writing. This accounts for capturing the savings inherent in the custom project avenue, in addition to the prescriptive measure offerings, accurately without applying a subjective percentage (based on historic performance) of custom project therm savings on top of the simulated savings. Second, for both the residential and commercial/industrial programs, measures deemed cost effective at the 50% level of incremental costs were run through the model at the higher incentive level. A higher incentive level yields a higher adoption curve because installation of the measure becomes more cost effective and thus more appealing to participants. In return, a higher level of potential therm savings becomes possible. A full list of included measures' cost effectiveness and incentive levels by customer class are available in Appendix D, Demand Side Management.

Below is a summary of the other model inputs, updated from the last IRP:

- Inflation rate decreased from 2.00% to 1.00% and is in line with the remainder of the IRP. It was also applied to the administrative costs per levelized therm by end use, based on 2015 Annual Report achievements. Thus, the decrease in inflation rate helped decrease the long-term administrative costs' forecast, and brought down the overall costs needed to acquire therm savings, thereby increasing the benefit-cost ratios for measures to pass cost-effectiveness.
- Transmission Loss rate decreased from 0.1959% to 0.1348%
- Long-term discount rate decreased from 4.17% to 3.52%, aligned with the rest of the IRP sections' models. The lower the long-term discount rate, the higher the therm savings potential because future years' therm savings' avoided cost values are discounted less, and thus more of the avoided costs can be included, thereby allowing the benefit-cost ratios for measures to pass the 0.90 cost-effectiveness threshold.
- Administrative costs increased, as discussed on page 7-5, to bring the residential program administration in- house, thereby increasing accuracy of reporting and improving control of the customers' rebate processing experiences. It also allowed expansion of commercial and industrial CIP outreach. The 2017 budget was set at $550,000 for the Residential program and $1 million for the Commercial/Industrial program to accommodate the additional outreach efforts. While this may appear to have a negative impact on the benefit-cost ratio for each measure, and raises the costs needed to acquire therm savings, it is necessary to accommodate higher therm savings goals.
- Avoided costs were updated per Appendix H, Avoided Cost Calculations, and divided by climate zone. The higher the avoided costs, the higher the therm savings potential because avoided costs under the UCT increase the benefit-cost ratio to allow more measures to be considered cost-effective. Conversely, the lower the avoided costs, the lower the therm savings potential forecasted.
- Load profile system-wide and customers and volume, divided by climate zone were updated per Section 3, Demand Forecast.

Nexant's model provides three levels of potential: Technical, Economic, and Achievable.

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.

Economic Potential: Is developed from the most efficient measures that pass economic screening tests and are a subset of technical potential. Because measure cost effectiveness differs by climate zone, market segmentation, and vintage, Cascade implements a 0.90 cost-effectiveness threshold in order to be able to include the largest breadth of measures feasible.

The Company uses two adoption curves to decrement economic potential to achievable potential. It applies a base adoption curve to represent potential customer uptake at the 30% of incremental costs incentive level that is S-shaped and reaches its maximum of 50% at the end of the 20-year time horizon. For measures deemed cost-effective enough to be able to afford to be bumped up to the 50% incentive level of incremental costs, the Company chooses a moderate adoption curve to reflect the additional uptake that increasing the incentive amounts is expected to incur, leveling out at the end of the 20-year time horizon around 70%. Using the final forecasts, the Company builds an outreach plan around the goal of reaching all customers, across the service territory, in order to cost-effectively maximize awareness and spur participation.

Achievable Potential: Embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase to simulate a realistic estimate of real-life conditions.

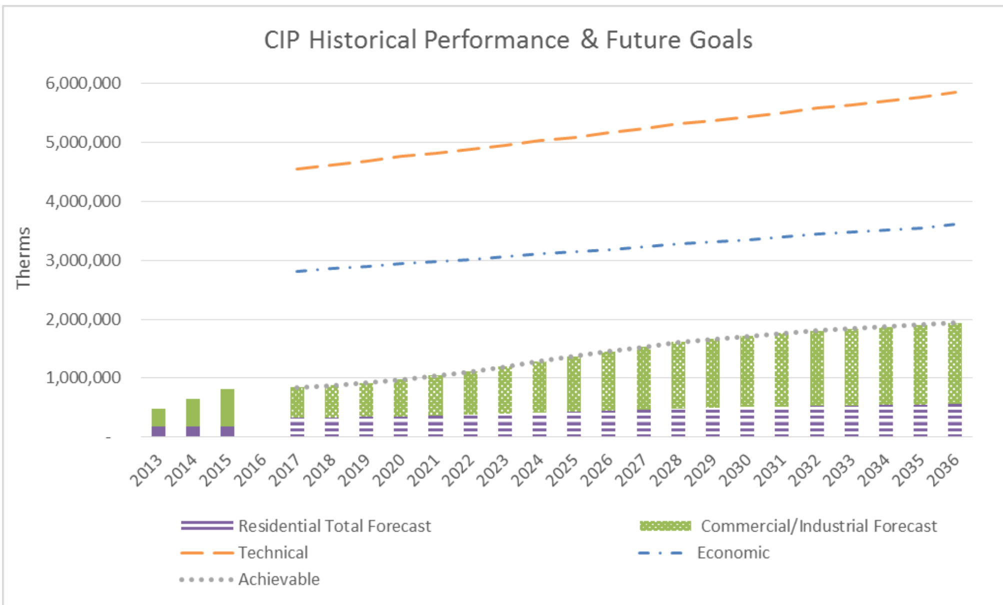
The 20-year horizon of the proportion of Achievable potential filtered from the Economic Potential can be viewed in Table 7-4.

Table 7-4: Achievable Proportion of Economic Potential

Achievable Proportion of Economic Potential (Therms)		
Year	**Economic**	**Achievable**
2017	2,815,454	30%
2018	2,858,324	31%
2019	2,896,840	33%
2020	2,948,056	34%
2021	2,977,179	36%
2022	3,018,791	38%
2023	3,060,537	40%
2024	3,115,644	42%
2025	3,145,133	44%
2026	3,187,846	46%
2027	3,229,479	48%
2028	3,229,479	51%
2029	3,229,479	52%
2030	3,229,479	54%
2031	3,229,479	55%
2032	3,229,479	57%
2033	3,229,479	58%
2034	3,229,479	59%
2035	3,229,479	60%
2036	3,229,479	61%

The model was run individually by Climate Zone in order to provide increased granularity. The outcomes shown are by Climate Zone, whereas the summary of the model's output (Figure 7-7) combines Technical, Economic, and Achievable therm savings potentials, in addition to the past three years' programs' performance for perspective. Figures for 2016 are not available at the time of this writing because the program year has not ended, January 1, 2016 through December 31, 2016. Further breakdown of these numbers can be found in Appendix D, Demand Side Management.

Figure 7-7: Technical, Economic, Achievable 20-year Potential Snapshot



The following Tables, 7-5 through 7-8, demonstrate the total baseline projection of savings compared to the total achievable, economic and technical potential. They also represent cumulative savings as a percent of baseline for the Washington Cascade territory for the next 20 years.

Table 7-5: Total Forecast Comparison to Baseline by Potential Screen

Totals Forecasts Comparison (Therms)						
Year	**Baseline**	**Technical**	**Economic**	**Achievable**	**Low Income**	**Total Achievable**
2017	232,414,950	4,552,099	2,815,454	839,876	15,000	854,876
2018	235,577,228	4,622,799	2,858,324	876,574	15,000	891,574
2019	238,716,713	4,686,406	2,896,840	921,441	25,000	946,441
2020	242,854,393	4,769,664	2,948,056	979,599	25,000	1,004,599
2021	244,965,630	4,817,844	2,977,179	1,039,878	25,000	1,064,878
2022	248,096,580	4,886,307	3,018,791	1,113,877	25,000	1,138,877
2023	251,234,573	4,954,176	3,060,537	1,195,669	25,000	1,220,669
2024	255,448,260	5,044,322	3,115,644	1,287,472	25,000	1,312,472
2025	257,546,271	5,093,061	3,145,133	1,369,370	25,000	1,394,370
2026	260,716,343	5,163,110	3,187,846	1,453,596	25,000	1,478,596
2027	263,898,367	5,231,124	3,229,479	1,531,149	25,000	1,556,149
2028	268,200,108	5,323,281	3,285,965	1,608,109	25,000	1,633,109
2029	270,278,862	5,369,238	3,313,850	1,662,601	25,000	1,687,601
2030	273,476,011	5,437,697	3,355,253	1,715,853	25,000	1,740,853
2031	276,664,014	5,503,930	3,395,364	1,761,343	25,000	1,786,343
2032	281,006,139	5,592,090	3,449,201	1,808,177	25,000	1,833,177
2033	282,990,679	5,634,670	3,474,518	1,835,577	25,000	1,860,577
2034	286,128,518	5,701,664	3,515,157	1,870,829	25,000	1,895,829
2035	289,256,438	5,765,748	3,553,879	1,902,851	25,000	1,927,851
2036	293,590,373	5,863,812	3,614,278	1,941,272	25,000	1,966,272

Table 7-6: Cumulative Forecast Comparison to Baseline by Potential Screen

Cumulative Totals Forecasts Comparison (Therms)						
Year	Baseline	Technical	Economic	Achievable	Low Income	Total Achievable
2017	232,414,950	4,552,099	2,815,454	839,876	15,000	854,876
2018	235,577,228	9,174,898	5,673,778	1,716,450	30,000	1,746,450
2019	238,716,713	13,861,303	8,570,618	2,637,891	55,000	2,692,891
2020	242,854,393	18,630,968	11,518,674	3,617,490	80,000	3,697,490
2021	244,965,630	23,448,811	14,495,853	4,657,368	105,000	4,762,368
2022	248,096,580	28,335,118	17,514,644	5,771,245	130,000	5,901,245
2023	251,234,573	33,289,294	20,575,181	6,966,914	155,000	7,121,914
2024	255,448,260	38,333,616	23,690,826	8,254,385	180,000	8,434,385
2025	257,546,271	43,426,676	26,835,959	9,623,755	205,000	9,828,755
2026	260,716,343	48,589,787	30,023,805	11,077,351	230,000	11,307,351
2027	263,898,367	53,820,911	33,253,284	12,608,500	255,000	12,863,500
2028	263,898,368	59,144,192	36,539,249	14,216,609	280,000	14,496,609
2029	263,898,369	64,513,430	39,853,099	15,879,210	305,000	16,184,210
2030	263,898,370	69,951,126	43,208,352	17,595,063	330,000	17,925,063
2031	263,898,371	75,455,056	46,603,717	19,356,407	355,000	19,711,407
2032	263,898,372	81,047,146	50,052,918	21,164,583	380,000	21,544,583
2033	263,898,373	86,681,817	53,527,436	23,000,160	405,000	23,405,160
2034	263,898,374	92,383,481	57,042,593	24,870,989	430,000	25,300,989
2035	263,898,375	98,149,229	60,596,472	26,773,840	455,000	27,228,840
2036	263,898,376	104,013,041	64,210,750	28,715,113	480,000	29,195,113

Table 7-7: Total Forecast Comparison as Percent of Annual Baseline by Potential Screen

Totals Forecasts Comparison (Percent of Annual Forecasted Baseline Therms)						
Year	**Baseline**	**Technical**	**Economic**	**Achievable**	**Low Income**	**Total Achievable**
2017	232,414,950	1.96%	1.21%	0.36%	0.01%	0.37%
2018	235,577,228	1.96%	1.21%	0.37%	0.01%	0.38%
2019	238,716,713	1.96%	1.21%	0.39%	0.01%	0.40%
2020	242,854,393	1.96%	1.21%	0.40%	0.01%	0.41%
2021	244,965,630	1.97%	1.22%	0.42%	0.01%	0.43%
2022	248,096,580	1.97%	1.22%	0.45%	0.01%	0.46%
2023	251,234,573	1.97%	1.22%	0.48%	0.01%	0.49%
2024	255,448,260	1.97%	1.22%	0.50%	0.01%	0.51%
2025	257,546,271	1.98%	1.22%	0.53%	0.01%	0.54%
2026	260,716,343	1.98%	1.22%	0.56%	0.01%	0.57%
2027	263,898,367	1.98%	1.22%	0.58%	0.01%	0.59%
2028	268,200,108	1.98%	1.23%	0.60%	0.01%	0.61%
2029	270,278,862	1.99%	1.23%	0.62%	0.01%	0.62%
2030	273,476,011	1.99%	1.23%	0.63%	0.01%	0.64%
2031	276,664,014	1.99%	1.23%	0.64%	0.01%	0.65%
2032	281,006,139	1.99%	1.23%	0.64%	0.01%	0.65%
2033	282,990,679	1.99%	1.23%	0.65%	0.01%	0.66%
2034	286,128,518	1.99%	1.23%	0.65%	0.01%	0.66%
2035	289,256,438	1.99%	1.23%	0.66%	0.01%	0.67%
2036	293,590,373	2.00%	1.23%	0.66%	0.01%	0.67%

Table 7-8: Cumulative Forecast Comparison as Percent of Annual Baseline by Potential Screen

Cumulative Total Forecast (Percent of Annual Forecasted Baseline Therms)						
Year	**Baseline**	**Technical**	**Economic**	**Achievable**	**Low Income**	**Total Achievable**
2017	232,414,950	1.96%	1.21%	0.36%	0.01%	0.37%
2018	235,577,228	3.89%	2.41%	0.73%	0.01%	0.74%
2019	238,716,713	5.81%	3.59%	1.11%	0.02%	1.13%
2020	242,854,393	7.67%	4.74%	1.49%	0.03%	1.52%
2021	244,965,630	9.57%	5.92%	1.90%	0.04%	1.94%
2022	248,096,580	11.42%	7.06%	2.33%	0.05%	2.38%
2023	251,234,573	13.25%	8.19%	2.77%	0.06%	2.83%
2024	255,448,260	15.01%	9.27%	3.23%	0.07%	3.30%
2025	257,546,271	16.86%	10.42%	3.74%	0.08%	3.82%
2026	260,716,343	18.64%	11.52%	4.25%	0.09%	4.34%
2027	263,898,367	20.39%	12.60%	4.78%	0.10%	4.87%
2028	268,200,108	22.05%	13.62%	5.30%	0.10%	5.41%
2029	270,278,862	23.87%	14.75%	5.88%	0.11%	5.99%
2030	273,476,011	25.58%	15.80%	6.43%	0.12%	6.55%
2031	276,664,014	27.27%	16.84%	7.00%	0.13%	7.12%
2032	281,006,139	28.84%	17.81%	7.53%	0.14%	7.67%
2033	282,990,679	30.63%	18.91%	8.13%	0.14%	8.27%
2034	286,128,518	32.29%	19.94%	8.69%	0.15%	8.84%
2035	289,256,438	33.93%	20.95%	9.26%	0.16%	9.41%
2036	293,590,373	35.43%	21.87%	9.78%	0.16%	9.94%

Conservation Two-Year Action Plan

Based on the stated potential and goals for the Conservation Incentive Programs, the Company will be centering on a few areas as part of a two-year action plan leading into the long-term program goals.

- Increase incentives to a level that maintains the cost effectiveness of the programs but increases program uptake commensurate with customers receiving additional funds for their efforts (going beyond 30% levels where appropriate.)
  - This will be accomplished by having run the TEA-Pot modeling tool with varying levels of 30% and 50% incentives dependent on individual measures.
  - Propose updates by the end of Q1 2017.

  - Updates will be discussed with the CAG.
- Explore the full breadth of measures included in the Nexant model for inclusion into the Company's portfolio of measures.
  - Currently the full breadth of cost-effective commercial and industrial measures in the study are included under the "Custom" option for the Cascade CIP. The Company will review the equipment and non-equipment measures on a regular basis for potential inclusion into the portfolio, keeping in mind cost-effectiveness (based on current avoided costs), and administrative cost parameters, on-the-ground realities, and changes in technology and the potential for market transformation in the territory.
- Increase engagement in the Northwest Energy Efficiency Alliance (NEEA) Natural Gas Market Transformation Collaborative over the next two years with a focus on Cascade's territory and viable increases in availability of the pilot efforts (including the high-efficiency commercial rooftop unit).
  - In 2017 engage fully with the Gas Technology Institute Emerging Technologies group through the NEEA membership to explore new technology opportunities.
  - The Company will also leverage its collaborative membership beginning in Q3 2017 and into 2018 by exploring the study possibilities related to the residential and commercial building stock assessments created by NEEA. These studies can provide a snapshot of specific stock and can tell about gas service percentages in portions of the Company's territory where they overlap with electric providers who engage with NEEA, although there is no gas metering data. NEEA has offered to provide some recommendations and assistance with exploring what else from the data can be extrapolated specific to Cascade as a gas utility. The Company had a service territory specific potential study performed by Nexant Inc. in 2013/2014 which incorporated similar data to the NEEA information. There is opportunity for the Company to explore updating the individualized potential study in the latter half of 2018 if deemed necessary.[4]
- Work with Nexant Inc. throughout Q1 and into Q2 2017 to fine tune reporting availability for EM&V related tracking through iDSM platform.

While addressing the conservation two-year action plan, the Company will consistently monitor the state of natural gas conservation technologies within its service territory and make adjustments commensurate with evolving ENERGY STAR® standards and code requirements. In line with these efforts the Company in October 2016 updated its offerings to remove an upgrade to a 95% efficient furnace for the whole home ENERGY STAR® incentive to align with altered ENERGY STAR® standards and added the Demand Control Ventilation measure to its commercial offerings as noted in the 2016 Conservation Plan.

[4] *See* the Cascade Natural Gas Corporation Assessment of Achievable Potential & Program Evaluation Volumes 1-3 dated February 25, 2014.

The Company is also monitoring the residential natural gas furnace code standards as well as water heater criteria and will alter the program offerings as standards and building codes change in the next few years.

Paths to Increase Conservation Forecast Precision

The Energy Efficiency and Outreach Department at Cascade is exploring opportunities to increase precision of the Demand Side Management forecasting. Examples include:

- Update the building stock used in the TEA-Pot model's market segmentation and end use to reflect potentially changing trends over the last five years, such as by using NEEA's study mentioned above.
- Update the incremental costs based on Nexant's EM&V portion of the current Residential software packaging contract. Recognizing prices have likely changed since the 2012 figures, Cascade ensured the 2015 Request for Proposal included EM&V and has since worked closely with the software developers to build a system that captures the costs associated with installing the measures offered. Further analysis will require surveying Cascade's service territories to determine accurate installation pricing for standard models before the incremental costs can be recalculated based on collected data on the customers' applications and their invoices.
- Discussing with the CAG during the first quarter of 2017, which measures in the full Nexant portfolio are viable considering the customer base, costs to install versus rebate amounts able to be offered, and contractors available for installation with adequate knowledge, experience, and licensing. Considerations must be made for Cascade's unique service territory which includes areas that are sparsely populated and remote, and, therefore, lack an adequate market for contractor availability.
- Exploring ways of recalculating the Administrative Costs per therm by Climate Zone instead of a flat average. This could include weighting by premise count or throughput or by past annual conservation achievements, for example.

Importance of Outreach and Increased Messaging

One of the steps the Company is engaging in to increase its savings achievements toward its potential is to commit more fully in outreach and community engagement. There is a direct link between customer participation and service territory message saturation. The energy efficiency department consistently reaches out to the Company's customers through the following means:

- Bill inserts to all qualifying Washington rate schedule customers;

- Radio campaigns in select territories to promote the CIP and general low cost/no cost options for reducing natural gas consumption;
- Leveraged messaging with community organizations and other utilities as applicable;
- Community project engagement;
- Home Builder's Association directories, Tours of Homes and Home and Garden Show participation;
- Business Exposition tabling and exhibition; and
- Targeted direct mail efforts.

In addition to the standard practices above, the Company notes where additional efforts that are above and beyond standard messaging are underway to help increase program uptake in the near future.

Community Energy Program Partnerships

Cascade has partnered with local community based energy programs for years to both support their reduction accomplishments and leverage the opportunity to provide messaging about the CIP to the general public. A few of the programs the Company has directly supported include Sustainable Connections, Sustainable Living Center and the Community Energy Challenge.

Additional support efforts for the past two years have included assisting three of the local Washington service territory towns (Bellingham, Walla Walla, and Anacortes) with their engagement in the Georgetown University Energy Prize Competition – which promotes the goal to raise awareness of energy-efficiency in communities by local governments, communities and utilities working together to develop and implement plans for innovative, replicable, scalable, and continual reductions in their per capita energy consumption from both natural gas and electric providers. Cascade has served as an integral part in these efforts including helping the Georgetown group develop the data management and release processes for the national prize competition, meeting all data release requirements associated with the efforts and has worked with each of the towns to assist with their unique efforts as applicable.

In line with the Company's commitment to community engagement and the desire to increase awareness of its conservation programs, Cascade's staff has also partnered with the Western Washington University Institute for Energy Studies to provide guest lectures on DSM and conservation in CY 2015 and CY 2016 and has fully supported and engaged with the Women in Energy Mentoring Network.

Regional Efforts and Long-Term Benefits

The efforts relating to community engagement in tandem with regional efforts like the NEEA Natural Gas Market Transformation Collaborative have longstanding effects on future savings accomplishments. As mentioned previously, the Company has elected to partner through NEEA with other gas utilities in the region to engage in the first Regional Gas Market Transformation Collaborative in the nation. The goal is to increase market adoption of energy-efficient natural gas products and practices in the future. As part of the project the Collaborative pilots five distinct technologies by increasing their uptake and availability in the joint service territories to improve cost effectiveness of these natural gas technologies. The five-year effort began in 2015 and should result in increased savings, if not immediately, then as the technology is adapted and uptake increases in future years. Company investment in the Collaborative is shown in Table 7-9.

Table 7-9: Cascade NEEA Collaborative Funding Commitment

Year	Cascade's Washington Commitment at 9.3% of total budget for five-year pilot
2015	$145,848
2016	$244,956
2017	$313,122
2018	$452,211
2019	$548,712
Total	$1,704,849

Targeted Outreach

The CIP has identified some areas below where it will be targeting outreach activities into CY 2017. These potential audiences offer a new opportunity for efficiency messaging and continued partnerships.

Cascade will increase its direct outreach and program material availability to the Hispanic speaking Community housed within its service territory. Review of the service territory has indicated a need to provide more tailored program materials readily accessible to this community as well as in person presentations to explain program offerings and provide general support.

The Company plans to tailor presentations and messaging to the real-estate community as many customers seeking to purchase a home are best able to consider efficiency upgrades in line with that new home purchase or sale. Along with the real-estate outreach, the program will engage in conversations and provide program materials to the banking community within the towns (namely the property loan departments) as financing of homes allows for an opportunity to tailor messages relevant to efficiency when the purchaser is thinking of overall costs of home ownership and future expenses.

Another element of program outreach involves messaging up the value chain to trade allies and contractors – those individuals who are in the home with the customers and are helping them make the decision whether or not to install high-efficiency or standard efficiency equipment. The program has always worked within a TA network, but the purchase and availability of the iTrade Ally software through Nexant Inc., in collaboration with internal coordination of the TA program by Company staff who are both familiar with the programs and have the technical expertise, will greatly increase the program's reach and acceptance by trade allies. The Company is also working through its Commercial and Industrial delivery vendor to create a second tier of trade allies uniquely poised to work with the commercial and industrial customers in helping to promote higher-efficiency commercial installs, in addition to increased engagements with manufacturers.

Lockheed Martin is also on a path to increased program communications and marketing about the commercial and industrial CIP. Implemented as of mid-2016 and beyond the goal is to highlight customer success stories as samples of projects that other customers may wish to emulate and provide a well-reasoned and represented return on investment opportunity for high-efficiency upgrades to business owners. The Lockheed Martin team has placed program specific articles in chamber of commerce publications, industry publications and has provided press releases and public recognition to highlight successful projects. Additional insight into marketing plans can be reviewed in the 2017 Conservation Plan.

SECTION 8

RESOURCE INTEGRATION

Overview

Resource integration is the last step in Cascade's IRP process. It involves finding the least cost mix of demand and supply side resources given the forecasted load requirements of the core customers. The tool used to accomplish this task is a computer optimization model known as SENDOUT®. This model permits the Company to quickly develop and analyze a variety of resource portfolios to help determine the type, size, and timing of resources best matched to forecast requirements. SENDOUT® is very powerful and complex. It operates by combining a series of existing and potential demand side and supply side resources and optimizes their utilization at the lowest net present cost over the entire planning period for a given demand forecast.

Key Points

- Cascade utilizes SENDOUT® to find the "solve" for forecasted resource deficiencies.
- Once an optimal solution is found, this expected portfolio is stress-tested through stochastic and deterministic scenarios.
- The optimal portfolio includes a combination of additional transportation, satellite LNG, and 3rd party citygate deliveries.
- Without incremental resources, Cascade's first material deficiency occurs in 2020.
- With incremental resources, no forecasted deficiencies exist until 2036, all of which are from customers on an interruptible tariff.

Scenarios versus Simulations

Prior to discussing the modeling process, inputs, and ultimately the results of the analyses, a brief discussion of the term scenarios versus simulations is necessary. As stated earlier, SENDOUT® relies on a series of inputs or assumptions and then solves for the least cost solution based on the information provided to the model. Each group of assumptions is considered a scenario. For example, the Company models medium load growth under average weather conditions where the assumed daily weather pattern is input into the SENDOUT® model. The Company also runs scenarios utilizing the low and high growth forecasts and historically has run several different price assumption scenarios. The results of each of these scenarios provide an answer or a least cost solution, which the optimization model has solved based on its perfect knowledge. Historically, this has provided the range of expected outcomes. With the use of the Monte Carlo functionality, SENDOUT® generates 200 random draws based on inputted mean, standard deviations, and minimum/maximums. These inputs are discussed in detail on page 8-30. The Company runs simulations of the scenarios referenced above to determine if the preferred portfolio is still reasonable. Stochastic simulations provide a range of results based on a statistical analysis.

Table 8-1, along with the glossary below it, provides the list of scenarios included in this IRP and their key assumptions. Appendix E, Current and Alternative Supply Resources, provides further detail regarding the inputs for each scenario. To assess the impacts due to variations in pricing and weather, the Company ran Monte Carlo simulations on the expected scenario. The Company utilized this expected scenario in the IRP as it represents the scenario that Cascade, after a thorough analysis of SENDOUT® results, considers most likely to be experienced over the planning horizon.

Table 8-1: Breakdown of Scenarios Modeled

Scenario	Weather	Price	Growth	Constrictions	First Year Unserved
As-Is	Average Weather with Peak Event	Average Price	Expected Growth	Only models current resources	2017
Incremental Transport	Average Weather with Peak Event	Average Price	Expected Growth	No additional Storage or LNG Facility modeled	2017
Incremental Storage	Average Weather with Peak Event	Average Price	Expected Growth	No additional LNG Facility Modeled	2022
All In	Average Weather with Peak Event	Average Price	Expected Growth	None	2036
Expected Scenario	Average Weather with Peak Event	Average Price	Expected Growth	Removal of any Storage, Transport, and supply that SENDOUT deemed not optimal	2036
Expected Scenario - Low Growth	Average Weather with Peak Event	Average Price	Low Growth	None	N/A
Expected Scenario - High Growth	Average Weather with Peak Event	Average Price	High Growth	None	2019
Limit BC	Average Weather with Peak Event	Average Price	Expected Growth	Only 20% of BC Supply used in Expected Case made Available	2017
Limit Alberta	Average Weather with Peak Event	Average Price	Expected Growth	Only 20% of Alberta Supply used in Expected Case made Available	2017
Limit Canada	Average Weather with Peak Event	Average Price	Expected Growth	Only 20% of Canadian Supply used in Expected Case made Available	2017
Limit Rockies	Average Weather with Peak Event	Average Price	Expected Growth	Only 20% of Rockies Supply used in Expected Case made Available	2034
All In - Low deter	Average Weather with Peak Event	Low Price	Expected Growth	None	2036
All in - Hi deter	Average Weather with Peak Event	High Price	Expected Growth	None	2036
All In - Lo MC	Average Weather with Peak Event	Low Monte Carlo Price	Expected Growth	None	2036
All In - all low MC	Average Weather with Peak Event	All Low Monte Carlo Price	Expected Growth	None	N/A
All In- hi MC	Average Weather with Peak Event	High Monte Carlo Price	Expected Growth	None	2036
All In - all hi MC	Average Weather with Peak Event	All High Monte Carlo Price	Expected Growth	None	2035
All In - Low MC Weather	Low Monte Carlo Weather	Average Price	Expected Growth	None	2035
All In - Hi MC Weather	High Monte Carlo Weather	Average Price	Expected Growth	None	N/A
Expected - 10% Carbon Adder	Average Weather with Peak Event	Average Price with 10% Carbon Adder	Expected Growth	None	2036
Expected - 20% Carbon Adder	Average Weather with Peak Event	Average Price with 20% Carbon Adder	Expected Growth	None	2036
Expected - 30% Carbon Adder	Average Weather with Peak Event	Average Price with 30% Carbon Adder	Expected Growth	None	2036

Glossary of Terms Used in Table 8-1

Average Weather with Peak Event. Weather pattern modeled using historical weather data in each of Cascade's climate zones for the past 30 years. In addition a design peak day is 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.

Average Price. Price is modeled using Cascade's price forecast, which is derived by weighting the forecasts from a number of consultants over the 20-year planning horizon.

Expected Growth. Cascade applies the growth rates gathered from Woods & Poole as mentioned on page 3-7 for the expected growth scenario.

Low Growth. Low growth scenarios were created by examining the percentage errors of previous Woods & Poole forecasts. Expected growth rates are reduced by .65% to simulate a low growth environment over the 20-year period.

High Growth. High growth scenarios were created by examining the percentage errors of previous Woods & Poole forecasts. Expected growth rates are increased by .65% to simulate a high growth environment over the 20-year period.

Low Monte Carlo Weather. Weather is modeled using the single Monte Carlo draw that produced the warmest weather, or lowest HDDs over the 20-year planning horizon.

High Monte Carlo Weather. Weather is modeled using the single Monte Carlo draw that produced the coldest weather, or highest HDDs over the 20-year planning horizon.

Low Price. Price is modeled using Cascade's price forecast, which is derived by weighting the forecasts from a number of consultants over the 20-year planning horizon. Prices are then reduced by 6% at all markets (i.e., NYMEX, Sumas, Rockies, AECO) to simulate a low pricing environment over the 20-year period.

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

Low Monte Carlo Price. Price is modeled using the single Monte Carlo draw that produced the lowest average cost of gas over the 20-year planning horizon.

All Low Monte Carlo Price. Pricing for each month is determined by selecting the lowest Monte Carlo draw for that month. This pricing profile is then run deterministically to simulate what is expected to be the most extreme low pricing environment.

High Monte Carlo Price. Price is modeled using the single Monte Carlo draw that produced the highest average cost of gas over the 20-year planning horizon.

All High Monte Carlo Price. Pricing for each month is determined by selecting the highest Monte Carlo draw for that month. This pricing profile is then run deterministically to simulate what is expected to be the most extreme high pricing environment.

Average Price with 10% Carbon Adder. Price is modeled using Cascade's price forecast, which is derived by weighting the forecasts from a number of consultants over the 20-year planning horizon. Prices are then increased by 10% at all markets to simulate the impact of a potential carbon tax.

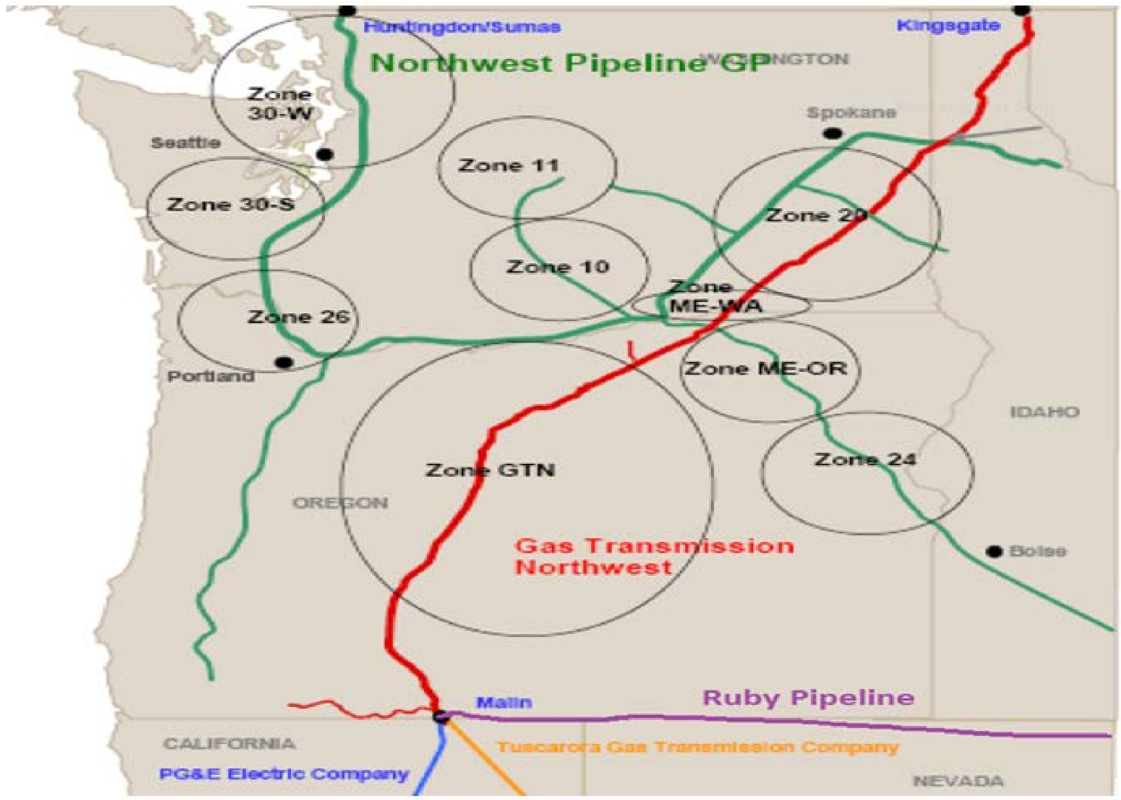
Average Price with 20% Carbon Adder. Price is modeled using Cascade's price forecast, which is derived by weighting the forecast of a number of consultants over the 20-year planning horizon. Prices are then increased by 20% at all markets to simulate the impact of a potential carbon tax.

Average Price with 30% Carbon Adder. Price is modeled using Cascade's price forecast, which is derived by weighting the forecast of a number of consultants over the 20-year planning horizon. Prices are then increased by 30% at all markets to simulate the impact of a potential carbon tax.

Planning and Modeling

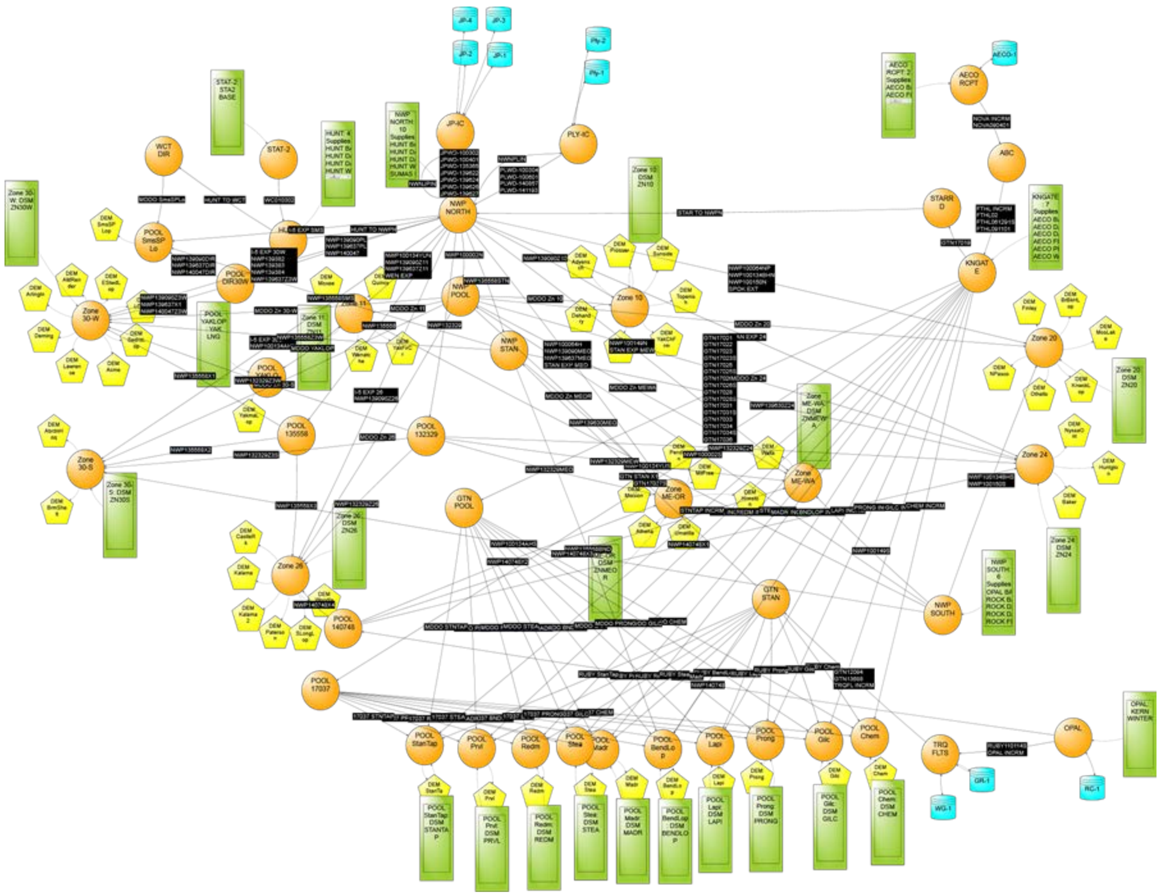
SENDOUT® has broad capabilities that allow the Company to develop supply and demand relationships that closely mirror Cascade's existing operations. Beginning with the 2008 IRP Cascade expanded its modeling from the district level to modeling the system grouped by the various pipeline zones. Figure 8-1 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 8-1: Pipeline Zones Used in this IRP



With the in-house load forecast model (LFM) application, which is discussed in detail in Section 3, Demand Forecast, modeling dives into an even more granular level. This IRP takes more of a citygate 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 8-2. The network diagram is provided to emphasize the difficulties in configuring the model to best replicate Cascade's complex system rather than being provided for its readability.

Figure 8-2: SENDOUT® Network Diagram of Cascade's System



Tools Used

Because SENDOUT® utilizes a linear programming approach, its results are considered deterministic. For example, the model knows the exact load and price for every day of the planning period based on inputs and can, therefore, minimize costs in a way that would not be possible in the real world. Therefore, it is important to acknowledge that linear programming analysis provides helpful but not perfect information to guide decisions.

Since decisions are made in the context of uncertainty about the future, Cascade uses SENDOUT® functionality that facilitates the ability to model gas price and load uncertainty (driven by weather) into the future. SENDOUT® utilizes a Monte Carlo approach in combination with the linear programming approach in SENDOUT®. The Monte Carlo modeling capability provides supplemental information to decision makers under conditions of uncertainty. This tool continues to enhance the robustness of the Company's long-term resource planning and acquisition activities.

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 number of very 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 report 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 situation is also present with respect to the Transportation Summary Report and the Storage Summary Report. SENDOUT® also offers monthly supply utilization information in a Load Factor Summary Report which some analysts may prefer to use in their approach to analyzing the SENDOUT® results.

Key Output Report - Supply vs. Requirements

This 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 reports determine 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 Reports to determine if the shortfall is supply or transportation related. If the shortfall occurs on a 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 ("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 load forecast model. 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 load forecast model. 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. There are also several fixed and variable cost rate inputs available to establish 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 Daily 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 or 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 then 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 determine the least cost set of resources given their specific pricing and quantifiable constraint characteristics. However, there are many other combinations of resources that may be available over the planning horizon. Cascade must still make subjective risk judgments about unquantifiable and intangible issues related to resource selections. These will 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 analysis to form the actual resource decisions.

Resource Integration

The following subsections summarize the analysis of the preceding sections bringing together the demand forecast, existing supply and demand side resources and potential alternative resources to develop the 20-year, most reasonably priced portfolio.

Demand Forecast

As explained in Section 3, Demand Forecast, load growth across Cascade's system through 2036 is expected to fluctuate between 1.16% and 1.31% annually after smoothing the leap year anomaly. Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow at a rate above 1% annually while industrial expects a growth rate of around 0.5%. Load across Cascade's two-state service territory is expected to increase 26% over the planning horizon, with the Oregon portion outpacing Washington at 36% versus 26%.

Long-Term Price Forecast

In Section 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 (EIA), the NPCC, 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 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 fluctuated dramatically over the course of the last ten years. Figure 8-3 shows the history of regional and Henry Hub prices over the past ten years. The Great Recession, 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.

Figure 8-4 shows the comparison of range of pricing of the planning horizon, including the expected scenario low, medium and high price.

Figure 8-3: Historical Regional Pricing for Past Ten Years

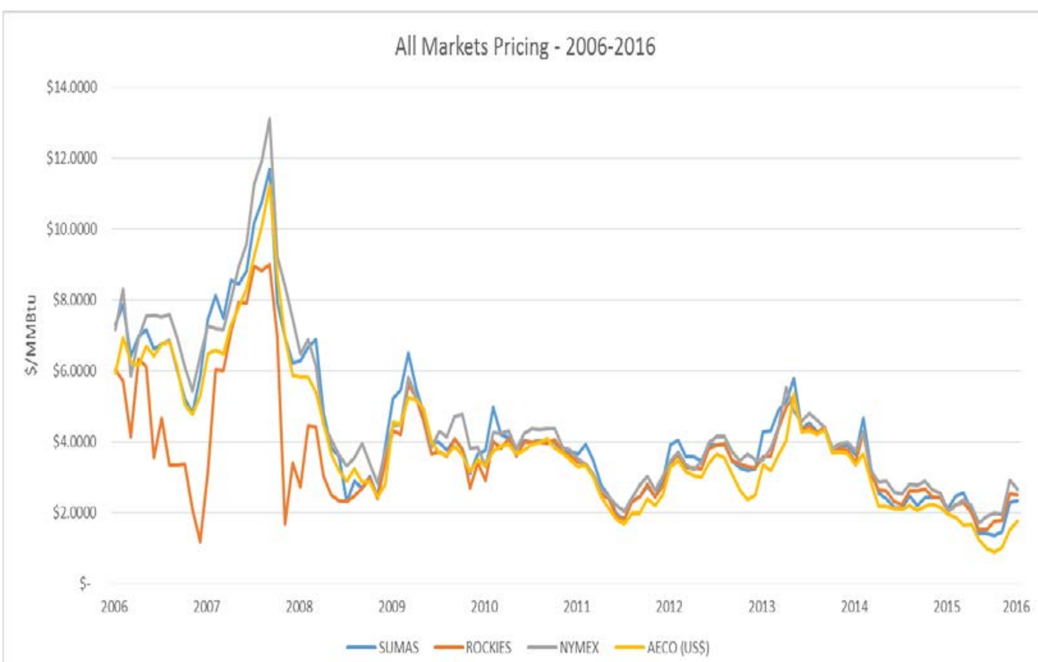
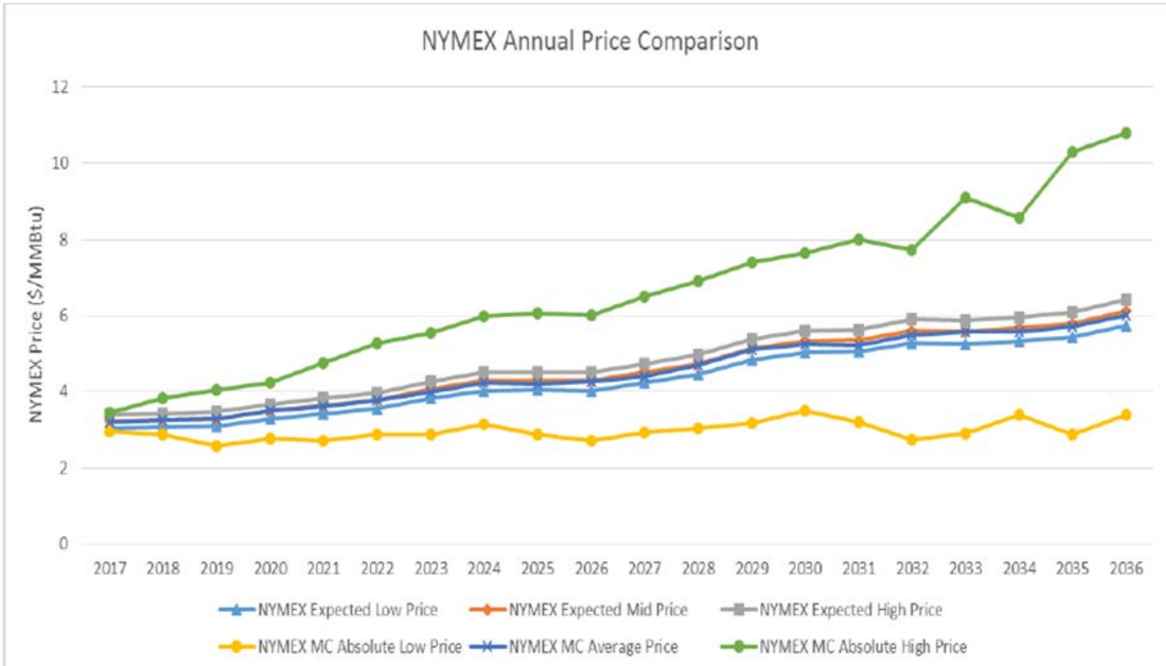


Figure 8-4: NYMEX Annual Price Comparison



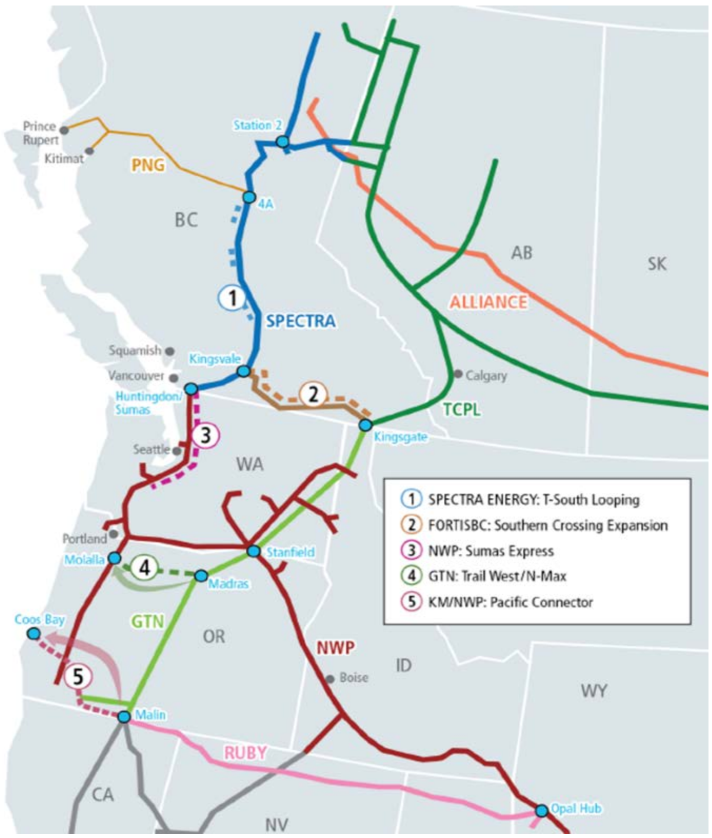
Carbon Policy

As discussed in Section 5, Environmental Considerations, the Company considered policies that aim to cost-effectively achieve state and federal carbon emission reduction policies and regulations. Specifically, these carbon methodologies and assumptions are considered for calculating inputs toward a 45-year avoided cost of natural gas for the 2016 IRP. The methodology examined by virtually all LDCs and electric utilities—as well as the Northwest Power and Conservation Council—have centered on the Carbon Cost Risk approach. Therefore, the Company has included a 10% carbon adder as a placeholder in the 2016 IRP's expected scenario 20-year price forecast.

Transportation/Storage

In Section 4, Supply Side Resources, the Company discussed 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 on Figure 8-5, 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 demand rights (Maximum Daily Delivery Obligations, or MDDOs) to citygates with potential peak day capacity shortfalls. The Company also works to use segmenting pipeline capacity as a way to maximize the utilization of Cascade's capacity. These resources plus leasing incremental storage at a number of regional facilities were all considered as a resource mix of possibilities to form the Company's 20-year integrated resource portfolio.

Figure 8-5: Alternative Transportation Resources



Demand Side Management

Section 7, Demand Side Management, described the methodology used to identify conservation potential and the interactive process that utilizes avoided cost thresholds for determining the cost effectiveness of conservation measures on an equivalent basis with supply side resources. For the 2016 IRP the system avoided costs ranges between $0.5041/therm and $0.6659/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.

Results

After incorporating these inputs into the SENDOUT® model, Cascade analyzed the demand compared to the existing resources as well as the demand against all the available resources. This serves as the foundation for the Company to see what resources are taken to meet system demand with the least cost mix of natural gas supply and conservation. The Company then runs the optimization again removing the resources SENDOUT® did not select from the All-In scenario. This allows Cascade to confirm that removing these resources does not impact the amount of served demand. Additionally, this step removes fixed costs associated with the resources not taken so Cascade can arrive at a true total system cost. Table 8-2 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. Table 8-3 displays the same information as Table 8-2, but for Washington citygates only.

Table 8-2: Load Centers with Potential Peak Day Unserved Demand in Dekatherms– As Is Scenario

Gate	2017	2020	2025	2030	2035	2036
BEND LOOP	2,114	6,470	14,077	22,116	30,555	32,285
BREMERTON (SHELTON)	-	-	-	1,810	3,991	4,030
HERMISTON	-	-	-	1,127	1,852	1,859
KENNEWICK LOOP	-	-	-	752	5,262	6,564
NYSSA-ONTARIO	-	-	-	923	1,063	1,062
SEDRO-WOOLLEY LOOP	-	-	-	137	4,381	5,970
ZILLAH (TOPPENISH)	-	-	-	-	1,301	1,504
WENATCHEE	806	1,041	1,410	1,766	2,098	2,161
YAKIMA LOOP	3,224	4,163	5,639	7,063	8,394	8,645
Total	6,144	11,674	21,126	35,694	58,897	64,079

Table 8-3: Washington Load Centers with Potential Peak Day Unserved Demand in Dekatherms – As Is Scenario

Gate	2017	2020	2025	2030	2035	2036
BREMERTON (SHELTON)	-	-	-	1,810	3,991	4,030
KENNEWICK LOOP	-	-	-	752	5,262	6,564
SEDRO-WOOLLEY LOOP	-	-	-	137	4,381	5,970
ZILLAH (TOPPENISH)	-	-	-	-	1,301	1,504
WENATCHEE	806	1,041	1,410	1,766	2,098	2,161
YAKIMA LOOP	3,224	4,163	5,639	7,063	8,394	8,645
Total	4,030	5,204	7,049	11,528	25,427	28,874

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.

Analysis of Unserved Demand

By many accounts, 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. One interesting item to note is that growth at one of the Company's citygates may cause unexpected shortfalls at other, seemingly unrelated citygates. For example, Cascade's Bremerton-Shelton citygate has a significant amount of customers on a residential tariff. 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 appears, even though this would not be the case in this hypothetical example. Page 3-8 goes into further detail regarding some of the major growth drivers.

Alternative Resources Selected

The SENDOUT® model selected the following resources for the 20-year portfolio. These resources and the quantities selected are summarized in Table 8-4.

Table 8-4: Projected Cumulative Incremental Transport and LNG Resources Needed – in Dekatherms

Resource	2017	2020	2030
Incremental GTN	-	20,472	11,814
I-5 Expansion	-	990	9,010
Wenatchee Expansion	-	5,810	1,500
Zone 20 Expansion	-	440	6,120
Incremental Starr Road	-	-	9,327
Eastern OR Expansion	-	3,920	1,170
Yakima LNG Plant	-	5,000	-
3rd Party Citygate Deliveries	6,144	-	-
DSM	279	305	527
Incremental Transport Acquired	6,144	36,632	38,940

Transport

- Third Party Citygate Deliveries – Allows Cascade to purchase delivered natural gas from a 3rd party. 6,144 dth/day.
- 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 where the Company expects shortfalls. 32,285 dth/day.
- I-5 Expansion – Allows Cascade to continue to serve customers as the Company's core load grows around the I-5 corridor, specifically in the Sedro-Woolley area. 10,000 dth/day.
- Wenatchee Expansion – Allows Cascade to continue to serve customers as the Company's core load grows in Central Washington in areas such as Wenatchee and Yakima. 7,310 dth/day.
- Zone 20 Expansion – Allows Cascade to continue to serve customers as the Company's core load grows in Eastern Washington in areas such as Kennewick. 6,560 dth/day.
- Incremental Starr Road – Allows Cascade the flexibility to move gas off of GTN and onto NWP through Starr Road when needed, displacing the need for potential incremental NWP capacity. 9,326 dth/day.
- Eastern Oregon Expansion – Allows Cascade to move gas from NWP to serve Eastern Oregon in areas such as Nyssa-Ontario. 3,950 dth/day.

Supply

- Yakima Satellite LNG Plant – Allows Cascade the opportunity to serve demand in a cost effective way directly to Yakima, WA without new transport, which in turn helps increase served demand system-wide through a displacement of Maximum Daily Delivery Obligations (MDDOs) among existing contracts. 5,000 dth/day.

Alternative Resources Not Selected

The SENDOUT® model did not select the following resources for the 20-year portfolio:

Transport

- Incremental NOVA/Foothills – There is currently no incremental NOVA capacity available. In addition, SENDOUT® did not determine there was a cost effective opportunity presented by moving gas along these contracts to Kingsgate versus buying gas at Kingsgate directly.

- Incremental Ruby/Turquoise Flats – SENDOUT® determined it was more cost effective for the Company to acquire unsubscribed transport from GTN to serve the incremental demand these incremental contracts would otherwise serve.

Supply

- Opal Incremental – Since SENDOUT® determined it was best to serve increasing demand through picking up unsubscribed GTN capacity, there was no need to purchase additional gas to move along Ruby.

Storage

- Ryckman Creek, Gill Ranch, Wild Goose, AECO Hub – No incremental storage was selected – none of the 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, as in the case of AECO Hub, no incremental NOVA capacity is available at this time.

Expected Scenario

Using input from the alternative resources selected, SENDOUT® derives a portfolio of existing and incremental resources that Cascade defined as the Expected Scenario. This scenario 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 scenario assumes 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 total system cost are shown on Tables 8-5, 8-6 and 8-7, as well as graphically in Figures 8-6 through 8-11. One thing that is important to note is that any remaining deficiency in the Expected Scenario would be for customers on an interruptible tariff.

Table 8-5: Load Centers with Potential Peak Day Unserved Demand in Dekatherms– Expected Scenario

Gate	2017	2020	2025	2030	2035	2036
BREMERTON (SHELTON)	-	-	-	-	-	794
KENNEWICK LOOP	-	-	-	-	-	362
NYSSA-ONTARIO	-	-	-	-	-	247
OTHELLO	-	-	-	-	-	157
PENDLETON	-	-	-	-	-	812
UMATILLA	-	-	-	-	-	365
TOTAL	-	-	-	-	-	2,737

Table 8-6: Washington Load Centers with Potential Peak Day Unserved Demand in Dekatherms– Expected Scenario

Gate	2017	2020	2025	2030	2035	2036
BREMERTON (SHELTON)	-	-	-	-	-	794
KENNEWICK LOOP	-	-	-	-	-	362
OTHELLO	-	-	-	-	-	157
TOTAL	-	-	-	-	-	1,313

Portfolio Evaluation

Table 8-7 summarizes the net present value of the revenue requirement (PVRR) of the portfolios considered. Each portfolio is based on unique assumptions, and therefore, a simple comparison of PVRR cannot be made.

Table 8-7: PVRR by Scenario (TSC in $000)

Scenario	Total System Cost	Average Cost/Served Therm
As-Is	4,213,446	0.5951053
Incremental Transport	4,085,782	0.5766252
Incremental Storage	4,085,782	0.5766252
All In	4,085,939	0.5766167
Expected Scenario	4,073,121	0.5748078

Figure 8-6: Annual Supply Take vs Demand – Expected Scenario

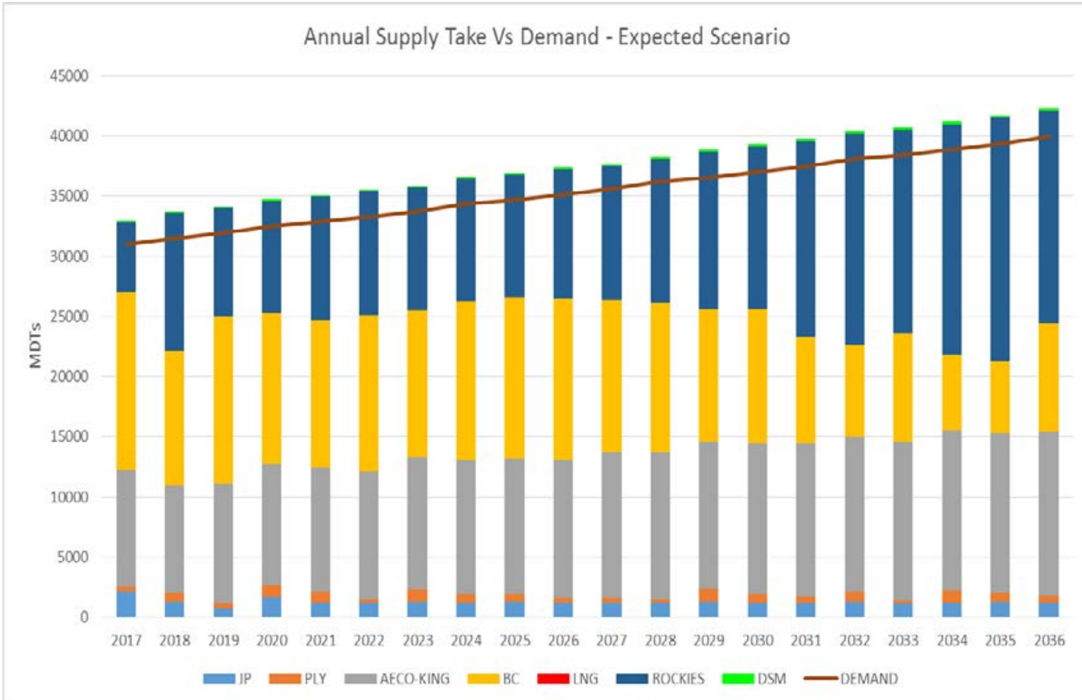


Figure 8-7: Peak Day Supply Take vs Demand – Expected Scenario

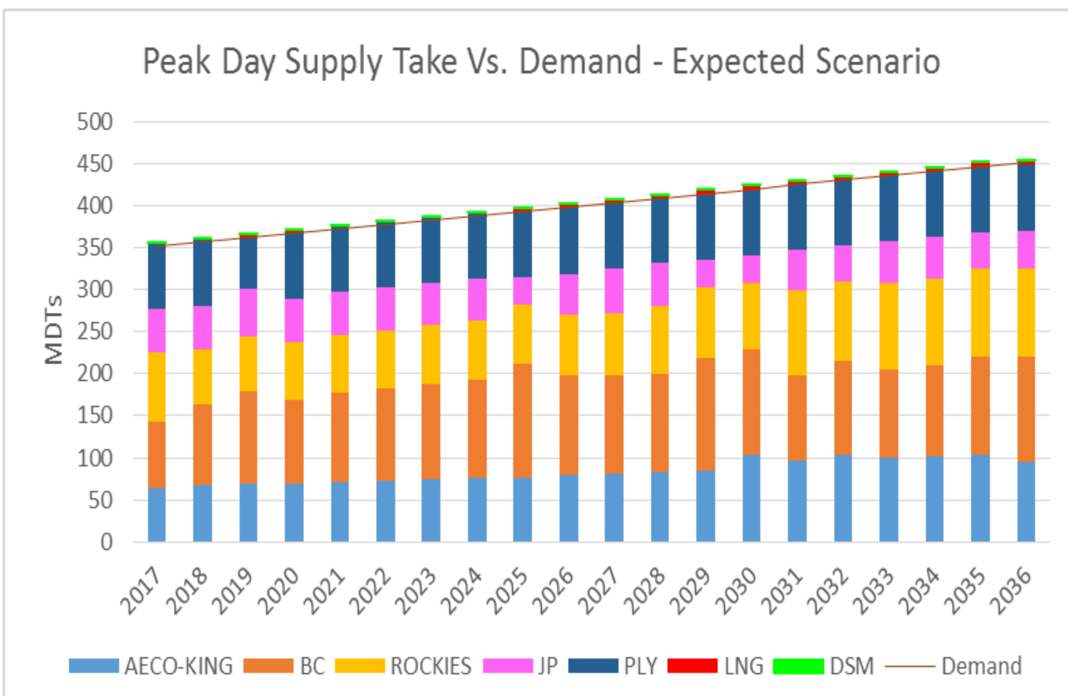


Figure 8-8: Peak Day Transport vs Demand, Incremental Broken Out – Expected Scenario

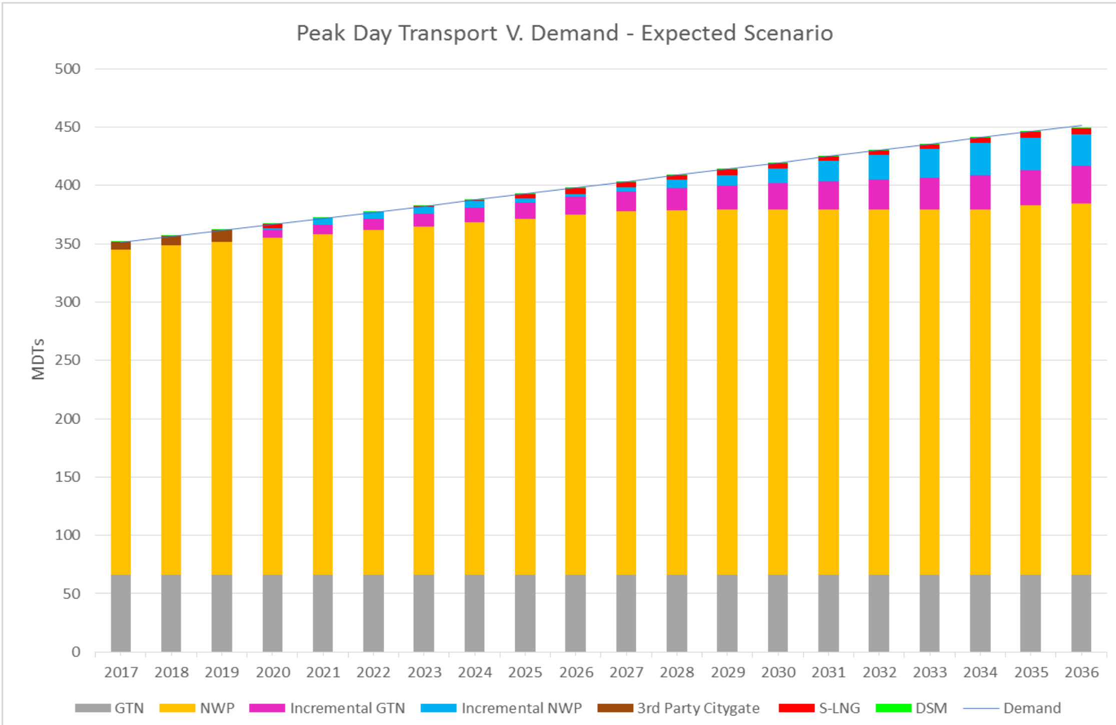


Figure 8-9: Peak Day Incremental Transportation – Expected Scenario

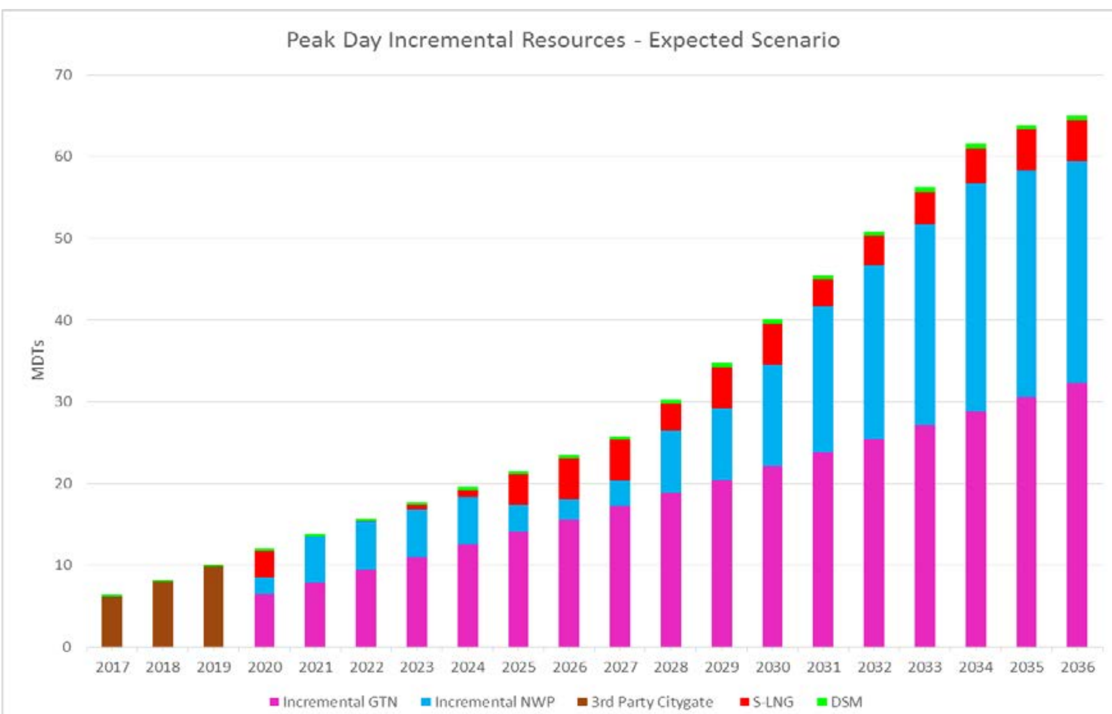


Figure 8-10: Annual Transport vs Demand – Expected Scenario

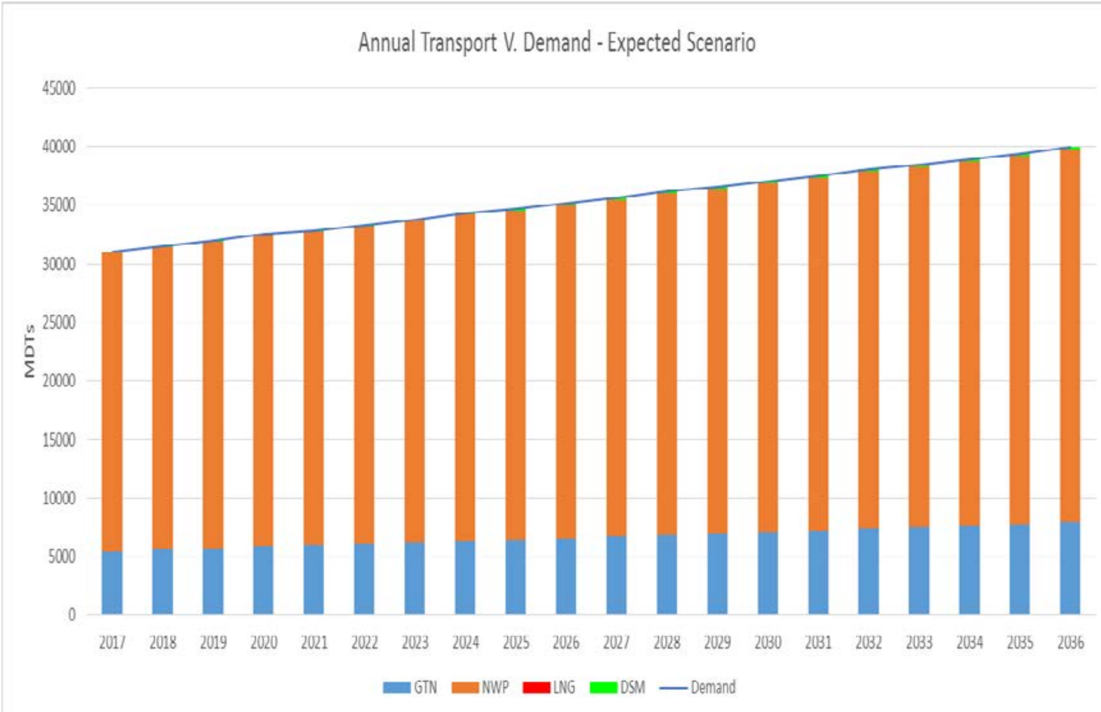
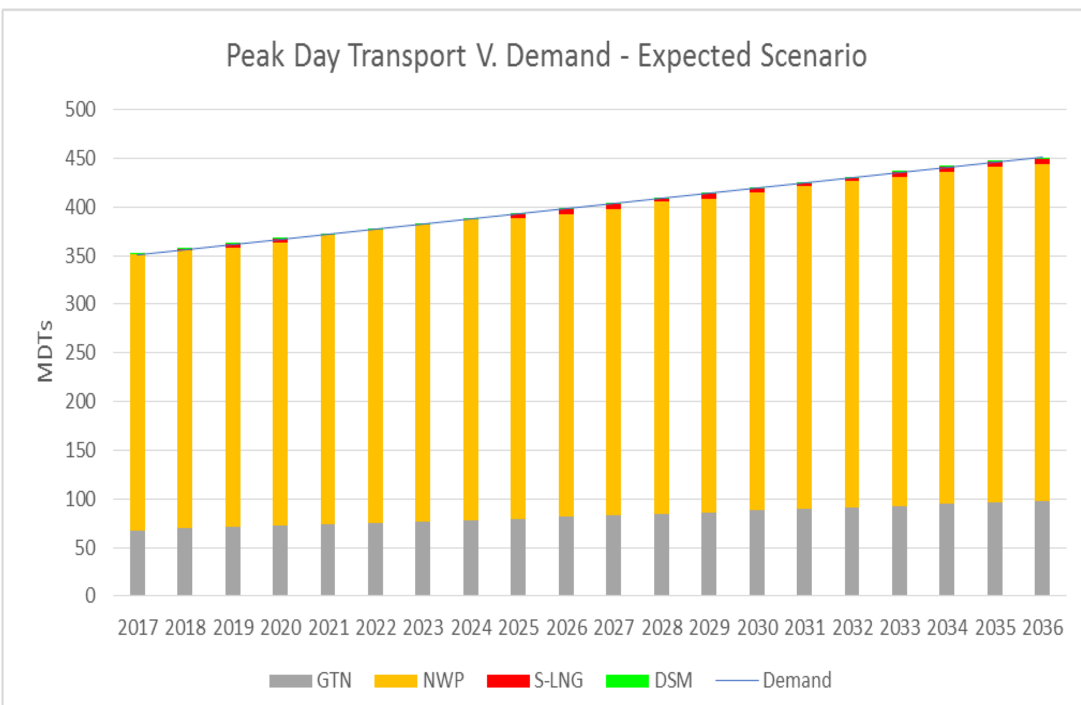


Figure 8-11: Peak Day Transport vs Demand – Expected Scenario



Portfolio Evaluation: Additional Scenarios

Table 8-8 summarizes the net present value of the revenue requirement (PVRR) of all additional demand scenarios reviewed. After the expected portfolio is selected, the Company tests it deterministically through a number of extreme situations, which are further explained in Appendix E, Current and Alternative Supply Resources. One scenario worth discussing further is the "All In – all hi MC" scenario**.** Here, Cascade selects the highest price per month from the Monte Carlo runs on price, and runs that pricing profile as a deterministic run. Since it is the highest price pulled in 200 draws, the total cost numbers for this run, while high, are not unreasonable. The results of all scenarios are also shown graphically in Figures 8-12 and 8-13.

Table 8-8: Total System Cost ($000) and Average Cost/Served Therm of Additional Demand Scenarios

Scenario	Total System Cost	Average Cost/Served Therm
Expected Scenario - Low Growth	3,822,848	0.5856308
Expected Scenario - High Growth	4,360,343	0.5657437
Limit BC	4,365,404	0.6161620
Lmit Alberta	4,371,552	0.6169275
Limit Canada	5,086,396	0.7179355
Limit Rockies	4,123,937	0.5819830
All In - Low deter	4,000,318	0.5645328
All in - Hi deter	4,151,112	0.5858141
All In - Lo MC	3,723,481	0.5254649
All In - all low MC	3,179,914	0.4487547
All In- hi MC	4,121,820	0.5816836
All In - all hi MC	4,801,535	0.6776102
All In - Low MC Weather	4,055,875	0.5794418
All In - Hi MC Weather	4,123,293	0.5771684
Expected - 10% Carbon Adder	4,203,755	0.5932432
Expected - 20% Carbon Adder	4,318,705	0.6094673
Expected - 30% Carbon Adder	4,421,042	0.6239108

Figure 8-12: Total System Cost Comparison by Scenarios

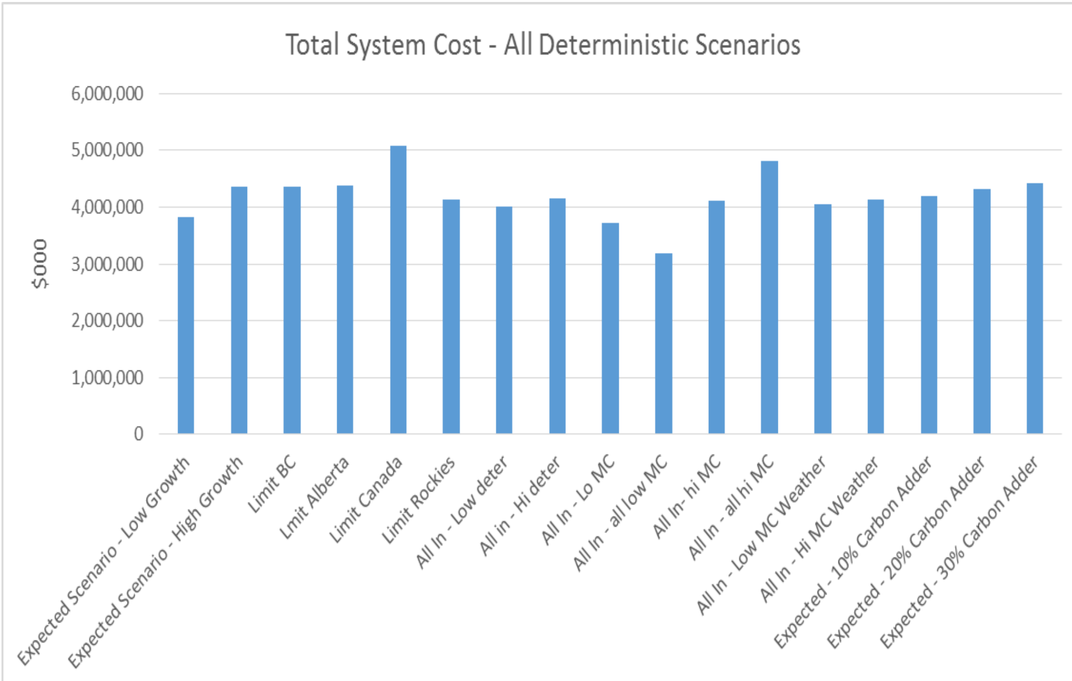
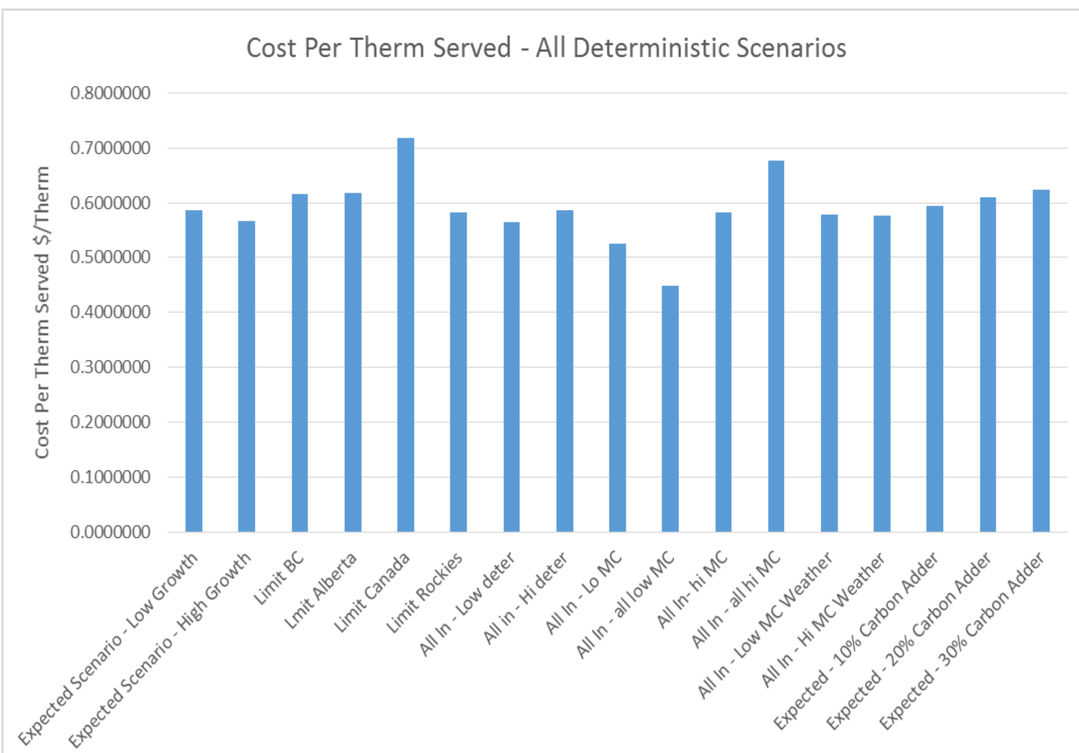


Figure 8-13: Cost per Therm Served – All Deterministic Scenarios



Stochastic Analyses - Annual Load Requirements and Weather Uncertainty

The annual load requirements will vary dramatically based on the weather assumptions. Through the use of the SENDOUT® Monte Carlo functionality, the Company has the ability to analyze the impacts of weather on its load forecast. Figure 8-14 provides the low parameter, which is based on the assumption that the low load growth forecast occurs. Figure 8-15 provides a more in-depth look at the expected, or medium, scenario results. This assumes that growth is at the expected rate, and price follows the expected price forecast. Figure 8-16 provides the high parameter occurring under the high load growth forecast. Capturing the uncertainty around load growth forecasting was accomplished through SENDOUT® Monte Carlo functionality. The Monte Carlo simulation performed 200 draws with each draw calculating the monthly load based on the weather as randomly determined by the model for each of the weather zones. The absolute maximum and absolute minimum amounts depict the minimum or maximum system demand from the 200 draws for a particular year. The absolute maximum/minimum does not represent any single results for the 20-year planning horizon.

Figure 8-14: Therms Served – Low Growth Monte Carlo Weather Scenarios – Expected Scenario

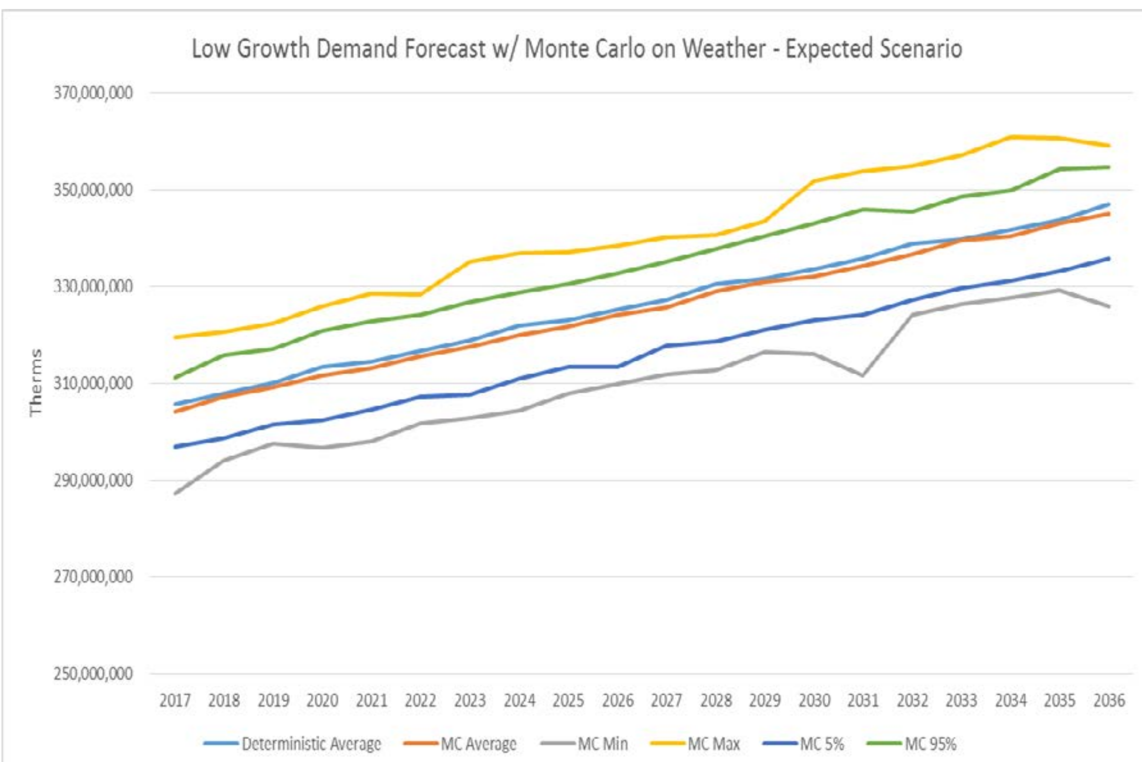


Figure 8-15: Therms Served – Average Growth Monte Carlo Weather Scenarios – Expected Scenario

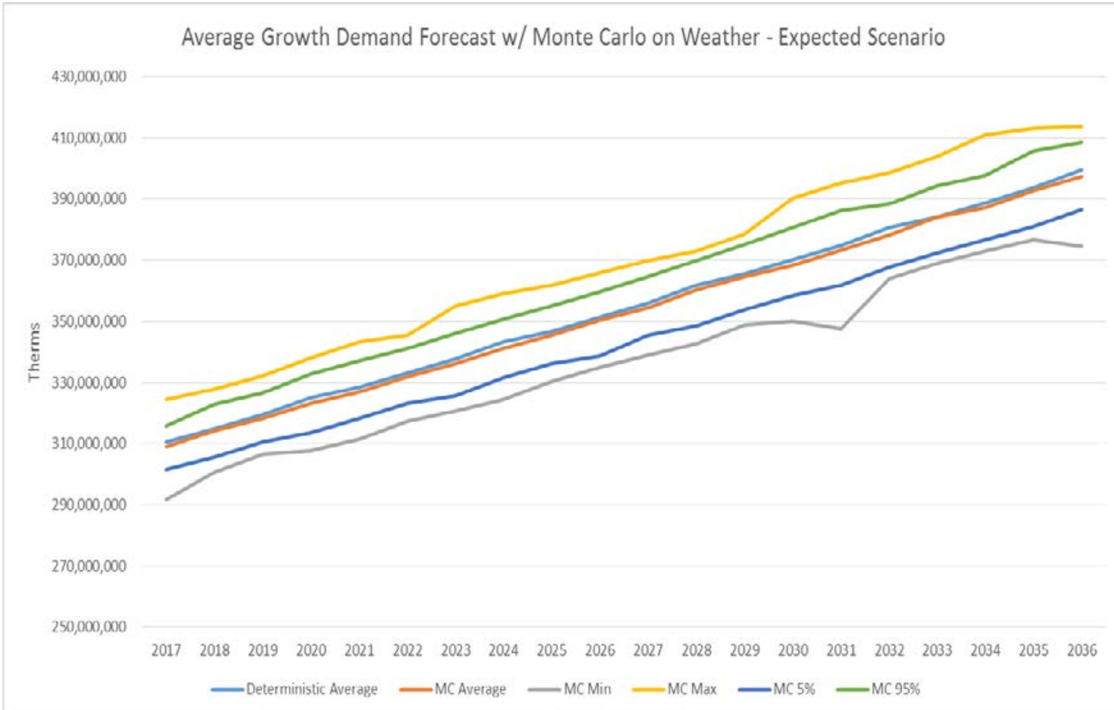
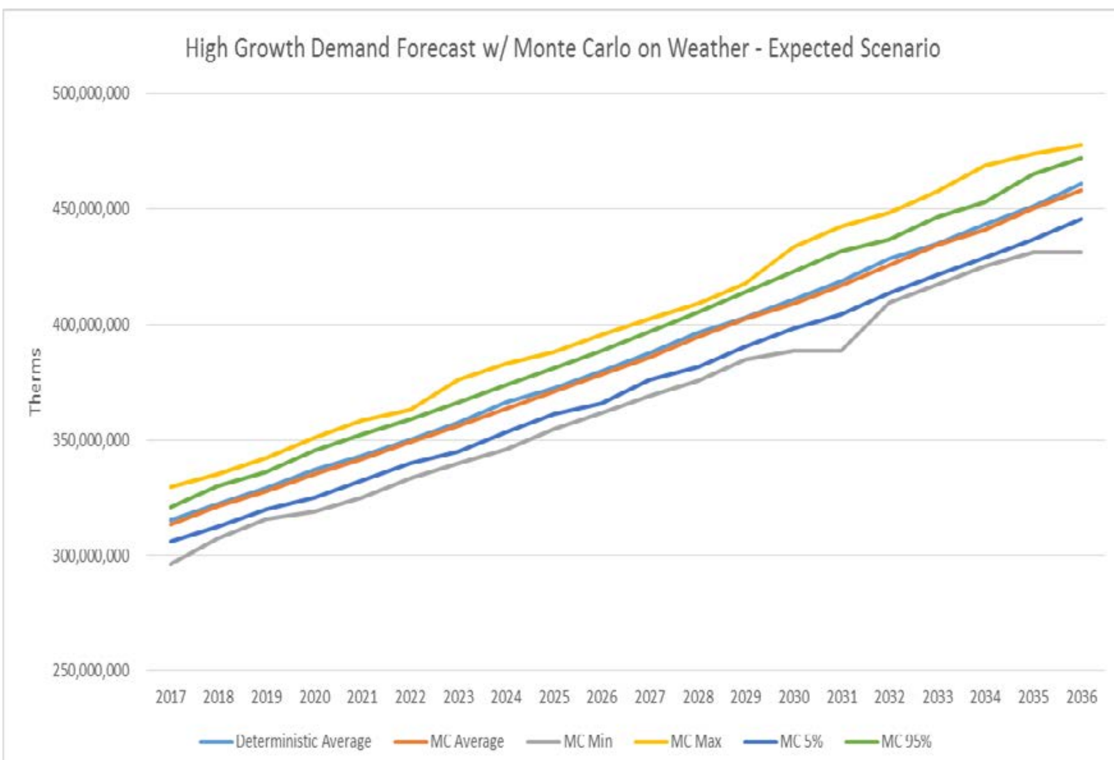


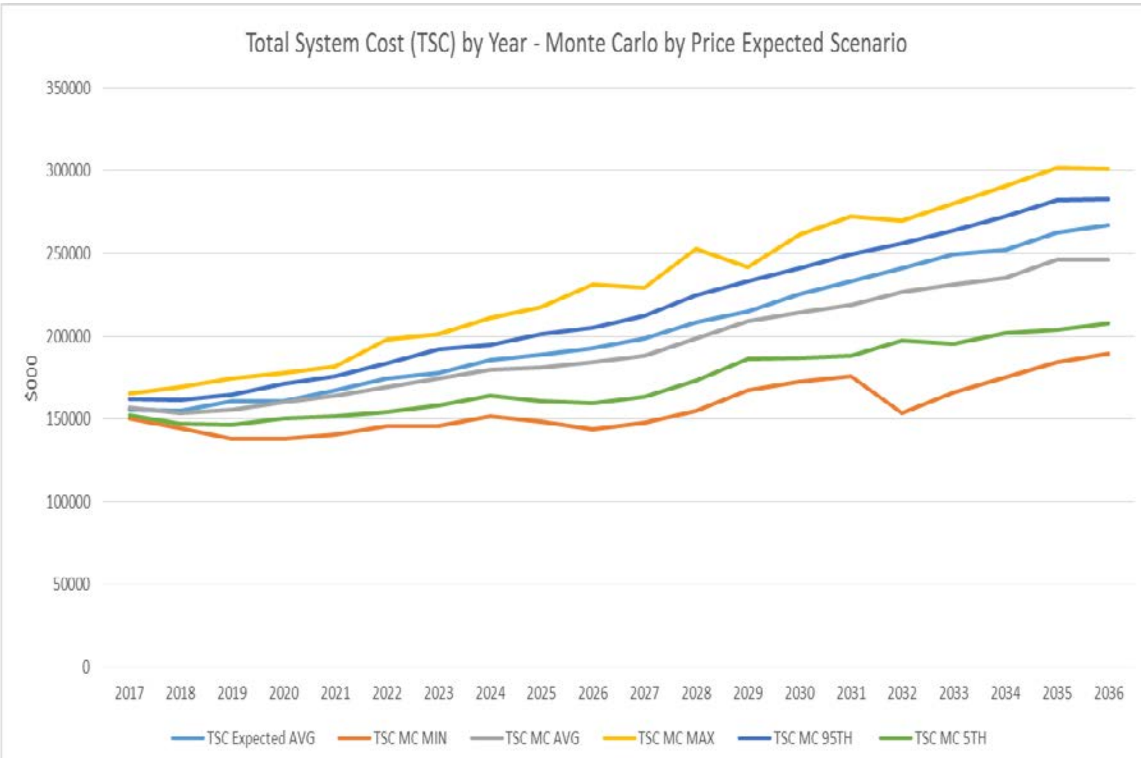
Figure 8-16: Therms Served – High Growth Monte Carlo Weather Scenarios – Expected Scenario



Stochastic Results: Price Uncertainty

The following charts show what happens when the expected portfolio is stress tested in different scenarios. For price, the Company shows how the portfolio performs with regard to total system costs in an expected growth environment over 200 random pricing scenarios. These results are shown in Figure 8-17. With the analyses on price and weather uncertainty, the Company can gain a perspective of how Cascade's expected portfolio would perform in extreme weather and price situations. Based on feedback from stakeholders, Cascade will be expanding its analysis to include Monte Carlo simulations on additional potential portfolio scenarios in its 2018 IRP.

Figure 8-17: Total System Cost – Monte Carlo by Price Expected Scenario



Monte Carlo Inputs

When performing a Monte Carlo simulation in SENDOUT®, the user provides the following inputs for both price and weather simulations:

Mean Value – this tells SENDOUT® what the mean value should be over the 200 draws. This number is the same as the deterministic input for either price (in $/mmbtu) or HDDs.

Standard Deviation (Std Dev) – this tells SENDOUT®, based on the type of distribution selected, how far above and below the mean that the data points will fall depending on the draw, and how many points should fall within a certain range.

Distribution - this tells SENDOUT® if the draws should be distributed normally or lognormally. Weather is distributed normally while price is distributed lognormally.

Max - this tells SENDOUT® what the highest result can be for either price or HDDs for a given month.

Min - this tells SENDOUT® what the lowest result can be for either price or HDDs for a given month.

Figures 8-18 and 8-19 below show an example of these inputs for an index, as well as for a climate zone.

Figure 8-18: Sample Monte Carlo Inputs - Index

	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017
*Mean Value	3.60	3.95	4.38	4.36	4.29	4.01	4.05
Std Dev	0.200	0.221	0.241	0.262	0.282	0.303	0.324
Distribution	Lognormal						
Max	4.10	4.51	4.99	5.01	4.99	4.77	4.86
Min	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Weather Effect Up Function							
Weather Effect Up Threshold DD							
Weather Effect Up Rate							
Weather Effect Down Function							
Weather Effect Down Threshold DD							
Weather Effect Down Rate							
Jump Threshold DD							
Jump Probability							
Jump Multiplier							
Max Daily							
Min Daily							

Figure 8-19: Sample Monte Carlo Inputs – Climate Zone

	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017
HDD Mean	764.6	1026.1	1031.8	804.1	639.6	453.9	254.2
HDD Std Dev	93.7	108.8	145.4	133.1	84.4	93.0	72.2
HDD Distribution							
HDD Max	932	1290	1291	1242	841	641	426
HDD Min	534	861	772	568	448	254	92
CDD Mean							
CDD Std Dev							
CDD Distribution							
CDD Max							
CDD Min							

Alternative Forecasting Methodologies and Consideration of Modeling Modification

Forecasting is the foundation of integrated resource planning, highly influencing most key items in the two-year action plan and 20-year planning horizon. Chief among these is the determination of the avoided cost of natural gas which, in addition to gas supply issues, affects conservation programs.

Qualitative (scenario planning) and quantitative methods (regression modeling of historic data) are combined to arrive at low, medium, and high forecasts. A range of end-results are used to determine sensitivity of specific parameters (e.g., customer growth, use per customer, retail price, carbon policy, etc.). Assumptions and inputs are highly scrutinized by Commission Staff and stakeholders. A low forecast would result in lesser planned conservation programs. High forecasts may be overly influenced by uncertainties of future industry issues (e.g., carbon policy), resulting in excess costs.

Commission Staffs and stakeholders, across states and fuels (i.e., natural gas and coal), request consideration of "alternative forecasting methods." This, in practicality, has two meanings. One meaning is technical, focusing on improvements and additions to previous modeling.[1] The second meaning is policy-based (although included in the technical modeling) and lies in sensitivity analysis and scenario planning. Such scenario planning incorporates any adders to the cost-per-ton of carbon emissions (i.e., CO_2) and the like.

Throughout each planning cycle, all Washington and Oregon jurisdictional utilities have been requested to improve their technical modeling and include robust sensitivity and scenario analyses to effectuate alternative forecasting methods.

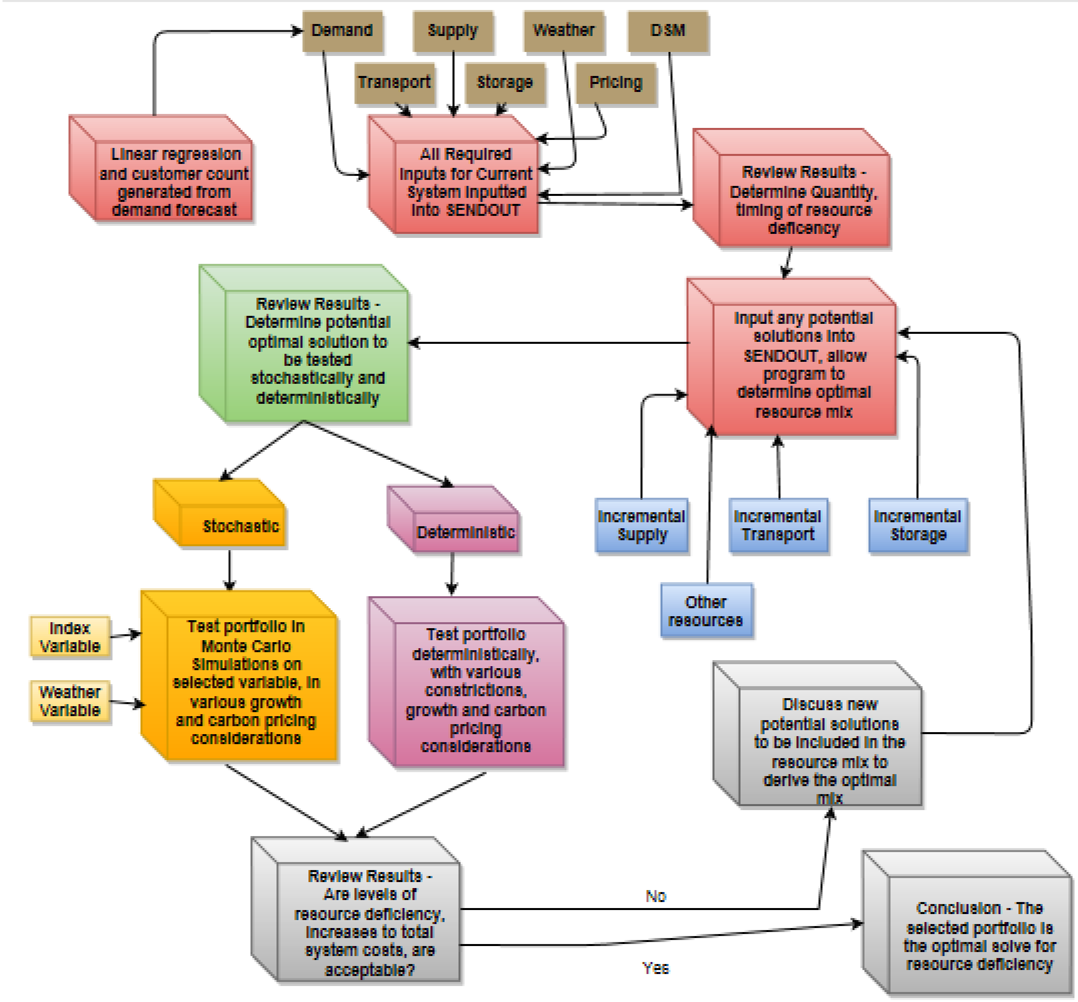
For this IRP the Company is using a linear forecasting methodology. Cascade currently uses SENDOUT®, a model employed by all Washington and Oregon LDCs, to find the optimal solve for any deficiency that is projected based on the forecast. Figure 8-20 shows all of the steps that are taken to go from forecasting to portfolio selection. Through linear forecasting methodology and scenario planning with Monte Carlo draws, a stochastic (that is, based on random event planning) 20-year forecast is derived.[2]

As previously identified in Section 3, Demand Forecast, the Company believes that future IRPs will be enhanced by adopting additional technical modifications. Cascade plans a greater inclusion of polynomial algorithms in future forecast

[1] For example, modifications could include modules that examine uncertainty and equations that take into account lagged effects of primary variables (e.g., economic conditions).
[2] A stochastic approach or randomly determined having a random probability distribution or pattern that may be analyzed statistically but may not be predicted precisely.

modeling with a continuing focus on developing a wide and deep range of scenarios. Given the improvements in forecasting, more analysis of primary variables can be gained by greater use of polynomial equations.[3] Piecewise can be used to incorporate a finite number of the most significant, but separate, components that provides for a more robust forecast.

Figure 8-20: Optimal Portfolio Selection Flow Chart



Conclusion

Cascade's optimum portfolio, referred to as the expected scenario, has the lowest cost and risk as expected when considering alternate supply 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

[3] Polynomial equations are an expression of more than two algebraic terms, especially the sum of several terms that contain different powers of the same variable(s).

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 cost of building or acquiring new supply resources would likely increase cost while keeping risk at similar levels.

The High Growth and Low Growth demand analyses provide a range for evaluating demand trajectories relative to the Expected scenario. Based on this analysis sufficient time is expected to plan for forecasted resource needs. Even under a high growth scenario, the first forecasted material deficiency in Cascade's modeling does not occur until 2020. This is important to highlight, as even though the Company's optimization shows a shortfall in 2017 as referenced in Table 8-2, this shortfall can be solved through 3rd party citygate deliveries, as referenced in Table 8-4. Many events could occur between now and when the first resource needs materialize, so Cascade will employ adaptive management to continue to monitor and analyze the system demand through reconciling and comparing forecast to actual customer counts and continually update and evaluate all demand side and supply side alternatives.

SECTION 9

DISTRIBUTION SYSTEM PLANNING

Overview

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 become secondary issues if distribution system growth behind the citygates becomes severely constrained. Important parts of the planning process include forecasting local demand growth, determining potential distribution system constraints, analyzing possible solutions and estimating costs for eliminating constraints.

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 three major enhancement projects over the next three years.

Analyzing resource needs in the IRP is primarily focused on ensuring adequate upstream capacity to the citygates, especially during a peak event. Distribution planning focuses on determining if there will be adequate pressure during a peak hour. Despite this different perspective, distribution planning shares many of the same goals, objectives, risks and solutions as resource planning.

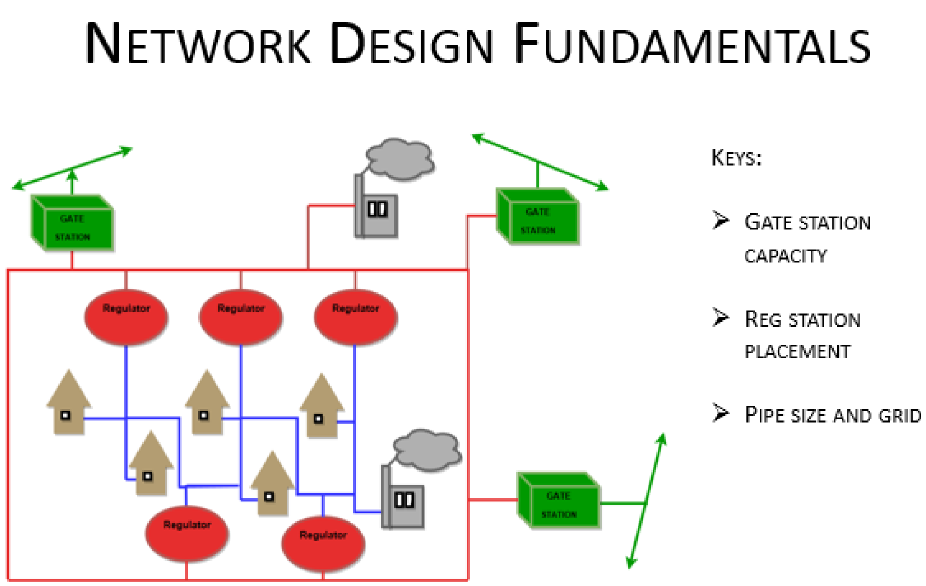
Cascade's natural gas distribution system consists of approximately 4,744 miles of distribution main pipelines in Washington, and 1,604 miles in Oregon, as well as numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment. Currently, there is a compressor station within Cascade's distribution system near Fredonia, WA. 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 place 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 times without overbuilding infrastructure are the key challenges in network design. Figure 9-1 provides an example of a network diagram.

Figure 9-1: Network Design Fundamentals

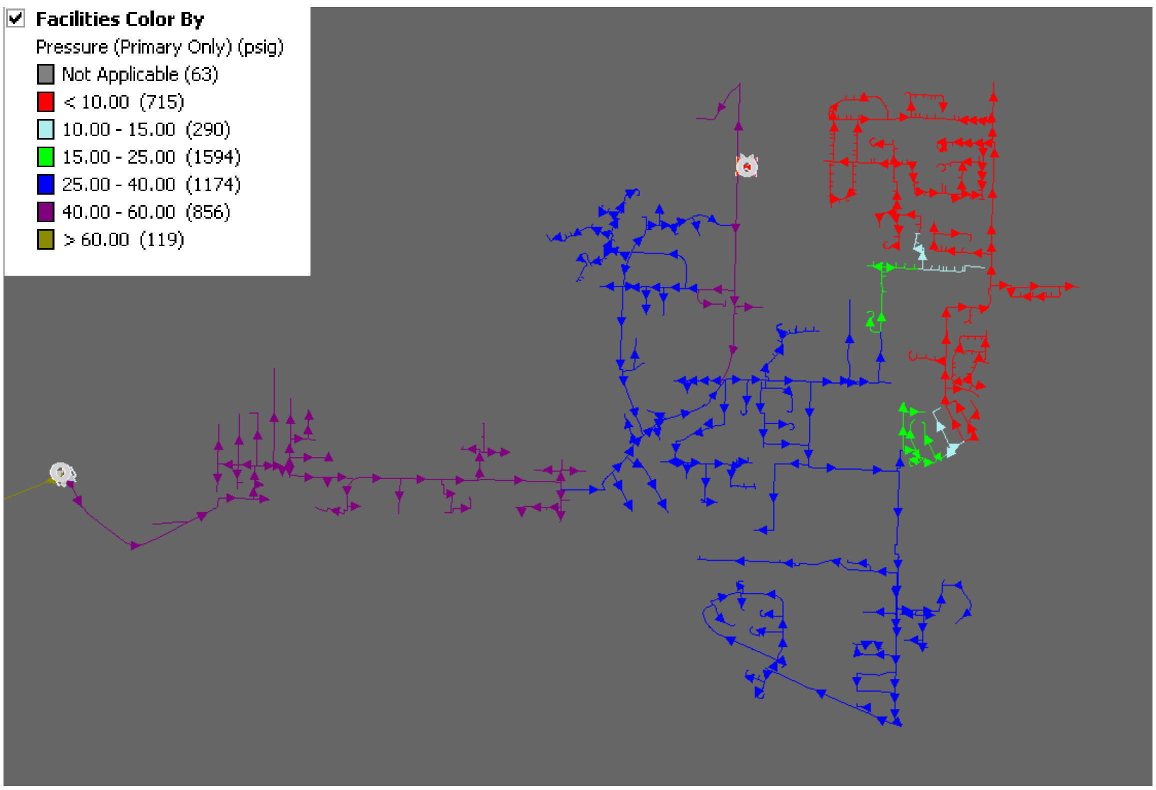


Computer Modeling

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 were 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 load 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 is determined to be a constraint area. When constraint areas are found, an engineer determines the most effective way of solving the problem.

Cascade's geographical information system (GIS) keeps an as-to-date record of pipe and facilities, complete with all system attributes such as date of install and operation pressure. Using the internal 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. Ultimately the identified projects can be funneled through the Project Process Flow (Figure 9-4 on Page 9-9) to be prioritized and slotted into the budget. Figure 9-2 is an example of a low pressure scenario identified using Synergi®.

Figure 9-2: Low Pressure Design Example



Synergi® is the successor to the GasWorks models that were built years ago and have been upgraded as needed. Cascade's philosophy is that every couple of years the models should be rebuilt and recalibrated to represent the system more accurately. Synergi® is more advanced than GasWorks and much more user friendly. Synergi® is also the modeling software of choice for many other 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, including distribution system reinforcements and expansions. Reinforcements are upgrades to existing infrastructure, or new system additions, which increase system capacity, reliability and safety. Expansions are new system additions to accommodate new demand. Collectively, these are distribution enhancements.

The engineering department works closely with engineering associates and district management to make sure the system is safe and reliable. As towns develop, the need for pipeline extensions 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 do not reduce demand nor do they create additional supply. Enhancements can increase the overall capacity of a distribution pipeline system while utilizing existing gate station supply points. 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 constructing 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 there is damaged pipe or where pipe integrity issues exist. 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 9-3 provides a snapshot of some of the major components of the system.

Figure 9-3: 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, customer's property or 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 allows 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

Equally important is to review the impacts of proposed conservation resources on anticipated distribution constraints. Although the Company historically provides utility sponsored conservation programs throughout a particular jurisdiction (i.e. all of Washington or all of Oregon), there may be instances where a more targeted approach could reduce or delay the estimated reinforcement for a specific area. However, as discussed in Section 5, Environmental Considerations, the acquisition of conservation resources is entirely dependent upon the individual consumers' day-to-day purchasing and behavior decisions. Although the utility attempts to influence these decisions through its conservation programs, the consumer is still the ultimate decision maker regarding the purchase of a conservation measure. Therefore, the Company does not anticipate that the peak day load reductions resulting from incremental conservation will be adequate enough to eliminate distribution system constraint areas at this time. However, over the longer term (through 2027), the opportunity for targeted conservation programs to provide a cumulative benefit that offsets potential constraint areas may be an effective strategy.

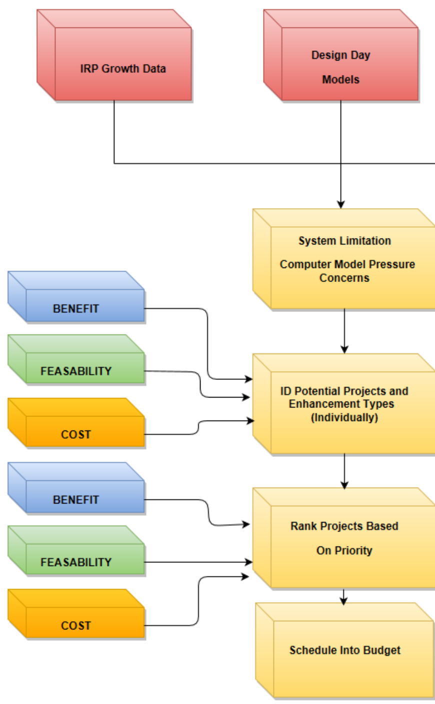
Distribution Scenario Decision-Making Process

After achieving a working load study, analyses are performed on every system at design day conditions to identify areas where potential outages may occur. These areas of concern are then risk ranked against each other to ensure the highest risk areas are corrected first. 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 or construction project coordinator (CPC) 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 9-4 provides a schematic representation of the distribution scenario process.

Figure 9-4: Distribution Scenario Process



Planning Results

Table 9-1 summarizes the cost and timing of major distribution system enhancements addressing growth-related system constraints, system integrity issues and the timing of expenditures. These projects are preliminary estimates of timing and costs of major reinforcement solutions. The scope and needs of distribution system enhancement projects generally evolve with new information requiring ongoing reassessment. Actual solutions may differ due to differences in actual growth patterns and/or construction conditions that differ from the initial assessment.

The following discussion provides information about key near-term projects:

- Stanwood 4" PE Reinforcement: This intermediate pressure reinforcement will create another connection to the eastside of the system at the north end. The growth has been seen in this area to the north and the west and this will provide the necessary capacity for continued growth. The project consists of about 1550' of 4" PE. The project cost is estimated to be $116,130 and it will be completed in 2017;

- Manchester 4" PE Reinforcement: This intermediate pressure reinforcement will help provide capacity to the end of the system, while also improving the system and allowing for growth to the north and south. The project will consist of 5,100' of 4" PE. The project will take place in 2018 and will cost an estimated $245,870; and

- South Walla Walla Gate and HP Line: The new gate station and high pressure pipeline in these projects will provide gas service to customers south of Walla Walla, Washington. The current distribution system has very limited capacity south of Walla Walla and flow modeling shows that it will not be able to serve the areas experiencing growth. Gate station is estimated to cost $3,106,259 and pipeline is estimated to cost $2,174,381. Construction is anticipated for 2018 and 2019.

Table 9-1: Distribution Planning Capital Projects

Location	2017	2018	2019
Stanwood 4" PE Reinforcement	$116,130		
Manchester 4" PE Reinforcement		$245,870	
South Walla Walla Gate & HP Line		$3,356,259	$2,190,610

Table 9-1 highlights just a few of Cascade's near future growth projects. With the use of the computer modeling software and Cascade's Distribution Scenario Process, the Company can identify projects for the longer term. As projects are completed they are integrated into the system to make sure the model is current. This ensures that Cascade is using the most recent versions of its system moving forward.

Conclusion

Cascade's goal is to maintain its natural gas distribution systems reliably and cost effectively to deliver natural gas to every 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 customer growth pattern.

SECTION 10

STAKEHOLDER ENGAGEMENT

Overview

Input and feedback from Cascade's Technical Advisory Group (TAG) is an important resource to help ensure the IRP includes perspectives external to the Company and responsive to stake-holders. Cascade believes its approach to public engagement exceeds that required by rule WAC 480-90-238.

Key Points

- Six Technical Advisory Group (TAG) meetings were held in SeaTac and Kennewick.
- Multiple opportunities for public participation were available.
- Several walkthroughs of technical components (e.g., SENDOUT® modeling) were conducted upon request.

Approach to Meetings and Workshops

As a result of various issues identified in the WUTC's April 14, 2016, letter to the Company regarding the 2014 IRP, the Commission ordered Cascade to file a new IRP on or before December 14, 2016. As a result, the Company faced a shortened IRP development and process arc of less than eight months. The Company committed to an aggressive timeline in order to ensure compliance with the WUTC order.

The Company's standard approach is to hold a series of public meetings, typically near Seattle. Cascade's IRP stakeholders are widely spread out geographically; Seattle is more easily accessible for individuals to attend than Kennewick. For those unable to travel, all meetings allowed for WebEx/teleconference participation. Cascade scheduled six TAG meetings between June and November 2016. Additionally, throughout the plan development stage Cascade responded to WUTC Staff requests to cover Cascade's forecasting methodology in greater detail, through supplemental workshops, as well as provided a more detailed overview of the Company's Gas Supply function.

Cascade recognizes the involvement in its Technical Advisory Group represents a material time commitment by participants. The Company very much appreciates the investment attendees provided to this process, through their time, review of multiple documents, and subsequent suggestions. This IRP has been improved due to the focus of the engaged stakeholders.

List of Stakeholders

The Company encourages public participation in the IRP process. Invited participants at these public meetings include interested customers, regional upstream pipelines, Pacific Northwest LDCs, utility Commission Staff, associated stakeholder representatives such as the Northwest Gas Association, Washington

Public Counsel, and the Northwest Industrial Gas Users. Internally, the Cascade IRP stakeholders and participants came from the following departments:

- Resource Planning
- Gas Supply/Gas Control
- Regulatory Affairs
- Operations/Engineering
- Conservation, Energy Efficiency
- Finance/Accounting
- Information Technology
- Executive group

Additionally, Cascade contracted the services of an IRP consultant, Bruce W Folsom Consulting LLC, to assist the Company with meeting the aggressive 2016 IRP schedule. More discussion about the Company's commitment to the IRP process can be found in Section 11, Regulatory Compliance.

TAG Meetings

Cascade held six public TAG meetings with internal and external stakeholders. Information about each meeting date and major agenda items are provided below.

2016 IRP TAG 1 Meeting – Thursday, June 16, 2016

- Location: Seattle, WA at the Sea-Tac Airport Conference Center from 9 am to noon
- IRP Timeline
- Demand Forecast Methodology
- Latest Economic Indicators

2016 IRP TAG 2 Meeting – Tuesday, July 19, 2016

- Location: Seattle, WA at the Sea-Tac Airport Conference Center from 9 am to noon
- Demand Forecast Results
- Current and Alternative Supply Resources
- Transport Issues

2016 IRP TAG 3 Meeting – Tuesday, August 23, 2016

- Location: Kennewick, WA at Cascade's Headquarters, Snake River Room from 9 am to 3 pm
- Demand Side Management
- Planned Scenarios and Sensitivities
- Carbon Legislation

2016 IRP TAG 4 Meeting – Thursday, September 15, 2016

- Location: Seattle, WA at the Sea-Tac Airport Conference Center from 9 am to noon
- Distribution System Planning
- Preliminary Resource Integration Results
- Avoided Costs

2016 IRP TAG 5 Meeting – Friday, October 14, 2016

- Location: Kennewick, WA at Cascade's Headquarters, Snake River Room from 9 am to noon
- Final Integration Results
- Proposed Two-Year Action Plan
- Discussion of any Remaining Items Prior to Filing the Draft 2016 IRP

2016 IRP TAG 6 Meeting – Thursday, November 17, 2016

- Location: Kennewick, WA at Cascade's Headquarters, Snake River Room from 9 am to 11am
- History and Current modeling of SENDOUT®
- Final Integration Results and solve for 2016 IRP

Opportunity for Public Participation

Cascade is fully committed to ensuring public participation in its IRP process. Cascade filed the Work Plan for the 2016 IRP with the WUTC on April 28, 2016. Notice was also provided via email to all participants of Cascade's 2014 IRP. Additionally, in order to improve the public's access to the Company's IRP related information, Cascade recently established a dedicated Internet webpage where all parties can view the IRP timeline, TAG presentations and minutes, as well as current and past IRPs.[1] For future IRPs the Company will announce the IRP process in a customer insert as close to practical to the filing of the IRP Work Plan.

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

SECTION 11

REGULATORY COMPLIANCE

Approach to Regulations, Policies and Stakeholder Comments

Cascade is subject to regulatory oversight by the Washington Utilities and Transportation Commission (WUTC) and the Public Utility Commission of Oregon (OPUC). Each Commission has established a set of guidelines or rules to which the Company's plan(s) must comply. In Washington those guidelines are established in WAC 480-90-238 and in Oregon the guidelines are found in the Commission Order No. 07-002 in Docket UM 1056. In general, both Commissions' guidelines require that Cascade develop a range of demand forecasts, examine all feasible resources for meeting that demand, whether they are supply side or demand side, and compare them on an equal basis, consider the uncertainty over the planning horizon, develop a two-year action plan, and involve the public and the various stakeholders in the planning process.

Key Points

- After filing this 2016 IRP in December, Cascade's next Washington IRP will be due December 14, 2018.
- Two new IRP analyst positons were approved by Cascade senior management in response to concerns regarding Cascade's IRP staffing. Currently one has been filled.
- Cascade's IRP team is staffed by three full time members, with input from consultants, internal staff, and an IRP Steering Committee.
- The IRP is a tool to maximize the efficiencies of the Company's utility operations.
- Cascade believes that the 2016 IRP meets all requirements of the WUTC.

Short History about Compressed Time Schedule

The WUTC formally issued a letter on April 14, 2016, which did not acknowledge the Company's 2014 IRP. In their letter the WUTC ordered Cascade to file its next IRP by December 14, 2016. This document represents the 2016 IRP. After filing the final 2016 IRP in December, Cascade's next Washington IRP will be due December 14, 2018.

The OPUC formally did not acknowledge Cascade's 2014 IRP at the public meeting on February 9, 2016. The Company was ordered to respond to all outstanding data requests by the filing deadline for the annual IRP Update (February 9, 2017). The next Oregon IRP is due February 9, 2018.

Resources Provided and Commitment Throughout the Company

In response to OPUC and WUTC concerns regarding Cascade's IRP staffing, a restructuring of the Resource Planning department was implemented in spring 2016. Two new IRP analyst positons were approved by Cascade senior management.

These incremental positions join the Manager of Resource Planning, and the Sr. Resource Planning Analyst to form the principle IRP team for Cascade.

In addition to expanding the Resource Planning team, the Company created an IRP Steering Committee to provide senior management oversight of the internal IRP process. The membership of the IRP Steering Committee is identified below:

- Garret Senger (Executive V.P. Regulatory Affairs, Customer Service & Gas Supply), Committee Chair
- Mark Chiles (V.P. Regulatory Affairs and Customer Service)
- Eric Martuscelli (V.P. Operations)
- Bob Morman (Director, Gas Supply)
- Mike Parvinen (Director, Regulatory Affairs (CNGC))

Internal IRP Team

The primary IRP team consists of Mark Sellers-Vaughn (Manager, Resource Planning), Brian Robertson (Sr. Resource Planning Analyst), Devin McGreal (Resource Planning Analyst I) and Bruce Folsom (Consultant with Bruce W Folsom Consulting LLC). One additional analyst position is vacant as of the drafting of this IRP. The Company is actively recruiting to fill this position.

Significant contributions are also made by internal staff in support of the IRP (Conservation, Engineering, Finance & Accounting, Gas Supply/Gas Control, Regulatory, Industrial Services, Information Technology and the Executive team.)

IRP Guidelines

Cascade utilizes integrated resource planning to maximize the efficiencies of the Company's utility operations. The planning process includes an assessment of current and future gas load requirements, the possible resource options for serving the projected load requirements, and a selection of the set of least cost resource alternatives with acceptable levels of reliability through the use of an optimization model. Monte Carlo simulation tools are utilized to further analyze the results of the optimization model to quantify the range of uncertainty in market price and demand due to changes in weather.

Compliance Matrices

Please refer to Appendix C, IRP Guideline Compliance, for expanded commentary of compliance with WUTC IRP rules, guidelines and orders.

This 2016 IRP Fully Complies with All Regulations, Orders, and Comments

Cascade believes that the 2016 IRP meets the requirements of the WUTC. This IRP includes a range of demand forecasts that encompass the anticipated forces, both economic and weather-driven, that will impact the load forecasts over the planning horizon. Section 7, Demand Side Management, includes an assessment of technically feasible improvements in the efficient use of natural gas. Section 4, Supply Side Resources, includes a discussion of the supply side resource options available including an assessment of conventional and commercially available non-conventional gas supplies, an assessment of opportunities for additional Company-owned and contracted storage, and an assessment of the Company's existing pipeline transportation capability and reliability along with the opportunity for incremental pipeline transportation resources. Section 8, Resource Integration, provides a comparative evaluation of the cost of the various resource options on a consistent and comparable method. Section 8, Resource Integration, also describes the incorporation of the demand forecast and resource evaluations into a long range resource plan describing the strategies designed to meet current and future needs reliably at the lowest reasonable cost to Cascade's customers. The short-term action plan describes the specific actions the utility will take to implement the long-range integrated resource plan during the next two years and reports on the Company's progress in meeting its prior two-year action plan goals.

Cascade believes all resources described in this IRP have been evaluated on a consistent and comparable basis through the use of its optimization model. Uncertainty is considered in each component of this plan. The demand forecast includes a reasonable range of uncertainty as quantified in the low, medium and high load growth scenarios along with the additional simulation analysis calculated through SENDOUT® Monte Carlo functionality that assesses the impacts of weather on the load forecasts. Section 4, Supply Side Resources, and Section 7, Demand Side Management, describe relative uncertainties regarding reliability, cost and operating constraints, and external costs. Uncertainties associated with the environmental effects of carbon emissions have also been included through an analysis of the impact of carbon legislation on the portfolio. Price volatility and market risks and their impacts on the Company's long-term resource portfolio have been assessed through the use of the SENDOUT® model.

To involve public interests in the development stages of this IRP, Cascade created a Technical Advisory Group (TAG). Multiple meetings were held to discuss the major IRP topics including the demand forecast, demand side resources, and supply side resources, distribution system planning and resource integration and optimization. The TAG meetings were helpful to Cascade as questions were answered and varying points of view were explored. Appendix A, IRP Process, contains copies of the meeting content, a list of participants, and the presentation materials.

As mentioned earlier, Appendix C, IRP Guideline Compliance, provides additional information regarding the specific requirements or guidelines for Washington and how the Company has met those requirements.

SECTION 12

TWO-YEAR ACTION PLAN

2016 Action Plan

The two-year action plan embodies Cascade's commitment to maximizing the efficiency from its Integrated Resource Plan and to achieving the lowest cost resource portfolio of reliable natural gas services and conservation.

Key Points
Cascade's 2016 Action Plan focuses on:
- Demand Forecast
- Demand Side Management
- Supply Side Resources
- Distribution System
- Integration

Demand Forecast

The Company has purchased SAS analytics, a statistical analysis software, and plans to continuously improve the forecasting model. Cascade will continue to analyze different regressions to find which provides the best results.

Cascade will also work on gathering growth information from other locations to compare with Woods & Poole. The Company will also look into improving the methodology to the customer growth forecast.

Demand Side Management (Conservation)

Based on the noted potential and goals for the Conservation Incentive Programs, the Company will be centering on a few areas as part of a two-year action plan leading into the long-term programmatic goals:

- Increase incentives to a level that maintains the cost effectiveness of the programs but increases program uptake commensurate with customers receiving additional funds for their efforts (going beyond 30% levels where appropriate);
    - This will be accomplished by having run the TEA-Pot modeling tool with varying levels of 30% and 50% incentives dependent on individual measures;
    - Propose updates by the end of Q1 2017;
    - Updates will be discussed with the CAG;
- Explore the full breadth of measures included in the Nexant model for inclusion into the Company's portfolio of measures;
    - Currently the full breadth of cost-effective commercial and industrial measures noted in the study are included under the "Custom" option for the Cascade CIP. The Company will review the equipment and non-equipment measures on a regular basis for potential inclusion into the portfolio, keeping in mind cost-effectiveness (based on current avoided costs), and administrative cost parameters, on-the-ground realities, and changes in technology and the potential for market transformation in Cascade's service territory;

- Increase engagement in the Northwest Energy Efficiency Alliance (NEEA) Natural Gas Market Transformation Collaborative over the next two years with a focus on Cascade's territory and viable increases in availability of the pilot efforts (including the high-efficiency commercial rooftop unit);
  - In 2017 engage fully with the Gas Technology Institute Emerging Technologies group through the NEEA membership to explore new technology opportunities;
  - The Company will also leverage its Collaborative membership in Q3 2017 and into 2018 by exploring the study possibilities related to the residential and commercial building stock assessments created by NEEA. These studies can provide a snapshot of specific stock and can tell about gas service percentages in portions of the territory where they overlap with electric providers who engage with NEEA although there is no gas metering data. NEEA has offered to provide some recommendations and assistance with exploring what else can be extrapolated from the data specific to Cascade as a gas utility. Note – the Company had a service territory specific potential study performed by Nexant Inc. in 2013/2014 which incorporated similar data to the NEEA information. There is opportunity for the Company to explore updating the individualized potential study in the latter half of 2018 if deemed necessary;[1] and
- Work with Nexant Inc. throughout Q1 and into Q2 2017 to fine-tune reporting availability for EM&V related tracking through iDSM platform.

While addressing the items above, the Company will consistently monitor the state of natural gas conservation technologies within its service territory and make adjustments commensurate with evolving ENERGY STAR® standards and code requirements. In line with these efforts, in October 2016 the Company updated its offerings to remove an upgrade to a 95% furnace for the whole home ENERGY STAR® incentive to align with altered ENERGY STAR® standards and added the Demand Control Ventilation measure to its commercial offerings as noted in the 2016 Conservation Plan.

The Company is also monitoring the residential natural gas furnace code standards as well as water heater criteria and will alter the program offerings as standards and building codes change in the next few years.

Supply Side Resources

The Company will continue to monitor the potential reporting, administrative and potential financial impacts of long-term resources as a result of concerns surrounding fracking.

[1] See the Cascade Natural Gas Corporation Assessment of Achievable Potential & Program Evaluation Volume 1-3 dated February 25, 2014.

Cascade will continue to evaluate gas supply resources on an ongoing basis, including supplies (base, swing, peaking) of varying lengths and pricing alternatives. The Company will continue to analyze the uncertainties associated with supply and demand relationships.

The Company will continue to monitor proposed pipeline expansion projects in the Pacific Northwest region. As cost estimates change, the Company will analyze those resources under consideration to determine if modifications to the preferred portfolio are necessary.

Cascade will continue to refine its specific peak day resource acquisition action plans to address anticipated capacity shortfalls. Possible solutions may be Satellite LNG, incremental storage, peak shaving facilities or pipeline looping to meet the growing requirements of the firm core load. Specifically, the Company will further analyze issues such as determination of project location issues and risks, project cost estimates, and construction/acquisition lead times.

The Company will continue to monitor proposed LNG import facilities as information becomes available and will evaluate the various options that, if built, could result. Issues to monitor include specific cost, the availability of pipeline capacity, project timing and the source of supply.

Distribution System

The Company will continue to explore options to incorporate biogas into its portfolio, as specific projects are identified in the service territory. Price, location and gas quality considerations of the biogas supply will be evaluated.

Integration

The Company will continue to monitor the futures market for price trends and will evaluate the effectiveness of its risk management policy. Cascade will continue to participate in the WUTC's hedging Docket UG-132019 and OPUC's hedging Docket UM-1720.

The Company will participate in activities associated with WUTC Docket UE-161024 (IRP Rulemaking). While electric utility IRPs will be the primary focus of this inquiry, the Commission anticipates that there will be broad topics related to the IRP process that may affect natural gas utilities such as Cascade. Table 12-1 highlights specific activities of the 2016 Action Plan that were discussed at the Company's TAG 5 meeting.

Table 12-1: Highlights of Draft 2016 Action Plan

Functional Area	Anticipated Action	Timing
Demand Forecast	Expanding forecasting to test non-linear regression methodology using SAS	Beginning in 2016 for 2018 IRP
Demand Forecast	Consider the new weather normalization model in the forecast	Beginning in 2016 for 2018 IRP
Demand Forecast	Cascade will work on gathering growth information from other locations to compare with Woods & Poole. Also include analysis from State Economist Report	Beginning in 2017 for inclusion in 2018 IRP
DSM	Investigate incorporating distribution system costs into the avoided cost calculation	Beginning in 2017 for inclusion in 2018 IRP
DSM	As specific carbon legislation is passed, the Company will update its avoided cost calculations, conservation potential and make modifications to its DSM incentive programs as necessary.	Consider in 2017 for possible modification in the 2018 IRP
Environmental, DSM, Demand Forecast	The Washington State Dept. of Ecology issued a new carbon rule. Cascade will need to consider IRP implications	Beginning in 2017 for inclusion in 2018 IRP
Resource Integration	Expand Monte Carlo methodology to include analyses of a variety of potential portfolio scenarios (e.g., high growth, low pricing, etc.)	Beginning in 2017 for inclusion in 2018 IRP
Supply Resources	Negotiate with TransCanada for the needed incremental GTN capacity for November 2017	Complete by June 2017, with a November 2018 in-service date
Supply Resources	Work with NWP to define what delivery rights can be modified to meet potential shortfalls	Complete assessment by July 2017
Supply Resources	Work with NWP and potentially other regional LDCs to determine if a combination of I-5, Wenatchee, etc. expansion or segmentation can address shortfalls and regional infrastructure concerns.	Complete assessment by July 2017
Distribution System Planning, Resource Planning, Gas Supply	Incorporate the citygate study into the IRP.	Beginning in 2016, complete in early 2017 for inclusion in IRP
Distribution System Planning, Gas Supply, Operations, Others	Use the results of the Study to confirm aligning of alternative resources, specifically satellite LNG	Confirm that satellite LNG is proper solution by July 2017;
Distribution System Planning, Gas Supply, Operations, Others	Upon confirmation of need to for satellite LNG, proceed with implementation of facility	Begins no later than July 2017, for potential in service date of November 2018

SECTION 13

GLOSSARY AND MAPS

GLOSSARY OF TERMS AND ACRONYMS

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™** utilizes a Monte Carlo approach in combination with the linear programming approach 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.

AFUE
Annual Fuel Utilization Efficiency. Thermal efficiency measure of combustion equipment like furnaces, boilers, and water heaters.

AMA
Asset Management Agreement. An arrangement that an LDC may enter into with a marketing company to assist with transportation and storage assistance.

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.

ARRA
The American Recovery and Reinvestment Act of 2009.

AVOIDED COST
Marginal Cost of serving the next unit of demand, which is saved through conservation efforts.

BACKHAUL SERVICE
A transaction where gas is transported the opposite direction of normal flow on a unidirectional pipeline.

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.

BNG
Bio natural gas and 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 (see below) of natural gas has an energy value of 100,000 BTUs and is approximately equivalent to 100 cubic feet of natural gas.

CC&B
Customer Care and Billing. Internal billing data for Cascade Natural Gas.

CD
Contract Demand.

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.

CNG
Compressed Natural Gas.

CNGC
Cascade Natural Gas Corporation.

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.

CONTRACT DEMAND
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.

COP
Coefficient of Performance.

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.

CPI
Consumer Price Index, as calculated and published by the U.S. Department of Labor, Bureau of Labor Statistics.

DAY GAS
Gas that can be purchased as needed to cover demand in excess of the base load.

DEKATHERM
Unit of measurement for natural gas; a dekatherm is 10 therms, which is one thousand cubic feet (volume) or one million 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.

DSM
Demand Side Management.

DTH
Unit of measurement for natural gas; a dekatherm is 10 therms, which is one thousand cubic feet (volume) or one million BTUs (energy).

EBB
Electronic Bulletin Board.

EIA
Energy Information Administration.

ENTITLEMENTS
Flow management tool used by upstream pipelines, in conjunction with OFOs.

EXPECTED SCENARIO
Least cost mix of existing and incremental resources to solve projected unserved demand under average weather with peak event, average price, and expected growth.

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.

FOM
First of the Month price; 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.

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 of where the gas was purchased to the citygate.

FUGITIVE METHANE EMISSIONS
Natural Gas that escapes the system during drilling, extraction and/or transportation of gas.

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.

GHG
Greenhouse Gas.

GMS
Gas Management System.

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 represents the sum of the high and low readings divided by two.

HENRY HUB
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; also called liquefaction when the storage facility is a liquefied natural gas plant.

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; the interruption happens when the demand of all firm customers exceeds the capability of the system to continue deliveries to all of those customers.

INTERSTATE PIPELINE
A federally regulated company that transports and/or sells natural gas across state lines.

IOU
Investor owned utility.

IRP
Integrated Resource Plan; the document that explains Cascade's plans and preparations to maintain sufficient resources to meet customer needs at a reasonable price.

JACKSON PRAIRIE
An underground storage project jointly owned by Avista Corp., Puget Sound Energy, and NWP; the project 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.

KORP
Kingsvale-Oliver Reinforcement Project.

LDC
Local Distribution Company. LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area.

LIQUEFIED NATURAL GAS (LNG)
Natural gas that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.

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.

LNG
Liquefied natural gas. Natural gas that has been liquefied by chilling. 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; 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 in the future.

LOAD MANAGEMENT
Seek to lower 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
Pattern of a customer's gas usage, hour to hour, day to day, or month to month.

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.

LRC
Lowest Reasonable Cost. Methodology used when evaluating alternatives to determine the optimal solution to a given problem.

MCF
A unit of volume equal to a thousand cubic feet.

MDDO
Maximum Daily Delivery Obligation.

MDQ
Maximum Daily Quantity.

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.

MOU
Memorandum of understanding.

NAESB
North American Energy Standards Board.

NAÏVE FORECAST
A methodology used for predicting future demand when the results from a regression analysis do not show enough of a correlation between actual demand and the forecast model. This forecast is performed by using the previous year's demand multiplied by a growth factor.

NATIONAL ENERGY BOARD
The Canadian equivalent to the Federal Energy Regulatory Commission (FERC).

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.

NEPA
National Environmental Policy Act.

NEW YORK MERCANTILE EXCHANGE (NYMEX)
An organization that facilitates the trading of several commodities including natural gas.

NGV
Natural Gas Vehicles.

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. Typical customers include large commercial, industrial, cogeneration, wholesale, and electric generation customers.

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
Consist of two members from each of the four Northwest states, Oregon, Washington, Idaho and Montana, to develop a regional plan.

NOVA GAS TRANSMISSION (NOVA)
See TransCanada Alberta System.

NWBOP
Northwest Builder Option Packages.

NWGA
Northwest Gas Association.

NWP
Williams-Northwest Pipeline.

NYMEX
New York Mercantile Exchange.

NYMEX HH
New York Mercantile Exchange Henry Hub.

OFO
Operation Flow Order is an order issued by an upstream pipeline to alleviate conditions, among other things that threaten the safe operations or integrity of the pipeline, or the maintenance of operations required to provide efficient and reliable firm service. The pipeline's ability to deliver anticipated quantities and maximize efficiency and capacity utilization is often dependent upon marinating project flow patterns (e.g. receipts, deliveries and balances). Violations or failure to comply with an OFO can result in the pipeline assessing penalties to offending shippers.

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.

ON SITE
At the point of injection.

OPAL (OPAL HUB)
Natural Gas trading hub in Lincoln County, WY.

PCGP
Pacific Connector Gas Pipeline Project.

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.

PRICE ELASTICITY
Economic concept which recognizes that customer consumption changes as prices rise or fall.

PSI
Pounds per Square Inch. This is the standard unit of measure when determining how much pressure is being applied when gas is flowing through a pipe.

PTCS
Performance Tested Comfort Systems.

PVRR
Present Value of Revenue Requirement.

REAL
Discounting method that excludes 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)

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 there are not high system demands.

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 power 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
Parties agree to exchange an index price for a fixed price over a defined period.

SYNERGI®
Engineering software used to theoretically 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.

TEA-POT
Microsoft Excel-based modeling tool to determine the Technical/Economic/Achievable Potential savings of various proposed DSM programs.

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.

TRANSCANADA ALBERTA SYSTEM
Previously known as NOVA Gas Transmission; 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
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 is 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.

TRC
Total Resource Cost.

TSA
Transportation Service Agreement.

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.

UPSTREAM PIPELINE CAPACITY
The pipeline delivering natural gas to another pipeline at an interconnection point where the second pipeline is closer to the consumer.

W&P
Woods & Poole, independent firm that specializes in long-term county economic and demographic projections.

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.

WUTC
Washington Utilities and Transportation Commission.

ZONE
A geographical area. A geological zone, however, 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 based on where the upstream pipelines have major compressor stations, have been historical upstream pipeline constraint or in specific weather areas. Where appropriate the Zone-IRP is separated by state. Please see the following chart 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 RNDERING	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
CHEMCIAL LIME	CHEMLIME	ZONE 24	NWP
CHEMULT	CHEM	ZONE GTN	GTN
DEHANNS DAIRY FARM TAP	DEHANDRY	ZONE 10	NWP
DEMING	DEMING	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
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
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 13-1: Map – AECO Hub Storage

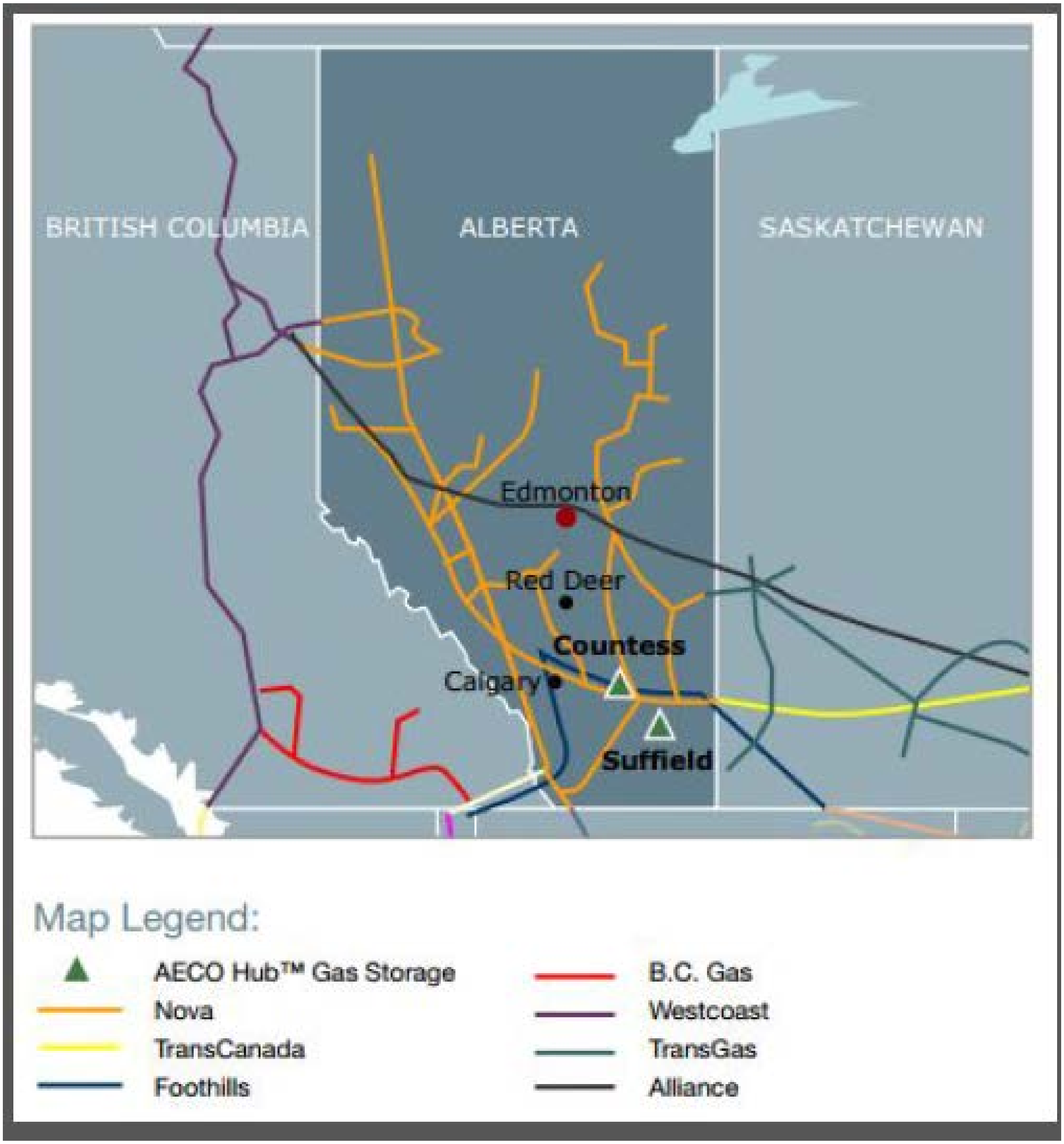


Figure 13-2: Map – California Storage Map

Figure 13-3: Map – Cascade Natural Gas Pipeline System

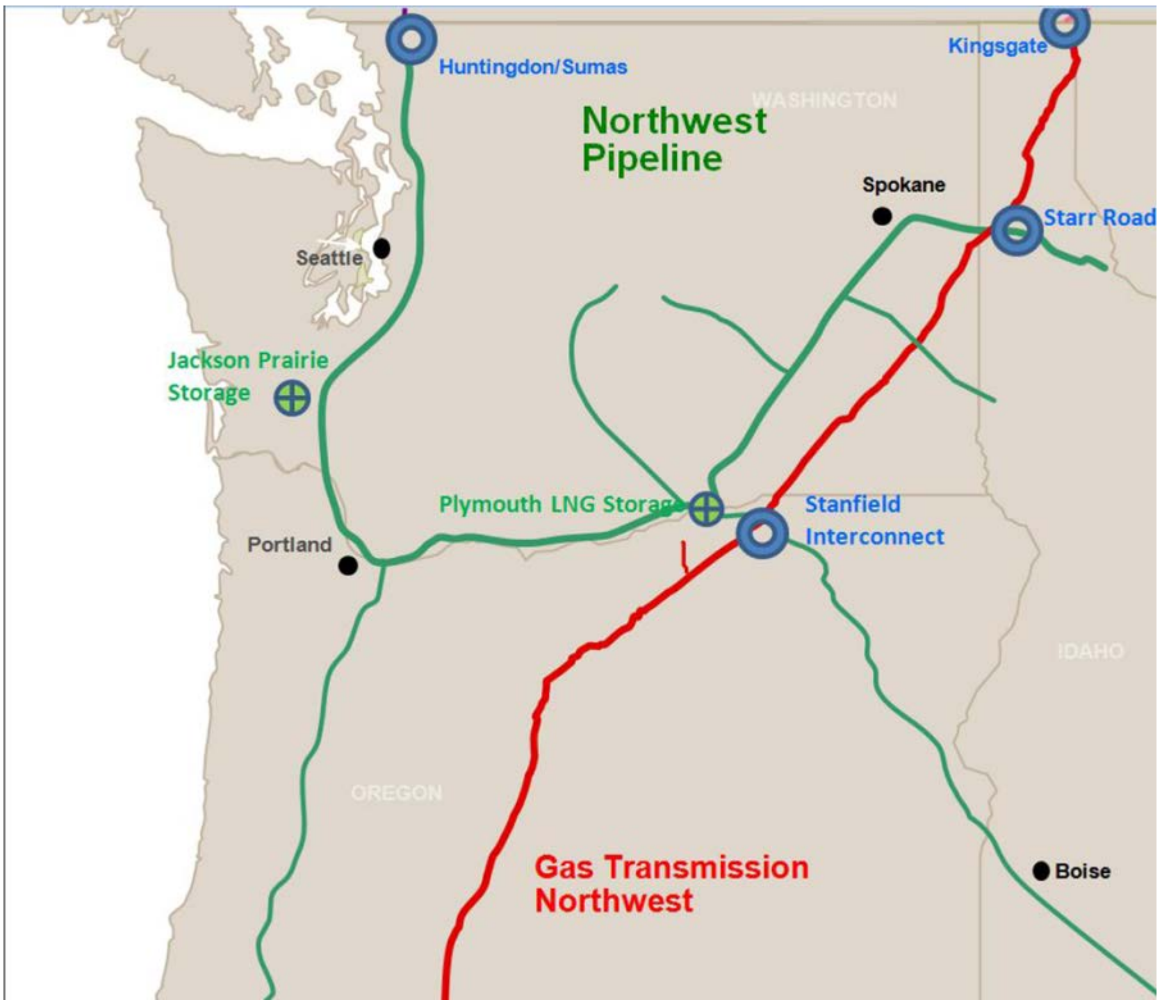


Figure 13-4: Map – Foothills-British Columbia Map

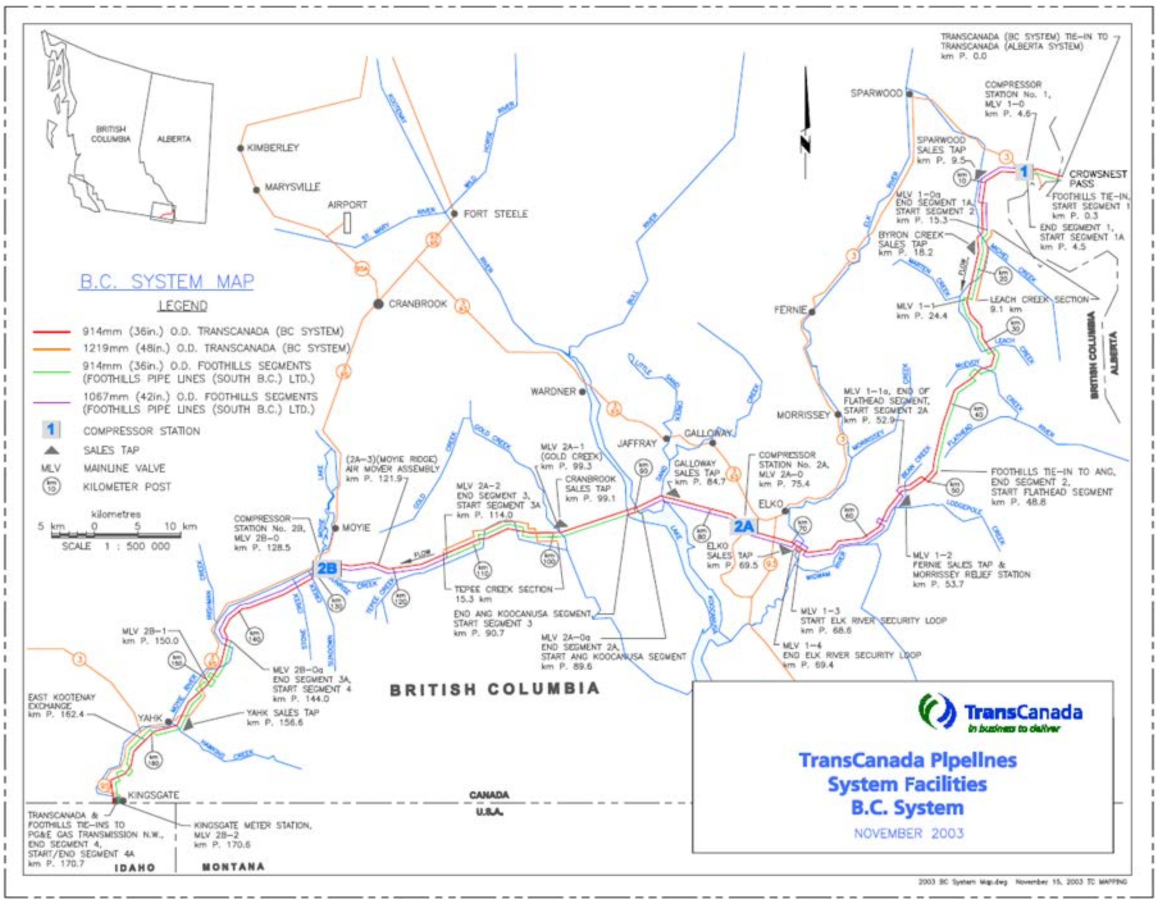


Figure 13-5: Map – Foothills-British Columbia Map 2

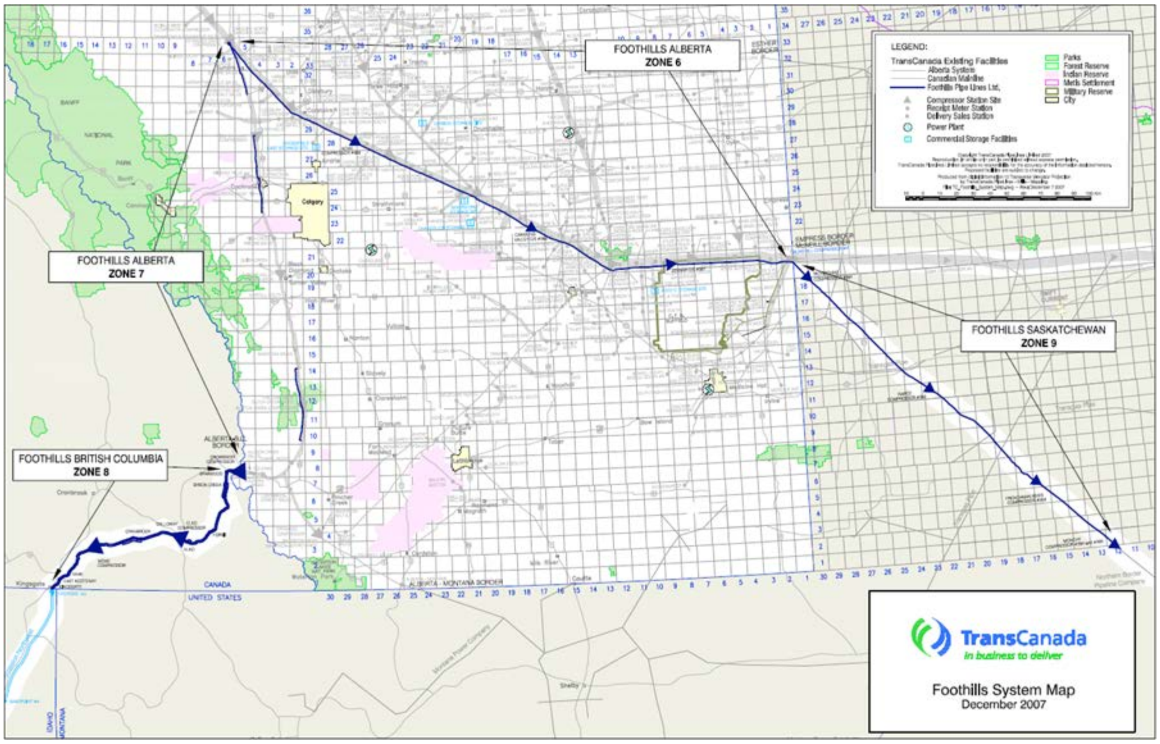


Figure 13-6: Map – GTN System Map

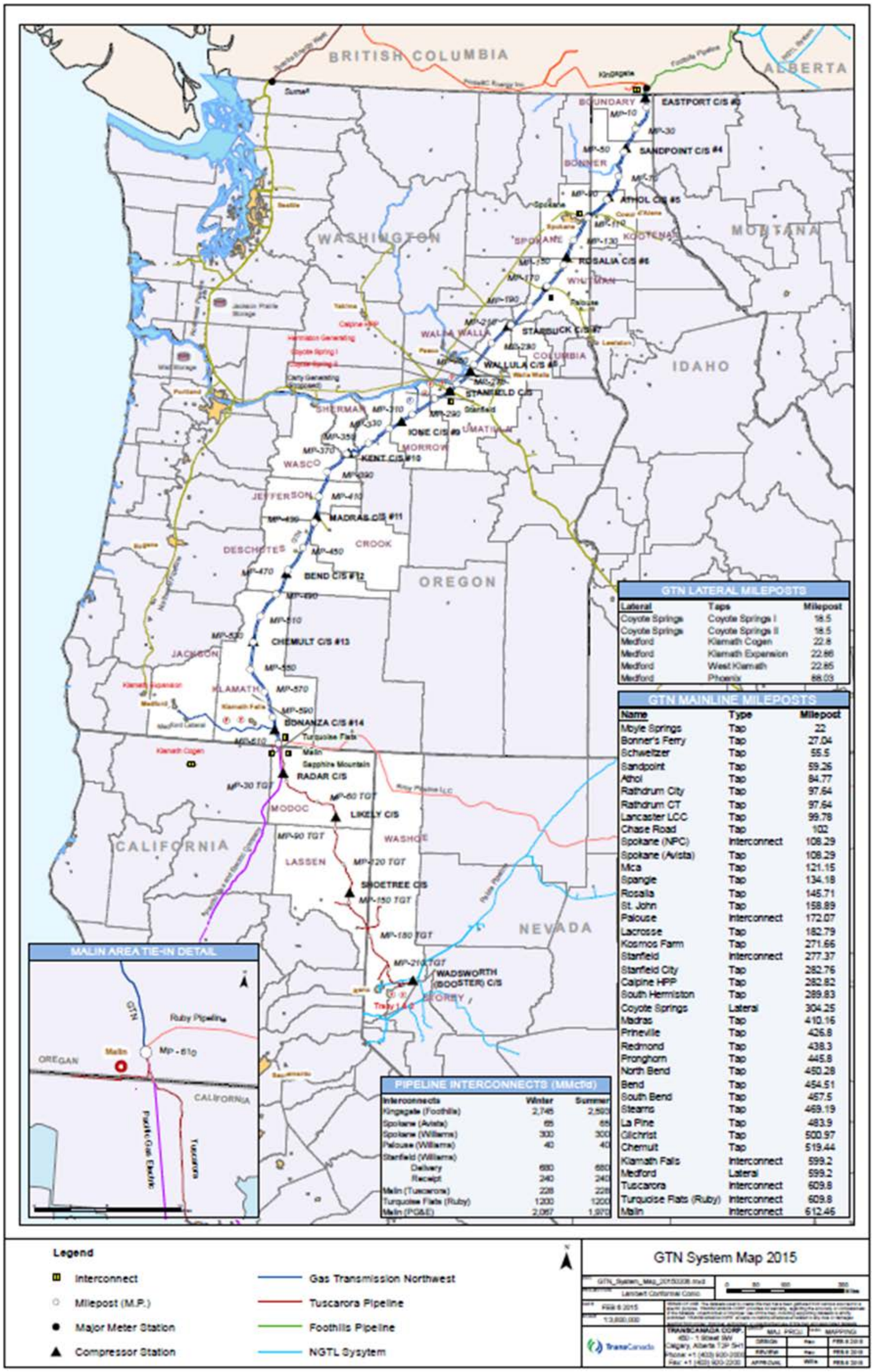
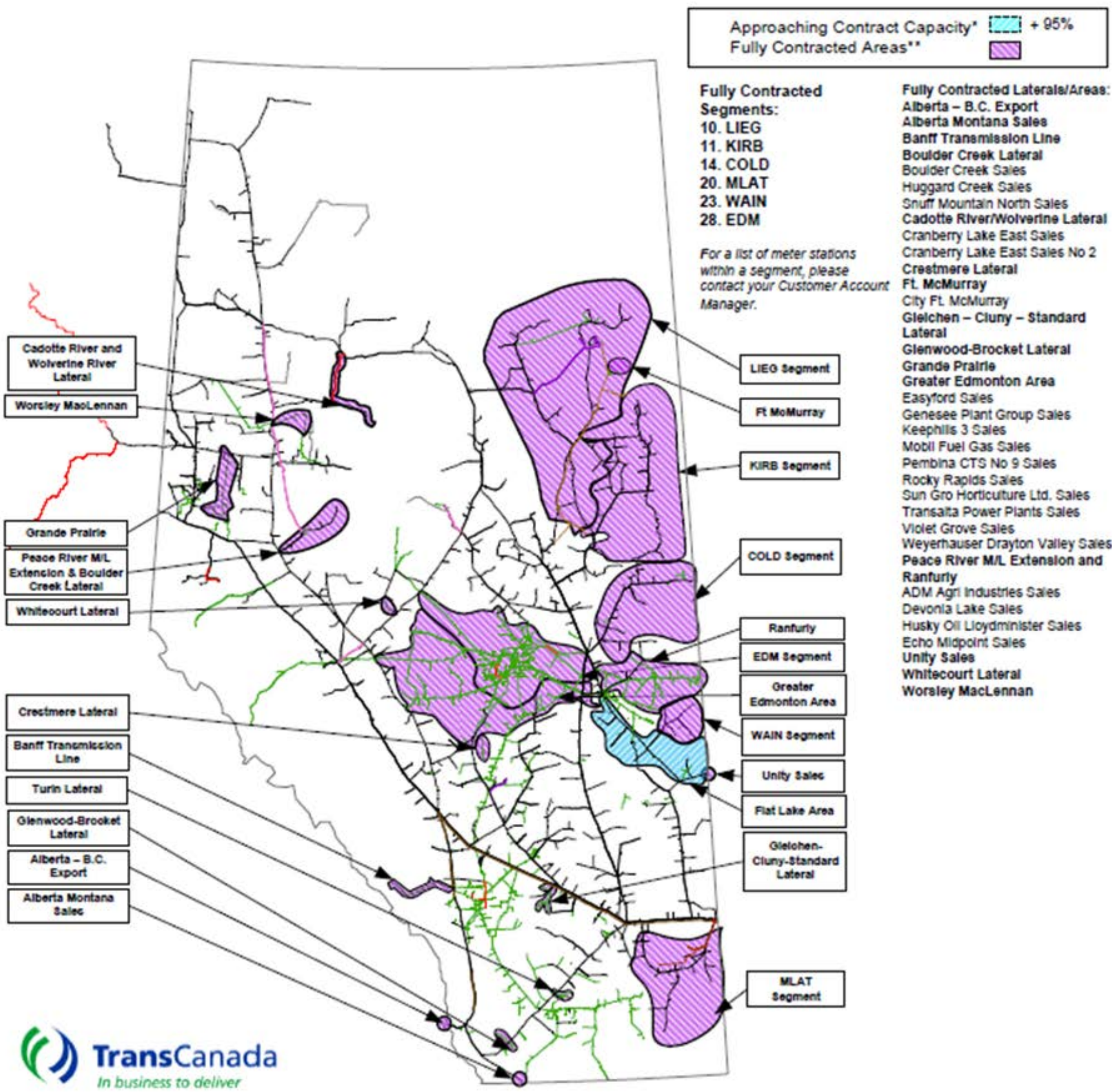


Figure 13-7: Map – NGTL Delivery System Map

TransCanada's NGTL System FT-D Availability Map
as of September 9, 2016

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 September 9, 2016 and is subject to change. Please contact your Customer Account Manager for clarification or additional information.

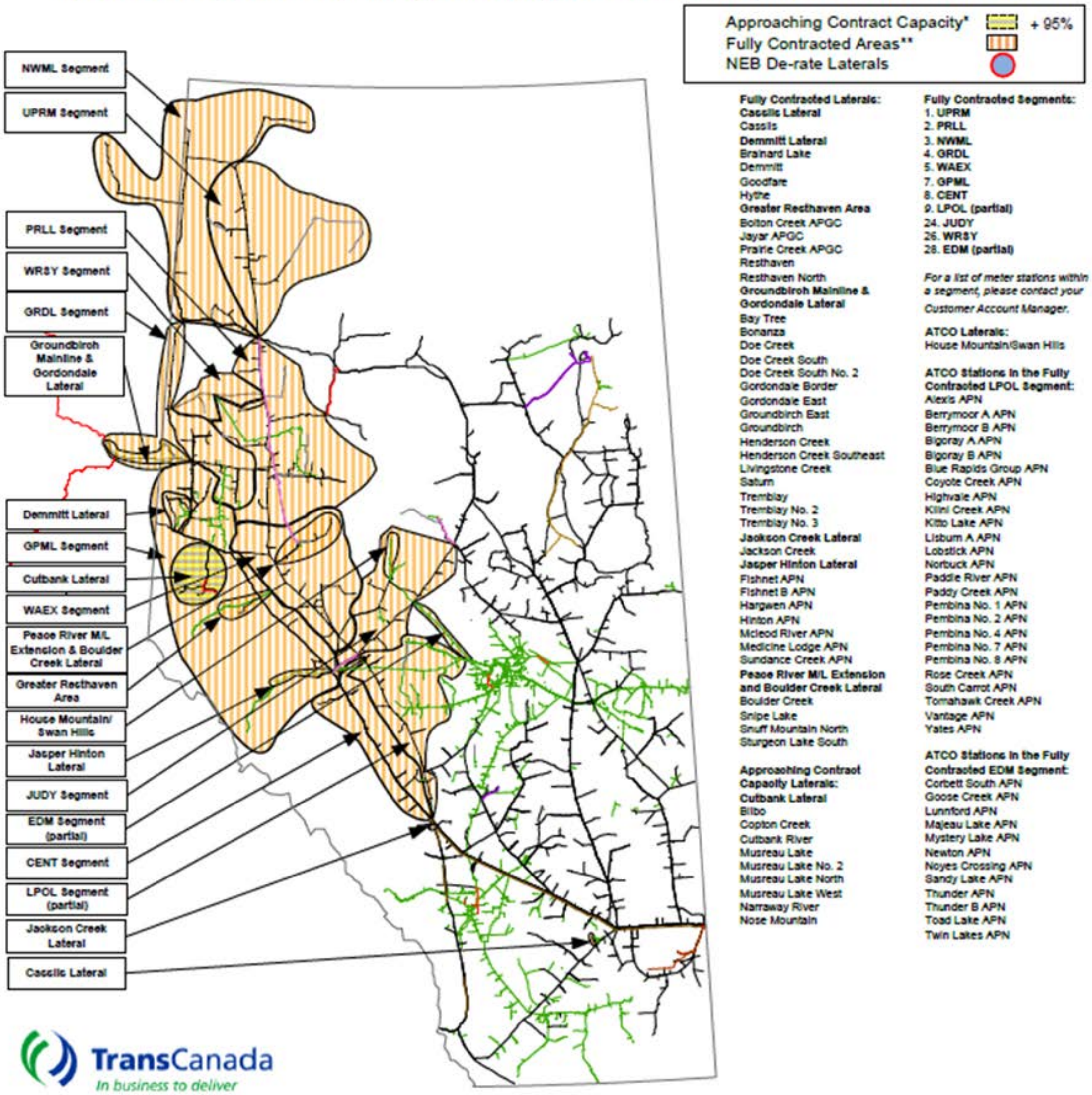


Approaching Contract Capacity*	Contracts are greater than 95% of the area or facility capability. It is recommended that Firm Transfers or New Firm Contracts be confirmed with TCPL Customer Sales.
Fully Contracted**	Area is fully contracted. Firm Transfers allowed within restricted area; upstream at 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, Delivery Capacity Update – September 9, 2016.
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 FT-D requirements to ensure that their FT-D levels align with their expected flow requirements.	

Figure 13-8: Map – NGTL Receipt System Map

TransCanada's NGTL System FT-R Availability Map
as of October 3, 2016

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 October 3, 2016 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. Firm Transfers or New Firm to be confirmed with TCPL Customer Sales.
FTR Fully Contracted**	Area is fully contracted. Firm Receipt Transfers allowed within restricted area; downstream at 1 to 1 ratio and upstream at determined hydraulic equivalence. Non-renewable firm service (FT-RN) may be available. For additional information refer to the Informational Postings on Customer Express, Project Area Receipt Capacity Update – July 27, 2016.
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.	

Figure 13-9: Map – NWP North System Map

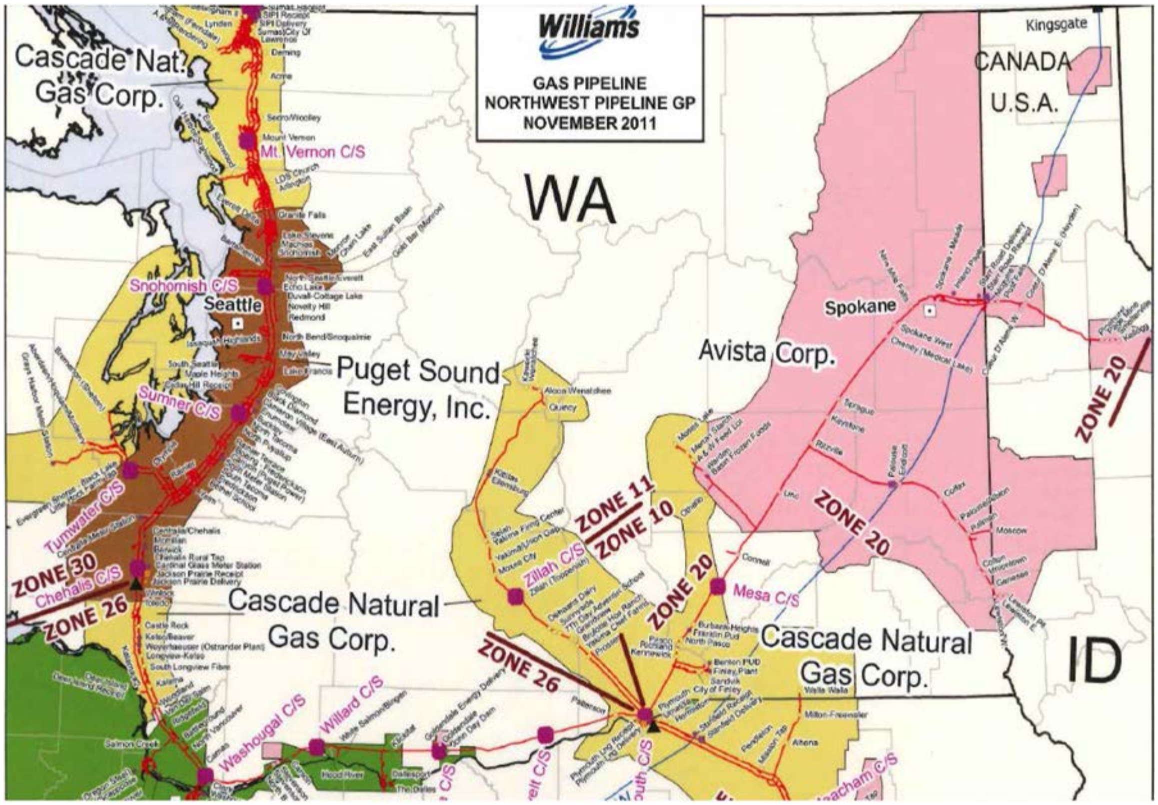


Figure 13-10: Map – NWP South System Map

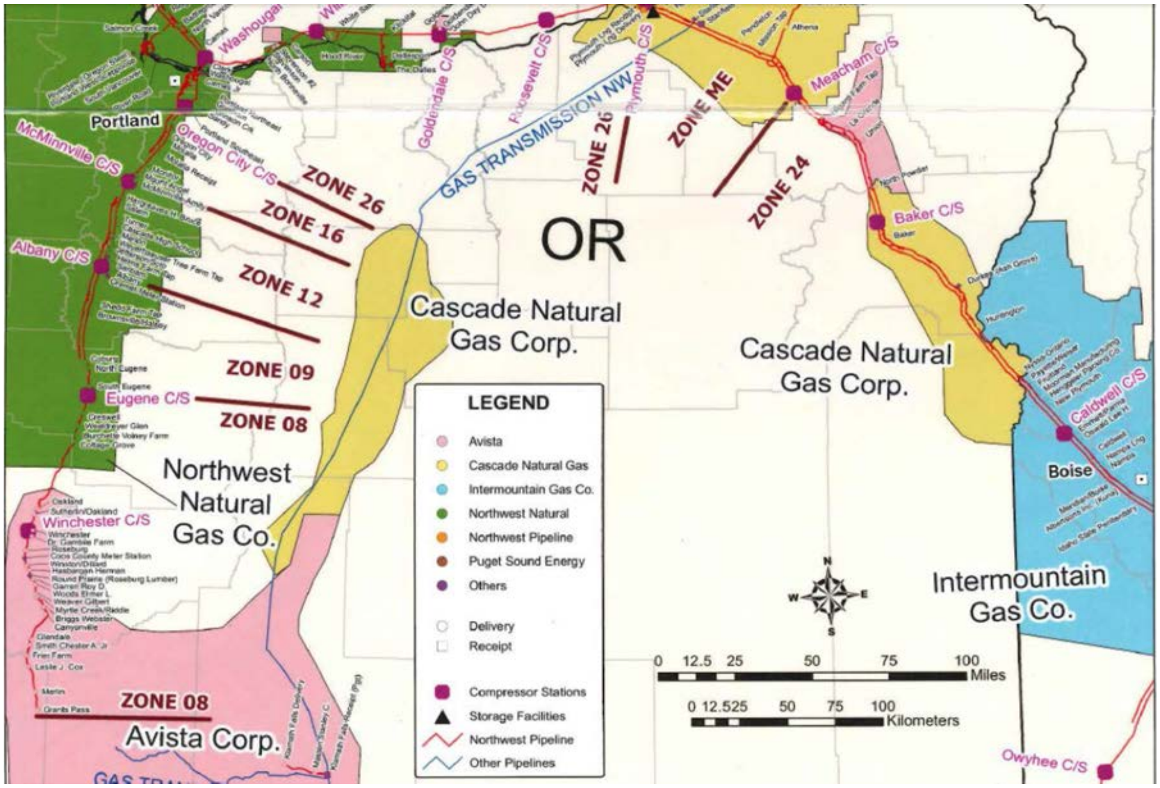


Figure 13-11: Map – Westcoast Sectional Map

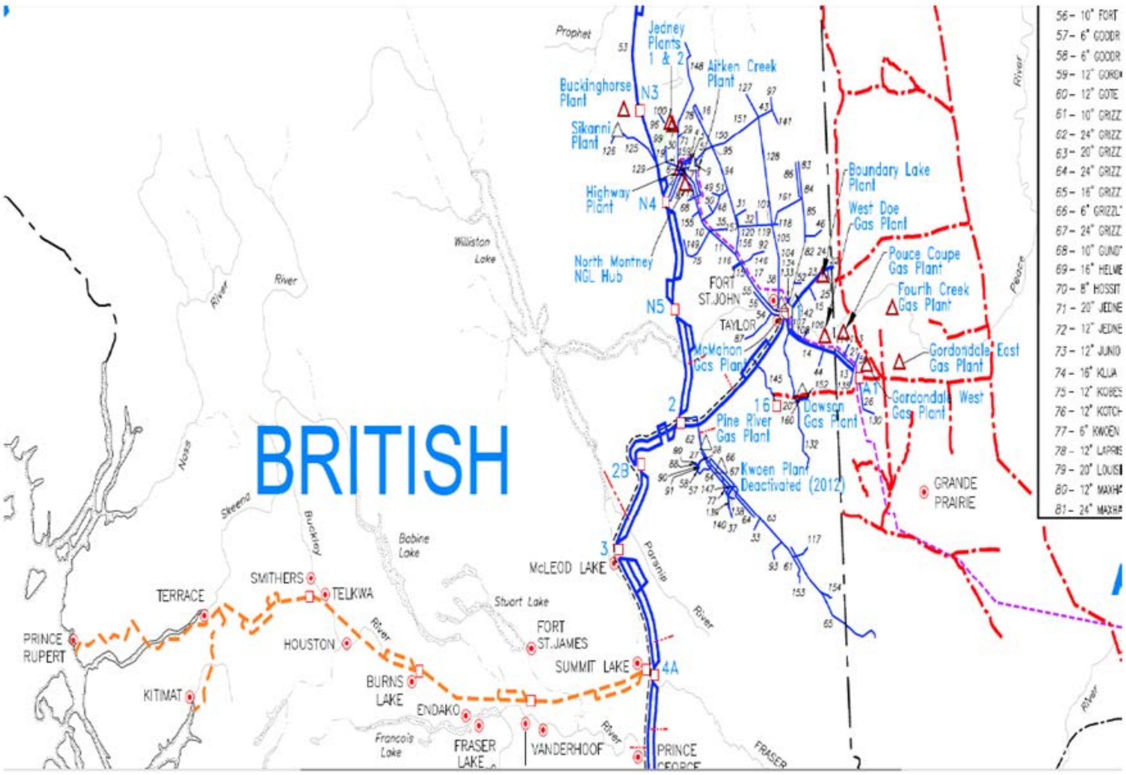


Figure 13-12: Map – Western U.S. and Canadian Pipeline Map

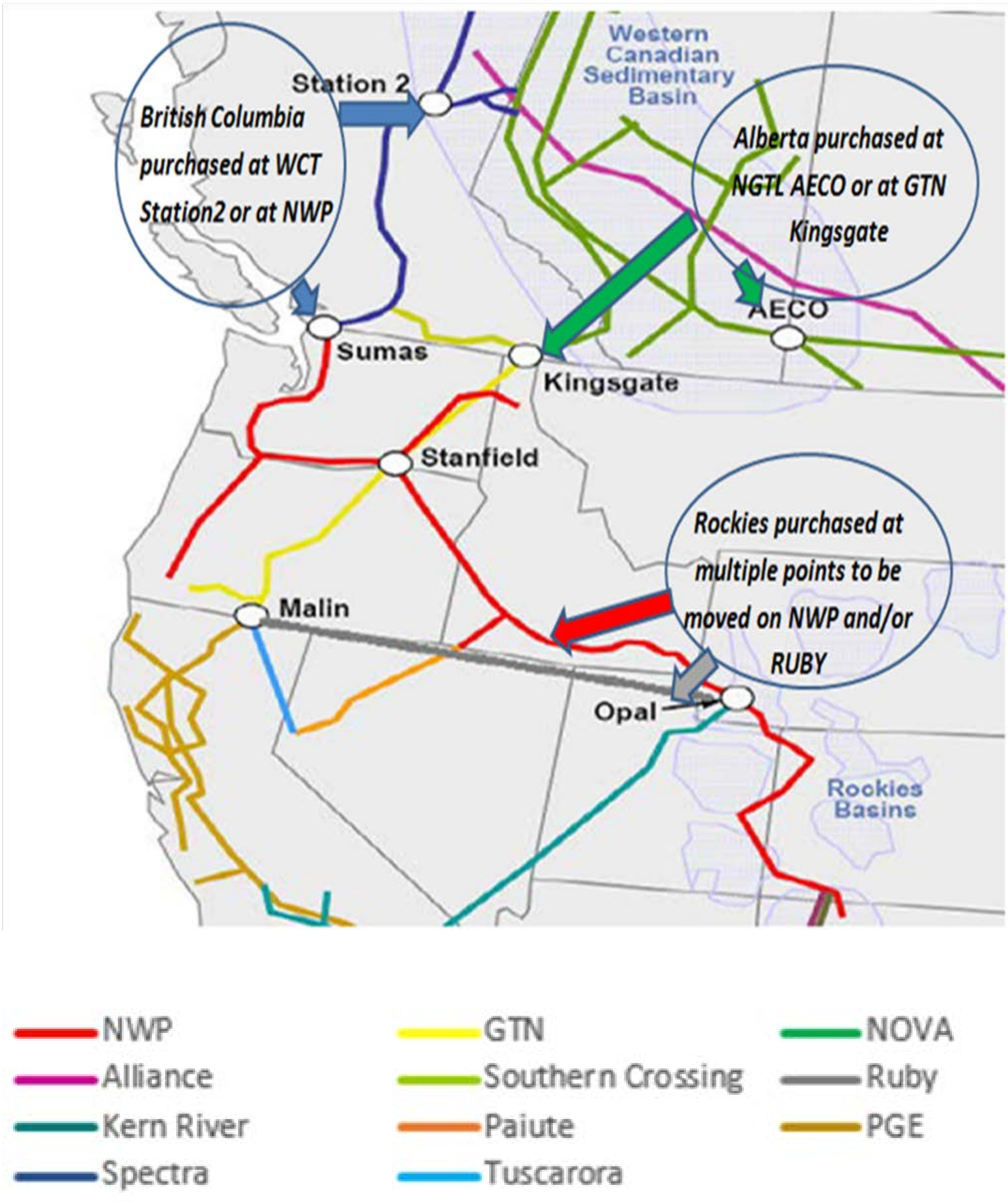


Figure 13-13: Map – Certificated Service Areas as Specified in RCW 80.28.190