AVISTA

2016

Natural Gas
Integrated Resource Plan

August 31, 2016

Safe Harbor Statement

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

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Executive Summary

Avista Corporation's 2016 Natural Gas Integrated Resource Plan (IRP) identifies a strategic natural gas resource portfolio to meet customer demand requirements over the next 20 years. While the primary focus of the IRP is meeting customers' needs under peak weather conditions, this process also provides a methodology for evaluating customer needs under normal or average conditions. The formal exercise of bringing together customer demand forecasts with comprehensive analyses of resource options, including supply-side resources and demand-side measures, is valuable to Avista, its customers, regulatory agencies, and other stakeholders for long-range planning.

IRP Process and Stakeholder Involvement

The IRP is a coordinated effort by several Avista departments along with input from our Technical Advisory Committee (TAC), which includes Commission Staff, peer utilities, customers, and other stakeholders. The TAC is a vital component of our IRP process, as it provides a forum for discussing multiple perspectives, identifies issues and risks, and improves analytical planning methods. Topics discussed with the TAC include natural gas demand forecasts, price forecasts, demand-side management (DSM), supply-side resources, modeling tools, and distribution planning. The process results in a resource portfolio designed to serve our customers' natural gas needs while balancing cost and risk.

Planning Environment

A long-term resource plan addresses the uncertainties inherent in any planning exercise. Compared to prior planning cycles, there is relatively more certainty about the availability of economically extractable natural gas. However, some of the future uses of this energy resource are unknown. There are questions concerning an industrial renaissance, liquefied natural gas (LNG) exports, natural gas vehicles, and power generation. We continue to analyze key assumptions by evaluating multiple scenarios over a range of possible outcomes to address the uncertainties.

Demand Forecasts

Avista defines eight distinct demand areas in this IRP structured around the pipeline transportation and storage resources that serve them. Demand areas include Avista's four service territories (Washington/Idaho; Medford/Roseburg, Oregon; Klamath Falls, Oregon and La Grande, Oregon) and then disaggregated by the pipelines that serve them. The Washington/Idaho service territory includes areas served only by Northwest Pipeline (NWP), only by Gas Transmission Northwest (GTN), and by both pipelines. The Medford service territory includes an area served by NWP and GTN.

Avista recognizes and accounts for weather, customer growth and use per customer as the most significant demand influencing factors. Other demand influencing factors include population, employment, age and income demographics, construction levels, conservation technology, new uses (e.g. natural gas vehicles), and use-per-customer trends.

Recognizing that customers may adjust consumption in response to price, Avista analyzed factors that could influence natural gas prices and demand through price elasticity. These factors include:

- **Supply:** shale gas, industrial use, and export LNG.
- **Infrastructure:** regional pipeline projects, national pipeline projects, and storage.
- **Regulatory:** subsidies, market transparency/speculation, and carbon legislation.
- **Other:** drilling innovation, thermal generation and energy correlations (i.e. oil/gas, coal/gas, and liquids/gas).

Avista developed a historical-based reference case and conducted sensitivity analysis on key demand drivers by varying assumptions to understand how demand changes. Using this information, and incorporating input from the TAC, Avista created alternate demand scenarios for detailed analysis. Table 1 summarizes these demand scenarios, which represent a broad range of potential scenarios for planning purposes. The Average Case represents Avista's demand forecast for normal planning purposes. The Expected Case is the most likely scenario for peak day planning purposes.

Table 1: Demand Scenarios

2016 IRP Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Alternate Weather Standard
Expected Case, Low Price

The IRP process defines the methodology for the development of two primary types of demand forecasts – annual average daily and peak day. The annual average daily demand forecast is useful for preparing revenue budgets, developing natural gas procurement plans, and preparing purchased gas adjustment filings. Forecasts of peak day demand are critical for determining the adequacy of existing resources or the timing for new resource acquisitions to meet our customers' natural gas needs in extreme weather conditions. The demand forecasts from the Average and Expected Cases revealed the data shown in Table 2:

Table 2: Annual Average and Peak Day Demand Cases (Dth/day)

Year	Annual Average Daily Demand	Peak Day Demand	Non-coincidental Peak Day Demand
2016	**94,164**	**361,901**	**331,820**
2035	**102,840**	**425,144**	**387,742**

Annual Average Daily Demand – Expected average day, system-wide core demand increases from an average of 94,164 dekatherms per day (Dth/day) in 2016 to 102,840 Dth/day in 2035. This is an annual average growth rate of 0.5 percent and is net of projected conservation savings from DSM programs. Appendix 3.1 shows gross demand, conservation savings and net demand.

Peak Day Demand – The peak day demand for the Washington/Idaho and La Grande service territories is modeled on and around February 15 of each year. For the southwestern Oregon service territories (Medford, Roseburg, Klamath Falls), the model assumes this event on and around December 20 each year. Expected coincidental peak day, or the sum of demand from each territories modeled peak, the system-wide core demand increases from a peak of 361,901 Dth/day in 2016 to 425,144 Dth/day in 2035. Forecasted non-coincidental peak day demand, or the sum of demand from the highest single day including all forecasted territories, peaks at 331,820 Dth/day in 2016 and increases to 387,742 Dth/day in 2035, a 0.8 percent average annual growth rate in peak day requirements. This is also net of projected conservation savings from DSM programs.

Figure 1 shows forecasted average daily demand for the six demand scenarios modeled over the IRP planning horizon.

Figure 1: Average Daily Demand (Net of DSM Savings)

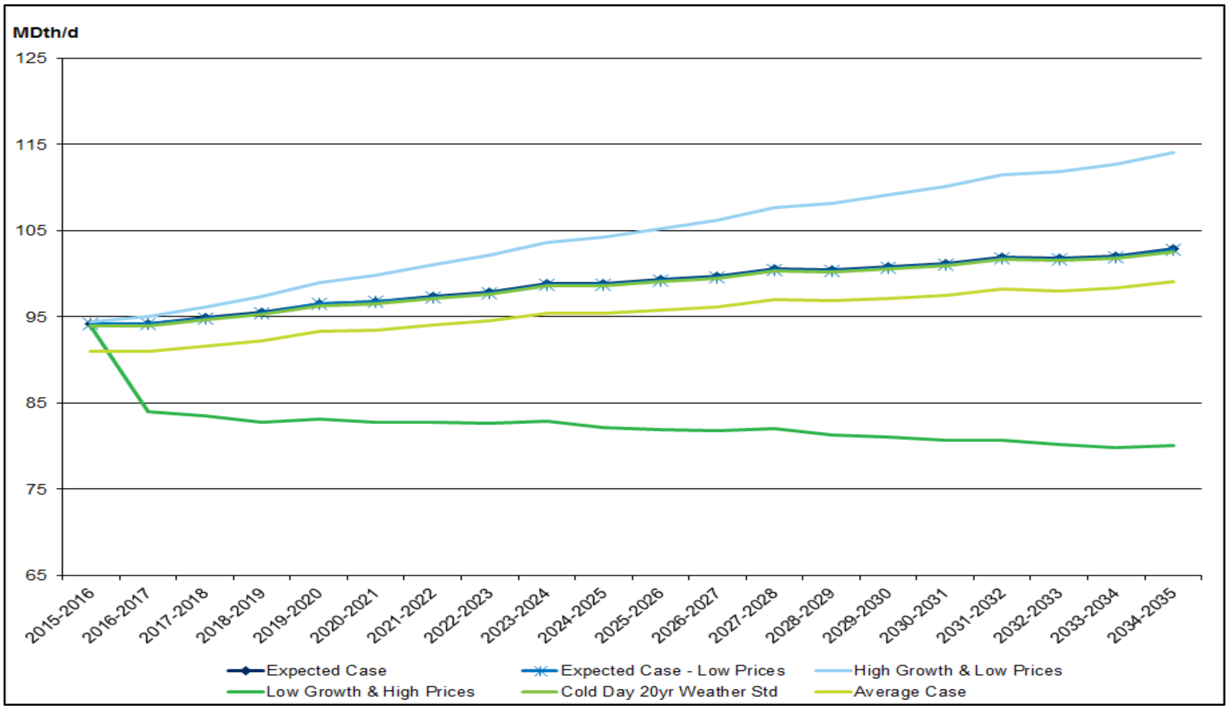
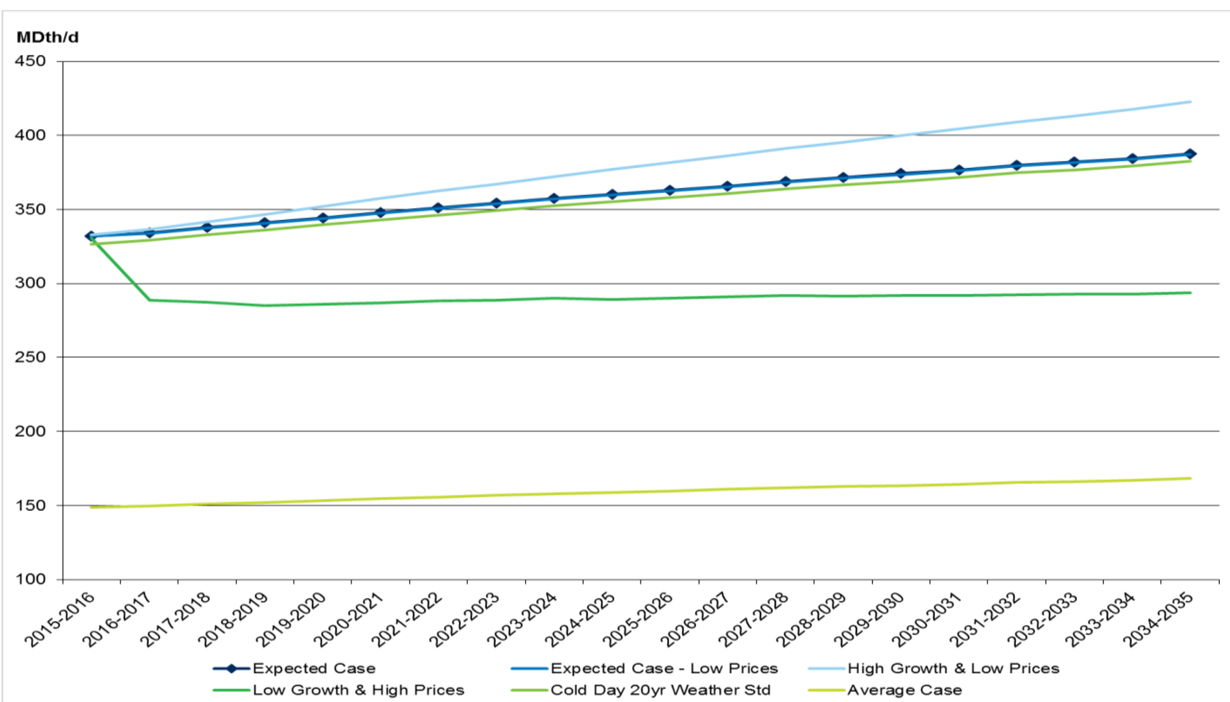


Figure 2 shows forecasted system-wide peak day demand for the six demand scenarios modeled over the IRP planning horizon.

Figure 2: Peak Day Demand Scenarios (Net of DSM Savings)



Natural Gas Price Forecasts

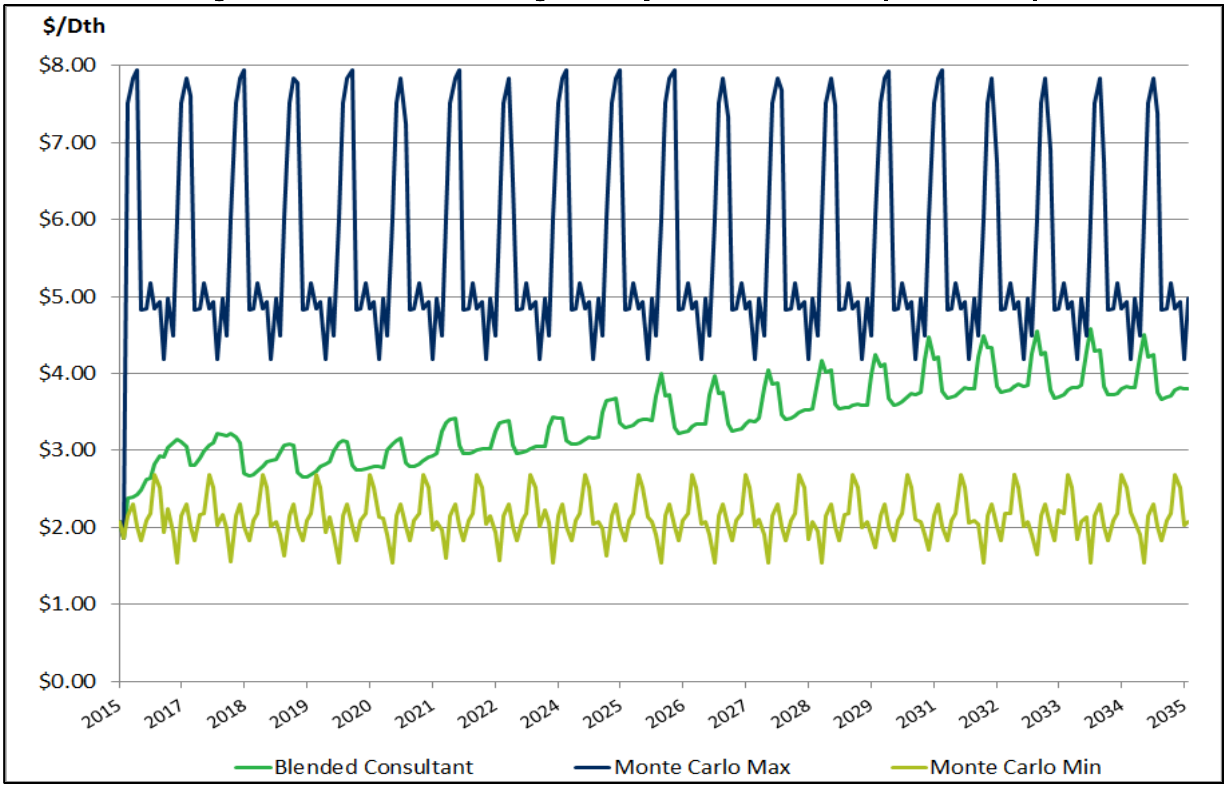
Natural gas prices are a fundamental component of integrated resource planning because the commodity price is a significant component of the total cost of a resource option. This affects the avoided cost threshold for determining cost-effectiveness of conservation measures. The price of natural gas also influences the consumption of natural gas by customers. A price elasticity adjustment to use per customer reflects customer responses to changing natural gas prices.

With more information known about the costs and volumes produced by shale gas there appears to be market consensus that production costs will remain low for quite some time. Avista expects continued low prices even with increased incremental demand for LNG exports, transportation fuels, and increased industrial consumption.

The carbon legislation debate continues. Avista's current estimate is that carbon legislation will occur at both the federal level, through the Clean Power Plan, and on the state level through a cap and trade or tax mechanism. Current IRP price forecasts include a slightly higher carbon tax, occurring earlier than the 2014 IRP. Avista analyzed four carbon sensitivities and their impact on demand forecasts to address the uncertainty about carbon legislation.

Avista reviewed several price forecasts from credible sources and created a blended price forecast to represent an expected price strip. A high and low price were developed via a Monte Carlo simulation using historical daily cash price data at the Henry Hub trading point dating back to 2009. These three price curves represent a reasonable range of pricing possibilities for this IRP analysis. The range of prices provides necessary variation for addressing uncertainty of future prices. Figure 3 depicts the price forecasts used in this IRP.

Figure 3: Low/Medium/High Henry Hub Forecasts (Real $/Dth)



Historical statistical analysis shows a long run consumption response to price changes. In order to model consumption response to these price curves, Avista utilized an expected elasticity response factor of -0.15 that was applied under various scenarios. Avista will continue to monitor and research this assumption and make any necessary adjustments as described in the Ongoing Activities section of Chapter 8 – Action Plan.

Existing and Potential Resources

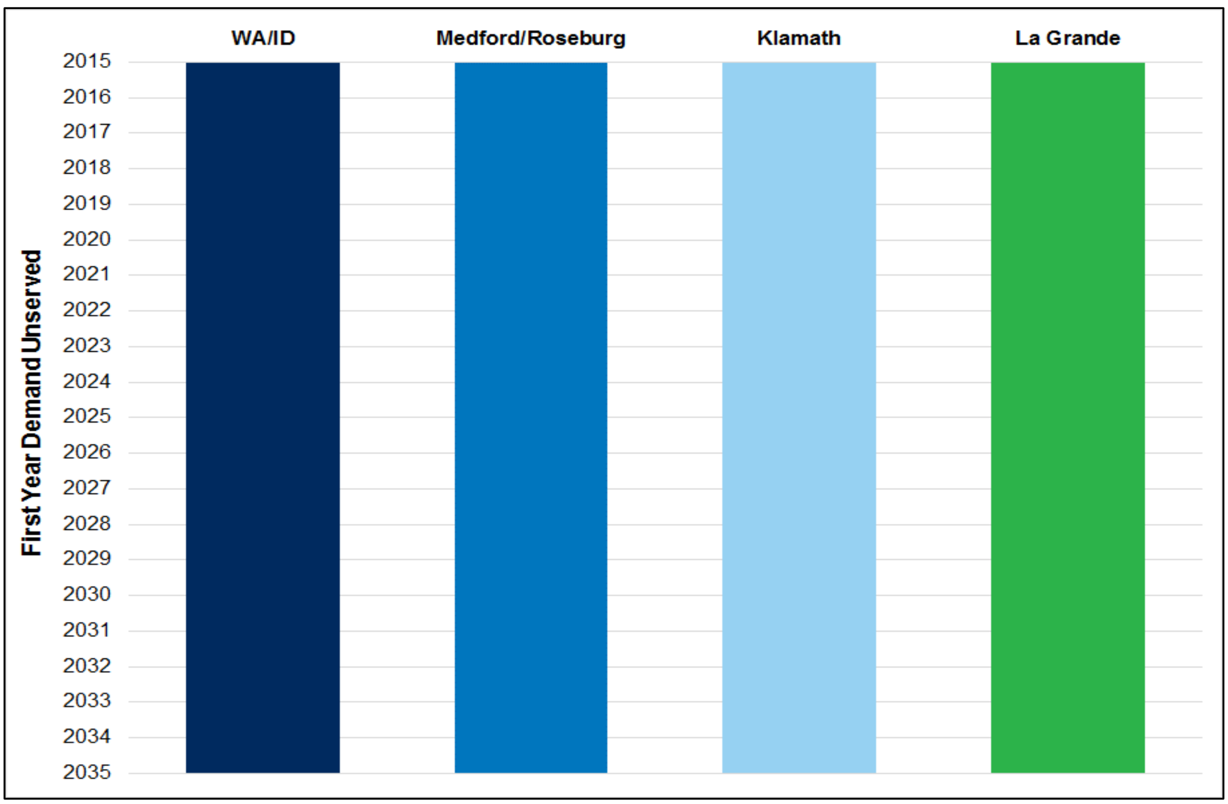
Avista has a diversified portfolio of natural gas supply resources, including access to and contracts for the purchase of natural gas from several supply basins; owned and contracted storage providing supply source flexibility; and firm capacity rights on six pipelines. For potential resource additions, Avista considers incremental pipeline transportation, storage options, distribution enhancements, and various forms of LNG storage or service. Beginning in Avista's 2018 IRP and all future planning documents and analysis thereafter, Avista intends to include conservation as a potential resource addition.

Avista models aggregated conservation potential that reduces demand if the conservation programs are cost-effective over the planning horizon. The identification and incorporation of conservation savings into the SENDOUT® model utilizes projected natural gas prices and the estimated cost of alternative supply resources. The operational business planning process starts with IRP identified savings and ultimately determines the near-term program offerings. Given current avoided costs, a limited number of DSM programs are cost effective in Idaho, Oregon, and Washington. Avista actively promotes cost-effective efficiency measures to our customers as one component of a comprehensive strategy to arrive at mix of best cost/risk adjusted resources.

Resource Needs

In the Average Case demand scenario, the analysis showed no resource deficiencies in the 20-year planning horizon given Avista's existing supply resources. The Expected Case demand scenario, using the existing resources, determined when the first year peak day demand would not be fully served. Figure 4 summarizes the results of this portfolio. Avista is not resource deficient in the Expected Case in the 20-year planning horizon.

Figure 4: Expected Case – First Year Demand Not Met with Existing Resources



Figures 5 through 8 illustrate Avista's peak day demand by service territory for both this and the prior IRP. These charts compare existing peak day resources to expected peak day demand by year and show the timing and extent of resource deficiencies, if any, for the Expected Case. Based on this information, and more specifically where a resource deficiency is nearly present as shown in Figure 6, Avista has time to carefully monitor, plan and take action on potential resource additions as described in Ongoing Activities section of Chapter 8 – Action Plan. Any underutilized resources will be optimized to mitigate the costs incurred by customers until the resource is required to meet demand. This management of long- and short-term resources provides the flexibility to meet firm customer demand in a reliable and cost-effective manner as described in Supply Side Resources – Chapter 4.

Figure 5: Expected Case – WA/ID Existing Resources vs. Peak Day Demand (Net of DSM)

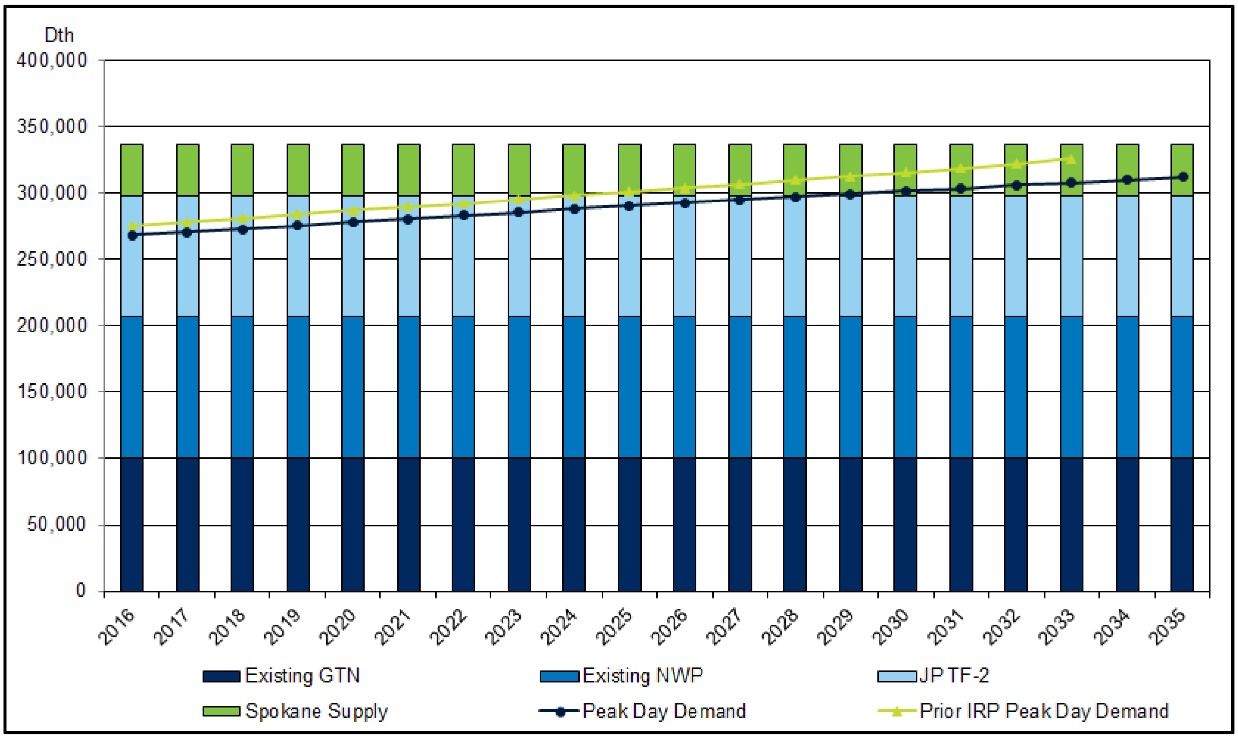


Figure 6: Expected Case – Medford/Roseburg Existing Resources vs. Peak Day Demand (Net of DSM)

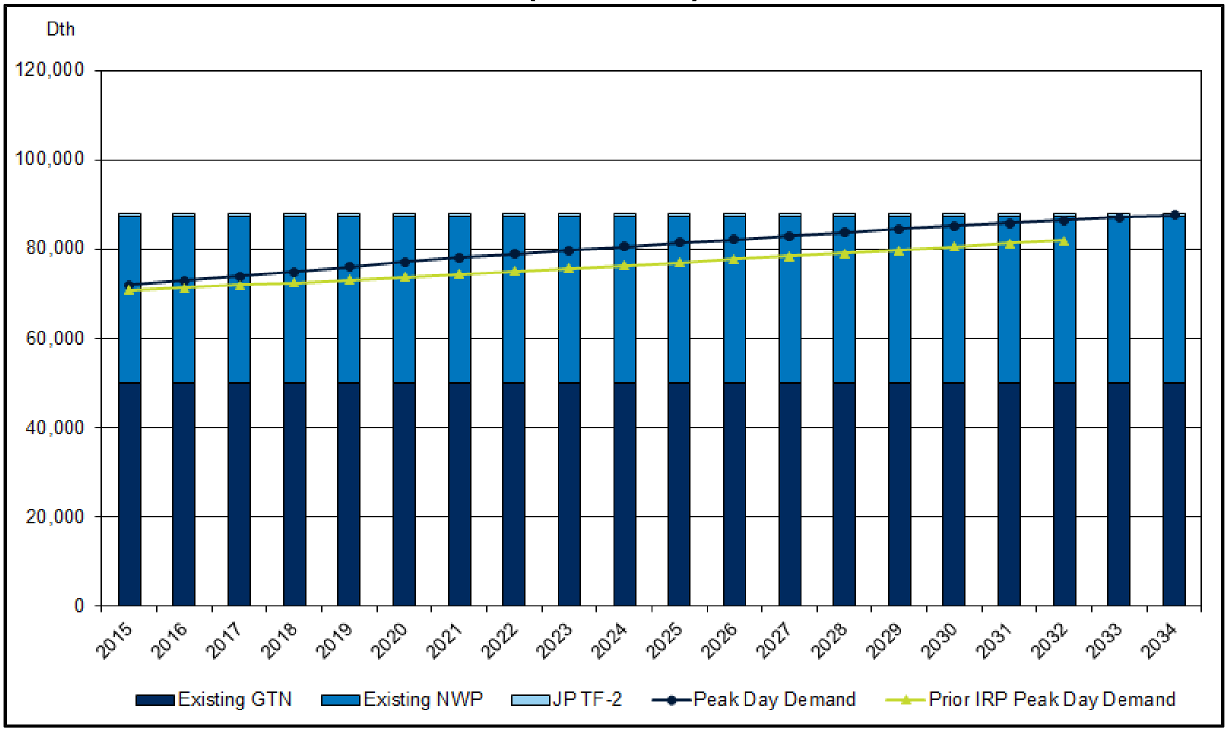


Figure 7: Expected Case – Klamath Falls Existing Resources vs. Peak Day Demand (Net of DSM)

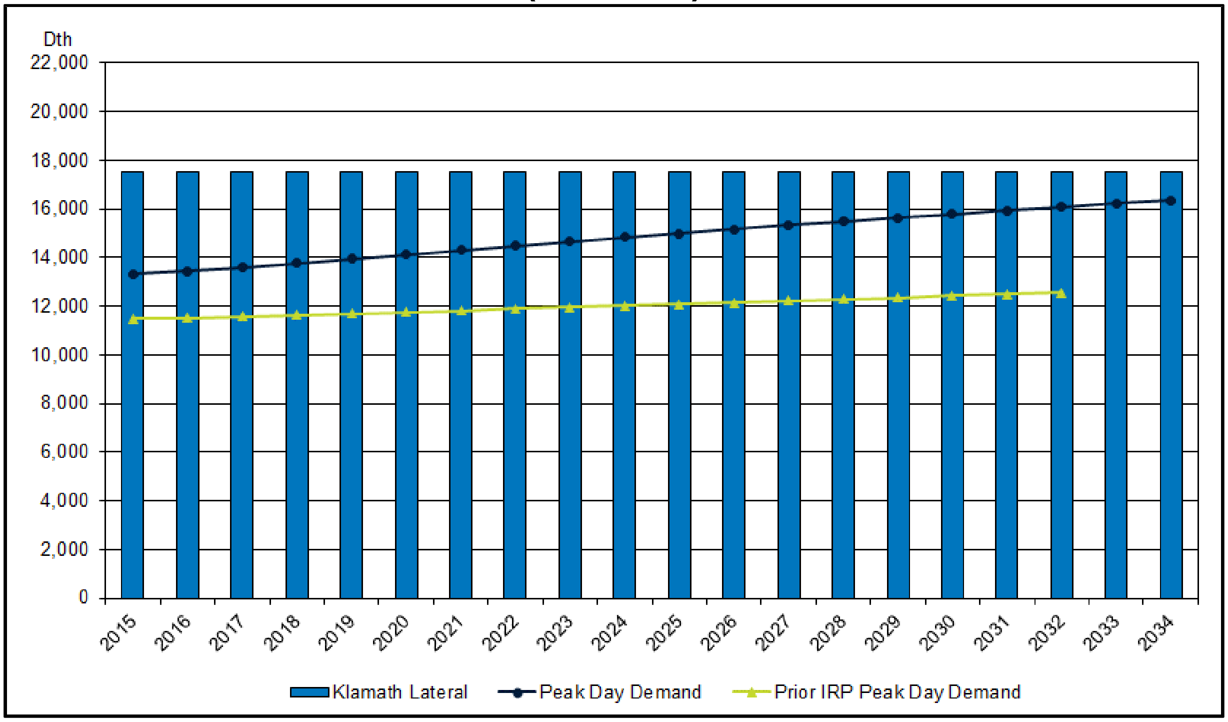
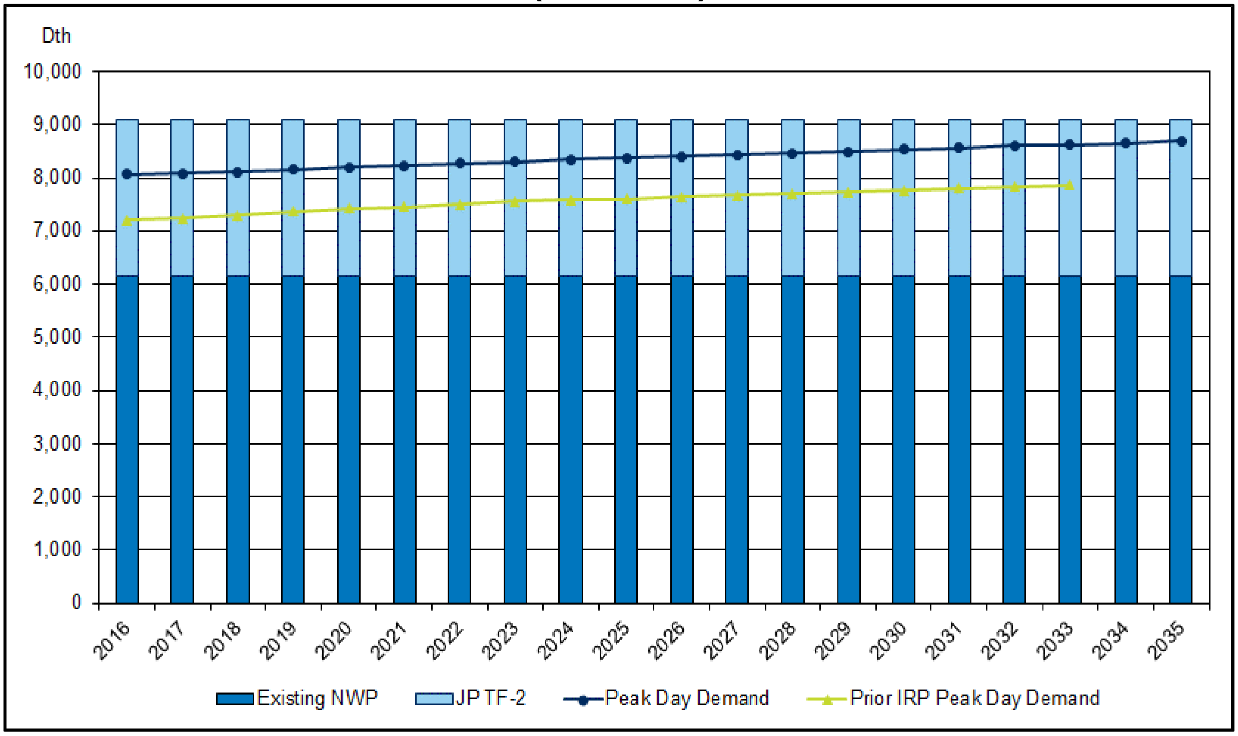
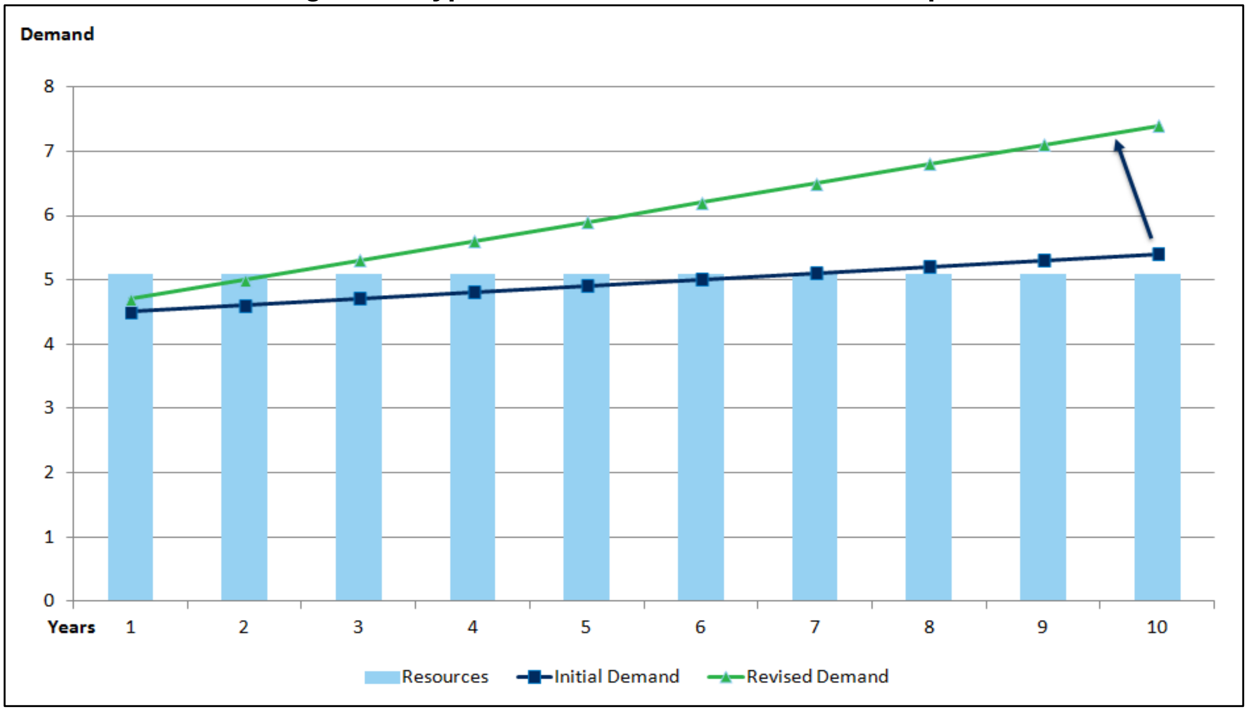


Figure 8: Expected Case – La Grande Existing Resources vs. Peak Day Demand (Net of DSM)



A critical risk is the slope of forecasted demand growth, which although increasing continues to be almost flat in Avista's current projections. This outlook implies that existing resources will be sufficient within the planning horizon to meet demand. However, if demand growth accelerates, the steeper demand curve could quickly accelerate resource shortages by several years. Figure 9 conceptually illustrates this risk. In this hypothetical example, a resource shortage does not occur until year eight in the initial demand case. However, the shortage accelerates by five years under the revised demand case to year three. This "flat demand risk" requires close monitoring of accelerating demand, as well as careful evaluation of lead times to acquire the preferred incremental resource.

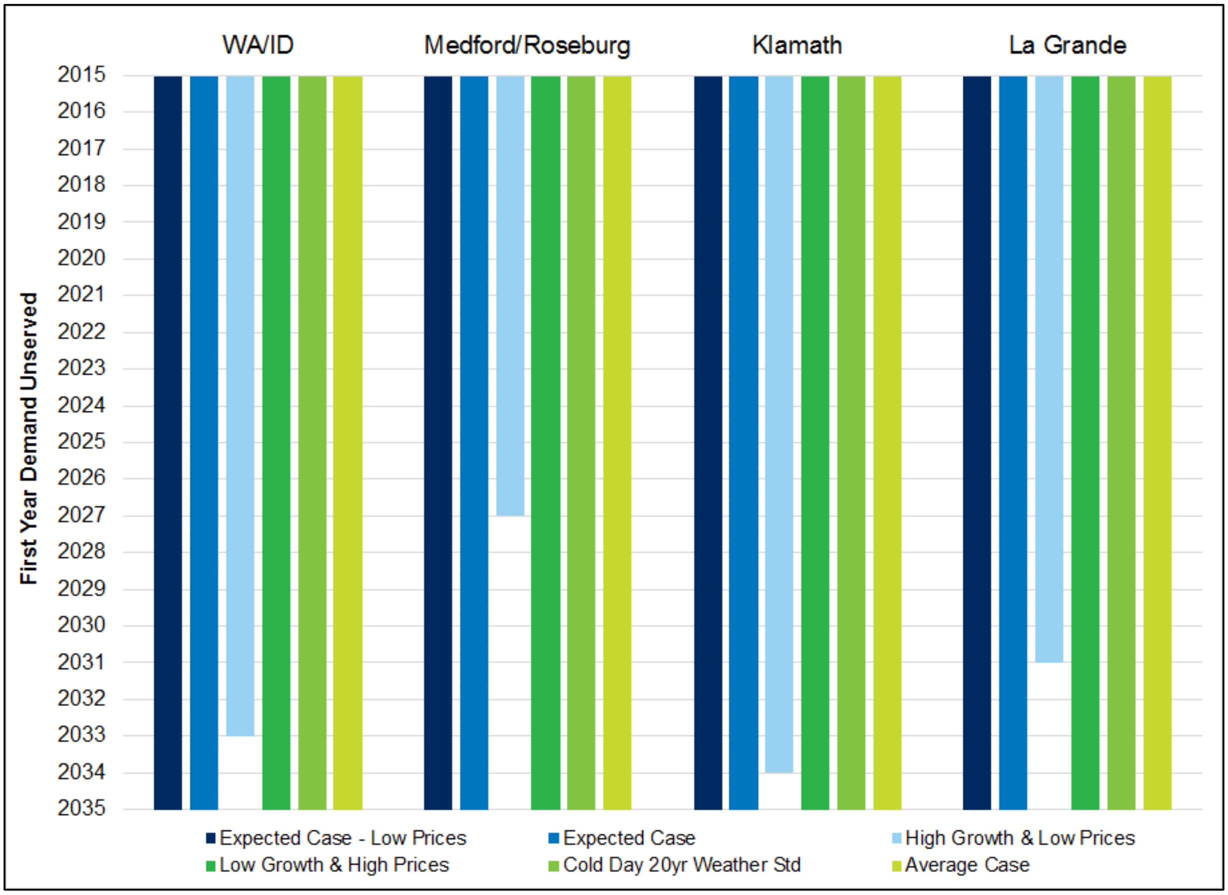
Figure 9: Hypothetical Flat Demand Risk Example



Alternate Demand Scenarios

Avista performed the same analysis for five other demand scenarios: Average, Expected/Low Price, High Growth/Low Price, Low Growth/High Price, and Coldest in 20 years. As expected, the High Growth/Low Price scenario has the most rapid growth and is the only scenario with unserved demand. This "steeper" demand lessens the "flat demand risk" discussed above, yet resource deficiencies occur very late in the planning horizon. Figure 10 shows first year resource deficiencies under each scenario.

Figure 10: Scenario Comparisons of First Year Peak Demand Not Met with Existing Resources



Issues and Challenges

Even with the planning, analysis, and conclusions reached in this IRP, there is still uncertainty requiring diligent monitoring of the following issues.

Demand Issues

Although the future customer growth trajectory in Avista's service territory has slightly increased compared to the 2014 IRP, the need in considering a range of demand scenarios provides insight into how quickly resource needs can change if demand varies from the Expected Case.

With an increase in natural gas supply and subsequent low costs, there is increasing interest in using natural gas. Avista does not anticipate that traditional residential and commercial customers will provide increased growth in demand. Power generation from natural gas is increasingly being used to back up solar and wind technology as well as replacing retired coal plants. There is also potential for increased natural gas usage in other markets, such as transportation and as an industrial feedstock. Most of these emerging markets will not be core customers of the LDC, however they will affect regional gas infrastructure and could affect natural gas pricing.

Price Issues

Shale gas and drilling technology continues to change the face of North American gas supply. The abundance of shale gas combined with lagging demand has created a near-term supply glut that continues to suppress price levels. The mild winter of 2015-2016 brought decreased demand. This has led to a glut of natural gas in the market from both record production and very high storage levels and will lead to a depressed market until a supply and demand balance is found. These low prices are beneficial for customers, but to address uncertainty in pricing, this plan includes high and low price scenarios along with stochastic price analysis to capture a range of possible prices.

LNG Exports

The availability of natural gas in North America has changed global LNG dynamics. Existing and new LNG facilities are looking to export low cost North American gas to the higher priced Asian and European markets. In Canada, 20 LNG export projects are in various stages of the permitting process. In the Northwest, there is one proposed terminal in Oregon. How many of these terminals actually get approval and ultimately built is yet to be determined. However, LNG exporting could alter the price, constrain existing pipeline networks, stimulate development of new pipeline resources, and change flows of natural gas across North America.

Action Plan

Avista's 2017-2018 Action Plan outlines activities for study, development and preparation for the 2018 IRP. The purpose of the action plan is to position Avista to provide the best cost/risk resource portfolio and to support and improve IRP planning. The Action Plan identifies needed supply and demand side resources and highlights key analytical needs in the near term. It also highlights essential ongoing planning initiatives and natural gas industry trends Avista will monitor as a part of its ongoing planning processes (Chapter 8 – Action Plan).

The price of natural gas has dropped significantly since the 2014 IRP. This is primarily due to the amount of economically extractable natural gas in shale formations, efficient drilling techniques and technology, and warmer than normal weather. Wells have been drilled, but left uncompleted due to the poor market economics. This is depressing natural gas prices and forcing many oil and gas companies into bankruptcy. Due to historically low prices Avista will research market opportunities including: procuring a derivative based contract, 10 year forward strip, and natural gas reserves.

Avista's 2018 IRP will contain a dynamic DSM program structure in its analytics. In prior IRP's it was a deterministic method based off of the Expected Case assumptions. In the 2018 IRP, each portfolio will have the ability to make a new selection of conservation to meet unserved customer demand. Avista will explore methods to enable a dynamic analytical process for the evaluation of conservation potential within individual portfolios.

Key ongoing components of the Action Plan include:

- Monitor actual demand for accelerated growth can address resource deficiencies arising from exposure to "flat demand" risk. This will include providing Commission Staff with IRP demand forecast-to-actual variance analysis on customer growth and use per customer at least bi-annually.
- Continue to monitor supply resource trends including the availability and price of natural gas to the region, LNG exports, methanol plants, supply and market dynamics and pipeline and storage infrastructure availability.
- Monitor availability of resource options and assess new resource lead-time requirements relative to resource need to preserve flexibility.
- Meet regularly with Commission Staff to provide information on market activities and significant changes in assumptions and/or status of Avista activities related to the IRP or natural gas procurement practices.
- Appropriate management of existing resources including optimizing underutilized resources to help reduce costs to customers.

Conclusion

Slightly higher customer growth has been offset by lower use per customer and has eliminated the need for Avista to acquire additional supply-side resources, therefore appropriate management of underutilized resources to reduce costs until resources are needed is essential. Additionally, the lower cost of natural gas continues to challenge the cost-effectiveness of DSM programs. While Avista believes adoption of conservation is the best strategy for minimizing costs to customers and meeting environmental goals, this IRP shows a similar conservation potential as compared to the 2014 IRP, but is lower than prior planning documents. The IRP has many objectives, but foremost is to ensure that proper planning enables Avista to continue delivering safe, reliable, and economic natural gas service to our customers.

1: Introduction

Avista is involved in the production, transmission and distribution of natural gas and electricity, as well as other energy-related businesses. Avista was founded in 1889 as Washington Water Power and has been providing reliable, efficient and reasonably priced energy to customers for over 125 years.

Avista entered the natural gas business with the purchase of Spokane Natural Gas Company in 1958. In 1970, it expanded into natural gas storage with Washington Natural Gas (now Puget Sound Energy) and El Paso Natural Gas (its interest subsequently purchased by NWP) to develop the Jackson Prairie natural gas underground storage facility in Chehalis, Washington. In 1991, Avista added 63,000 customers with the acquisition of CP National Corporation’s Oregon and California properties. Avista subsequently sold the California properties and its 18,000 South Lake Tahoe customers to Southwest Gas in 2005. Figure 1.1 shows where Avista currently provides natural gas service to approximately 334,000 customers in eastern Washington, northern Idaho and several communities in northeast and southwest Oregon. Figure 1.2 shows the number of natural gas customers by state.

Figure 1.1: Avista’s Natural Gas Service Territory

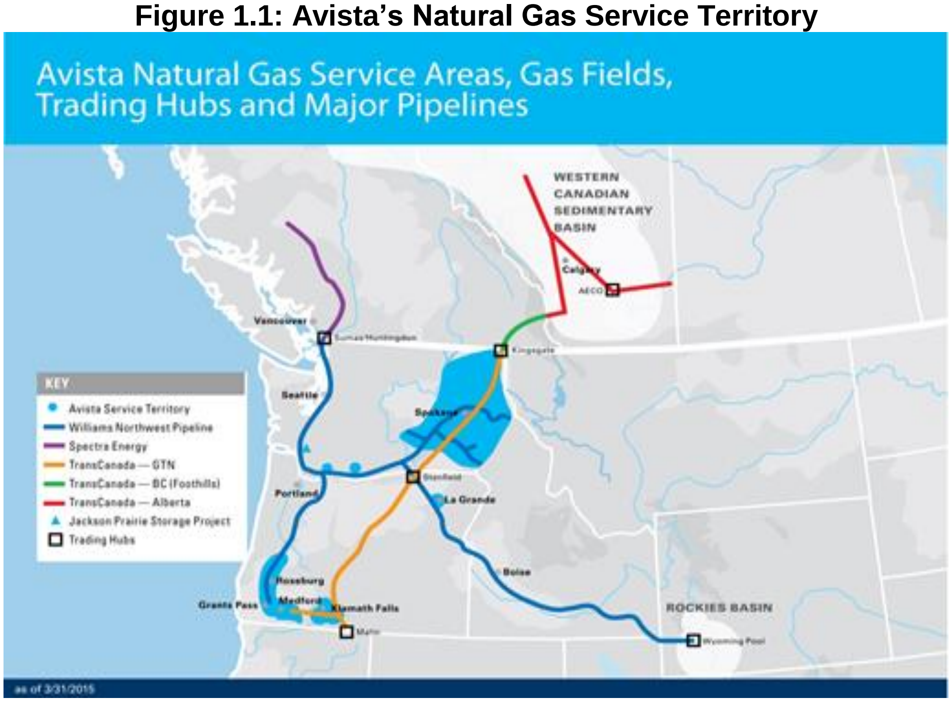
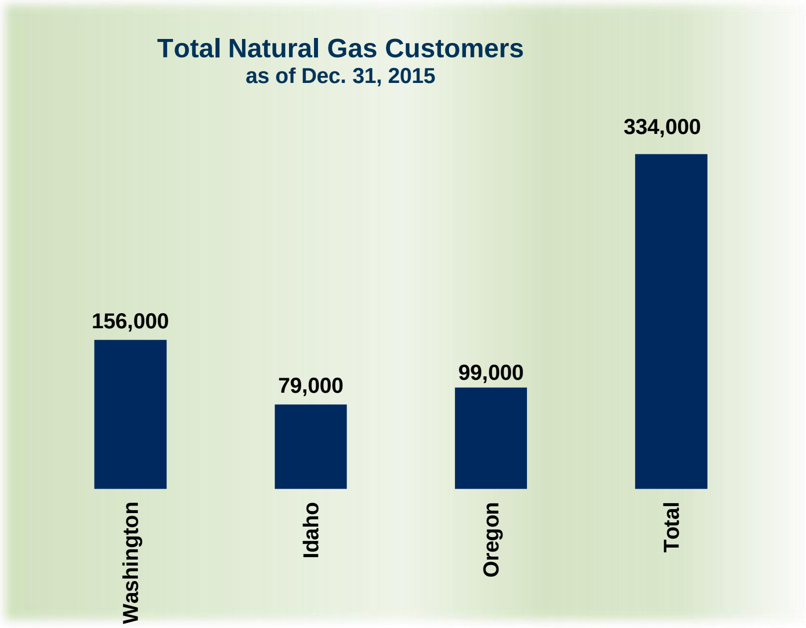


Figure 1.2: Avista's Natural Gas Customer Counts



Avista manages its natural gas operation through two operating divisions – North and South:

- The North Division covers about 26,000 square miles, primarily in eastern Washington and northern Idaho. Over 840,000 people live in Avista's Washington/Idaho service area. It includes urban areas, farms, timberlands, and the Coeur d'Alene mining district. Spokane is the largest metropolitan area with a regional population of approximately 490,000 followed by the Lewiston, Idaho/Clarkston, Washington and Coeur d'Alene, Idaho areas. The North Division has about 73 miles of natural gas transmission pipeline and 9,100 miles in the distribution system. The North Division receives natural gas at more than 40 points along interstate pipelines and distributes it to over 235,000 customers.
- The South Division serves four counties in southwest Oregon and one county in northeast Oregon. The combined population of these areas is over 480,000 residents. The South Division includes urban areas, farms and timberlands. The Medford, Ashland and Grants Pass areas, located in Jackson and Josephine Counties, is the largest single area served by Avista in this division with a regional population of approximately 297,000 residents. The South Division consists of about 51 miles of natural gas transmission main and 3,745 miles of distribution pipelines. Avista receives natural gas at more than 20 points along interstate pipelines and distributes it to almost 99,000 customers.

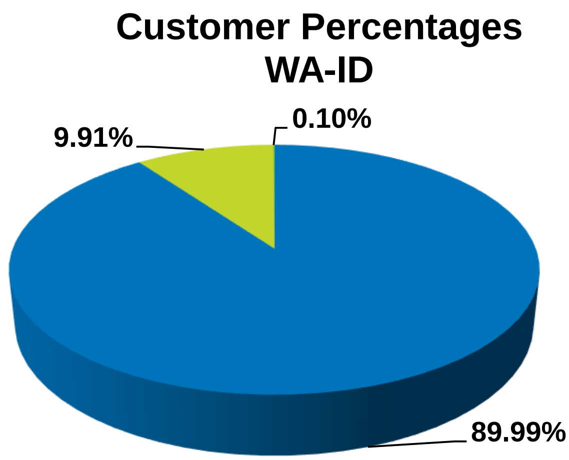
Customers

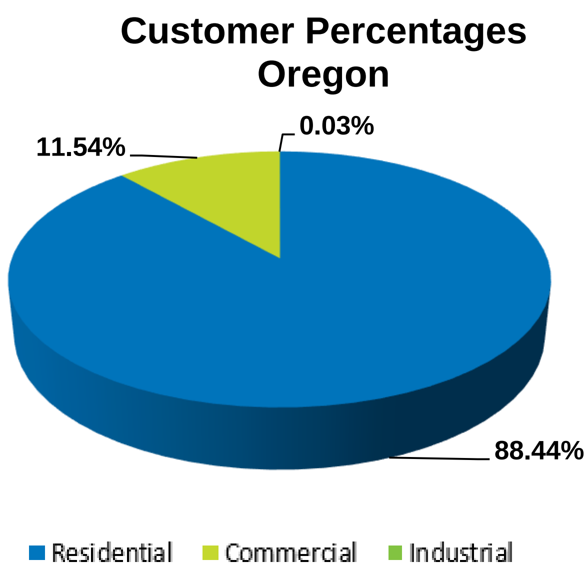
Avista provides natural gas services to core and transportation-only customer classes. Core or retail customers purchase natural gas directly from Avista with delivery to their home or business under a bundled rate. Core customers on firm rate schedules are entitled to receive any volume of natural gas they require. Some core customers are on interruptible rate schedules. These customers pay a lower rate than firm customers because their service can be interrupted. Interruptible customers are not considered in peak day IRP planning.

Transportation-only customers purchase natural gas from third parties who deliver the purchased gas to our distribution system. Avista delivers this natural gas to their business charging a distribution rate only. Avista can interrupt the delivery service when following the priority of service tariff. The long-term resource planning exercise excludes transportation-only customers because they purchase their own gas and utilize their own interstate pipeline transportation contracts. However, distribution planning exercises include these customers.

Avista's core or retail customers include residential, commercial and industrial categories. Most of Avista's customers are residential, followed by commercial and relatively few industrial accounts (Figure 1.3).

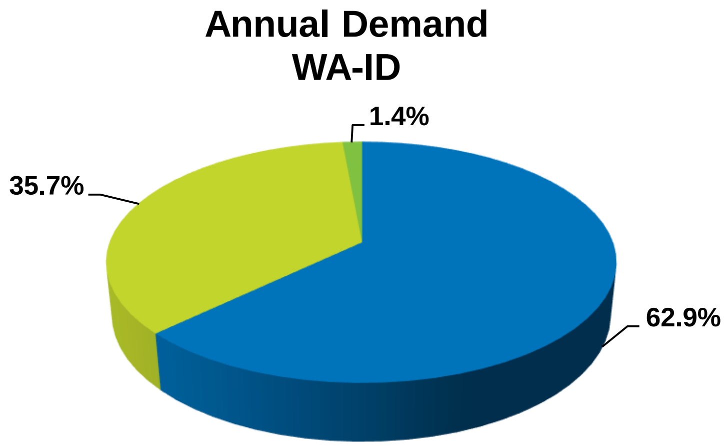
Figure 1.3: Firm Customer Mix

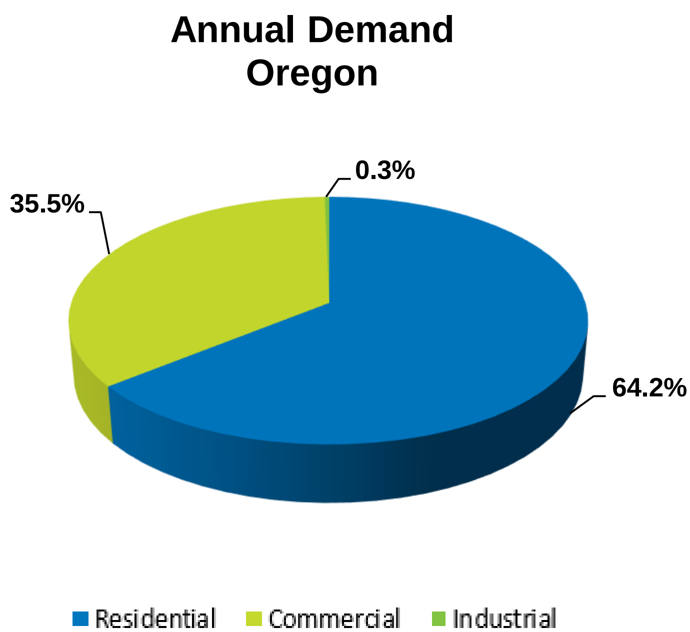




The customer mix is more balanced between residential and commercial accounts on an annual volume basis (Figure 1.4). Volume consumed by core industrial customers is not significant to the total, partly because most industrial customers in Avista's service territories are transportation-only customers.

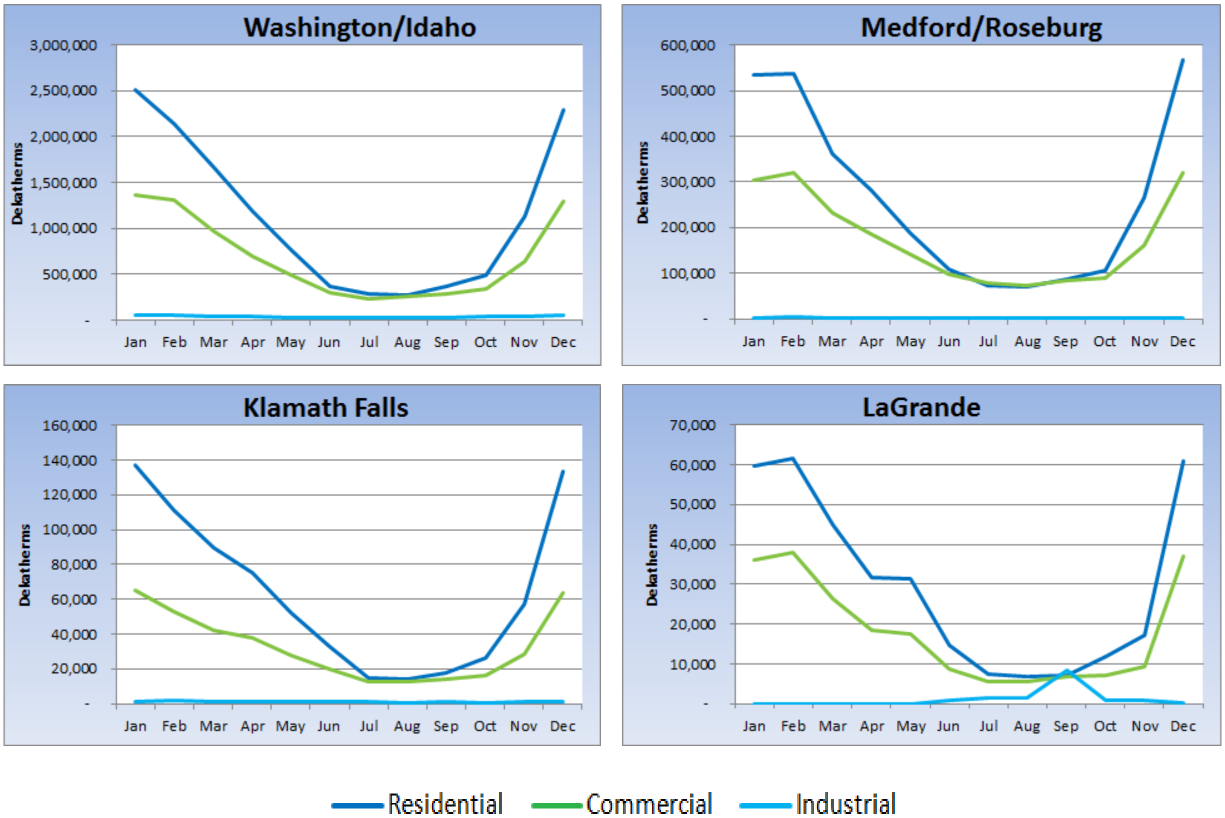
Figure 1.4 Therms by Class





Core customer demand is seasonal, especially residential accounts in Avista's service territories with colder winters (Figure 1.5). Industrial demand, which is typically not weather sensitive, has very little seasonality. However, the La Grande service territory has several industrially classified agricultural processing facilities that produce a late summer seasonal demand spike.

Figure 1.5: Customer Demand by Service Territory



Integrated Resource Planning

Avista's IRP involves a comprehensive analytical process to ensure that core firm customers receive long-term reliable natural gas service at a reasonable price. The IRP evaluates, identifies, and plans for the acquisition of an optimal combination of existing and future resources using expected costs and associated risks to meet average daily and peak-day demand delivery requirements over a 20-year planning horizon.

Purpose of the IRP

Avista's 2016 Natural Gas IRP:

- Provides a comprehensive long-range planning tool;
- Fully integrates forecasted requirements with existing and potential resources;
- Determines the most cost-effective, risk-adjusted means for meeting future demand requirements; and
- Meets Washington, Idaho and Oregon regulations, commission orders, and other applicable guidelines.

Avista's IRP Process

The natural gas IRP process considers:

- Customer growth and usage:
- Weather planning standard;
- Conservation opportunities;
- Existing and potential supply-side resource options;
- Current and potential legislation/regulation;
- Risk; and
- Least cost mix of supply and conservation.

Public Participation

Avista's TAC members play a key role and have a significant impact in developing the IRP. TAC members include Commission Staff, peer utilities, public interest groups, customers, academics, government agencies, and other interested parties. TAC members provide important input on modeling, planning assumptions, and the general direction of the process.

Avista sponsored four TAC meetings to facilitate stakeholder involvement in the 2016 IRP. The first meeting convened on January 21, 2016, and the last meeting occurred on April 21, 2016. Meetings are at a variety of locations convenient for stakeholders and are electronically available for those unable to attend in person. Each meeting included a broad spectrum of stakeholders. The meetings focused on specific planning topics, reviewing the progress of planning activities, and soliciting input on IRP development. TAC members received a draft of this IRP in late May 2016 for their review. Avista appreciates all of the time and effort TAC members gave to the IRP process; they provided valuable input through their participation in the TAC process. A list of these organizations can be found below (Table 1.1).

Table 1.1: TAC Member Participation

Cascade Natural Gas	Northwest Industrial Gas Users	Oregon Public Utility Commission
Fortis	Northwest Natural Gas	Puget Sound Energy
Idaho Public Utilities Commission	Williams - Northwest Pipeline	TransCanada
Northwest Gas Association	Citizens Utility Board of Oregon	Washington Utilities and Transportation Commission

Preparation of the IRP is a coordinated endeavor by several departments within Avista with involvement and guidance from management. We are grateful for their efforts and contributions.

Regulatory Requirements

Avista submits a natural gas IRP to the public utility commissions in Idaho, Oregon and Washington on or before August 31 every two years as required by state regulation. There is a statutory obligation to provide reliable natural gas service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. Avista regards the IRP as a means for identifying and evaluating potential resource options and as a process to establish an Action Plan for resource decisions. Ongoing investigation, analysis and research may cause Avista to determine that alternative resources are more cost effective than resources reviewed and selected in this IRP. Avista will continue to review and refine our understanding of resource options and will act to secure these risk-adjusted, least-cost options when appropriate.

Planning Model

Consistent with prior IRPs, Avista used the SENDOUT® planning model to perform comprehensive natural gas supply planning and analysis for this IRP. SENDOUT® is a linear programming-based model that is widely used to solve natural gas supply, storage and transportation optimization problems. This model uses present value revenue requirement (PVRR) methodology to perform least-cost optimization based on daily, monthly, seasonal and annual assumptions related to the following:

- Customer growth and customer natural gas usage to form demand forecasts;
- Existing and potential transportation and storage options and associated costs;
- Existing and potential natural gas supply availability and pricing;
- Revenue requirements on all new asset additions;
- Weather assumptions; and
- Conservation.

Avista incorporated stochastic modeling by utilizing a SENDOUT® module to simulate weather and price uncertainty. The module generates Monte Carlo weather and price simulations, running concurrently to account for events and to provide a probability distribution of results that aid resource decisions. Some examples of the types of stochastic analysis provided include:

- Price and weather probability distributions;
- Probability distributions of costs (i.e. system costs, storage costs, commodity costs); and
- Resource mix (optimally sizing a contract or asset level of competing resources).

These computer-based planning tools were used to develop the 20-year best cost/risk resource portfolio plan to serve customers.

Planning Environment

Even though Avista publishes an IRP biannually, the process is ongoing with new information and industry related developments. In normal circumstances, the process can become complex as underlying assumptions evolve, impacting previously completed analyses. Every planning cycle has challenges and uncertainties; this cycle was no different. Widespread agreement on the availability of shale gas and the ability to produce it at lower prices has increased interest in the use of natural gas for LNG exports and for more transportation and industrial uses. However, there is uncertainty about the timing and size of those markets.

IRP Planning Strategy

Planning for an uncertain future requires robust analysis that encompasses a wide range of possibilities. Avista has determined that the planning approach needs to:

- Recognize that historical trends may be fundamentally altered:
- Critically review all assumptions;
- Stress test assumptions via sensitivity analysis;
- Pursue a spectrum of possible scenarios;
- Develop a flexible analytical framework to accommodate changes; and
- Maintain a long-term perspective.

With these objectives in mind, Avista developed a strategy encompassing all required planning criteria. This produced a complete IRP that effectively analyzes risks and resource options, which sufficiently ensures customers will receive safe and reliable energy delivery services with the best-risk, lease-cost, long-term solutions. The following chart summarizes significant changes from the 2014 IRP (Table 1.2).

Table 1.2: Summary of changes from the 2014 IRP

Chapter	Issue	2016 Natural Gas IRP	2014 Natural Gas IRP
Demand	Expected Customer Growth	Expected Case customer growth is 1.1% compounded annually.	Expected Case customer growth is 1% compounded annually.
Environmental Issues	Carbon Dioxide Emission (Carbon)	Three sensitivities on level of carbon tax ($/ton) were compared. The expected case has a probability of 2 sigma of the likely policy. The remainder of probability equally assumed to Low and Washington State's I-732 were used to represent the tails in a normal distribution. The base carbon case is the expected case. The high and low cases help bracket the base case results.	Three sensitivities on level of carbon tax ($/ton) were compared. The base carbon case is the medium case. The high and low cases help bracket the base case results.
Prices	Price Curve	Lower Price curve can drive the conservation potential-downward.	A higher price curve with slightly higher conservation potential.
Supply Side Resources	Supply Side Scenarios	The only case that identifies a resource deficiency is the High Growth/Low Price scenario. Avista solved this case by using existing resources plus added contracted capacity on GTN for WA/ID. In Klamath Falls, Medford and Roseburg an upsized compressor would be added on the Medford lateral.	Evaluated three supply side scenarios on cases with resource deficiencies. Existing resources, Existing plus Expected Available, and GTN fully subscribed. Did not solve for high growth/low price unserved

2: Demand Forecasts

Overview

The integrated resource planning process begins with the development of forecasted demand. Understanding and analyzing key demand drivers and their potential impact on forecasts is vital to the planning process. Utilization of historical data provides a reliable baseline, however past trends may not be indicative of future trends. This IRP mitigates the uncertainty by considering a range of scenarios to evaluate and prepare for a broad spectrum of outcomes.

Demand Areas

Avista defined eight demand areas, structured around the pipeline transportation resources that serve them, within the SENDOUT® model (Table 2.1). These demand areas are aggregated into four service territories and further summarized as North or South divisions for presentation throughout this IRP.

Table 2.1 Geographic Demand Classifications

Demand Area	Service Territory	Division
Spokane NWP	Washington/Idaho	North
Spokane GTN	Washington/Idaho	North
Spokane Both	Washington/Idaho	North
Medford NWP	Medford/Roseburg	South
Medford GTN	Medford/Roseburg	South
Roseburg	Medford/Roseburg	South
Klamath Falls	Klamath Falls	South
La Grande	La Grande	South

Demand Forecast Methodology

Avista uses the IRP process to develop two types of demand forecasts – annual and peak day. Annual average demand forecasts are useful for preparing revenue budgets, developing natural gas procurement plans, and preparing purchased gas adjustment filings. Peak day demand forecasts are critical for determining the adequacy of existing resources or the timing for acquiring new resources to meet customers' natural gas needs in extreme weather conditions.

In general, if existing resources are sufficient to meet peak day demand, they will be sufficient to meet annual average day demand. Developing annual average demand first and evaluating it against existing resources is an important step in understanding the performance of the portfolio under normal circumstances. It also facilitates synchronization of modeling processes and assumptions for planning purposes.

Peak weather analysis aids in assessing resource adequacy and any differences in resource utilization. For example, storage may be dispatched differently under peak weather scenarios.

Demand Modeling Equation

Developing daily demand forecasts is essential because natural gas demand can vary widely from day-to-day, especially in winter months when heating demand is at its highest. In its most basic form, natural gas demand is a function of customer base usage (non-weather sensitive usage) plus customer weather sensitive usage. Basic demand takes the formula in Table 2.2:

Table 2.2: Basic Demand Formula

# of customers x daily base usage / customer Plus # of customers x daily weather sensitive usage / customer

SENDOUT® requires inputs as expressed in the Table 2.3 format to compute daily demand in dekatherms.

Table 2.3: SENDOUT® Demand Formula

# of customers x daily Dth base usage / customer
Plus
# of customers x daily Dth weather sensitive usage / customer x # of daily degree days

SENDOUT® performs this calculation daily for each customer class and each demand area. The base and weather sensitive usage (heating degree day usage) factors use customer demand coefficients developed outside the SENDOUT® model, and the coefficients capture a variety of demand usage assumptions. This is discussed in more detail in the Use-per-Customer Forecast section below. The number of daily degree days is simply heating degree days (HDDs), which are discussed in the Weather Forecast section later in this chapter.

Customer Forecasts

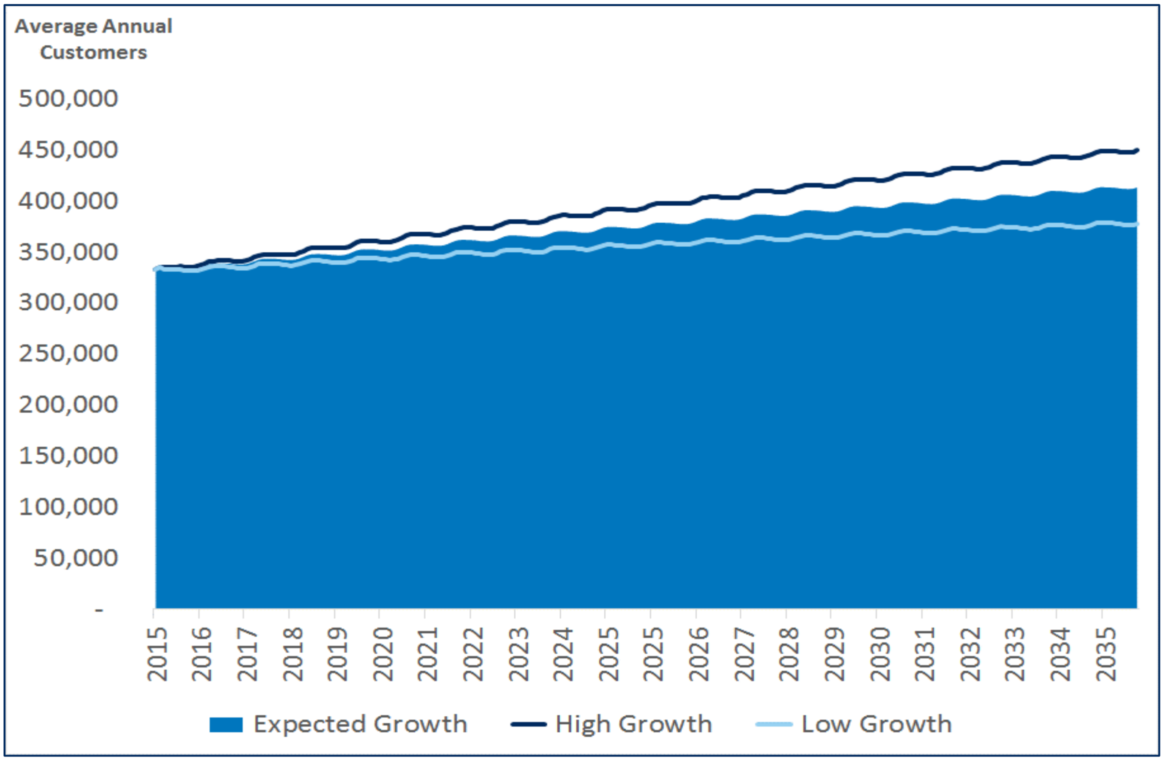
Avista's customer base includes residential, commercial and industrial categories. For each of the customer categories, Avista develops customer forecasts incorporating national economic forecasts and then drilling down into regional economies. U.S. GDP growth, national and regional employment growth, and regional population growth expectations are key drivers in regional economic forecasts and are useful in estimating the number of natural gas customers. A detailed description of the customer forecast is found in Appendix 2.1 – Economic Outlook and Customer Count Forecast. Avista combines this data with local knowledge about sub-regional construction activity, age and other demographic trends, and historical data to develop the 20-year customer forecasts.

Several Avista departments use these forecasts, but Finance, Accounting, Rates, and Gas Supply are the primary users. The natural gas distribution engineering group utilizes the forecast data for system optimization and planning purposes (see discussion in Chapter 7 – Distribution Planning).

Forecasting customer growth is an inexact science, so it is important to consider different forecasts. Two alternative growth forecasts were developed for this IRP. Avista developed High and Low Growth forecasts to provide potential paths and test resource adequacy. Appendix 2.1 contains a description of how these alternatives were developed.

Figure 2.1 shows the three customer growth forecasts. Due to a change in forecasting methodology for customer growth, the expected case customer counts are lower than the last IRP. This has impacted forecasted demand from both the average and peak day perspective. Detailed customer count data by region and class for all three scenarios is in Appendix. 2.2 – Customer Forecasts by Region.

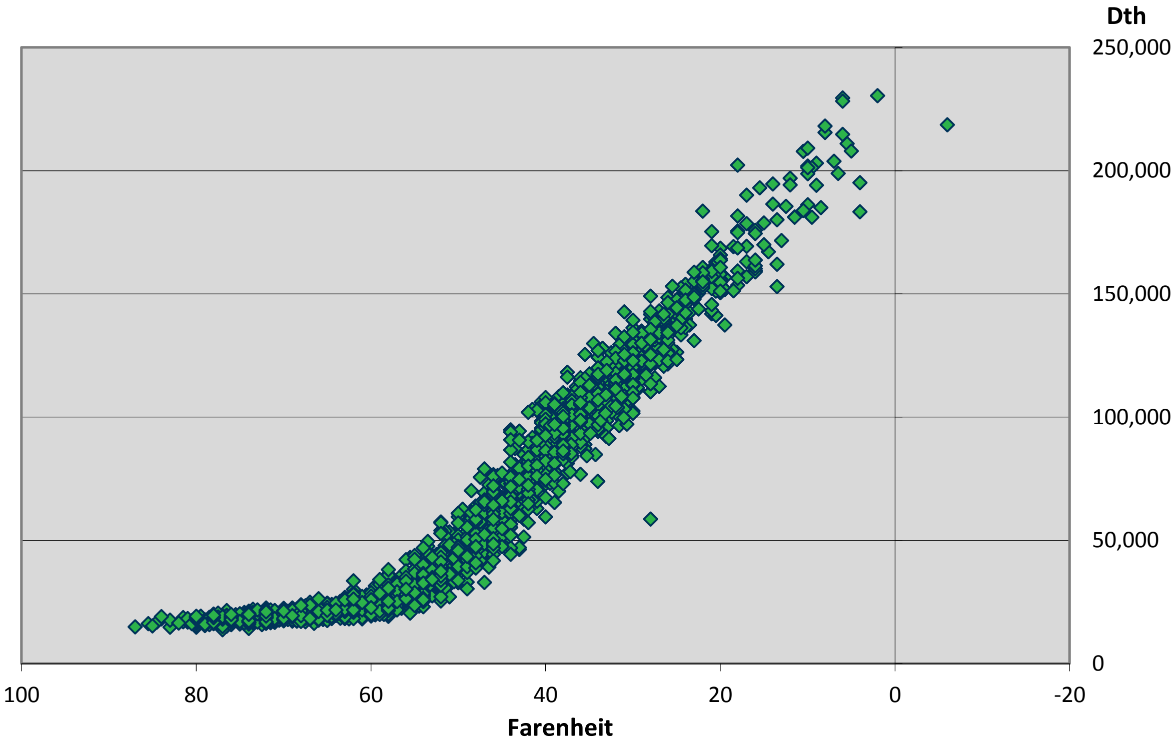
Figure 2.1: Customer Growth Scenarios



Use-per-Customer Forecast

The goal for a use-per-customer forecast is to develop base and weather sensitive demand coefficients that can be combined and applied to HDD weather parameters to reflect average use-per-customer. This produces a reliable forecast because of the high correlation between usage and temperature as depicted in the example scatter plot in Figure 2.2.

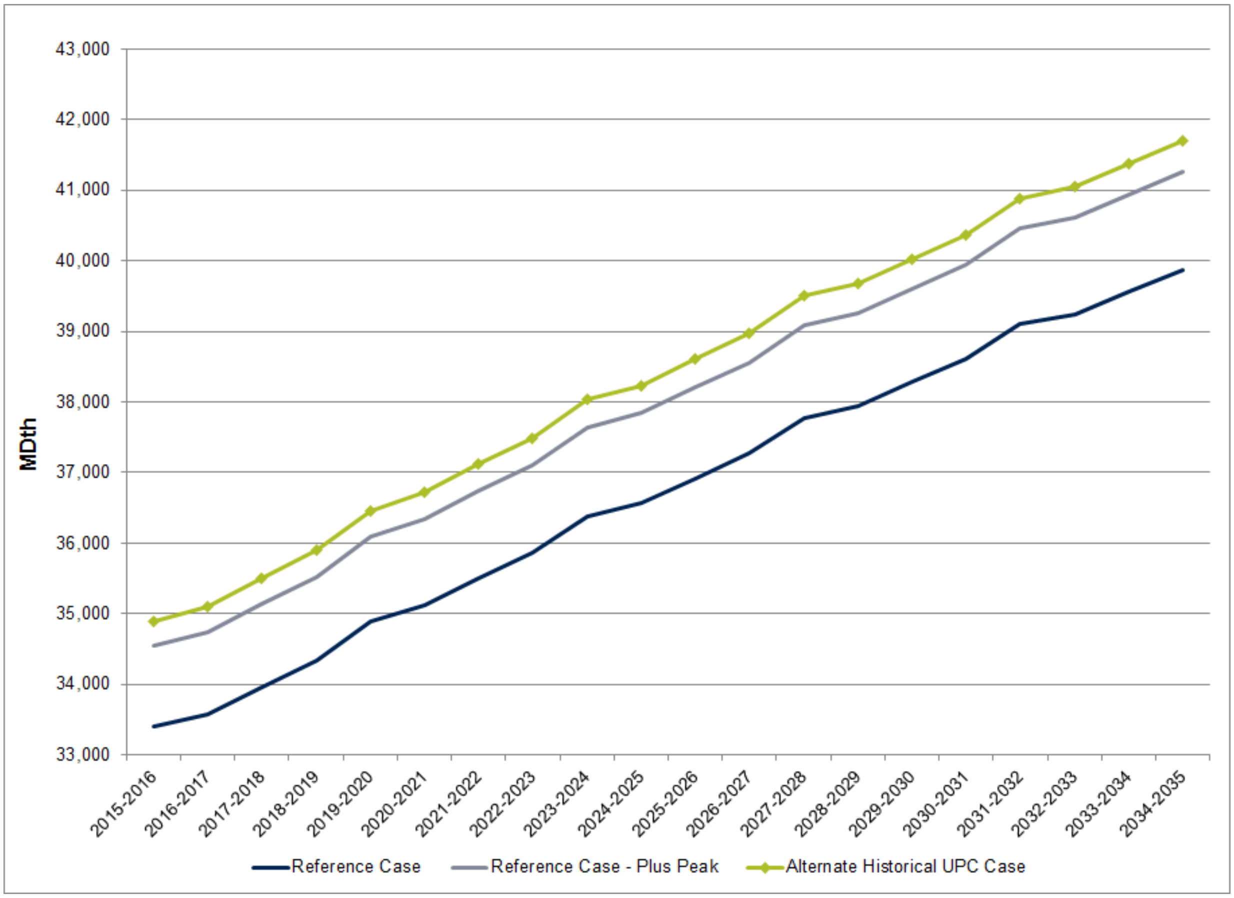
Figure 2.2: Example Demand vs. Average Temperature – WA/ID



The first step in developing demand coefficients was gathering daily historical gas flow data for all of Avista's city gates. The use of city gate data over revenue data is due to the tight correlation between weather and demand. The revenue system does not capture data on a daily basis and, therefore, makes a statistical analysis with tight correlations on a daily basis virtually impossible. Avista reconciles city gate flow data to revenue data to ensure that total demand is properly captured.

The historical city gate data was gathered, sorted by service territory/temperature zone, and then by month. As in the last IRP, Avista used three years of historical data to derive the use-per-customer coefficients, but also considered varying the number of years of historical data. When comparing five years of historical use-per-customer to three years of data, the five-year data had slightly higher use-per-customer, which may overstate use as efficiency and use-per-customer-per-HDD have been on a downward trend since 2006. Three years struck a balance between historical and current customer usage patterns. Figure 2.3 illustrates the annual demand differences between the three and five-year use-per-customer with normal and peak weather conditions.

Figure 2.3: Annual Demand – Demand Sensitivities 3-Year vs. 5-Year Use-per-Customer



The base usage calculation used three years of July and August data to derive coefficients. Average usage in these months divided by the average number of customers provides the base usage coefficient input into SENDOUT®. This calculation is done for each area and customer class based on customer billing data demand ratios.

To derive weather sensitive demand coefficients for each monthly data subset, Avista removed base demand from the total and plotted usage by HDD in a scatter plot chart to verify correlation visually. The process included the application of a linear regression to the data by month to capture the linear relationship of usage to HDD. The slopes of the resulting lines are the monthly weather sensitive demand coefficients input into SENDOUT®. Again, this calculation is done by area and by customer class using allocations based on customer billing data demand ratios.

Weather Forecast

The last input in the demand modeling equation is weather (specifically HDDs). This started with the most current 20 years of daily weather data from the National Oceanic Atmospheric Administration (NOAA), converted to HDDs, and is used to compute an average for each day to develop the weather forecast. The Oregon weather input used four weather stations, corresponding to the areas where Avista provides natural gas services. HDD weather patterns between these areas are uncorrelated. Weather data for the Spokane Airport is used for the eastern Washington and northern Idaho portions of the service area, as HDD weather patterns within that region are correlated.

The NOAA 20-year average weather serves as the base weather forecast to prepare the annual average demand forecast. The peak day demand forecast includes adjustments to average weather to reflect a five-day cold weather event. This consists of adjusting the middle day of the five-day cold weather event to the coldest temperature on record for a service territory, as well as adjusting the two days on either side of the coldest day to temperatures slightly warmer than the coldest day. For the Washington/Idaho and La Grande service territories, the model assumes this event on and around February 15 each year. For the southwestern Oregon service territories (Medford, Roseburg, Klamath Falls), the model assumes this event on and around December 20 each year. The following section provides details about the coldest days on record for each service territory.

The Washington/Idaho service areas coldest day on record was an 82 HDD for Spokane and occurred on Dec. 30, 1968. This is equal to an average daily temperature of -17 degrees Fahrenheit. Only one 82 HDD has been experienced in the last 48 years for this area; however, within that same time period, 80, 79 and 74 HDD events occurred on Dec. 29, 1968, Dec. 31,1978 and Jan. 5, 2004, respectively.

Medford experienced the coldest day on record, a 61 HDD, on Dec. 9, 1972. This is equal to an average daily temperature of 4 degrees Fahrenheit. Medford has experienced only one 61 HDD in the last 43 years; however, it has also experienced 59 and 58 HDD events on Dec. 8, 1972 and Dec. 21, 1990, respectively.

The other three areas in Oregon have similar weather data. For Klamath Falls, a 72 HDD occurred on Dec. 8, 2013; in La Grande a 74 HDD occurred on Dec. 23, 1983; and a 55

HDD occurred in Roseburg on Dec. 22, 1990. As with Washington/Idaho and Medford, these days are the peak day weather standard for modeling purposes.

Utilizing a peak planning standard of the coldest temperature on record may seem aggressive given a temperature experienced rarely, or only once. Given the potential impacts of an extreme weather event on customers' personal safety and property damage to customer appliances and Avista's infrastructure, it is a prudent regionally accepted planning standard. While remote, peak days do occur, as on Dec. 8, 2013, when Avista matched the previous peak HDD in Klamath Falls.

Avista analyzes an alternate planning standard using the coldest temperature in the last twenty years. The Washington/Idaho service area uses a 76 HDD, which is equal to an average daily temperature of -11 degrees Fahrenheit. In Medford, the coldest day in 20 years is a 54 HDD, equivalent to an average daily temperature of 11 degrees Fahrenheit. In Roseburg, the coldest day in 20 years is a 48 HDD, equivalent to an average daily temperature of 17 degrees Fahrenheit. In Klamath Falls, the coldest day in 20 years is a 72 HDD, equivalent to an average daily temperature of -7 degree Fahrenheit. In La Grande, the coldest day in 20 years is a 74 HDD, equivalent to an average daily temperature of -9 degree Fahrenheit. The HDDs by area, class and day entered into SENDOUT® are in Appendix 2.4 – Heating Degree Day Data.

Developing a Reference Case

To adjust for uncertainty, Avista developed a dynamic demand forecasting methodology that is flexible to changing assumptions. To understand how various alternative assumptions influence forecasted demand Avista needed a reference point for comparative analysis. For this, Avista defined the reference case demand forecast shown in Figure 2.4. This case is only a starting point to compare other cases.

Figure 2.4: Reference Case Assumptions

1. **Customer Compound Annual Growth Rates**

Area	Residential	Commercial	Industrial
Washington/ Idaho	1.1%	0.6%	0.0%
Klamath Falls	1.3%	0.9%	0.0%
La Grande	0.6%	0.4%	0.1%
Medford	1.3%	1.0%	0.0%
Roseburg	1.1%	0.2%	0.0%

2. **Use-Per-Customer Coefficients**
   Flat Across All Classes
   3-year Average Use per Customer per HDD by Area/Class
3. **Weather**
   20-year Normal – NOAA (1996-2015)
4. **Elasticity**
   None
5. **Conservation**
   None

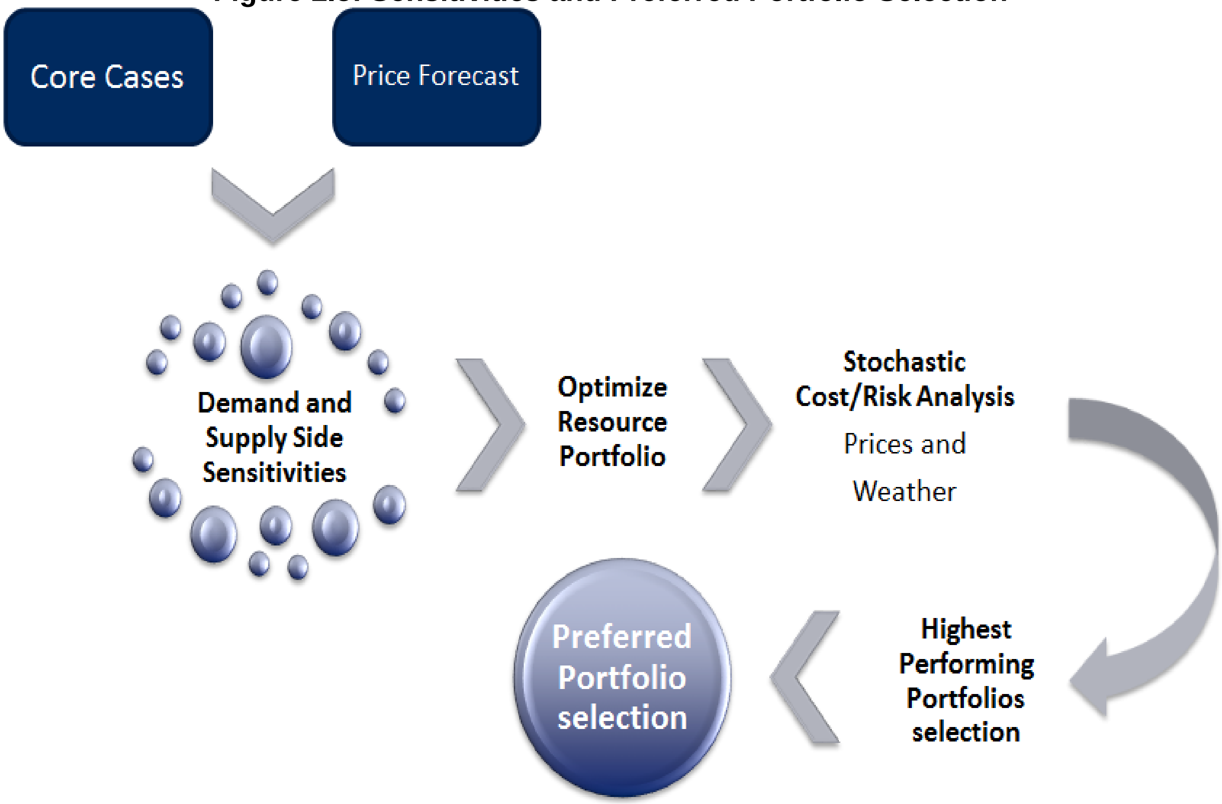
Dynamic Demand Methodology

The dynamic demand planning strategy examines a range of potential outcomes. The approach consists of:

- Identifying key demand drivers behind natural gas consumption;
- Performing sensitivity analysis on each demand driver;
- Combining demand drivers under various scenarios to develop alternative potential outcomes for forecasted demand; and
- Matching demand scenarios with supply scenarios to identify unserved demand.

Figure 2.5 represents Avista's methodology of starting with sensitivities, progressing to portfolios, and ultimately selecting a preferred portfolio.

Figure 2.5: Sensitivities and Preferred Portfolio Selection



Sensitivity Analysis

In analyzing demand drivers, Avista grouped them into two categories based on:

- Demand Influencing Factors directly influencing the volume of natural gas consumed by core customers.
- Price Influencing Factors indirectly influencing the volume of natural gas consumed by core customers through a price elasticity response.

After identifying demand and price influencing factors, Avista developed sensitivities to focus on the analysis of a specific natural gas demand driver and its impact on forecasted demand relative to the Reference Case when modifying the underlying input assumptions.

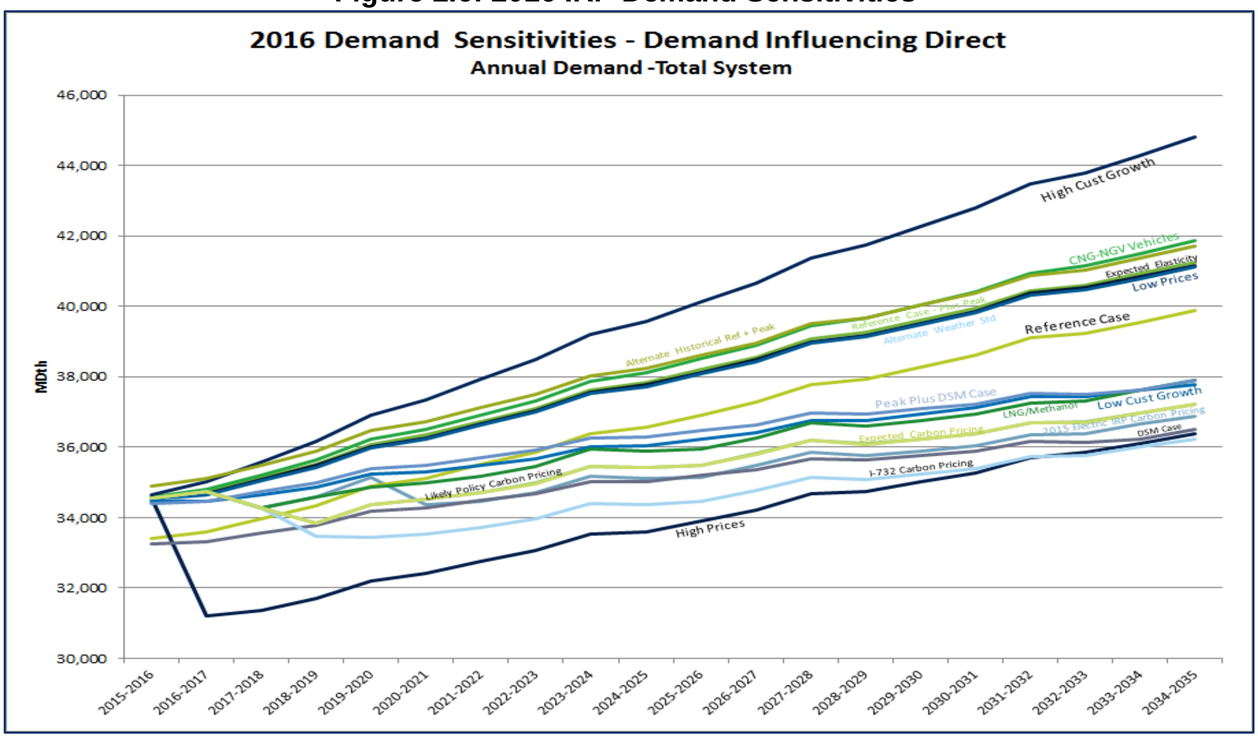
Sensitivity assumptions reflect incremental adjustments not captured in the underlying Reference Case forecast. Avista analyzed 18 demand sensitivities to determine the results relative to the Reference Case. Table 2.4 lists these sensitivities. Detailed information about these sensitivities is in Appendix 2.6 – Demand Forecast Sensitivities and Scenarios Descriptions.

Table 2.4: Demand Sensitivities

Scenario	Influence	Weather	Growth	Use per Customer	Price Curve	Carbon Adder	LNG Adder	DSM	New Markets	Elasticity
Reference Case	Direct	Normal	Expected	3 year	Expected	No	No	No	No	No
Reference Case plus Peak Weather	Direct	Peak	Expected	3 year	Expected	No	No	No	No	No
High Growth Case	Direct	Peak	High	3 year	Expected	No	No	No	No	No
Low Growth Case	Direct	Peak	Low	3 year	Expected	No	No	No	No	No
Alternate Use per Customer	Direct	Peak	Expected	5 year	Expected	No	No	No	No	No
CNG/NGV Case	Direct	Peak	Expected	3 year	Expected	No	No	No	Yes	No
DSM	Direct	Normal	Expected	3 year	Expected	No	No	No	No	No
Peak plus DSM	Direct	Peak	Expected	3 year	Expected	No	No	Yes	No	No
Alternate Weather Planning Standard	Direct	Coldest in 20	Expected	3 year	Expected	No	No	Yes	No	No
Expected Elasticity	Indirect	Peak	Expected	3 year	Expected	No	No	No	No	Yes
Low Price	Indirect	Peak	Expected	3 year	Low	No	No	No	No	No
High Price	Indirect	Peak	Expected	3 year	High	No	No	No	No	No
Carbon Legislation - Expected	Indirect	Peak	Expected	3 year	Expected	Yes	No	No	No	No
Carbon Legislation - Low	Indirect	Peak	Expected	3 year	Expected	Yes	No	No	No	No
Carbon Legislation - High	Indirect	Peak	Expected	3 year	Expected	Yes	No	No	No	No
Exported LNG	Indirect	Peak	Expected	3 year	Expected	No	Yes	No	No	No

Figure 2.6 shows the annual demand from each of the sensitivities modeled for this IRP.

Figure 2.6: 2016 IRP Demand Sensitivities



Scenario Analysis

After testing the sensitivities, Avista grouped them into meaningful combinations of demand drivers to develop demand forecasts representing scenarios. Table 2.5 identifies the scenarios developed for this IRP. The Average Case represents the case used for normal planning purposes, such as corporate budgeting, procurement planning, and PGA/General Rate Cases. The Expected Case reflects the demand forecast Avista believes is most likely given peak weather conditions. The Expected Case/Low Price represents the Expected Case assumptions combined with the low price curve. The High Growth/Low Price and Low Growth/High Price cases represent a range of possibilities for customer growth and future prices. The Alternate Weather Standard case utilizes the coldest day in Avista's service territories in the last 20 years. Each of these scenarios provides a "what if" analysis given the volatile nature of key assumptions, including weather and price. Appendix 2.6 lists the specific assumptions within the scenarios while Appendix 2.7 contains a detailed description of each scenario.

Table 2.5: Demand Scenarios

2016 IRP Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Alternate Weather Standard
Expected Case, Low Price

Price Elasticity

The economic theory of price elasticity states that the quantity demanded for a good or service will change with its price. Price elasticity is a numerical factor that identifies the relationship of a consumer's consumption change in response to a price change. Typically, the factor is a negative number as consumers normally reduce their consumption in response to higher prices or will increase their consumption in response to lower prices. For example, a price elasticity factor of negative 0.15 for a particular good or service means a 10 percent price increase will prompt a 1.5 percent consumption decrease and a 10 percent price decrease will prompt a 1.5 percent consumption increase.

Complex relationships influence price elasticity and given the current economic environment, Avista questions whether current behavior will become normal or if customers will return to historic usage patterns. Furthermore, complex regulatory pricing mechanisms shield customers from price volatility, thereby dampening price signals and affecting price elastic responses. For example, budget billing averages a customer's bills into equal payments throughout the year. This popular program helps customers manage household budgets, but does not send a timely price signal. Additionally, natural gas cost adjustments, such as the Purchased Gas Adjustment (PGA), annually adjusts the commodity cost which shields customers from daily gas price volatility. These mechanisms do not completely remove price signals, but they can significantly dampen the potential demand impact.

When considering a variety of studies on energy price elasticity, a range of potential outcomes was identified, including the existence of positive price elastic adjustments to demand. One study looking at the regional differences in price elasticity of demand for energy found that the statistical significance of price becomes more uncertain as the geographic area of measurement shrinks.[1] This is particularly important given Avista's geographically diverse and relatively small service territories.

Avista acknowledges changing price levels can and do influence natural gas usage, so this IRP includes a price elasticity of demand factor of -0.15 into the modeling assumptions to allow use-per-customer to vary as the natural gas price forecast changes.

Recent usage data indicates that even with declines in the retail rate for natural gas, long run use-per-customer continues to decline. This likely includes a confluence of factors including high regional unemployment, increased investments in energy efficiency measures, building code improvements, behavioral changes, and heightened focus of consumers' household budgets.

Results

During 2016, the Average Case demand forecast indicates Avista will serve an average of 334,000 core natural gas customers with 33,219,431 Dth of natural gas. By 2035, Avista projects 412,000 core natural gas customers with an annual demand of over 36,154,721 Dth. In Washington/Idaho, the projected number of customers increases at an average annual rate of 1.10 percent, with demand growing at a compounded average annual rate of 0.36 percent. In Oregon, the projected number of customers increases at an average annual rate of 1.18 percent, with demand growing 0.70 percent per year.

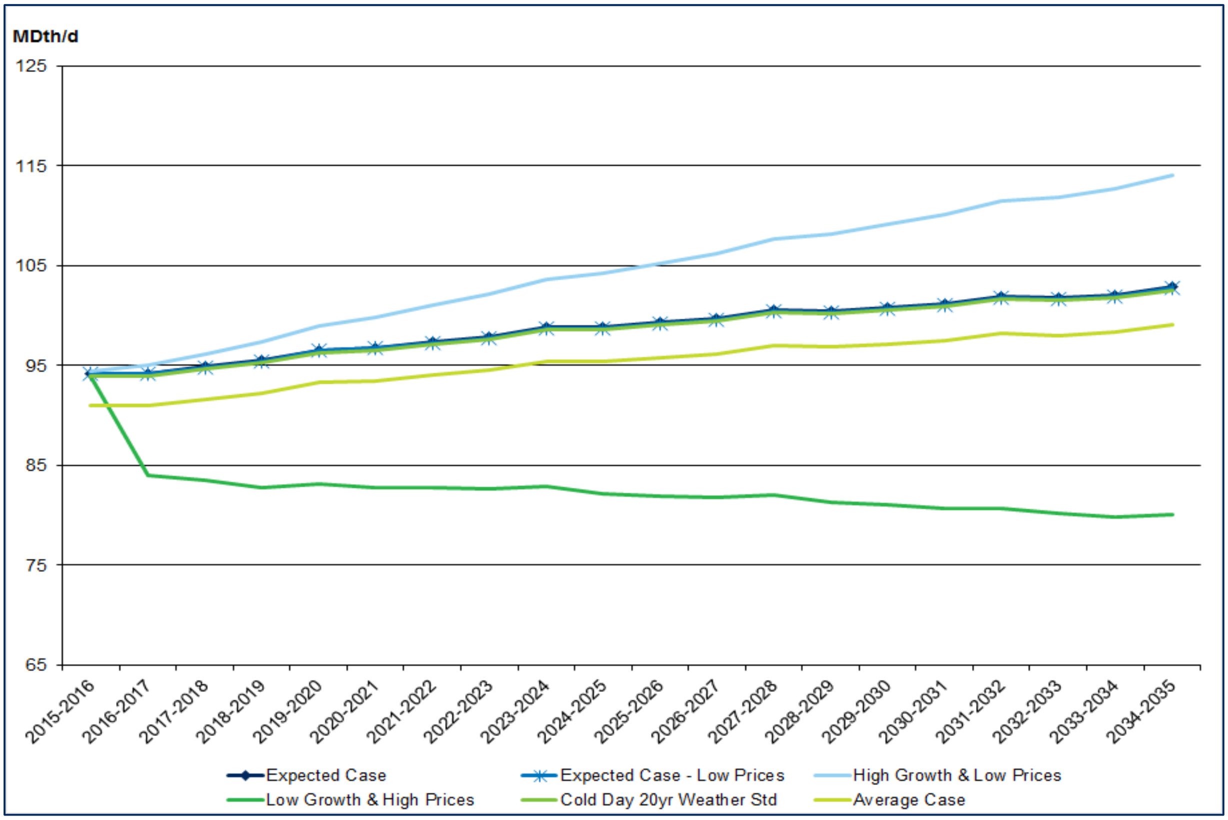
During 2016, the Expected Case demand forecast indicates Avista will serve an average of 334,000 core natural gas customers with 34,369,993 Dth of natural gas. By 2035,

[1] Bernstein, M.A. and J. Griffin (2005). Regional Differences in Price-Elasticity of Demand for Energy, Rand Corporation.

Avista projects 412,000 core natural gas customers with an annual demand of 37,536,603 Dth.

Figure 2.7 shows system forecasted demand for the demand scenarios on an average daily basis for each year.[2]

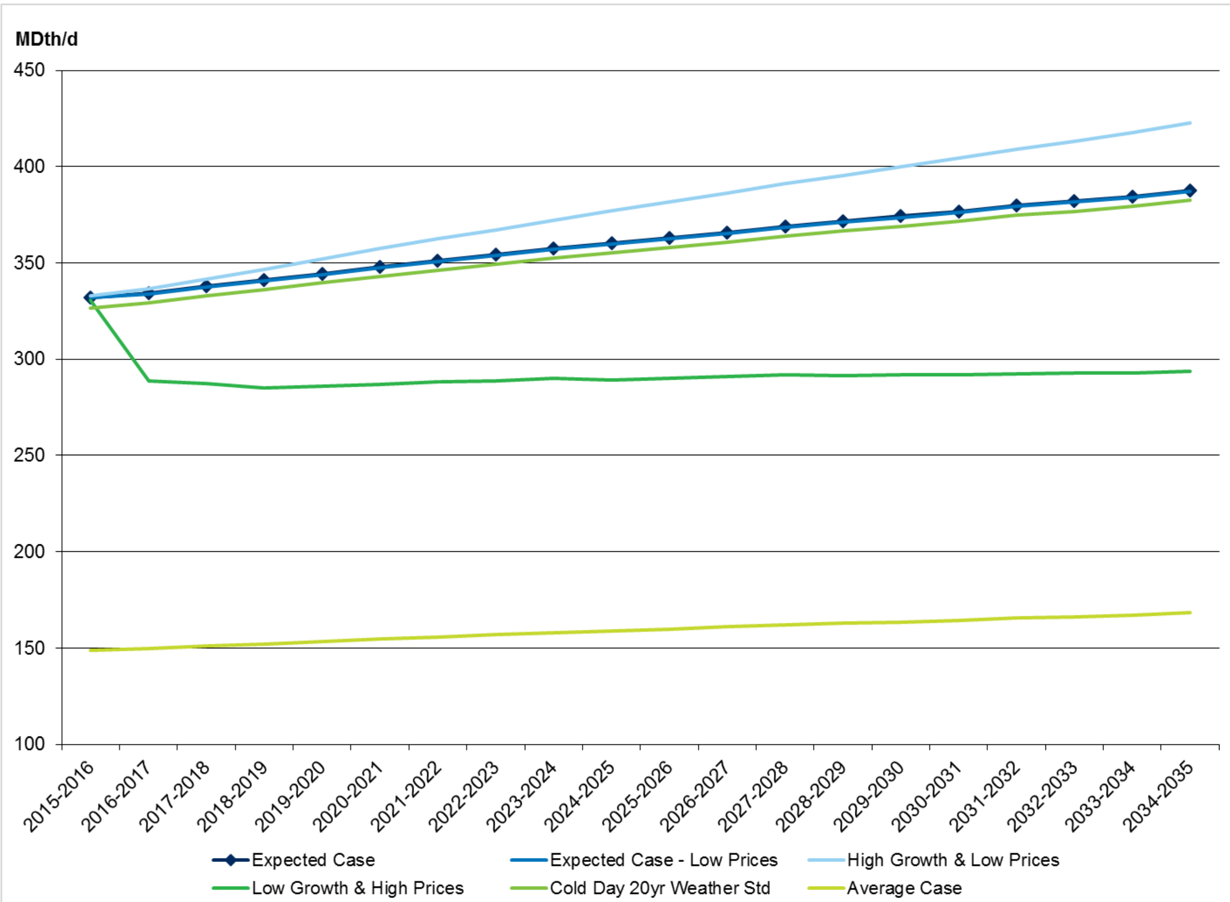
Figure 2.7: Average Daily Demand – 2016 IRP Scenarios



[2] Appendix 2.1 shows gross demand, conservation savings and net demand.

Figure 2.8 shows system forecasted demand for the Expected, High and Low Demand cases on a peak day basis for each year relative to the Average Case average daily winter demand. Detailed data for all demand scenarios is in Appendix 2.8 – Demand Before and After DSM.

Figure 2.8: February 15th – Peak Day – 2016 IRP Demand Scenarios



The IRP balances forecasted demand with existing and new supply alternatives. Since new supply sources include conservation resources, which act as a demand reduction, the demand forecasts prepared and described in this section include existing efficiency standards and normal market acceptance levels. The methodology for modeling DSM initiatives is in Chapter 3 – Demand-Side Resources.

Alternative Forecasting Methodologies

There are many forecasting methods available and used throughout different industries. Avista uses methods that enhance forecast accuracy, facilitate meaningful variance analysis, and allows for modeling flexibility to incorporate different assumptions. Avista believes the IRP statistical methodology to be sound and provides a robust range of demand considerations. The methodology allows for the analysis of different statistical inputs by considering both qualitative and quantitative factors. These factors come from data, surveys of market information, fundamental forecasts, and industry experts. Avista is always open to new methods of forecasting natural gas demand and will continue to assess which, if any, alternative methodologies to include in the dynamic demand forecasting methodology.

Key Issues

Demand forecasting is a critical component of the IRP requiring careful evaluation of the current methodology and use of scenario planning to understand how changes to the underlying assumptions will affect the results. The evolution of demand forecasting over recent years has been dramatic, causing a heightened focus on variance analysis and trend monitoring. Current techniques have provided sound forecasts with appropriate variance capabilities. However, Avista is mindful of the importance of the assumptions driving current forecasts and understands that these can and will change over time. Therefore, monitoring key assumptions driving the demand forecast is an ongoing effort that will be shared with the TAC as they develop.

Flat Demand Risk

Forecasting customer usage is a complex process because of the number of underlying assumptions and the relative uncertainty of future patterns of usage with a goal of increasing forecast accuracy. There are many factors that can be incorporated into these models, assessing which ones are significant and improving the accuracy are key. Avista continues to evaluate economic and non-economic drivers to determine which factors improve forecasting accuracy. The forecasting process will continue to review research on climate change and the best way to incorporate the results of that research into the forecasting process.

For the last few planning cycles, the TAC has discussed the changing slope of forecasted demand. Growth has slowed due to the recent recession and declining use-per-customer. Use-per-customer seems to have stabilized, but customer growth in Avista’s service territory may not return to pre-recession levels.

This reduced demand pushes the need for resources beyond the planning horizon, which means no new investment in resources is necessary. However, should assumptions about lower customer growth prove to be inaccurate and there is a rebound in demand, new resource needs will occur sooner than expected. Therefore, careful monitoring of demand trends in order to identify signposts of accelerated demand growth is critical to the identification of new resource needs coming earlier than expected.

Action Plan

- Monitor actual demand for accelerated growth can address resource deficiencies arising from exposure to "flat demand" risk. This will include providing Commission Staff with IRP demand forecast-to-actual variance analysis on customer growth and use per customer at least bi-annually.

Emerging Natural Gas Demand

The shale gas revolution has fundamentally changed the long-term availability and price of natural gas. This revolution has prompted an evolution in the increased use of natural gas. An ever growing demand for natural gas-fired generation to integrate variable wind and solar resources along with an increasing demand from coal retirements and fuel switching has developed over the last few years. This demand is expected to increase due to the availability of natural gas combined with its lower carbon emissions. Other areas of emerging demand include everything from methanol plants to food processors, and interest in industrial processes using natural gas as a feedstock is growing.

Conclusion

Recessionary impacts have significantly reduced Avista's outlook for customer growth and reduced the long-term demand forecasts. Avista's dynamic demand methodology provides a means to assess the individual and collective demand impact of a variety of economic and non-economic drivers. The results of this comprehensive analysis provides a better understanding of the possible outcomes with respect to core consumption of natural gas and helps drive resource decisions based on changing consumer needs.

3: Demand-Side Resources

Overview

Avista is committed to offering natural gas DSM portfolios to residential, commercial and industrial customers when it is feasible to do so in a cost-effective manner as prescribed within each jurisdiction. Improved drilling and extraction techniques of natural gas has led to declines in natural gas prices in recent years which has made offering cost-effective DSM programs challenging. In May 2012, Avista proposed to suspend its Washington and Idaho natural gas DSM programs due to decreased natural gas prices. The WUTC guided utilities to continue natural gas programs using the Utility Cost Test (UCT), Oregon provided cost-effectiveness exemptions for certain measures using the Total Resource Cost Test (TRC) and Avista requested and was given approval to suspend Avista's Idaho natural gas DSM programs under the TRC. During 2015, the Avista DSM group reviewed the current composition and components of natural gas avoided costs and compared them with both other regional and national utilities. The research and proposed additions to Avista's avoided cost were presented to Avista's DSM Advisory Group for feedback on August 19th and August 20th, 2015 to ensure these were appropriate changes and to seek advice about other future avoided cost components analyses the company should perform. After the review of Avista's avoided cost methodology and with an IPUC ruling that allows companies to emphasize the UCT when seeking prudence for their DSM programs, Avista filed for and was approved to reinstate its Idaho Natural Gas DSM programs as of January 1, 2016.

As part of the settlement for the Avista 2015 Oregon General Rate case, the company will begin to transition the regular income DSM programs to the Energy Trust of Oregon (ETO) in 2016, with the full program delivery and administration from the ETO January 1st, 2017. Avista will continue to administer the Oregon Low-Income conservation programs, which are not offered through the ETO.

During 2015, the proposed and accepted changes to avoided cost methodology were to include the additional costs associated with bringing natural gas from the wellhead to the customer meter beyond the firm transmission variable costs. Avista contracts for enough natural gas pipeline transportation to provide firm transportation capacity for a peak day. A large majority of the transaction costs are in reserving the capacity with a small component for the amount of natural gas that actually flows at a given time. Only including the variable portion of the transportation contracts does not accurately represent all of the costs of transporting natural gas from the wellhead to the customer meter and when excess capacity is available, the company releases or optimizes excess capacity for the direct benefit of customers. Transportation costs are built into the demand portion of Washington and Idaho schedule 150 which is a variable cost to customers that encompasses the net fixed costs to Avista to deliver natural gas to customer's meters. In Washington, a $10/ton carbon cost starting 2020 was included to account for the potential carbon reduction approaches currently occurring in the state.

The company has also been working to quantify the deferred distribution capacity benefits from natural gas conservation. Natural gas measures have two primary savings distribution: level annual therms and heating driven therm savings. For level annual therms for every 365 therms saved approximately one therm of peak load is reduced and the equivalent figure for space heating driven therms is 140 therms (~Average Day Dth/Peak Day Dth * 365) and on average a customer uses about 11.5 therms on a peak day. Using these figures, Avista DSM programs in Washington and Idaho since 2001 have offset the peak load of approximately 8,380 customers. The company is looking to quantifying the value of a peak day therm reduction and has a couple of potential approaches. The first is utilizing the cost per service as a value for the equivalent offset of capital expenditures. This approach benefits from data that is currently tracked and reported, but might not be the most accurate approach. The second approach looks at the costs associated with the recent and future reinforcement and capacity upgrade projects and calculating either the increased system capacity or the number of potential low pressure customers avoided under the design conditions due to the capacity upgrade. This approach would provide a more direct correlation, however the company does not currently track the upgraded system capacity or avoided low pressure customers and an exact calculation might be difficult due to the interconnected nature of the natural gas distribution system. Since the benefits of deferred capacity are a one-time cost, the benefits would be spread over the life of a typical distribution upgrade (35 years) as an avoided payment. This component of avoided costs was not included in this IRP and will be discussed with Avista's DSM Advisory Group as well as the TAC to determine the correct approach for the 2018 IRP.

Conservation Potential Assessment Methodology Overview

Avista issued an RFP and Applied Energy Group (AEG) was chosen to perform an external independent evaluation of the technical, economic and achievable conservation potential within each of Avista's three jurisdictions over a 20-year planning horizon. This process involves indexing existing nationally recognized Conservation Potential Assessment (CPA) models to the Avista service territory load forecast, housing stock, end-use saturations and other key characteristics. Additional consideration of the impact of energy codes and appliance standards for end-use equipment at both the state and national level are incorporated into the projection of energy use and the baseline for the evaluation of efficiency options. The modeling process also utilizes ramp rates for the acquisition of efficiency resources over time in a manner generally consistent with the assumptions used by the Northwest Power and Conservation Council (NPCC).

The process described above defines an Avista-specific supply curve for conservation resources. Simultaneously, the avoided cost of natural gas consistent with serving the full forecasted demand was defined as part of the SENDOUT® modeling of the Avista system. The preliminary cost-effective conservation potential is determined by applying the stream of annual natural gas avoided costs to the Avista-specific supply curve for conservation resources. This quantity of conservation acquisition is then decremented from the load which the utility must serve and the SENDOUT® model is rerun against the modified (reduced) load requirements. The resulting avoided costs are compared to those obtained from the previous iteration of SENDOUT® avoided costs. This process continues until the differential between the avoided cost streams of the most recent and the immediately previous iteration becomes immaterial. The cost-effectiveness test used for Washington and Idaho was the UCT, and Oregon continued to utilize the TRC to determine conservation selection.

Integrating the DSM portfolio into the IRP process by equilibrating the avoided costs in this iterative process is useful since Avista's DSM acquisition is small relative to the total western natural gas market used to establish the commodity prices driving the avoided cost stream. Therefore, few iterations are necessary to reach a stable avoided cost. Additionally, it provides some assurance, at least at the aggregate level, that the quantity of DSM resource selected will be cost-effective when the final avoided cost stream is used in retrospective portfolio evaluation.

Conservation Potential Assessment Findings

Prior to the development of potential conservation estimates, AEG created a baseline end-use forecast to quantify the use of natural gas by end use in the base year, and projections of consumption in the future in the absence of utility programs and naturally occurring conservation. The end-use forecast includes the relatively certain impacts of codes and standards that will unfold over the study timeframe. All such mandates defined as of January 2015 are included in the baseline. The baseline forecast is the foundation for the analysis of savings from future DSM programs as well as the metric against which potential savings are measured.

Inputs to the baseline forecast include current economic growth forecasts (e.g. customer growth and income growth), natural gas price forecasts, trends in fuel shares and equipment saturations developed by AEG, existing and approved changes to building codes and equipment standards, and Avista's internally developed load forecast.

According to the CPA, the residential sector natural gas consumption for all end uses and technologies increases primarily due to the projected 1.1 percent annual growth in the number of households and the slight increase in the average home size. Other heating, which includes unit wall heaters and miscellaneous loads, have a relatively high growth rate compared to other loads. However, at the end of the 20-year planning period these loads represent only a small part of overall use.

For the commercial and industrial sectors, natural gas use continues to grow slowly over the 20-year planning horizon as new construction increases the overall square footage in this sector. Growth in heating, ventilation and air conditioning (HVAC) and water heating end uses is moderate. Food preparation, though a small percentage of total usage, grows at a higher rate than other end uses. Consumption by miscellaneous equipment and process heating are also projected to increase.

Table 3.1 illustrates the baseline consumption broken out by state and sector for selected years over the 20-year planning horizon. The overall baseline consumption is expected to increase 21 percent over the 20-year planning horizon corresponding to an annualized growth of 1.1 percent. The forecast projects steady growth over the next 20 years with growth in the residential sector making up for the flat sales in the industrial sector. Idaho is projected to experience the highest level of growth with Washington having the next highest level of growth.

Table 3.1: Baseline Forecast Summary (Dth)

Sector	2015	2017	2018	2021	2026	2036	% Change ('17-'36)	Avg. Growth Rate ('17-'36)
Residential	17,796,844	19,617,372	19,846,006	20,458,537	21,702,908	24,462,944	25%	1.1%
Commercial	10,890,632	12,092,364	12,119,571	12,265,926	12,651,011	13,816,504	14%	0.7%
Industrial	507,024	546,799	556,102	582,284	632,932	748,791	37%	1.6%
Total	**29,194,500**	**32,256,535**	**32,521,679**	**33,306,747**	**34,986,852**	**39,028,239**	**21%**	**1.0%**
Washington	15,192,109	16,571,868	16,714,623	17,138,164	18,008,011	20,090,687	21%	1.0%
Idaho	6,948,564	7,610,218	7,683,310	7,918,057	8,399,424	9,552,526	26%	1.1%
Oregon	7,053,827	8,074,449	8,123,746	8,250,527	8,579,416	9,385,026	16%	0.8%
Total	**29,194,500**	**32,256,535**	**32,521,679**	**33,306,747**	**34,986,852**	**39,028,239**	**21%**	**1.0%**

The next step in the study is the development of the three types of potential: technical, economic and achievable. Technical potential is the theoretical upper limit of conservation potential. This assumes that all customers replace equipment with the most efficient option available and adopt the most efficient energy use practices possible at every opportunity without regard to cost-effectiveness. Economic potential represents the adoption of all cost-effective conservation measures based on the TRC test in Oregon and the UCT test in Washington and Idaho. The achievable potential takes into account market maturity, customer preferences for energy efficiency technologies and expected program participation. Achievable potential establishes a realistic target for conservation savings that a utility can expect to achieve through its efficiency programs.

DSM measures that achieve generally uniform year round energy savings independent of weather are considered base load measures. Examples include high efficiency water heaters, cooking equipment and front load clothes washers. Weather sensitive measures are those which are influenced by heating degree day factors and include higher efficiency furnaces, ceiling/wall/floor insulation, weather stripping, insulated windows, duct work improvements (tighter sealing to reduce leaks) and ventilation heat recovery systems (capturing chimney heat). Weather sensitive measures are often referred to as winter load shape measures and are typically valued using a higher avoided cost (due to summer to winter natural gas pricing differentials) while base load measures often called annual load shape measures are valued at a lower avoided cost.

Conservation measures are offered to residential, non-residential and low-income[1] customers. Measures offered to residential customers are almost universally on a prescriptive basis, meaning they have a fixed incentive for all customers and do not require individual pre-project analysis by the utility. Low-income customers are treated with a more flexible approach through cooperative arrangements with participating Community Action Agency partnerships. Non-residential customers have access to various prescriptive and site-specific conservation measures. Site-specific measures are customized to specific applications and have cost and therm savings that are unique to the individual facility.

In Oregon, some conservation measures are required by law and therefore their costs and benefits are incorporated into the portfolio without being subject to cost-effectiveness testing. These measures, for example, include energy audits that do not in and of themselves generate energy savings absent customer action and the timing and cost-effectiveness of the action(s) taken by the customer are uncertain.

See Table 3.2 for residential, commercial and industrial measures evaluated in this study for all three states.

[1] For purposes of tables, figures and targets, low income is a subset of residential class.

Table 3.2: Conservation Measures

Residential Measures	Commercial and Industrial Measures
Furnace – Maintenance	Furnace – Maintenance
Boiler – Pipe Insulation	Boiler – Maintenance
Insulation – Ducting	Boiler – Hot Water Reset
Insulation – Infiltration Control	Boiler – High Efficiency Hot Water Circulation
Insulation – Ceiling	Space Heating – Heat Recovery Ventilator
Insulation – Wall Cavity	Insulation – Ducting
Insulation – Attic Hatch	Insulation – Ceiling
Insulation – Foundation (new only)	Insulation – Wall Cavity
Ducting – Repair and Sealing	Ducting – Repair and Sealing
Doors – Storm and Thermal	Windows – High Efficiency
Windows – ENERGY STAR	Energy Management System
Thermostat – Clock/Programmable	Thermostat – Clock/Programmable
Water Heating – Faucet Aerators	Water Heating – Faucet Aerators
Water Heating – Low Flow Showerheads	Water Heating – Pipe Insulation
Water Heating – Pipe Insulation	Water Heating – Tank Blanket/Insulation
Water Heating – Tank Blanket/Insulation	Water Heating – Hot Water Saver
Water Heating – Thermostat Setback	Advanced New Construction Designs (new only)
Water Heating – Timer	Comprehensive Commissioning
Water Heating – Hot Water Saver	Process – Boiler Hot Water Reset (industrial only)
Water Heating – Drain Water Heat Recovery (new only)	Furnace – Efficient Heating
Home Energy Management System	Boiler – Efficient Heating
Advanced new Construction Designs (new only)	Unit Heater – Efficient Heating
ENERGY STAR Homes (new only)	Water Heating – Efficient Water Heating
Furnace – Efficient Heating	Food Preparation – Oven
Boiler – Efficient Heating	Food Preparation – Fryer
Water Heating – Efficient Water Heating	Food Preparation – Broiler
Appliances – Clothes Dryer	Food Preparation – Griddle
Appliances – Stove	Food Preparation – Range
Pool Heater – Efficient Water Heating	Food Preparation – Steamer
Insulation – Basement Sidewall	Pool Heater – Efficient Heater
Building Shell – Air Sealing	Steam Trap Maintenance
Insulation – Radiant Barrier	Boiler – High Turndown
Insulation – Wall Sheathing	Boiler – O2 Trim
Water Heater – Thermostatic Restrictor Shower Valve	Boiler – Parallel Positioning Control
Pool/Spa Cover	HVAC – Shut Off Damper
Boiler – Maintenance	Boiler – Stack Economizer
Boiler – Hot Water Reset	Ozone Laundry
Behavioral Programs	Pool Heater – Night Covers

Conservation Potential Assessment Results

Based upon the previously described methodology and baseline forecasts, AEG developed technical, economic and achievable potentials by jurisdiction and segment over a full 20-year horizon.

The technical potential for the overall Avista service territory for the full 20-year IRP horizon period ultimately reaches 27.5 percent of the baseline end-use forecast.

Economic potential applies the cost-effectiveness metric appropriate to each jurisdiction to DSM measures identified within the technical potential and quantify the impact of the adoption of only those DSM measures that are cost-effective. By the end of the 20-year timeframe this represents 16.4 percent of the baseline energy forecast. The significant difference between the technical and economic potential is a reflection of the economic impact of falling natural gas avoided costs as well as the conservation market saturation that was achieved in previous years with higher prevailing natural gas avoided costs. Past adoption of the most cost-effective measures leads to progressively higher costs for the remaining measures. At the same time the avoided cost value of these future adoptions is falling.

The achievable potential across the residential, commercial and industrial sectors, incorporating ramp rates derived from the NPCC and past company performance, is 9.1 percent of the baseline energy forecast by the end of 2036.

Tables 3.3 and 3.4 summarize cumulative conservation for each potential type for selected years across the 20-year CPA and IRP horizon. Initially the large commercial sector provides a relatively higher percentage of the achievable savings compared with its share of sales but over time this situation reverses such that the residential sector’s share of savings is the greatest due to growth in residential customer count. For more specific detail, please refer to the natural gas CPA provided in Appendix 3.1.

Table 3.3: Summary of Cumulative Achievable, Economic and Technical Conservation Potential (Dth)

Washington	2017	2018	2021	2026	2036
Baseline Forecast (DTh)	**16,571,868**	**16,714,623**	**17,138,164**	**18,008,011**	**20,090,687**
Potential Forecasts (DTh)					
Achievable Potential	16,522,957	16,604,429	16,774,904	17,128,936	18,033,128
Economic Potential	16,376,621	16,324,360	16,158,725	16,036,550	16,301,340
Technical Potential	16,272,909	16,117,023	15,652,845	15,062,160	14,504,805
Cumulative Savings (DTh)					
Achievable Potential	48,911	110,194	363,259	879,075	2,057,559
Economic Potential	195,247	390,263	979,438	1,971,461	3,789,348
Technical Potential	298,959	597,600	1,485,318	2,945,852	5,585,883
Energy Savings (% of Baseline)					
Achievable Potential	0.3%	0.7%	2.1%	4.9%	10.2%
Economic Potential	1.2%	2.3%	5.7%	10.9%	18.9%
Technical Potential	1.8%	3.6%	8.7%	16.4%	27.8%

Idaho	2017	2018	2021	2026	2036
Baseline Forecast (DTh)	**7,610,218**	**7,683,309**	**7,918,056**	**8,399,424**	**9,552,525**
Potential Forecasts (DTh)					
Achievable Potential	7,590,455	7,638,632	7,771,409	8,044,198	8,677,000
Economic Potential	7,531,121	7,525,047	7,520,628	7,589,742	7,909,518
Technical Potential	7,477,826	7,418,444	7,255,838	7,070,733	6,949,808
Cumulative Savings (DTh)					
Achievable Potential	19,764	44,677	146,648	355,226	875,525
Economic Potential	79,098	158,262	397,428	809,682	1,643,007
Technical Potential	132,392	264,865	662,219	1,328,691	2,602,717
Energy Savings (% of Baseline)					
Achievable Potential	0.3%	0.6%	1.9%	4.2%	9.2%
Economic Potential	1.0%	2.1%	5.0%	9.6%	17.2%
Technical Potential	1.7%	3.4%	8.4%	15.8%	27.2%

Oregon	2017	2018	2021	2026	2036
Baseline Forecast (DTh)	**8,074,448**	**8,123,746**	**8,250,527**	**8,579,416**	**9,385,026**
Potential Forecasts (DTh)					
Achievable Potential	8,059,948	8,092,232	8,156,777	8,341,963	8,759,342
Economic Potential	8,030,116	8,035,068	8,027,229	8,120,949	8,427,077
Technical Potential	7,934,077	7,846,087	7,566,082	7,227,445	6,836,516
Cumulative Savings (DTh)					
Achievable Potential	14,501	31,514	93,750	237,453	625,684
Economic Potential	44,332	88,678	223,297	458,467	957,949
Technical Potential	140,371	277,659	684,445	1,351,972	2,548,510
Energy Savings (% of Baseline)					
Achievable Potential	0.2%	0.4%	1.1%	2.8%	6.7%
Economic Potential	0.5%	1.1%	2.7%	5.3%	10.2%
Technical Potential	1.7%	3.4%	8.3%	15.8%	27.2%

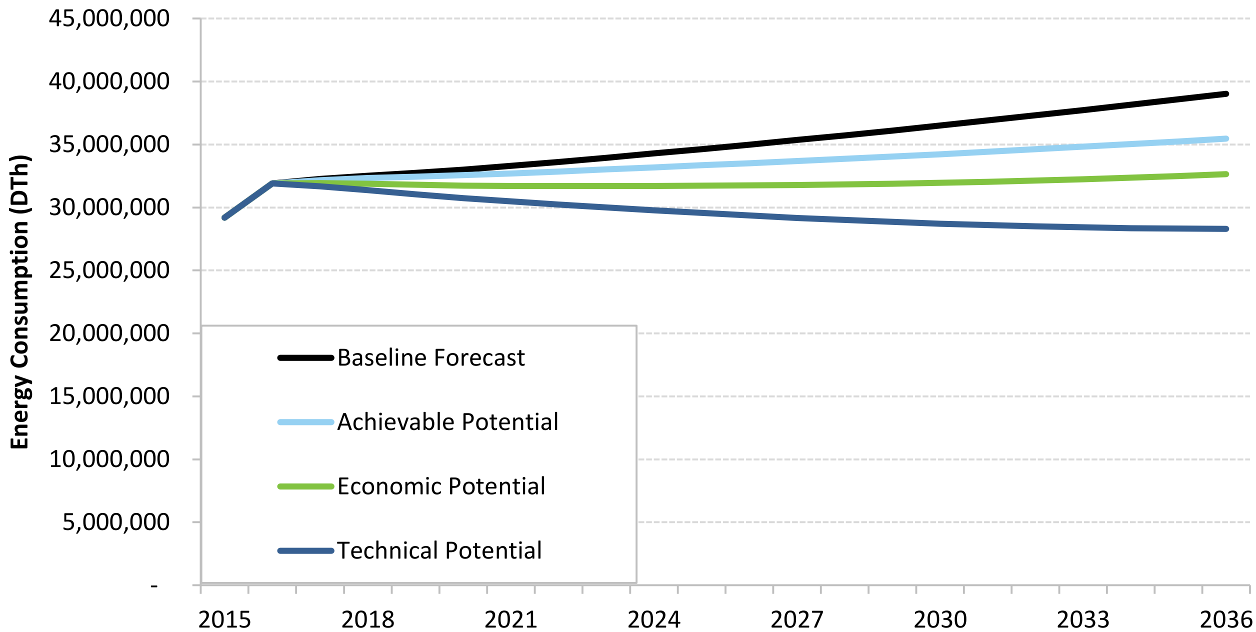
The overall achievable potential is presented first by state and by sector in the following table.

Table 3.4: Summary of Cumulative Achievable Potential by State and Sector (Dth)

Cumulative Savings	2017	2018	2021	2026	2036
Washington	48,911	110,194	363,259	879,075	2,057,559
Idaho	19,764	44,677	146,648	355,226	875,525
Oregon	14,501	31,514	93,750	237,453	625,684
Total	**83,176**	**186,385**	**603,657**	**1,471,754**	**3,558,768**
Residential	45,243	101,737	332,135	800,034	2,024,490
Commercial	37,171	83,084	267,342	662,485	1,510,525
Industrial	762	1,564	4,180	9,235	23,754
Total	**83,176**	**186,385**	**603,657**	**1,471,754**	**3,558,768**

Figure 3.1 illustrates the impact of the conservation potential forecast upon the end-use baseline absent of any conservation acquisition.

Figure 3.1 - Conservation Potential Energy Forecast (1000 therms)



Potential Results – Residential

Single-family homes represent 61 percent of Avista's residential natural gas customers, but account for 65 percent of the sector's consumption in the study base year 2015. In the current IRP residential provides the largest opportunity for cumulative savings over the next 20 years. Table 3.5 provides a distribution of achievable potential by state for the residential sector.

Table 3.5 Residential Cumulative Achievable Potential by State, Selected Years

	2017	2018	2021	2026	2036
Baseline projection Dth					
Washington	10,067,567	10,191,025	10,534,588	11,198,918	12,661,346
Idaho	4,741,736	4,802,813	4,992,555	5,366,588	6,213,091
Oregon	4,808,069	4,852,168	4,931,394	5,137,402	5,588,507
Total	**19,617,372**	**19,846,006**	**20,458,537**	**21,702,908**	**24,462,943**
Natural Gas Cumulative Savings Dth					
Washington	27,598	62,492	207,653	497,074	1,226,734
Idaho	11,138	25,406	85,812	208,875	536,817
Oregon	6,507	13,839	38,671	94,086	260,939
Total	**45,243**	**101,737**	**332,135**	**800,034**	**2,024,490**
% of Total Residential Savings					
Washington	61%	61%	63%	62%	61%
Idaho	25%	25%	26%	26%	27%
Oregon	14%	14%	12%	12%	13%

The bulk of the residential potential exists in space heating end-uses followed by water heating applications. Appliances and miscellaneous end-use loads contribute a small percentage of potential. Based on a measure-by-measure finding of the potential study the greatest sources of residential achievable potential across all three jurisdictions are:

- Shell measures and insulation;
- High efficiency furnaces;
- Thermostats and home energy monitoring systems;
- Water-saving devices (low-flow showerheads and faucet aerators); and
- Water heater tank blankets and pipe insulation.

Conservation Potential Results – Commercial and Industrial

The large commercial sector provides the next biggest opportunities for savings. Although potential as a percentage of baseline use varies between sectors, results do not vary greatly among the three states under the TRC test; Washington and Idaho have relatively higher savings due to using the UTC cost effectiveness test. Table 3.6 below details the achievable conservation potential by sector for selected years.

Table 3.6 Commercial Achievable Potential by Selected Years

	2017	2018	2021	2026	2036
Baseline projection Dth					
Washington	6,220,478	6,236,027	6,305,231	6,490,547	7,066,197
Idaho	2,656,853	2,664,007	2,695,763	2,776,753	3,021,253
Oregon	3,215,033	3,219,537	3,264,933	3,383,711	3,729,054
Total	**12,092,364**	**12,119,571**	**12,265,926**	**12,651,011**	**13,816,504**
Natural Gas Cumulative Savings Dth					
Washington	20,930	46,926	153,614	377,951	822,411
Idaho	8,320	18,631	59,027	141,940	324,991
Oregon	7,921	17,527	54,701	142,594	363,123
Total	**37,171**	**83,084**	**267,342**	**662,485**	**1,510,525**
% of Total Commercial Savings					
Washington	56%	56%	57%	57%	54%
Idaho	22%	22%	22%	21%	22%
Oregon	21%	21%	20%	22%	24%

Table 3.7 Industrial Cumulative Achievable Potential by Selected Years

	2017	2018	2021	2026	2036
Baseline projection Dth					
Washington	283,824	287,571	298,345	318,546	363,144
Idaho	211,629	216,490	229,739	256,083	318,182
Oregon	51,346	52,041	54,200	58,303	67,465
Total	**546,799**	**556,101**	**582,284**	**632,933**	**748,791**
Natural Gas Cumulative Savings Dth					
Washington	383	777	1,993	4,050	8,414
Idaho	306	641	1,809	4,411	13,717
Oregon	73	147	379	773	1,622
Total	**762**	**1,564**	**4,180**	**9,235**	**23,754**
% of Total Industrial Savings					
Washington	50%	50%	48%	44%	35%
Idaho	40%	41%	43%	48%	58%
Oregon	10%	9%	9%	8%	7%

Most of the commercial and industrial conservation potential exists within space heating and water heating applications. Food preparation, process and miscellaneous represents a smaller proportion of potential. Primary sources of commercial and industrial sector achievable savings are:

- Energy management systems and programmable thermostats:
- Retro-commissioning:
- Boiler operating measures such as maintenance;
- Hot water reset and efficient circulation;
- Equipment upgrades for furnaces, boilers and unit heaters; and
- Food service equipment.

Aggregate Conservation Potential Results

The following three tables provide the 2017-2018 CPA identified conservation opportunity for Idaho, Oregon and Washington, respectively.

Table 3.8: Idaho Natural Gas Target (2017-2018)

Incremental Annual Savings (DTh)	2017	2018
Residential	11,138	14,268
Commercial & Industrial	8,626	10,376
Total	**19,764**	**24,644**

Table 3.9: Oregon Natural Gas Target (2017-2018)

Incremental Annual Savings (Dth)	2017	2018
Residential	6,507	7,332
Commercial & Industrial	7,994	9,680
Total	**14,501**	**17,012**

Table 3.10: Washington Natural Gas Target (2017-2018)

Incremental Annual Savings (Dth)	2017	2018
Residential	27,598	34,894
Commercial & Industrial	21,313	26,390
Total	**48,911**	**61,284**

Uses and Applications of the CPA

It is useful to place the IRP process and the CPA component of that process into the larger perspective of Avista's efforts to acquire all available cost-effective conservation resources. Activities outside the immediate scope of the IRP process include the formal annual business planning and annual cost-effectiveness and acquisition reporting processes in addition to the ongoing management of the DSM portfolio.

The IRP leads to the establishment of a 20-year avoided cost stream that is essential to determining the quantity of DSM resources that are cost-effective when compared to the CPA-identified conservation supply curve and the management of the DSM portfolio between the two year IRP cycles. The many related and coordinated processes all contribute to the planning and management of the DSM portfolio towards meeting its cost-effectiveness and acquisition goals.

The relationship between the CPA and the annual business planning process is of particular note. The CPA is regarded as a high-level tool that is useful for establishing aggregate targets and identifying general target markets and target measures. However the CPA of necessity must make certain broad assumptions regarding key characteristics that are fine-tuned as part of the creation of an operational business plan. Some of the assumptions that are most frequently modified include market segmentation, customer eligibility, measure definition, incentive level, interaction between measures and the opportunities for packaging measures or coordinated the delivery of measures.

One issue that inevitably arises as part of moving from the CPA analysis to the business planning process is the treatment of market segments. The CPA defines market segments (e.g. by residential building type or vintage) to appropriately define the cost-effective potential for efficiency options and to ensure consistency with system loads and load forecasts. However, it is often infeasible to recognize these distinctions on an operational basis. This may result in aggregations of market segments into programs that could lead to more or less operationally achievable savings.

A second issue that often arises is the "clumpiness" that often occurs with large Commercial and Industrial projects. Large natural gas conservation projects typically have long lead times with multiple years between the original customer contact and design of a project to the final completion with any required measurement and verification. These projects can lead to over or underperforming targets in individual years but typically average out over the 20-year time frame of an IRP.

Conservation Action Plan

The analytical process for the CPA is based on a deterministic model as compared to the assumptions within the Expected Case. In order to further enhance our analytical methodology, Avista will focus on the following:

- Explore methods to enable a dynamic analytical process for the evaluation of conservation potential within individual portfolios.

Conclusion

Avista has a long-term commitment to responsibly pursuing all available and cost-effective efficiency options as an important means to reduce our customer's energy cost. Cost-effective demand-side management options are a key element in our strategy to meet those commitments. Falling avoided costs and lower growth in customer demand have led to a reduced role for conservation in the overall natural gas portfolio compared with IRPs done prior to 2012 however, a regulatory shift to utilizing the UCT in Washington and Idaho DSM programs will continue to provide a vital role in offsetting future natural gas load growth. The company has begun to transition our regular income Oregon DSM programs to the ETO with the ETO being the sole administrator beginning January 1, 2017. Avista is continuing to adaptively manage our DSM programs in response to the ever shifting economic climate.

Perhaps of most importance in the long-term are the Company's ongoing efforts to work with key regional players to develop a regional natural gas market transformation organization and portfolio. NEEA has begun to execute the first stages of their 2015 – 2019 Natural Gas Market Transformation Business Plan and we look forward to the conservation opportunities that arise out of their work in the coming years.

Market transformation is not itself called out within the CPA since the CPA focuses upon conservation potential without regard to how that potential is achieved. The prospect for a regional market transformation entity will potentially bring a valuable tool to bear in working towards the achievement of the cost-effective conservation opportunities identified within the natural gas CPA.

4: Supply-Side Resources

Overview

Avista analyzed a range of future demand scenarios and possible cost-effective conservation measures to reduce demand. This chapter discusses supply options to meet net demand. Avista's objective is to provide reliable natural gas to customers with an appropriate balance of price stability and prudent cost under changing market conditions. To achieve this objective, Avista evaluates a variety of supply-side resources and attempts to build a diversified natural gas supply portfolio. The resource acquisition and commodity procurement programs resulting from the evaluation consider physical and financial risks, market-related risks, and procurement execution risks; and identifies methods to mitigate these risks.

Avista manages natural gas procurement and related activities on a system-wide basis with several regional supply options available to serve core customers. Supply options include firm and non-firm supplies, firm and interruptible transportation on six interstate pipelines, and storage. Because Avista's core customers span three states, the diversity of delivery points and demand requirements adds to the options available to meet customers' needs. The utilization of these components varies depending on demand and operating conditions. This chapter discusses the available regional commodity resources and Avista's procurement plan strategies, the regional pipeline resource options available to deliver the commodity to customers, and the storage resource options available to provide additional supply diversity, enhanced reliability, favorable price opportunities, and flexibility to meet a varied demand profile. Non-traditional resources are also considered.

Commodity Resources

Supply Basins

Avista is fortunate to be located near the two largest natural gas producing regions in North America – the Western Canadian Sedimentary Basin (WCSB), located in the Canadian provinces of Alberta and British Columbia, and the Rocky Mountain (Rockies) gas basin, located in parts of Wyoming, Utah and Colorado. Avista sources most of its natural gas supplies from these two basins.

Several large pipelines connect the WCSB and Rockies gas basins to the Pacific Northwest, Southwest, Midwest and Northeast sections of the continent. Historically, natural gas supplies from the WCSB and Rockies cost less relative to other parts of the country. Shale gas production from the Northeast has altered flow dynamics and helped sustain the regional pricing discount. Forecasts show a long-term regional price advantage for WCSB and Rockies gas basins as the need for these supplies in the East diminishes as more shale gas supply develops in the East.

Increased availability of North American natural gas has prompted a change in the global LNG landscape. Excess supply has prompted LNG developers to consider exporting natural gas to capture higher prices in the Asian and European markets. The oil markets continued oversupply has changed the fortunes of LNG. Since oil prices maintain a depressed state, the expected fuel switching has not taken place. Switching can occur when oil is high enough to force users to want to make the switch to an alternate form of fuel. LNG was expected to be the primary beneficiary of fuel switching. Regionally there is only one proposed project in Oregon - Jordan Cove. Jordan Cove has received their FERC export authorization, but in 2016 FERC turned down its supply source known as Pacific Connector pipeline due to the perception there was insufficient demand. An updated filing showing demand is expected to take place in the near term, but the results are unknown at this time. There are 17 announced export LNG projects in British Columbia. While there is much uncertainty about the number of completed facilities, the bigger question is the impact of exports on regional infrastructure and prices.

Regional Market Hubs

There are numerous regional market hubs where natural gas is traded extending from the two primary basins. These regional hubs are typically located at pipeline interconnects. Avista is located near, and transacts at, most of the Pacific Northwest regional market hubs, enabling flexible access to several supply points. These supply points include:

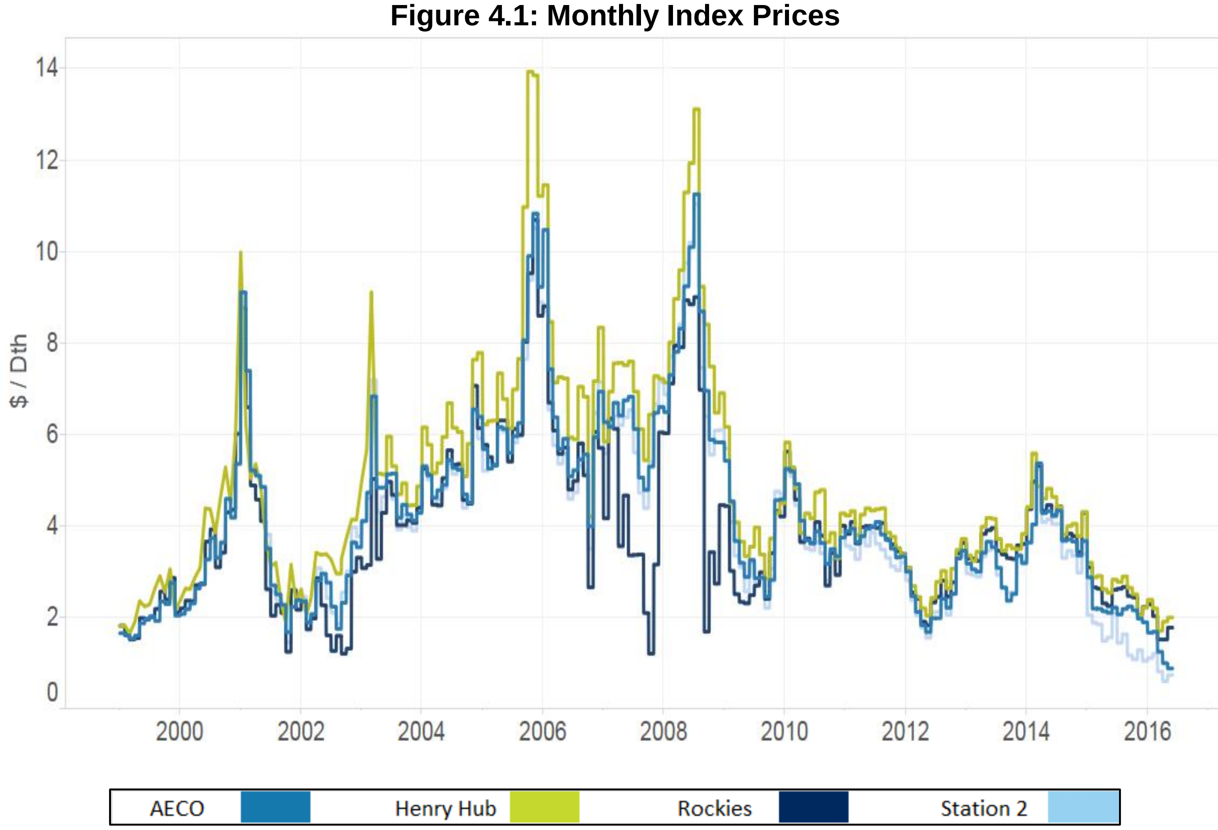
- **AECO** – The AECO-C/Nova Inventory Transfer market center located in Alberta is a major connection region to long-distance transportation systems, which take natural gas to points throughout Canada and the United States. Alberta is the major Canadian exporter of natural gas to the U.S. and historically produced 90 percent of Canada's natural gas.
- **Rockies** – This pricing point represents several locations on the southern end of the NWP system in the Rocky Mountain region. The system draws on Rocky Mountain natural gas-producing areas clustered in areas of Colorado, Utah and Wyoming.
- **Sumas/Huntingdon** – This pricing point at Sumas, Washington, is on the U.S./Canadian border where the northern end of the NWP system connects with Spectra Energy’s Westcoast Pipeline and predominantly markets Canadian natural gas from Northern British Columbia.

- **Malin** – This pricing point is at Malin, Oregon, on the California/Oregon border where the pipelines of TransCanada Gas Transmission Northwest (GTN) and Pacific Gas & Electric Company connect.
- **Station 2** – Located at the center of the Spectra Energy/Westcoast Pipeline system connecting to northern British Columbia natural gas production.
- **Stanfield** – Located near the Washington/Oregon border at the intersection of the NWP and GTN pipelines.
- **Kingsgate** – Located at the U.S./Canadian (Idaho) border where the GTN pipeline connects with the TransCanada Foothills pipeline.

Given the ability to transport natural gas across North America, natural gas pricing is often compared to the Henry Hub price. Henry Hub, located in Louisiana, is the primary natural gas pricing point in the U.S. and is the trading point used in NYMEX futures contracts.

Figure 4.1 shows historic natural gas prices for first-of-month index physical purchases at AECO, Sumas, Rockies and Henry Hub. The figure illustrates the usually tight relationship among the regional market hubs; however, there have been periods where one or more price points have disconnected.

Figure 4.1: Monthly Index Prices



Northwest regional natural gas prices typically move together; however, the basis differential can change depending on market or operational factors. This includes differences in weather patterns, pipeline constraints, and the ability to shift supplies to higher-priced delivery points in the U.S. or Canada. By monitoring these price shifts, Avista can often purchase at the lowest-priced trading hubs on a given day, subject to operational and contractual constraints.

Liquidity is generally sufficient in the day-markets at most Northwest supply points. AECO continues to be the most liquid supply point, especially for longer-term transactions. Sumas has historically been the least liquid of the four major regional supply points (AECO, Rockies, Sumas and Malin). This illiquidity contributes to generally higher relative prices in the high demand winter months.

Avista procures natural gas via contracts. Contract specifics vary from transaction-to-transaction, and many of those terms or conditions affect commodity pricing. Some of the terms and conditions include:

- **Firm vs. Non-Firm:** Most term contracts specify that supplies are firm except for force majeure conditions. In the case of non-firm supplies, the standard provision is that they may be cut for reasons other than force majeure conditions.
- **Fixed vs. Floating Pricing:** The agreed-upon price for the delivered gas may be fixed or based on a daily or monthly index.
- **Physical vs. Financial:** Certain counterparties, such as banking institutions, may not trade physical natural gas, but are still active in the natural gas markets. Rather than managing physical supplies, those counterparties choose to transact financially rather than physically. Financial transactions provide another way for Avista to financially hedge price.
- **Load Factor/Variable Take:** Some contracts have fixed reservation charges assessed during each of the winter months, while others have minimum daily or monthly take requirements. Depending on the specific provisions, the resulting commodity price will contain a discount or premium compared to standard terms.
- **Liquidated Damages:** Most contracts contain provisions for symmetrical penalties for failure to take or supply natural gas.

For this IRP, the SENDOUT® model assumes natural gas purchases under a firm, physical, fixed-price contract, regardless of contract execution date and type of contract. Avista pursues a variety of contractual terms and conditions to capture the most value for customers. Avista‘s natural gas buyers actively assess the most cost-effective way to meet customer demand and optimize unutilized resources.

Avista's Natural Gas Procurement Plan

No company can accurately predict future natural gas prices, but market conditions and experience help shape the overall approach to procurement. Avista's natural gas procurement plan process seeks to acquire natural gas supplies while reducing exposure to short-term price volatility. The procurement strategy includes hedging, storage utilization and index purchases. Although the specific provisions of the procurement plan will change based on ongoing analysis and experience, the following principles guide Avista's procurement plan.

Avista employs a time, location and counterparty diversified hedging strategy. It is appropriate to hedge over a period and establish hedge periods when portions of future demand are physically and/or financially hedged. Avista views hedging as an appropriate part of a diversified procurement plan with a ***mission to provide a diversified portfolio of reliable supply with a level of price certainty in volatile markets***. Hedges may not be at the lowest possible price, but they still protect customers from price volatility. With access to multiple supply basins, Avista transacts with the lowest priced basin at the time of the hedge. Furthermore, Avista transacts with a range of counterparties to spread supply among a wider range of market participants.

Avista evaluates market opportunities as they become available. The abundance of shale gas, combined with recent lagging weather related demand, has created a near-term supply glut that continues to suppress price levels. Because of this oversupply, many oil and natural gas companies have been shedding their assets due to high debts incurred in the exploration and production side of the business. These companies need cash to pay debts, so many of these assets can be purchased at a favorable rate providing a potential market opportunity for Avista to hedge natural gas into the future at depressed prices.

These market opportunities can include physical/financial instruments or contracts used to trade or reduce risk or exposure in our current procurement plan portfolio. These opportunities are primarily market driven with a very short timeframe. A derivative based contract, a ten-year forward strip or natural gas reserves are some examples of these market opportunities. Avista has written procedures and guidelines as to whether the specific opportunity might fit within our portfolio, with a detailed analysis being used to vet each opportunity when appropriate.

Avista uses a disciplined, but flexible hedging approach. Avista's hedging strategy includes the prompt year as part of our short term hedging combined with our long term hedging of two, three and four future winter periods. In addition to establishing periods when hedges are to be completed, Avista also sets upper and lower pricing points. This reduces Avista's exposure to extreme price spikes in a rising market and encourages capturing the benefit associated with lower prices.

Avista regularly reviews its procurement plan in light of changing market conditions and opportunities. Avista's plan is open to change in response to ongoing review of the procurement plan assumptions. Even though the initial plan establishes various targets, policies provide flexibility to exercise judgment to revise targets in response to changing conditions.

Avista utilizes a number of tools to help mitigate financial risks. Avista purchases gas in the spot market and forward markets. Spot purchases are for the next day or weekend. Forward purchases are for future delivery. Many of these tools are financial instruments or derivatives that can provide fixed prices or dampen price volatility. Avista continues to evaluate how to manage daily demand volatility, whether through option tools from counterparties or through access to additional storage capacity and/or transportation.

Market-Related Risks and Risk Management

There are several types of risk and approaches to risk management. The 2016 IRP focuses on two areas of risk: the financial risk of the cost of natural gas to supply customers will be unreasonably high or volatile, and the physical risk that there may not be enough natural gas resources (either transportation capacity or the commodity) to serve core customers.

Avista's Risk Management Policy describes the policies and procedures associated with financial and physical risk management. The Risk Management Policy addresses issues related to management oversight and responsibilities, internal reporting requirements, documentation and transaction tracking, and credit risk.

Two internal organizations assist in the establishment, reporting and review of Avista's business activities as they relate to management of natural gas business risks:

- The Risk Management Committee includes corporate officers and senior-level management. The committee establishes the Risk Management Policy and monitors compliance. They receive regular reports on natural gas activity and meet regularly to discuss market conditions, hedging activity and other natural gas-related matters.
- The Strategic Oversight Group coordinates natural gas matters among internal natural gas-related stakeholders and serves as a reference/sounding board for strategic decisions, including hedges, made by the Natural Gas Supply department. Members include representatives from the Gas Supply, Accounting,

Regulatory, Credit, Power Resources, and Risk Management departments. While the Natural Gas Supply department is responsible for implementing hedge transactions, the Strategic Oversight Group provides input and advice.

Transportation Resources

Although proximity to liquid market hubs is important from a cost perspective, supplies are only as reliable as the pipeline transportation from the hubs to Avista's service territories. Capturing favorable price differentials and mitigating price and operational risk can also be realized by holding multiple pipeline transport options. Avista contracts for a sufficient amount of diversified firm pipeline capacity from various receipt and delivery points (including storage facilities), so that firm deliveries will meet peak day demand. This combination of firm transportation rights to Avista's service territory, storage facilities and access to liquid supply basins ensure peak supplies are available to serve core customers.

The major pipelines servicing the region include:

- **Williams - Northwest Pipeline (NWP)**
  A natural gas transmission pipeline serving the Pacific Northwest moving natural gas from the U.S./Canadian border in Washington and from the Rocky Mountain region of the U.S.
- **TransCanada Gas Transmission Northwest (GTN):** A natural gas transmission pipeline originating at Kingsgate, Idaho, (Canadian/U.S. border) and terminating at the California/Oregon border close to Malin, Oregon.
- **TransCanada Alberta System:** This natural gas gathering and transmission pipeline in Alberta, Canada, delivers natural gas into the TransCanada Foothills pipeline at the Alberta/British Columbia border.
- **TransCanada Foothills System:** This natural gas transmission pipeline delivers natural gas between the Alberta, British Columbia, border and the Canadian/U.S. border at Kingsgate, Idaho.
- **TransCanada Tuscarora Gas Transmission:** This natural gas transmission pipeline originates at Malin, Oregon, and terminates at Wadsworth, Nevada.

- **Spectra Energy - Westcoast Pipeline:** This natural gas transmission pipeline originates at Fort Nelson, British Columbia, and terminates at the Canadian/U.S. border at Huntington, British Columbia/Sumas, Washington.
- **El Paso Natural Gas - Ruby pipeline:** This natural gas transmission pipeline brings supplies from the Rocky Mountain region of the U.S. to interconnections near Malin, Oregon.

Avista has contracts with all of the above pipelines (with the exception of Ruby Pipeline) for firm transportation to serve core customers. Table 4.1 details the firm transportation/resource services contracted by Avista. These contracts are of different vintages with different expiration dates; however, all have the right to be renewed by Avista. This gives Avista and its customers available capacity to meet existing core demand now and in the future.

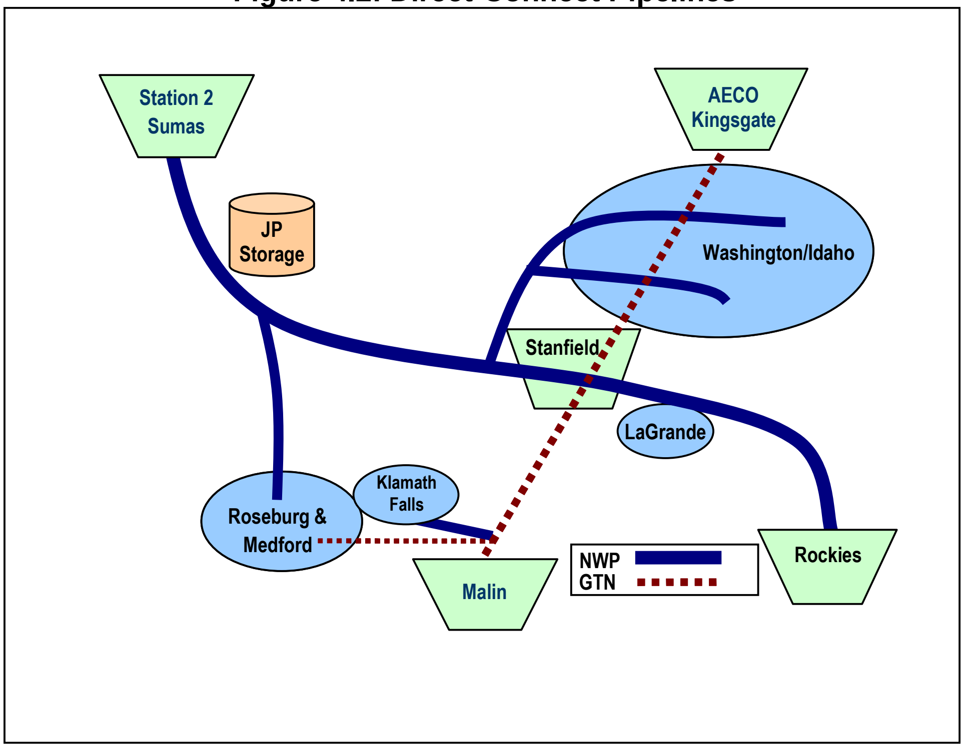
Table 4.1: Firm Transportation Resources Contracted (Dth/Day)

	Avista North		Avista South	
Firm Transportation	**Winter**	**Summer**	**Winter**	**Summer**
NWP TF-1	157,869	157,869	42,699	42,699
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2	91,200		2,623	
Total	**349,674**	**233,651**	**87,582**	**63,339**
Firm Storage Resources - Max Deliverability				
Jackson Prairie (Owned and Contracted)	346,667		54,623	
Total	**346,667**		**54,623**	

** Represents original contract amounts after releases expire.*

Avista defines two categories of interstate pipeline capacity. Direct-connect pipelines deliver supplies directly to Avista's local distribution system from production areas, storage facilities or interconnections with other pipelines. Upstream pipelines deliver natural gas to the direct-connect pipelines from remote production areas, market centers and out-of-area storage facilities. Firm storage - max deliverability is specifically tied to Avista's withdrawal rights at the Jackson Prairie storage facility and is based on our one third ownership rights. This number only indicates how much we can withdraw from the facility as transport on NWP is needed to move it from the facility itself. Figure 4.2 illustrates the direct-connect pipeline network relative to Avista's supply sources and service territories.[1]

Figure 4.2: Direct-Connect Pipelines



Supply-side resource decisions focus on where to purchase natural gas and how to deliver it to customers. Each LDC has distinctive service territories and geography relative to supply sources and pipeline infrastructure. Solutions that deliver supply to service territories among regional LDCs are similar but are rarely generic.

The NWP system, for the most part, is a fully-contracted system. With the exception of La Grande, Avista's service territories lie at the end of NWP pipeline laterals. The Spokane, Coeur d'Alene and Lewiston laterals serve Washington/Idaho load, and the Grants Pass lateral serves Roseburg and Medford. Capacity expansions of these laterals

1 Avista has a small amount of pipeline capacity with TransCanada Tuscarora Gas Transmission, a natural gas transmission pipeline originating at Malin, Oregon, to service a small number of Oregon customers near the southern border of the state.

would be lengthy and costly endeavors which Avista would likely bear most of the incremental costs.

The GTN system currently has ample unsubscribed capacity. This pipeline runs directly through or near most of Avista's service territories. Mileage based rates provide an attractive option for securing incremental resource needs.

Peak day planning aside, both pipelines provide an array of options to flexibly manage daily operations. The NWP and GTN pipelines directly serve Avista's two largest service territories, providing diversification and risk mitigation with respect to supply source, price and reliability. The NWP system (a bi-directional, fixed reservation fee-based pipeline) provides direct access to Rockies and British Columbia supply and facilitates optionality for storage facility management. The Stanfield interconnect of the two lines is also geographically well situated to Avista's service territories.

The rates used in the planning model start with filed rates currently in effect (See Appendix 4.1 – Current Transportation/Storage Rates and Assumptions). Forecasting future pipeline rates is challenging. Assumptions for future rate changes are the result of market information on comparable pipeline projects, prior rate case experience, and informal discussions with regional pipeline owners. Pipelines will file to recover costs at rates equal to the GDP with adjustments made for specific project conditions.

NWP and GTN also offer interruptible transportation services. Interruptible transportation is subject to curtailment when pipeline capacity constraints limit the amount of natural gas that may be moved. Although the commodity cost per dekatherm transported is the same as firm transportation, there are no demand or reservation charges in these transportation contracts. As the marketplace for release of transportation capacity by the pipeline companies and other third parties has become more prevalent, the use of interruptible transportation services has diminished. Avista does not rely on interruptible capacity to meet peak day core demand requirements.

Avista's transportation acquisition strategy is to contract for firm transportation to serve core customers on a peak day in the planning horizon. Since contracts for pipeline capacity are often lengthy and core customer demand needs can vary over time, determining the appropriate level of firm transportation is a complex analysis. The analysis includes the projected number of firm customers and their expected annual and peak day demand, opportunities for future pipeline or storage expansions, and relative costs between pipelines and upstream supplies. This analysis is on an annual basis and through the IRP. Active management of underutilized transportation capacity through the capacity release market and engaging in optimization transactions offsets some transportation costs. Timely analysis is also important to maintain an appropriate time cushion to allow for required lead times should the need for securing new capacity arise

(See Chapter 5 – Integrated Resource Portfolio for a description of the management of underutilized pipeline resources).

Avista manages existing resources through optimization to mitigate the costs incurred by customers until the resource is required to meet demand. The recovery of costs is often market based with rules governed by the FERC. Avista is recovering full costs on some resources and partial costs on others. The management of long- and short-term resources ensures the goal to meet firm customer demand in a reliable and cost-effective manner. Unutilized resources like supply, transportation, storage and capacity can combine to create products that capture more value than the individual pieces. Avista has structured long-term arrangements with other utilities that allow available resources utilization and provide products that no individual component can satisfy. These products provide more cost recovery of the fixed charges incurred for the resources. Another strategy to mitigate transportation costs is to participate in the daily market to assess if unutilized capacity has value. Avista seeks daily opportunities to purchase natural gas, transport it on existing unutilized capacity, and sell it into a higher priced market to capture the cost of the natural gas purchased and recover some pipeline charges. The recovery is market dependent and may or may not recover all pipeline costs, but mitigates pipeline costs to customers.

Storage Resources

Storage is a valuable strategic resource that enables improved management of a highly seasonal and varied demand profile. Storage benefits include:

- Flexibility to serve peak period needs;
- Access to typically lower cost off-peak supplies;
- Reduced need for higher cost annual firm transportation;
- Improved utilization of existing firm transportation via off-season storage injections; and.
- Additional supply point diversity.

While there are several storage facilities available in the region, Avista’s existing storage resources consist solely of ownership and leasehold rights at the Jackson Prairie Storage facility.

Avista optimizes storage as part of its asset management program. This helps to ensure a controlled cost mechanism is in place to manage the large supply found within the storage facility. An example of this storage optimization is selling today at a cash price and buying a forward month contract. Since forward months have risks or premiums built into the price the result is Avista locking in a given spread. All optimization of assets go directly to the customer to reduce their monthly billing.

Jackson Prairie Storage

Avista is one-third owner, with NWP and Puget Sound Energy (PSE), of the Jackson Prairie Storage Project for the benefit of its core customers in all three states. Jackson Prairie Storage is an underground reservoir facility located near Chehalis, Washington approximately 30 miles south of Olympia, Washington. The total working natural gas capacity of the facility is approximately 25 Bcf. Avista's current share of this capacity for core customers is approximately 8.5 Bcf and includes 398,667 Dth of daily deliverability rights. Besides ownership rights, Avista leased an additional 95,565 Dth of Jackson Prairie capacity with 2,623 Dth of deliverability from NWP to serve Oregon customers.

Incremental Supply-Side Resource Options

Avista's existing portfolio of supply-side resources provides a mix of assets to manage demand requirements for average and peak day events. Avista monitors the following potential resource options to meet future requirements in anticipation of changing demand requirements. When considering or selecting a transportation resource, the appropriate natural gas supply pairs with the transportation resource and the SENDOUT® model prices the resources accordingly.

System Enhancements

Distribution planning plays a role in the IRP, but is not the primary focus. Distribution works with supply to meet customer demand on average and peak days. Modifications, enhancements or upgrades occur on the distribution system that are routine projects, enhancing system reliability. However, in certain instances, Avista can facilitate additional peak and base load-serving capabilities through a modification or upgrade of distribution facilities. These projects enable more takeaway capacity from the interstate pipelines. When resource deficiencies are identified, Gas Supply works with Distribution Engineering to assess if the distribution system can facilitate additional take away. These opportunities are geographically specific and require case-by-case study. Costs of these types of enhancements are included in the context of the IRP. A description of routine and non-routine system enhancements are in Chapter 7 – Distribution Planning.

Capacity Release Recall

Pipeline capacity not utilized to serve core customer demand is available to sell to other parties or optimized through daily or term transactions. Released capacity is generally marketed through a competitive bidding process and can be on a short-term (month-to-month) or long-term basis. Avista actively participates in the capacity release market with short-term and long-term capacity releases. Avista assesses the need to recall capacity or extend a release of capacity on an on-going basis. The IRP process evaluates if or when to recall some or all long-term releases.

Existing Available Capacity

In some instances, there is available capacity on existing pipelines. NWP's mainline is fully subscribed; however, GTN mainline has available capacity. There is some uncertainty about the future capacity availability as the demand needs of utilities and end-users vary across the region. Avista models access to the GTN capacity as an option to meet future demand needs.

GTN Backhauls

The GTN interconnection with the Ruby Pipeline has enabled GTN the physical capability to provide a limited amount of firm back-haul service from Malin with minor modifications to their system. Fees for utilizing this service are under the existing Firm Rate Schedule (FTS-1) and currently include no fuel charges. Additional requests for back-haul service may require additional facilities and compression (i.e., fuel).

This service can provide an interesting solution for Oregon customers. For example, Avista can purchase supplies at Malin, Oregon and transport those supplies to Klamath Falls or Medford. Malin-based natural gas supplies typically include a higher basis differential to AECO supplies, but are generally less expensive than the cost of forward-haul transporting traditional supplies south and paying the associated demand charges. The GTN system is a mileage-based system, so Avista pays only a fraction of the rate if it is transporting supplies from Malin to Medford and Klamath Falls. The GTN system is approximately 612 miles long and the distance from Malin to the Medford lateral is only about 12 miles.

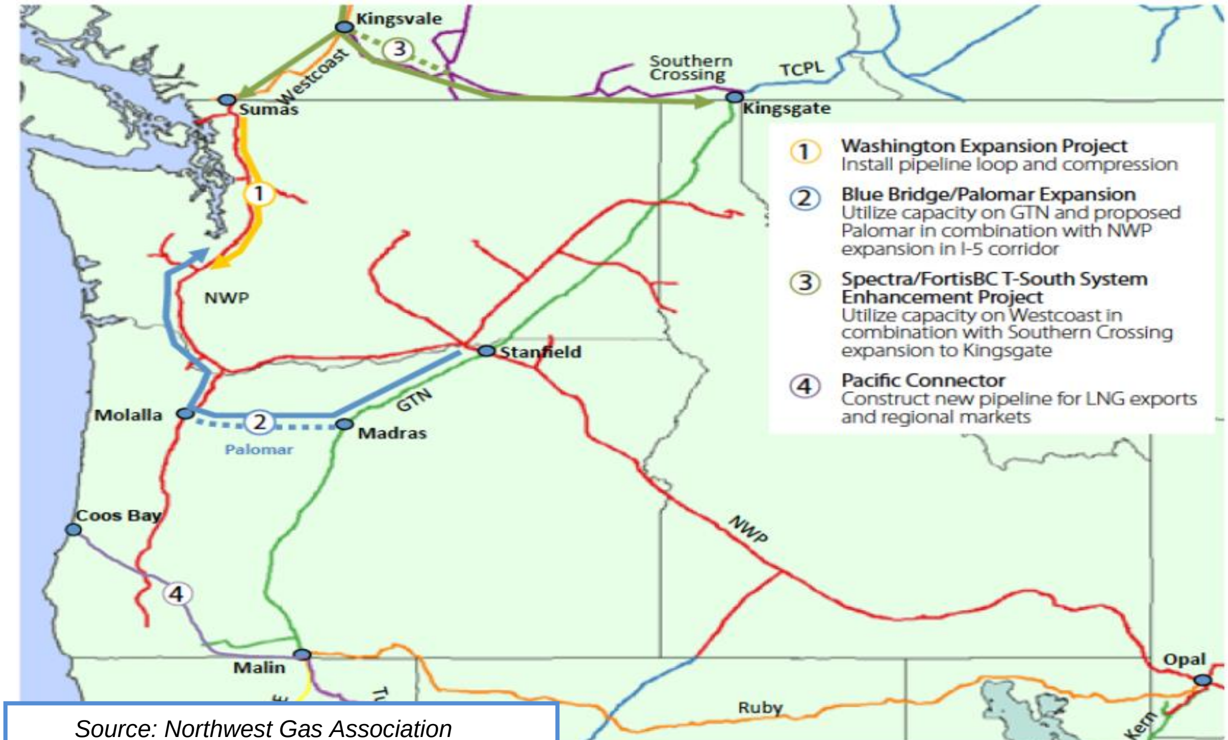
New Pipeline Transportation

Additional firm pipeline transportation resources are viable and attractive resource options. However, determining the appropriate level, supply source and associated pipeline path, costs and timing, and if existing resources will be available at the appropriate time, make this resource difficult to analyze. Firm pipeline transportation provides several advantages; it provides the ability to receive firm supplies at the production basin, it provides for base-load demand, and it can be a low-cost option given optimization and capacity release opportunities. Pipeline transportation has several drawbacks, including typically long-dated contract requirements, limited need in the summer months (many pipelines require annual contracts), and limited availability and/or inconvenient sizing/timing relative to resource need.

Pipeline expansions are typically more expensive than existing pipeline capacity and often require long-term contracts. Even though expansions may be more expensive than existing capacity, this approach may still provide the best option given that some of the other options require matching pipeline transportation. Matching pipeline transportation is creating equivalent volumes on different pipelines from the basin to the delivery point in order to fully utilize subscribed capacity. Expansions may also provide increased reliability or access to supply that cannot be obtained through existing pipelines. This is the case with the Pacific Connector pipeline being proposed as the connecting feedstock for the Jordan Cove LNG facility in Oregon. The pipeline's current path connects into Northwest Pipelines Grants Pass Lateral where capacity is limited. The Pacific Connector pipeline would add an additional 50,000 Dth/day of capacity along that lateral and would push up from a south-to-north direction.

Several specific projects have been proposed for the region. The following summaries describe these projects while Figure 4.3 illustrates their location.

Figure 4.3: Proposed Pipeline Locations



Source: Northwest Gas Association

- **NWP Washington Expansion**

  NWP continues to explore options to expand service from Sumas, Wash., to markets along the Interstate-5 corridor. Looping sections of 36-inch diameter pipeline with the existing pipeline and additional compression at existing compressor stations can add incremental capacity. Actual miles of pipe and incremental compression will determine the amount of capacity created, but it can scale to meet market demand. This project is currently under FERC review.

- **Blue Bridge/Palomar Expansion**

  NWP began working with Palomar Gas Transmission (a partnership between NW Natural and TransCanada) to develop the Cascade (eastern) section of the previously proposed Palomar gas transmission line in conjunction with an expansion of NWP's existing system. The proposed 106-mile, 30-inch-diameter pipeline would extend from TransCanada's GTN's mainline to NW Natural's system near Molalla, Oregon. It would be a bi-directional pipeline with an initial capacity of up to 300 MMcf/d expandable to 750 MMcf/d. In 2011, Palomar Gas Transmission withdrew its application for this pipeline, yet remains prepared if natural gas demand rebounds.

- **Spectra/FortisBC System Enhancement**

  FortisBC and Spectra Energy are considering a 100-mile, 24-inch expansion project from Kingsvale to Oliver, British Columbia, to expand service to the Pacific Northwest and California markets. Removing constraints will allow expansion of Spectra's T-South enhanced service offering, which provides shippers the options of delivering to Sumas or the Kingsgate market. Expanding the bi-directional Southern Crossing system would increase capacity at Sumas during peak demand periods. Initial capacity from the Spectra system to Kingsgate would be 300 MMcf/d, expandable to 450 MMcf/d. An expanded east-to-west flow will increase delivery of supply to Sumas by an additional 150 MMcf/d. Currently, there is no plan to construct this pipeline, but it would be available if demand was sufficient.

- **Pacific Connector**

  Veresen and The Williams Company are currently attempting to acquire approval for a 232-mile, 36-inch diameter pipeline designed to transport up to 1 billion cubic feet of natural gas per day from interconnects near Malin, Oregon, to the Jordan Cove LNG terminal in Coos Bay, Oregon. The pipeline would deliver the feedstock to the LNG terminal providing natural gas to international markets, but also to the Pacific Northwest. The pipeline will connect with Williams' Northwest Pipeline on the Grants Pass lateral. This ties in directly within Avista's service territory and will bring in an additional 50,000 Dth/day of capacity into that area. This new option could provide Avista's customers in the area new capacity for growth and supply diversity. In order to show support of this project, Avista signed a 10,000 Dth/day non-binding contract for capacity in a display of its support to the project.

Avista supports proposals that bring supply diversity and reliability to the region. Supply diversity provides a diverse supply base in the procurement of goods and services. Since there are few options in the Northwest, supply diversity provides options and security when constraints or high demand are present. Avista engages in discussions and analysis of the potential impact of each regional proposal from a demand serving and reliability/supply diversity perspective. In most cases, for Avista to consider them a viable incremental resource to meet demand needs would require combining them with additional capacity on existing pipeline resources. However, the IRP considers a generic expansion that represents a new pipeline build to Avista's service territories.

In-Ground Storage

In-ground storage provides advantages when natural gas from storage can be delivered to Avista's city-gates. It enables deliveries of natural gas to customers during peak cold weather events. It also facilitates potentially lower-cost supply for customers by capturing peak/non-peak pricing differentials and potential arbitrage opportunities within individual months. Although additional storage can be a valuable resource, without deliverability to Avista's service territory, this storage cannot be an incremental firm peak serving resource.

Jackson Prairie

Jackson Prairie is a potential resource for expansion opportunities. Any future storage expansion capacity does not include transportation and therefore cannot be considered an incremental peak day resource. However, Avista will continue to look for exchange and transportation release opportunities that could fully utilize these additional resource options. When an opportunity presents itself, Avista assesses the financial and reliability impact to customers. Due to the fast paced growth in the region, and the need for new resources, a future expansion is possible, though a robust analysis would be required to determine feasibility. Currently, there are no plans for immediate expansion of Jackson Prairie.

Other In-Ground Storage

Other regional storage facilities exist and may be cost effective. Additional capacity at Northwest Natural's Mist facility, capacity at one of the Alberta area storage facilities, Questar's Clay Basin facility in northeast Utah, Ryckman Creek in Uinta County, Wyo., and northern California storage are all possibilities. Transportation to and from these facilities to Avista's service territories continues to be the largest impediment to these options. Avista will continue to look for exchange and transportation release opportunities while monitoring daily metrics of load, transport and market environment.

LNG and CNG

LNG is another resource option in Avista's service territories and is suited for meeting peak day or cold weather events. Satellite LNG uses natural gas that is trucked to the facilities in liquid form from an offsite liquefaction facility. Alternatively, small-scale liquefaction and storage may also be an effective resource option if natural gas supply during non-peak times is sufficient to build adequate inventory for peak events. Permitting issues notwithstanding, facilities could be located in optimal locations within the distribution system.

CNG is another resource option for meeting demand peaks and is operationally similar to LNG. Natural gas could be compressed offsite and delivered to a distribution supply point or compressed locally at the distribution supply point if sufficient natural gas supply and power for compression is available during non-peak times.

LNG and CNG supply resource options for LDCs are becoming more attractive as the market for LNG and CNG as alternative transportation fuels develops. The combined demand for peaking and transportation fuels can increase the volume and utilization of these resource assets thus lowering unit costs for the benefit of both market segments.

Estimates for LNG and CNG resources vary because of sizing and location issues. This IRP uses estimates from other facilities constructed in the area and from conversations with experts in the industry. Avista will monitor and refine the costs of developing LNG and CNG resources while considering lead time requirements and environmental issues.

Plymouth LNG

NWP owns and operates an LNG storage facility at Plymouth, Wash., which provides natural gas liquefaction, storage and vaporization service under its LS-1 and LS-2F tariffs. An example ratio of injection and withdrawal rates show that it can take more than 200 days to fill to capacity, but only three to five days to empty. As such, the resource is best suited for needle-peak demands. Incremental transportation capacity to Avista's service territories would have to be obtained in order for it to be an effective peaking resource. With available capacity, Plymouth LNG was considered in our supply side resource modeling but was not selected.

Avista-Owned Liquefaction LNG

Avista could construct a liquefaction LNG facility in the service area. Doing so could use excess transportation during off-peak periods to fill the facility, avoid tying up transportation during peak weather events, and it may avoid additional annual pipeline charges.

Construction would depend on regulatory and environmental approval as well as cost-effectiveness requirements. Preliminary estimates of the construction, environmental, right-of-way, legal, operating and maintenance, required lead times, and inventory costs indicate company-owned LNG facilities have significant development risks. Avista modeling included LNG, but it was not selected as a resource when compared to existing resources.

Biogas

Biogas typically refers to a mixture of gases produced by the biological breakdown of organic matter in the absence of oxygen. Biogas can be produced by anaerobic digestion or fermentation of biodegradable materials such as woody biomass, manure or sewage, municipal waste, green waste and energy crops. This type of biogas is primarily methane and carbon dioxide.

Biogas is a renewable fuel, so it may qualify for renewable energy subsidies. Avista is not aware of any current subsidies, but future stimulus or state or federal energy policies could lead to some form of financial incentives.

Biogas projects are unique, so reliable cost estimates are difficult to obtain. Project sponsorship has many complex issues, and the more likely participation in such a project is as a long-term contracted purchaser. Avista did not consider biogas as a resource in this planning cycle, since they are small and relatively insignificant compared to demand, but remains receptive to such projects as they are proposed.

Supply Scenarios

The 2016 IRP includes two supply scenarios. Additional details about the results of the supply scenarios are in Chapters 5 and 6.

- **Existing Resources:** This scenario represents all resources currently owned or contracted by Avista.
- **Existing + Expected Available:** In this scenario, existing resources plus supply resource options expected to be available when resource needs are identified. This includes currently available south and north bound GTN, capacity release recalls, NWP expansions and satellite LNG.

Supply Issues

The abundance and accessibility of shale gas has fundamentally altered North American natural gas supply and the outlook for future natural gas prices. Even though the supply is available and the technology exists to access it, there are issues that can affect the cost and availability of natural gas.

Hydraulic Fracturing

Improvements in hydraulic fracturing, a 60-year-old technique used to extract oil and natural gas from shale rock formations, coupled with horizontal drilling has enabled access to previously uneconomic resources. However, the process does not come without challenges. The publicity caused by movies, documentaries and articles in national newspapers about "fracking" has plagued the natural gas and oil industry. There is concern that hydraulic fracturing is contaminating aquifers, increasing air pollution and causing earthquakes. The wide-spread publicity generated interest in the production process and caused some states to issue bans or moratoriums on drilling until further research was conducted.

Government, industry and universities engaged in studies to understand the actual and potential impacts of hydraulic fracturing. Industry has been working to refute these claims by focusing on ensuring companies use best practices for well drilling, disclosing the fluids used in the hydraulic fracturing processing, and implementing "green completions" for wells. In the past, wells either flared off the initial natural gas or released an excess amount of natural gas into the air. Green completions is now a standard for well drilling and captures the natural gas at the well head instead of releasing it.

Pipeline Availability

The Pacific Northwest has efficiently utilized its relatively sparse network of pipeline infrastructure to meet the region's needs. As the amount of renewable energy increases, future demand for natural gas-fired generation will increase. Pipeline capacity is the link between natural gas and power.

Adding additional pressure to existing pipeline resources is the announcement of three proposed methanol plants in the region. The plants use large amounts of natural gas as a feedstock for creating methanol, which is used to make other chemicals and as a fuel. To date, the Port of Kalama is gaining ground in its approval process and is looking like the most probable of the three methanol plants and will take around 300,000 Dth/day in a region already constrained by pipeline deliverability.

LDCs will have to compete with power generators, LNG exporters and other large end users for limited pipeline capacity. The new mix could alter current pipeline operations and the potential availability of infrastructure to the region. This future competition of pipeline capacity should have little impact on Avista's existing portfolio of pipeline contracts unless the overall cost of the new pipeline capacity is less than the current cost with the same deliverability. In general, new pipeline capacity will have higher costs than operational pipelines, though a thorough analysis is needed prior to making this determination.

Ongoing Activity

Without resource deficiencies or a need to acquire incremental supply-side resources to meet peak day demands over the next 20 years, Avista will focus on normal activities in the near term, including:

- Continue to monitor supply resource trends including the availability and price of natural gas to the region, LNG exports, supply dynamics and marketplace, and pipeline and storage infrastructure availability.
- Monitor availability of resource options and assess new resource lead-time requirements relative to resource need to preserve flexibility.
- Appropriate management of existing resources including optimizing underutilized resources to help reduce costs to customers.

Conclusion

Avista is committed to providing reliable supplies of natural gas to its customers. Avista procures supplies with a diversified plan that seeks to acquire natural gas supplies while reducing exposure to short-term price volatility through a strategy that includes hedging, storage utilization and index purchases. The supply mix includes long-term contracts for firm pipeline transportation capacity from many supply points and ownership and leasing of firm natural gas storage capacity sufficient to serve customer demand during peak weather events and throughout the year.

5: Integrated Resource Portfolio

Overview

This chapter combines the previously discussed IRP components and the model used to determine resource deficiencies during the 20-year planning horizon. This chapter also provides an analysis of potential resource options to meet resource deficiencies as exhibited in the High Growth, Low Prices scenario.

The foundation for integrated resource planning is the criteria used for developing demand forecasts. Avista uses the coldest day on record as its weather-planning standard for determining peak-day demand. This is consistent with past IRPs as described in Chapter 2 – Demand Forecasts. This IRP utilizes coldest day on record and average weather data for each demand region. Avista plans to serve expected peak day in each demand region with firm resources. Firm resources include natural gas supplies, firm pipeline transportation and storage resources. In addition to peak requirements, Avista also plans for non-peak periods such as winter, shoulder and summer demand. The modeling process includes a daily optimization for every day of the 20-year planning period.

It is assumed that on a peak day all interruptible customers have left the system in order to provide service to firm customers. Avista does not make firm commitments to serve interruptible customers. Therefore, IRP analysis of demand-serving capabilities only includes the residential, commercial and firm industrial classes. Using coldest day on record weather criteria, a blended price curve developed by industry experts, and an academically backed customer forecast all work together to develop stringent planning criteria.

Forecasted demand represents the amount of natural gas supply needed. In order to deliver the forecasted demand, the supply forecast needs to be increased between 1.0 percent and 3.0 percent on both an annual and peak-day basis to account for additional supplies that are purchased primarily for pipeline compressor station fuel. The 1.0 percent to 3.0 percent, known as fuel, varies depending on the pipeline. The FERC and National Energy Board approved tariffs govern the percentage of required additional fuel supply.

SENDOUT® Planning Model

The SENDOUT® Gas Planning System from Ventyx performs integrated resource optimization modeling. Avista purchased the SENDOUT® model in April 1992 and has used it to prepare all IRPs since then. Avista has a long-term maintenance agreement with Ventyx for software updates and enhancements. Enhancements include software corrections and improvements driven by industry needs.

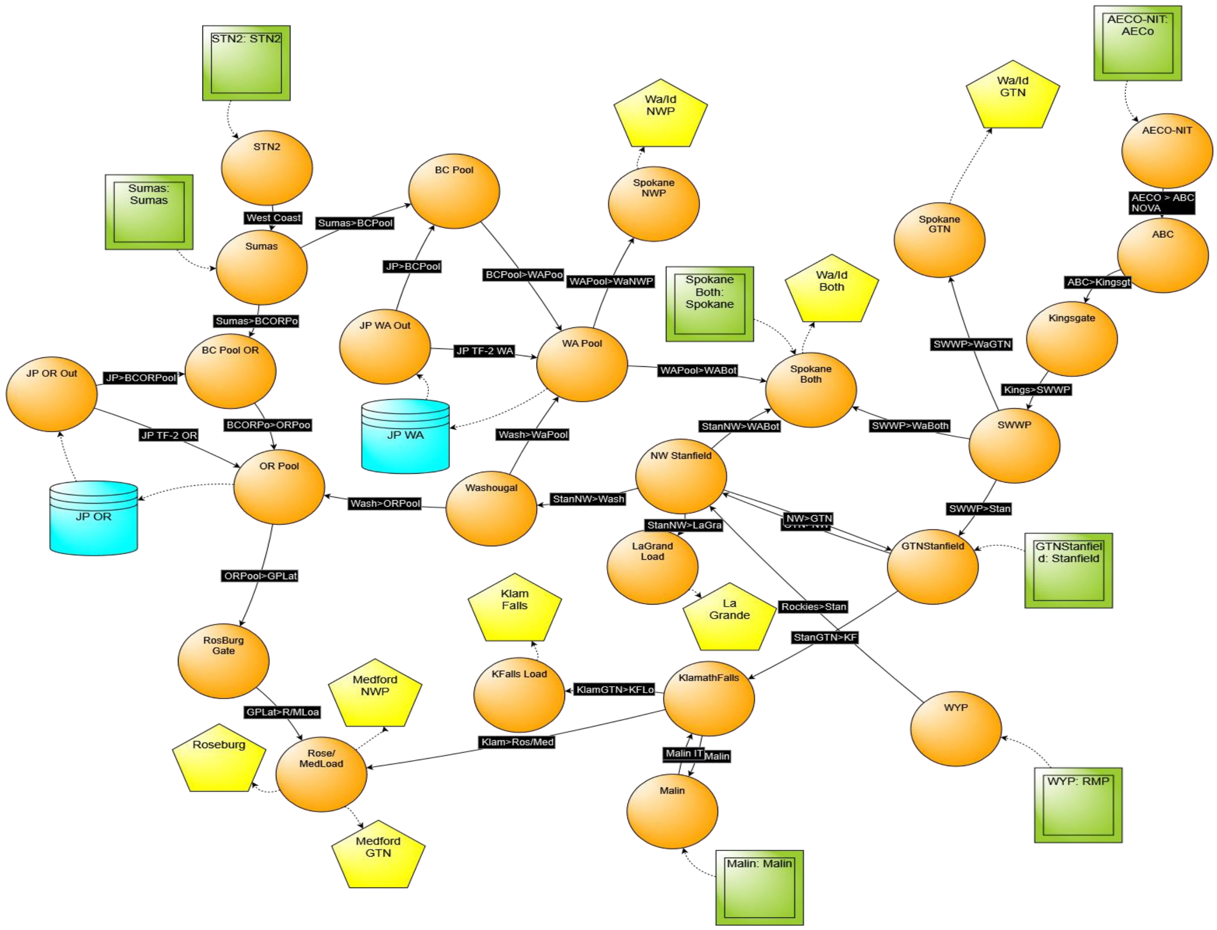
SENDOUT® is a linear programming model widely used to solve natural gas supply and transportation optimization questions. Linear programming is a proven technique to solve minimization/maximization problems. SENDOUT® analyzes the complete problem at one time within the study horizon, while accounting for physical limitations and contractual constraints.

The software analyzes thousands of variables and evaluates possible solutions to generate a least cost solution. The model uses the following variables:

- Demand data, such as customer count forecasts and demand coefficients by customer type (e.g., residential, commercial and industrial).
- Weather data, including minimum, maximum and average temperatures.
- Existing and potential transportation data which describes the network for physical movement of natural gas and associated pipeline costs.
- Existing and potential supply options including supply basins, revenue requirements as the key cost metric for all asset additions and prices.
- Natural gas storage options with injection/withdrawal rates, capacities and costs.
- Conservation potential.

Figure 5.1 is a SENDOUT® network diagram of Avista's demand centers and resources. This diagram illustrates current transportation and storage assets, flow paths and constraint points.

Figure 5.1 SENDOUT® Model Diagram



The SENDOUT® model provides a flexible tool to analyze scenarios such as:

- Pipeline capacity needs and capacity releases;
- Effects of different weather patterns upon demand;
- Effects of natural gas price increases upon total natural gas costs;
- Storage optimization studies;
- Resource mix analysis for conservation;

- Weather pattern testing and analysis;
- Transportation cost analysis;
- Avoided cost calculations; and
- Short-term planning comparisons.

SENDOUT® also includes Monte Carlo capabilities, which facilitates price and demand uncertainty modeling and detailed portfolio optimization techniques to produce probability distributions. More information and analytical results are located in Chapter 6 – Alternate Scenarios, Portfolios and Stochastic Analysis.

Resource Integration

The following sections summarize the comprehensive analysis bringing demand forecasting and existing and potential supply and demand-side resources together to form the 20-year, least-cost plan.

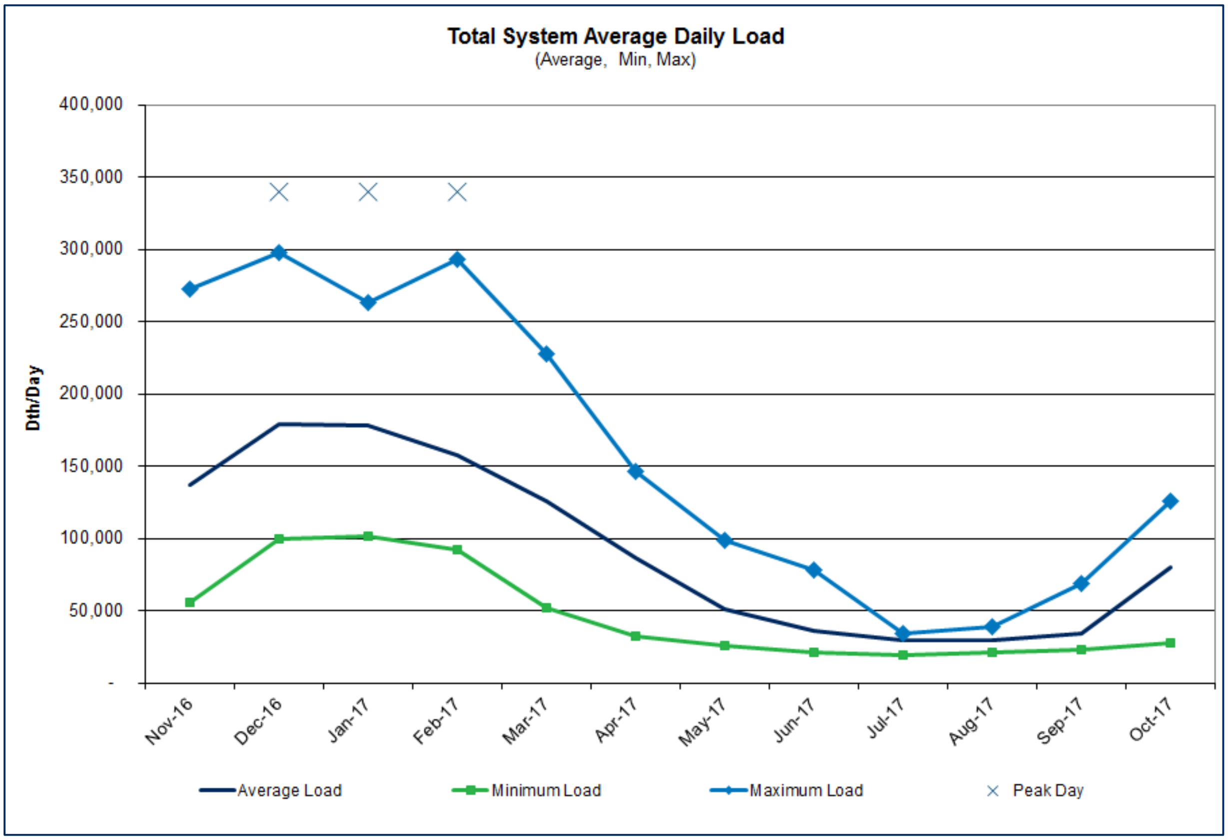
Demand Forecasting

Chapter 2 - Demand Forecasts describes Avista's demand forecasting approach.

Avista forecasts demand in the SENDOUT® model in eight service areas given the existence of distinct weather and demand patterns for each area and pipeline infrastructure dynamics. The SENDOUT® areas are Washington/Idaho (disaggregated into three sub-areas because of pipeline flow limitations); Medford (disaggregated into two sub-areas because of pipeline flow limitations); and Roseburg, Klamath Falls and La Grande. In addition to area distinction, Avista also models demand by customer class within each area. The relevant customer classes are residential, commercial and firm industrial customers.

Customer demand is highly weather-sensitive. Avista's customer demand is not only highly seasonable, but also highly variable. Figure 5.2 captures this variability showing monthly system-wide average demand, minimum demand day observed by month, maximum demand day observed in each month, and winter projected peak day demand for the first year of the Expected Case forecast as determined in SENDOUT®.

Figure 5.2: Total System Average Daily Load (Average, Minimum and Maximum)



Natural Gas Price Forecasts

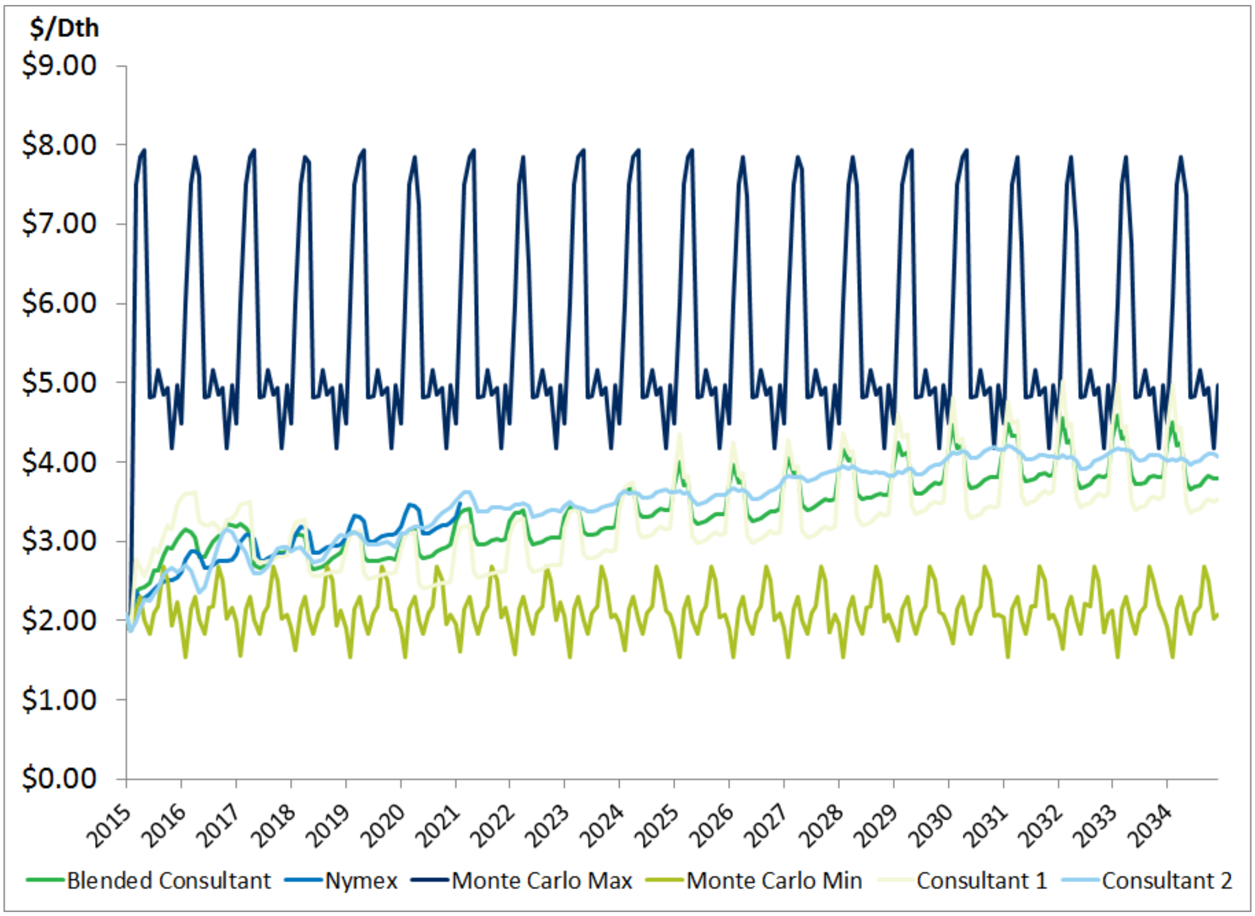
Natural gas prices are a fundamental component of the IRP. The commodity price is a significant component of the total cost of a resource option. This affects the avoided cost threshold for determining cost-effectiveness of conservation measures. The price of natural gas influences consumption, so price elasticity is part of the demand evaluation shown in Chapter 2 – Demand Forecasts.

The natural gas price outlook has changed dramatically in recent years in response to several influential events and trends affecting the industry. The recent recession, shale gas production, greenhouse gas issues, and renewable energy standards creating the potential for more natural gas-fired generation impact the natural gas outlook. The rapidly changing environment and uncertainty in predicting future events and trends, requires modeling a range of forecasts.

Many additional factors influence natural gas pricing and volatility, such as regional supply/demand issues, weather conditions, hurricanes/storms, storage levels, natural gas-fired generation, infrastructure disruptions, and infrastructure additions (e.g. new pipelines and LNG terminals).

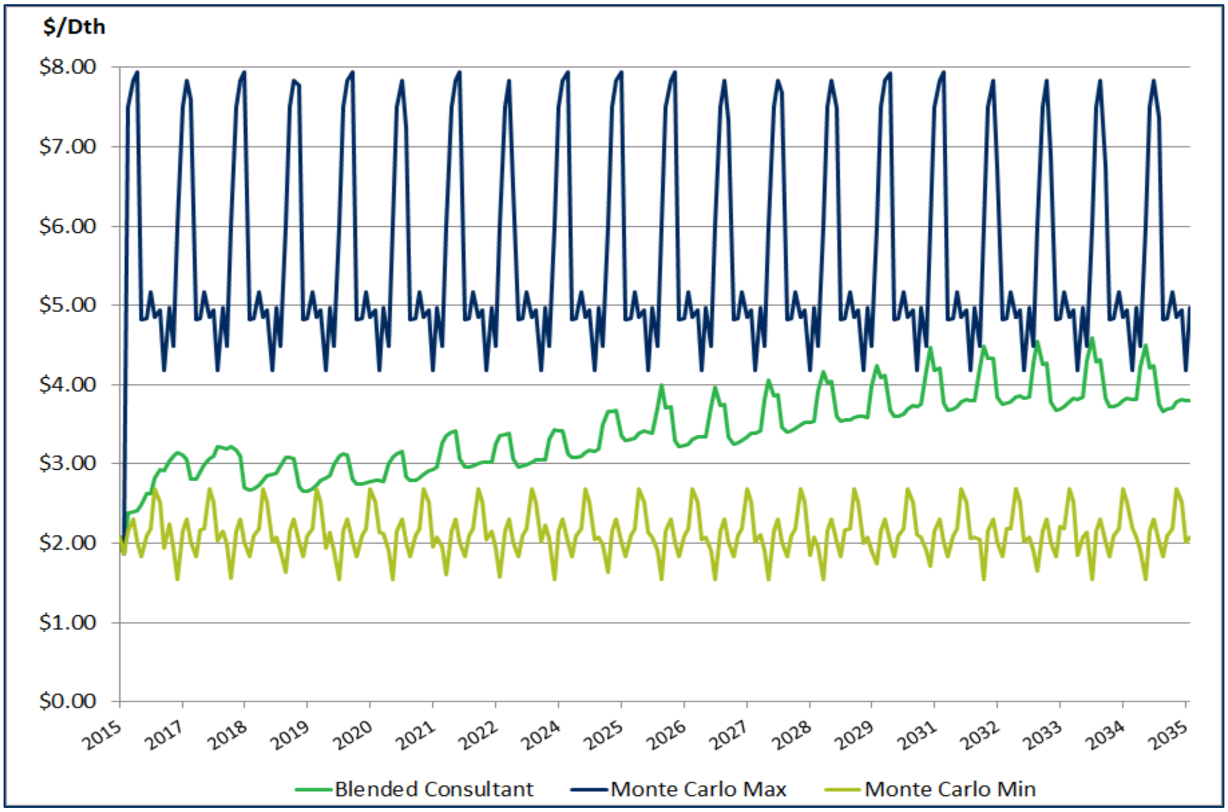
Even though Avista continually monitors these factors, we cannot accurately predict future prices for the 20-year horizon of this IRP. This IRP reviewed several price forecasts from credible sources. Figure 5.3 depicts the price forecasts considered in the IRP analyses.

Figure 5.3: Henry Hub Forecasted Price (Real $/Dth)



Selecting the price curves can be more art than science. With the assistance of the TAC, Avista selected high, expected and low price curves to consider possible outcomes and their impact on resource planning. The expected curve was a blended price derived from two consulting services subscriptions along with the NYMEX forward strip on January 7, 2016. The high and low price curves were derived via a Monte Carlo simulation of 500 draws where a high and low price were selected from these draws. The selected price curves have variation and provide reasonable upper and lower bounds, consistent with stretching modeling assumptions to address uncertainty in the planning environment. These curves are in real dollars in Figure 5.4. Additionally, stochastic modeling of natural gas prices is also completed. The results from that analysis are in Chapter 6 – Alternate Scenarios, Portfolios and Stochastic Analysis.

Figure 5.4 Henry Hub Forecasts for IRP Low/ Medium/ High Forecasted Price – Real $/Dth



Each of the price forecasts above are for Henry Hub, which is located in Louisiana just onshore from the Gulf of Mexico. Henry Hub is recognized as the most important pricing point in the U.S. because of its proximity to a large portion of U.S. natural gas production and the sheer volume traded in the daily or spot market, as well as the forward markets via the New York Mercantile Exchange's (NYMEX) futures contracts. Consequently, all other trading points tend to be priced off of the Henry Hub.

The primary physical supply points at Sumas, AECO and the Rockies (and other secondary regional market hubs) determine Avista's costs. Prices at these points typically trade at a discount, or negative basis differential, to Henry Hub because of their proximity to the two largest natural gas basins in North America (the WCSB and the Rockies).

Table 5.1 shows the Pacific Northwest regional prices from the consultants, historic averages and the prior IRP as a percent of Henry Hub price, along with three-year historical comparisons.

Table 5.1: Regional Price as a Percent of Henry Hub Price

	AECO	Sumas	Rockies	Malin	Stanfield
Consultant1 Forecast Average	89.9%	98.8%	95.4%	101.4%	100.4%
Consultant2 Forecast Average	85.3%	94.2%	96.7%	98.6%	96.8%
Historic Cash Three-Year Average	86.8%	97.2%	97.1%	99.6%	97.5%
2014 IRP	82.5%	90.8%	88.9%	94.5%	92.1%

This IRP used monthly prices for modeling purposes because of Avista's winter-weighted demand profile. Table 5.2 depicts the monthly price shape used in this IRP. A slight change to the shape of the pricing curve occurred since the last IRP. Driven primarily by supply availability, the forecasted differential between winter and summer pricing has decreased to some extent compared to historic data.

Table 5.2: Monthly Price as a Percent of Average Price

	Jan	Feb	Mar	Apr	May	Jun
Consult1	104.7%	104.2%	96.8%	95.9%	96.6%	98.2%
Consult2	101.0%	101.6%	101.5%	98.9%	98.8%	98.5%
2014 IRP	102.0%	101.5%	98.5%	98.0%	98.5%	100.5%
	Jul	Aug	Sep	Oct	Nov	Dec
Consult1	99.2%	99.7%	98.9%	99.4%	101.0%	105.2%
Consult2	99.3%	99.3%	100.3%	99.3%	100.5%	101.1%
2014 IRP	101.5%	102.0%	98.5%	98.5%	99.0%	103.0%

Avista selected a blend of Consultant 1 and Consultant 2's forecast of regional prices and monthly shapes. Appendix 5.1 – Monthly Price Data by Basin contains detailed monthly price data behind the summary table information discussed above.

Carbon Policy

To help address carbon scenarios within our jurisdictions and at a federal level, Avista included multiple sensitivities and analysis around carbon policy and legislation. The expected price was derived from a consultants forecast beginning in 2026 to 2035. Avista's expectation of a carbon policy begins earlier, from 2018-2025, and includes a form of cap and trade policy in several of our jurisdictions. The blending occurred in a way to ensure no double counting of price adders as there are no cross over years between policies.

Avista models carbon as an incremental price adder to address any potential policy. Carbon adders increase the price of a dekatherm of natural gas and can impact resource selections and demand through expected elasticity (Chapter 2 – Demand Forecasts, Price Elasticity). The starting price was assumed to be similar to California's cap and trade system where the initial floor was set at $10 per metric ton of CO_2. A blending of the likely policy as an assumed two sigma, or 95.45 percent, of expected outcomes. The remaining distribution was equally divided into the remaining likelihood between the high case, Washington State's I-732, and the low case of no carbon adder. The final, Expected Case, incremental adder to our Henry Hub pricing has a starting price of $9.89 per metric ton starting in 2018 and ramps up to $19.93 by 2035.

Transportation and Storage

Valuing natural gas supplies is a critical first step in resource integration. Equally important is capturing all costs to deliver the natural gas to customers. Daily capacity of existing transportation resources (described in Chapter 4 – Supply-Side Resources) is represented by the firm resource duration curves depicted in Figures 5.6 and 5.7.

Figure 5.6: Existing Firm Transportation Resources – Washington/Idaho

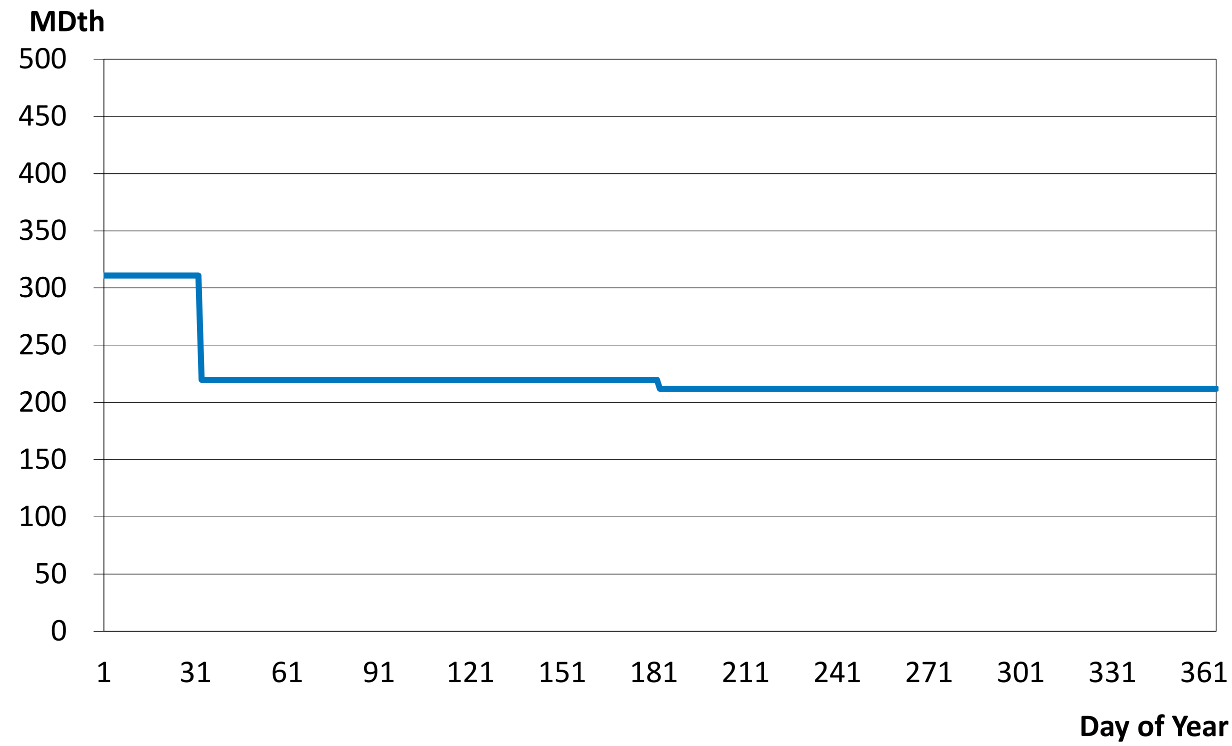
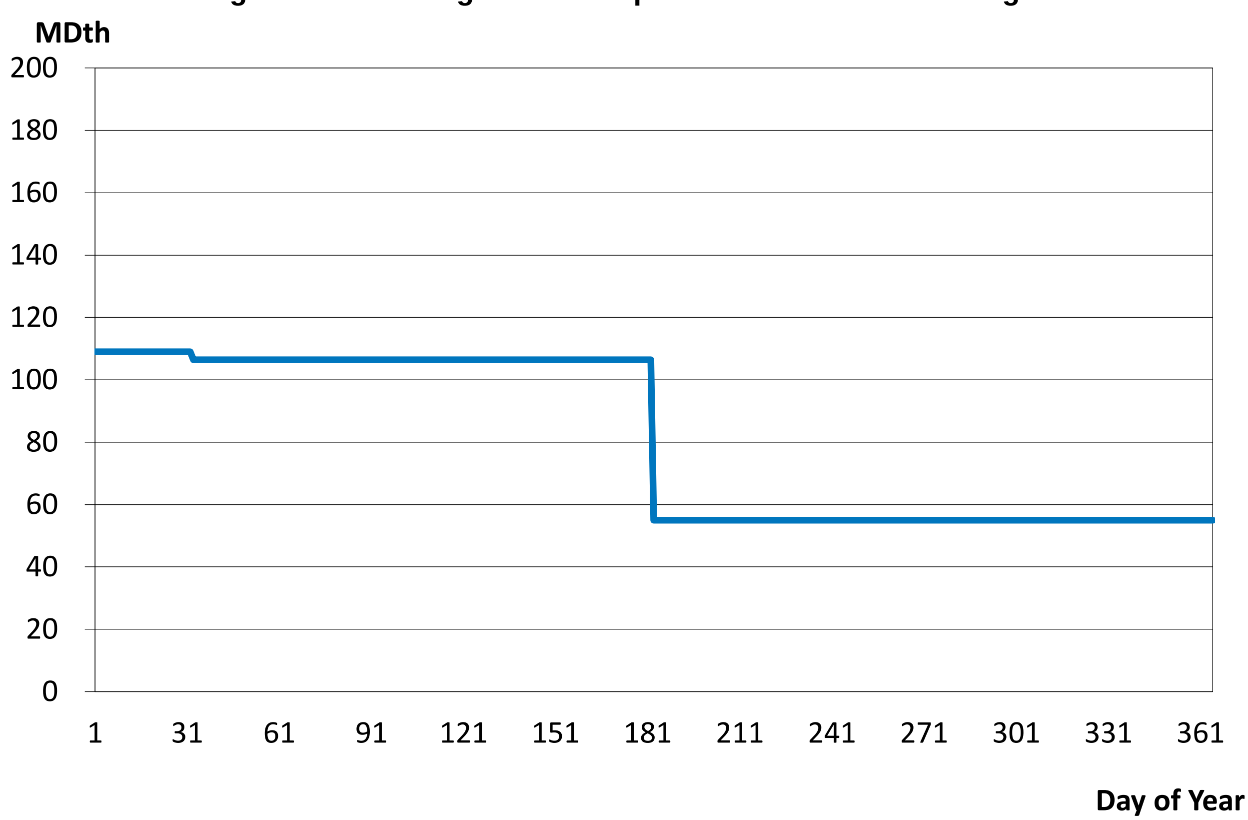


Figure 5.7: Existing Firm Transportation Resources – Oregon



Current rates for capacity are in Appendix 5.1 – Monthly Price Data by Basin. Forecasting future pipeline rates can challenging because of the need to estimate the amount and timing of rate changes. Avista's estimates and timing of future pipeline rate increases are based on knowledge obtained from industry discussions and participation in pipeline rate cases. This IRP assumes that pipelines will file to recover costs at rates equal to increases in GDP (see Appendix 5.2 – Weighted Average Cost of Capital).

Demand-Side Management

Chapter 3 – Demand-Side Resources describes 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.

Preliminary Results

After incorporating the above data into the SENDOUT® model, Avista generated an assessment of demand compared to existing resources for several scenarios. Chapter 2 – Demand Forecasts discusses the demand results from these cases, with additional details in Appendices 2.1 through 2.9.

Figures 5.8 through 5.11 provide graphic summaries of Average Case demand as compared to existing resources on a peak day. This demand is net of conservation savings and shows the adequacy of Avista's resources under normal weather conditions. For this case, current resources meet demand needs over the planning horizon.

Figure 5.8: Average Case – Washington/Idaho Existing Resources vs. Peak Day Demand – February 15th

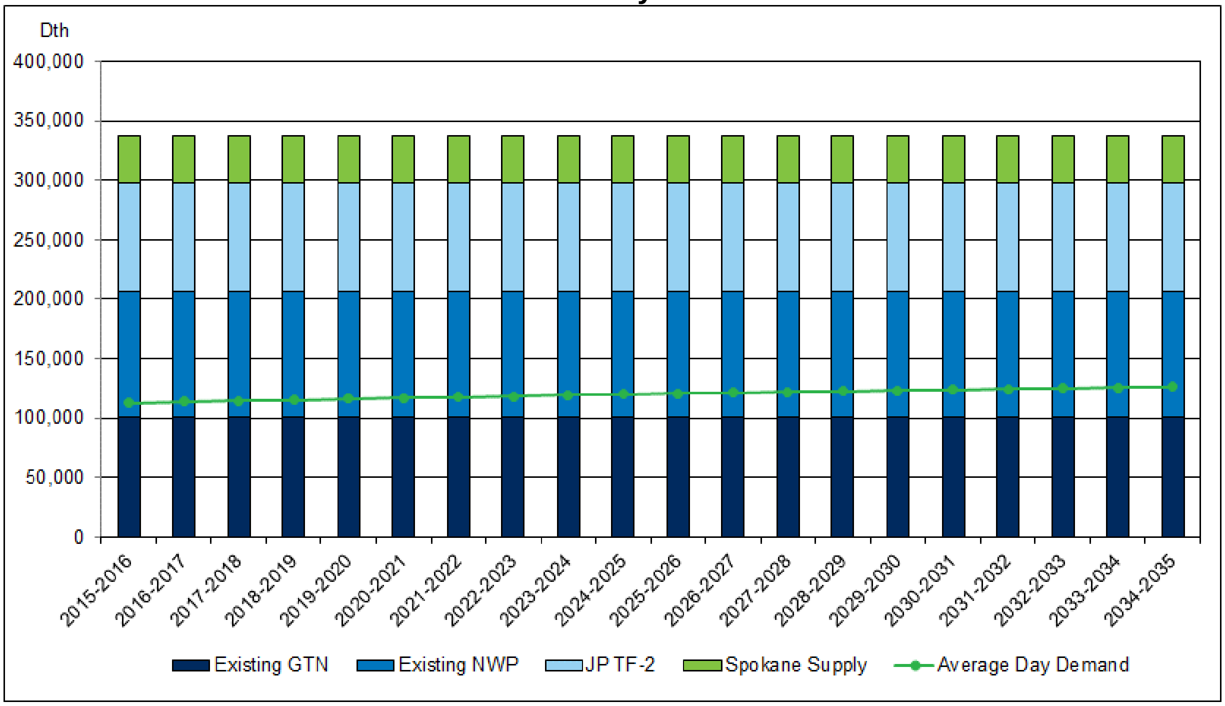


Figure 5.9: Average Case – Medford / Roseburg Existing Resources vs. Peak Day Demand – December 20th

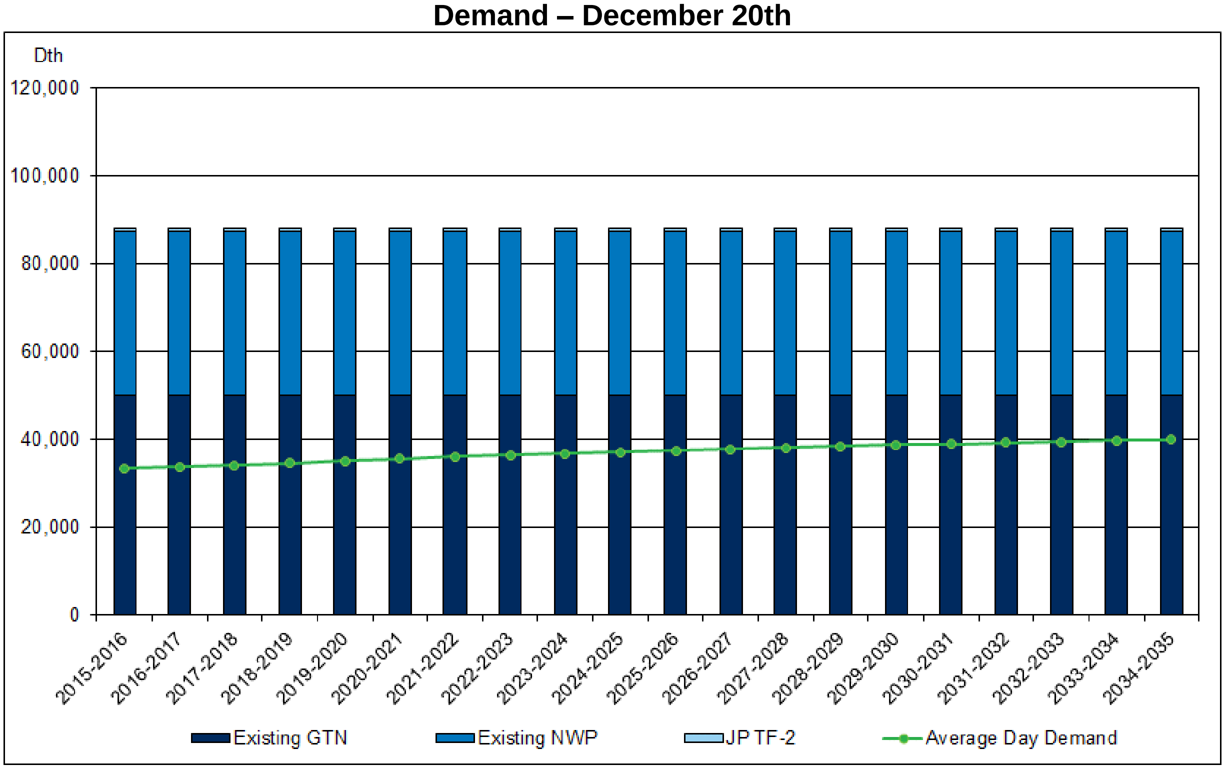


Figure 5.10: Average Case – Klamath Falls Existing Resources vs. Peak Day Demand – December 20th

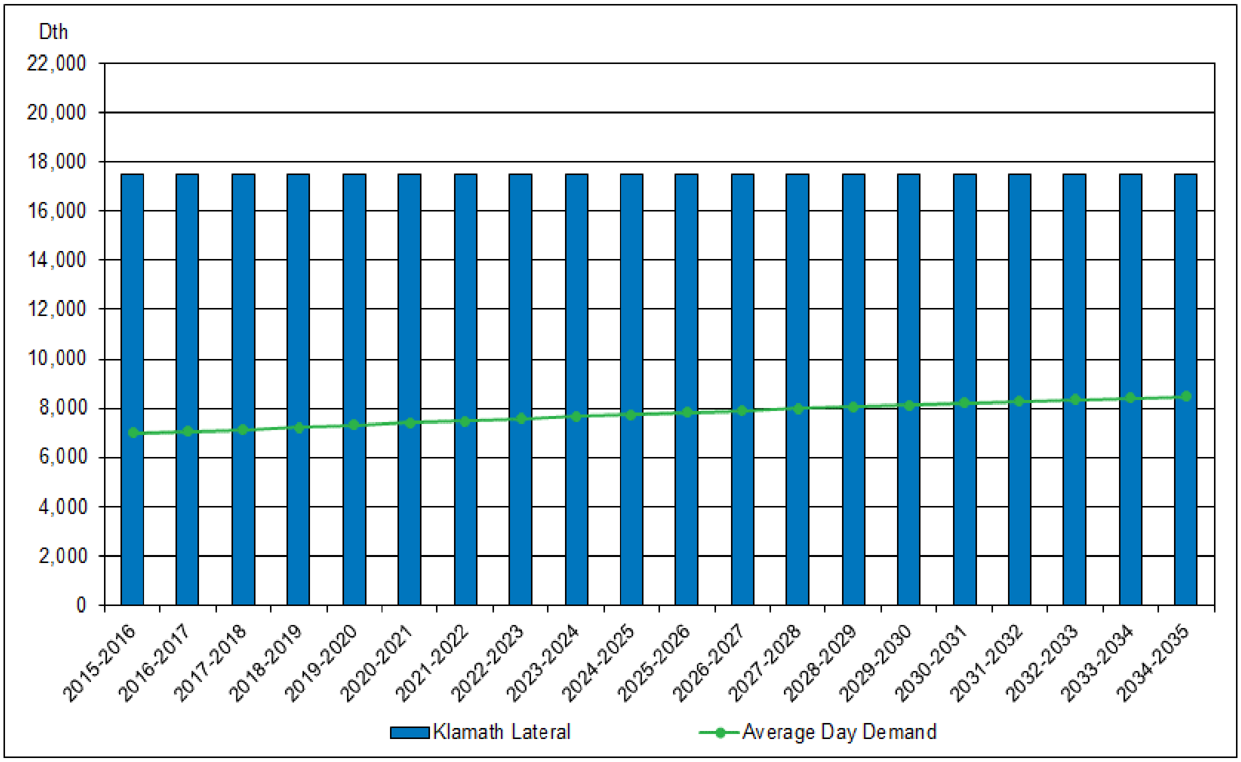
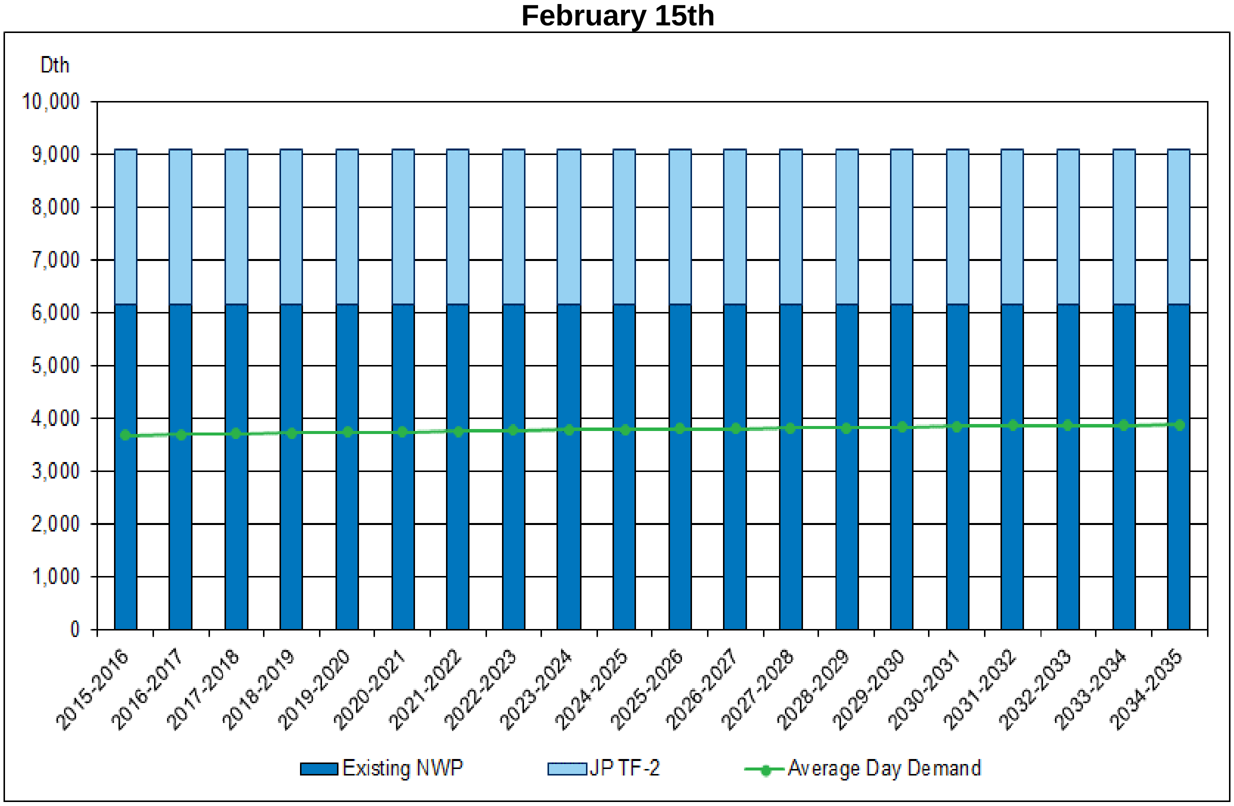


Figure 5.11: Average Case – La Grande Existing Resources vs. Peak Day Demand – February 15th



Figures 5.12 through 5.15 summarize Expected Case peak day demand compared to existing resources, as well as demand comparisons to the 2014 IRP. This demand is net of conservation savings. Based on this information, and more specifically where a resource deficiency is nearly present as shown in Figure 5.9, Avista has time to carefully monitor, plan and take action on potential resource additions as described in the Ongoing Activities section of Chapter 8 – Action Plan. Any underutilized resources will be optimized to mitigate the costs incurred by customers until the resource is required to meet demand. This management, of both long- and short-term resources, ensures the goal to meet firm customer demand in a reliable and cost-effective manner as described in Supply Side Resources – Chapter 4.

Figure 5.12: Expected Case – Washington/Idaho Existing Resources vs. Peak Day Demand – February 15th

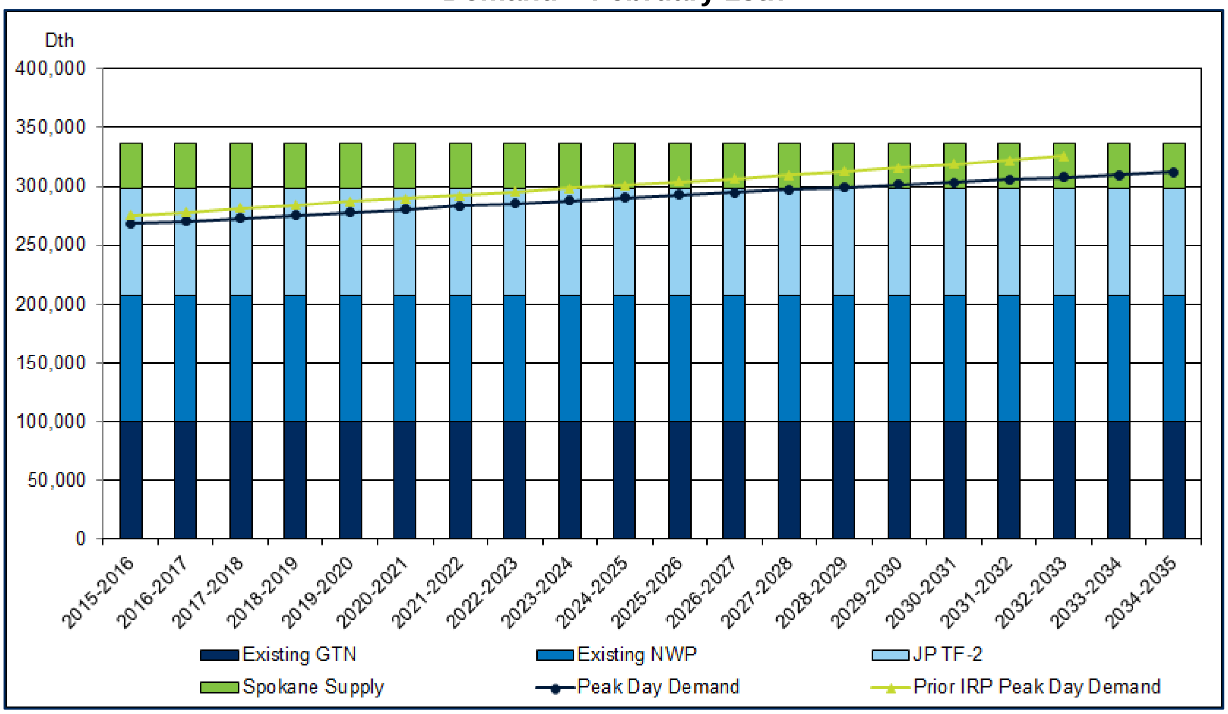


Figure 5.13: Expected Case – Medford / Roseburg Existing Resources vs. Peak Day Demand – December 20th

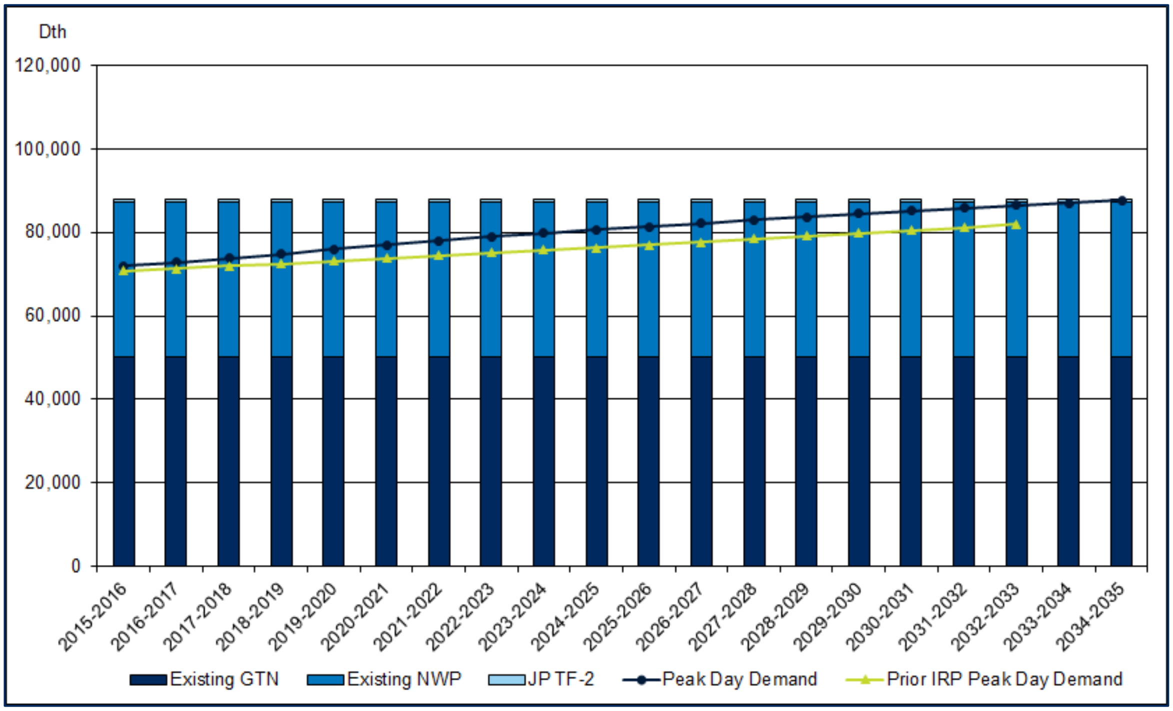


Figure 5.14: Expected Case – Klamath Falls Existing Resources vs. Peak Day Demand – December 20th

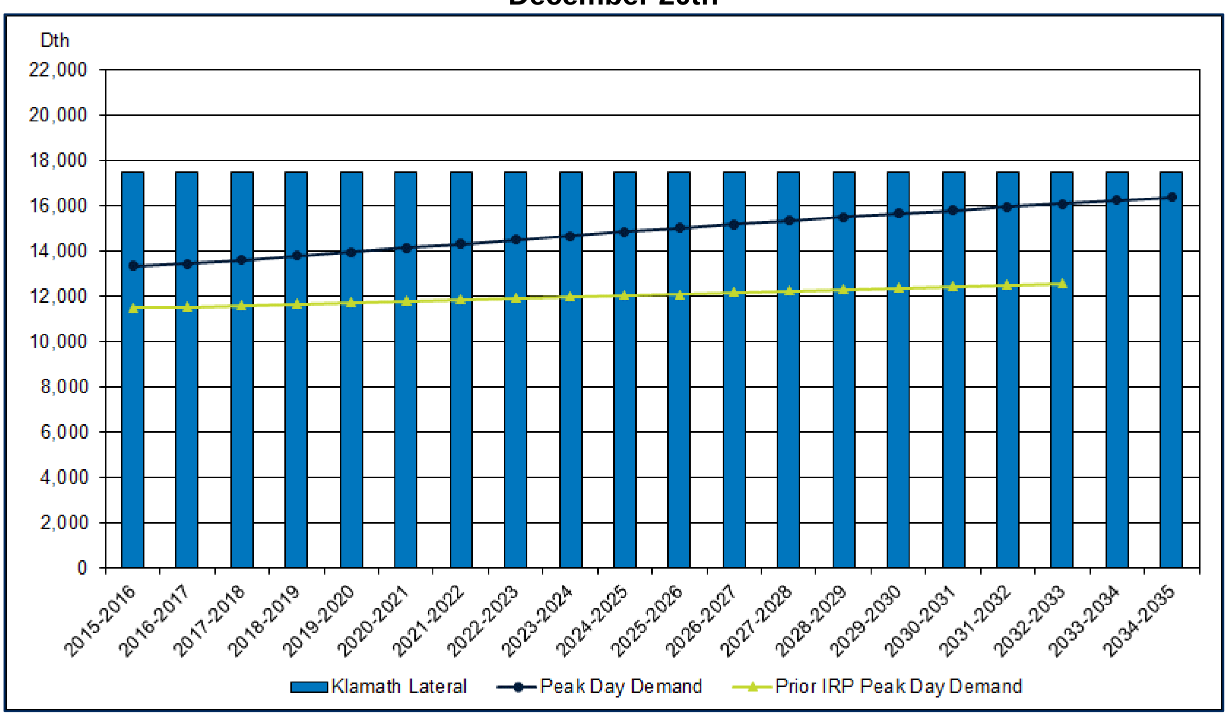
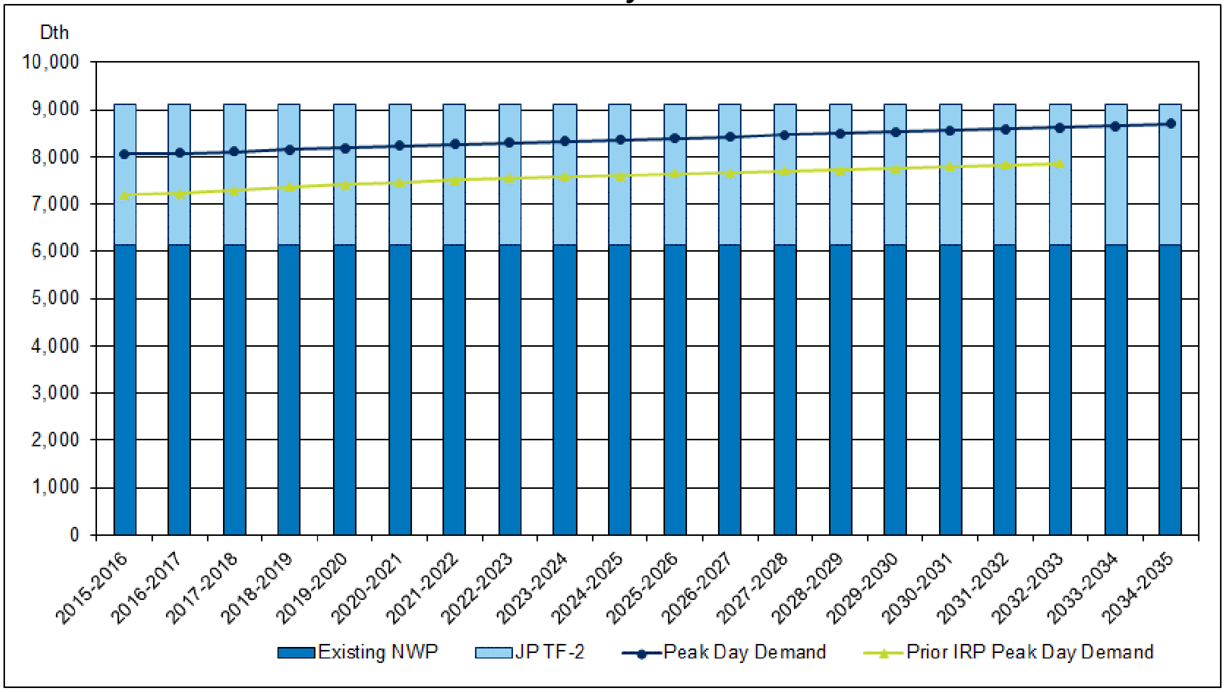


Figure 5.15: Expected Case – La Grande Existing Resources vs. Peak Day Demand – February 15th



If demand grows faster than expected, the need for new resources will come earlier. Flat demand risk requires close monitoring for signs of increasing demand and reevaluation of lead times to acquire preferred incremental resources. Monitoring of flat demand risk includes a reconciliation of forecasted demand to actual demand on a monthly basis. This reconciliation helps identify customer growth trends and use-per-customer trends. If they meaningfully differ compared to forecasted trends, Avista will assess the impacts on planning from procurement and resource sufficiency standing.

Table 5.3 quantifies the forecasted total demand net of conservation savings and unserved demand from the above charts.

Table 5.3: Peak Day Demand – Served and Unserved (MDth/day)

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	La Grande % of Peak Day Served	WA/ID Served	WA/ID Unserved	WA/ID Total	WA/ID % of Peak Day
Expected	2015-2016	8.06	-	8.06	100%	268.50	-	268.50	100%
Expected	2016-2017	8.08	-	8.08	100%	270.43	-	270.43	100%
Expected	2017-2018	8.12	-	8.12	100%	272.99	-	272.99	100%
Expected	2018-2019	8.16	-	8.16	100%	275.50	-	275.50	100%
Expected	2019-2020	8.20	-	8.20	100%	278.13	-	278.13	100%
Expected	2020-2021	8.23	-	8.23	100%	280.73	-	280.73	100%
Expected	2021-2022	8.27	-	8.27	100%	283.25	-	283.25	100%
Expected	2022-2023	8.30	-	8.30	100%	285.65	-	285.65	100%
Expected	2023-2024	8.34	-	8.34	100%	288.15	-	288.15	100%
Expected	2024-2025	8.37	-	8.37	100%	290.37	-	290.37	100%
Expected	2025-2026	8.40	-	8.40	100%	292.65	-	292.65	100%
Expected	2026-2027	8.43	-	8.43	100%	294.87	-	294.87	100%
Expected	2027-2028	8.46	-	8.46	100%	297.29	-	297.29	100%
Expected	2028-2029	8.50	-	8.50	100%	299.28	-	299.28	100%
Expected	2029-2030	8.53	-	8.53	100%	301.43	-	301.43	100%
Expected	2030-2031	8.56	-	8.56	100%	303.56	-	303.56	100%
Expected	2031-2032	8.60	-	8.60	100%	305.93	-	305.93	100%
Expected	2032-2033	8.63	-	8.63	100%	307.75	-	307.75	100%
Expected	2033-2034	8.66	-	8.66	100%	309.82	-	309.82	100%
Expected	2034-2035	8.69	-	8.69	100%	312.42	-	312.42	100%

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Klamath Falls % of Peak Day Served	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total	Medford/ Roseburg % of Peak Day Served
Expected	2015-2016	13.33	-	13.33	100%	72.01	-	72.01	100%
Expected	2016-2017	13.44	-	13.44	100%	72.85	-	72.85	100%
Expected	2017-2018	13.60	-	13.60	100%	73.82	-	73.82	100%
Expected	2018-2019	13.77	-	13.77	100%	74.88	-	74.88	100%
Expected	2019-2020	13.94	-	13.94	100%	75.96	-	75.96	100%
Expected	2020-2021	14.12	-	14.12	100%	77.06	-	77.06	100%
Expected	2021-2022	14.30	-	14.30	100%	78.06	-	78.06	100%
Expected	2022-2023	14.48	-	14.48	100%	78.93	-	78.93	100%
Expected	2023-2024	14.66	-	14.66	100%	79.76	-	79.76	100%
Expected	2024-2025	14.83	-	14.83	100%	80.58	-	80.58	100%
Expected	2025-2026	15.00	-	15.00	100%	81.40	-	81.40	100%
Expected	2026-2027	15.17	-	15.17	100%	82.19	-	82.19	100%
Expected	2027-2028	15.33	-	15.33	100%	82.98	-	82.98	100%
Expected	2028-2029	15.49	-	15.49	100%	83.75	-	83.75	100%
Expected	2029-2030	15.63	-	15.63	100%	84.49	-	84.49	100%
Expected	2030-2031	15.78	-	15.78	100%	85.19	-	85.19	100%
Expected	2031-2032	15.93	-	15.93	100%	85.86	-	85.86	100%
Expected	2032-2033	16.07	-	16.07	100%	86.48	-	86.48	100%
Expected	2033-2034	16.22	-	16.22	100%	87.09	-	87.09	100%
Expected	2034-2035	16.37	-	16.37	100%	87.66	-	87.66	100%

New Resource Options

When existing resources are not sufficient to meet expected demand, there are many important considerations in determining the appropriateness of potential resources. Interruptible customers' transportation may be cut, as needed, when existing resources are not sufficient to meet firm customer demand.

Resource Cost

Resource cost is the primary consideration when evaluating resource options, although other factors mentioned below also influence resource decisions. Newly constructed resources are typically more expensive than existing resources, but existing resources are in shorter supply. Newly constructed resources provided by a third party, such as a pipeline, may require a significant contractual commitment. Newly constructed resources are often less expensive per unit, if a larger facility is constructed, because of economies of scale.

Lead Time Requirements

New resource options can take from one to five or more years to put in service. Open season processes to determine interest in proposed pipelines, planning and permitting, environmental review, design, construction, and testing are some of the aspects contributing to lead time requirements for new facilities. Recalls of released pipeline capacity typically require advance notice of up to one year. Even DSM programs can require significant time from program development and rollout to the realization of natural gas savings.

Peak versus Base Load

Avista's planning efforts include the ability to serve firm natural gas loads on a peak day, as well as all other demand periods. Avista's core loads are considerably higher in the winter than the summer. Due to the winter-peaking nature of Avista's demand, resources that cost-effectively serve the winter without an associated summer commitment may be preferable. Alternatively, it is possible that the costs of a winter-only resource may exceed the cost of annual resources after capacity release or optimization opportunities are considered.

Resource Usefulness

Available resources must effectively deliver natural gas to the intended region. Given Avista's unique service territories, it is often impossible to deliver resources from a resource option, such as storage, without acquiring additional pipeline transportation. Pairing resources with transportation increases cost. Other key factors that can contribute to the usefulness of a resource are viability and reliability. If the potential resource is either not available currently (e.g., new technology) or not reliable on a peak day (e.g., firm), they may not be considered as an option for meeting unserved demand.

"Lumpiness" of Resource Options

Newly constructed resource options are often "lumpy." This means that new resources may only be available in larger-than-needed quantities and only available every few years. This lumpiness of resources is driven by the cost dynamics of new construction, where lower unit costs are available with larger expansions and the economics of expansion of existing pipelines or the construction of new resources dictate additions infrequently. The lumpiness of new resources provides a cushion for future growth. Economies of scale for pipeline construction provide the opportunity to secure resources to serve future demand increases.

Competition

LDCs, end-users and marketers compete for regional resources. The Northwest has been efficient in the utilization of existing resources and has an appropriately sized system. Currently, the region can accommodate the regional demand needs. However, future needs vary, and regional LDCs may find they are competing with each other and other parties to secure firm resources for customers.

Risks and Uncertainties

Investigation, identification, and assessment of risks and uncertainties are critical considerations when evaluating supply resource options. For example, resource costs are subject to degrees of estimation, partly influenced by the expected timeframe of the resource need and rigor determining estimates, or estimation difficulties because of the uniqueness of a resource. Lead times can have varying degrees of certainty ranging from securing currently available transport (high certainty) to building underground storage (low certainty).

Resource Selection
After identifying supply-side resource options and evaluating them based on the above considerations, Avista entered the supply-side scenarios (see Table 5.2) and conservation measures (see Chapter 3 – Demand-Side Resources) into the SENDOUT® model for it to select the least cost approach to meeting resource deficiencies, if they exist. SENDOUT® compares demand-side and supply-side resources (see Appendix 5.3 – Supply Side Resource Options for a list of available options) using PVRR analysis to determine which resource is a least cost/least risk resource.

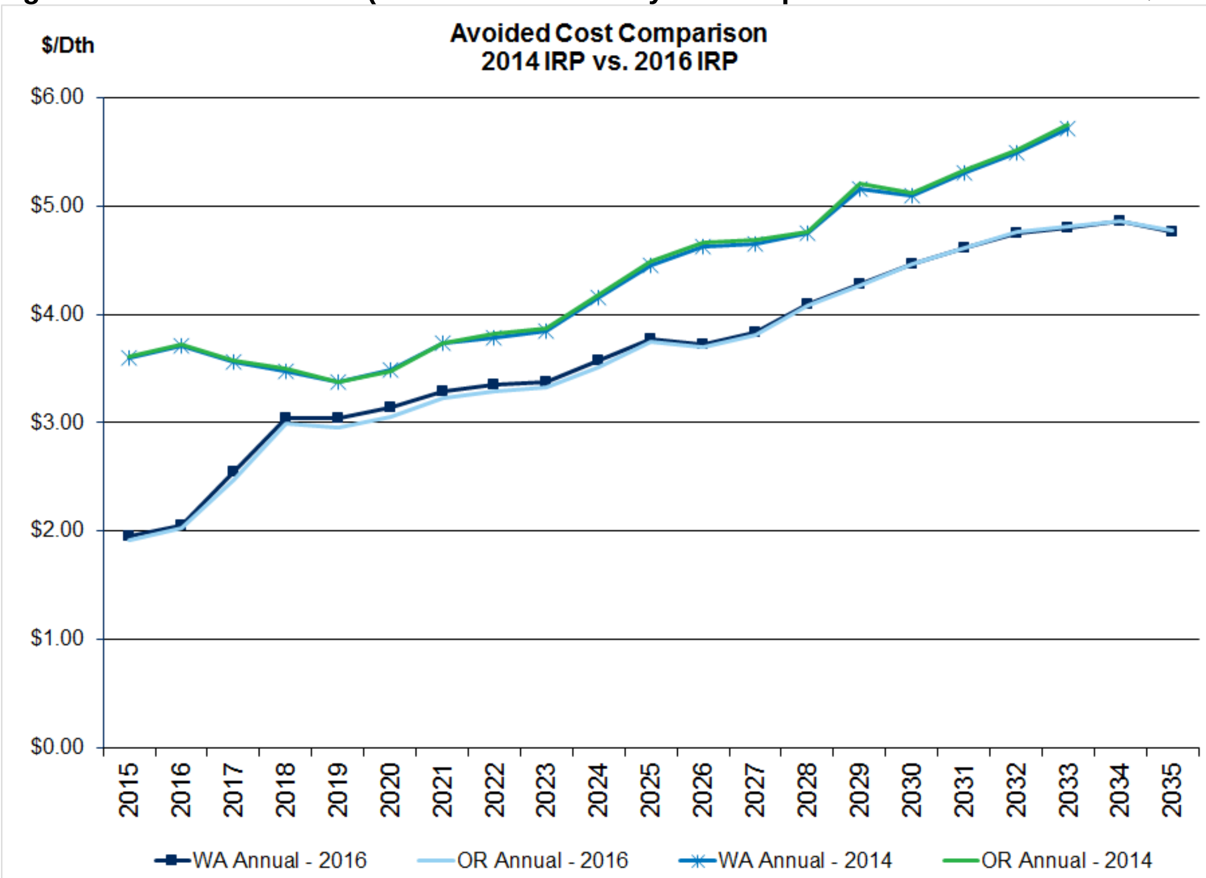
Demand-Side Resources

Integration by Price
As described in Chapter 3 – Demand-Side Resources, the model runs without future DSM programs. This preliminary run provides an avoided cost curve for Applied Energy Group (AEG). AEG then evaluates the cost effectiveness of DSM programs against the initial avoided cost curve using the appropriate resource cost tests. The therm savings and associated program costs are incorporated into the SENDOUT® model. After incorporation, the avoided costs are re-evaluated. This process continues until the change in avoided cost curve is immaterial.

Avoided Cost
The SENDOUT® model determined avoided-cost figures represent the unit cost to serve the next unit of demand with a supply-side resource option during a given period. If a conservation measure's total resource cost (for Idaho and Oregon), or utility cost (for Washington), is less than this avoided cost, it will be cost effective to reduce customer demand and Avista can avoid commodity, storage, transportation and other supply resource costs.

SENDOUT® calculates marginal cost data by day, month and year for each demand area. A summary graphical depiction of avoided annual and winter costs for the Washington/Idaho and Oregon areas is in Figure 5.16. The detailed data is in Appendix 5.4 – Avoided Cost Details. Other than the carbon tax adder embedded in the expected price curve, avoided costs do not include additional environmental externality adders for adverse environmental impacts. Appendix 3.2 – Environmental Externalities discusses this concept more fully and includes specific requirements required in modeling for the Oregon service territory.

Figure 5.16: Avoided Cost (Includes Commodity & Transport Cost – 2014 vs. 2016 $/Dth)



Conservation Potential

Using the avoided cost thresholds, AEG selected all potential cost effective DSM programs. Table 5.4 shows potential DSM savings in each region from the selected conservation potential for the Expected Case. The conservation potential includes anticipated annual acquisition and is cumulative.

Table 5.4: Annual and Average Daily Demand Served by Conservation

Case	Gas Year	Annual Klamath DSM (MDth)	Daily Klamath DSM (MDth/Day)	Annual La Grande DSM (MDth)	Daily La Grande DSM (MDth/Day)	Annual Medford/ Roseburg DSM (MDth)	Daily Medford/ Roseburg DSM (MDth/Day)
Expected	2015-2016	4.39	0.01	2.46	0.01	21.77	0.06
Expected	2016-2017	7.25	0.02	4.07	0.01	35.99	0.10
Expected	2017-2018	10.38	0.03	5.83	0.02	51.63	0.14
Expected	2018-2019	13.73	0.04	7.72	0.02	68.41	0.19
Expected	2019-2020	17.39	0.05	9.78	0.03	86.68	0.24
Expected	2020-2021	21.37	0.06	12.03	0.03	106.65	0.29
Expected	2021-2022	25.68	0.07	14.46	0.04	128.23	0.35
Expected	2022-2023	30.38	0.08	17.12	0.05	151.74	0.42
Expected	2023-2024	35.32	0.10	19.90	0.05	176.44	0.48
Expected	2024-2025	40.64	0.11	22.90	0.06	202.93	0.56
Expected	2025-2026	46.25	0.13	26.05	0.07	230.76	0.63
Expected	2026-2027	51.98	0.14	29.26	0.08	259.18	0.71
Expected	2027-2028	57.78	0.16	32.52	0.09	287.90	0.79
Expected	2028-2029	63.64	0.17	35.81	0.10	316.98	0.87
Expected	2029-2030	69.59	0.19	39.15	0.11	346.45	0.95
Expected	2030-2031	75.57	0.21	42.51	0.12	376.16	1.03
Expected	2031-2032	81.97	0.22	46.11	0.13	408.04	1.12
Expected	2032-2033	88.27	0.24	49.66	0.14	439.45	1.20
Expected	2033-2034	94.50	0.26	53.17	0.15	470.49	1.29
Expected	2034-2035	95.54	0.26	53.75	0.15	475.66	1.30

Case	Gas Year	Annual Oregon DSM (MDth)	Daily Oregon DSM (MDth/Day)	Annual WA/ID DSM (MDth)	Daily WA/ID DSM (MDth/Day)	Annual Total System DSM (MDth)	Daily Total System DSM (MDth/Day)
Expected	2015-2016	28.62	0.08	148.77	0.41	177.39	0.49
Expected	2016-2017	47.30	0.13	257.08	0.70	304.38	0.83
Expected	2017-2018	67.83	0.19	384.21	1.05	452.04	1.24
Expected	2018-2019	89.86	0.25	523.29	1.43	613.15	1.68
Expected	2019-2020	113.85	0.31	669.67	1.83	783.52	2.15
Expected	2020-2021	140.05	0.38	812.24	2.23	952.30	2.61
Expected	2021-2022	168.38	0.46	960.52	2.63	1,128.90	3.09
Expected	2022-2023	199.24	0.55	1,114.29	3.05	1,313.53	3.60
Expected	2023-2024	231.66	0.63	1,272.10	3.49	1,503.76	4.12
Expected	2024-2025	266.46	0.73	1,433.64	3.93	1,700.11	4.66
Expected	2025-2026	303.05	0.83	1,599.93	4.38	1,902.98	5.21
Expected	2026-2027	340.42	0.93	1,769.13	4.85	2,109.54	5.78
Expected	2027-2028	378.20	1.04	1,940.48	5.32	2,318.68	6.35
Expected	2028-2029	416.44	1.14	2,113.24	5.79	2,529.68	6.93
Expected	2029-2030	455.19	1.25	2,286.87	6.27	2,742.06	7.51
Expected	2030-2031	494.24	1.35	2,460.99	6.74	2,955.23	8.10
Expected	2031-2032	536.12	1.47	2,639.05	7.23	3,175.17	8.70
Expected	2032-2033	577.38	1.58	2,817.16	7.72	3,394.54	9.30
Expected	2033-2034	618.15	1.69	2,993.98	8.20	3,612.13	9.90
Expected	2034-2035	624.94	1.71	3,023.41	8.28	3,648.35	10.00

Conservation Acquisition Goals

The avoided cost established in SENDOUT®, the conservation potential selected, and the amount of therm savings is the basis for determining conservation acquisition goals and subsequent DSM program implementation planning. Chapter 3 – Demand-Side Resources has additional details on this process.

Supply-Side Resources

SENDOUT® considers all options entered into the model, determines when and what resources are needed, and which options are cost effective. Selected resources represent the best cost/risk solution, within given constraints, to serve anticipated customer requirements. Since the Expected Case has no resource additions in the planning horizon, Avista will continue to review and refine knowledge of resource options and will act to secure best cost/risk options when necessary or advantageous.

Resource Utilization

Avista's plans to meet firm customer demand requirements in a cost-effective manner. This goal encompasses a range of activities from meeting peak day requirements in the winter to acting as a responsible steward of resources during periods of lower resource utilization. As the analysis presented in this IRP indicates, Avista has ample resources to meet highly variable demand under multiple scenarios, including peak weather events.

Avista acquired the majority of its upstream pipeline capacity during the deregulation or unbundling of the natural gas industry. Pipelines were required to allocate capacity and costs to their existing customers as they transitioned to transportation only service providers. The FERC allowed a rate structure for pipelines to recover costs through a Straight Fixed Variable rate design. This structure is based on a higher reservation charge to cover pipeline costs whether natural gas is transported or not, and a much smaller variable charge which is incurred only when natural gas is transported. An additional fuel charge is assessed to account for the compressors required to move the natural gas to customers. Avista maintains enough firm capacity to meet peak day requirements under the Expected Case in this IRP. This requires pipeline capacity contracts at levels in excess of the average and above minimum load requirements. Given this load profile and the Straight Fixed Variable rate design, Avista incurs ongoing pipeline costs during non-peak periods.

Avista chooses to have an active, hands-on management of resources to mitigate upstream pipeline and commodity costs for customers when the capacity is not utilized for system load requirements. This management simultaneously deploys multiple long and short-term strategies to meet firm demand requirements in a cost effective manner. The resource strategies addressed are:

- Pipeline contract terms;
- Pipeline capacity;
- Storage;
- Commodity and transport optimization; and
- Combination of available resources.

Pipeline Contract Terms

Pipeline costs are incurred whether the capacity is utilized or not. Winter demand must be satisfied and peak days must be met. Ideally, capacity could be contracted from pipelines only for the time and days it is required. Unfortunately, this is not how pipelines are contracted or built. Long-term agreements at fixed volumes are the usual requirements for building or acquiring firm transport. This assures the pipeline of long-term, reasonable cost recovery.

Avista has negotiated and contracted for several seasonal transportation agreements. These agreements allow volumes to increase during the demand intensive winter months and decrease over the lower demand summer period. This is a preferred contracting strategy because it eliminates costs when demand is low. Avista refers to this as a front line strategy because it attempts to mitigate costs prior to contracting the resource. Not all pipelines offer this option. Avista seeks this type of arrangement when available. Avista currently has some seasonal transportation contracts on TransCanada GTN, TransCanada BC and TransCanada Alberta. These pipelines match up transport capacity to move natural gas from Alberta (AECO) to Avista's service territories. Avista also contracted for TF2 on NWP. This is a storage specific contract and matches up the withdrawal capacity at Jackson Prairie with pipeline transport to Avista's service territories. TF2 is a firm service and allows for contracting a daily amount of transportation for a specified number of days rather than a daily amount on an annual basis as is usually required. For example, one of the TF2 agreements allows Avista to transport 91,200 Dth/day for 31 days. This is a more cost effective strategy for storage transport than contracting for an annual amount. Through NWP's tariff, Avista maintains an option to increase and decrease the number of days this transportation option is available. More days correspond to increased costs, so balancing storage, transport and demand is important to ensure an optimal blend of cost and reliability.

Pipeline Capacity

After contracting for pipeline capacity, its management and utilization determine the actual costs. The worst-case economic scenario is to do nothing and simply incur the costs associated with this transport contract over the long-term to meet current and future peak demand requirements. Avista develops strategies to ensure this does not happen on a regular basis.

Capacity Release

Through the pipeline unbundling of transportation, the FERC establishes rules and procedures to ensure a fair market developed to manage pipeline capacity as a commodity. This evolved into the capacity release market and is governed by FERC regulations through individual pipelines. The pipelines implement the FERC's posting requirements to ensure a transparent and fair market is maintained for the capacity. All capacity releases are posted on the pipelines Bulletin Boards and, depending on the terms, may be subject to bidding in an open market. This provides the transparency sought by the FERC in establishing the release requirements. Avista utilizes the capacity release market to manage both long-term and short-term transportation capacity.

For capacity under contract that may exceed current demand, Avista seeks other parties that may need it and arranges for capacity releases to transfer rights, obligations and costs. This shifts all or a portion of the costs away from Avista's customers to a third party until it is needed to meet customer demand.

There are many variables in determining the value of transportation. Certain pipeline paths are more valuable and this can vary by year, season, month and day. The term, volume and conditions precedent also contribute to the value recoverable through a capacity release. For example, a release of winter capacity to a third party may allow for full cost recovery; while a release for the same period that allows Avista to recall the capacity for up to 10 days during the winter may not be as valuable to the third party, but of high value to us. Avista may be willing to offer a discount to retain the recall rights during high demand periods. This turns a seasonal-for-annual cost into a peaking-only cost. These are market terms and conditions that are negotiated to determine the value or discount required by both parties.

Avista has several long-term releases, some extending through 2025 providing full recovery of all the pipeline costs. These releases maintain Avista's long-term rights to the transportation capacity without incurring the costs of waiting until demand increases. As the end of these release terms near, Avista surveys the market against the IRP to determine if these contracts should be reclaimed or released, and for what duration.

Avista has releases to third parties that terminate in 2016. Results of this IRP show that this capacity is not needed in 2016 as originally anticipated, and Avista is negotiating new terms and conditions to continue full cost recovery until it is required. Through this process, Avista retains the rights to vintage capacity without incurring the costs or having to participate in future pipeline expansions that will cost more than current capacity.

On a shorter term, excess capacity not fully utilized on a seasonal, monthly or daily basis can also be released. Market conditions often dictate less than full cost recovery for shorter-term requirements. Mitigating some costs for an unutilized, but required resource reduces costs to our customers.

Segmentation

Through a process called segmentation, Avista creates new firm pipeline capacity for the service territory. This doubles some of the capacity volumes at no additional cost to customers. With increased firm capacity, Avista can continue some long-term releases, or even reduce some contract levels, if the release market does not provide adequate recovery.

Storage

As a one-third owner of the Jackson Prairie Storage facility, Avista holds an equal share of capacity (space available to store gas) and delivery (the amount of natural gas that can be withdrawn on a daily basis).

Storage allows lower summer-priced gas to be stored and used in the winter during high demand or peak day events. Similar to transportation, unneeded capacity and delivery can be optimized by selling into a higher priced market. This allows Avista to manage storage capacity and delivery to meet growing peak day requirements when needed.

The injection of natural gas into storage during the summer utilizes existing pipeline transport and helps increase the utilization factor of pipeline agreements. Avista employs several storage optimization strategies to mitigate costs. Revenue from this activity flows through the annual PGA/Deferral process.

Commodity and Transportation Optimization

Another strategy to mitigate transportation costs is to participate in the daily market to assess if unutilized capacity has value. Avista seeks daily opportunities to purchase gas, transport it on existing unutilized capacity, and sell it into a higher priced market to capture the cost of the gas purchased and recover some pipeline charges. The recovery is market dependent and may or may not recover all pipeline costs, but mitigates pipeline costs to customers.

Combination of Resources

Unutilized resources like supply, transportation, storage and capacity can combine to create products that capture more value than the individual pieces. Avista has structured long-term arrangements with other utilities that allow available resources utilization and provide products that no individual component can satisfy. These products provide more cost recovery of the fixed charges incurred for the resources while maintaining the rights to utilize the resource for future customer needs.

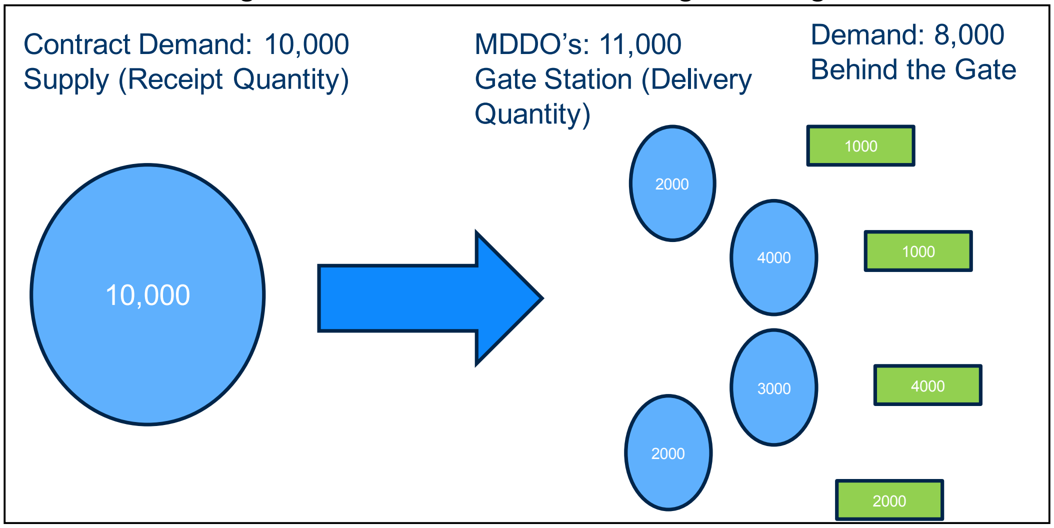
Resource Utilization Summary

As determined through the IRP modeling of demand and existing resources, new resources under the Expected Case are not required over the next 20 years. Avista manages the existing resources to mitigate the costs incurred by customers until the resource is required to meet demand. The recovery of costs is often market based with rules governed by the FERC. Avista is recovering full costs on some resources and partial costs on others. The management of long- and short-term resources meets firm customer demand in a reliable and cost-effective manner.

Gate Station Analysis

In past IRP's, Avista identified a risk associated with the aggregated methodology for supply and demand forecasting in previous IRPs. The forecasting methodology is consistent with operational practices which aggregate capacity at individual points for scheduling/nomination purposes. Typically, the amount of natural gas that can flow from a contract demand (i.e., receipt/supply quantity) is fixed and the deliverable amount (i.e., maximum daily delivery obligation or delivery quantity) to gate stations is greater. (See Figure 5.17) However, aggregation could mask deficiencies at individual gate stations.

Figure 5.17: Gate Station Modeling Challenge



To address this concern, a gate-by-gate analysis was developed outside of SENDOUT®. The analysis involved coordination between Gas Supply, Gas Engineering and intrastate pipeline personnel. Utilizing historical gate station flow data and demand forecasting methodologies detailed in the IRP, forecasted peak-day gate station demand was calculated. This demand was compared to contracted and operational capacities at each gate station.

If forecasted demand exceeded contracted and/or operational capacities, further analysis was completed. The additional analysis involved assessing the economic way to address the gate deficiency. This could involve a gate station expansion, reassigning maximum daily delivery obligations, targeted DSM programs or distribution system enhancements.

Avista has completed the gate station analysis. The analysis found peak day deficiencies at seven gate stations. The data set was static so some of the gate station shortages have already experienced mitigation fixes. The area of La Grande is one such example where the Ladd Canyon city gate station was completed in December 2015 to help offset the flow at the La Grande city gate. Also, a high pressure reinforcement project will begin in 2017 to help ensure a physical limitation at this city gate is not exceeded. As for the remaining city gate deficiencies, the potential fixes will be reviewed between Avista's Gas Supply and Distribution Engineering departments. A current list of distribution planning capital projects can be found in table 7.1 and city gate station upgrades in table 7.2 (section as described in Chapter 7 – Distribution Planning).

Conclusion

The IRP portfolio analysis summarized in this chapter was performed on the Average Case and then on the Expected Case demand scenario. Although the results show no resource deficiencies during the 20-year forecasted term, Avista has chosen to utilize the Expected Case for peak operational planning activities because this case is the most likely outcome given experience, industry knowledge and understanding of future natural gas markets. This case provides reasonable demand growth given current expectations of natural gas prices over the planning horizon. If realized, this case allows Avista protection against resource shortages and does not over commit to additional long-term resources.

Avista recognizes that there are other potential outcomes. The process described in this chapter applies to the alternate demand and supply resource scenarios covered in Chapter 6 – Alternate Scenarios, Portfolios and Stochastic Analysis.

6: Alternate Scenarios, Portfolios and Stochastic Analysis

Overview

Avista applied the IRP analysis in Chapter 5 – Integrated Resource Portfolio to alternate demand and supply resource scenarios to develop a range of alternate portfolios. This deterministic modeling approach considered different underlying assumptions vetted with the TAC members to develop a consensus about the number of cases to model.

Avista also performed stochastic modeling for estimating probability distributions of potential outcomes by allowing for random variation in natural gas prices and weather based on fluctuations in historical data. This statistical analysis, in conjunction with the deterministic analysis, enabled statistical quantification of risk from reliability and cost perspectives related to resource portfolios under varying price and weather conditions.

Alternate Demand Scenarios

As discussed in the Demand Forecasting section, Avista identified alternate scenarios for detailed analysis to capture a range of possible outcomes over the planning horizon. Table 6.1 summarizes these scenarios and Chapter 2 – Demand Forecasts and Appendices 2.6 and 2.7 describes them in detail. The scenarios consider different demand influencing factors and price elasticity effects for various price influencing factors.

Table 6.1: 2016 IRP Scenarios

Proposed Scenarios INPUT ASSUMPTIONS	Expected Case - Low Prices	Expected Case	High Growth & Low Prices	Low Growth & High Prices	Cold Day 20yr Weather Std	Average Case
Customer Growth Rate	Reference Case Cust Growth Rates	Reference Case Cust Growth Rates	High Growth Rate	Low Growth Rate	Reference Case Cust Growth Rates	Reference Case Cust Growth Rates
Use per Customer	3 yr Flat + Price Elast.	3 yr Flat + Price Elast.	3 yr Flat + Price Elast. + CNG/NGV	3 yr Flat + Price Elast.	3 yr Flat + Price Elast.	3 yr Flat + Price Elast.
Demand Side Management	Yes	Yes	Yes	Yes	Yes	Yes
Weather Planning Standard	Coldest Day	Coldest Day	Coldest Day	Coldest Day	Alternate Planning Standard	Normal
Prices						
Price curve	Low	Expected	Low	High	Expected	Expected
Carbon Legislation ($/Ton)	$9.89 - 19.93	$9.89 - 19.93	None	$9.89 - 19.93	$9.89 - 19.93	$9.89 - 19.93
RESULTS						
First Gas Year Unserved						
WA/ID	N/A	N/A	2033	N/A	N/A	N/A
Medford	N/A	N/A	2027	N/A	N/A	N/A
Roseburg	N/A	N/A	2027	N/A	N/A	N/A
Klamath	N/A	N/A	2034	N/A	N/A	N/A
La Grande	N/A	N/A	2031	N/A	N/A	N/A

Demand profiles over the planning horizon for each of the scenarios shown in Figures 6.1 and 6.2 reflect the two winter peaks modeled for the different service territories (Dec. 20 and Feb. 15).

Figure 6.1 Peak Day (Feb 15) – 2016 IRP Demand Scenarios

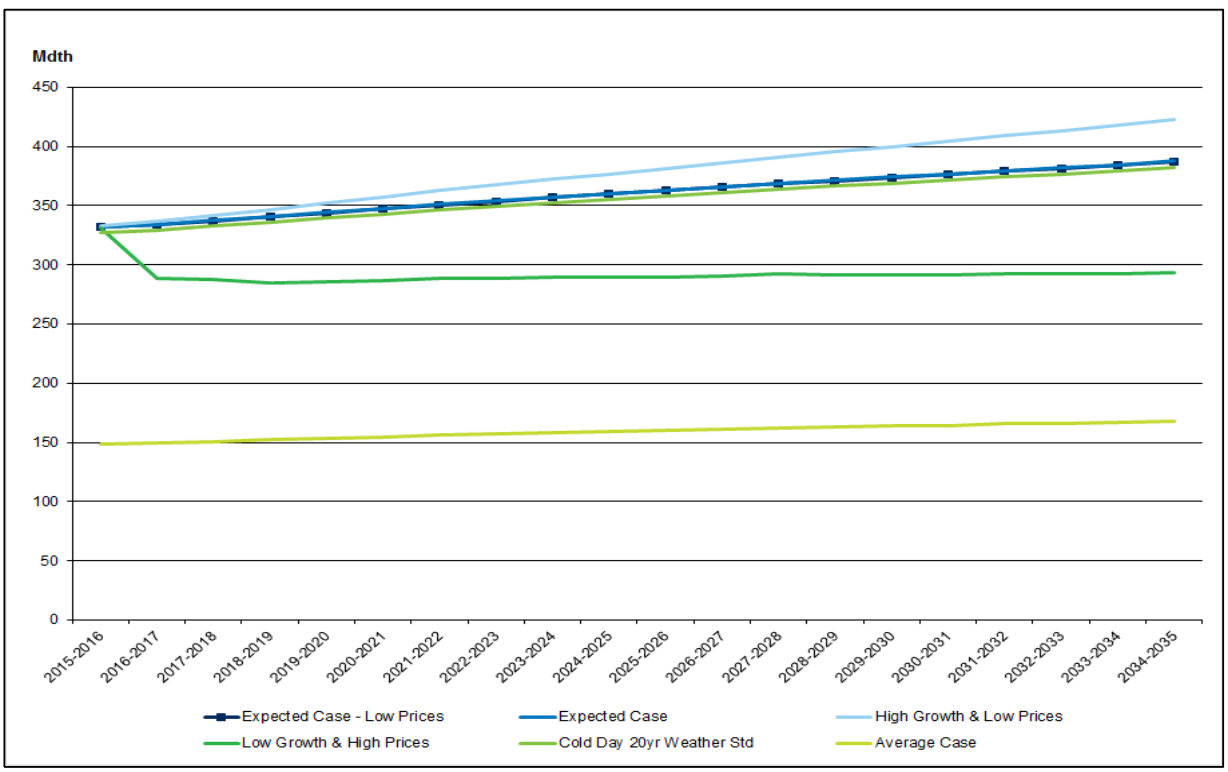
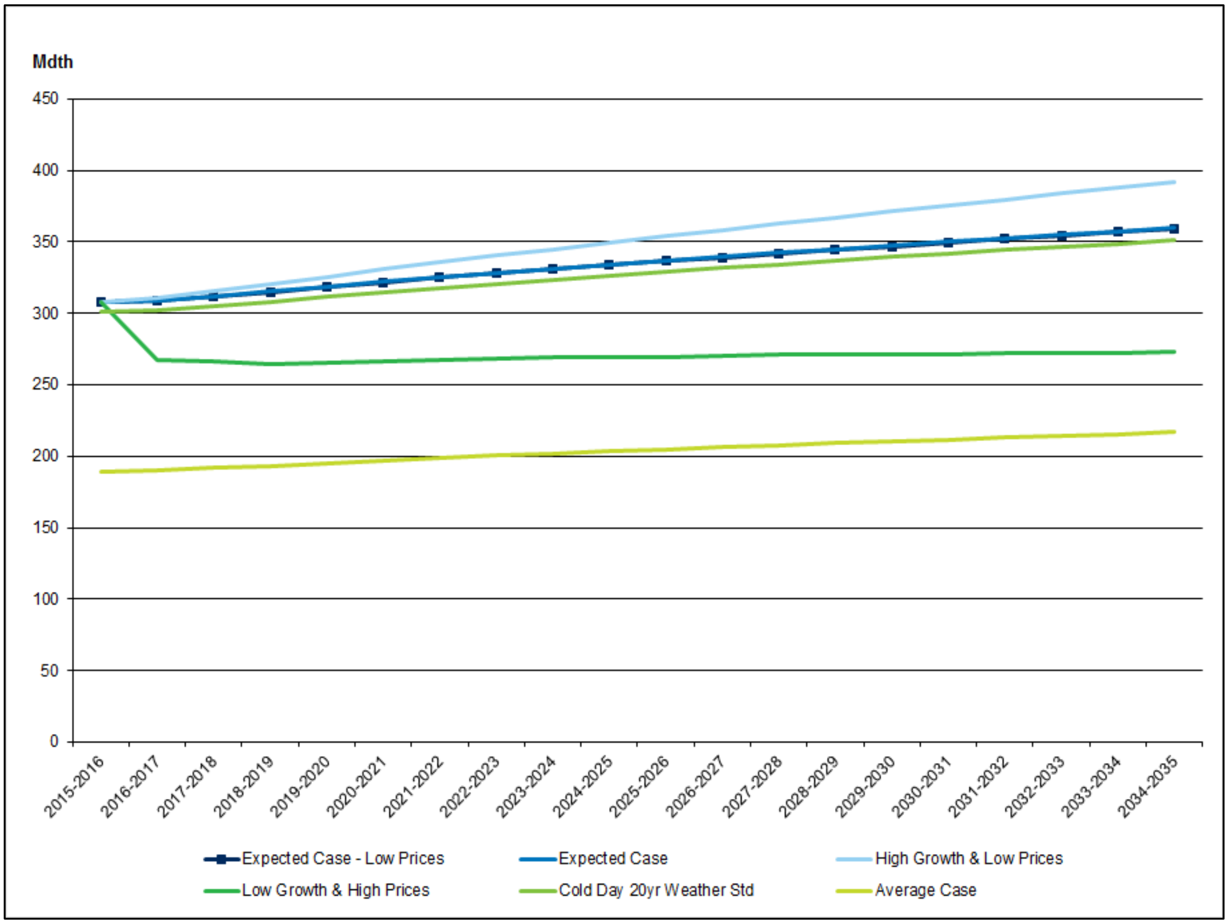
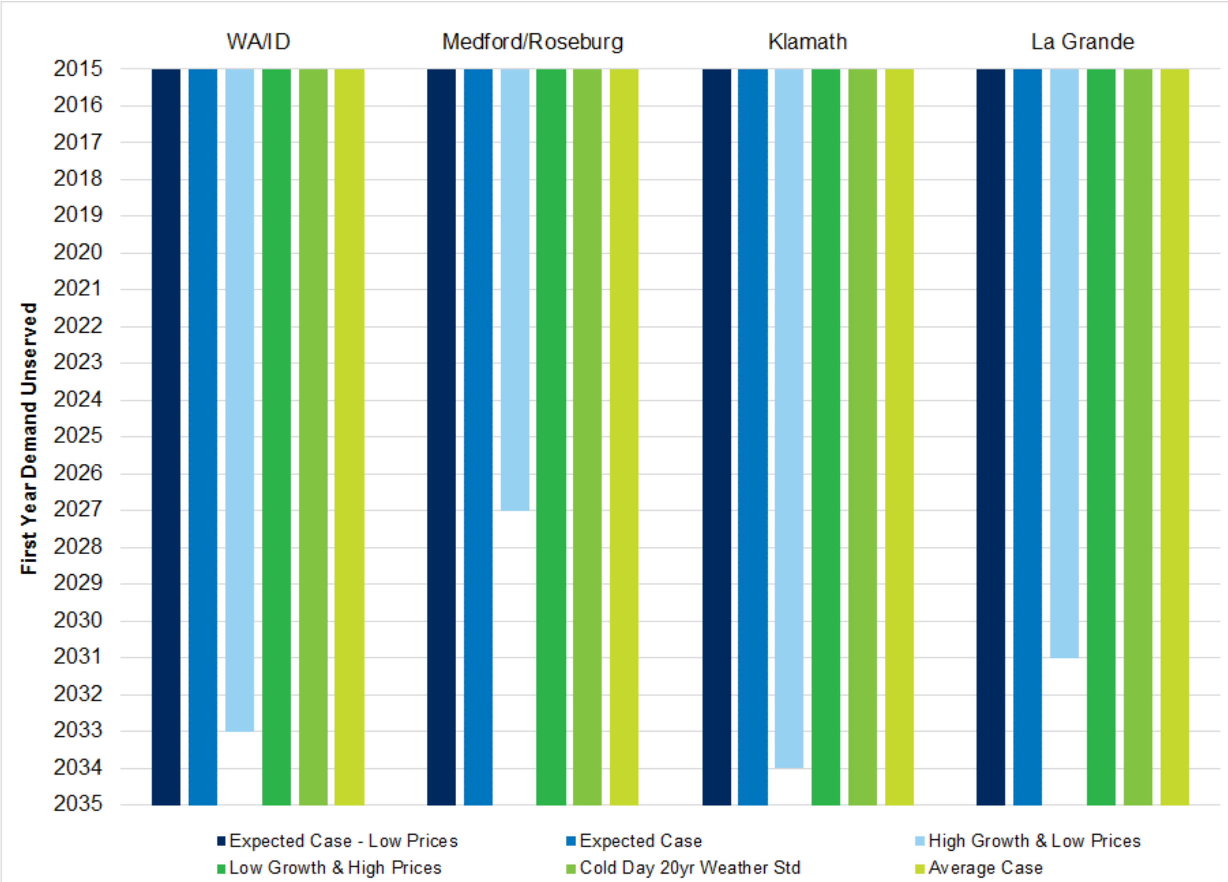


Figure 6.2 Peak Day (Dec 20) – 2016 IRP Demand Scenarios



As in the Expected Case, Avista used SENDOUT® to model the same resource integration and optimization process described in this section for each of the six demand scenarios (see Appendix 2.7 for a complete listing of portfolios considered). This identified the first year unserved dates for each scenario by service territory shown in Figure 6.3.

Figure 6.3: First Year Peak Demand Not Met with Existing Resources



As anticipated, the High Growth & Low Price scenario has the most rapid growth and the earliest first year unserved dates. This scenario includes customer growth rates higher than the Expected Case, incremental demand driven by emerging markets and no adjustment for price elasticity. Even with aggressive assumptions, resource shortages do not occur until late in the planning horizon.

- 2033 in Washington/Idaho
- 2027 in Medford/Roseburg
- 2034 in Klamath Falls
- 2031 in La Grande

The model chose to solve these unserved demand areas via the following supply resources:

- Washington/Idaho – Increase contracting on Alberta System, Foothills, and GTN pipeline by 13,000 Dth/day.
- Medford/Roseburg – Add an upsized compressing station on the Medford Lateral increasing deliverability by 50,000 Dth/day.
- Klamath Falls – Increase the Operating Pressure on the Klamath Falls Lateral.
- La Grande – Increase contract delivery on Northwest Pipeline.

Steeper demand highlights the flat demand risk discussed earlier. The likelihood of this scenario occurring is remote due to a yearly recurrence of coldest day on record weather paired with a much steeper growth of customer population; however, any potential for accelerated unserved dates warrants close monitoring of demand trends and resource lead times as described in the Ongoing Activities section of Chapter 8 – Action Plan. The remaining scenarios do not identify resource deficiencies in the planning horizon.

Due to their importance and connection with the IRP process, additional detailed information on certain selected scenarios is included in the following appendices:

- Demand and Existing Resources graphs by service territory (High Growth Case only) – Appendix 6.1
- Peak Day Demand, Served and Unserved table (all cases) – Appendix 6.2

Alternate Supply Resources

Avista identified supply-side resources that could meet resource deficiencies or provide a least cost solution. There are other options Avista considered in its modeling approach to solve for High Growth & Low Price unserved conditions and to determine whether the Expected Case with existing resources is least cost/least risk. Some of the currently available resources are included in Table 6.2 and potential future resources are included in Table 6.3:

Table 6.2: Available Supply Resources

Available Supply Resources	Size	Cost/Rates	Availability	Notes
Capacity Release Recall	27,000 Dth	NWPL Rate	2018	Recall of previously released capacity
Unsubscribed GTN Capacity	Up to 50,000 Dth	GTN Rate plus Upstream TCPL	Now	Currently available unsubscribed capacity from Kingsgate to Stanfield or Malin plus associated Alberta transport
NWP Expansion	Up to 50,000 Dth	$0.74 / Dth	2018	Expansion from Sumas to JP
Citygate Deliveries	Variable	Varies	Now	Represents the ability to buy a delivered product from another utility or marketer. Limited counterparties
Satellite LNG	90,000 Dth w/30,000 Dth deliverability	$12.3 Million capital cost plus $665K O&M	2018	Provides for peaking services and alleviates the need for costly pipeline expansions. $3,000 per m3. O&M assumed at 5.4%
Medford Lateral Exp	50,000 Dth	$10M / GTN estimated rate	2018	Additional compression to facilitate more gas to flow from mainline GTN to Medford.
Malin Backhauls	50,000	GTN Rate	Now	Currently available

Table 6.3: Future Supply Resources

Future Supply Resources	Size	Cost/Rates	Availability	Notes
Co. Owned LNG	600,000 Dth w/ 150,000 of deliverability	$75 Million plus $2 Million annual O&M	2022	On site, in service territory liquefaction and vaporization facility
Various pipelines – Pacific Connector, Cross-Cascades, etc.	Varies	Precedent Agreement Rates	2020	Requires additional mainline capacity on NWPL or GTN to get to service territory
Large Scale LNG	Varies	Commodity less Fuel	2020	Speculative, needs pipeline transport
In Ground Storage	Varies	Varies	Varies	Requires additional mainline transport to get to service territory

For example, contracted city gate deliveries in the form of a structured purchase transaction could meet peak conditions. However, the market-based price and other terms are difficult to reliably determine until a formal agreement is negotiated. Exchange agreements also have market-based terms and are hard to reliably model when the resource need is later in the planning horizon.

Many of the potential resources are not yet commercially available or well tested, technically making them speculative. Resources such as coal-bed methane, LNG imports and natural gas hydrates would fall into this category. Avista will continue to monitor all resources and assess their appropriateness for inclusion in future IRPs as described in Chapter 8 – Action Plan.

One resource which will be closely observed is exported LNG. While Avista considered LNG exports, it was primarily as a price-influencing factor. However, if the proposed export LNG terminal in Oregon is approved and a pipeline built to supply that facility, it potentially could bring new supply through Avista's service territory. Avista will monitor (Chapter 8 – Action Plan) this situation through industry publications and daily operations to consider inclusion of this supply scenario for future IRPs.

Deterministic – Portfolio Evaluation

There is no resource deficiency identified in the planning period and the existing resource portfolio is adequate to meet forecasted demand. The alternate demand scenarios and supply scenarios are placed in the model as predicted future conditions that the supply portfolio will have to satisfy via least cost and least risk strategies. This creates bounds for analyzing the Expected Case by creating high and low boundaries for customer count, weather and pricing. Each portfolio runs through SENDOUT® where the supply resources (Chapter 4 – Supply Side Resources) and conservation resources (Chapter 3 – Demand Side Management – see tables 3.2, 3.3 and 3.4) are compared and selected on a least cost basis. Once new resources are determined, a net present value of the revenue requirement (PVRR) is calculated.

Table 6.4 summarizes the PVRR of the portfolios considered. In addition to the portfolios in table 6.4, modeling was done to compare the existing resources to alternate resources. The analysis begins as deterministic based on the Expected Case portfolio. Existing transportation was tested in small increments to show the overall change to the PVRR. In the first alternate resource cases, 10,000 Dth/day was taken from NWP and then an equal amount added to GTN. The second case reversed these amounts where 10,000 additional Dth/day were added to NWP and taken away from GTN. Both NWP and GTN quantities are flowing into the WA-ID service territory. The third case removes transport to Oregon on NWP, from Sumas, and is replaced with an enhanced compressor on the Medford lateral that connects to the GTN mainline. All three alternate resource portfolios show a higher cost than the Expected Case PVRR. This testing of existing resources in comparison to alternate resources determines whether a least cost and least risk solution is present in the existing resource stack. If any of these scenarios showed a lower deterministic system PVRR, a stochastic analysis would be used to look at the optimal resource stack and its cost under varying conditions.

Table 6.4: PVRR by Portfolio

	Portfolio	Unserved Demand	PVRR in (000's)
Average Case	Average Demand	No	$ 4,830,594
Expected Case	Expected predicted future conditions	No	$ 4,938,795
-Alternate Resources of Expected Case			
	10,000 less GTN, 10,000 more NWP	No	$ 4,940,866
	10,000 less NWP; 10,000 more GTN	No	$ 4,948,022
	Less NWP Oregon transport, Upgraded Compressor on GTN at Medford	No	$ 5,292,999
Additional Demand Scenarios			
	Expected Case, Low Prices	No	$ 3,946,275
	High Growth, Low Prices	Yes	$ 3,574,465
	Low Growth, High Prices	No	$ 4,965,789
	Alternate Weather Standard	No	$ 5,702,501

Stochastic Analysis[1]

The scenario (deterministic) analysis described earlier in this chapter represents specific what if situations based on predetermined assumptions, including price and weather. These factors are an integral part of scenario analysis. To understand a particular portfolio's response to cost and risk, through price and weather, Avista applied stochastic analysis to generate a variety of price and weather events.

Deterministic analysis is a valuable tool for selecting an optimal portfolio. The model selects resources to meet peak weather conditions in each of the 20 years. However, due to the recurrence of design conditions in each of the 20 years, total system costs over the planning horizon can be overstated because of annual recurrence of design conditions and the recurrence of price increases in the forward price curve. As a result, deterministic analysis does not provide a comprehensive look at future events. Utilizing Monte Carlo simulation in conjunction with deterministic analysis provides a more complete picture of portfolio performance under multiple weather and price profiles.

[1] SENDOUT® uses Monte Carlo simulation to support stochastic analysis, which is a mathematical technique for evaluating risk and uncertainty. Monte Carlo simulation is a statistical modeling method used to imitate future possibilities that exist with a real-life system.

This IRP employs stochastic analysis in two ways. The first tested the weather-planning standard and the second assessed risk related to costs of our Expected Case (existing portfolio) under varying price environments. The Monte Carlo simulation in SENDOUT® can vary index price and weather simultaneously. This simulates the effects each have on the other.

Weather

In order to evaluate weather and its effect on the portfolio, Avista developed 200 simulations (draws) through SENDOUT®'s stochastic capabilities. Unlike deterministic scenarios or sensitivities, the draws have more variability from month-to-month and year-to-year. In the model, random monthly total HDD draw values (subject to Monte Carlo parameters – see Table 6.5) are distributed on a daily basis for a month in history with similar HDD totals. The resulting draws provide a weather pattern with variability in the total HDD values, as well as variability in the shape of the weather pattern. This provides a more robust basis for stress testing the deterministic analysis.

Table 6.5: Example of Monte Carlo Weather Inputs – Spokane

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
HDD Mean	867	1,110	1,170	935	799	541	318	140	31	40	194	523
HDD Std Dev	111	133	179	129	99	87	81	51	26	31	73	86
HDD Max	1,374	1,519	1,759	1,389	1,059	740	494	260	168	144	363	695
HDD Min	609	839	850	703	561	269	146	12	-	-	59	334

Avista models five weather areas: Spokane, Medford, Roseburg, Klamath Falls and La Grande. Avista assessed the frequency that the peak day occurs in each area from the simulation data. The stochastic analysis shows that in over 200, 20-year simulations, peak day (or more) occurs with enough frequency to maintain the current planning standard for this IRP. This topic remains a subject of continued analysis. For example, the Medford weather pattern over the 200 20-year draws (i.e, 4,000 years). HDDs at or above peak weather (61 HDDs) occur 128 times. This equates to a peak day occurrence once every 31 years (4,000 simulation years divided by 128 occurrences). The Spokane area has the least occurrences of peak day (or more) occurrences and La Grande has the most occurrences. This is primarily due to the frequency in which each region's peak day HDD occurs within the historical data, as well as near peak day HDDs. See Figures 6.4 through 6.8 for the number of peak day occurrences by weather area.

Figure 6.4: Frequency of Peak Day Occurrences – Spokane

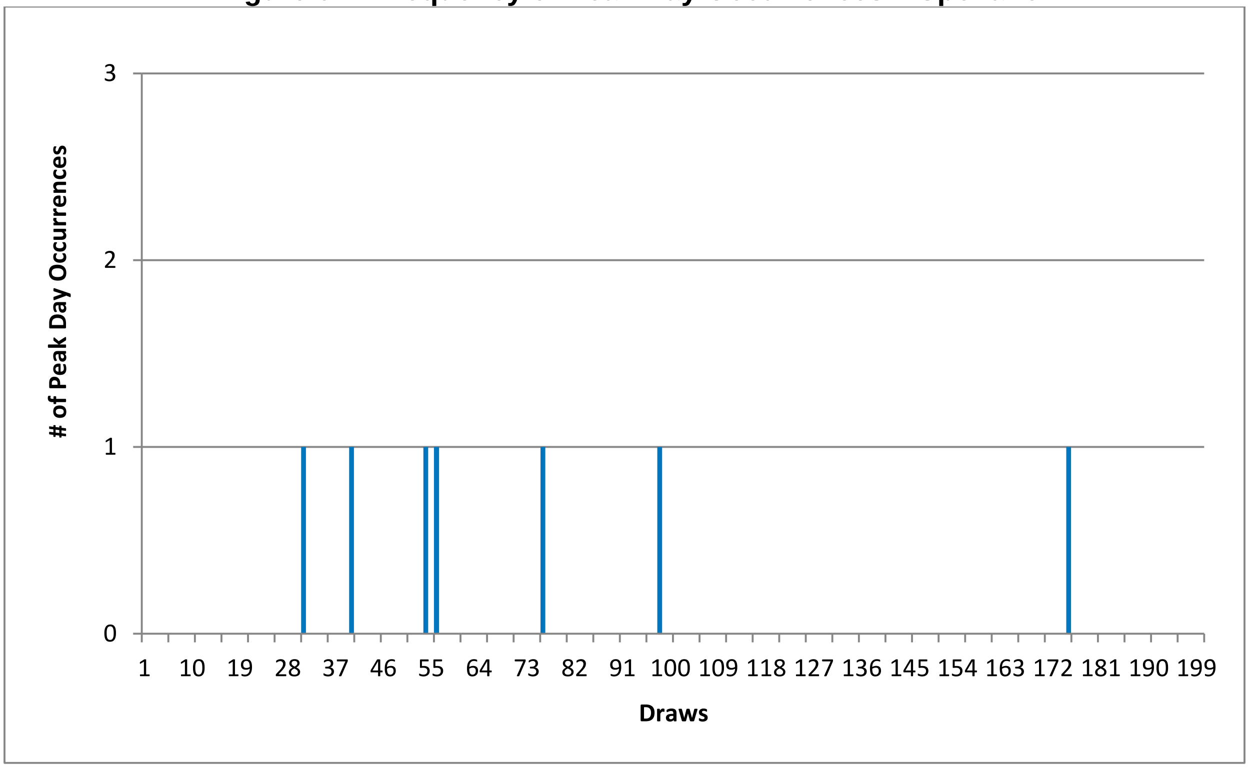


Figure 6.5: Frequency of Peak Day Occurrences – Medford

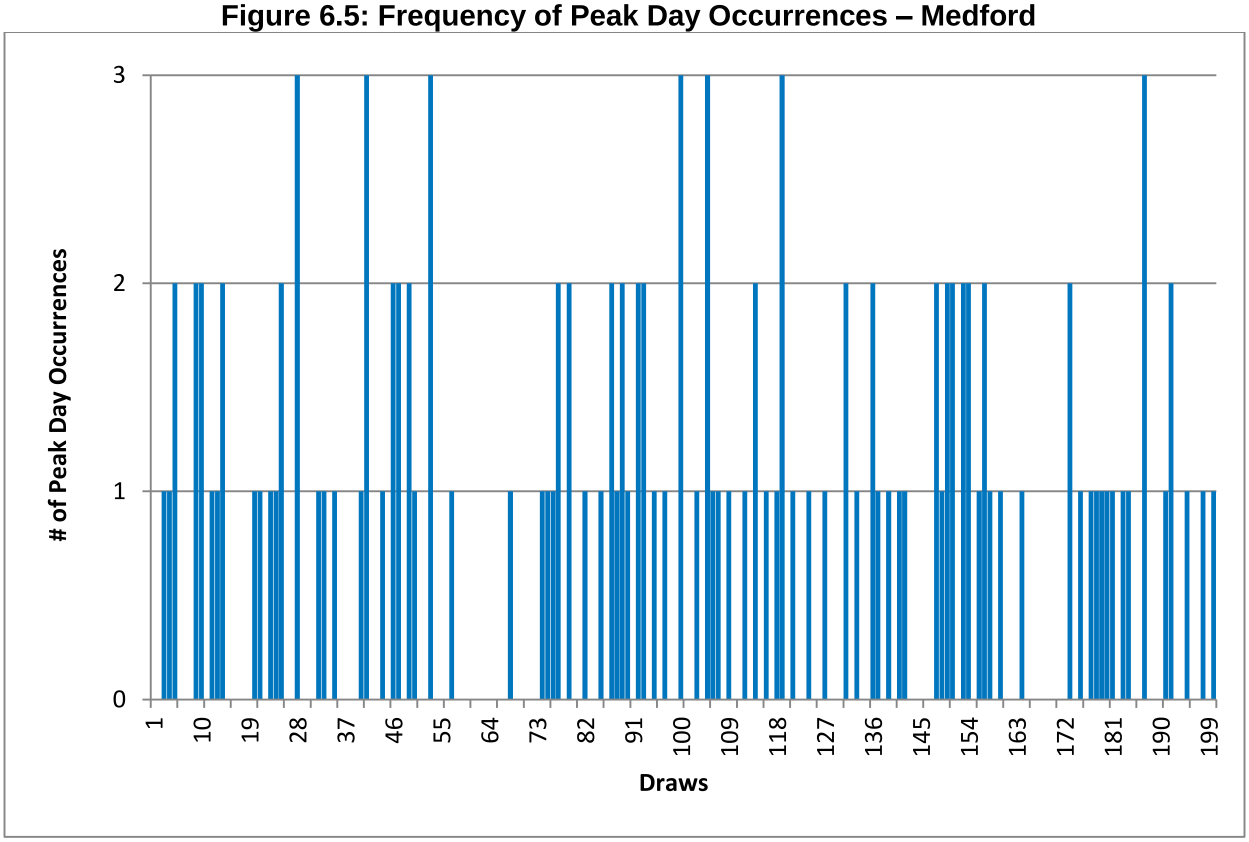


Figure 6.6: Frequency of Peak Day Occurrences – Roseburg

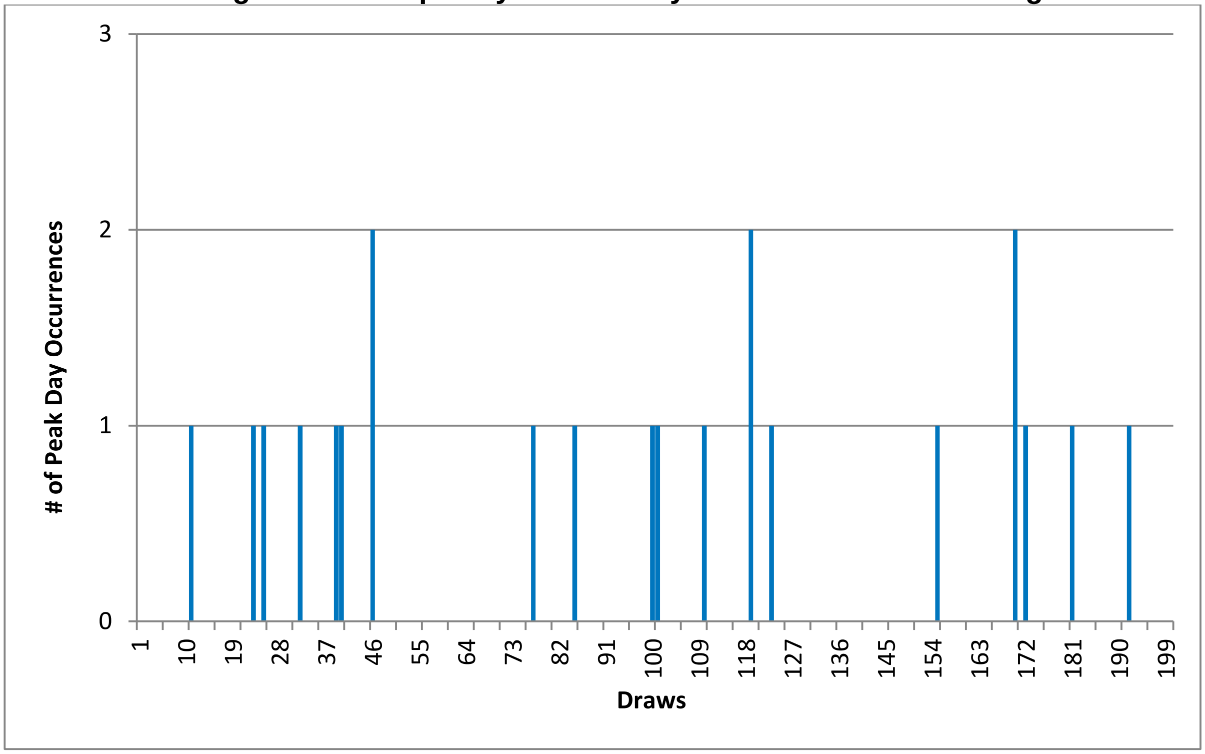


Figure 6.7: Frequency of Peak Day Occurrences – Klamath Falls

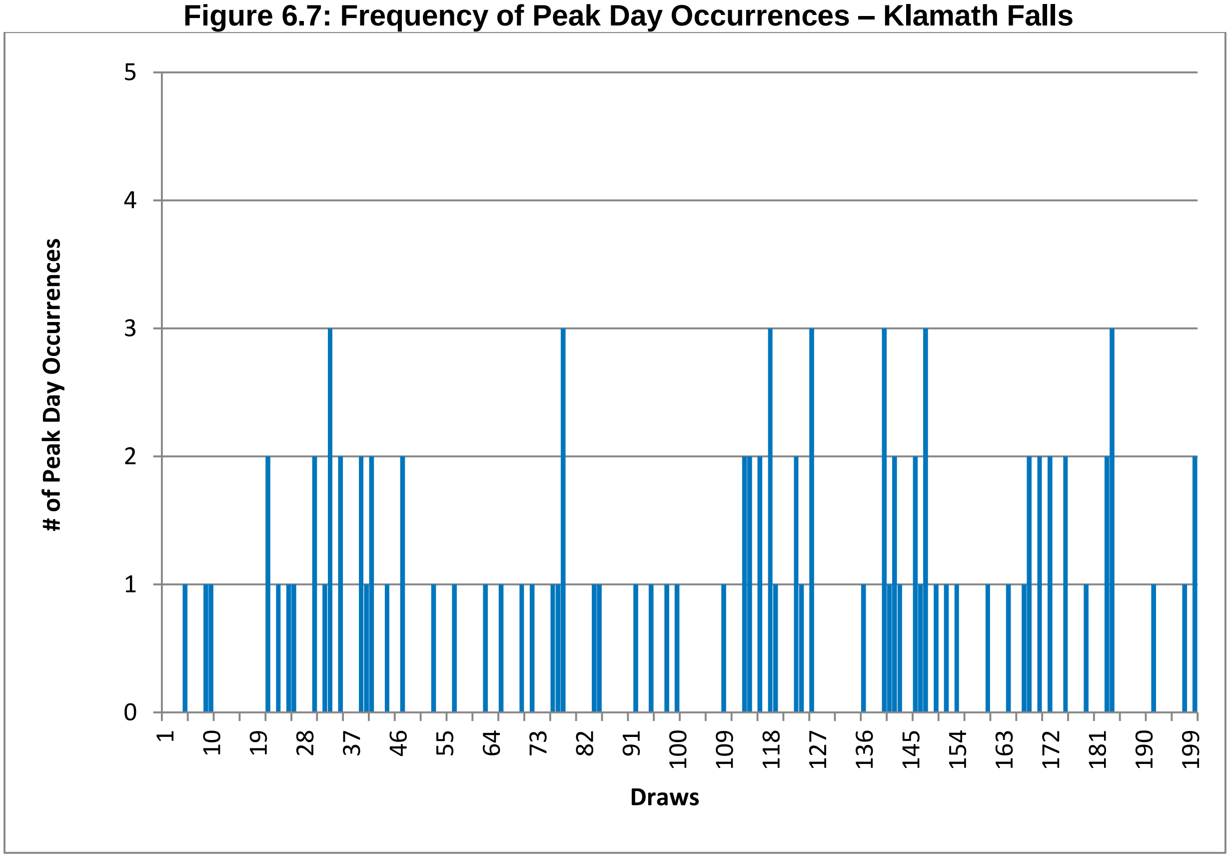
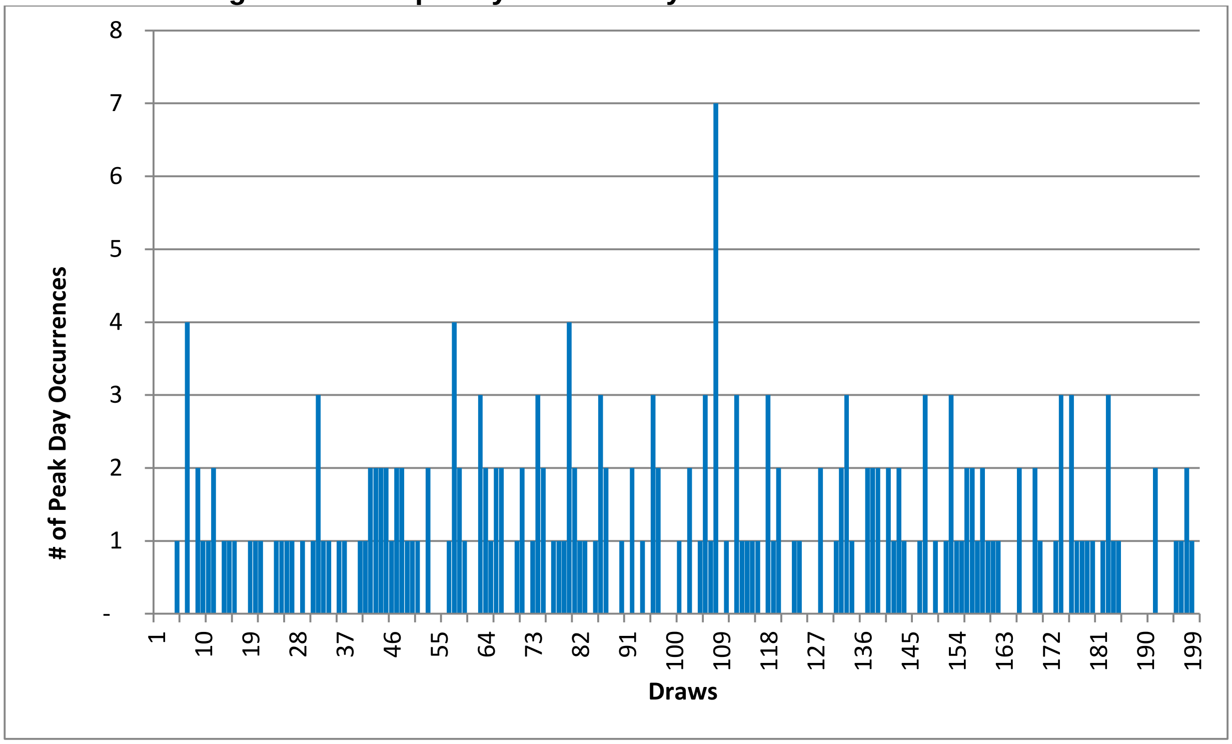


Figure 6.8: Frequency of Peak Day Occurrences – La Grande

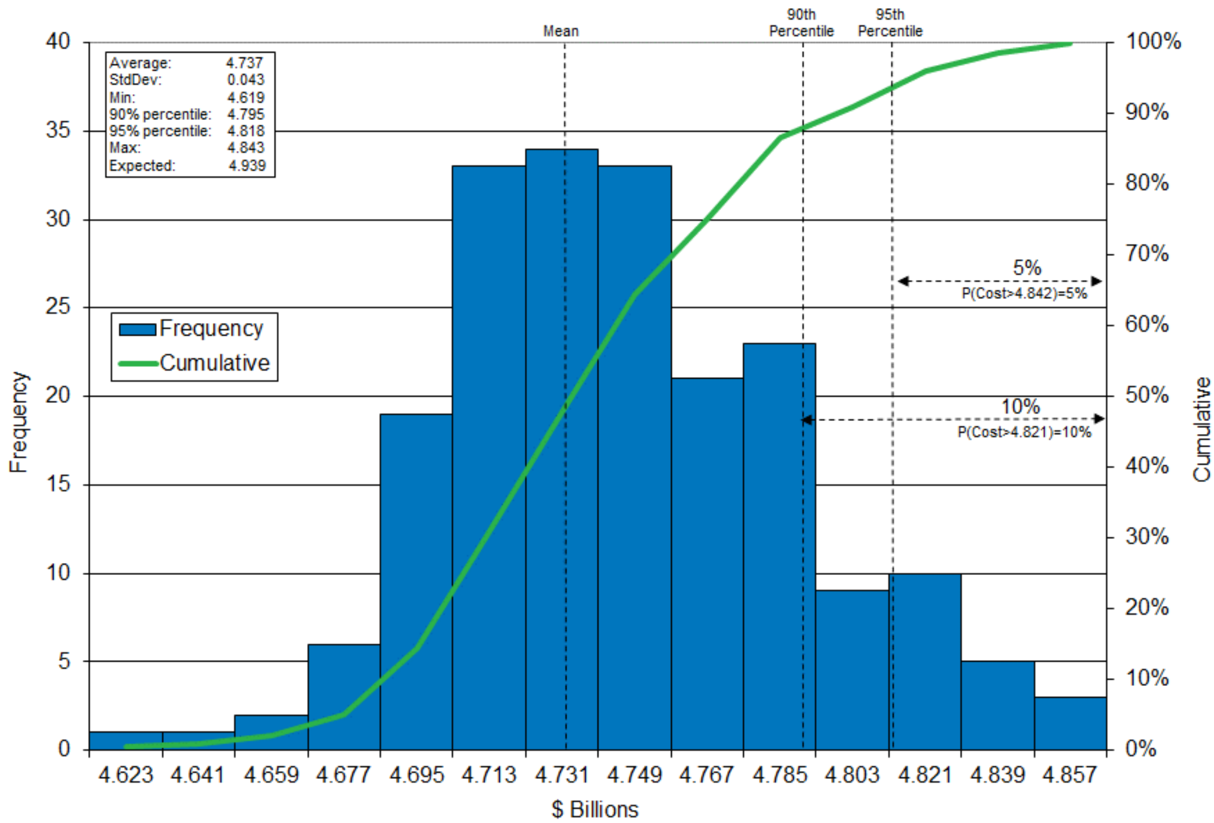


Price

While weather is an important driver for the IRP, price is also important. As seen in recent years, significant price volatility can affect the portfolio. In deterministic modeling, a single price curve for each scenario is used for analysis. There is risk that the price curve in the scenario will not reflect actual results.

Avista used Monte Carlo simulation to test the portfolio and quantify the risk to customers when prices do not materialize as forecast. Avista performed a simulation of 200 draws, varying prices, to investigate whether the Expected Case total portfolio costs from the deterministic analysis is within the range of occurrences in the stochastic analysis. Figure 6.9 shows a histogram of the total portfolio cost of all 200 draws, plus the Expected Case results. This histogram depicts the frequency and the total cost of the portfolio among all the draws, the mean of the draws, the standard deviation of the total costs, and the total costs from the Expected Case. The figure confirms that Expected Case total portfolio cost is within an acceptable range of total portfolio costs based on 200 unique pricing scenarios.

Figure 6.9: 2016 IRP Total 20-Year Cost



Performing stochastic analysis on weather and price in the demand analysis provided a statistical approach to evaluate and confirm the findings in the scenario analysis with respect to adequacy and reasonableness of the weather-planning standard and the natural gas price forecast. This analytical perspective provides confidence in the conclusions and stress tests the robustness of the selected portfolio of resources, thereby mitigating analytical risks.

Regulatory Requirements

IRP regulatory requirements in Idaho, Oregon and Washington call for several key components. The completed plan must demonstrate that the IRP:

- Examines a range of demand forecasts.

- Examines feasible means of meeting demand with both supply-side and demand-side resources.
- Treats supply-side and demand-side resources equally.
- Describes the long-term plan for meeting expected demand growth.
- Describes the plan for resource acquisitions between planning cycles.
- Takes planning uncertainties into consideration.
- Involves the public in the planning process.

Avista addressed the applicable requirements throughout this document. Appendix 1.2 – IRP Guideline Compliance Summaries lists the specific requirements and guidelines of each jurisdiction and describes Avista's compliance.

The IRP is also required to consider risks and uncertainties throughout the planning and analytical processes. Avista's approach in addressing this requirement was to identify factors that could cause significant deviation from the Expected Case planning conclusions. This included dynamic demand analytical methods and sensitivity analysis on demand drivers that impacted demand forecast assumptions. From this, Avista created 16 demand sensitivities and modeled five demand scenario alternatives, which incorporated different customer growth, use-per-customer, weather, and price elasticity assumptions.

Avista analyzed peak day weather planning standard, performing sensitivity on HDDs and modeling an alternate weather-planning standard using the coldest day in 20 years. Stochastic analysis using Monte Carlo simulations in SENDOUT® supplemented this analysis. Avista also used simulations from SENDOUT® to analyze price uncertainty and the effect on total portfolio cost.

Avista examined risk factors and uncertainties that could affect expectations and assumptions with respect to DSM programs and supply-side scenarios. From this, Avista assessed the expected available supply-side resources and potential conservation savings for evaluation.

The investigation, identification, and assessment of risks and uncertainties in our IRP process should reasonably mitigate surprise outcomes.

Conclusion

The Expected Case has the lowest cost and risk when considering alternate supply resources. This is primarily due to Avista's geographic location, the longstanding subscription to these pipeline services as well as the supply basins/storage facilities available to secure supply. Avista has geographically disparate areas where in many cases only one pipeline is available to deliver supply. 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 Case demand analyses provide a range for evaluating demand trajectories relative to the Expected Case. Based on this analysis there appears to be sufficient time to plan for forecasted resource needs. Even under an extreme growth scenario, the first forecasted deficiency does not occur until 2027. Many things could happen between now and when the first resource needs occur, so Avista will carefully monitor (Chapter 8 – Action Plan) demand trends through reconciling and comparing forecast to actual customer counts and continually update and evaluate all demand-side and supply-side alternatives.

7: Distribution Planning

Overview

Avista's IRP evaluates the 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 Avista's city gates become secondary issues if distribution system growth behind the city gates increases faster than expected and the system becomes severely constrained. Important parts of the distribution planning process include forecasting local demand growth, determining potential distribution system constraints, analyzing possible solutions and estimating costs for eliminating constraints.

Analyzing resource needs to this point has focused on ensuring adequate capacity to the city gates, especially during a peak event. Distribution planning focuses on determining if there will be adequate pressure during a peak hour. Despite this altered perspective, distribution planning shares many of the same goals, objectives, risks and solutions as integrated resource planning.

Avista's natural gas distribution system consists of approximately 3,300 miles of distribution main and services pipelines in Idaho, 3,700 miles in Oregon and 5,800 miles in Washington; as well as numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment. Currently, there are no storage facilities or compression systems within Avista's distribution system. Distribution network pipelines and regulating stations operate and maintain system pressure solely from the pressure provided by the interstate transportation pipelines.

Distribution System Planning

Avista conducts two primary types of evaluations in its distribution system planning efforts: capacity requirements and integrity assessments.

Capacity requirements include 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.

Ongoing evaluations of each distribution network in the four primary service territories identify strategies for addressing local distribution requirements resulting from customer growth. Customer growth assessments are made based on factors including IRP demand forecasts, monitoring gate station flows and other system metering, new service requests, field personnel discussion, and inquiries from major developers.

Avista regularly conducts integrity assessments of its distribution systems. Ongoing system evaluation can also indicate distribution-upgrading requirements for system maintenance needs rather than customer and load growth. In some cases, the timing for system integrity upgrades coincides with growth-related expansion requirements.

These planning efforts provide a long-term planning and strategy outlook and integrate into the capital planning and budgeting process, which incorporates planning for other types of distribution capital expenditures and infrastructure upgrades.

Gas Engineering planning models are also compared with capacity limitations at each city gate station. Referred to as city gate analysis, the design day hourly demand generated from planning analyses must not exceed the actual physical limitation of the city gate station. A capacity deficiency found at a city gate station establishes a potential rebuild or addition of a new city gate station.

Network Design Fundamentals

Natural gas distribution networks rely on pressure differentials to flow natural gas from one place to another. When pressures are the same on both ends of a pipe, the natural gas does not move. As natural gas exits the pipeline network, it causes a pressure drop due to its movement and friction. As customer demand increases, pressure losses increase, reducing the pressure differential across the pipeline network. If the pressure differential is too small, flow stalls and the network could run out of pressure.

It is important to design a distribution network such that intake pressure from gate stations and/or regulator stations within the network is high enough to maintain an adequate pressure differential when natural gas leaves the network.

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.

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. Using a pipeline fluid flow formula, a specified parameter for each pipe element can be simultaneously solved. Many pipeline equations exist, each tailored to a specific flow behavior. Through years of research, these equations have been refined to the point where modeling solutions closely resemble actual system behavior.

Avista conducts network load studies using GL Noble Denton's Synergi software. This modeling tool allows users to analyze and interpret solutions graphically.

Determining Peak Demand

Avista's distribution network is comprised of high pressure (90-500 psig) and intermediate pressure (5-60 psig) mains. Avista operates its intermediate networks at a relatively low maximum pressure of 60 psig or less for ease of maintenance and operation, public safety, reliable service and cost considerations. Since most distribution systems operate through relatively small diameter pipes, there is essentially no line-pack capability for managing hourly demand fluctuations. Line pack is the difference between the natural gas contents of the pipeline under packed (fully pressurized) and unpacked (depressurized) conditions. Line pack is negligible in Avista's distribution system due to the smaller diameter pipes and lower pressures. In transmission and inter-state pipelines, line-pack contributes to the overall capacity due to the larger diameter pipes and higher operating pressures.

Core demand typically has a morning peaking period between 6 a.m. and 10 a.m. and the peak hour demand for these customers can be as much as 50 percent above the hourly average of daily demand. Because of the importance of responding to hourly peaking in the distribution system, planning capacity requirements for distribution systems uses peak hour demand.[1]

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

[1] This method differs from the approach that Avista uses for IRP peak demand planning, which focuses on peak day requirements to the city gate.

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 paved surfaces, 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.

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 city gate stations, district regulator stations, farm taps and customer services.

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 natural 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 compressor station, along with engineering and construction time can be a significant deterrent. Adding compressor stations typically involves considerable capital expenditure. Based on Avista's detailed knowledge of the distribution system, there are no foreseeable plans to add compressors to the distribution network.

Conservation Resources

The evaluation of distribution system constraints includes consideration of targeted conservation resources to reduce or delay distribution system enhancements. The consumer is still the ultimate decision-maker regarding the purchase of a conservation measure. Because of this, Avista attempts to influence conservation through the DSM measures discussed in Chapter 3 – Demand-Side Resources, but does not depend on estimates of peak day demand reductions from conservation to eliminate near-term distribution system constraints. Over the longer-term, targeted conservation programs may provide a cumulative benefit that could offset potential constraint areas and 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.

Avista's design HDD for distribution system modeling is determined using the coldest day on record for each given service area. This practice is consistent with the peak day demand forecast utilized in other sections of Avista's natural gas IRP.

Utilizing a peak planning standard of the coldest temperature on record may seem aggressive given a temperature experienced rarely, or only once. Given the potential impacts of an extreme weather event on customers' personal safety and property damage to customer appliances and Avista's infrastructure, it is a prudent regionally accepted planning standard.

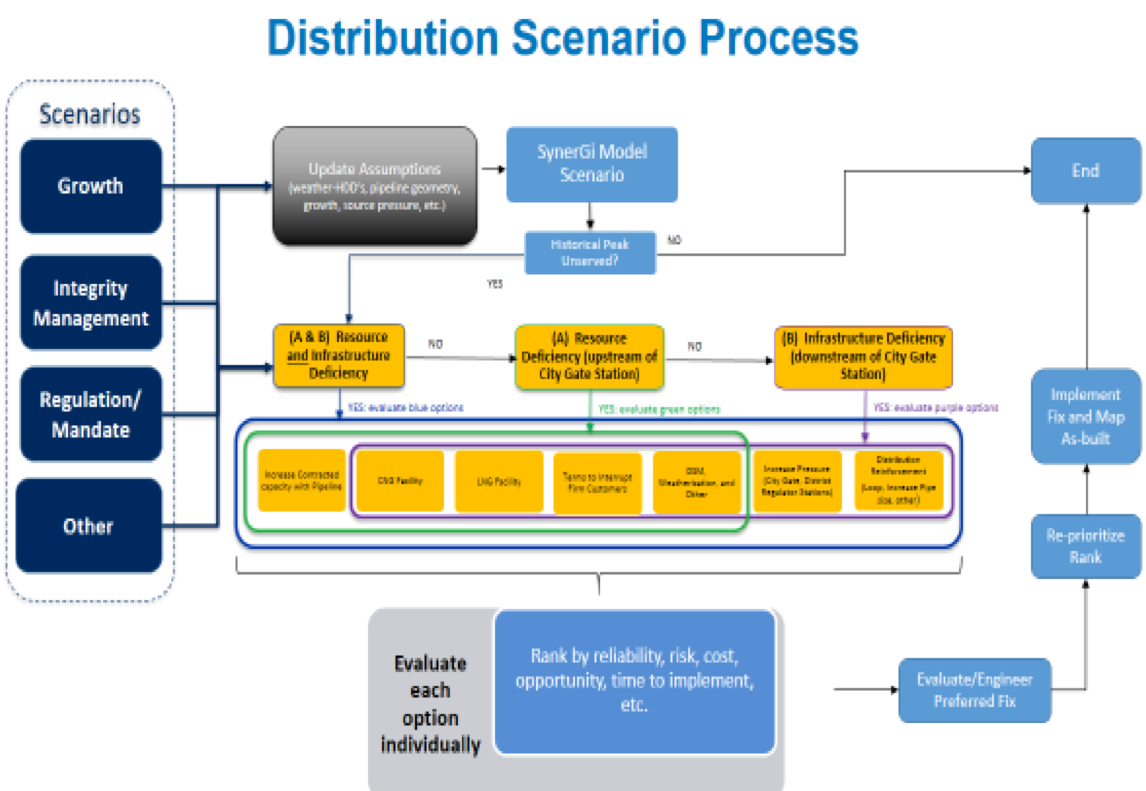
These areas of concern are then risk ranked against each other to ensure the highest risk areas are corrected first. Within a given area, projects/reinforcements are selected using the following criteria:

- 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 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 7.1 provides a schematic representation of the distribution scenario process.

Figure 7.1 Distribution Scenario Process



An example of the distribution scenario decision making process is from the Medford high pressure loop reinforcement where the analysis resulted in multiple paths or pipeline routes. The initial path was based on quantitative factors, specifically the shortest length and least cost route. However, as field investigations and coordination with local city and county governments began, alternative routes had to be determined to minimize future conflicts, environmental considerations, and field and community disruptions. The final path was based on several qualitative factors that including:

- Available right-of-way along city streets
- Availability of private easements from property owners
- Restrictions due to City of Medford future planned growth with limited planning information; and
- Potential to avoid conflict with other utilities including a large electric substation along the initial route.

Planning Results

Table 7.1 summarizes the cost and timing, as of the publication date of this IRP, of major distribution system enhancements addressing growth-related system constraints, system integrity issues and the timing of expenditures.

The Distribution Planning Capital Projects criteria includes:

- Prioritized need for system reliability (necessary to maintain reliable service)
- Scale of project (large in magnitude and will require significant engineering and design support); and
- Budget approval (will require approval for capital funding)

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 and timing of planned completion may change based on the aforementioned ongoing reassessment of information.

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

La Grande High Pressure Reinforcement: This project will reinforce the La Grande and Elgin high pressure distribution system and is fed from the Ladd Canyon Gate Station which will displace flow and remove the capacity constraint at the La Grande Gate station. Currently, the distribution system cannot maintain adequate pressures at Elgin during cold winter conditions. Approximately 16,900 feet of high pressure (HP) steel gas main will be installed beginning in 2017. This reinforcement will ensure that the physical limitation at the La Grande city gate is not exceeded.

North Spokane Reinforcement: This project will reinforce the area north of Spokane along U.S. Highway 2. This mixed-use area experiences low pressure during winter at unpredictable times given demand profiles of the diverse customer base. Completion of this reinforcement will improve pressures in the U.S. Highway 2 North Kaiser area. Approximately 10,800 feet of HP steel gas main will be installed in a newly established easement along U.S. Highway 2. Phase 2 includes approximately 12,400 feet of HP steel gas main will be installed along the electric transmission easement to improve pressures on the western end of North Spokane. This project also includes two district regulator stations. Timing is yet to be determined on Phase 2.

Coeur d'Alene High Pressure Reinforcement: This project will reinforce the Coeur d'Alene distribution system as well as greatly improve the Hayden Lake distribution system, which currently cannot maintain adequate pressure during cold winter conditions. Approximately 17,200 feet of HP steel gas main and two district regulator stations will be designed in 2016 with construction in 2017 and 2018.

Table 7.1 Distribution Planning Capital Projects

Location	2016	2017	2018
La Grande High Pressure Reinforcement		$3,500,000	
North Spokane Reinforcement	$2,000,000		
Coeur d'Alene High Pressure Reinforcement	$250,000	$4,000,000	$4,000,000
Schweitzer Mountain Rd High Pressure Reinforcement			$1,500,000

*Details of project described in IRP as of August 2016

Table 7.2 shows city gate stations identified as over utilized or under capacity. Estimated cost, year and the plan to remediate the capacity concern are shown.

These projects are preliminary estimates of timing and costs of city gate station upgrades. The scope and needs of each project 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.

In addition to improving the Coeur d'Alene distribution system, the Coeur d'Alene High Pressure Reinforcement mentioned above will redirect the flow of gas away from the capacity constrained city gate stations: CDA East, Post Falls, and CDA West.

To maintain minimum design pressures to serve Elgin on a design day, two projects were required: rebuild the Union City Gate Station in La Grande to increase the physical capacity (completed in December 2015), and the La Grande High Pressure Reinforcement to minimize pressure drop across the distribution system (scheduled for completion in 2017).

The remaining city gate station projects in Table 7.2 have relatively small capacity constraints, and thus will be periodically reevaluated to determine if upgrades need to be accelerated or deferred. Under currently planning considerations, these projects will be tentatively scheduled for 2019 or later.

Table 7.2 City Gate Station Upgrades

Location	Gate Station	Project to Remediate	Cost	Year
CDA (East), ID	CDA East #221	Coeur d'Alene High Pressure Reinforcement	$10M	2016-17
La Grande, OR	La Grande #815	Union HP Connector	$3M	2017
Athol, ID	Athol #219	TBD	-	2019+
Bonners Ferry, ID	Bonners Ferry #208	TBD	-	2019+
Colton, WA	Colton #316	TBD	-	2019+
Genesee, ID	Genesee #320	TBD	-	2019+
Klamath Falls, OR	Klamath Falls #2703	TBD	-	2019+
Mica, WA	Mica #15	TBD	-	2019+
Pullman, WA	Pullman #350	TBD	-	2019+
Sprague, WA	Sprague #117	TBD	-	2019+
Sutherlin, OR	Sutherlin #2626	TBD	-	2019+

*Details of project described in IRP as of August 2016

CONCLUSION

Avista'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 patterns.

8: Action Plan

The purpose of an action plan is to position Avista to provide the best cost/risk resource portfolio and to support and improve IRP planning. The Action Plan identifies needed supply and demand side resources and highlights key analytical needs in the near term. It also highlights essential ongoing planning initiatives and natural gas industry trends Avista will monitor as a part of its planning processes.

2015-2016 Action Plan Review

Action Item
Avista will continue to optimize underutilized resources to recover value for customers and reduce their costs until resources are required to meet changing demand needs.

Results
Avista optimizes underutilized resources to recover value for customers and reduce their costs until these resources are required to meet demand needs. A new storage optimization program has been developed to help recover costs at our Jackson Prairie facility. This program uses the storage field's intrinsic value to sell natural gas when prices are higher, to sell on a cash to forward basis, or other market opportunities, all while maintaining deliverability on a peak day. Avista sells into the daily market for transport optimization. An example of this optimization is based on the cost difference, or spread, between the AECO and Malin basins and is almost always economic. Avista will sell into this market based on the remaining unused transportation in our portfolio.

Action Item
Avista will comply with Commission findings to try to increase the cost effectiveness of DSM measures by reducing administration and audit costs, analyzing non-natural gas benefits and increasing measure lives. Avista will monitor natural gas prices as a signpost for increasing avoided costs. If avoided costs increase, Avista will reevaluate DSM programs for cost effectiveness and submit to resume natural gas DSM programs.

Results
Avista continues to build on its history of collaboration with all stakeholders in delivering meaningful cost-effective conservation measures as a way to reduce their energy bills and promote a cleaner environment. The company considered several approaches to improve the amount of cost-effective natural gas DSM measures offered to our customers

since the 2014 IRP. During 2015, the Avista DSM group began to look at the current composition and components of natural gas avoided costs and compare them with other regional and national utilities. The research and proposed additions to Avista's avoided cost were presented to Avista's DSM Advisory Group for feedback on August 19 and 20, 2015 to ensure these were appropriate changes and to seek advice about other avoided cost component analyses the company should perform. The company also changed how non-incentive utility costs (NIUC) were being distributed to the overall DSM portfolio from the ratio of BTUs to ratio of benefits. This helped balance the cost effectiveness between electric and natural gas measures and programs. After the reevaluation of Avista's avoided cost methodology, change in distribution of NIUC, and with an Idaho Commission ruling that allows companies to emphasize the UTC when seeking prudence for their DSM programs, Avista filed for and was approved to reinstate its Idaho Natural Gas DSM programs as of January 1, 2016.

Action Item

Complete the gate station analysis to assess resource deficiencies masked by aggregated IRP analysis. Any identified deficiencies and potential solutions will be discussed with Commission Staff. Avista will continue to coordinate analytic efforts between Gas Supply, Gas Engineering and the intrastate pipelines to perform gate station analysis and develop least cost solutions should deficiencies exist.

Results

Avista has completed the gate station analysis and communicated the results to TAC members during the third TAC meeting in the Distribution section. The data set was a static set from 2014 so some of the gate station shortages have already received some mitigation fixes. The area of La Grande is one example, where the Ladd Canyon gate station was completed in December 2015 to help offset the flow at the La Grande city gate. Also, a high pressure reinforcement project will begin in 2017 to help ensure a physical limitation at this city gate is not exceeded. As for the remaining city gate deficiencies, the potential fixes will be reviewed between Avista's Gas Supply and Distribution Engineering departments. This review and potential fixes will be addressed in regular meetings between Avista and all three commissions as addressed in the ongoing activities section below.

Action Item

As part of its next IRP process, Avista must convene workshops with Staff and stakeholders to explore how best to model major resource acquisitions and major capital investments.

Results

Avista reviewed current resources in the second Technical Advisory Committee (TAC) meeting and distribution projects in the third TAC meeting. A shortage in the High Growth and Low Price case was our only case where any demand was unserved. Avista presented to the TAC members a list of resources modeled as well as the chosen resources to best solve the unserved demand. In future IRP processes, Avista will review its assumptions with the TAC members via open dialogue as well as how best to model these potential resources.

Action Item

For the next IRP, Avista must work with Staff and stakeholders to resolve forecasting methodology concerns, and seek to identify the most reliable methodology so that future resource needs may be clearly identified.

Results

Avista provided a Sendout overview following the third TAC meeting on March 30, 2016 to interested TAC members. This overview helped provide a level set on the types of inputs within the model and a general understanding on how the model works. Avista also worked directly with Oregon Staff to produce a more accurate forecasting methodology diagram. This diagram can be viewed in figure 2.5. In addition to this review, Avista added analysis around modeling alternative resources to test the least cost and least risk portion of the Expected Case Portfolio. As described in Chapter 6, Avista modeled three alternative resources and compared PVRR to determine whether a new resource stack may be appropriate. These actions have resolved forecasting methodology concerns.

Action Item
In its next IRP, Avista must include a clear presentation of how Avista decides which distribution system projects to include in the IRP, and a clear description of the included projects, along with a justification for recommending or proceeding with the projects.

Results
Avista has provided a description of distribution system projects and the most current knowledge and analysis supporting the timeframe for completing each project. Also included is an example to help describe the qualitative versus quantitative analysis for each distribution project and the new decision process flow (Figure 7.1 – Distribution Scenario Process).

Action Item
As part of its next IRP process, Avista must convene discussions with Staff and stakeholders to discuss potential impacts associated with: (1) new regulations to reduce methane emissions; and (2) potential increases in natural gas prices stemming from increased demand for natural gas for generation under Section 111 (d) of the Clean Air Act.

Results
During the second TAC meeting the company reviewed regulations affecting the natural gas industry at a state or federal level along with an overview of each rule. Avista presented its carbon pricing and methodology in the third TAC meeting. Avista will continue to monitor impacts associated with potential methane emissions and the effects these regulations may have on Avista's jurisdictions.

Action Item

In Order No. 13-159, the Oregon Commission documented several demand side actions. These actions included filing specific DSM targets with achievable savings and costs by measure and program for the next two to four years, noting any exceptions by measure, and participate in NEEA's natural gas market transformation program and include the achievable savings in the 2016 IRP.

Results

Order No. 13-159 directed Avista to continue DSM programs in Oregon and to achieve at least 225,000 therms in 2013 and 250,000 therms in 2014. In addition, the company needed to provide the following results by April 30, 2015:

- DSM program savings and cost effectiveness;
- Actions to reduce delivery costs, including administration and audit;
- Activities taken to increase the amount of cost effective efficiency measures;
- Analysis of non-natural gas benefits of existing and proposed DSM measures; and
- Analysis of measure lives for all DSM measures.

In addition Avista was directed to do the following:

- Develop a potential mechanism for funding a low-income energy efficiency program and report the mechanism to Staff.
- Determine the possibility of a regional elasticity study through the NWGA or the AGA.
- Evaluate potential demand from NGV/CNG vehicles and other new uses of natural gas.

As described in the 2014 IRP and 2014 IRP update, Avista met the actions in the following manner:

- Avista continued the DSM program in Oregon in 2013 and 2014 and achieved 217,177 therms in 2013 and 192,955 therms in 2014.
- The Commission approved the Company's DSM targets and exceptions on September 22, 2015 in Commission Order No. 15-288 in LC 61. Subsequently, Avista agreed to transition its DSM program to the Energy Trust of Oregon (ETO). In a settlement approved on February 29, 2016 via Order No. 16-076. Avista will transition to the ETO in 2016 with a final transition on January 1, 2017.
- Avista took steps to increase the cost effectiveness of the DSM program. Specifically, measure lives were extended, certain tariff changes were implemented to reduce administration costs, audit costs were separated from other program costs, a new software program is being implemented for calculating savings, and a separate low-income energy efficiency program was created.
- Avista worked with Staff and other stakeholders to develop a low-income energy efficiency program and submitted a report to Staff outlining a proposed mechanism on October 30, 2013. The company filed tariffs to implement the Avista Oregon Low-Income Energy Efficiency (AOLIEE) Program on January 8, 2014 and the tariffs were approved and the AOLIEE Program started on March 1, 2014.
- Price elasticity predicts that energy consumers reduce consumption as prices rise, but the amount of a response is debatable. Avista has reviewed research on price elasticity for natural gas. The analysis shows a wide range of results from statistically significant to statistically insignificant and even positive in some cases. Avista contacted the AGA and they are willing to facilitate a process if a regional price elasticity study moves forward. Avista is assessing the costs and

benefits of such an undertaking. A regional natural gas price elasticity study will commence if enough interest develops in the project.

- In our assessment of potential demand impact due to NGV/CNG vehicles, modeling results show a direct sensitivity to NGV/CNG vehicles. This results in an increase of 9 MDTh on a February 20th peak day compared to the reference case. In the Exported LNG case, price elasticity sensitivity shows a decrease in usage in direct response to higher pricing. The analysis timeframe is over the IRP's 20-year horizon with no shortages on a peak day in either case.
- Avista is participating in NEEA's natural gas market transformation initiative. Details about the status of the initiative are in Chapter 3 – Demand Side Resources.

2017-2018 Action Plan

Avista's 2017-2018 Action Plan outlines activities for study, development and preparation for the 2018 IRP.

New Activities for the 2018 IRP

- The price of natural gas has dropped significantly since the 2014 IRP. This is primarily due to the amount of economically extractable natural gas in shale formations, more efficient drilling techniques, and warmer than normal weather. Wells have been drilled, but left uncompleted due to the poor market economics. This is depressing natural gas prices and forcing many oil and natural gas companies into bankruptcy. Due to historically low prices Avista will research market opportunities including procuring a derivative based contract, 10-year forward strip, and natural gas reserves.
- Avista's 2018 IRP will contain a dynamic DSM program structure in its analytics. In prior IRP's, it was a deterministic method based on Expected Case assumptions. In the 2018 IRP, each portfolio will have the ability to select conservation to meet unserved customer demand. Avista will explore methods to enable a dynamic analytical process for the evaluation of conservation potential within individual portfolios.
- Monitor actual demand for accelerated growth to address resource deficiencies arising from exposure to "flat demand" risk. This will include providing Commission Staff with IRP demand forecast-to-actual variance analysis on customer growth and use-per-customer at least bi-annually.

Ongoing Activities

- Continue to monitor supply resource trends including the availability and price of natural gas to the region, LNG exports, methanol plants, supply and market dynamics and pipeline and storage infrastructure availability.
- Monitor availability of resource options and assess new resource lead-time requirements relative to resource need to preserve flexibility.
- Meet regularly with Commission Staff to provide information on market activities and significant changes in assumptions and/or status of Avista activities related to the IRP or natural gas procurement practices.
- Appropriate management of existing resources including optimizing underutilized resources to help reduce costs to customers.

9: Glossary of Terms and Acronyms

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.

AGA
American Gas Association

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.

Average Case
Represents Avista's demand forecast for normal planning purposes. This case uses a 20 year rolling average NOAA weather for the five major areas (Spokane, WA., Medford, OR. Klamath Falls, OR, Roseburg, OR. La Grande, OR.).

Avista
The regulated Operating Division of Avista Corp.; separated into north (Washington and Idaho) and south (Oregon) regions. Avista Utilities generates, transmits and distributes electricity, in addition to the transmission and distribution of natural gas.

Backhaul
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.

Basis Differential
The difference in price between any two natural gas pricing points or time periods. One of the more common references to basis differential is the pricing difference between Henry Hub and any other pricing point in the continent.

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.

Capacity
The sum amount of natural gas transportation contracts or storage available in Avista's current portfolio.

CD
Contract Demand

C&I
Commercial and Industrial

City Gate (also known as gate station or pipeline delivery point)
The point at which natural gas deliveries transfer from the interstate pipelines to Avista's distribution system.

CNG
Compressed Natural Gas

Compression
Increasing the pressure of natural gas in a pipeline by means of a mechanically-driven compressor station to increase flow capacity.

Conservation Measures
Installations of appliances, products or facility upgrades that result in energy savings.

Contract Demand (CD)
The maximum daily, monthly, seasonal or annual quantities of natural gas, which the supplier agrees to furnish, or the pipeline agrees to transport, and for which the buyer or shipper agrees to pay a demand charge.

Core Load
Firm delivery requirements of Avista, which are comprised of residential, commercial and firm industrial customers.

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.

CPA
Conservation Potential Assessment

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

Cubic Foot (cf)
A measure of natural gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor; one cubic foot of natural gas has the energy value of approximately 1,000 BTUs and 100 cubic feet of natural gas equates to one therm (see below).

Curtailment
A restriction or interruption of natural gas supplies or deliveries; may be caused by production shortages, pipeline capacity or operational constraints or a combination of operational factors.

Dekatherm (Dth)
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).

EIA
Energy Information Administration

Expected Case
The most likely scenario for peak day planning purposes. This case uses a 20 year rolling average NOAA weather for the five major areas (Spokane, WA., Medford, OR. Klamath Falls, OR, Roseburg, OR. La Grande, OR.). Combined with this 20 year rolling average weather is the coldest day on record.

External Energy Efficiency Board
Also known as the "Triple-E" board, this non-binding external oversight group was established in 1999 to provide Avista with input on DSM issues.

Externalities
Costs and benefits borne by a third party 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 Avista does business and determines rates charged in interstate transactions.

FERC
Federal Energy Regulatory Commission

Firm Service
Service offered to customers under schedules or contracts that anticipate no interruptions; the highest quality of service offered to customers.

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.

Forward Haul
A transaction where gas is transported the normal direction of normal flow on a unidirectional pipeline.

Forward Market
An over-the-counter marketplace that sets the price of a financial instrument or physical asset for future delivery.

Forward Price
The future price for a quantity of natural gas to be delivered at a specified time.

Gas Transmission Northwest (GTN)
A subsidiary of TransCanada Pipeline which owns and operates a natural gas pipeline that runs from the Canada/USA border to the Oregon/California border. One of the six natural gas pipelines Avista transacts with directly.

Gross Domestic Product (GDP)
The monetary value of all the finished goods and services produced within a country's borders in a specific time period.

Geographic Information System (GIS)
A system of computer software, hardware and spatially referenced data that allows information to be modeled and analyzed geographically.

GHG
Greenhouse Gas

Global Insight, Inc.
A national economic forecasting company.

GTN
Gas Transmission Northwest

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 65 degrees Fahrenheit; a daily average temperature represents the sum of the high and low readings divided by two.

Henry Hub
The physical location in Louisiana that is widely recognized as the most important natural gas pricing point in the U.S., as well as the trading hub for the New York Mercantile Exchange (NYMEX).

HP
High Pressure

Injection
The process of putting natural gas into a storage facility; also called liquefaction when the storage facility is a liquefied natural gas plant.

Integrity Management Plan
A federally regulated program that requires companies to evaluate the integrity of their natural gas pipelines based on population density. The program requires companies to identify high consequence areas, assess the risk of a pipeline failure in the identified areas and provide appropriate mitigation measures when necessary.

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.

IPUC
Idaho Public Utilities Commission

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

Jackson Prairie
An underground natural gas storage project jointly owned by Avista Corp., Puget Sound Energy and NWP. The project is a naturally occurring aquifer near Chehalis, Wash., which is located about 1,800 feet beneath the surface and capped with a thick layer of dense shale.

Liquefaction
Any process converting natural gas from the gaseous to the liquid state. For natural gas, this process is accomplished through lowering the temperature of the natural gas (see LNG).

Liquefied Natural Gas (LNG)
Natural gas 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.

Load Duration Curve
An array of daily send outs observed, sorted from highest send out day to lowest to demonstrate peak requirements and the number of days it persists.

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.

Local Distribution Company (LDC)
A utility that purchases natural gas for resale to end-use customers and/or delivers customer's natural gas or electricity to end users' facilities.

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.

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

MDDO
Maximum Daily Delivery Obligation

MDQ
Maximum Daily Quantity

MMbtu
A unit of heat equal to one million British thermal units (BTUs) or 10 therms. Used interchangeably with Dth.

National Energy Board
The Canadian equivalent to the Federal Energy Regulatory Commission (FERC).

National Oceanic Atmospheric Administration (NOAA)
Publishes the latest weather data; the 30-year weather study included in this IRP is based on this information.

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.

Natural Gas Reserves
Proven volumes of natural gas found in geological formations. These formations include both drilled wells, wells with a remaining volume and have already been drilled, and undrilled wells.

New York Mercantile Exchange (NYMEX)
An organization that facilitates the trading of several commodities, including natural gas.

NGV
Natural Gas Vehicles

NOAA
National Oceanic and Atmospheric Administration

Nominal
Discounting method that includes inflation.

Nomination
The scheduling of daily natural gas requirements.

Non-Coincidental Peak Demand
The demand forecast for a 24-hour period for multiple regions that includes at least one peak day and one non-peak day.

Non-Firm Open Market Supplies
Natural gas purchased via short-term purchase arrangements. May supplement firm contracts during times of high demand or to displace other volumes when cost-effective. Also referred to as spot market supplies.

Northwest Pipeline Corporation (NWP)
A principal interstate pipeline serving the Pacific Northwest and one of six natural gas pipelines Avista transacts with directly. NWP is a subsidiary of The Williams Companies, headquartered in Salt Lake City, Utah.

NOVA Gas Transmission (NOVA)
See TransCanada Alberta System

Northwest Power and Conservation Council (NPCC)
A regional energy planning and analysis organization headquartered in Portland, Ore.

NPCC
Northwest Power and Conservation Council

NWP
Williams-Northwest Pipeline

NYMEX
New York Mercantile Exchange

OPUC
Oregon Public Utility Commission

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 Curtailment
Curtailment imposed on a day-to-day basis during periods of extremely cold weather when demands for natural gas exceed the maximum daily delivery capability of a pipeline system.

Peaking Capacity
The capability of facilities or equipment normally used to supply incremental natural gas under extreme demand conditions (i.e. peaks); generally available for a limited number of days at this maximum rate.

Peaking Factor
A ratio of the peak hourly flow and the total daily flow at the city-gate stations used to convert daily loads to hourly loads.

Prescriptive Measures
Avista's DSM tariffs require the application of a formula to determine customer incentives for natural gas-efficiency projects. For commonly encountered efficiency applications that are relatively uniform in their characteristics, the utility has the option to define a standardized incentive based upon the typical application of the efficiency measure. This standardized incentive takes the place of a customized calculation for each individual customer. This streamlining reduces both the utility and customer administrative costs of program participation and enhances the marketability of the program.

Psig
Pounds per square inch gauge – a measure of the pressure at which natural gas is delivered.

PVRR
Present Value Revenue Requirement

Rate Base
The investment value established by a regulatory authority upon which a utility is permitted to earn a specified rate of return; generally this represents the amount of property used and useful in service to the public.

Real
Discounting method that excludes inflation.

Resource Stack
Sources of natural gas infrastructure or supply available to serve Avista's customers.

Seasonal Capacity
Natural gas transportation capacity designed to service in the winter months.

Sendout
The amount of natural gas consumed on any given day.

SENDOUT®
Natural gas planning system from Ventyx; a linear programming model used to solve gas supply and transportation optimization questions.

Service Area
Territory in which a utility system is required or has the right to provide natural gas service to ultimate customers.

Shoulder Months

Months leading into or out of the winter heating season.

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.

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.

Summer

Months including April, May, June, July, August, September and October where heating demand is typically much lower than Winter.

TAC
Technical Advisory Committee

Tariff
A published volume of regulated rate schedules, plus general terms and conditions under which a product or service will be supplied.

TF-I
NWP's rate schedule under which Avista moves natural gas supplies on a firm basis.

TF-2
NWP's rate schedule under which Avista moves natural gas supplies out of storage projects on a firm basis.

Technical Advisory Committee (TAC)
Industry, customer and regulatory representatives that advise Avista during the IRP planning process.

Technical Potential
An estimate of all energy savings that could theoretically be accomplished if every customer who 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.

Town Code
A town code is an unincorporated area within a county and a municipality within a county served by Avista natural gas retail services.

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 Avista 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 Avista 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

Triple E
External Energy Efficiency Board

Tuscarora Gas Transmission Company
Tuscarora is a subsidiary of Sierra Pacific Resources and TransCanada; this natural gas pipeline runs from the Oregon/California border to Reno, Nev.; one of the six natural gas pipelines Avista transacts with directly.

Vaporization
Any process in which natural gas is converted from the liquid to the gaseous state.

WCSB
Western Canadian Sedimentary Basin

Weighted Average Cost of Gas (WACOG)
The price paid for a volume of natural gas and associated transportation based on the prices of individual volumes of natural gas that make up the total quantity supplied over an established time period.

Weather Normalization
The estimation of the average annual temperature in a typical or "normal" year based on examination of historical weather data; the normal year temperature is used to forecast utility sales revenue under a procedure called sales normalization.

Weather Sensitive Measures
Conservation measures whose energy savings are influenced by weather temperature changes. Weather sensitive measures are also often referred to as winter measures.

Winter

Months including November, December, January, February and March where heating demand is at its highest point.

Winter Measures
Conservation measures whose energy savings are influenced by weather temperature changes. Winter measures are also often referred to as weather sensitive measures.

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