AVISTA 2014 NATURAL GAS IRP

DRAFT

Distributed to TAC May 30, 2014

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Note: Appendices provided under separate cover.

SAFE HARBOR STATEMENT

This document contains forward-looking statements, including statements regarding our current expectations for future financial performance and cash flows, capital expenditures, financing plans, our current plans or objectives for future operations and other factors, which may affect the company in the future. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond our control and many of which could have significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

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, which are available on our website at www.avistacorp.com. The forward-looking statements contained in this document speak only as of the date hereof. We undertake 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 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 our 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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2014 IRP KEY MESSAGES

- Avista has a diversified portfolio of existing natural gas supply resources including owned and contracted storage, firm capacity rights on six pipelines and purchase contracts from several different supply basins. Our philosophy is to reliably provide natural gas to customers with an appropriate balance of price stability and prudent cost.
- Avista's 2014 Integrated Resource Plan (IRP) forecasts lower demand for all service territories than our previous plans. These reductions are driven by lower growth rates and declining use-per-customer in our service territories than originally anticipated driven primarily by the decade long recession.
- There are no resource needs in the Expected Case. Demand growth averages less than 1.0 percent per year in the respective jurisdictions. Customer accounts are expected to grow at an annual average rate of approximately 1.0 percent across the system.
- An important risk is the relatively flat slope of forecasted demand growth. Should demand growth accelerate, the steepening of the demand curve could quickly accelerate resource shortages by several years.
- Other risks evaluated include long term natural gas pricing levels, potential impacts of carbon legislation, price implication of exporting LNG, alternate weather planning standard, and potential increased use of natural gas by emerging markets..
- Conservation potential is an integral component of our IRP process and a starting point for the DSM business planning process, as these programs result in multiple benefits including reduced customers' bills, reduced supply-side resource needs and reduced greenhouse gas (GHG) emissions. We continue to pursue cost-effective natural gas demand side management programs.
- Management of underutilized supply side resources in order to recover value for customers is essential. Avista chooses to have an active, hands-on management of these resources to mitigate upstream pipeline and commodity costs for our customers when the capacity is not being utilized for system load requirements.
- The IRP identifies and establishes an Action Plan that continues to guide us toward the risk-adjusted, least-cost method of providing service to our natural gas customers. Included in this Action Plan are efforts to closely monitor avoided costs and the cost effectiveness of natural gas DSM, finalizing a decision on proceeding with current regional price elasticity study, and completion of gate station analysis.

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CHAPTER 1 ■ EXECUTIVE SUMMARY

Avista's 2014 Natural Gas Integrated Resource Plan (IRP) identifies a strategic natural gas resource portfolio that meets future customer demand requirements over the next 20 years. While the primary focus of the IRP is ensuring our ability to meet customer's 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 Commissions 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. This group is a vital component of our IRP process, as it provides a forum for the exchange of ideas from multiple perspectives, identifies issues and risks and improves analytical methods. Topics discussed with the TAC include natural gas demand forecasts, demand-side management (DSM), supply-side resources, computer modeling tools and distribution planning. The end result is an integrated resource portfolio designed to serve our customers' natural gas needs well into the future while balancing cost and risk.

Our collaborative planning process results in a resource portfolio that meets customer's long-term needs considering cost and risk.

PLANNING ENVIRONMENT

A long- term resource plan must consider and address the many uncertainties inherent in any planning exercise. Compared to prior planning cycles, there is more certainty about the availability of natural gas and that much of it can be extracted at favorable prices for consumers. However, how this plentiful and economic resource will be used is an unknown. Will an industrial renaissance emerge? How much LNG will be exported and from where? What is the market for natural gas vehicles? How much will be needed for power generation? We continue to challenge key assumptions and evaluate multiple scenarios to cover a broad range of possible outcomes to address the uncertainty.

DEMAND FORECASTS

We define eight distinct demand areas, which are structured around the pipeline transportation and storage resources that serve them. Our demand areas are aggregated into four large 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 is disaggregated into areas that can be served only by Northwest Pipeline (NWP), only by Gas Transmission Northwest (GTN) and by both pipelines. The Medford service territory is also disaggregated into an area that can only be served by NWP and GTN.

Avista's approach to demand forecasting focuses on customer growth and use-per-customer as the base components of demand. We recognize and have accounted for weather as the most significant direct demand-influencing factor. We also study other factors that can influence demand, including population, employment trends, age and income demographics, construction trends, conservation technology, new uses development (e.g. natural gas vehicles) and use-per-customer trends.

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

- Supply Trends – Shale gas, Canadian supply availability, and export LNG

- Infrastructure Trends – regional pipeline projects, national pipeline projects, and storage
- Regulatory Trends – subsidies, market transparency/speculation, and carbon legislation
- Other Trends – thermal generation, and energy correlations (i.e. oil/gas, coal/gas, liquids/gas)

We 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, we formed several alternate demand scenarios for detailed analysis. Table 1.1 summarizes these scenarios, which do not represent the maximum bounds of possible cases, but frame a range of potential outcomes. Within this range, we define an Average Case, which represents our demand forecast for normal planning purposes. Then we define an Expected Case, which we view as the most likely scenario for peak day planning purposes.

Table 1.1 Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Alternate Weather Standard

The IRP process defines the methodology and is the basis for the development of two primary types of demand forecasts – annual average daily and peak day. First is an evaluation of annual average daily demand forecasts which 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 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 following:

Annual Average Daily Demand – Average day, system-wide core demand is projected to increase from an average of 91,352 dekatherms per day (Dth/day) in 2014 to 104,300 Dth/day in 2033. This is an annual average growth rate of .7 percent and is net of projected conservation savings from DSM programs.[1]

Peak Day Demand – Coincidental peak day, system-wide core demand is projected to increase from a peak of 357,610 Dth/day in 2014 to 402,936 Dth/day in 2033. Forecasted non-coincidental peak day demand peaks at 333,129 Dth/day in 2014 and increases to 375,747 Dth/day in 2031, a .6 percent compounded growth rate in peak day requirements. This is also net of projected conservation savings from DSM programs.

[1] Appendix 3.9 shows gross demand, DSM savings and net demand.

Figure 1.1 shows forecasted **average daily demand** for the five main demand scenarios modeled over the planning horizon.

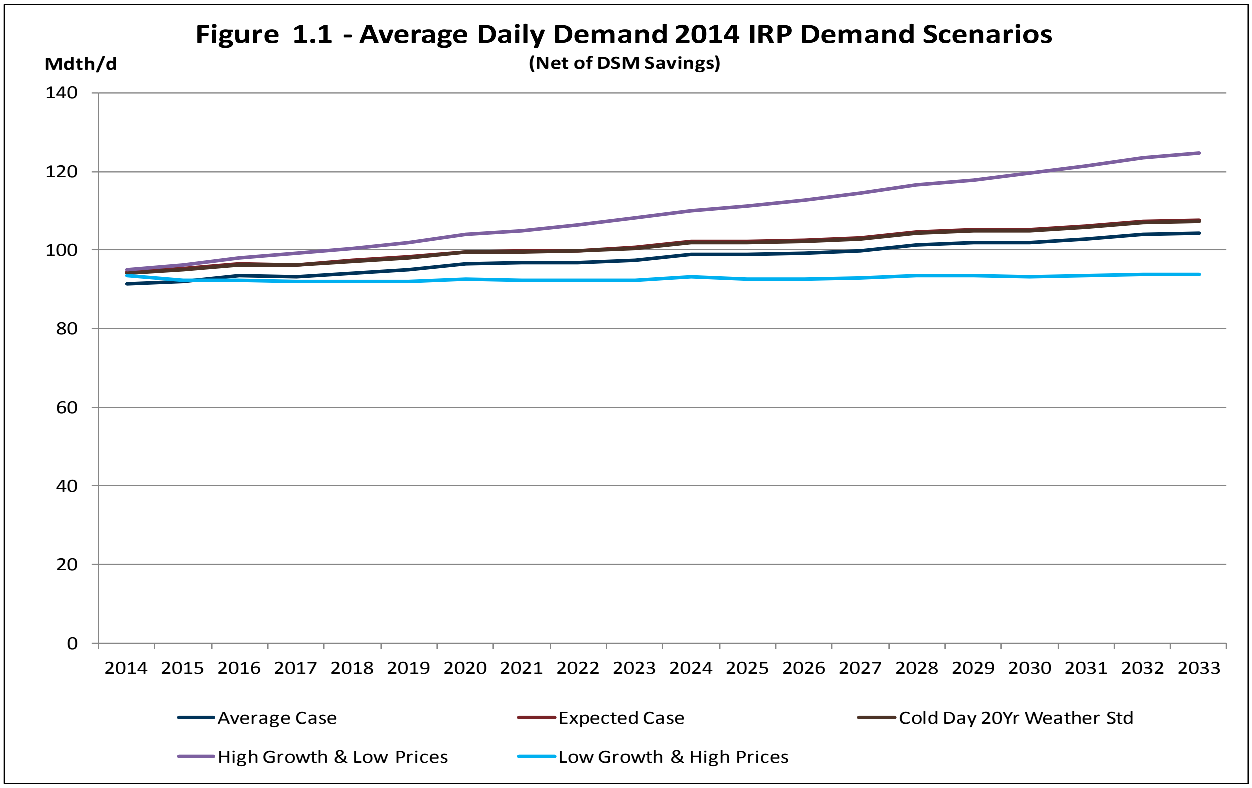
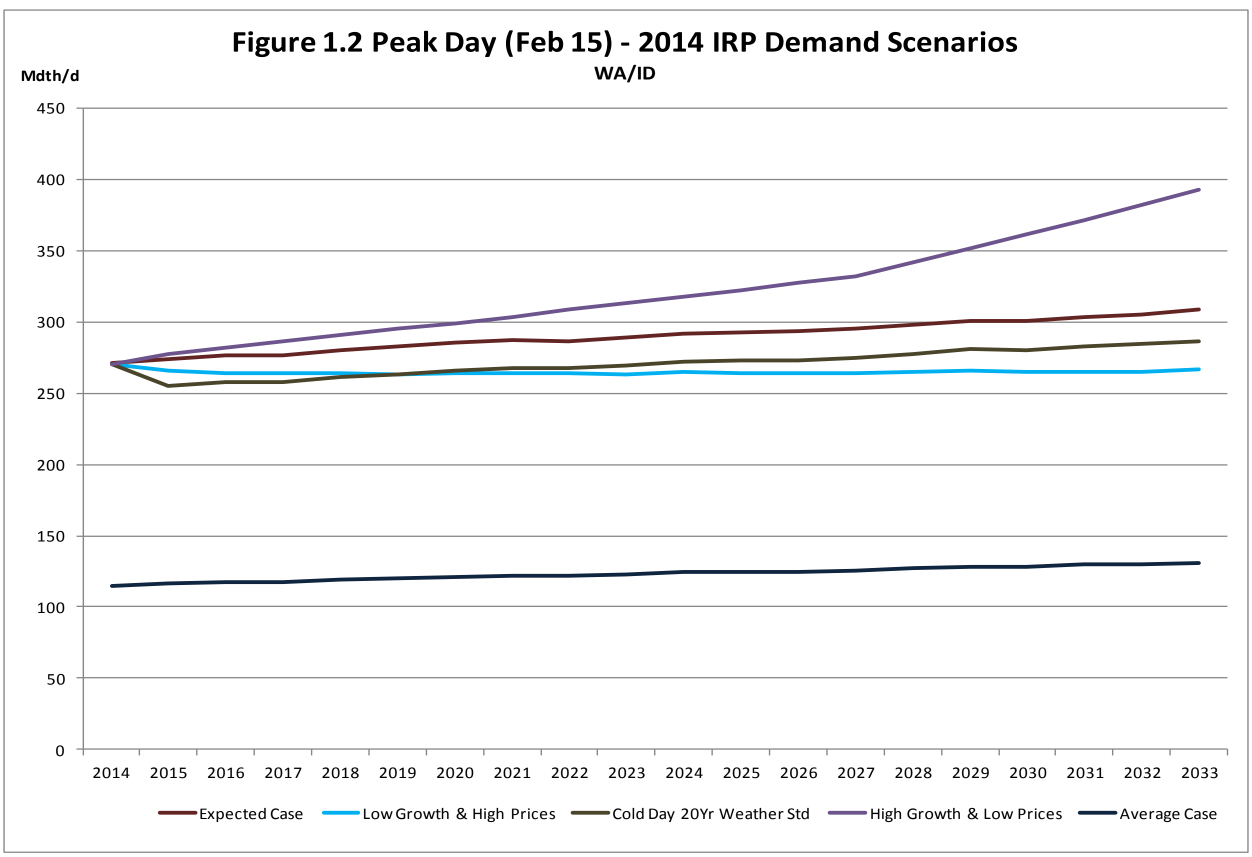


Figure 1.2 shows forecasted system-wide **peak day demand** for the five main demand scenarios modeled over the planning horizon.



NATURAL GAS PRICE FORECASTS

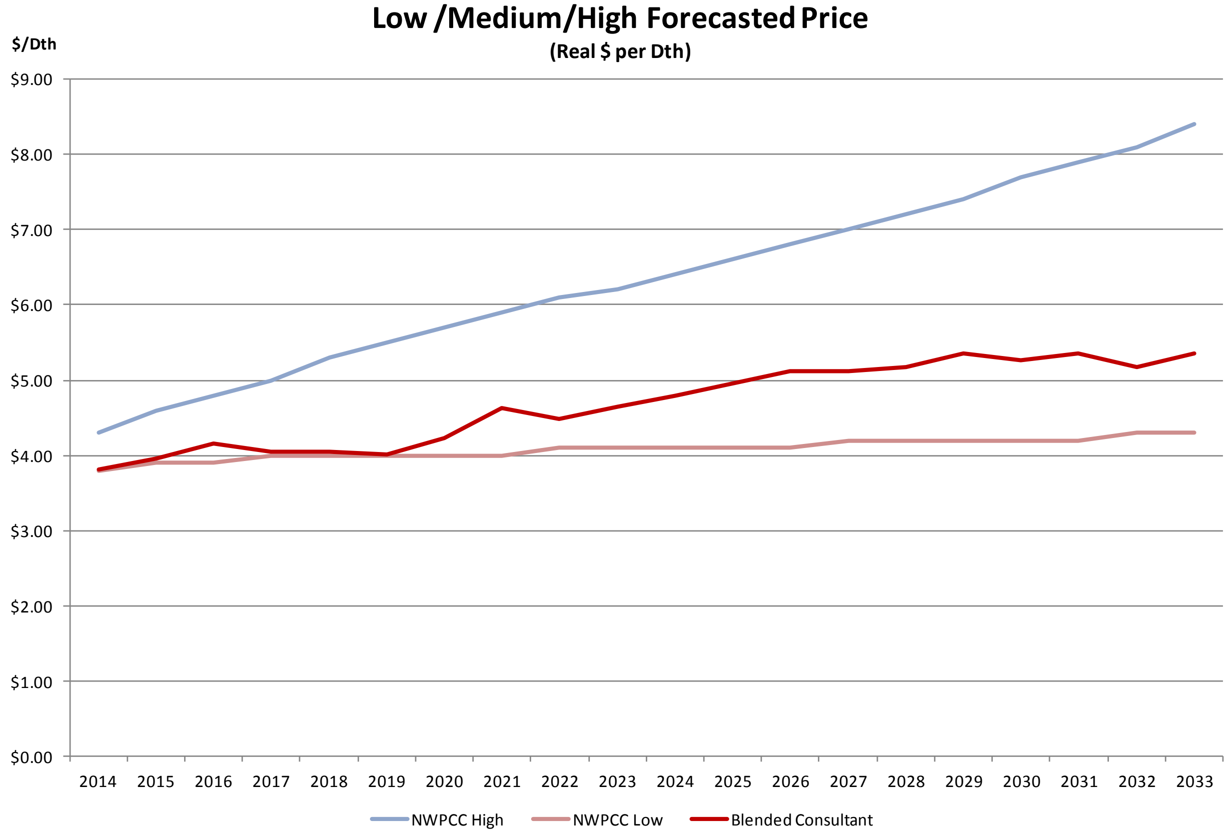
Natural gas prices are a fundamental component of integrated resource planning because the commodity price is a significant component of the total cost of a resource option. This affects the avoided cost threshold for determining cost-effectiveness of conservation measures. The price of natural gas also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

With more information known about the costs and volumes produced by shale gas there appears to be consensus that production costs will continue to stay low for quite some time. Even with some level of incremental demand for LNG exports, transportation fuels, and an industrial consumption prices are anticipated to remain low.

Carbon legislation has been debated for many years. Current thinking is that legislation at the federal level may not occur and carbon will be addressed at the state level. Our current price forecasts include a federal carbon tax however, the timing and magnitude has been delayed and lowered. To address the uncertainty about when, where, and how much surrounding carbon legislation we looked at three carbon sensitivities and their impact to our demand forecasts.

Although we do not believe we can accurately predict future prices for the 20-year horizon of this IRP, we have reviewed several price forecasts from credible sources and have selected high, medium and low price forecasts to represent a reasonable range of pricing possibilities for our analysis. The range of prices provides necessary variation for addressing uncertainty of future prices. Figure 1.3 depicts the price forecasts used in our IRP.

Figure 1.3 Henry Hub Forecasts for IRP
Low /Medium/High Forecasted Price
(Real $ per Dth)



Historical statistical analysis shows a long run consumption response to changes in price. In order to model a consumption response to these price curves, we utilized an expected elasticity response factor, which was applied under various scenarios. We will continue to monitor and research this assumption and make any necessary adjustments.

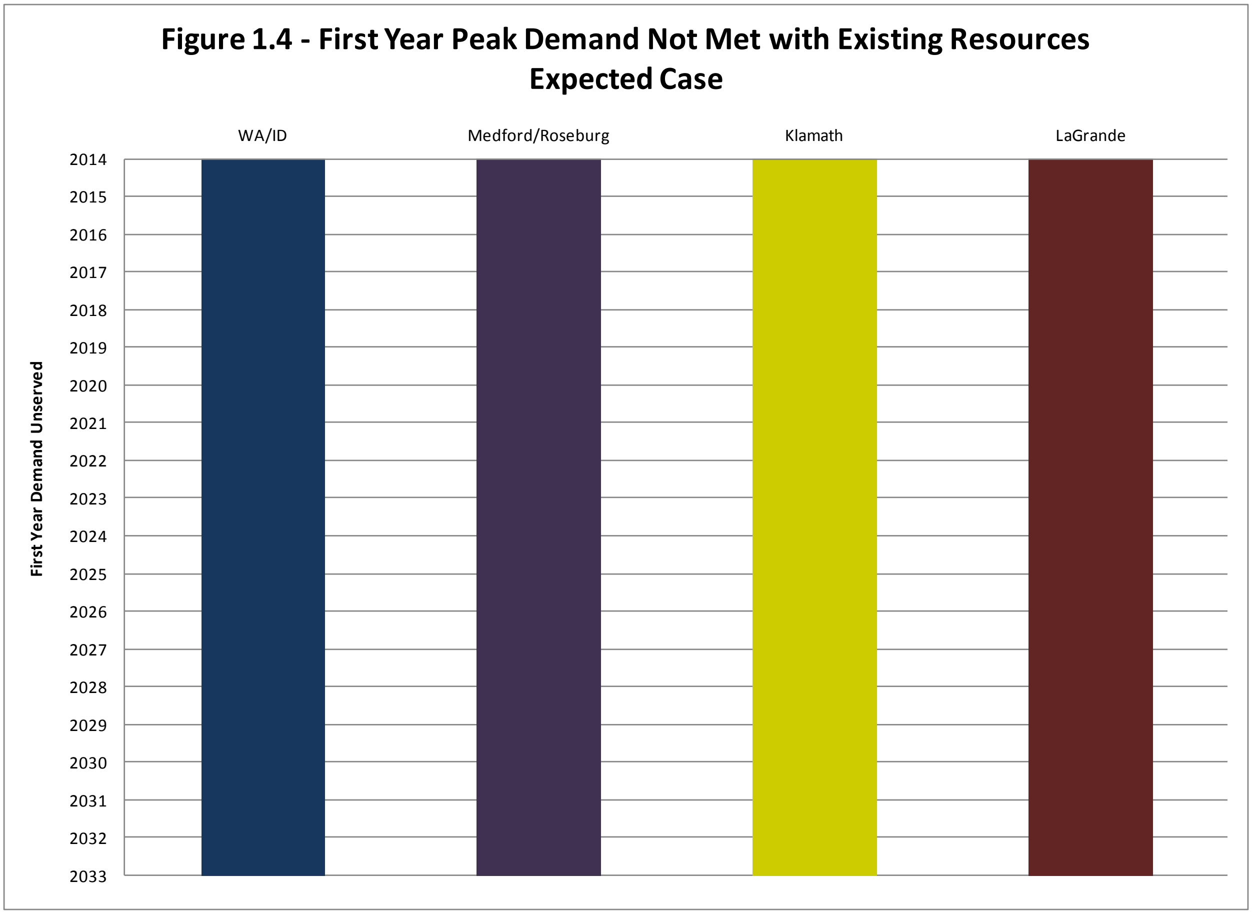
EXISTING AND POTENTIAL RESOURCES

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 flexibility of supply sources; and firm capacity rights on six pipelines diversifies delivery of supply to our service territory city gates. For potential resource additions, we consider incremental pipeline transportation, storage options, distribution enhancements and various forms of liquefied natural gas storage or service.

In our IRP process, we model aggregated conservation potential that reduces demand if they are cost-effective over the planning horizon. Based on the projected natural gas prices and the estimated cost of alternative supply resources, conservation savings are identified and incorporated into the SENDOUT® model. Utilizing IRP identified savings as a starting point the operational business planning process ultimately determines the near term program offerings. Given current avoided costs, a limited number of programs are cost effective in Idaho, Oregon, and Washington. Currently, we are not running natural gas DSM programs in Idaho. We actively promote cost-effective measures to our customers as one component of a comprehensive strategy to arrive at mix of best cost/risk adjusted resources.

RESOURCE NEEDS

In our Average Case demand scenario matched with our existing supply resources scenario, we determined we are not resource deficient in the 20 year planning horizon. Using our Expected Case demand scenario, matched with our existing resources supply scenario, we assessed when the first year peak day demand is not fully served. The results of this portfolio are summarized in Figure 1.4. In our Expected Case we are not resource deficient in any area throughout the 20-year planning horizon.



Figures 1.5 through 1.8 illustrate our peak day demand by service territory for both this IRP and our prior IRP. These charts compare existing peak day resources to expected peak day demand by year and show timing and extent of resource deficiencies, if any, for the Expected Case. Given this information, it appears we have ample time to carefully monitor, plan and take action on potential resource additions.

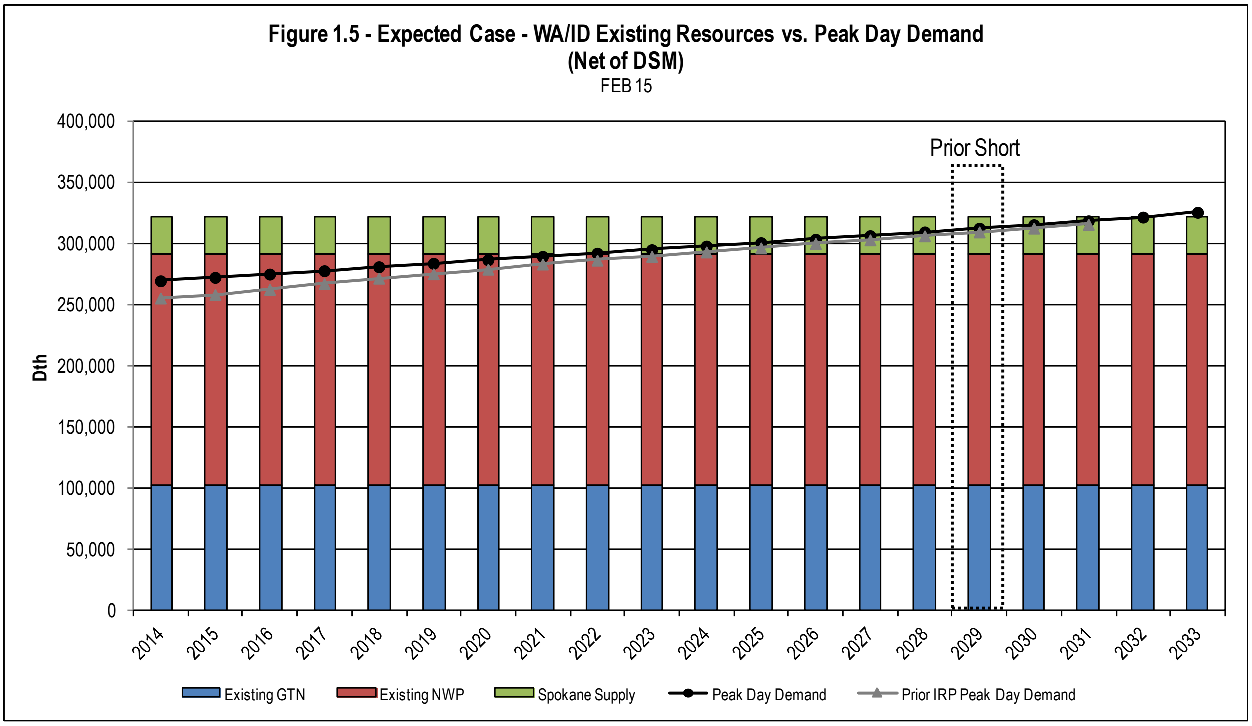


Figure 1.5 - Expected Case - WA/ID Existing Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Prior Short
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033
Existing GTN
Existing NWP
Spokane Supply
Peak Day Demand
Prior IRP Peak Day Demand

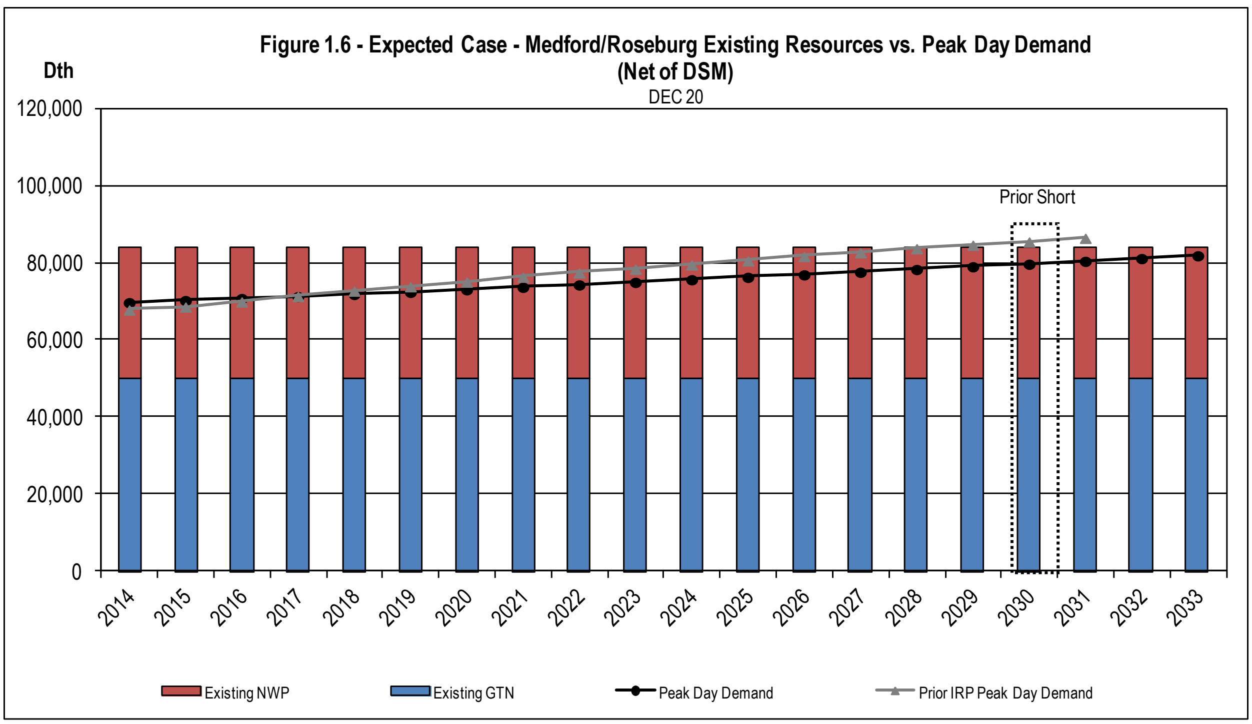
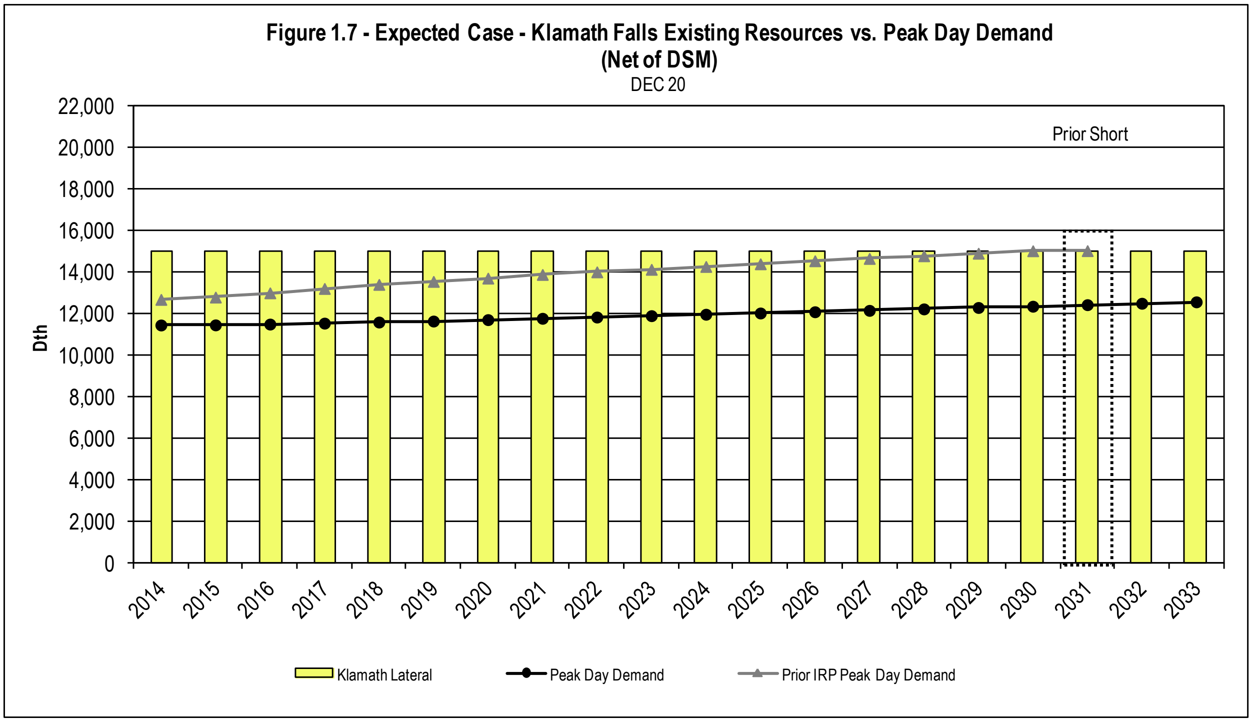
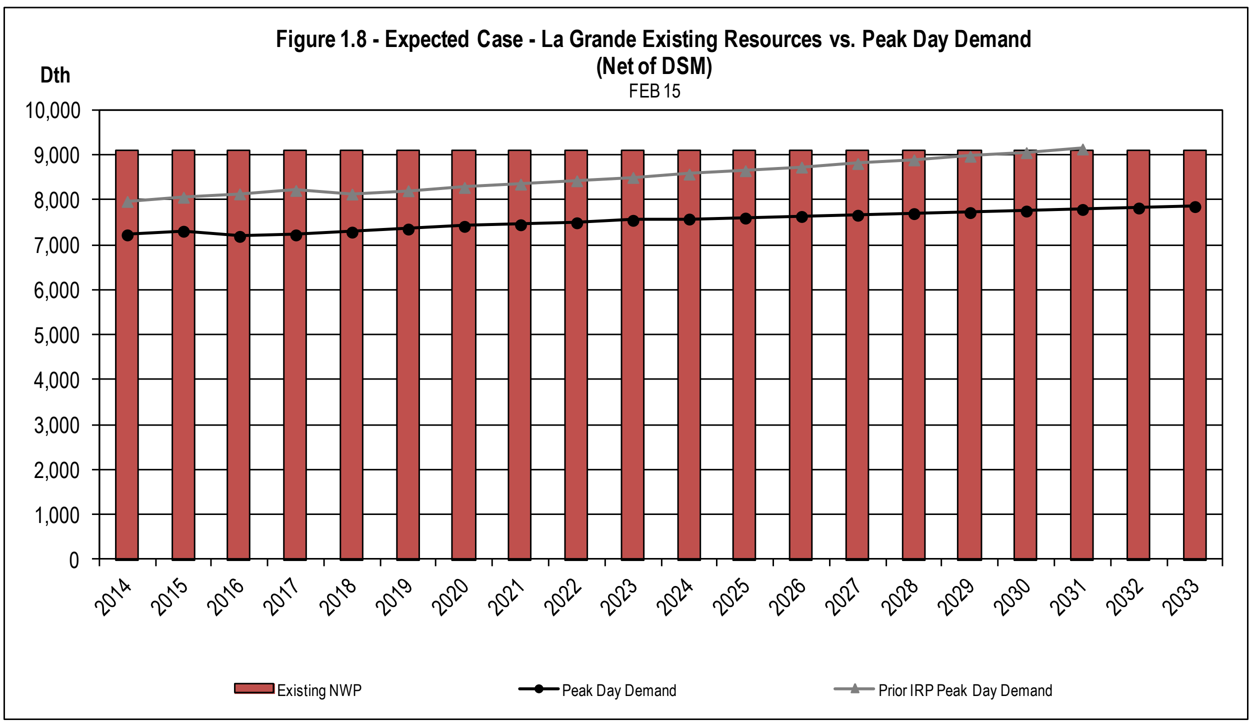


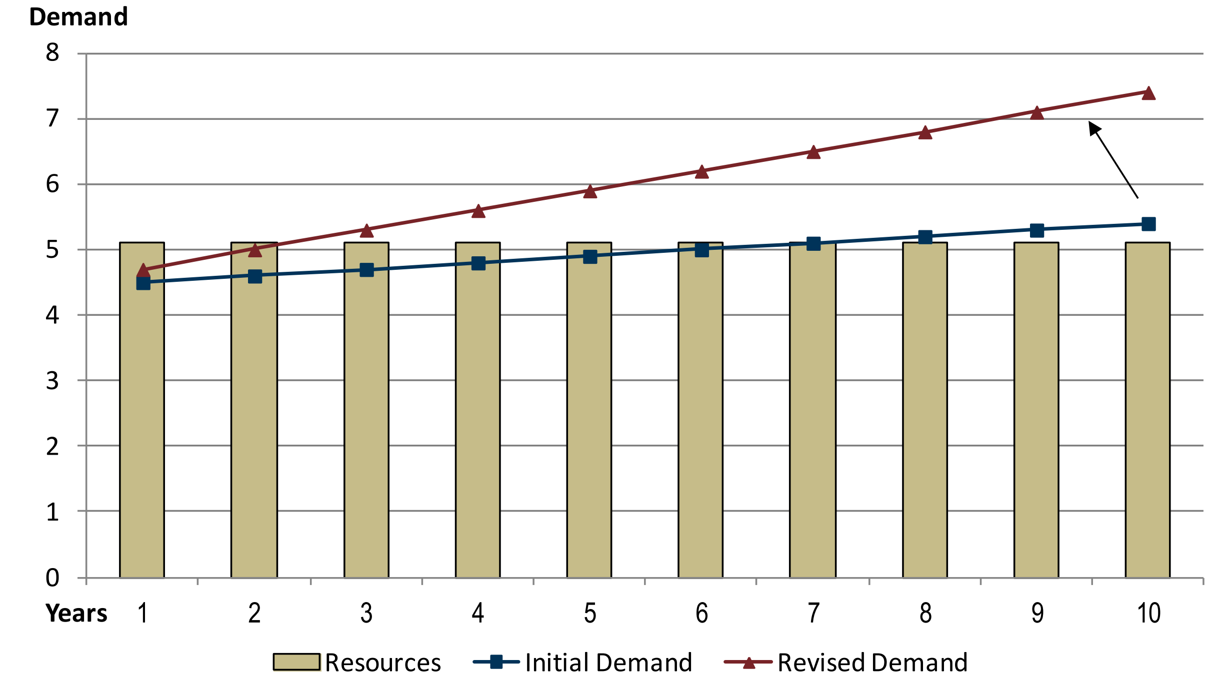
Figure 1.6 - Expected Case - Medford/Roseburg Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Prior Short
2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033
Existing NWP
Existing GTN
Peak Day Demand
Prior IRP Peak Day Demand





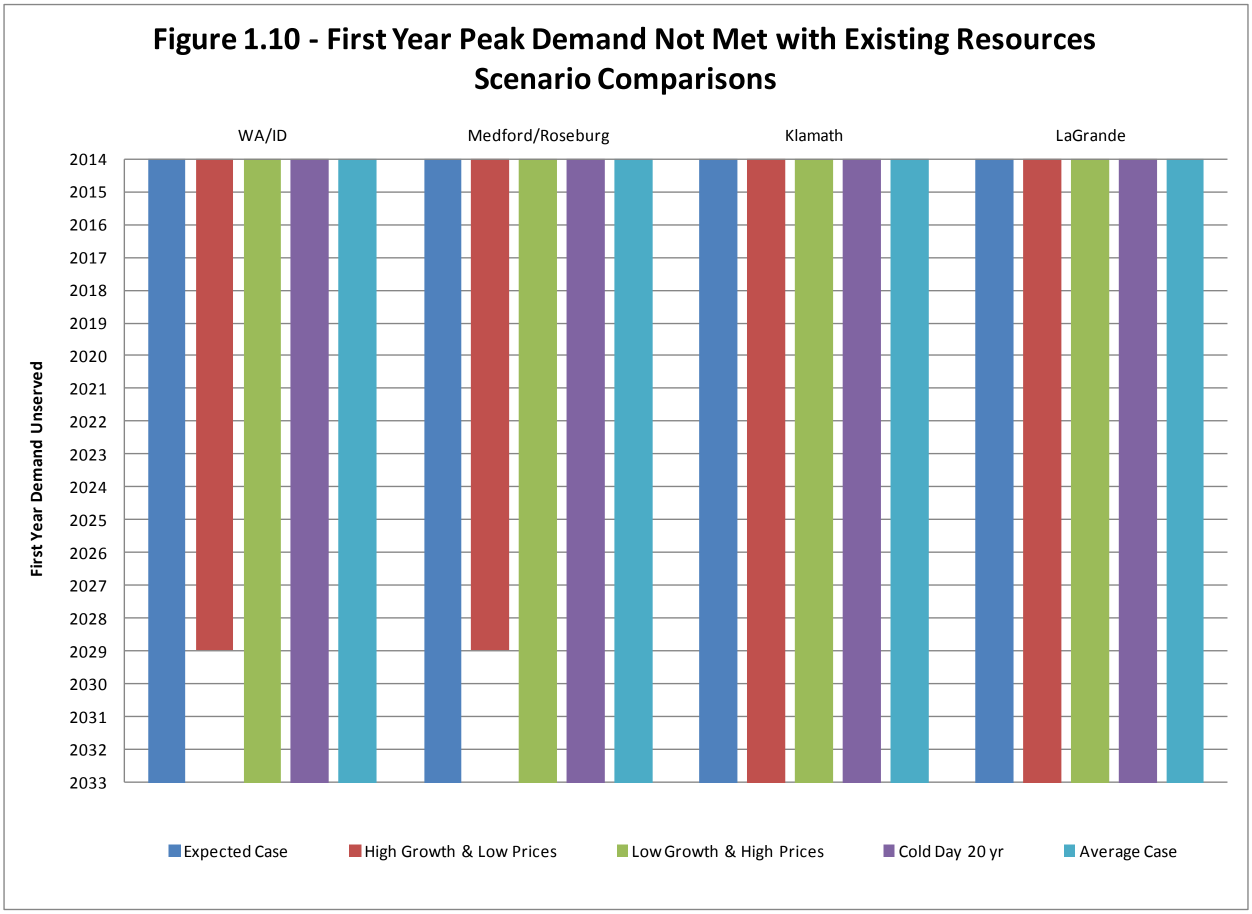
A critical risk is the slope of forecasted demand growth, which is almost flat. This outlook implies that existing resources will be sufficient within the planning horizon to meet demand. However, if demand growth accelerates, the steeper demand curve could quickly accelerate resource shortages by several years. Figure 1.9 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 dramatically accelerates by five years under the revised demand case to year three. This "flat demand risk" necessitates close monitoring of accelerating demand as well as careful evaluation of lead times to acquire the preferred incremental resource.

Figure 1.9 Flat Demand Risk Example



ALTERNATE DEMAND SCENARIOS

We performed the same analytic process for four other demand scenarios, Average, 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. First year resource deficiencies under each scenario are depicted in Figure 1.10.



ISSUES AND CHALLENGES

Although we are satisfied with the planning, analysis and conclusions reached in this IRP, we recognize wide spread uncertainty exists requiring diligent monitoring of the following issues and challenges:

WHERE'S THE DEMAND?

Understanding the recession's significant impact to future customer growth in our service territory and with changing use per customer our long-term forecast for natural gas demand has declined dramatically. Considering a broad range of demand scenarios provides valuable insight into how quickly our resource needs can change should demand vary from the Expected Case.

With supply abundance and low costs, there is increasing interest in use of natural gas. It is not anticipated that traditional residential and commercial customers will provide growth in demand. There is potential for increased natural gas usage in other markets, whether to fuel vehicles, generate electricity, or as a feedstock for industrial processes. Most of these emerging markets will not be core customers of the LDC, however they can and will impact regional gas infrastructure and could impact natural gas pricing.

THE PRICE IS RIGHT

The reality of shale gas has changed the face of North American supply. The abundance of shale along with lagging demand has created a near term supply glut which kept prices at low levels. The winter of 2013-2014 brought increased demand and rebalanced the market reversing the downward pricing trend. However, the relative higher prices are a short-term phenomenon and forecasters anticipate a return to lower prices. For our customers we hope that the forecaster's expectations come to fruition, but we are mindful of past experiences and understand that markets can change quickly and dramatically. To address this uncertainty, our plan includes high and low price scenarios along with stochastic price analysis to capture a range of possible pricing outcomes.

EXPORTING LNG

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

ACTION PLAN

Our 2015-2016 Action Plan outlines activities identified by our IRP team, with advice from management and TAC members, for development and inclusion in this IRP. The purpose of these action items 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 also highlights key analysis that needs to be completed in the near term. It also highlights essential ongoing planning initiatives and gas industry trends Avista will be monitoring as a part of its routine planning processes.

The analysis indicates there is no near term needs to acquire additional supply side resources to meet customer demand. Therefore, appropriate management of our existing resources is paramount. Optimizing underutilized resources reduces costs to customers while providing reliability should customers needs exceed forecasted expectations.

Avista also believes in the pursuit of cost-effective demand-side solutions, but recognizes the challenges of the current low cost environment. Within the IRP, Washington and Idaho conservation measures are targeted to reduce demand by approximately 151,500 dekatherms in the first year (2015). In Oregon, conservation measures are targeted to reduce demand by approximately 16,100 dekatherms in the first year.

We will comply with current Commission findings try to increase the cost effectiveness of measures within the portfolio by reducing administration and audit costs, analyzing non-natural gas benefits, and measure lives. We will monitor natural gas prices as signpost for increasing avoided costs. Should avoided costs increase we will evaluate our demand side programs for cost-effectiveness and be proactive in submitting to resume our natural gas demand side management options.

Completion of the gate station analysis to assess any resource deficiencies masked by aggregated IRP analysis. Should deficiencies be identified we will discuss findings and potential solutions with Commission Staff. We 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.

Key ongoing components of the Action Plan include:

- Monitor actual demand for indications of growth exceeding our forecast to respond aggressively to address potential accelerated 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. This information will be provided in Avista’s updates to each Commission Staff at least bi-annually.

- Continue to monitor supply resource trends including the availability and price of natural gas to the region, exporting LNG, Canadian natural gas supply availability and interprovincial consumption, as well as pipeline and storage infrastructure availability.
- Monitor availability of current resource options and assess new resource lead time requirements relative to when resources are needed to preserve flexibility.
- Regularly meet with Commission Staff members 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.

CONCLUSION

Anticipated low customer growth has eliminated the need 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 demand-side management programs. While Avista believes adoption of conservation is the best strategy for minimizing costs to our customers and promoting a cleaner environment, this IRP shows a lower conservation potential than previous IRP's. The IRP process has many objectives, but foremost, is to ensure that proper planning will enable us to continue delivering safe, reliable and economic natural gas service to our customers well into the future. We are confident this plan delivers on that objective.

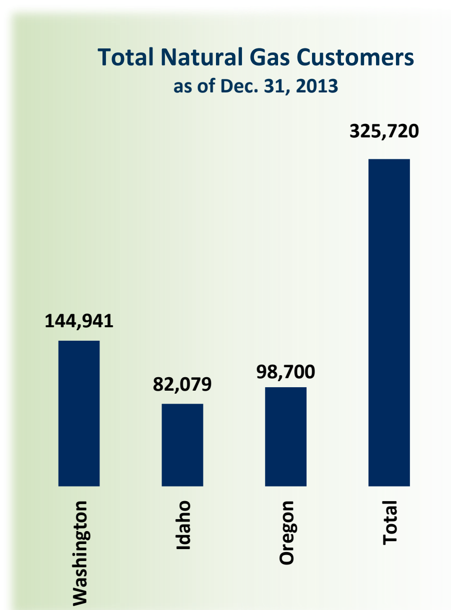
CHAPTER 2 ■ INTRODUCTION

OUR COMPANY

Avista is involved in the production, transmission and distribution of energy as well as other energy-related businesses. Avista was founded in 1889 as Washington Water Power and has been providing reliable, efficient and competitively 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 Williams-Northwest Pipeline (NWP)) to develop the Jackson Prairie natural gas underground storage facility in Chehalis, Wash. In 1991 we 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. Avista currently provides natural gas service to approximately 325,000 customers in eastern Washington, northern Idaho and several communities in northeast and southwest Oregon.

SERVICE TERRITORIES AND NUMBER OF CUSTOMERS



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 450,000 followed by the Lewiston, Idaho/Clarkston, Wash. and Coeur d'Alene, Idaho. The North Division has about 74 miles of natural gas distribution mains and 5,000 miles of distribution lines. Natural gas is received at more than 40 points along interstate pipelines and distributed to over 222,000 customers.

- The South Division serves four counties in southwest Oregon and one county in northeast Oregon. The combined population of these two 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 280,000 residents. The South Division consists of about 67 miles of natural gas distribution mains and 2,000 miles of distribution lines. Natural gas is received at more than 20 points along interstate pipelines and distributed to almost 96,000 residential, commercial and industrial customers.

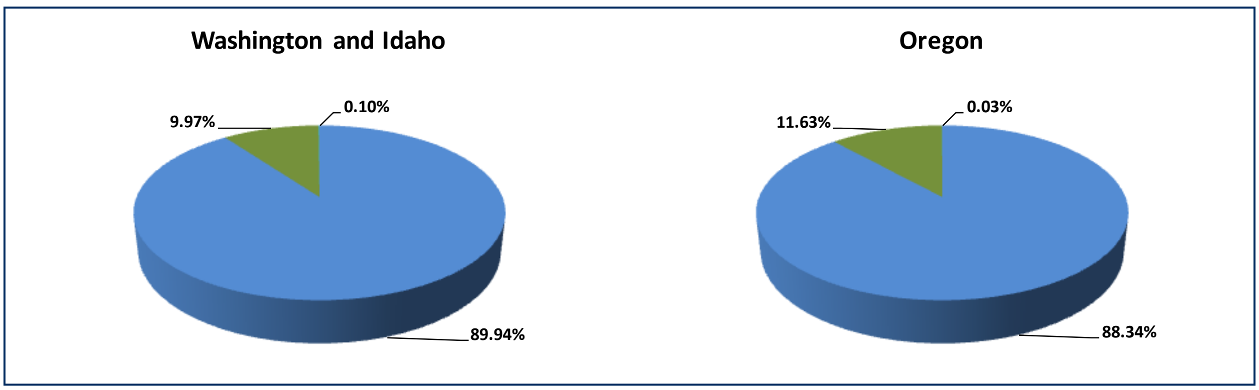
OUR CUSTOMERS

We provide natural gas services to two customer classifications – “core” and “transportation only.” Core or retail customers purchase natural gas directly from us with delivery to their home or business under a bundled rate. Those core customers on firm rate schedules are entitled to receive whatever volume of gas is needed. There are some core customers who are on interruptible rate schedules. These customers pay a lesser rate than firm customers since their service can be interrupted. These interruptible customers are not considered in our peak day IRP planning.

Transportation-only customers purchase natural gas from third parties who deliver their gas to our distribution system. We then deliver this gas to their business charging a distribution rate only. This delivery service can be interrupted by Avista following our priority of service tariff. Since our transportation-only customers purchase their own gas and utilize their own interstate pipeline transportation contracts they too are excluded from this long-term resource planning exercise.

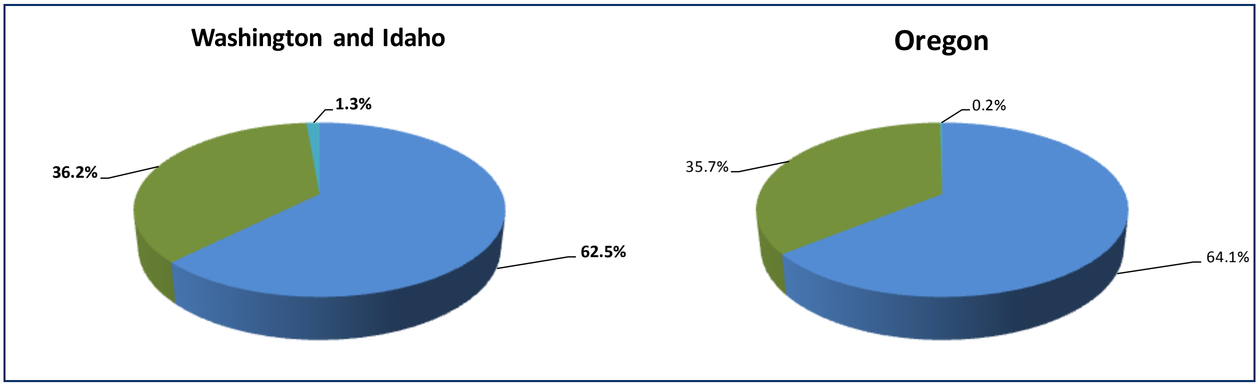
Our core or retail customers are further divided into three categories – residential, commercial and industrial. Most of our customers are residential, followed by commercial. Relatively few are industrial accounts (Figure 2.1).

Figure 2.1 Firm Customer Mix



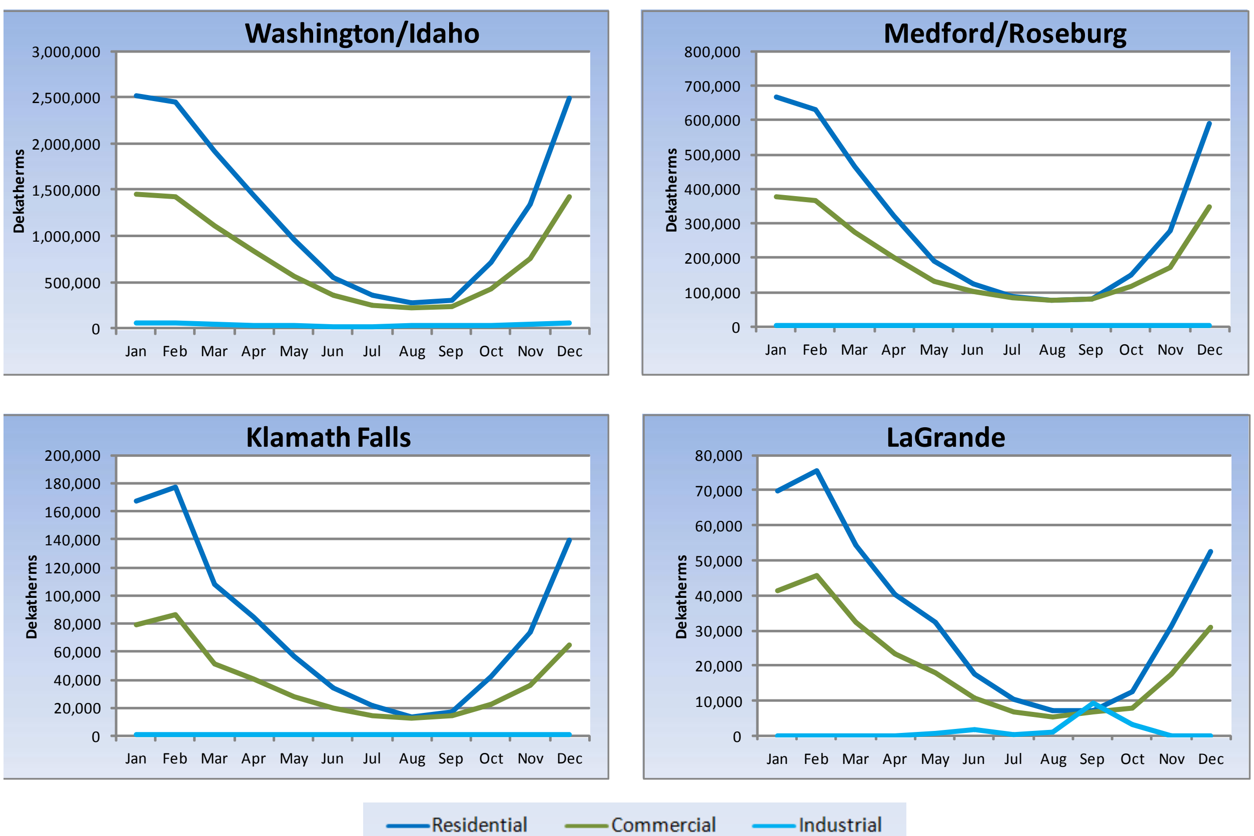
The mix is more balanced between residential and commercial accounts on an annual volume basis (Figure 2.2). Volume consumed by core industrial customers is not significant to the total, partly because most industrial customers in our service territories are transportation only customers.

Figure 2.2 Therms by Class



Core customer demand is seasonal, especially by our residential accounts in our service territories with colder winters (Figure 2.3). Industrial demand, which is typically not weather sensitive, has very little seasonality. However, our La Grande service territory has several agricultural processing facilities, classified as industrial, that produce a late summer seasonal demand spike.

Figure 2.3 Customer Demand by Service Territory (Dekatherms)



INTEGRATED RESOURCE PLANNING

In order to ensure that our core firm customers are provided with long-term reliable natural gas service at a competitive price, we undertake a comprehensive analytical process through the IRP. We evaluate, identify and plan for the acquisition of the best-risk, least-cost portfolio of existing and future resources to meet average daily and peak-day demand delivery requirements over a 20-year planning horizon.

PURPOSE OF THE IRP

This document has several objectives:

- 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 demand requirements
- Responds to Washington, Idaho and Oregon rules and orders

AVISTA'S IRP PROCESS

The IRP process considers:

- Customer growth and usage
- Weather planning standard
- DSM opportunities
- Existing and potential supply-side resource options
- Current and potential legislation/regulation
- Risk

PUBLIC PARTICIPATION

Members of Avista's TAC play a key role and have a significant impact in development of 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 2014 IRP. The first meeting convened on January 24, 2014 and the last meeting was held on April 23, 2014. Meetings are held at a variety of locations convenient for stakeholders and can be attended electronically for those unable to attend in person. A broad spectrum of stakeholders was represented at each meeting. The meetings focused on specific planning topics, reviewed the status and progress of planning activities and solicited input on the IRP development. A draft of this IRP was provided to TAC members on May 30, 2014. We gained valuable input from the interaction and communication with TAC members and express our sincere thanks and appreciation for their contributions and participation.

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

REGULATORY REQUIREMENTS

Avista submits an IRP to the public utility commissions in Washington, Idaho and Oregon every two years as required by state regulation.[1] We will file our IRP with all three Commissions on or before Aug. 31, 2014. We have a statutory obligation to provide reliable natural gas service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. We regard 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 us to determine that alternative resources are more cost effective than resources reviewed and selected in this IRP. We 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 is the use of SENDOUT®, the computer planning model we use to perform comprehensive and effective natural gas supply planning and analysis. SENDOUT® is a linear programming-based model that is widely used in the industry 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:

- Customer growth and customer natural gas usage to form demand forecasts
- Existing and potential transportation and storage options
- Existing and potential natural gas supply availability and pricing
- Revenue requirements on all new asset additions
- Weather assumptions
- Demand-side management

We have also incorporated stochastic modeling utilizing a module within SENDOUT® to simulate weather and price uncertainty. The module uses Monte Carlo functionality to generate simulations of weather and price to provide a probability distribution of results which can provide insight and support for 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)
- Resource mix (optimally sizing a contract or asset level of various and competing resources)

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

PLANNING ENVIRONMENT

Although we prepare and publish an IRP biannually, the process is ongoing, taking into account new information and developments. In “normal” circumstances, the process can become complex as underlying assumptions evolve and impact previously completed analyses. Every planning cycle has

1 In Washington the IRP requirements are outlined in WAC 480-90-238 entitled “Integrated Resource Planning.”
In Idaho the IRP requirements are outlined in Case No. GNR-G-93-2, Order No. 25342. In Oregon the IRP requirements are outlined in Order Nos. 07-002, 07-047 and 08-339. Appendix 2.2 provides details of these requirements and how they are met.

challenges and uncertainties; this cycle was no different. Realization that recessionary impacts greatly impacted our forecasted service territory growth has significantly reduced our long-term natural gas needs. Widespread agreement on the availability of shale and the ability to produce it economically at lower prices has increased interest in the use of natural gas. Whether used as a feedstock for industrial processes, as transportation fuel, or exported to other markets, the potential is great. However, there is uncertainty about when, how much, and if those markets ever develop.

IRP PLANNING STRATEGY

Planning for an uncertain future requires robust analysis that encompasses a wide range of possibilities. We have determined our approach needs to:

- Recognize 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
- Maintain a long-term perspective

With these objectives in mind we believe we have developed a strong strategy encompassing all required planning criteria that allowed us to produce a complete IRP that effectively analyzes risks and resource options, which sufficiently ensure our customers will receive safe and reliable energy delivery services well into the future with the best-risk, lease-cost, long-term solutions.

SUMMARY OF CHANGES FROM THE 2012 IRP

Chapter	Issue	2014	2012
Demand	Expected Customer Growth	Expected case customer growth is 1% compounded annually.	Expected case customer growth of 1.8% compounded annually.
	High/Low Growth	High and low growth based on forecasted long run employment growth.	Based on Washington State Office of Financial Management, 40% below and 60% above expected growth.
	Price Elasticity	Utilized a -.15 response based on multiple historic analysis. Incorporated mechanism to represent existing rate mechanisms that shield customers from timely price signals (i.e. comfort level billing, PGA mechanisms, deferrals,etc.)	Utilized a -.13 response based on AGA survey. Applied to change year over year on commodity price.
	Weather	Rolling 20 year average with no adjustment for	Rolling 30 year average with an adjustment for

		global warming.	global warming.
Demand Side Management	SENDOUT® modeling methodology	Integrated by price. SENDOUT® will be run without DSM and the resulting avoided costs will be calculated. Those costs will be given to ENERNOC for incorporation into their model to determine cost effective programs and savings. Resultant savings and costs will be incorporated into SENDOUT® and avoided costs will be re-evaluated until there is not a material change.	Utilized SENDOUT® DSM module, aggregated program bundles by demand area and type. Modeling at this level can mask individual cost effectiveness of programs and results in more DSM being selected than might otherwise be selected.
Environmental Issues	Carbon Tax	Three sensitivities on level of carbon tax ($/ton) were compared.	One carbon sensitivity was analyzed.
Supply Side Resources	Spokane Supply	Increased the amount of supply available to take from GTN onto NWP to serve WA/ID that was not included in the previous IRP.	Resource not included in this IRP
	Resource Deficiency	Not resource deficient in the Expected Case.	Resource deficient in 2029 in Oregon and 2030 in Washington and Idaho in the Expected Case.
	Supply Side Scenarios	The only case that identifies a resource deficiency is the High Growth/Low Price scenario. Therefore, we utilized only the existing resource scenario and existing plus expected available resource scenario for modeling purposes.	Evaluated three supply side scenarios on cases with resource deficiencies. Existing resources, Existing plus Expected Available, and GTN fully subscribed.

CHAPTER 3 ■ 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 our forecasts is vital to the planning process. Utilization of historical data provides a reliable baseline, however it is important to remember that past trends may not be indicative of future trends. This uncertainty leads us to consider a range of scenarios to evaluate and prepare for a broad spectrum of outcomes.

DEMAND AREAS

Eight demand areas, structured around the pipeline transportation resources that serve them, were defined within the SENDOUT® computer model (Table 3.1). These demand areas are aggregated into four service territories and further summarized into two divisions for presentation throughout this IRP.

Table 3.1 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 several purposes, including 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 our customers' natural gas needs in extreme weather conditions throughout the planning period.

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 all planning purposes.

Peak weather analysis aids in assessing not only resource adequacy but differences, if any, in resource utilization. For example, storage may be dispatched differently under peak weather scenarios.

DEMAND MODELING EQUATION

Because natural gas demand can vary widely from day to day, especially in winter months when heating demand is at its highest, developing daily demand forecasts is essential. In its most basic form, demand is a function of customer base usage (non-weather sensitive usage) plus customer weather sensitive usage. This can be expressed by the following general formula:

Table 3.2 Basic Demand Formula

# of customers **x** Daily **base usage** / customer
Plus
# of customers **x** Daily **weather sensitive** usage / customer

More specifically, SENDOUT® requires inputs as expressed in the below format to compute daily demand in dekatherms (Dth):

Table 3.3 SENDOUT® Demand Formula

# of customers **x** Daily **Dth base usage** / customer
Plus
# of customers **x** Daily Dth **weather sensitive** usage / customer **x** # of daiy degree days

This calculation is performed by SENDOUT® for each day for each customer class and each demand area. The base and weather sensitive usage (heating degree day usage) factors are customer demand coefficients developed outside the SENDOUT® model and 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 further discussed in the Weather Forecast section later in this chapter.

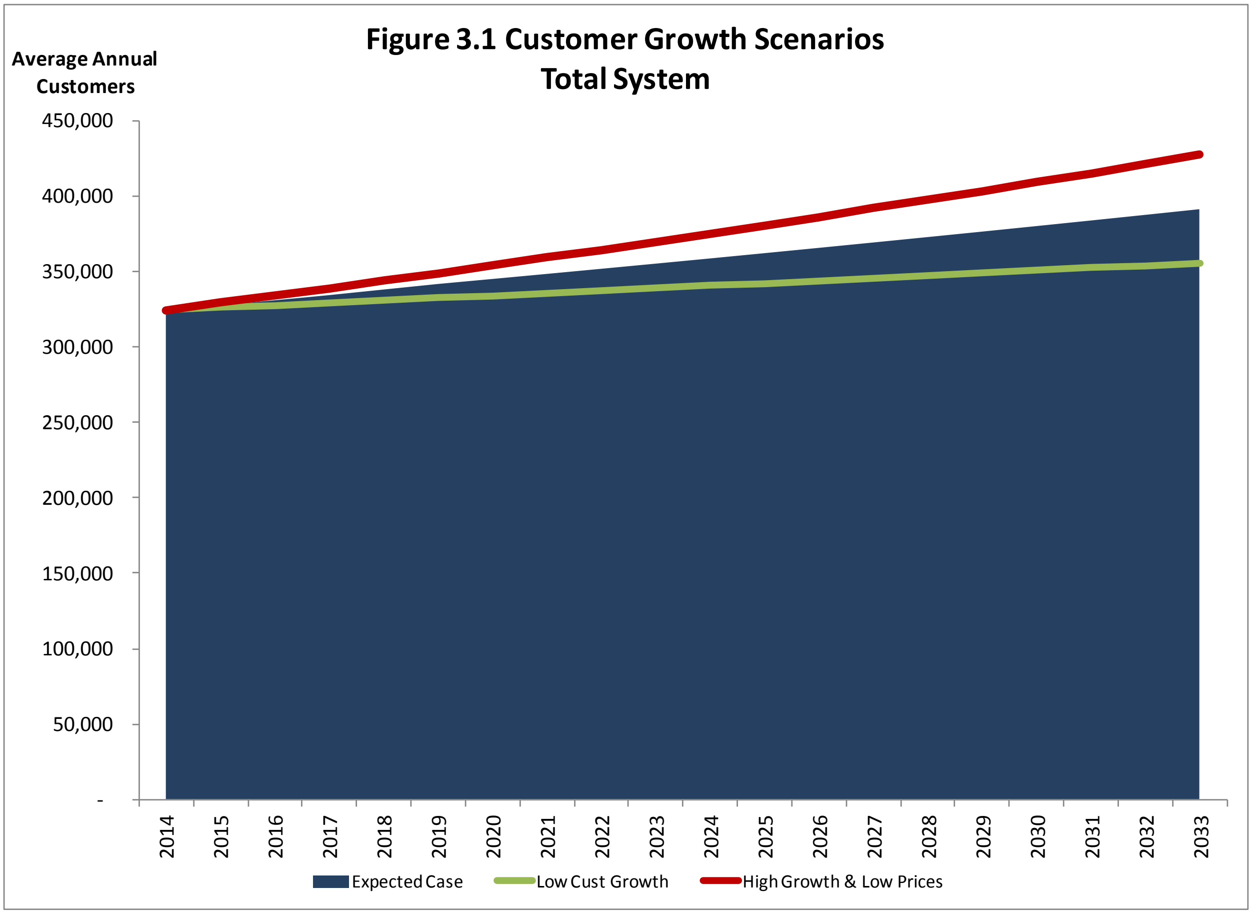
Customer Forecasts

Avista's customer base is segregated into three categories: residential, commercial and industrial. For each of the customer categories we develop our customer forecasts incorporating national economic forecasts and then drilling down into regional economies. U.S. GDP growth, U.S. and regional employment growth, and regional population growth expectations are key drivers in regional economic forecasts and are useful in estimating natural gas customers. A detailed description of the customer forecast is found in Appendix 3.1. We combine this data with local knowledge about sub-regional construction activity, age and other demographic trends and historical data to develop our 20-year customer forecasts.

These forecasts are used by multiple departments within the company. Finance, Accounting, Rates, and Gas Supply are primary users of these forecasts. Additionally, the distribution engineering group utilizes the forecast data for system optimization and planning purposes (see further discussion in Chapter 8 – Distribution Planning).

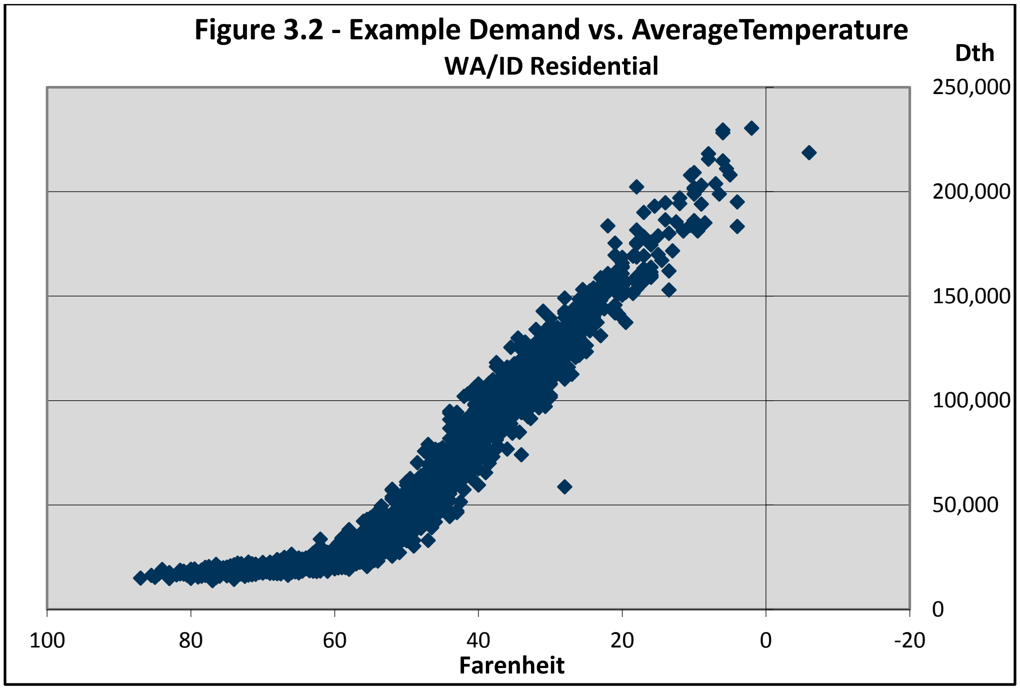
Forecasting customer growth is an inexact science so it is important to consider alternative forecasts. Two alternative growth forecasts were developed for consideration in this IRP. The High and Low growth forecast were developed to provide potential paths and test resource adequacy. Appendix 3.1 contains a description of how these alternatives were developed.

These three customer growth forecasts are shown in Figure 3.1. Due to a change in forecasting customer growth our expected case customer counts are lower than the last IRP. This has impacted forecasted demand from both and average and peak day perspective. Detailed customer count data by region and class for all three scenarios is in Appendix. 3.2.



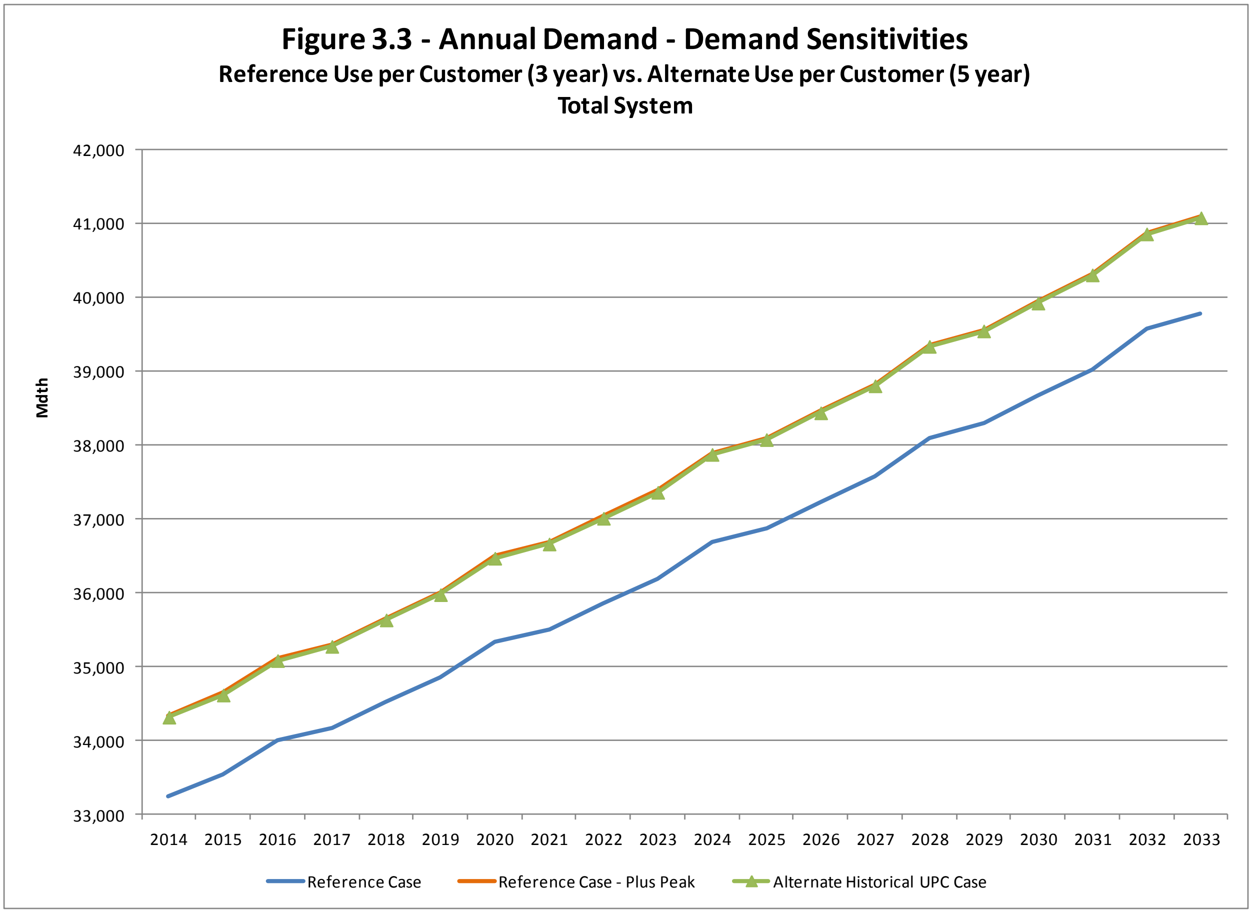
Use-per-Customer Forecast

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 very reliable forecast because of the high correlation between usage and temperature as depicted in the example scatter plot in Figure 3.2.



The first step in developing demand coefficients was gathering daily historical gas flow data for all of our city gates. Our preference to use city gate data over revenue data is due to the tight correlation between weather and demand. Our 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. We do reconcile city gate flow data to revenue data to ensure that we are properly capturing total demand.

The historical city gate data was gathered, segregated by service territory/temperature zone and then by month. As in our last IRP we used three years of historical data to derive our use per customer coefficients. Continuing with our theme of challenging each assumption we considered varying the number of years of historical data. We compared five years of historical use per customer to the three years of data. The five year data had slightly lower use per customer, which may understate use as the economy moderately recovers and customer's usage patterns migrate back towards pre-recession patterns. Three years seemed to strike the right balance between historical and contemporaneous customer usage patterns. Figure 3.3 illustrates the annual demand differences between the three year and five year use per customer with normal and peak weather conditions.



To calculate base usage, three years of July and August data was used to derive coefficients. Average usage in these months divided by 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, we removed base demand from the total and plotted usage by HDD in a scatter plot chart to visually verify correlation. We then applied 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.

In extreme weather conditions, demand can sometimes begin to flatten out relative to the linear relationships at less extreme temperatures. This occurs, for example, when appliances such as furnaces reach maximum output and do not consume any more natural gas regardless of how much colder temperatures get. We sought to capture this phenomenon through development of super peak coefficients.

The methodology for deriving super peak coefficients was derived by averaging the heat coefficients for the months of December, January, and February. One inherent drawback to this methodology is the lack of sufficient data points to develop a strong linear relationship. We will continue to test this theory and monitor trends.

As a final step, to check coefficient reasonableness, we applied the coefficients to actual customer count and weather data to backcast demand. This was compared to actual demand with satisfactory results.

Weather Forecast

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

The NOAA 20-year average weather serves as the base weather forecast that is used to prepare the annual average demand forecast. In preparing the peak day demand forecast we adjust 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 either side of the coldest day to temperatures slightly warmer than the coldest day. For our Washington/Idaho and La Grande service territories, we model this event on and around February 15 each year. For our southwestern Oregon service territories (Medford, Roseburg, Klamath Falls) we model this event on and around December 20 each year.

The following describes specific details on the coldest days on record for each service territory:

- On Dec. 30, 1968, the Washington/Idaho service area experienced the coldest day on record, an 82 HDD for Spokane. This is equal to an average daily temperature of -17 degrees Fahrenheit. Only one 82 HDD has been experienced in the last 40 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 January 5, 2004, respectively.
- On Dec. 9, 1972, Medford experienced the coldest day on record, a 61 HDD. This is equal to an average daily temperature of 4 degrees Fahrenheit. Medford has experienced only one 61 HDD in the last 40 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, 2014, 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 used as the peak day weather standard for modeling purposes.

Utilizing a peak planning standard of the coldest temperature on record may seem aggressive given we are using, in some cases, a temperature experienced only once. Given the potential impacts of an extreme weather event on our customers' personal safety and property damage to customer appliances and company infrastructure, we believe it is a prudent planning standard. We were reminded that while remote, peak days can do occur. On December 8, 2014 we matched our previous peak HDD in Klamath Falls.

We do analyze an alternate planning standard using the coldest temperature in the last twenty years For our Washington/Idaho service area we use a 76 HDD, which is equal to an average daily temperature of -11 degrees Fahrenheit. In Medford the coldest in twenty year is a 54 HDD, equivalent to a temperature of 11 degrees Fahrenheit. In Roseburg the coldest in twenty year is a 48 HDD, equivalent to a temperature of 17 degrees Fahrenheit. In Klamath Falls the coldest in twenty is a 72 HDD, equivalent to a temperature of -7 degree Fahrenheit. In La Grande the coldest in twenty years is a 64 HDD, equivalent to a temperature of 1 degree Fahrenheit.

These HDDs by area, class and by day entered into SENDOUT® can be found in Appendix 3.4.

Global Warming

In previous IRP's an adjustment has been made to NOAA weather data to incorporate estimates for global warming. This adjustment was based on analysis of historical weather data in each of the areas we serve. In this IRP, we have moved away from making an adjustment to the weather data in favor of moving from a rolling 30 year average to a 20 year average.

A 20 year average was chosen for several reasons. First, NASA climate studies indicate that the distribution of temperatures in North America began to shift up significantly about 20 years ago.[1] In this case, a 20 year average matches when the temperature shift. Second, there is a tradeoff between the length of the normal weather definition and its volatility.[2] For example, although a 10 year moving average will capture turning points in climate trends more quickly than 15, 20, or 30 year averages, it will do so at the cost of larger year-to-year changes in the measurement of normal weather. That is, short-term weather variations not necessarily related to climate change will play a larger role in the definition of normal weather as the years for calculating the moving average declines. This can lead to excessive forecast volatility each time the 10 year average is updated. In this respect, the 20 year average is a comprise between the traditional 30 year average, which may not be sufficient for capturing climate trends, and the 10 year average, which greatly increases the volatility of the year-to-year definition of normal weather.

We were unable to discern any definitive evidence to support a peak day warming trend. We continue to search but have be unsuccessful in finding supporting studies or analysis on the topic and, after discussion with our TAC, determined we would not make warming trend adjustments to our peak day weather events in our HDD forecast. Therefore, our modeling and analysis with respect to peak day planning is unaffected by global warming.

DEVELOPING A REFERENCE CASE

To adjust for uncertainty, we developed a dynamic demand forecasting methodology that is flexible to changing assumptions. To understand how various alternative assumptions influence forecasted demand we needed a reference point for comparative analysis. For this we define a reference case demand forecast (Figure 3.4). We stress that this case is not intended to reflect anything other than a simple assumption start point.

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[1] See Hansen, J.; M. Sato; and R. Ruedy, "Global Temperature Update Through 2012," *Science Summary of NASA's 2012 Temperature Summary* January 2013, http://www.nasa.gov/topics/earth/features/2012-temps.html

[2] For a detailed discussion of this issue, see Livezey, R. E., and P. Q. Hanser, "Redefining Normal Temperatures: Resource Planning and Forecasting in a Changing Environment," *Public Utilities Fortnightly*, May 2013, 151(5), pp. 28-33,56.

Figure 3.4 - Reference Case Assumptions

1. Customer Annual Average Growth Rates

Area	Residential	Commercial	Industrial
Washington - Idaho	1.0%	1.0%	-0.53%
Klamath Falls	0.66%	0.66%	0.0%
LaGrande	0.40%	0.40%	0.0%
Medford	1.1%	1.1%	0.0%
Roseburg	0.8%	0.02%	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 (1994-2013)

4. Elasticity

None

5. Demand Side Management

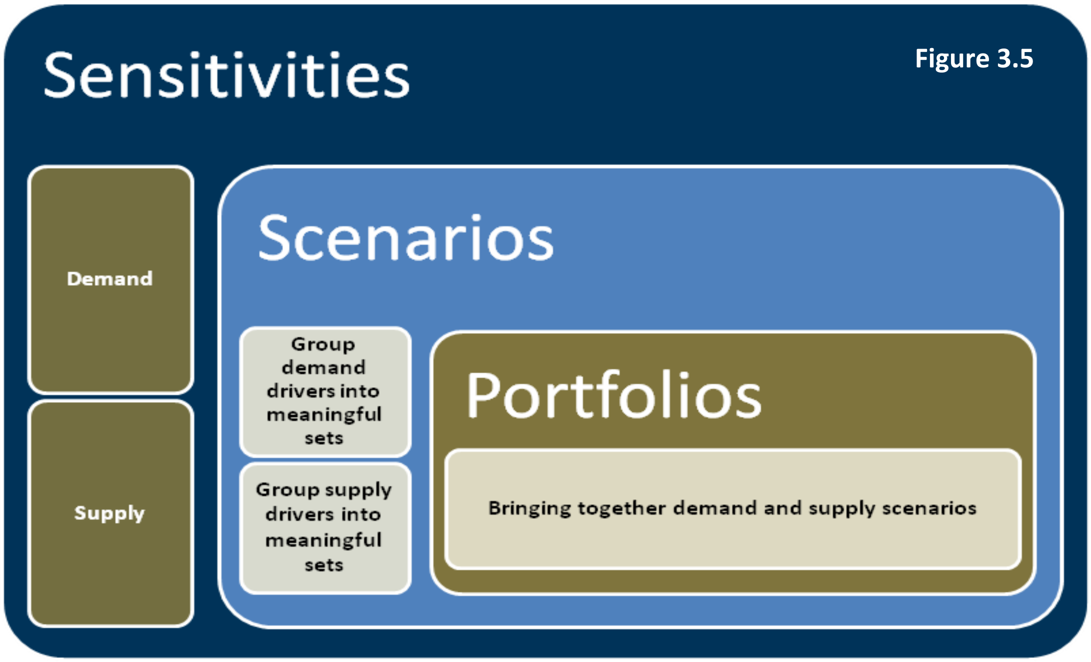
None

DYNAMIC DEMAND METHODOLOGY

The dynamic demand planning strategy critically examines a wide range of potential outcomes. The approach developed 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
- Matching demand scenarios with supply scenarios to identify unserved demand

Figure 3.5 represents our methodology of starting with sensitivities, progressing to scenarios, and ultimately creating portfolios.



SENSITIVITY ANALYSIS

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

- **Demand Influencing Factors** – Factors that directly influence the volume of natural gas consumed by our core customers
- **Price Influencing Factors** – Factors that, through price elasticity response, indirectly influence the volume of natural gas consumed by our core customers

Once factors were identified, we developed sensitivities which we define as focused analysis of a specific natural gas demand driver and its impact on forecasted demand relative to our Reference Case when the underlying input assumptions are modified.

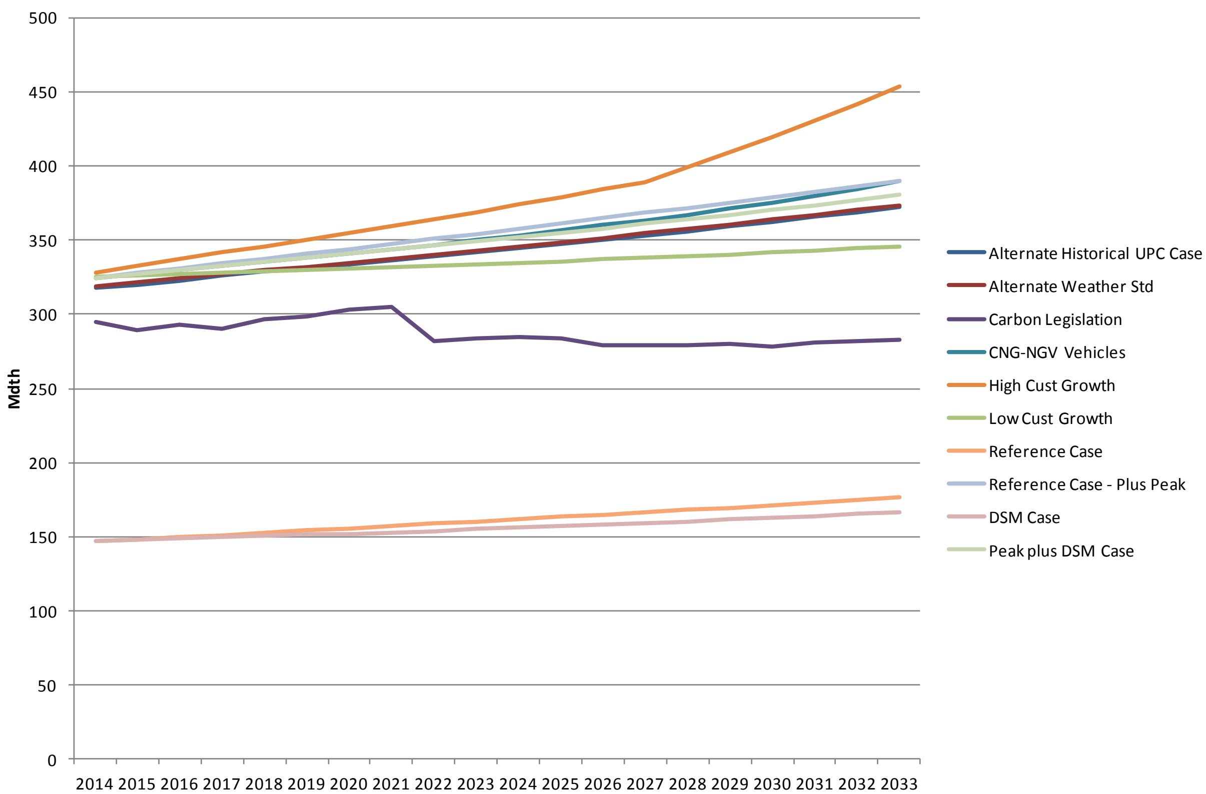
Sensitivity assumptions reflect incremental adjustments we estimate are not captured in the underlying Reference Case forecast. We analyzed 17demand sensitivities to determine the resultant effect relative to the reference case. Table 3.4 lists these sensitivities. More detailed information about these sensitivities can be found in Appendix 3.6.

Table 3.4 - 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 3.6 shows the annual demand from each of the sensitivities we modeled.

Figure 3.6 - 2014 Demand Sensitivities
Annual Demand - Total System



SCENARIO ANALYSIS

Following our testing of the various sensitivities we grouped them into meaningful combinations of demand drivers to develop demand forecasts representing scenarios. Table 3.5 identifies the scenarios we developed. Our Average Demand Case is representative of what we would consider for normal planning purposes, such as corporate budgeting, procurement planning, and PGA/General Rate Cases. The Expected Case reflects the demand forecast we believe is most likely given peak weather conditions. The High Growth/Low Price and Low Growth/High Price represent a forecasted range of possibilities for customer growth and future prices. The Alternate Weather Standard utilizes the coldest day in the last twenty years. Each of these scenarios helps provide us with sufficient "what if" analysis given the volatile nature of many key assumptions including weather and price. Appendix 3.6 lists the specific assumptions within the scenarios while Appendix 3.7 contains a detailed description of each scenario.

Table 3.5

Demand Scenarios
Average Demand
Expected Demand - Peak
High Growth/Low Price
Low Growth/High Price
Alternate Weather Standard

PRICE ELASTICITY

Economic theory of price elasticity states that the quantity demanded for a good or service will change with its price. Price elasticity is usually expressed as a numerical factor that defines the relationship of a consumer's consumption change in response to 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 means a 10% price increase will prompt a 1.5% consumption decrease and a 10% price decrease will prompt a 1.5% consumption increase.

Complex relationships influence price elasticity and given the new economic environment, we question whether current behavior will be considered normal or if customers will return to historic usage patterns. Furthermore, complex regulatory pricing mechanisms shield customers from price volatility dampening price signals and effecting theoretical 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, gas cost adjustments such as the Purchased Gas Adjustment (PGA) which annually adjusts the commodity cost shields customers from daily gas price volatility. These mechanisms do not completely remove price signals however; 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 geographic area of measurement shrinks.[3] This is particularly important given our geographically diverse and relatively small service territories.

We acknowledge changing price levels can and do influence usage so we incorporate a price elasticity of demand factor of -.15 into our modeling assumptions to allow use per customer to vary into the future as our natural gas price forecast changes.

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

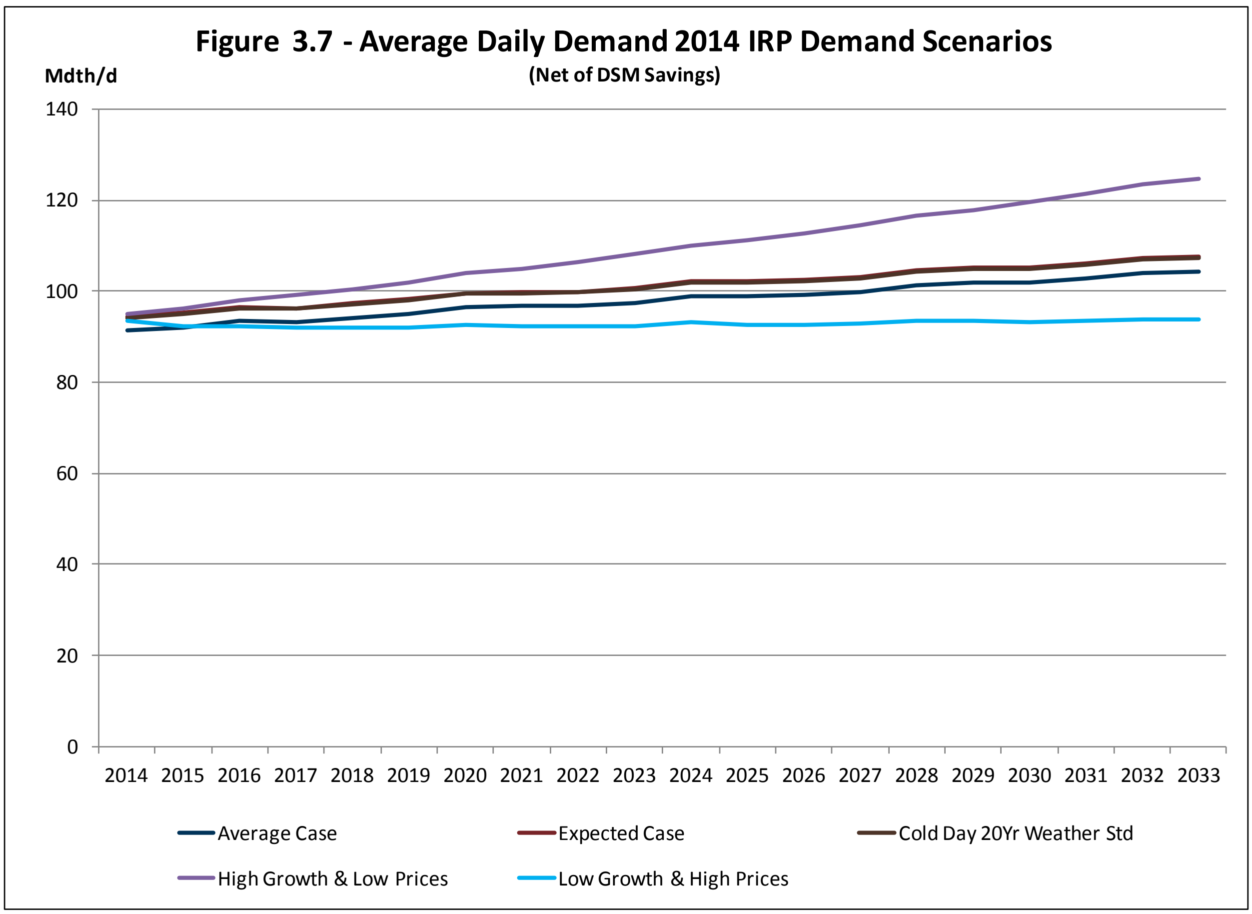
Our recent usage data indicates that even with declines in the retail rate for natural gas, long run use-per-customer continues to decline. This is likely driven by a confluence of factors including high unemployment, increased investments in energy efficiency measures, building code improvements, behavioral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

RESULTS

During 2014, our Average Case demand forecast indicates we will serve an average of 324,606 core natural gas customers with 33,343,423 dekatherms of natural gas. By 2033, we project 391,203 core natural gas customers with an annual demand of over 38,069,627 dekatherms. In Washington/Idaho, the number of customers is projected to increase at an average annual rate of .99 percent with demand growing at a compounded average annual rate of 1.03 percent. In Oregon, the number of customers is projected to increase at an average annual rate of 1.7percent, with demand growing 1.3 percent per year.

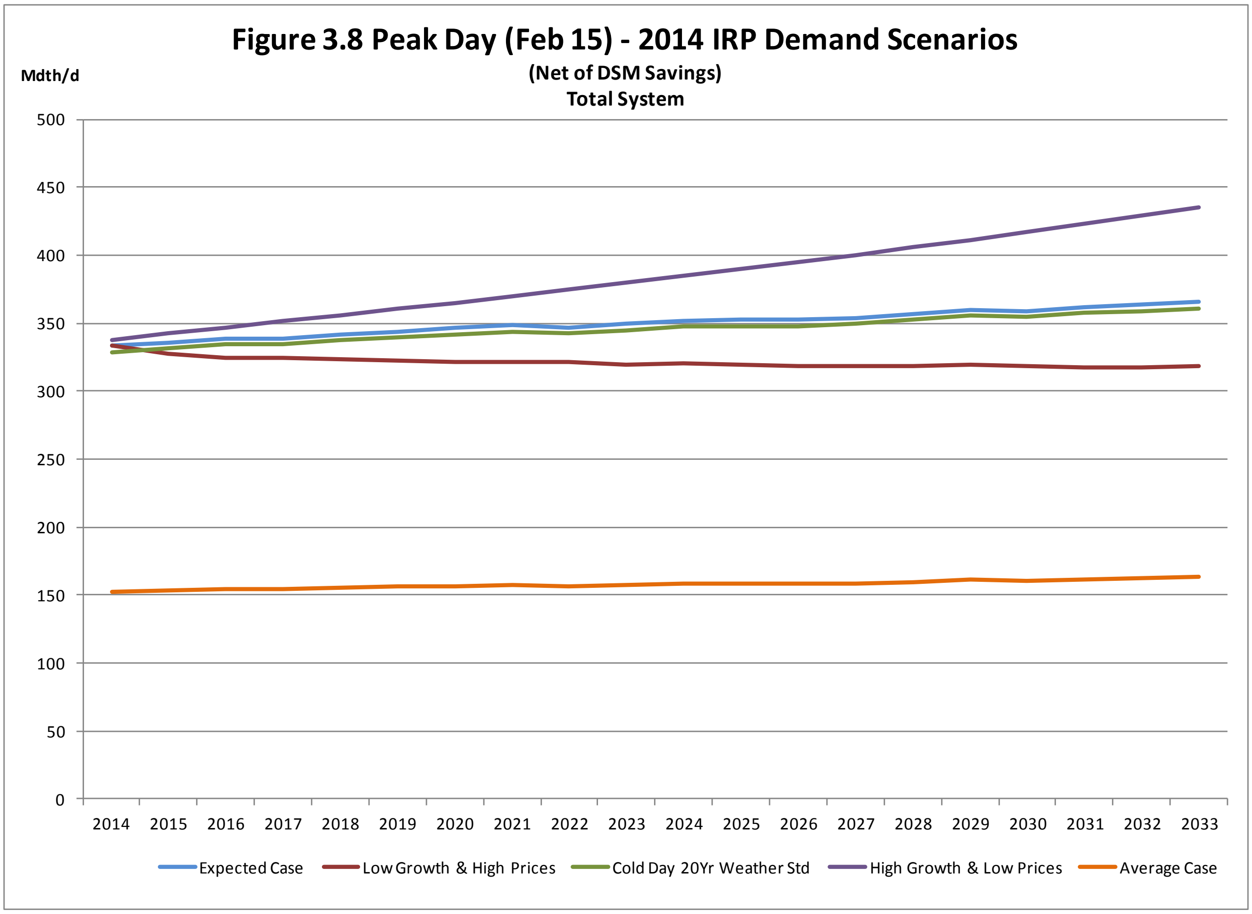
During 2014 our Expected Case demand forecast indicates we will serve an average of 324,606 core natural gas customers with 34,095,766 dekatherms of natural gas. By 2033 we project 391,203 core natural gas customers with an annual demand of over 38,889,977 dekatherms.

Figure 3.7 shows system forecasted demand for the demand scenarios on an **average daily basis** for each year[4].



[4] Appendix 3.9 shows gross demand, DSM savings, and net demand.

Figure 3.8 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 3.8.



The purpose of the IRP is to balance 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 demand side management initiatives is described in Chapter 4 - Demand-Side Resources.

ALTERNATIVE FORECASTING METHODOLOGIES

There are many forecasting methods available and used throughout different industries. We strive to use methods that enhance forecast accuracy, facilitate meaningful variance analysis and allow for modeling flexibility to incorporate differing assumptions. We believe our statistical methodology to be sound and provide us with a robust range of demand considerations. Our methodology allows for us to vary the results of our statistical inputs by considering both qualitative and quantitative factors. These factors can be derived from data or surveys of market information, fundamental forecasters, and industry experts. We are always open to new methods of forecasting demand and we continually assess which, if any, alternative methodologies to include in our dynamic demand forecasting methodology.

KEY ISSUES

Demand forecasting is a critical component, careful evaluation of the current methodology and sufficient scenario planning is essential. The evolution of demand 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, we are mindful of the assumptions driving current forecasts and understand that these can and will change over time. Therefore, monitoring key assumptions driving the demand forecast is ongoing.

PRICE ELASTICITY

We continue to question the best way to incorporate a price elastic response to demand given the complex cross commodity relationships, regulatory pricing mechanisms, flat forward price curve and changing technologies in energy efficiency that make discerning how much demand response we can reasonably expect over the long term.

An action item from our previous IRP had us exploring the possibility of a regional elasticity study facilitated by the company in conjunction with a third party such as the NWGA or the AGA. We have approached the NWGA and they are willing to assess regional interest and facilitate the process. We are developing the scope, assessing who best to conduct a study, and the associated costs. Once those decisions have been made we will assess the interest level of others then make decision whether to proceed or not.

"FLAT-LINED" DEMAND RISK

Forecasting customer usage is a complex process. There is a balance between simplicity and complexity with the ultimate goal of increasing forecast accuracy. There are many factors that can be incorporated into these models, assessing which ones are significant and improve the accuracy are key. We continue to evaluate economic and non-economic drivers to see which if any improve forecasting accuracy. We will also stay abreast of research on climate change and how it can be incorporated into the forecasting process.

For the last few planning cycles we have discussed the changing slope of our forecasted demand. Slowed growth due to the recession and declining use per customer driven by energy efficiency and price elastic responses to higher commodity costs and higher costs of everything else. Use per customer seems to have stabilized and now what has eroded is the hope that customer growth in our service territory will return to pre-recession levels.

This reduced demand pushes the need for resources beyond our planning horizon which means no new investment in resources is necessary. However, should those assumptions change causing a rebound in demand resource needs are accelerated. Therefore, careful monitoring of demand trends in order to identify signposts of accelerated demand growth is critical.

EMERGING NATURAL GAS DEMAND

The shale gas revolution has changed the long-term availability and price of natural gas. With this revolution an evolution in usage of natural gas is emerging. From fertilizer plants to food processors interest in industrial processes which use natural gas as a feedstock are growing. Another likely demand is in the transportation sector, both land based and marine fleets are turning to natural gas for their fuel supply due to its low price and better environmental footprint when compared to diesel. It remains to be seen if these new customers are served by an LDC, in all likelihood they will not be firm sales customers, however their demands will have an impact on regional supply which could trigger price movement.

CONCLUSION

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

CHAPTER 4 ■ DEMAND-SIDE RESOURCES

OVERVIEW

Avista is committed to offering natural gas Demand-Side Management (DSM) portfolios to our residential, commercial and industrial customers when it is feasible to do so in a cost-effective manner as prescribed within each jurisdiction. In recent years our customers have benefitted from precipitous declines in natural gas avoided costs. At the same time these falling avoided costs have made it more challenging to design a cost-effective DSM portfolio as well as limiting the traction that efficiency programs have with our retail customers. The Company is working in collaboration with our regulators and key external stakeholders to restructure potential natural gas DSM opportunities in a manner that can be responsibly offered to our customers. Currently the status of the Company's natural gas DSM programs differs significantly in each of the three jurisdictions where the Company functions.

The Company's Washington and Idaho DSM programs are managed, to the extent possible, as a single portfolio due to the geography and communications inherent within that portion of the Avista service territory. Previous analysis, using the then-prevailing avoided cost that were more favorable to DSM resources, led Avista to the conclusion that it was not possible to field a Washington and Idaho natural gas DSM portfolio that would be cost-effective under the Total Resource Cost (TRC) test. The TRC cost-benefit test is a measurement of the success that a portfolio has in reducing the customer's total energy cost for providing end-use services.

As a consequence of the inability to offer a TRC cost-effective portfolio in Idaho, the Company filed for and received approval for a suspension of the natural gas DSM portfolio in that jurisdiction. The Company did commit to continuing to monitor the weighted average cost of gas (WACOG) as a proxy for the avoided cost between IRP evaluations and re-evaluate the potential for a cost-effective portfolio if these costs were to increase. This is in addition to a more in-depth evaluation as part of the natural gas IRP cycle and annual business planning process.

The Washington Utilities and Transportation Commission responded to the Company's filing for suspending the natural gas DSM portfolio by directing the Company to apply the Program Administrator Cost (PAC) test (also known as the Utility Cost Test) in place of the TRC test. The PAC cost-effectiveness test takes the perspective of managing only the customer's utility bill through efficiency programs and not the customers total cost of energy. It does this by excluding from consideration the customer's incremental investment in purchasing efficiency beyond what is paid for by the utility. Since incentives are almost invariably only part of the incremental cost associated with efficiency measures the restricted cost definition of the PAC test leads to higher benefit-to-cost ratios. The Company did find it necessary to reduce incentives but was able to design a portfolio that was anticipated to be cost-effective under the more narrowly defined PAC test.

The Company's Oregon DSM portfolio is distinctly separate from that which is offered in the Washington and Idaho jurisdictions. Though the substantial reductions in the avoided cost created circumstances where the existing natural gas DSM portfolio would no longer be TRC cost-effective, the Company was able to identify several strategies that could significantly improve the portfolio performance in a low avoided cost environment. The Oregon Public Utility Commission has granted a two year period of time for the Company to identify and implement these optimizations. Many of these improvements have been completed and more are in-progress with favorable impacts upon the cost-effectiveness performance to date.

THE CONSERVATION POTENTIAL ASSESSMENT METHODOLOGY OVERVIEW

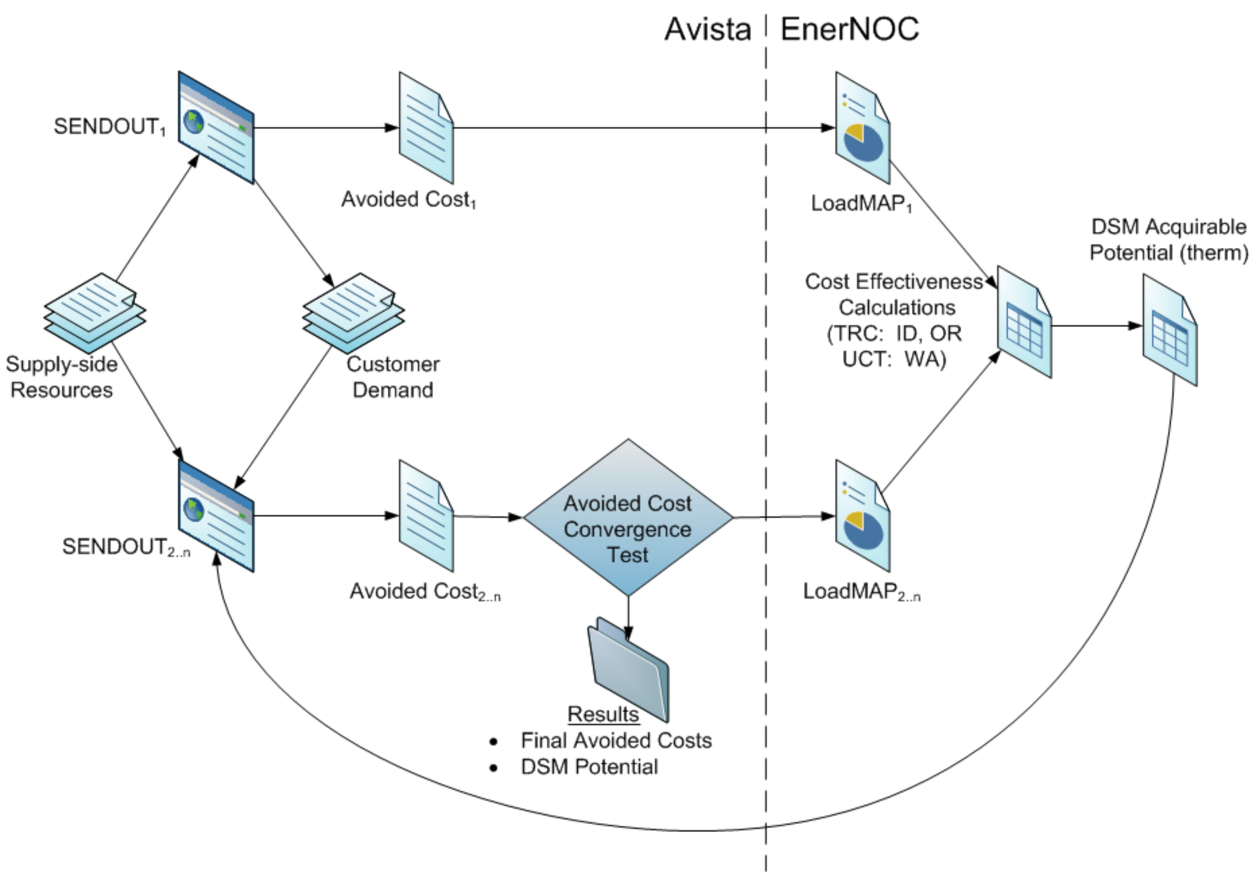
Avista engaged EnerNOC to perform an external independent evaluation of the technical, economic and achievable potential within each of Avista's three jurisdictions over a 20 year planning horizon. This process involves indexing existing nationally recognized Conservation Potential Assessment (CPA) models 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 Planning Council.

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 to reiterate until the differential between the avoided cost streams of the most recent and the immediately previous iteration becomes immaterial. At that point both supply and demand side options are functioning from comparable (including a 10% preference for DSM resources) avoided costs and the resulting load is meeting all load requirements.

The illustration below is a graphical depiction of the previously described methodology used in the presentation of this methodology to the IRP Technical Advisory Committee.

Figure 4.1 – Integration of DSM into the IRP process



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 a 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.

It should be noted that, based upon guidance provided by the WUTC and as previously explained, the cost-effectiveness metric applied in developing the Washington DSM supply curve was the PAC test rather than the TRC test used in past IRP evaluations of Washington and continuing to be used in the Idaho and Oregon jurisdictions. The PAC tests narrower definition of costs lead to proportionately higher DSM acquisition targets within the Washington jurisdiction.

ENVIRONMENTAL EXTERNALITIES

The gathering, transmission, distribution and use of natural gas involve some inherent environmental costs that are not necessarily borne by the parties to the transaction or the user of the resource. These costs are referred to as externalities since they represent those costs that are external to the parties involved in the transaction. It is difficult to quantify the value of these externalities since they are borne by individuals within society who may drastically differ on the value that they place on the absence of these impacts. Furthermore there is a lack of well-defined markets for exchanging the impact of these externalities in a way that would reveal how society would collectively value their impact.

It is the intent of the IRP to consider the full cost of the resources acquired by the utility and used by our customers in the resource selection process. Towards that end the Company incorporates a DSM preference in recognition of the lesser environmental externality cost incurred when customer end-use needs are met with efficiency resources rather than supply resources. This preference is incorporated into the CPA by increasing the avoided cost used to determine if DSM resources are cost-effective by 10%. By artificially increasing this avoided cost price signal there are DSM measures that would not otherwise pass the cost-effectiveness test that are accepted into the optimized DSM portfolio and incorporated within the acquisition target. This preference for DSM resources is separate from and in addition to any quantifiable non-energy impacts (generally benefits) that the Company is able to quantify for inclusion as an efficiency resource option benefit within the TRC cost-effectiveness test.

THE CONSERVATION POTENTIAL ASSESSMENT FINDINGS

Prior to the development of potential estimates EnerNOC 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 that were defined as of January 2013 are included in the baseline. The baseline forecast is the foundation for the analysis of savings from future DSM efforts 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 EnerNOC, existing and approved changes to building codes and equipment standards, and Avista’s internally developed load forecast.

According to the CPA completed for Avista, the residential sector natural gas consumption for all end uses and technologies increases primarily due to the projected 1.0 percent annual growth in the number of households but also due to 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 4.1 illustrates the system-wide baseline forecast of natural gas use across all sectors for selected years to include the baseline year, annually for the years to the next IRP cycle and selected years thereafter. This baseline is expected to increase by 11 percent over the 20 year planning horizon corresponding to an annualized growth of 0.5 percent. Overall the forecast projects steady growth over the next 20 years with growth in the residential sector making up for the decrease in sales in the industrial sector. Idaho is projected to experience the highest level of growth with Oregon having the next highest level of growth.

Table 4.1 Baseline Forecast Summary (1000 therms*)*

Sector	2013	2015	2016	2019	2024	2034	% Change ('13-'34)	Avg. Growth Rate ('13-'34)
Residential	199,115	197,496	199,264	204,876	206,391	232,976	17%	0.7%
Commercial	126,489	126,009	127,191	129,099	127,577	129,402	2%	0.1%
Industrial	5,015	5,252	5,524	5,867	5,477	4,491	-10%	-0.5%
Total	**330,619**	**328,757**	**331,980**	**339,842**	**339,444**	**366,869**	**11%**	**0.5%**

State	2013	2015	2016	2019	2024	2034	% Change ('13-'34)	Avg. Growth Rate ('13-'34)
Washington	173,409	171,422	172,719	176,166	175,134	183,693	6%	0.3%
Idaho	76,250	77,988	79,291	82,207	82,739	91,603	20%	0.9%
Oregon	80,960	79,346	79,969	81,469	81,571	91,574	13%	0.6%
Total	**330,619**	**328,757**	**331,980**	**339,842**	**339,444**	**366,869**	**11%**	**0.5%**

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 Idaho and Oregon and the PAC test in Washington. 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 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 4.2 for residential, commercial and industrial measures evaluated in this study for all three states.

Table 4.2 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)	
Home Energy Management System	
Advanced new Construction Designs (new only)	
ENERGY STAR Homes (new only)	

CONSERVATION POTENTIAL ASSESSMENT RESULTS

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

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

The technical potential for the overall Avista service territory for the full 20 year IRP horizon period ultimately reaches 46.5 percent of the baseline end-use forecast.

Economic potential applies the cost-effectiveness metric appropriate to each jurisdiction to 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 13.5 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 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 Northwest Power and Conservation Council, is 10.1 percent of the baseline energy forecast by the end of 2034.

Tables 4.3 and 4.4 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 4.1.

Table 4.3 Summary of Cumulative Achievable, Economic and Technical Conservation Potential

	2015	2016	2019	2024	2034
Baseline projection (1,000Therms)	328,757	331,980	339,842	339,444	366,869
Cumulative Natural Gas Savings (1,000Therms)					
Achievable Potential	1,677	2,639	9,890	20,615	36,887
Economic Potential	4,152	5,877	17,371	32,580	49,566
Technical Potential	12,512	19,298	53,433	100,103	170,543
Cumulative Natural Gas as a % of Baseline					
Achievable Potential	0.5%	0.8%	2.9%	6.1%	10.1%
Economic Potential	1.3%	1.8%	5.1%	9.6%	13.5%
Technical Potential	3.8%	5.8%	15.7%	29.5%	46.5%

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

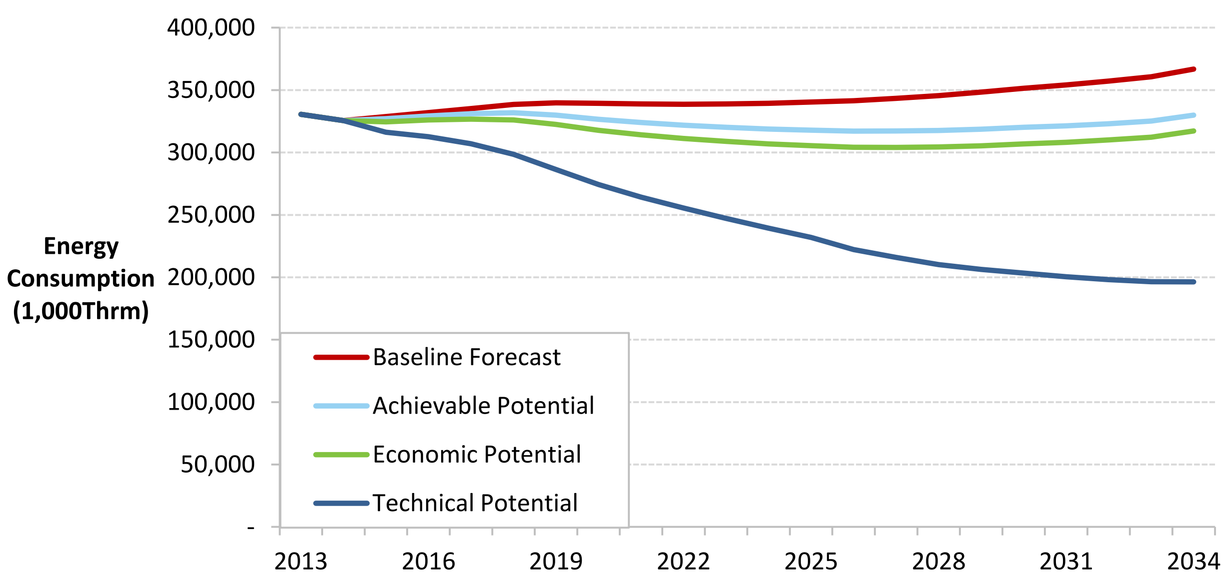
Table 4.4 Summary of Cumulative Achievable Potential by State and Sector

Cumulative Savings (1,000Therms)	2015	2016	2019	2024	2034
Washington	1,287	2,024	7,781	15,822	26,997
Idaho	228	342	1,029	2,316	4,504
Oregon	161	272	1,080	2,477	5,386
Total	**1,677**	**2,639**	**9,890**	**20,615**	**36,887**

Cumulative Savings (1,000Therms)	2015	2016	2019	2024	2034
Residential	384	727	5,279	10,154	15,957
Small Commercial	296	480	1,400	3,286	6,924
Large Commercial	969	1,390	3,085	6,907	13,599
Industrial	27	42	126	268	407
Total	**1,677**	**2,639**	**9,890**	**20,615**	**36,887**

Figure 4.1 below illustrates the impact of the DSM potential forecast upon the end-use baseline absent of any DSM acquisition. By the end of the 20 year period the achievable potential (indicated by the light blue line) offsets 102 percent of the growth in the baseline forecast for the Avista service territory. This is in part the consequence of low load growth as well as the higher level of achievable DSM identified within Washington (Avista's largest jurisdiction) using the more generous PAC cost-effectiveness test metric.

Figure 4.2 - Conservation Potential Energy Forecast (1000 therm*)*



POTENTIAL RESULTS – RESIDENTIAL

Single-family homes represent 78 percent of Avista's residential natural gas customers but account for 83 percent of the sector's consumption in the study base year 2013. The state of Washington makes up a strongly disproportionate quantity of the savings since the target acquisition is based upon the PAC test while Oregon and Idaho are based on the TRC test.

Table 4.5 provides a distribution of achievable potential by state for the residential sector.

Table 4.5 Residential Cumulative Achievable Potential by State, Selected Years

	2015	2016	2019	2024	2034
Baseline projection (1,000Therms)					
Washington	101,488	102,205	105,064	105,708	116,970
Idaho	46,978	47,633	49,224	49,670	58,109
Oregon	49,029	49,426	50,589	51,012	57,897
Total	**197,496**	**199,264**	**204,876**	**206,391**	**232,976**
Natural Gas Cumulative Savings (1,000Therms)					
Washington	370	682	4,643	8,898	13,676
Idaho	6	18	261	493	875
Oregon	8	27	375	763	1,405
Total	**384**	**727**	**5,279**	**10,154**	**15,957**
% of Total Residential Savings					
Washington	96%	94%	88%	88%	86%
Idaho	1%	3%	5%	5%	5%
Oregon	2%	4%	7%	8%	9%

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 measure-by-measure finding of the potential study the greatest sources of residential achievable potential across all three jurisdictions are:

- Shell measures and insulation
- Thermostats and home energy monitoring systems
- Water-saving devices such as low-flow showerheads and faucet aerators
- Water heater tank blankets and pipe insulation

POTENTIAL RESULTS – COMMERCIAL AND INDUSTRIAL

The baseline forecast for the commercial and industrial sector grows steadily during the forecast period. Consequently energy efficiency opportunities are significant for this sector. However, similar to the residential sector, the historically low avoided cost projections limit the achievable potential.

The large commercial sector provides the greatest opportunities for savings. Although potential as a percentage of baseline use varies from one sector to the next, results do not vary greatly among the three states under the TRC test; Washington has higher savings due to using the PAC cost effectiveness test. Table 4.6 below details the achievable potential by sector for selected years.

Table 4.6 Commercial and Industrial Cumulative Achievable Potential by Selected Years

	2015	2016	2019	2024	2034
Baseline projection (1,000Therms)					
Small Commercial	51,170	51,514	51,931	50,861	52,475
Large Commercial	74,839	75,677	77,168	76,716	76,927
Industrial	5,252	5,524	5,867	5,477	4,491
Total	**178,239**	**180,349**	**184,098**	**182,156**	**189,882**
Natural Gas Savings (1,000Therms)					
Small Commercial	296	480	1,400	3,286	6,924
Large Commercial	969	1,390	3,085	6,907	13,599
Industrial	27	42	126	268	407
Total	**1,292**	**1,912**	**4,611**	**10,461**	**20,930**
% of Total Commercial and Industrial Savings					
Small Commercial	23%	25%	30%	31%	33%
Large Commercial	75%	73%	67%	66%	65%
Industrial	2%	2%	3%	3%	2%

Table 4.7 Commercial and Industrial Cumulative Achievable Potential by State and Selected Years

Cumulative Savings (1,000Therms)	2015	2016	2019	2024	2034
Washington	917	1,343	3,138	6,924	13,321
Idaho	223	324	768	1,824	3,629
Oregon	153	245	705	1,714	3,981
Total	**1,292**	**1,912**	**4,611**	**10,461**	**20,930**
Cumulative Natural Gas Savings (% of Statewide Baseline)					
Washington	1.3%	1.9%	4.4%	10.0%	20.0%
Idaho	0.7%	1.0%	2.3%	5.5%	10.8%
Oregon	0.5%	0.8%	2.3%	5.6%	11.8%
Total	**1.0%**	**1.4%**	**3.4%**	**7.9%**	**15.6%**

Similar to residential, the bulk of the commercial and industrial 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
- Boiler operating measures such as maintenance
- Hot water reset and efficient circulation
- Equipment upgrades for furnaces, boilers and unit heaters
- Food service equipment

AGGREGATE POTENTIAL RESULTS

The following three tables provide the 2015-2016 CPA identified DSM opportunity for Idaho, Oregon and Washington, respectively.

Table 4.8 Idaho Natural Gas Target (2015-2016)

Incremental Annual Savings (1,000Therms)	2015	2016
Residential	6	13
Commercial & Industrial	223	101
Total	**228**	**114**

Table 4.9 Oregon Natural Gas Target (2015-2016)

Incremental Annual Savings (1,000Therms)	2015	2016
Residential	8	19
Commercial & Industrial	153	92
Total	**161**	**111**

Table 4.10 Washington Natural Gas Target (2015-2016)

Incremental Annual Savings (1,000Therms)	2015	2016
Residential	370	311
Commercial & Industrial	917	426
Total	**1,287**	**737**

USES AND APPLICATIONS OF THE CONSERVATION POTENTIAL ASSESSMENT

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 DSM resources. Those 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 not only to determining the quantity of DSM resources that are cost-effective when compared to the CPA-identified DSM supply curve, but also and perhaps more importantly the management of the DSM portfolio between the two year IRP cycles. The avoided costs are critical to the selection and optimization of individual DSM delivery options on a real-time basis and as part of a comprehensive formal annual business planning process. The IRP-identified avoided costs also serve as the foundation for calculating the portfolios actual cost-effectiveness performance as part of the Company's retrospective DSM Annual Report.

These 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.

As a general rule the increased level of detail brought into the operational business planning process leads to an improvement in the cost-effectiveness of both the individual measures and the overall portfolio. Eligibility and measure definitions can be fine-tuned so as to target the most cost-effective elements of a candidate measure in such a way that marginally cost-ineffective measures can be become cost-effective contributors to the portfolio. However it can also be true that the high-level assumptions made as part of the CPA may be overly optimistic when applied to individual operational programs.

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.

The continuation of the downward trend in natural gas avoided cost expectations is causing a growing deviation between the CPA and business planning process. Specifically CPA processes generally make the simplifying assumption that non-incentive utility costs are a constant percentage of the customer incremental cost or of the offered incentive. In operational reality there may be fixed and incremental components to these non-incentive costs and there are generally economies of scale involved in enlarging the size of the portfolio (or conversely diseconomies of scale when the size of the portfolio diminishes due to falling avoided costs). CPA processes generally function at too high of a level to recognize these operational details and as such are unable to predict the point at which the quantity of cost-effective DSM and the cost-effectiveness margin associated with those measures are insufficient to offset fixed portfolio costs and diseconomies of scale. These challenges are more appropriately left to the operational business planning processes.

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. Progressively falling avoided costs and low growth in customer demand have led to a reduced role for DSM in the overall natural gas portfolio, though as a consequence of the lower growth and the change in the cost-effectiveness metric applicable to the Washington jurisdiction DSM does nevertheless greatly offset future load growth.

The Company is actively working to optimize how natural gas efficiency resources can be acquired under this radically different economic environment. Important factors that must be considered within this optimization include:

- The criteria established for adopting measures within the portfolio
- The nature of the Company's non-incentive utility cost
- The level of incentives established with particular attention to their implications upon the PAC test performance.
- Alternative means of moving cost-effective efficiency options forward.

In June 2014 the Company will begin the process leading towards the Washington and Idaho 2015 DSM Business Plan. This process is an opportunity to comprehensively review the electric and natural gas DSM portfolio and perform the optimizations noted above. Within Washington, where the PAC test is being applied to this optimization process, there will be a review of the customer financial incentives to determine if the lower avoided costs are sufficient to support the existing incentive levels. The Idaho portfolio will be reviewed to determine if there are new opportunities that would allow a TRC cost-effective portfolio to be offered.

Within Oregon the on-going optimization of the portfolio has led to significant improvements in TRC cost-effectiveness performance in 2013, though revised unit energy savings may make it difficult to deliver the same level of performance in 2014. Nevertheless there is a favorable trend occurring in the cost-effectiveness of the non-mandated components of the portfolio.

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. This concept has been developing for nearly a decade but current circumstances have moved the discussion closer to the realization of such an organization. Regional natural gas utilities are actively working with the Northwest Energy Efficiency Alliance (NEEA) to develop a proposal for a natural gas market transformation entity similar to that which presently exists for electric market transformation efforts. The viability of market transformation efforts are likely to be less directly adversely impacted by falling avoided costs since they focus upon technologies and markets where strategically selected market transformation interventions can have a disproportionately large impact upon markets for efficient products and services. This makes market transformation a valuable tool in a lower avoided cost environment.

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 CPA.

The Company is also working with regional natural gas utilities on an ad hoc natural gas heat pump water heater technology pilot in anticipation of a future market transformation portfolio. The progress and prospective funding of this venture is a favorable indication that a cooperative regional market transformation effort is viable.

The Company anticipates that a proposal for a permanent natural gas market transformation organization will be advanced for regional discussion by the end of calendar year 2014. It is hoped that successes in this area will not just augment cost-effective local efforts but will create additional local programmatic opportunities.

CHAPTER 5 ■ SUPPLY-SIDE RESOURCES

OVERVIEW

We have analyzed a range of anticipated future demand scenarios and a variety of possible cost-effective conservation measures to reduce demand. This chapter discusses possible supply options to meet net demand. Our objective is to reliably provide natural gas to customers with an appropriate balance of price stability and prudent cost while navigating continuously changing market conditions. To achieve this, we evaluate a variety of supply-side resources and attempt to build a supply portfolio that is appropriately diversified. The resource acquisition and commodity procurement programs resulting from our evaluation consider physical and financial risks, market-related risks and procurement execution risks and identify the methods we deploy to mitigate these risks.

We manage our natural gas procurement and related activities on a system-wide basis. We have a number of regional supply options available to serve our core customers. These 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. In this chapter, we discuss the available regional commodity resources and our procurement plan strategies, the regional pipeline resource options available to deliver the commodity to our customers, and the storage resource options available which provide additional supply diversity, enhanced reliability, favorable price opportunities and flexibility to meet a varied demand profile. Beyond these traditional supply-side resources we discuss non-traditional resources which are also considered.

COMMODITY RESOURCES

SUPPLY BASINS

Avista is fortunate to be located in relatively close proximity to the two largest natural gas producing regions in North America – the Western Canadian Sedimentary Basin (WCSB), which is located primarily in the Canadian provinces of Alberta and British Columbia, and the Rocky Mountain (Rockies) gas basin, located primarily in Wyoming, Utah and Colorado. Avista sources virtually all 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, supplies from the WCSB and Rockies are priced lower relative to other parts of the country. Shale gas production from the Northeast has altered flow dynamics and has helped sustain the regional pricing discount. Forecasts show a long-term price advantage for the region in both the WCSB and Rockies basins as the need for these supplies to move East diminishes.

Increased availability of North American natural gas has prompted a change in the global LNG landscape. More supply than demand has prompted LNG developers to look to exporting gas in order to capture better pricing in the Asian and European markets. Regionally, there are two proposed projects in Oregon, Jordan Cove and Oregon LNG. Jordan Cove has received its FERC export authorization. Oregon LNG is next in the queue. In British Columbia, 16 export LNG projects have been announced. While there is much uncertainty about how many facilities actually get built the bigger question is how regional infrastructure and prices will be impacted by potential exports.

REGIONAL MARKET HUBS

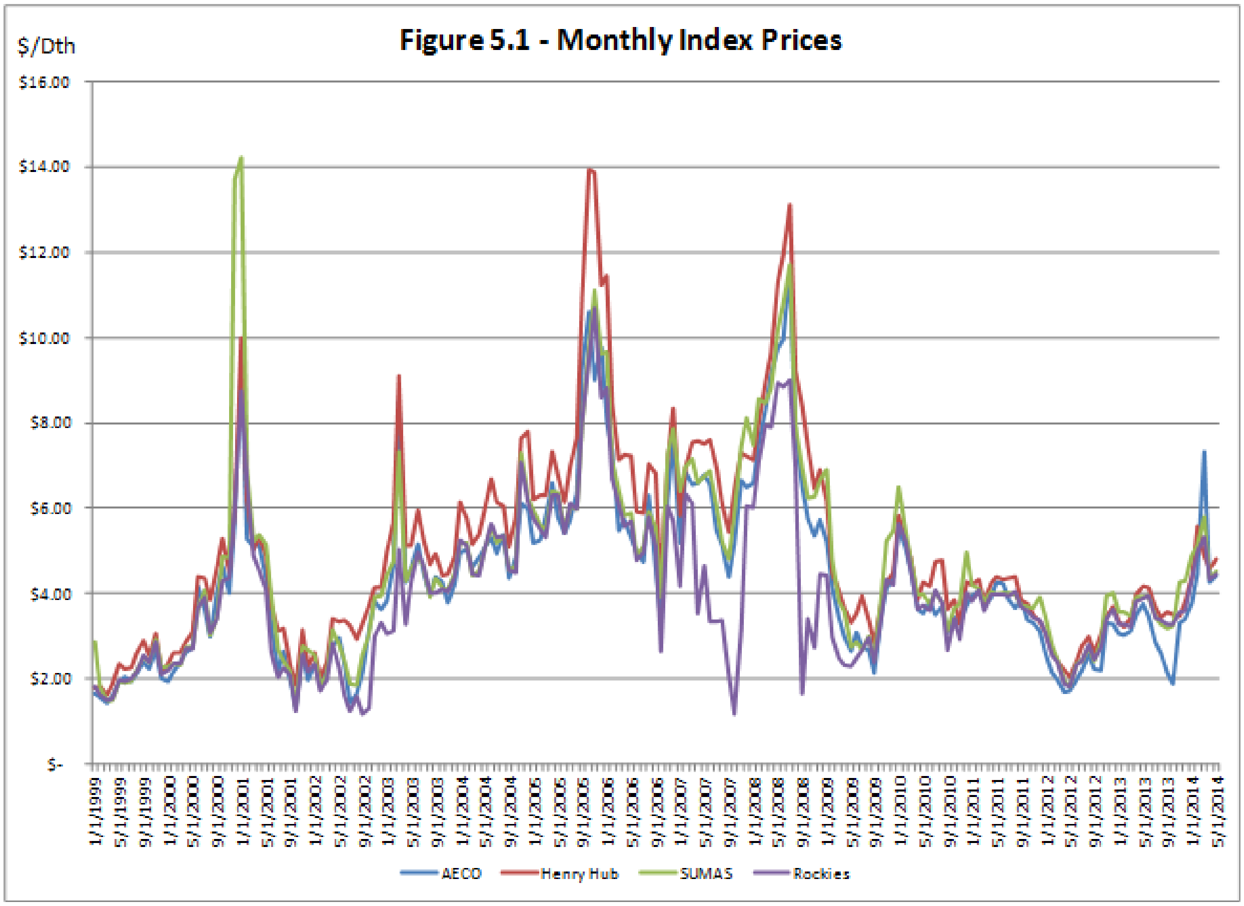
Extending out from the two primary basins are numerous regional market hubs where natural gas is traded. These typically are located at pipeline interconnects. Avista is located near and transacts at most of the

Pacific Northwest regional market hubs, enabling flexible access to a diversity of supply points. These supply points include:

- **AECO –** The AECO-C/Nova Inventory Transfer market center is a major connection region to long-distance transportation systems, which take gas to points throughout Canada and the United States. Alberta has historically produced 90% of Canada's natural gas and is the source of most Canadian natural gas exports to the United States.
- **Rockies** – This pricing "point" actually represents several locations on the southern end of the NWP system in the Rocky Mountain region. The system draws on Rocky Mountain gas-producing areas clustered in areas of Colorado, Utah, and Wyoming.
- **Sumas/Huntingdon** – This pricing point at Sumas, Wash., is on the U.S./Canadian border where the northern end of the NWP system connects with Spectra Energy's Westcoast Pipeline, and is predominantly Canadian gas coming south from Northern British Columbia.
- **Malin** – this pricing point is at Malin, Ore. on the California/Oregon border where the pipelines of TransCanada Gas Transmission Northwest (GTN) and Pacific Gas & Electric Co. connect.
- **Station 2** – Located at the center of the Spectra Energy/Westcoast Pipeline system connecting to northern British Columbia 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 to other portions of North America natural gas pricing is often compared to the Henry Hub price for natural gas. Henry Hub is a natural gas trading point located in Louisiana is the primary natural gas pricing point in the U.S. and is also the trading point used in NYMEX futures contracts.

Figure 5.1 shows historic natural gas prices for first-of-month index physical purchases at AECO, Sumas, Rockies and Henry Hub. The figure illustrates there is usually a tight relationship among the various locations; however, there have been periods where one or more price points have disconnected.



Natural gas prices among the Northwest regional supply points typically move together as well; however, the basis differential can change depending on market or operational factors. This includes differences in weather patterns, pipeline constraints at different locations and the ability to shift supplies to higher-priced delivery points in the U.S. or Canada. By monitoring these price shifts we are often able to 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 supply points (AECO, Rockies, Sumas, Malin). This illiquidity contributes to generally higher relative prices in the high demand winter months.

Procurement of natural gas is done via contracts. There are a number of contract specifics that vary from transaction-to-transaction, and many of those terms or conditions impact commodity pricing. Some of the agreed-upon 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 upon 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 the natural gas is purchased as a firm, physical, fixed-price contract regardless of when the contract is executed and what type of contract it is. However, in reality, we pursue a variety of contractual terms and conditions in order to capture the most value from each transaction.

AVISTA'S PROCUREMENT PLAN

We cannot accurately predict future natural gas prices but market conditions and experience help shape our overall approach. Avista has designed a natural gas procurement plan process that seeks to competitively acquire natural gas supplies while reducing exposure to short-term price volatility. Our procurement strategy includes hedging, storage utilization and index purchases. Although the specific provisions of the procurement plan will change as a result of ongoing analysis and experience, the following principles guide Avista's development of its procurement plan:

Avista employs a time, location and counterparty diversified hedging strategy. It is appropriate to hedge over a period of time and we establish hedge periods within which portions of future demand are physically and/or financially hedged. The hedges may not be completed at the lowest possible price but they will protect our customers from price volatility. With access to multiple supply basins, when we transact we seek the lowest priced basin. Furthermore, we transact with a range of counterparties.

Avista establishes a disciplined but flexible hedging approach. In addition to establishing hedge periods within which hedges are to be completed we also set upper and lower pricing points. In a rising market this reduces Avista's exposure to extreme price spikes. In a declining market this 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 assumptions that led to the procurement plan. Although we establish various targets in the initial plan design, policies provide flexibility to exercise judgment to revise/adjust targets in response to changing conditions.

A number of tools are utilized to help mitigate financial risks. Avista purchases gas in the spot market as well as the forward market. Spot purchases are made on a day for the next day or weekend. Forward purchases are made on a day for a designated future delivery period. Many of these tools are financial instruments or derivatives that can be utilized to provide fixed prices or dampen price volatility. We continue to evaluate how to manage daily demand volatility, whether through option tools available from counterparties or through access to additional storage capacity and/or transportation.

MARKET-RELATED RISKS AND RISK MANAGEMENT

While risk management can be defined in a variety of ways, the integrated resource plan focuses on two areas of risk: the financial risk under which the cost to supply customers will be unreasonably high or unreasonably volatile, and the physical risk that there may not be enough natural gas resources (either the transportation capacity or the commodity) to serve core customers.

Avista has a Risk Management Policy that describes the policies and procedures associated with financial and physical risk management. The Risk Management Policy addresses, among other things, issues related to management oversight and responsibilities, internal reporting requirements, documentation and transaction tracking, and credit risk.

There are two internal organizations that 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 consists of several 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 exists to coordinate natural gas matters among internal natural gas-related stakeholders and to serve as a reference/sounding board for strategic decisions, including hedges, made by the Natural Gas Supply department. Members include representatives from the Accounting, Regulatory, Credit, Power Resources and Risk Management departments. While the Natural Gas Supply department is responsible for implementing hedge transactions, the Group provides input and advice.

TRANSPORTATION RESOURCES

Although proximity to the liquid hubs is important from a cost perspective those supplies are only as reliable or firm 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. Consequently, we have contracted for a sufficient amount of diversified firm pipeline capacity from various receipt and delivery points (including out of storage facilities) so that firm deliveries will meet peak day demand. We believe the combination of firm transportation rights to our service territory, storage facilities and access to liquid supply basins will ensure peak supplies are available to our core customers.

The major pipelines servicing our region are as follows:

- **Williams - Northwest Pipeline (NWP)**
  A natural gas transmission pipeline serving the Pacific Northwest moving natural gas from the US/Canadian border in Washington and from the Rocky Mtn. region of the US.
- **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, Ore.
- **TransCanada Alberta System**
  A natural gas gathering and transmission pipeline in Alberta Canada that delivers natural gas into the TransCanada Foothills pipeline at the Alberta/British Columbia border.
- **TransCanada Foothills System**
  A natural gas transmission pipeline that delivers natural gas between the Alberta, British Columbia border and the Canadian/U.S. border at Kingsgate, Idaho.
- **TransCanada Tuscarora Gas Transmission**
  A natural gas transmission pipeline originating at Malin, Ore and terminating at Wadsworth, Nev.

- **Spectra Energy - Westcoast Pipeline**
  A natural gas transmission pipeline originating at Fort Nelson, British Columbia and terminating at the Canadian/U.S. border at Huntington, British Columbia/Sumas, Wash.
- **El Paso natural gas– Ruby pipeline**
  A natural gas transmission pipeline bringing supplies from the Rocky Mountain region of the U.S. to interconnections near Malin, Ore.

Avista has contracts with all of the above pipelines (with the exception of Ruby Pipeline) for firm transportation to serve our core customers. Table 5.1 details the firm transportation/resource services contracted by Avista. These contracts are of different vintages, thus different expiration dates; however, all have the right to be renewed by Avista. This gives Avista and its customers the knowledge that Avista will have available capacity to meet existing core demand now and in the future.

Table 5.1
Firm Transportation/Resources Contracted*
Dth/Day

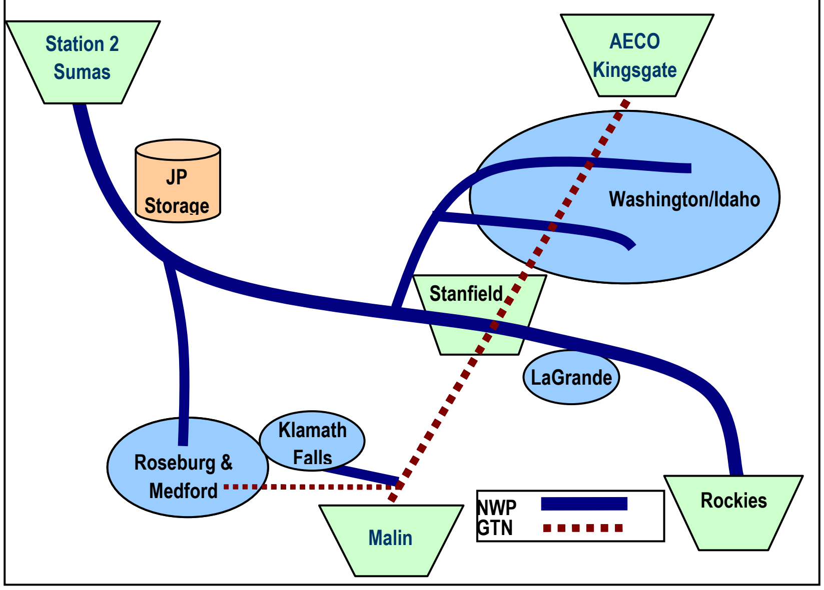
	Avista North		Avista South	
Firm Transportation	**Winter**	**Summer**	**Winter**	**Summer**
NWP TF-1	157,869	157,869	42,699	42,699
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2	91,200		2,623	
Total	**349,674**	**233,651**	**87,582**	**63,339**
Firm Storage Resources - Max Deliverability				
Jackson Prairie (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 our 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. Figure 5.2 illustrates the direct-connect pipeline network relative to our supply sources and service territories1.

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.

Figure 5.2 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 – instead they are almost always unique.

The NWP system for the most part is a fully contracted system. With the exception of La Grande our service territories lie at the end of various NWP pipeline laterals. Washington/Idaho is served via the Spokane, Coeur d' Alene and Lewiston laterals while Roseburg and Medford are served by the Grants Pass lateral. Capacity expansions on each of these laterals are lengthy and costly endeavors which Avista would likely bear most of the incremental costs.

The GTN system, on the other hand, currently has ample unsubscribed capacity. This pipeline runs directly through or lies in close proximity to most of our service territories. Mileage based rates provides an attractive option for securing incremental resource needs.

Peak day planning aside, both pipelines provide an array of options to flexibly manage daily operations. Our two largest service territories are directly served by both pipelines providing diversification and risk management 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 Columbian supply and facilitates excellent optionality for storage facility management. The Stanfield interconnect of the two lines is also geographically well situated to our service territories.

The rates we use in our planning model start with filed rates that are currently in effect (See Appendix 5.1). Forecasting future pipeline rates is challenging. Our assumptions for future rate changes are the result of market information on comparable pipeline projects, prior rate case experience and informal discussions. It is generally assumed that the 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. The level of service of 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. We do 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 should a peak day occur in the planning horizon. Since contracts for pipeline capacity are often lengthy in tenor and core customer demand needs can vary over time determining the appropriate level of firm transportation is a complex analysis of many factors. 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 their upstream supplies. This analysis is done on an annual basis as well as through the IRP. Active management of underutilized capacity through the capacity release market and engaging in optimization transactions offsets some of the transportation costs. Timely analysis is also important in order to maintain an appropriate time cushion to allow for required lead times should the need for securing new capacity arise (See Chapter 6 for a more detailed description of the management of underutilized pipeline resources).

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
- Additional supply point diversity

While there are a number of different storage facilities available to the region, Avista’s existing storage resources consist solely of ownership and leasehold rights at the Jackson Prairie storage facility.

JACKSON PRAIRIE STORAGE

Avista is one-third owner, with NWP and Puget Sound Energy (PSE) in 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, Wash. approximately 30 miles south of Olympia, Wash. The total working 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.

Outside of Avista’s ownership rights, we have 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

Our existing portfolio of supply-side resources provides a good mix of assets to manage demand requirements for an average day and peak day events. But in anticipation of growing and changing demand requirements, we monitor the following potential resource options to meet future requirements.

SYSTEM ENHANCEMENTS

Within the context of the IRP, distribution planning plays a role but is not the primary focus. Distribution works hand in hand with supply to ensure that customer demand is met on both and average day and a peak day.

There are modifications, enhancements, or upgrades that occur on the distribution system that are routine projects enhancing reliability of our system. However, in certain instances, Avista can facilitate additional peak and base load-serving capabilities through a modification or upgrade of our distribution facilities. These projects would enable more takeaway capacity from the interstate pipelines. 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 more detailed description of system enhancements (including both routine and non-routine) can be found in Chapter 8.

CAPACITY RELEASE RECALL

As discussed earlier, pipeline transportation that is not utilized to serve core customer demand can be released to other parties or optimized through daily or term transactions. Released capacity is generally marketed through a competitive bidding process and can be done on a short-term (month-to-month) or long-term basis. We actively participate in the capacity release market and have both short-term and long-term capacity releases.

We assess the need to recall capacity or extend a release of capacity on an on-going basis. The IRP process also helps evaluate if or when we need to recall some or all of our long-term releases.

EXISTING AVAILABLE CAPACITY

In some instances there is currently available capacity on existing pipelines. NWP's mainline is currently 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. We do model access to the GTN capacity as an option to meet our future demand needs.

GTN NORTH BOUND

The GTN interconnection with the Ruby Pipeline has enabled GTN the physical capability to provide a limited amount of firm forward haul service from Malin with minor modifications to their system. Fees for utilizing this service will be provided under the existing Firm Rate Schedule (FTS-1) and currently no fuel charges will be assessed. Additional requests for north bound service may necessitate the need for additional facilities and compression (i.e. fuel).

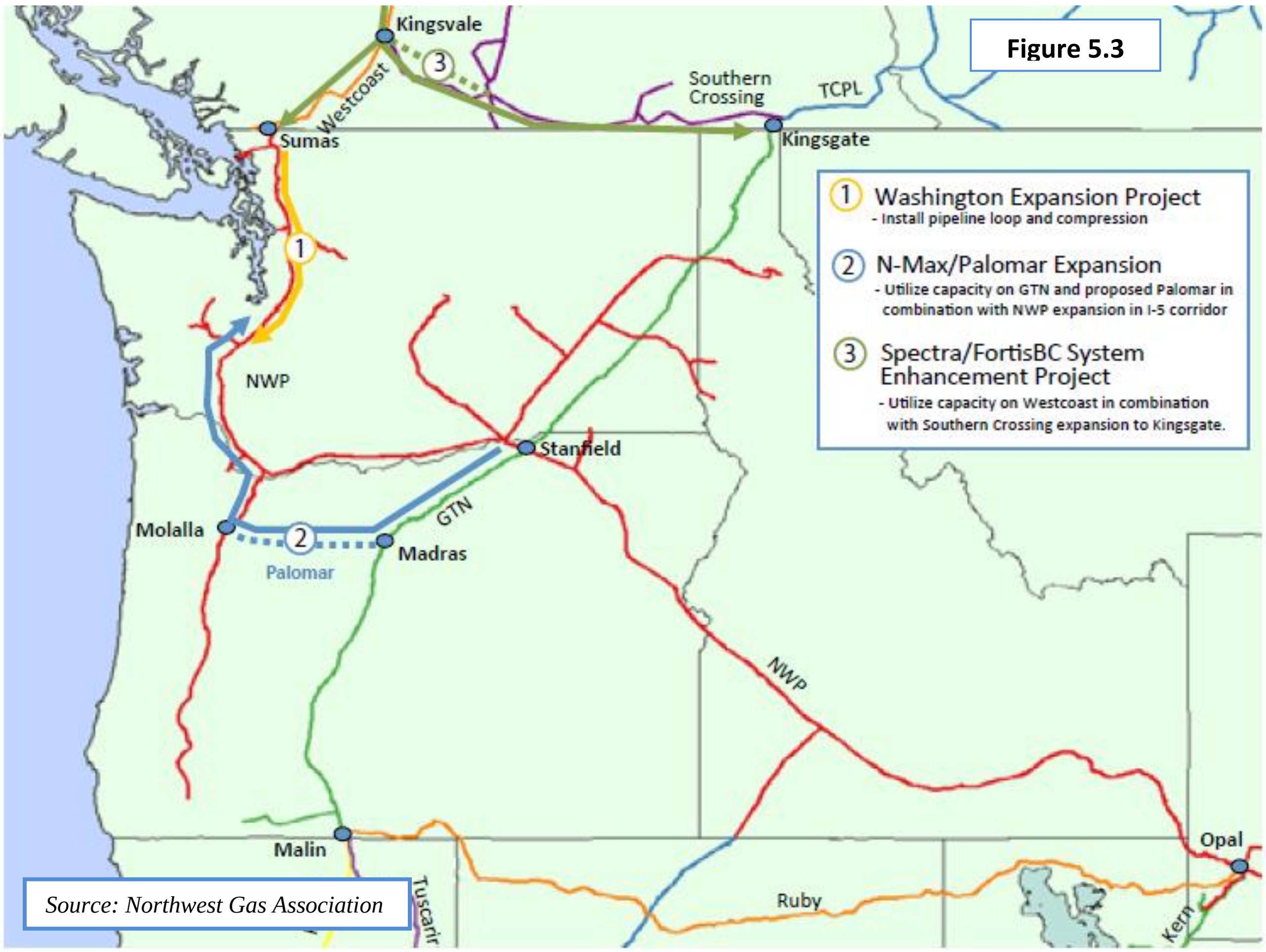
This service has the potential to be a particularly interesting solution for our Oregon customers. For example, Avista can purchase supplies at Malin, Ore. and transport those supplies to our service territory at either Klamath Falls or Medford. Malin-based natural gas supplies typically price at a premium to AECO supplies but are generally less expensive than the cost of transporting those traditional supplies south and paying the associated demand charges. The GTN system is a mileage-based system so we pay 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 determining whether or not existing resources will be available at the appropriate time, make this resource difficult to analyze. Firm pipeline capacity 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 capacity also 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 annual contracts. Even though expansions may be more expensive than existing capacity, this approach may still provide the best option to us given that some of the other options discussed in this section require matching pipeline transportation anyway. Expansions may also provide reliability or access to supply that cannot otherwise be obtained through existing pipelines.

Several specific projects have been proposed for the region. The following summaries describe these projects while Figure 5.3 illustrates their location:



Source: Northwest Gas Association

- **NWP Washington Expansion**

  NWP continues to explore options to expand its service from Sumas, WA to markets along the I-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 can be scaled to meet market demand.

- **Northwest Market Access Expansion (N-MAX)/Palomar Expansion**

  NWP has begun working with Palomar Gas Transmission (a partnership between NW Natural and TransCanada) to develop the Cascade (eastern) section of the previously proposed Palomar 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, Ore. It would be a bi-directional pipeline with an initial capacity of up to 300 MMcf/d expandable up to 750 MMcf/d.

- **Spectra/FortisBC System Enhancement**

> Fortis, British Columbia 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. Expansion of 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. Expanded east-to-west flow will increase delivery of supply to Sumas by an additional 150 MMcf/d.

Avista is supportive of proposals that bring supply diversity and reliability to the region. We actively engage in discussions and analysis of the potential impact to Avista of each regional proposal from a demand serving and reliability/supply diversity perspective. None of the above projects provide direct delivery connection to any of our service territories. For Avista to consider them to be a viable incremental resource to meet demand needs would require combining with additional capacity on existing pipeline resources. Given this situation we did not model these specific projects. However we do consider a generic expansion that represents a new pipeline build to Avista's service territories.

IN-GROUND STORAGE

In-ground storage provides many advantages when gas from storage can be delivered to Avista's service territory city-gates. It can enable deliveries of natural gas to customers during cold weather events when they need it most. It also facilitates potentially lower cost supply for our 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 considered 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, we will continue to look for exchange and transportation release opportunities that could fully utilize these additional resource options. Even without deliverability, we believe it can make financial sense to utilize Jackson Prairie capacity to optimize time spreads within the natural gas market and provide net revenue offsets to customer gas costs. There are no current 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, Wyoming, and northern California storage are all possibilities. Again, transportation to and from these facilities to Avista's service territories continues to be the largest impediment to contracting for these options.

Satellite LNG

Satellite LNG is another storage option that could be constructed within Avista's service territories and is ideal for meeting peak day or cold weather events. Satellite LNG uses natural gas that is trucked to the facilities in liquid form rather than liquefying on site. Locating the facility in the service area would avoid interstate pipeline transportation and related charges. Permitting issues notwithstanding, facilities could be located in optimal locations within the distribution system.

Estimates for this type of resource are somewhat varied because of sizing and location issues. For our modeling, we have used estimates from other facilities constructed in the area and from informal conversations with experts in the industry and believe these to be reasonable estimates for planning purposes. We will continue to monitor and refine the costs of developing satellite LNG while remaining mindful of lead time requirements and environmental issues.

Plymouth LNG
NWP owns and operates an LNG storage facility located at Plymouth, Washington, which provides a gas liquefaction, storage, and vaporization service under its LS-1 and LS-2F tariffs. An example ratio of injection and withdrawal rates are such that it can take more than 200 days to fill to capacity, but only 3-5 days to empty. As such, the resource is best suited for needle-peak demands. Incremental transportation capacity to our service territories would have to be obtained in order for it to be a truly effective peaking resource.

This peaking resource is fully contracted and not available for contracting at this time. Given this situation, this option is not being modeled in SENDOUT® for this IRP. However, due to the fact that many of the current capacity holders are on one-year rolling evergreen contracts, it is possible that this option will again become viable in the future. As with other storage options, firm transportation from the facility would be required.

COMPANY OWNED LIQUEFACTION LNG

Instead of leasing LNG capacity from Plymouth, Avista could construct a liquefaction LNG facility within our service area. Doing so could use excess transportation during off-peak periods to fill the facility but avoid tying up transportation during peak weather events. Additional annual pipeline charges could probably be avoided.

Construction would be dependent 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. Due to these risks we did not include this resource in our modeling, recognizing this type of project is highly complex and there are many risk considerations that require evaluation and monitoring.

BIOGAS

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

Biogas is a renewable fuel so it sometimes attracts renewable energy subsidies in some parts of the world. We are not aware of any current subsidies but future stimulus or energy policies could lead to some form of financial incentives at a later time.

Biogas projects are inherently individualized, making reasonable and reliable cost estimates 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. We did not consider biogas as a resource in this planning cycle but remain receptive to such projects as they are proposed.

SUPPLY SCENARIOS

For this IRP we modeled two supply scenarios. Table 5.2 lists the supply scenarios and Appendix 5.2 provides the details on what is included in each of these scenarios. Additional detail about the results of these supply scenarios modeled is included in Chapters 6 and 7.

Table 5.2 Supply Scenarios
Existing Resources
Existing + Expected Available

- **Existing Resources**
  Represents all resources currently owned or contracted by Avista.
- **Existing + Expected Available**
  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 supply and the outlook for future natural gas prices. With certainty that the molecules exist and the technology exists to access them, there are issues that can impact the cost and availability.

- **Hydraulic Fracturing**
  Improvements in hydraulic fracturing (HF), a sixty-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 its challenges. The hype caused by movies, documentaries, and articles in national newspapers about “fracking” has plagued the natural gas and oil industry. There is worry that HF is contaminating aquifers, increasing air pollution, and most recently 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.

  To that end many levels of government, industry, and universities have or are engaged in conducting studies to better understand the actual and potential impacts of HF. 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 HF processing, and implementing “green completions” for wells. The state governments are participating in independent audits of their regulations to ensure that proper oversight is in place. The outcome of these audits, studies, and further research could greatly impact both the cost and availability of natural gas and oil.

- **Pipeline Availability**
  The Pacific Northwest has efficiently utilized its relatively sparse network of pipeline infrastructure to reliably meet the regions needs. As we move closer and closer to a more renewable energy future demand for natural gas via gas-fired generation will increase. Pipeline capacity is the link between gas and power.

  Adding additional pressure to existing pipeline resources is the announcement of three methanol plants. The plants use large amounts of natural gas a feedstock for creating methanol, which is used primarily to make other chemicals but is also used as fuel.

  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.

ACTION ITEMS

With no immediate need to acquire incremental supply side resources to meet peak day demands Avista's focus in the near term will include the following:

- Continue to monitor supply resource trends including the availability and price of natural gas to the regions, exporting LNG, Canadian natural gas imports, regional plans for gas fired generation and its affect on pipeline availability, as well as future regional pipeline and storage infrastructure plans.
- We will also monitor new resource lead time requirements relative to when resources are needed to preserve resource option flexibility.

CONCLUSION

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

CHAPTER 6 ■ INTEGRATED RESOURCE PORTFOLIO

OVERVIEW

This chapter combines all 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 should they exist.

The foundation for integrated resource planning is the demand planning criteria used for developing demand forecasts. Avista currently uses the “coldest day on record” as its weather planning standard for determining peak-day demand. This is consistent with our past IRPs and is more fully described in Chapter 3 – Demand Forecasts. We utilize historic peak and average weather data for each demand region for this IRP. We plan to serve our expected peak day in each demand region with firm resources. Firm resources include natural gas supplies, pipeline transportation and storage resources. In addition to planning for peak requirements, we also plan for non-peak periods such as winter, shoulder and summer demand. Our modeling process includes running an 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, our IRP analysis of demand-serving capabilities only focuses on the residential, commercial and firm industrial classes.

Our supply forecasts are 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 percentage of additional supply that must be purchased is governed through FERC and National Energy Board approved tariffs.

SENDOUT® PLANNING MODEL

The SENDOUT® Gas Planning System from Ventyx is used to perform integrated resource optimization. The SENDOUT® model was purchased in April 1992 and has been used in preparing all IRPs since then. Avista has a long-term maintenance agreement with Ventyx that allows us to receive software updates and enhancements. These enhancements include software corrections and improvements brought on by industry change.

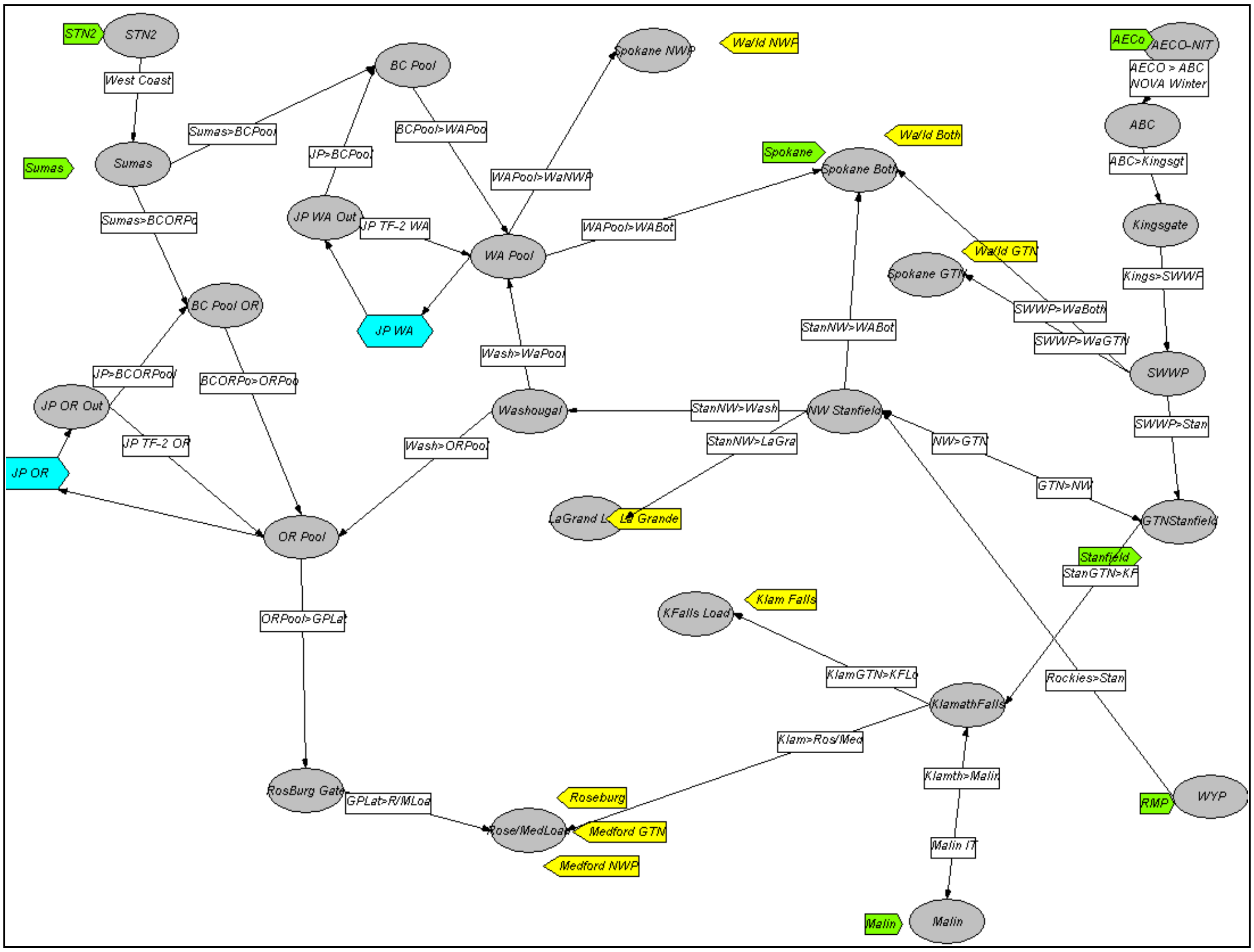
SENDOUT® is a linear programming model widely used to solve natural gas supply and transportation optimization questions. Linear programming is a proven technique used to solve minimization/maximization problems. SENDOUT® looks at the complete problem at one time within the study horizon, while taking into account 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 – minimum, maximum and average temperatures
- Existing and potential transportation data which describes to the model the network for the physical movement of the 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
- DSM potential

Figure 6.1 is a SENDOUT® network diagram of our demand centers and resources. This diagram illustrates Avista's current transportation and storage assets, flow paths and constraint points.

FIGURE 6.1 SENDOUT® MODEL DIAGRAM



The SENDOUT® model also provides a flexible tool to analyze potential 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 DSM
- Weather pattern testing and analysis
- Transportation cost analysis
- Avoided cost calculations
- 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 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

RESOURCE INTEGRATION

We have defined the planning methodologies, described the modeling tools and identified the existing and potential resources. The following summarizes the comprehensive analysis of bringing demand forecasting and existing and potential supply and demand-side resources together to form our 20-year, risk adjusted least-cost plan.

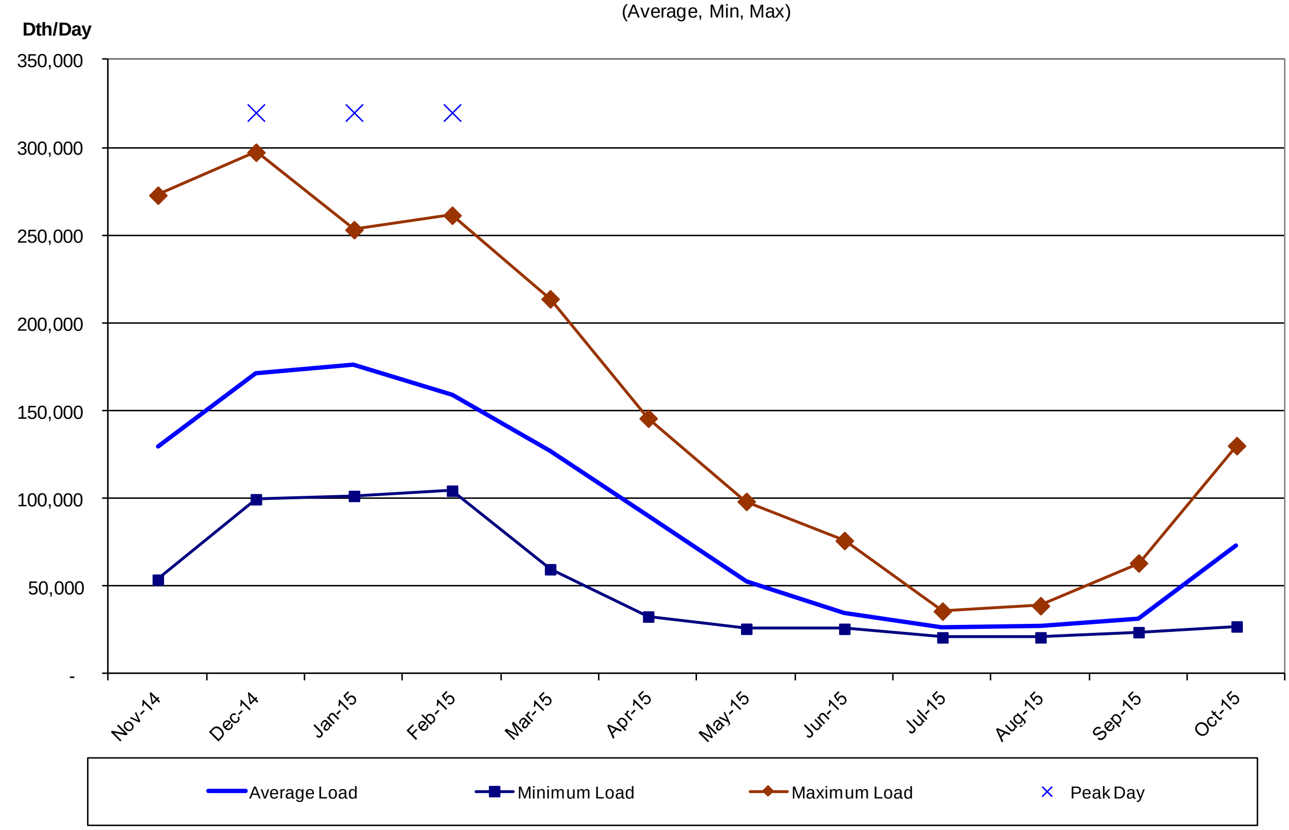
DEMAND FORECASTING

Avista's demand forecasting approach is described in detail in the Chapter 3 - Demand Forecasts.

We forecast 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, we also model demand by customer class within each area. The relevant customer classes in Avista's service territories are residential, commercial and firm industrial customers.

Customer demand reflects a highly weather-sensitive component. Avista's customer demand is not only highly seasonable but also highly variable. Figure 6.2 captures this variability showing our monthly system-wide average demand, minimum demand day observed in each month, and maximum demand day observed in each month, and our winter projected peak day demand for the first year of our Expected Case forecast as determined in SENDOUT®.

Figure 6.2 Total System Average Daily Load
(Average, Min, Max)



NATURAL GAS PRICE FORECASTS

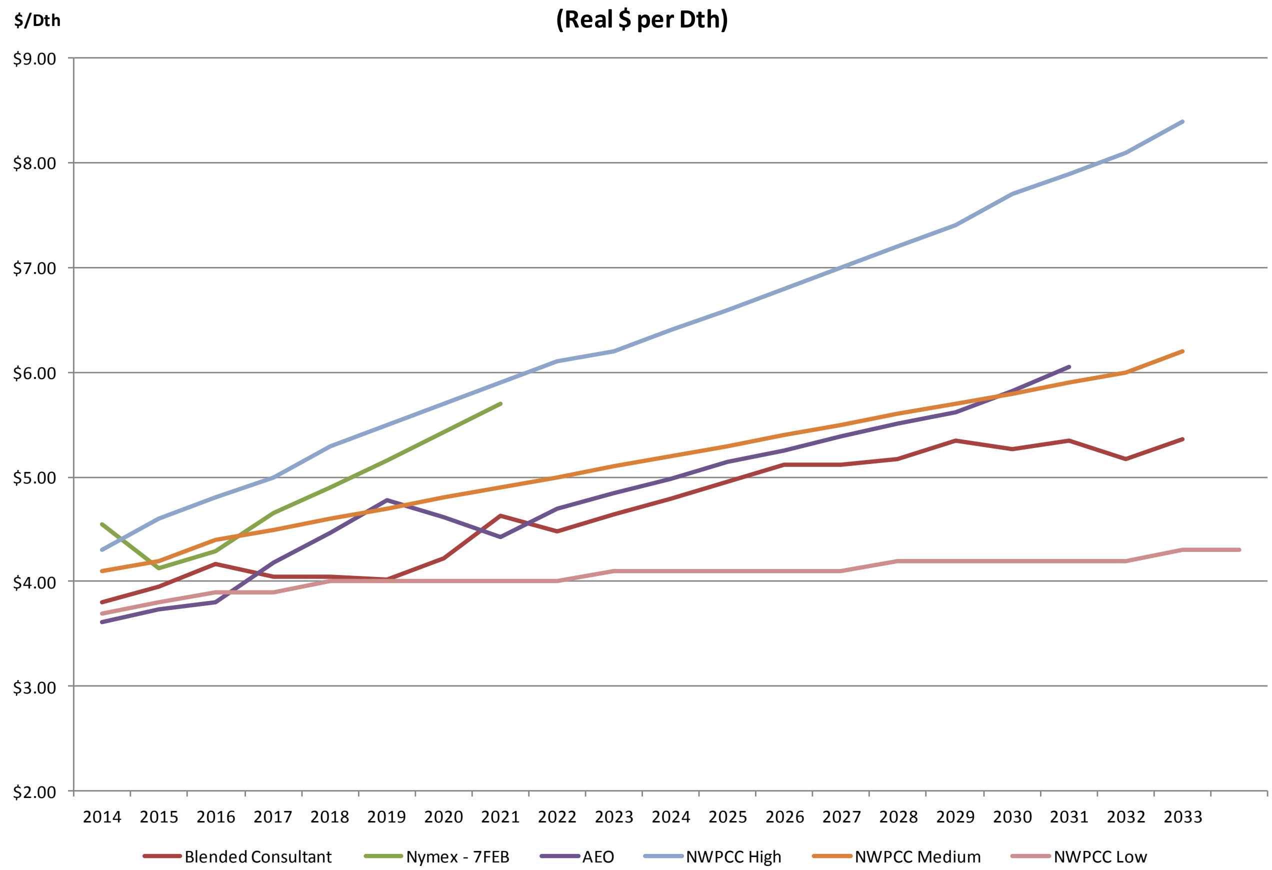
Natural gas prices are a fundamental component of the IRP. The commodity price is a significant component of the total cost of a resource option. This in turn affects the avoided cost threshold for determining cost-effectiveness of conservation measures. We also recognize the price of natural gas influences consumption, so we include price elasticity analysis in our demand evaluation (see Chapter 3 – 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 recession, shale gas production, green house gas legislation, and renewable energy standards creating the potential for more gas-fired generation are impacting the natural gas outlook. Due to the rapidly changing environment and uncertainty in predicting future events and trends, modeling a range of forecasts is necessary.

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

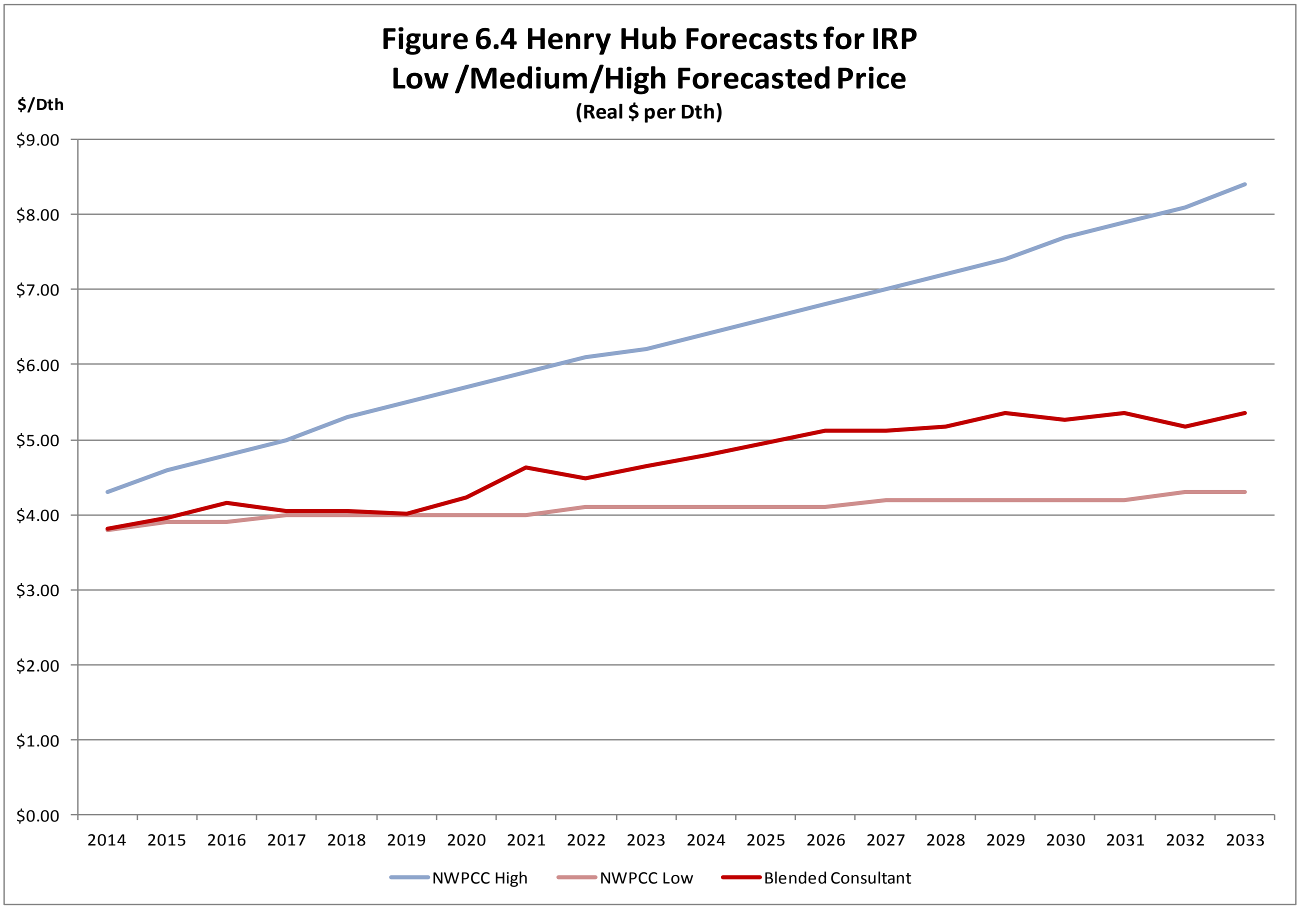
Even though we continually monitor these factors, we cannot accurately predict future prices for the 20-year horizon of this IRP. We have reviewed several price forecasts from credible sources. Figure 6.3 depicts the price forecasts we considered in our analyses.

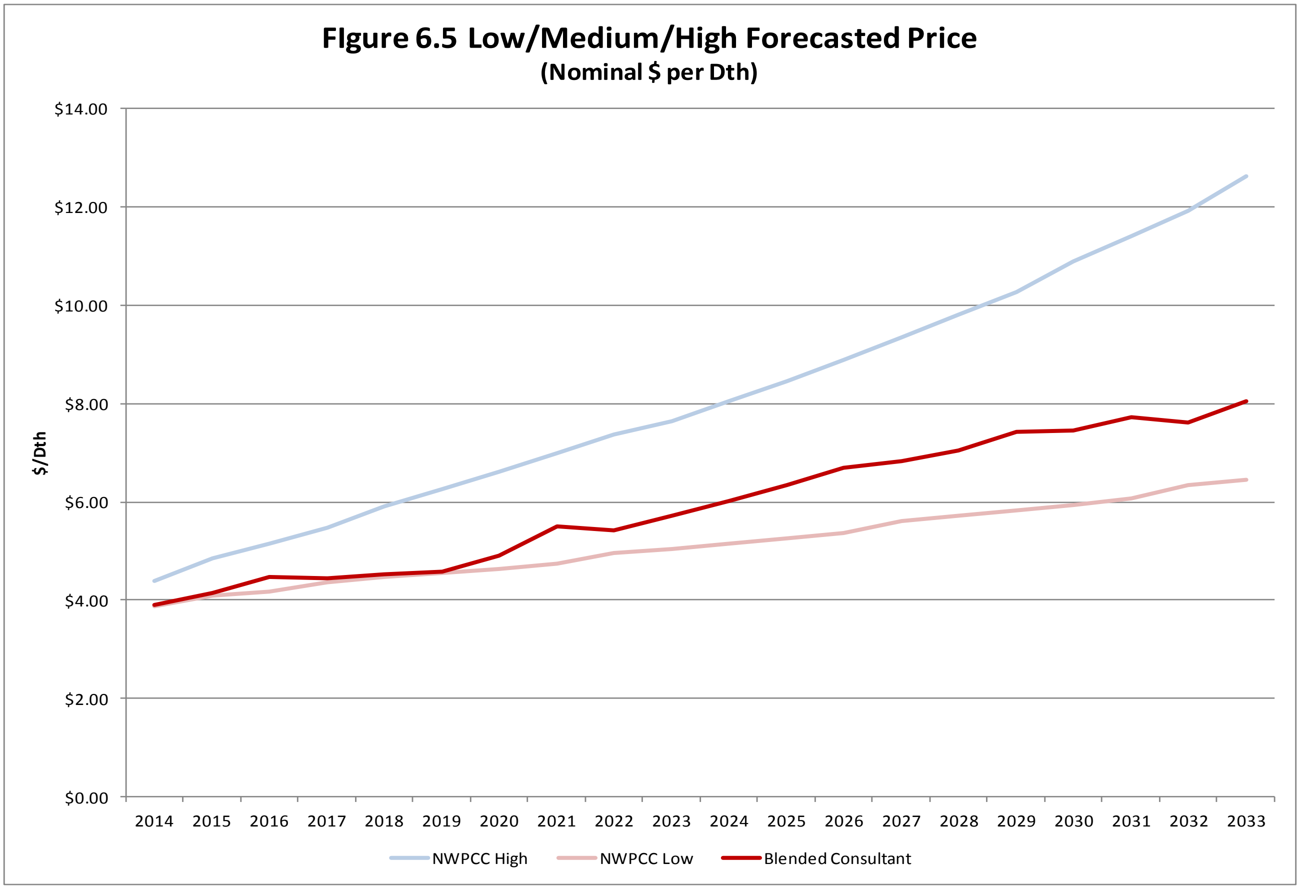
Figure 6.3 Henry Hub Forecasted Price
(Real $ per Dth)



Selecting the price curves can be more art than science. With assistance and concurrence of the TAC we selected high, expected and low price curves to consider possible outcomes and the impact on resource planning. The price curves we have selected have variation and provide reasonable upper and lower bounds, which is consistent with our theme of stretching modeling assumptions to address uncertainty in the planning environment. These curves are shown in real dollars in Figure 6.4 and nominal dollars in Figure 6.5.

Additionally, stochastic modeling of natural gas prices is also completed. The results from that analysis are shown in Chapter 7 – Alternate Scenarios, Portfolios, and Stochastic Analysis.





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 widely 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) ultimately determine Avista's costs. Prices at these points typically trade at a discount or negative basis differential to Henry Hub primarily because of their relative close proximity to the two largest natural gas basins in North America (the WCSB and the Rockies).

Table 6.1 shows the Pacific Northwest regional prices from our consultants, historic averages, and the prior IRP as a percent of Henry Hub price along with historical comparisons.

Table 6.1 Regional Price as a Percent of Henry Hub Price

	AECO	Sumas	Rockies	Malin	Stanfield
Consultant1 Forecast Average	91.9%	101.4%	99.2%	105.3%	102.7%
Consultant2 Forecast Average	84.9%	93.6%	91.6%	97.3%	94.8%
Historic Cash Three-Year Average	87.4%	98.4%	116.4%	99.2%	97.5%
Prior IRP	88.60%	89.90%	90.80%	92.30%	91.40%

This IRP used monthly prices for modeling purposes because of our heavily winter-weighted demand profile. Table 6.2 depicts the monthly price shape we used in this IRP. A slight change to the shape of the pricing curve has occurred since the last IRP. Driven primarily by supply availability, the forecasted differential between winter and summer pricing has come in to some extent when compared to historic data.

Table 6.2 Monthly Price as a Percent of Average Price						
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**
Consult 1	101%	102%	102%	99%	99%	99%
Consult 2	104%	104%	97%	96%	97%	98%
Prior IRP	101%	101%	98%	98%	98%	100%
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Consult 1	99%	100%	101%	100%	100%	100%
Consult 2	99%	100%	99%	99%	102%	106%
Prior IRP	102%	103%	100%	100%	100%	102%

We selected Consultant 1's forecast of regional prices and monthly shape. Appendix 6.1 contains detailed monthly price data behind the summary table information discussed above.

TRANSPORTATION AND STORAGE

Valuing natural gas supplies is a critical first step in resource integration. Equally important is capturing all costs to deliver the gas to the customer. Daily capacity of our existing transportation resources (described in Chapter 5 – Supply-Side Resources) is represented by the firm resource duration curves depicted in Figures 6.6 and 6.7.

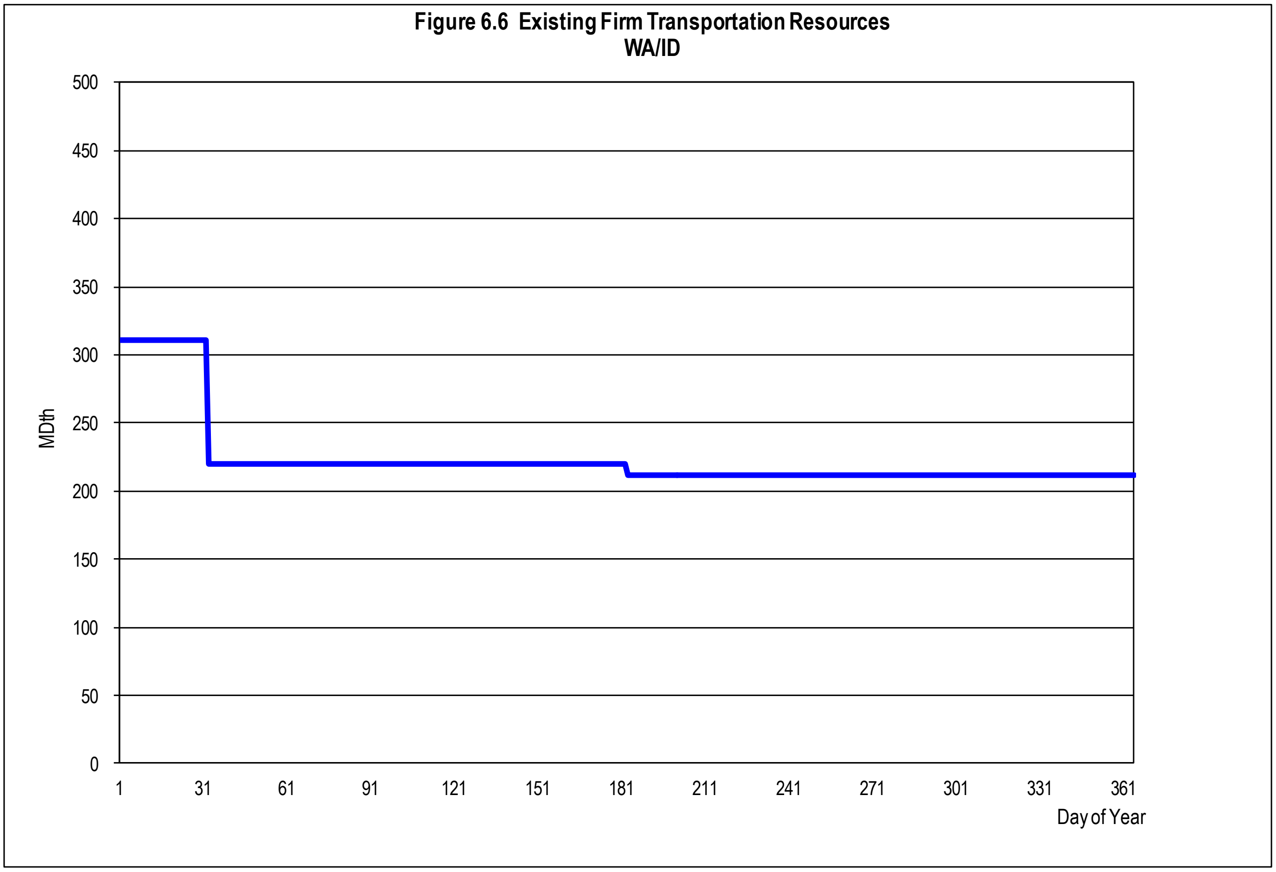


Figure 6.6 Existing Firm Transportation Resources
WA/ID
500
450
400
350
300
250
200
150
100
50
0
MDth
1
31
61
91
121
151
181
211
241
271
301
331
361
Day of Year

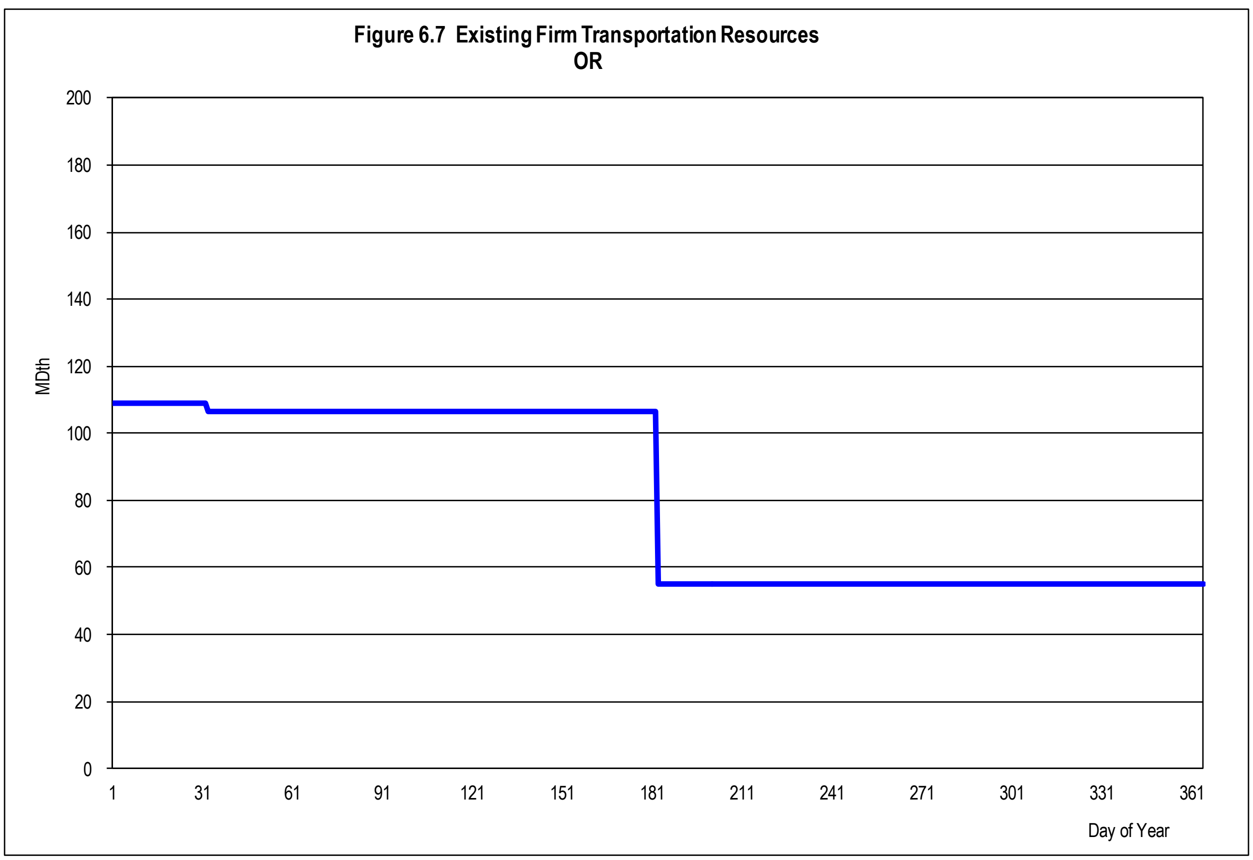


Figure 6.7 Existing Firm Transportation Resources
OR
200
180
160
140
120
100
80
60
40
20
0
MDth
1
31
61
91
121
151
181
211
241
271
301
331
361
Day of Year

Current rates for capacity are in Appendix 5.1. Forecasting future pipeline rates can be a challenge as we need to estimate the amount and timing of rate changes. Our estimates and timing of future rate increases are based on knowledge obtained from industry discussions and participation in various pipeline rate cases. This IRP assumes that pipelines will file to recover costs at rates equal to increases in GDP (see Appendix 6.2 – General Assumptions).

DEMAND-SIDE MANAGEMENT

Chapter 4 – Demand-side Resources describes the methodology used to identify conservation potential and the interactive process deployed that utilizes avoided cost thresholds for determining cost effectiveness of conservation measures on an equivalent basis with supply-side resources.

PRELIMINARY RESULTS

After incorporating the above data into the SENDOUT® model, we then generate an assessment of demand compared to existing resources for several scenarios. The demand results from these cases are discussed in Chapter 3 – Demand Forecasts, with additional details supported in the Appendices 3.1 through 3.10.

Figures 6.8 through 6.11 graphically represent summaries of Average Case demand compared to existing resources. This demand is net of DSM savings and shows the adequacy of our resources under normal weather conditions. For this case, current resources meet our demand needs over the planning horizon.

Figure 6.8 Average Case - WA/ID Existing Resources vs. Peak Day Demand (Net of DSM)
FEB 15

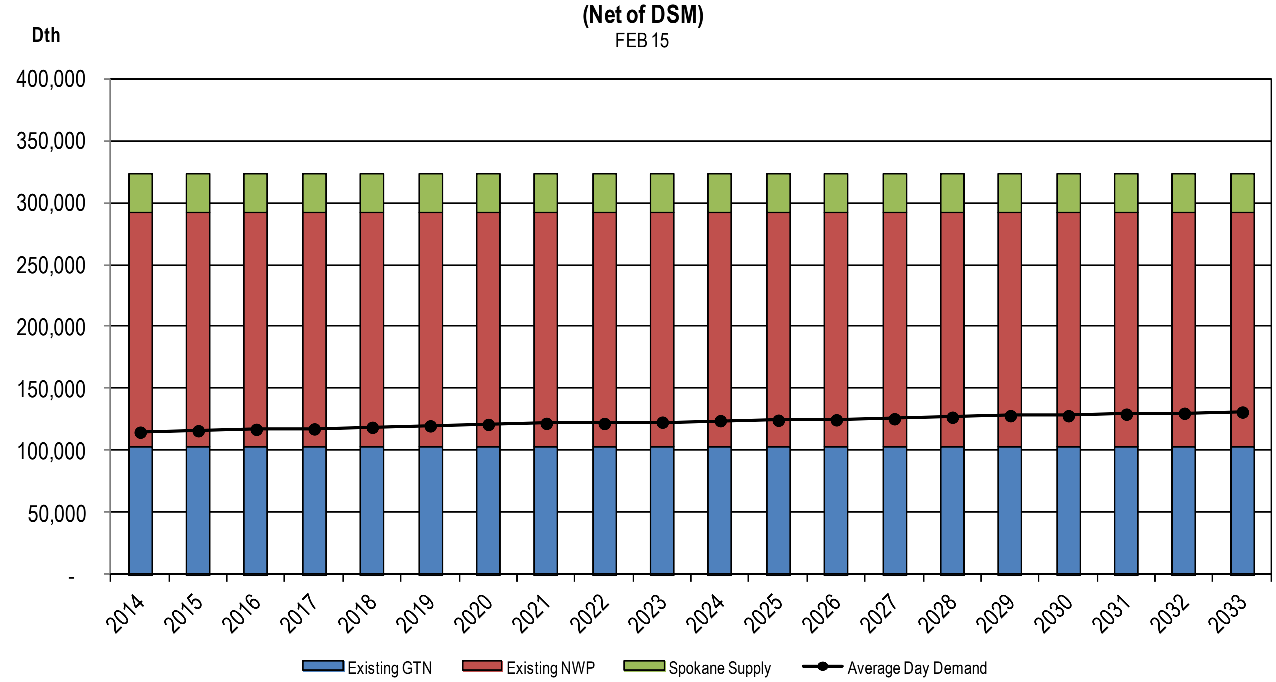


Figure 6.9 Average Case - Medford/Roseburg Existing Resources vs. Peak Day Demand (Net of DSM)
DEC 20

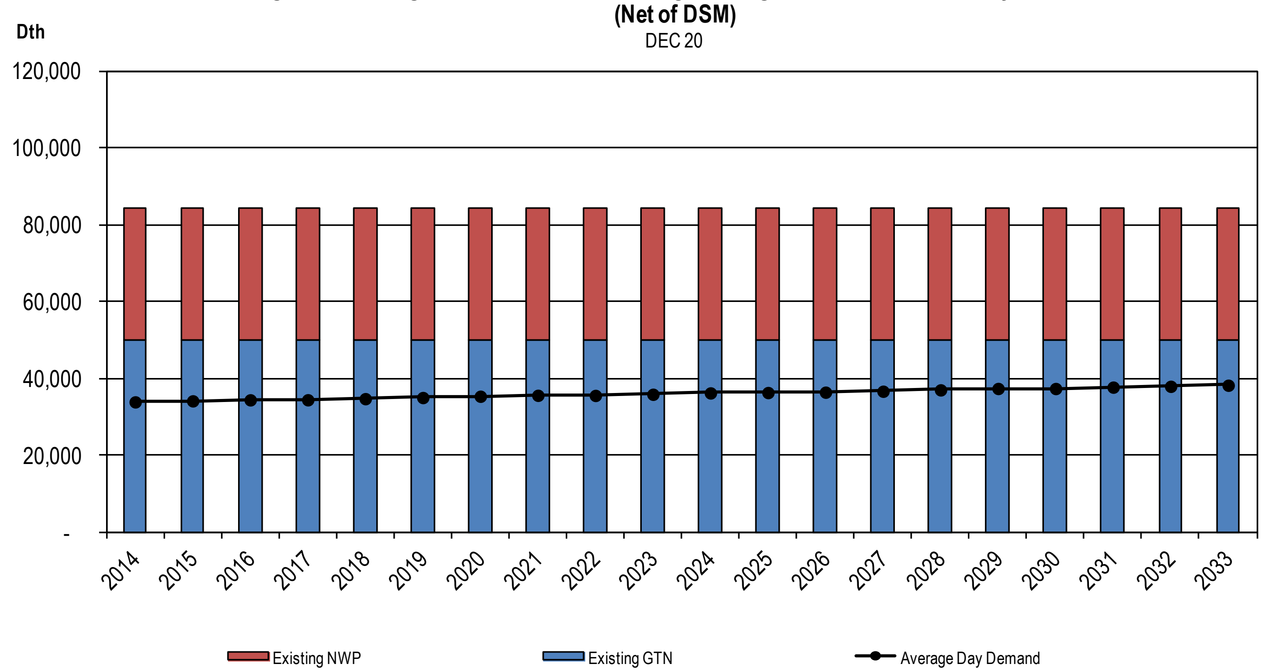
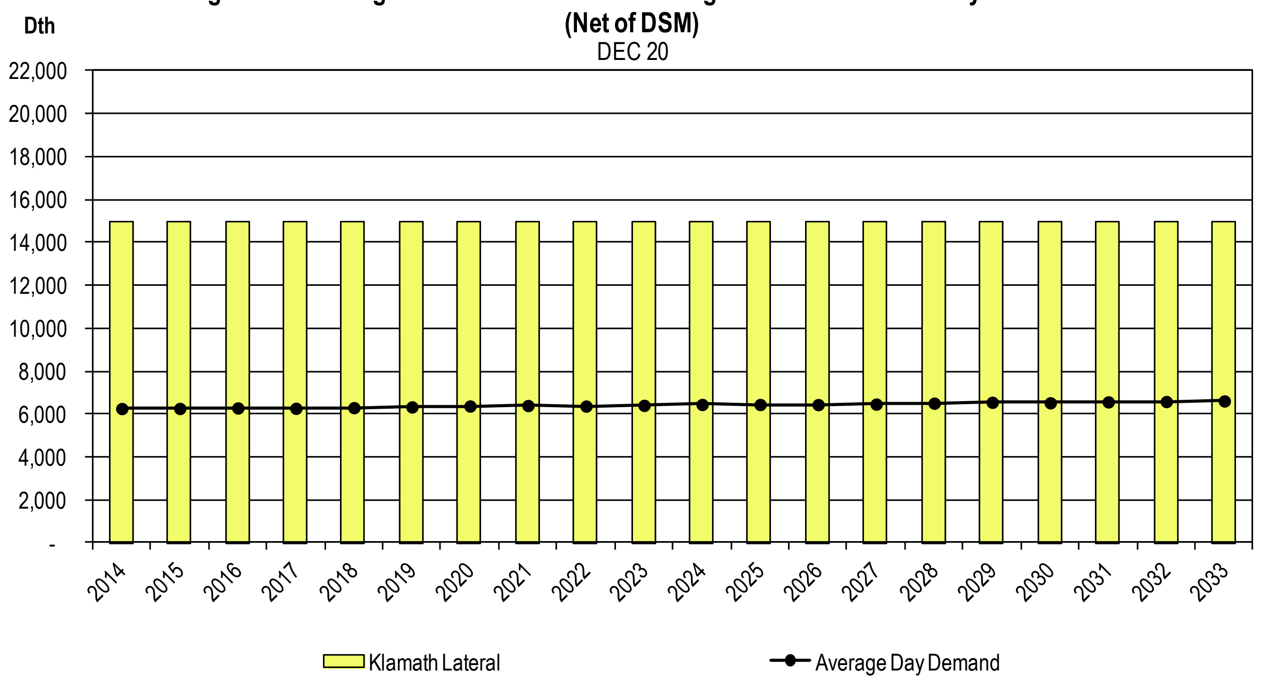
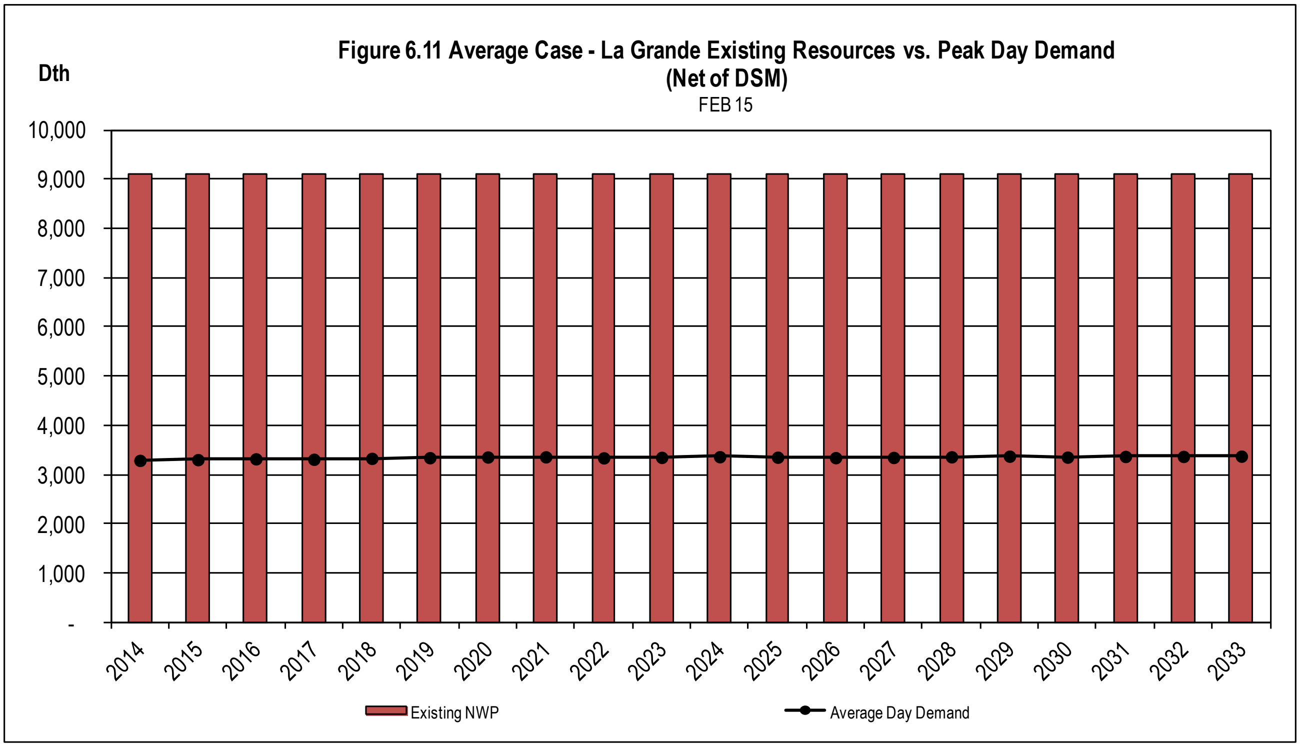
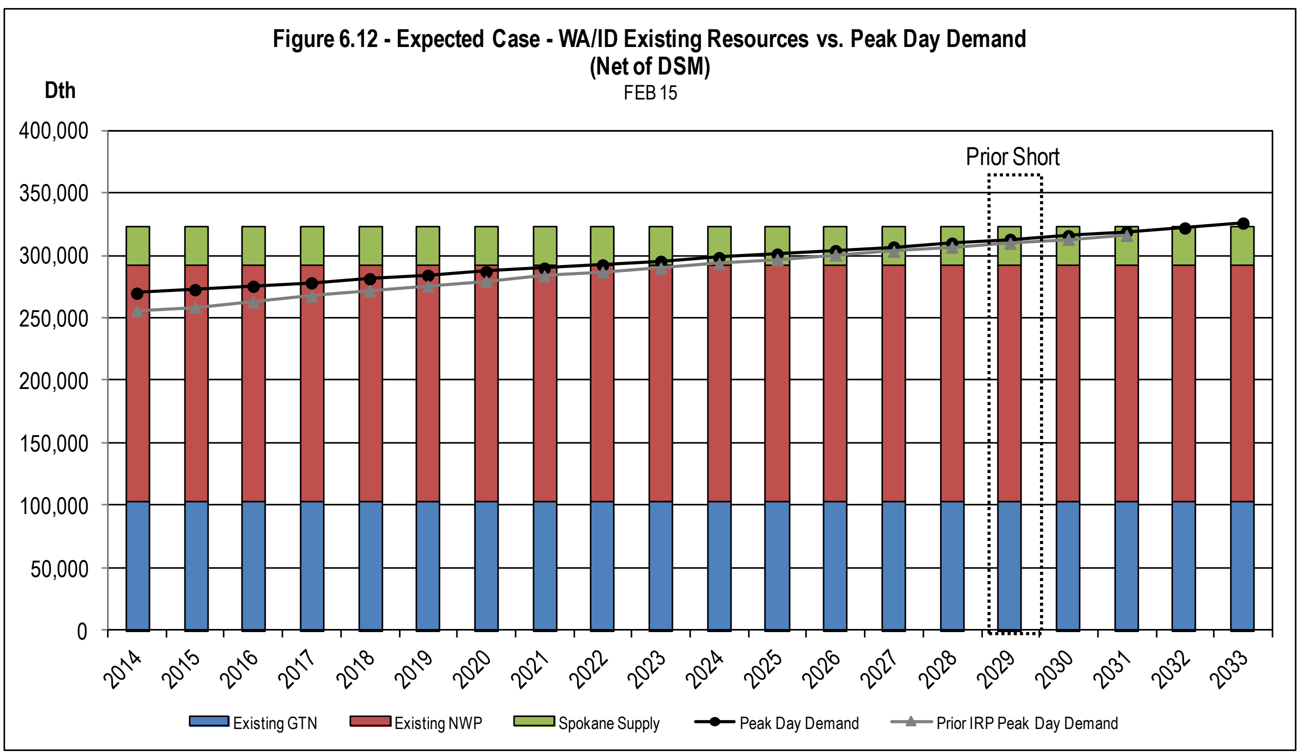


Figure 6.10 Average Case - Klamath Falls Existing Resources vs. Peak Day Demand (Net of DSM)
DEC 20





Figures 6.12 through 6.15 graphically represent summaries of Expected Case peak day demand compared to existing resources, as well as demand comparisons to our prior IRP. This demand is net of DSM savings. For this case, existing resources meet peak day demand needs over the planning horizon. This surplus resource situation provides ample time to carefully monitor, plan and act on potential resource additions.



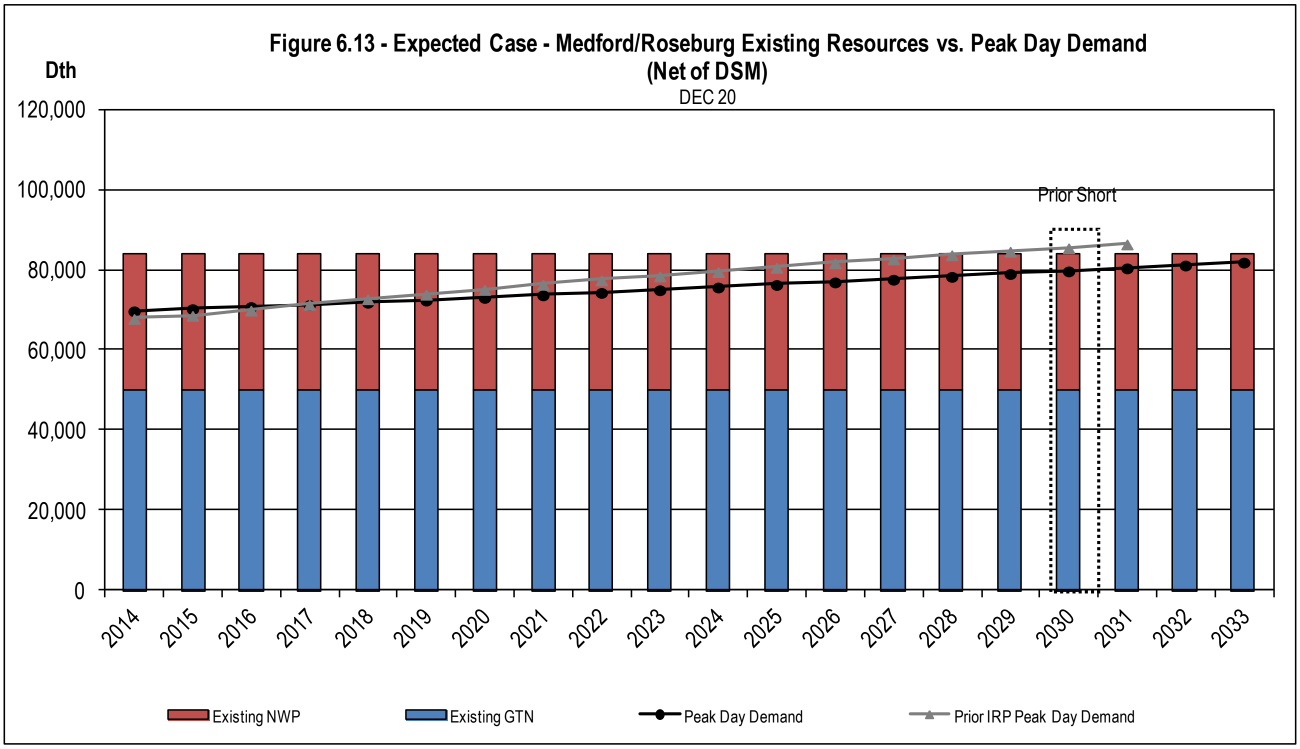


Figure 6.13 - Expected Case - Medford/Roseburg Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Prior Short
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Existing NWP
Existing GTN
Peak Day Demand
Prior IRP Peak Day Demand

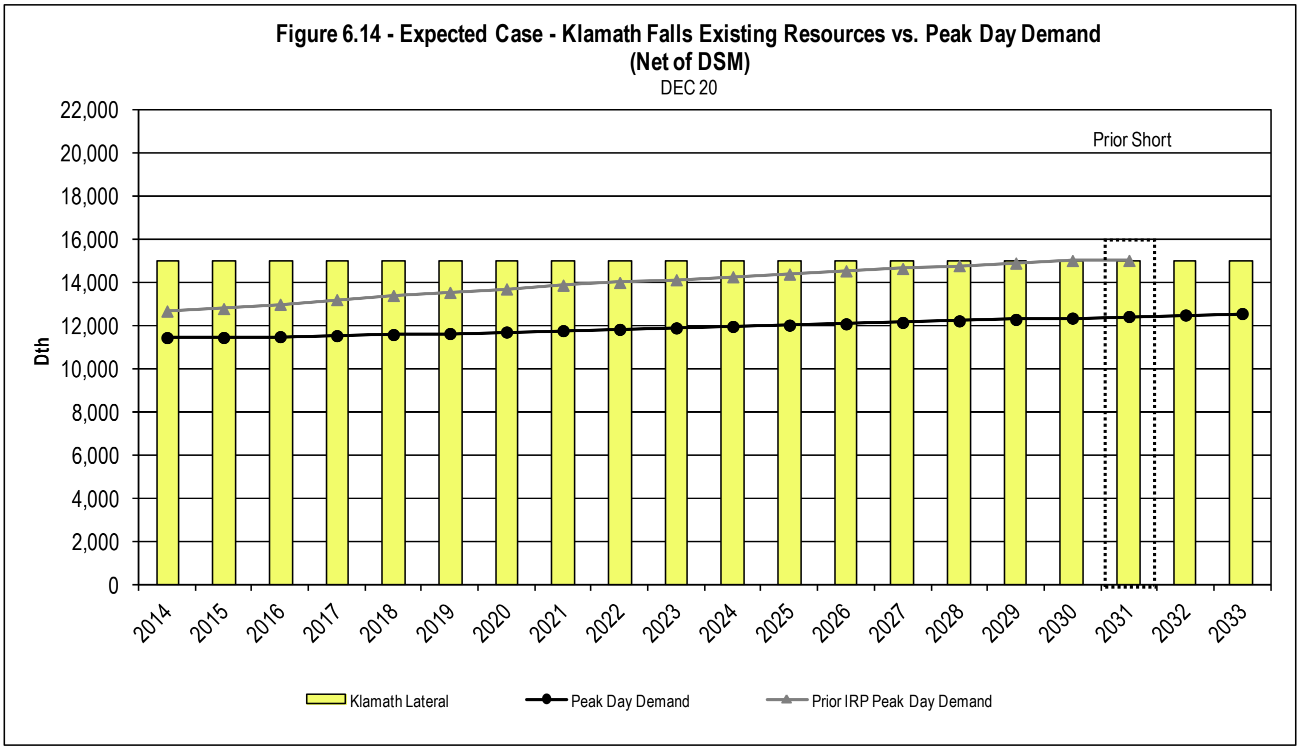
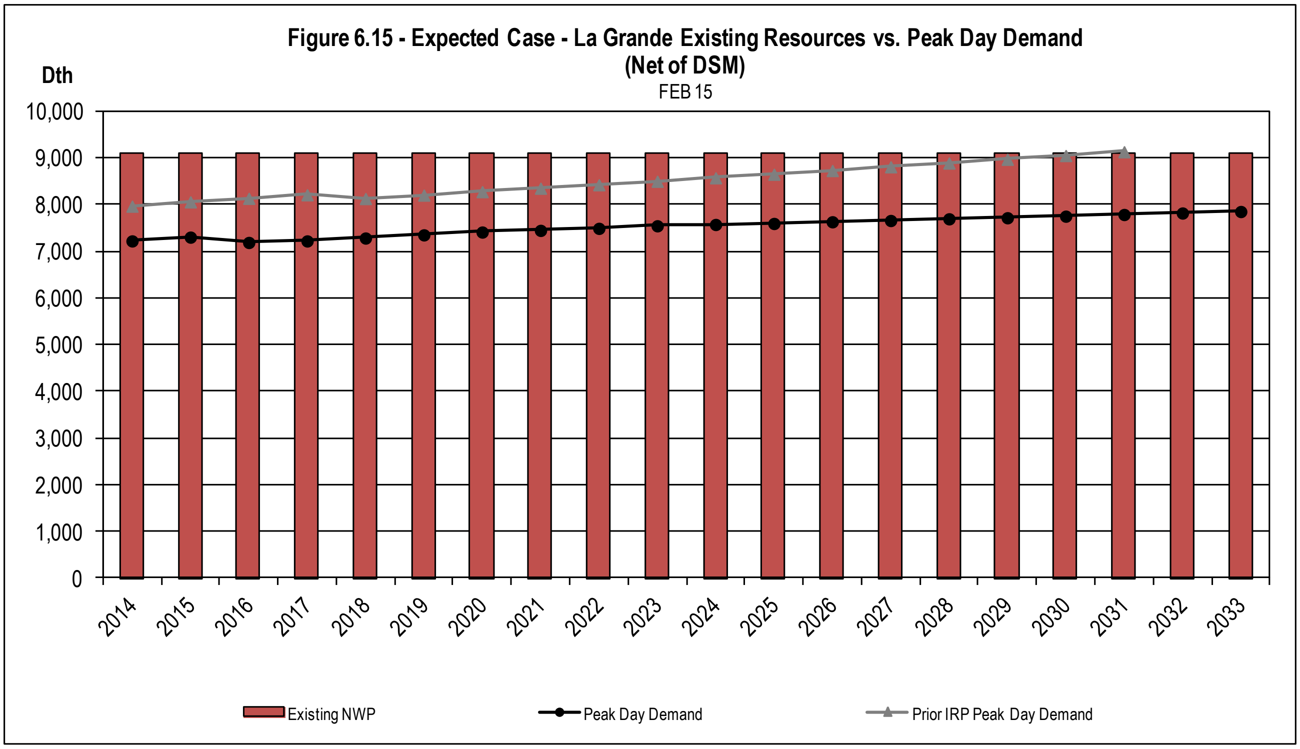


Figure 6.14 - Expected Case - Klamath Falls Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Prior Short
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Klamath Lateral
Peak Day Demand
Prior IRP Peak Day Demand



However, if demand accelerates the need for additional resources will also accelerate by several years. This "flat demand risk" necessitates close monitoring of signs of accelerating demand and careful evaluation of lead times to acquire preferred incremental resources.

Table 6.3 quantifies the forecasted total demand (net of DSM savings) and unserved demand from the above charts.

Table 6.3 Peak Day Demand - Served and Unserved (MDth/d)

Case	Year	LaGrande Served	LaGrande Unserved	LaGrande Total	LaGrande % of Peak Day Served	WA/ID Served	WA/ID Unserved	WA/ID Total	WA/ID % of Peak Day Served
Expected	2014	7.36	-	7.36	100%	270.11	0	270.11	100%
Expected	2015	7.39	-	7.39	100%	272.87	0	272.87	100%
Expected	2016	7.43	-	7.43	100%	275.55	0	275.55	100%
Expected	2017	7.40	-	7.40	100%	276.08	0	276.08	100%
Expected	2018	7.44	-	7.44	100%	279.16	0	279.16	100%
Expected	2019	7.47	-	7.47	100%	281.91	0	281.91	100%
Expected	2020	7.50	-	7.50	100%	284.69	0	284.69	100%
Expected	2021	7.51	-	7.51	100%	286.61	0	286.61	100%
Expected	2022	7.45	-	7.45	100%	285.97	0	285.97	100%
Expected	2023	7.47	-	7.47	100%	288.42	0	288.42	100%
Expected	2024	7.50	-	7.50	100%	291.26	0	291.26	100%
Expected	2025	7.47	-	7.47	100%	291.84	0	291.84	100%
Expected	2026	7.44	-	7.44	100%	292.39	0	292.39	100%
Expected	2027	7.45	-	7.45	100%	294.28	0	294.28	100%
Expected	2028	7.48	-	7.48	100%	297.18	0	297.18	100%
Expected	2029	7.51	-	7.51	100%	300.11	0	300.11	100%
Expected	2030	7.45	-	7.45	100%	299.63	0	299.63	100%
Expected	2031	7.48	-	7.48	100%	302.58	0	302.58	100%
Expected	2032	7.48	-	7.48	100%	304.17	0	304.17	100%
Expected	2033	7.49	-	7.49	100%	306.36	0	306.36	100%

Case	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	2014	11.45		11.45	100%	69.82	0	69.82	100%
Expected	2015	11.46		11.46	100%	70.38	0	70.38	100%
Expected	2016	11.50		11.50	100%	70.92	0	70.92	100%
Expected	2017	11.46		11.46	100%	70.90	0	70.90	100%
Expected	2018	11.52		11.52	100%	71.49	0	71.49	100%
Expected	2019	11.58		11.58	100%	72.10	0	72.10	100%
Expected	2020	11.66		11.66	100%	72.79	0	72.79	100%
Expected	2021	11.70		11.70	100%	73.27	0	73.27	100%
Expected	2022	11.64		11.64	100%	73.10	0	73.10	100%
Expected	2023	11.70		11.70	100%	73.72	0	73.72	100%
Expected	2024	11.78		11.78	100%	74.43	0	74.43	100%
Expected	2025	11.76		11.76	100%	74.58	0	74.58	100%
Expected	2026	11.75		11.75	100%	74.71	0	74.71	100%
Expected	2027	11.79		11.79	100%	75.19	0	75.19	100%
Expected	2028	11.87		11.87	100%	75.92	0	75.92	100%
Expected	2029	11.94		11.94	100%	76.66	0	76.66	100%
Expected	2030	11.89		11.89	100%	76.54	0	76.54	100%
Expected	2031	11.96		11.96	100%	77.28	0	77.28	100%
Expected	2032	11.99		11.99	100%	77.68	0	77.68	100%
Expected	2033	12.04		12.04	100%	78.24	0	78.24	100%

NEW RESOURCE OPTIONS

When existing resources are not sufficient to meet expected demand, there are many considerations that are important in determining the appropriateness of potential resources.

RESOURCE COST

Resource cost is the primary consideration when evaluating resource options although other factors mentioned below also influence resource decisions. We have found that 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, planning and permitting, environmental review, design, construction and testing are some of the aspects contributing to lead time requirements for new physical facilities. Recalls of released pipeline capacity typically require advance notice of up to a year. Even DSM programs require significant time from program development and rollout to the point when natural gas savings are realized.

PEAK VERSUS BASE LOAD

Our planning efforts include the ability to serve 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

It is paramount that an available resource effectively delivers natural gas to the intended geographical 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 together resources increases the 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) then 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, the fact that 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. Lumpiness provides a cushion for future growth. Given the economies of scale for pipeline construction, we are afforded the opportunity to secure resources to serve future demand increases.

COMPETITION

LDCs, end-users and marketers all compete for regional resources. The Northwest has been particularly efficient in the utilization of existing resources, which means the system is neither overbuilt nor under built. Currently, the region is able to sufficiently handle the demand needs of varying parties. However, the future needs vary and regional LDCs may find they are competing with each other and other parties in order 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 determinations are subject to various degrees of estimation, partly influenced by the expected timeframe of the resource need and degree of 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 in service territory underground storage (low certainty).

RESOURCE SELECTION

After identifying supply-side resource options and evaluating them based on the above considerations, we entered these supply-side scenarios (see Table 5.2) along with conservation measures (see Chapter 4 - 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 6.3 for a list of supply-side resource options) using PVRR analysis to determine which resource is the best risk adjusted/least cost resource.

DEMAND-SIDE RESOURCES

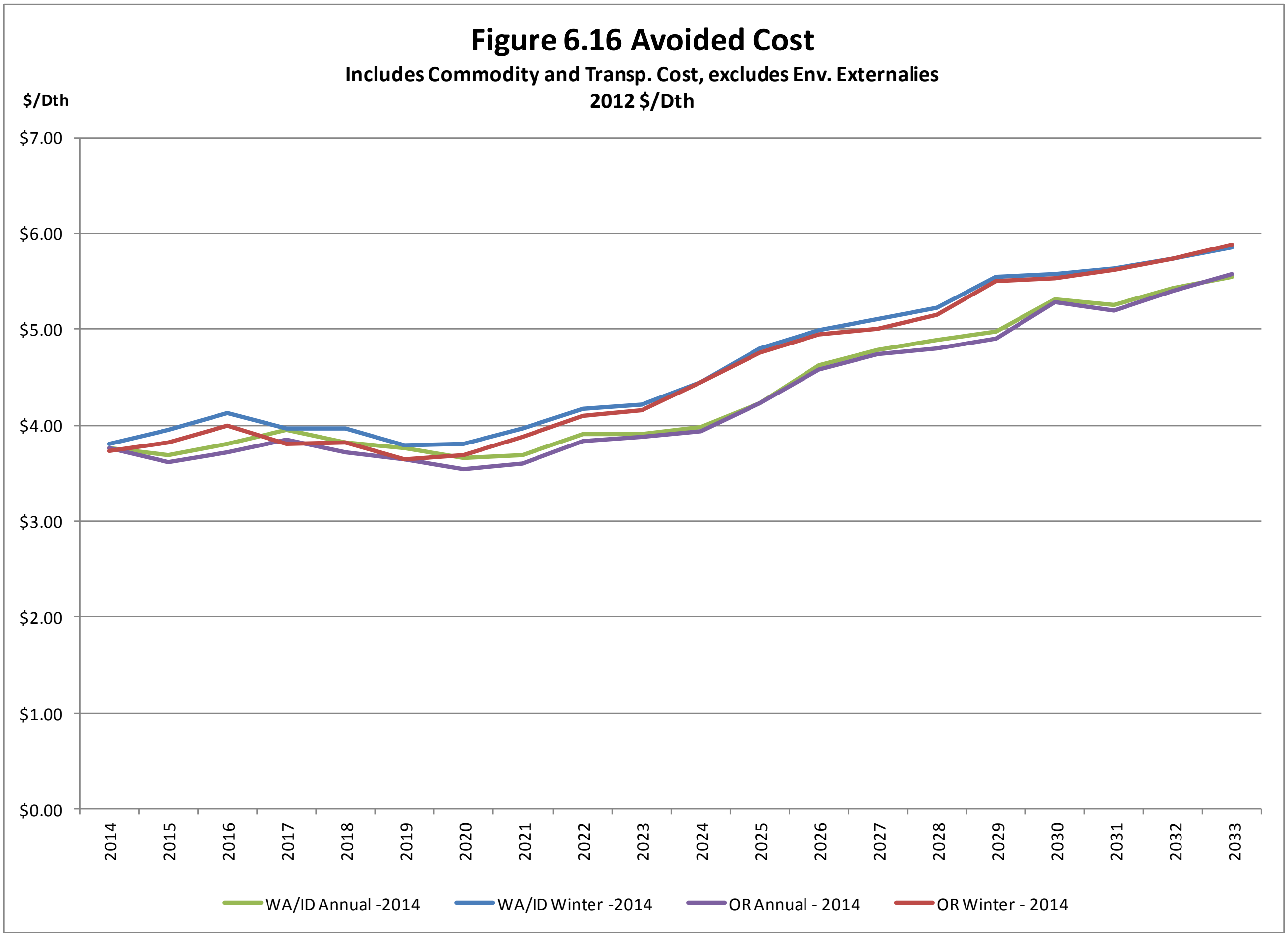
INTEGRATION BY PRICE

As described in Chapter 4, the model is run without the inclusion of future demand side management programs. This preliminary run provides an avoided cost curve which was provided to EnerNoc. EnerNoc then evaluates the cost effectiveness of programs against the initial avoided cost curve using the appropriate resource cost tests. The therm savings and associated program costs are then incorporated into the SENDOUT® model. After incorporation the avoided costs are re-evaluated. This process is reiterated 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 cost effectively reduce customer demand and Avista can "avoid" possible commodity, storage, transportation and other supply resource costs.

SENDOUT® calculates marginal cost data by day, month and year for each demand area. A summarized graphical depiction of avoided annual and winter costs for the Washington/Idaho and Oregon areas is in Figure 6.16. The detailed data is presented in Appendix 6.4. Other than the carbon tax adder embedded in the expected price curve, avoided costs do not include any additional environmental externality adders to monetarily recognize adverse environmental impacts. Appendix 4.2 discusses this concept more fully and includes specific requirements required in our Oregon service territory.



DSM POTENTIAL

Using the above avoided cost thresholds EnerNoc selected all cost effective DSM potential. Table 6.4 details the potential DSM savings in each region from the selected conservation potential for our Expected Case.

Table 6.4 – Annual and Average Daily Demand Served by DSM

Case	Year	Annual Klamath DSM (MDth)	Daily Klamath/DSM (MDth/day)	Annual LaGrande DSM (MDth)	Daily LaGrande DSM (MDth)	Annual Medford/ Roseburg DSM (MDth)	Daily Medford/ Roseburg DSM (MDth)
Expected	2014	-	-	-	-	-	0
Expected	2015	2.34	0.01	1.39	0.00	12.41	0.03
Expected	2016	3.98	0.01	2.34	0.01	20.93	0.06
Expected	2017	6.67	0.02	3.88	0.01	34.58	0.09
Expected	2018	10.97	0.03	6.31	0.02	55.91	0.15
Expected	2019	16.36	0.04	9.33	0.03	82.43	0.23
Expected	2020	21.20	0.06	12.07	0.03	106.55	0.29
Expected	2021	24.81	0.07	14.14	0.04	124.92	0.34
Expected	2022	28.42	0.08	16.36	0.04	143.59	0.39
Expected	2023	32.03	0.09	18.54	0.05	162.45	0.45
Expected	2024	35.86	0.10	20.88	0.06	182.53	0.50
Expected	2025	41.23	0.11	24.09	0.07	209.76	0.57
Expected	2026	45.39	0.12	26.66	0.07	231.34	0.63
Expected	2027	49.62	0.14	29.28	0.08	253.24	0.69
Expected	2028	53.93	0.15	31.94	0.09	275.56	0.75
Expected	2029	58.35	0.16	34.62	0.09	298.38	0.82
Expected	2030	62.67	0.17	37.20	0.10	320.60	0.88
Expected	2031	66.91	0.18	39.69	0.11	342.35	0.94
Expected	2032	71.15	0.19	42.16	0.12	364.06	1.00
Expected	2033	75.41	0.21	44.63	0.12	385.84	1.06

Case	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	2014	-	-	-	-	-	0.00
Expected	2015	16.15	0.04	151.53	0.42	167.68	0.46
Expected	2016	27.25	0.07	236.66	0.65	263.91	0.72
Expected	2017	45.13	0.12	370.38	1.01	415.51	1.14
Expected	2018	73.19	0.20	590.17	1.62	663.36	1.82
Expected	2019	108.13	0.30	877.24	2.40	985.37	2.70
Expected	2020	139.83	0.38	1,137.04	3.12	1,276.87	3.50
Expected	2021	163.88	0.45	1,309.86	3.59	1,473.73	4.04
Expected	2022	188.37	0.52	1,476.10	4.04	1,664.48	4.56
Expected	2023	213.01	0.58	1,636.98	4.48	1,849.99	5.07
Expected	2024	239.27	0.66	1,797.60	4.92	2,036.87	5.58
Expected	2025	275.07	0.75	1,959.19	5.37	2,234.27	6.12
Expected	2026	303.40	0.83	2,107.72	5.77	2,411.11	6.61
Expected	2027	332.14	0.91	2,251.57	6.17	2,583.71	7.08
Expected	2028	361.44	0.99	2,392.01	6.55	2,753.44	7.54
Expected	2029	391.35	1.07	2,528.87	6.93	2,920.23	8.00
Expected	2030	420.46	1.15	2,654.77	7.27	3,075.23	8.43
Expected	2031	448.95	1.23	2,766.17	7.58	3,215.12	8.81
Expected	2032	477.37	1.31	2,870.62	7.86	3,347.99	9.17
Expected	2033	505.88	1.39	2,968.83	8.13	3,474.71	9.52

DSM ACQUISITION GOALS

The avoided cost established in SENDOUT®, the demand-side potential selected and the therm savings is the basis for determining DSM acquisition goals and subsequent program implementation planning. Chapter 4 – 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 were determined to be cost effective. Those selected resources would 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, we will continue to review and refine knowledge of resource options and will act to secure these best cost/risk options when necessary or advantageous.

RESOURCE UTILIZATION

Our primary purpose and goal is to reliably meet our firm customer's 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 the IRP indicates, we have ample resources to meet highly variable demand under multiple scenarios, including peak weather events.

Avista acquired the majority of our upstream pipeline capacity during the deregulation or "unbundling" of natural gas. Pipelines were required to allocate their capacity (and costs) to their existing customers as they transitioned to a transportation only service provider. The Federal Energy Regulatory Committee (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 gas is transported or not, and a much smaller variable charge which is incurred only when gas is actually transported. An additional fuel charge is assessed to account for the necessary compressors required to "push" the gas to customers. Avista maintains enough firm capacity to meet our peak day requirements under the Expected Case in this IRP. This requires pipeline capacity to be contracted at levels in excess of our average and certainly above our minimum load requirements. Given this load profile and the Straight Fixed Variable rate design, we incur ongoing pipeline costs during non-peak periods.

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

- Pipeline Contract Terms
- Pipeline Capacity
- Storage
- Commodity and Transport Optimization
- 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 would only be contracted from pipelines 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 for contracted volumes to increase during the more 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. We refer to this as a front line strategy because it attempts to mitigate the costs prior to contracting the resource. Not all pipelines offer this as a contracting option. When available, we will seek out this type of arrangement. We currently have some seasonal transportation on TransCanada GTN, TransCanada BC and TransCanada Alberta. These three pipelines match up to move gas from Alberta (AECO) to our service territories. We also have contracted for TF2 on NWP. This is a storage specific contract and matches up to some of our Jackson Prairie storage capacity. TF2 allows for contracting a daily amount of firm service for a specified number of days rather than a daily amount on an annual basis as is usually required. For example, one of our TF2 agreements allows us to transport 91,200 Dth/day for 31 days. This is a much more cost effective strategy for storage transport than contracting for an annual amount. Through NWP's tariff, we maintain an option to increase and decrease the number of days this transport is available. Of course, the more days corresponds to more costs, so balancing storage, transport and demand is important to ensure the optimal blend for cost and reliability.

PIPELINE CAPACITY

Once pipeline capacity has been contracted, its management and utilization determine the actual costs. The worst case economic scenario is to do nothing and simply have the customer incur the costs associated with owning this transport over a long term to meet current and future peak demand requirements. We recognize this as the worst case and develop strategies to ensure it does not become the expected case.

CAPACITY RELEASE

Through the pipeline unbundling of transportation, FERC establish rules and procedures to ensure a fair market developed to try to manage pipeline capacity as a commodity. This evolved to be the capacity release market and is governed by FERC through individual pipelines. The pipelines implement FERC's posting requirements to ensure a transparent and fair market are 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 marketplace. This provides the transparency sought by FERC in establishing the release requirements.

Avista utilizes the capacity release market to manage both long term and short term transportation capacity.

For capacity that is under contract that we may not need to meet current demand, we will actively seek out other parties that may need it and arrange for capacity releases to transfer rights, obligations and costs. This shifts all or a portion of the costs away from our customers to a third party until such time as we need it to meet our customers' demand.

There are many variables in determining the value of the transport. Certain pipeline paths are more valuable than others and this can vary by year, season, month and day. The term, volume and conditions precedent also contribute to the value that can be recovered through a capacity release. For example, a release of capacity during the winter 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 ten days during the winter may not be as valuable to the third party but of high value to us. We may be willing to offer a discount to retain the recall rights during high demand periods. This allows us to turn 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 out through 2025 that provide for full recovery all the pipeline costs. These releases maintain our long term rights to the transportation capacity without incurring the long term costs of waiting until demand increases. As the end of these release terms near, we survey the market against our IRP to determine if these contracts should be brought back in for customer use or released again and for what duration. Avista has some releases to third parties that terminate in 2016. Based on the results of this IRP, we have modeled that this capacity is not needed in 2016 as originally anticipated and are currently negotiating new terms and conditions to continue full cost recovery until it is required. Through this management process we are able to retain the rights to “vintage” capacity without incurring the costs or having to participate in new pipeline expansions in the future that will undoubtedly cost more than the 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. Still it must be recognized that for a required resource, mitigating some costs when it isn’t being utilized moves the needle up from the worst case economic scenario and reduces costs to our customers.

SEGMENTATION

Through a process referred to as segmentation, Avista has actually created new firm pipeline capacity to our service territory. This has the effect of doubling some of our capacity volumes at no additional cost to customers. With increased firm capacity we can continue some of our long term releases or even look at reducing some contract levels if the release market does not provide adequate recovery.

STORAGE

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

Storage allows for summer priced gas to be stored and used in the winter during high demand or peak day events. Similar to transportation, capacity and delivery not being utilized or in excess of transport or demand requirements can be optimized by selling into a higher priced market. This allows us to actively manage the phasing in of our storage capacity and delivery to meet growing peak day requirements when it is needed.

The injection of gas into storage during the summer utilizes existing pipeline transport and therefore helps to increase the utilization factor of these 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 developed strategy to help mitigate transportation costs is to actively participate in the daily market to assess if any unutilized capacity has a market value. Daily, we seek 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 of the long term pipeline charges. The recovery is market dependent and may or may not recover all pipeline costs, but as stated earlier, moving off of the worst case economic scenario helps mitigate pipeline costs to our customers.

COMBINATION OF RESOURCES

Unutilized resources like supply, transportation, storage, and capacity release can all be combined to create market based products that can capture more value than the individual pieces on their own. This very much reflects the phrase “the whole is greater than the sum of its parts”. We have structured long term arrangements with other utilities that allow for available resources to be utilized and provide a product that no individual component could satisfy. These products allow for a higher level of cost recovery against the fixed charges incurred for the resources.

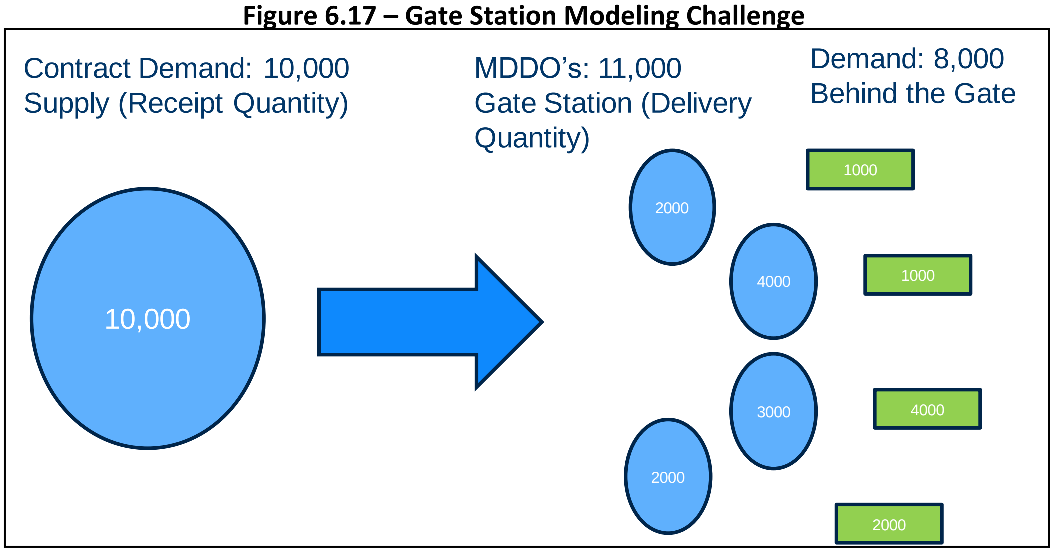
SUMMARY

As determined through our modeling of demand and existing resources, new resources under our Expected Case are not required. Avista is actively managing the existing resources to mitigate the costs incurred by our customers until the resource is required to meet demand. The recovery of costs is often market based with rules governed by FERC. We are recovering full costs on some resources, and recovering some costs on others. Through the active management of both long and short term resources we are able to ensure our goal to reliably meet our firm customer's demand requirements in a cost effective manner.

GATE STATION ANALYSIS

In previous IRP's we identified a risk associated with our aggregated methodology for supply and demand forecasting. Our 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 (CD) (i.e. receipt/supply quantity) is fixed and the amount that can be delivered (i.e. maximum daily delivery obligation (MDDO) or delivery quantity) to various gate stations is greater. (See Figure 6.17) However, aggregation could mask deficiencies at individual gate stations.

Figure 6.17 – Gate Station Modeling Challenge



In order 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 our IRP, forecasted peak day gate station demand was calculated. This demand was then compared to contracted and operational capacities at each gate station.

If forecasted demand exceeded contracted and/or operational capacities further analysis is completed. The additional analysis would involve assessing the most economic way to address the gate deficiency. This could involve a gate station expansion, re-assigning MDDO's, targeted DSM, or distribution system enhancements.

For example, in our last IRP the analysis identified a gate station on NWP's Coeur d'Alene Lateral where forecasted peak day demand exceeded both the gate station MDDO's and physical capacity. Working together with all parties, numerous solutions were examined. The analysis indicated the optimal solution is to take advantage of a pre-existing plan to build a new gate station at Chase Road off of GTN's mainline. The project originally was designed to alleviate capacity constraints at GTN's Rathdrum gate, however, the new gate's location allows for the potential to displace gas on the NWP Coeur d'Alene Lateral.

We are currently working on completion of the gate station analysis on Northwest Pipeline's system for those that serve our Oregon customers.. If any deficiencies are identified they will be communicated to Staff along with proposed least cost solutions. Once the analysis of the NWP gates is complete we will move to the GTN system gates.

ACTION ITEM

With no immediate need to acquire incremental supply side resources to meet peak day demands Avista's focus in the near term will include the following:

- Perform routine gate station analysis to determine if deficiencies exist and least cost solutions to remedy any identified deficiencies.

CONCLUSION

The integrated resource portfolio analysis process summarized in this chapter was first performed on our Average Case and then on the Expected Case demand scenario. We have chosen to utilize the Expected Case for our peak operational planning activities because this case is the most likely outcome given our experience, industry knowledge and our understanding of future natural gas markets. This case provides for reasonable demand growth given current expectations of natural gas prices over the planning horizon. If realized, this case is at a level that allows us to be well protected against resource shortages and does not over commit to additional long-term resources.

We fully recognize that there are numerous other potential outcomes. The process described in this chapter was applied to alternate demand and supply resource scenarios, which is covered in the Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

CHAPTER 7 ■ ALTERNATE SCENARIOS, PORTFOLIOS AND STOCHASTIC ANALYSIS

OVERVIEW

The integrated resource portfolio analysis process described in Chapter 6 was applied to several alternate demand and supply resource scenarios to develop a sufficient range of possible alternate portfolios. This deterministic modeling approach considered a host of underlying assumptions which were vetted with significant discussion and recommendations from our TAC to develop a consensus number of cases to model and analyze.

We 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 observed in historical data. This statistical analysis, in conjunction with our deterministic analysis, enabled us to statistically quantify the risk from a reliability and cost perspective related to resource portfolios under varying price and weather environments.

ALTERNATE DEMAND SCENARIOS

As discussed in the Demand Forecasting section, we have identified several alternate scenarios for detailed analysis to capture a wide range of possible outcomes over the planning horizon. These scenarios are summarized in Table 7.1 and are described in detail in the Chapter 3 - Demand Forecasts and Appendices 3.6 and 3.7. These alternate scenarios consider different demand influencing factors as well as price elasticity effects for various price influencing factors.

Table 7.1 Demand Scenarios
Average Case
Expected Case
High Growth/Low Price
Low Growth/High Price
Alternate Weather Standard

Demand profiles over the planning horizon for each of the alternate scenarios shown in Figures 7.1 and 7.2 reflect the two winter peaks we model for the different service territories (Dec. 20 and Feb. 15).

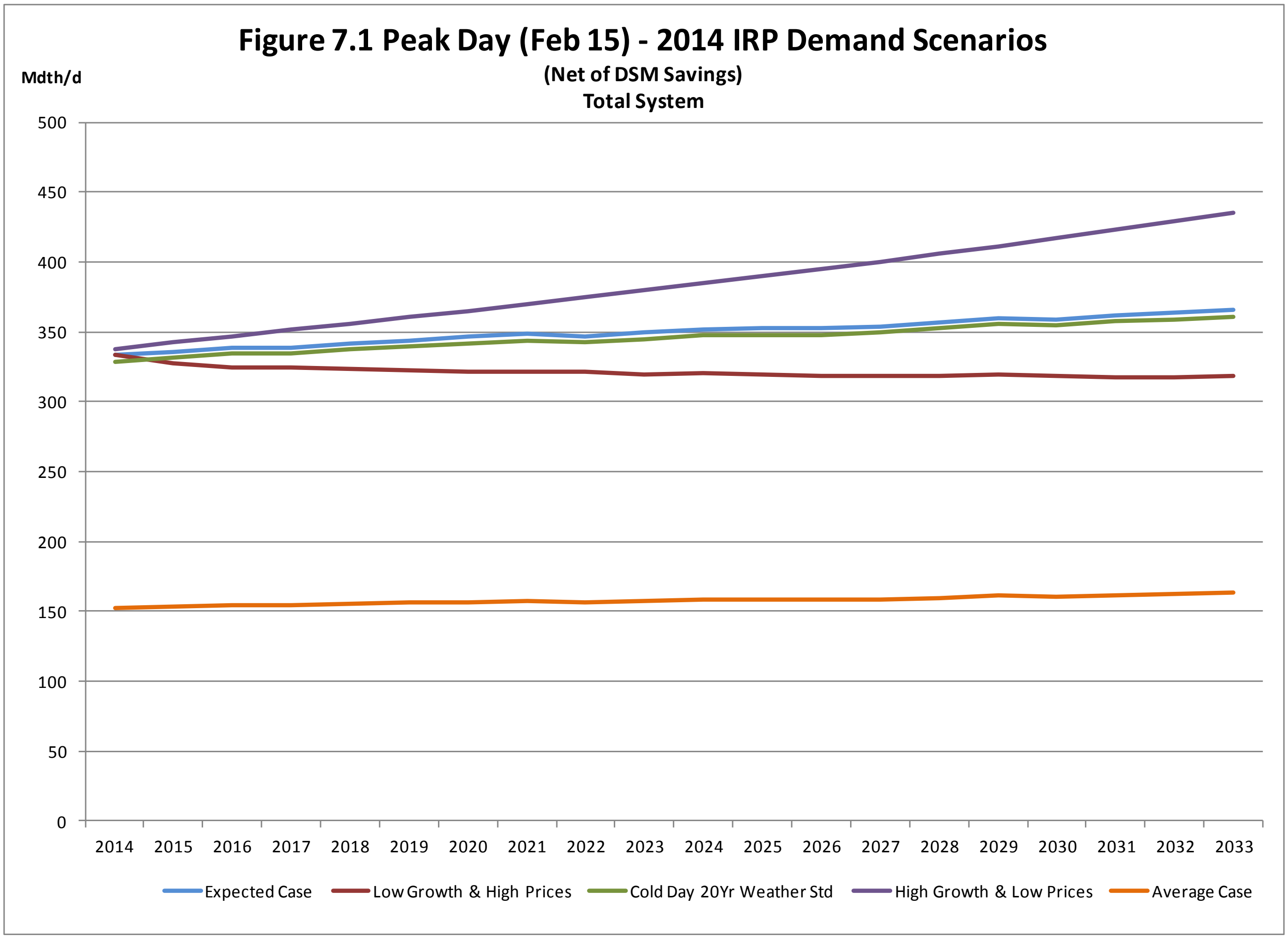
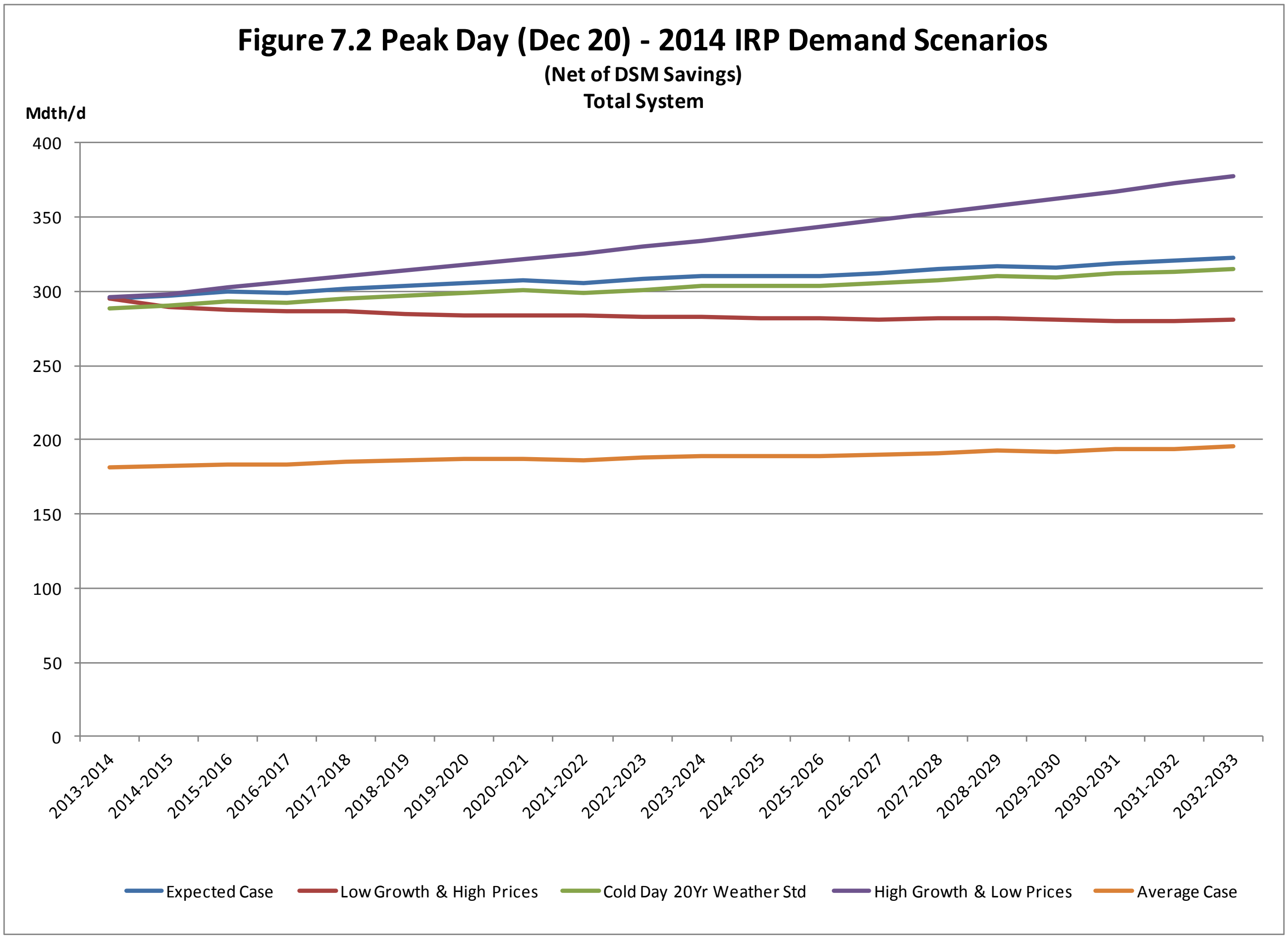
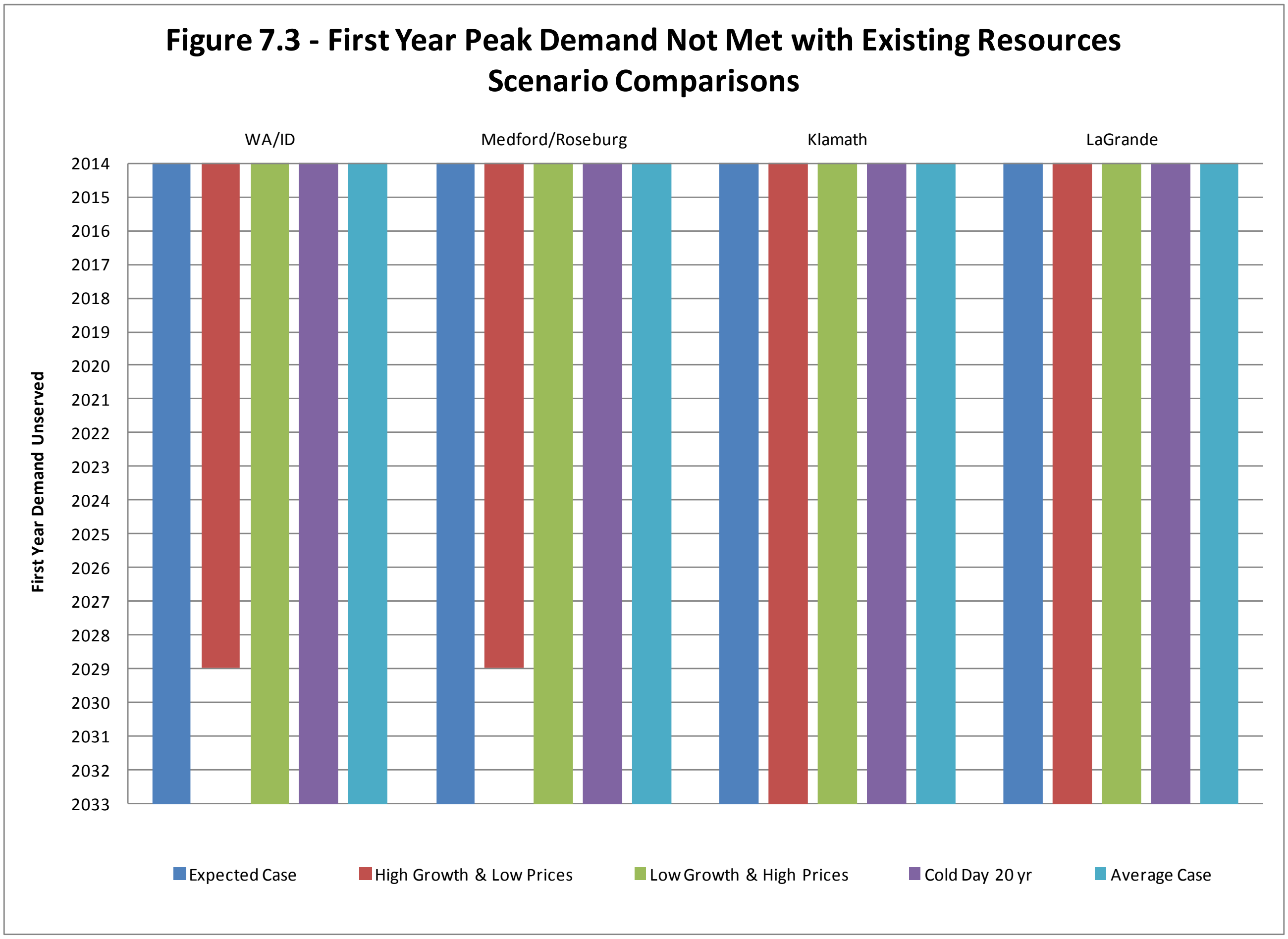


Figure 7.1 Peak Day (Feb 15) - 2014 IRP Demand Scenarios
(Net of DSM Savings)
Total System
Mdth/d
500
450
400
350
300
250
200
150
100
50
0
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Expected Case
Low Growth & High Prices
Cold Day 20Yr Weather Std
High Growth & Low Prices
Average Case



As in the Expected Case, we modeled in SENDOUT® the same resource integration and optimization process described in this section for each of the other five demand scenarios (see Appendix 3.7 for a complete listing of all portfolios considered). This identified first year unserved dates for each scenario by service territory (Figure 7.3).



As anticipated, our 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 these aggressive assumptions, resource shortages do not occur until late in the planning horizon.

- 2029 in Washington/Idaho
- 2029 in Medford/Roseburg

This "steeper" demand highlights the "flat demand risk" discussed earlier. The likelihood of this scenarios occurrence is remote; however any potential for accelerated unserved dates warrants close monitoring of demand trends and resource lead times.

The remaining scenarios do not identify any resource deficiencies in the planning horizon.

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 7.1
- Peak Day Demand, Served and Unserved table (all cases) – Appendix 7.2

- Avoided cost curve detail and graphs for High Growth and Low Growth cases – Appendix 6.4

ALTERNATE SUPPLY RESOURCES

We identified many supply-side resources which could be considered to meet resource deficiencies should they occur. Table 7.2 details available supply-side scenarios that were considered for this IRP. There are many other options that could be considered however, given the lack of need in the near term and the speculative nature of many of these resources they were excluded from SENDOUT® modeling for this IRP.

For example, contracted city gate deliveries in the form of a structured purchase transaction could be a viable and desirable option to 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 especially when the resource is not needed in the near term.

Further, many of these potential resources are not yet commercially available or well tested technically making them very speculative. Resources such as coal-bed methane, LNG imports, and absorbed natural gas (ANG) would fall into this category. We will continue to monitor all resources and assess their appropriateness for inclusion in future IRP's.

One resource which will be closely observed is exported LNG. While we considered LNG exports, it was primarily as a price influencing factor. However, if one of the proposed export LNG terminals in Oregon were to be approved and a pipeline was to be built to supply that facility it potentially could bring supply through Avista's service territory. This scenario is interesting however; there is much uncertainty about export LNG. New pipeline builds are expensive and there are currently existing pipeline options that would be more cost effective. We will continue to monitor this situation and will consider inclusion of this supply scenario for future IRPs.

Table 7.2 Supply Scenarios
Existing Resources
Existing + Expected Available

PORTFOLIO EVALUATION

The alternate demand scenarios and supply scenarios are matched together to form portfolios. Each of these unique portfolios is run through SENDOUT® where the supply resources and demand-side resources are compared and selected on a least cost basis. Once the resources are determined, a net present value of the revenue requirement (PVRR) is calculated.

Table 7.3 summarizes the PVRR of all the portfolios considered. Each of these portfolios is based on unique assumptions and therefore a simple comparison of PVRR cannot be made.

Table 7.3 Net Present Value of Revenue Requirement (PVRR) by Portfolio			
	Portfolio	Unserved Demand	PVRR in (000's)
Average Case	Average Demand with Existing Resources (before resource additions)	No	$ 4,463,055
Expected Case			
	Expected Demand with Existing Resources (before resource additions)	No	$ 4,717,654
Additional Demand Scenarios			
	High Growth, Low Price Demand with Existing Resources	Yes	$ 4,491,462
	Alternate Weather Standard Demand with Existing Resources	No	$ 4,557,367
	Low Growth, High Price with Existing Resources	No	$ 5,455,336

STOCHASTIC ANALYSIS[1]

The scenario (deterministic) analysis described earlier in this document represents specific “what if” situations based on predetermined assumptions including price and weather. These two factors are an integral part of scenario analysis. To better understand a particular portfolio’s response to price and weather, we applied stochastic analysis to generate a wide variety of price and weather events.

Deterministic analysis is a valuable tool for selecting the 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. This type of analysis is only one piece of the puzzle. Utilizing Monte Carlo simulation in conjunction with deterministic analysis provides a more complete picture of how the portfolio performs under multiple weather and price profiles.

For this IRP, stochastic analysis was employed in two ways. The first was to test our weather planning standard and the second was to assess the risk related to costs of our Expected portfolio under varying price environments.

WEATHER

In order to evaluate weather and its effect on our portfolio we derived 200 simulations (draws) through the use of 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 7.4) 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 more robust basis for stress testing the deterministic analysis.

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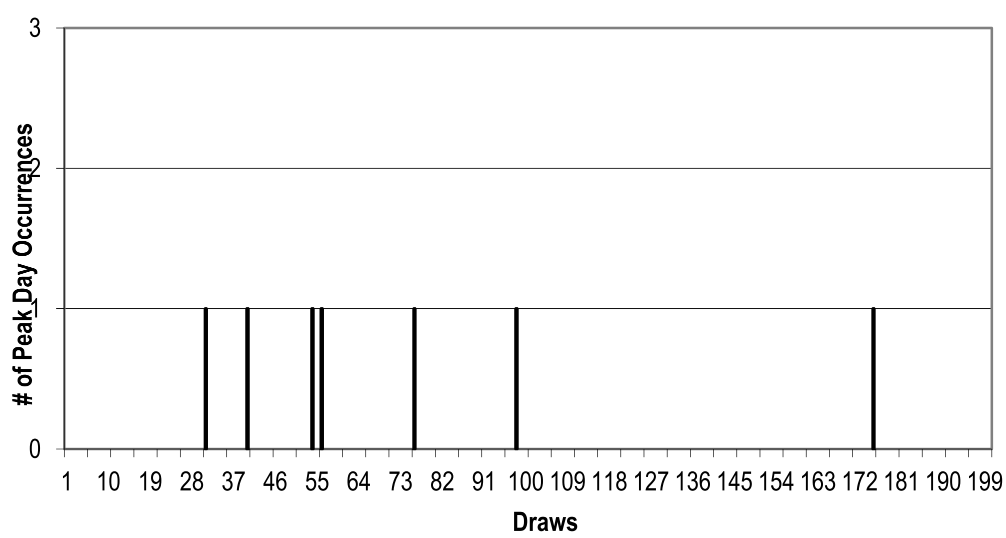
[1] SENDOUT® uses Monte Carlo simulation to support stochastic analysis, which is a mathematical technique for evaluating risk and uncertainty. Monte Carlo simulation is a statistical modeling method used to imitate the many future possibilities that exist with a real-life system.

Table 7.4 Example of Monte Carlo Weather Inputs
Spokane

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
HDD Mean	895	1,152	1,145	913	781	546	331	143	37	37	191	544
HDD Std Dev	132	141	159	115	85	73	72	52	28	28	77	70
HDD Max	1,361	1,506	1,681	1,204	953	694	471	248	151	97	343	677
HDD Min	699	918	897	716	598	392	192	61	-	1	54	361

Avista models five weather areas: Spokane, Medford, Roseburg, Klamath Falls and La Grande. From the simulation data we were able to assess the frequency that the peak day occurs in each area. The stochastic analysis shows that in over 200 twenty-year simulations, while still remote, peak day (or more) does occur with enough frequency to maintain our current planning standard for this IRP though this topic remains a subject of continued analysis. For example, in our Medford weather pattern over the 200 twenty-year draws (i.e. 4000 years, HDDs at or above peak weather (61 HDD) occur 128 times. This equates to a peak day occurrence once every 31 years (4000 simulation years divided by 128 occurrences). The Spokane area has the least occurrences of peak day (or more) occurrences in our simulations while 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 7.9 through 7.13 for the number of peak day occurrences for a weather area.

Figure 7.4 - Frequency of Peak Day Occurrences
Spokane



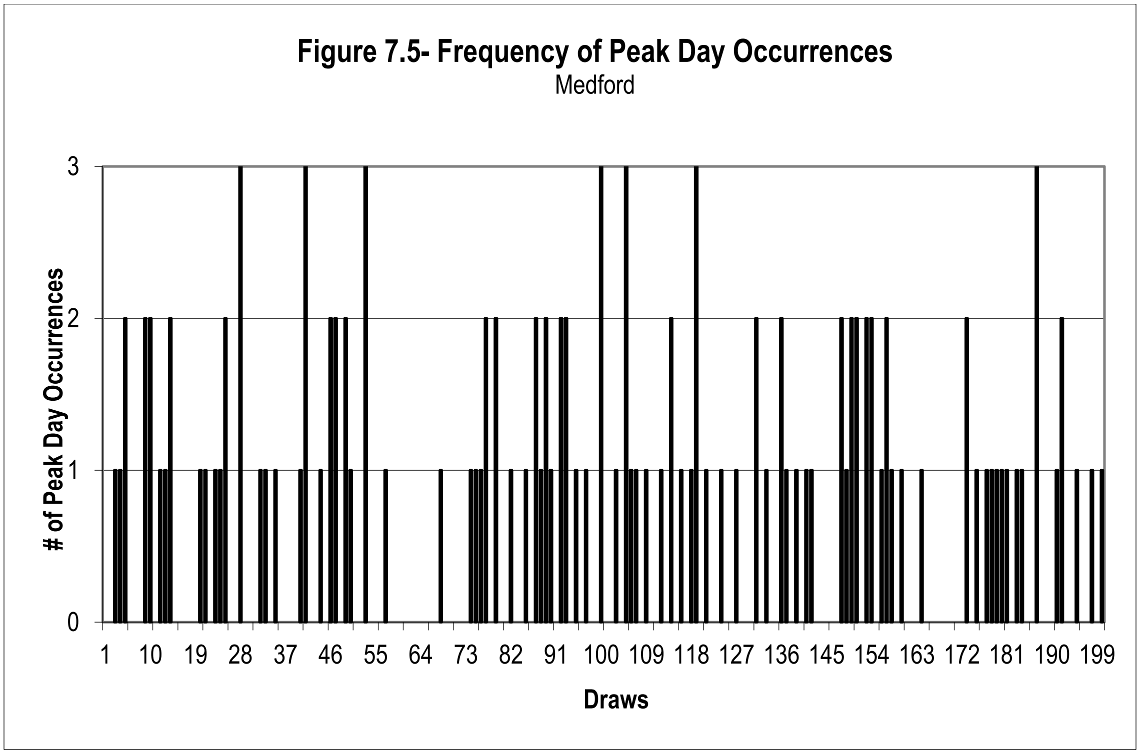


Figure 7.5- Frequency of Peak Day Occurrences
Medford
# of Peak Day Occurrences
0
1
2
3
1 10 19 28 37 46 55 64 73 82 91 100 109 118 127 136 145 154 163 172 181 190 199
Draws

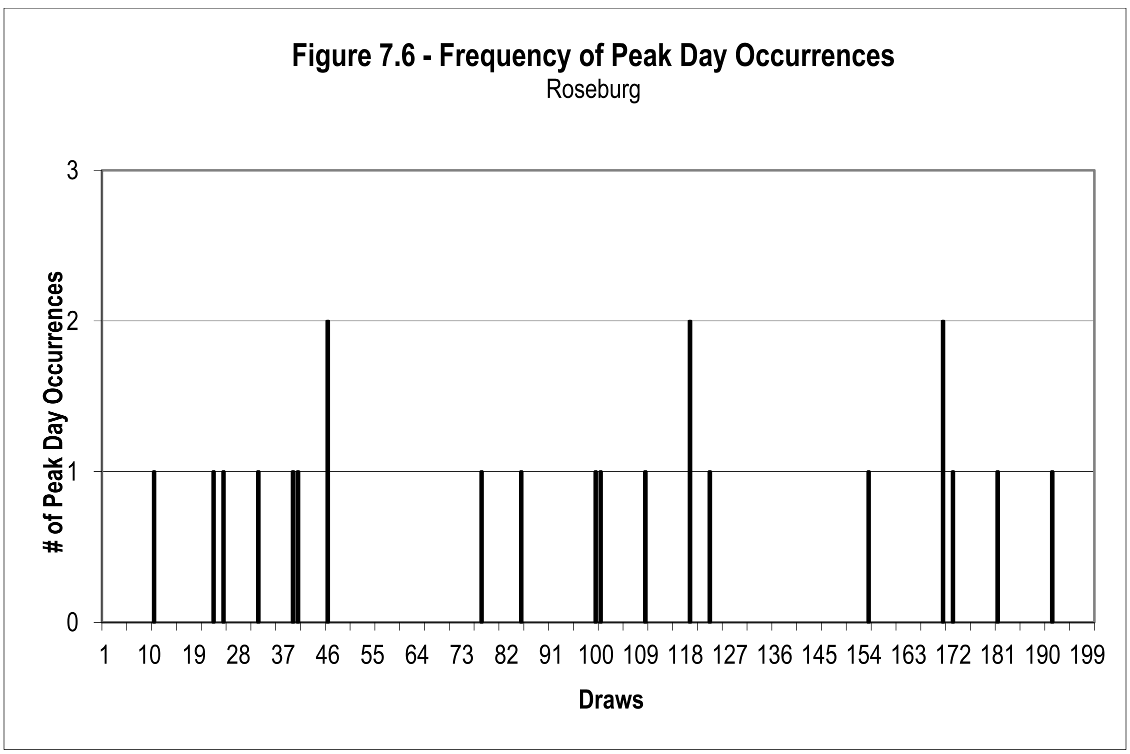
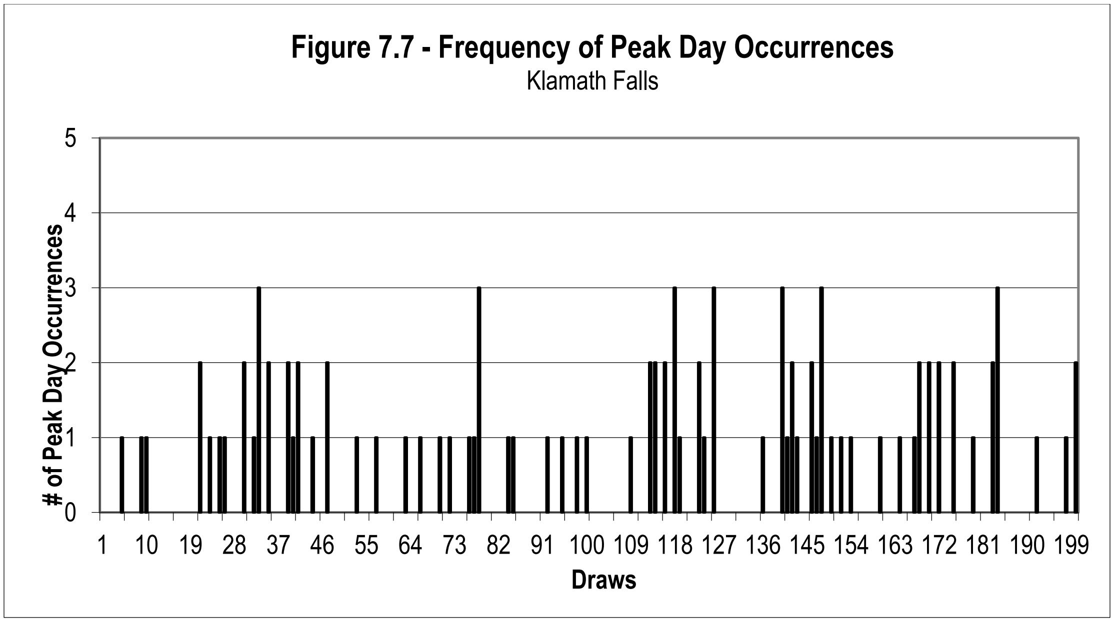
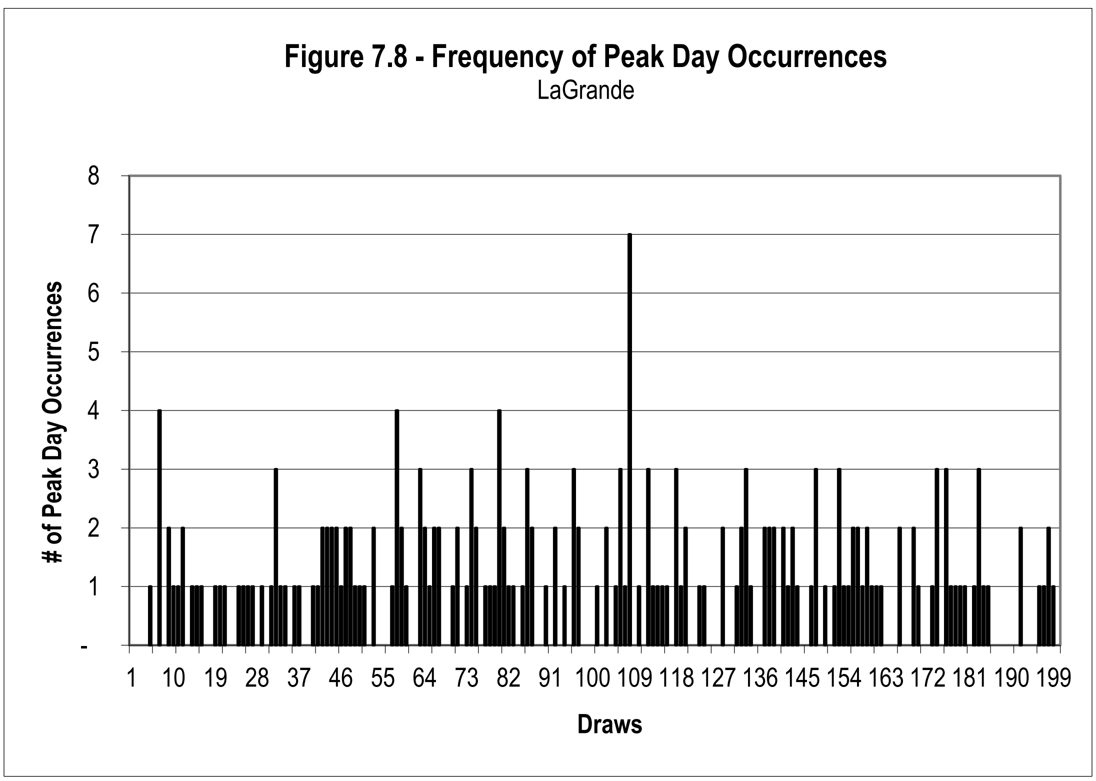


Figure 7.6 - Frequency of Peak Day Occurrences
Roseburg
# of Peak Day Occurrences
0
1
2
3
1 10 19 28 37 46 55 64 73 82 91 100 109 118 127 136 145 154 163 172 181 190 199
Draws



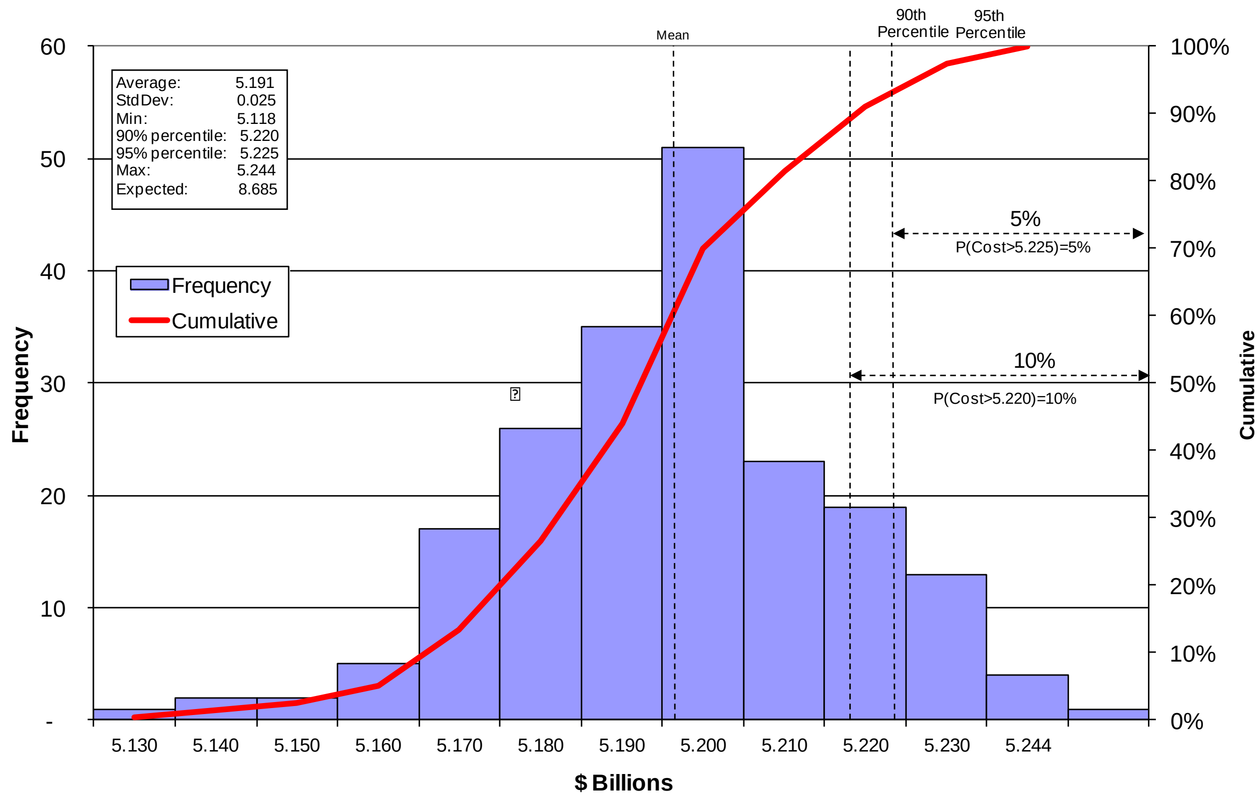


PRICE

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

Through Monte Carlo simulation we are able to test our portfolio and quantify the risk to our customers when prices do not materialize as forecasted. We performed a simulation of 200 draws, varying prices, to investigate whether the Expected Case total portfolio costs from our deterministic analysis is within the range of occurrences in our stochastic analysis. Figure 7.9 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 our Expected Case total portfolio cost is within an acceptable range of total portfolio costs based on 200 unique pricing scenarios.

Figure 7.9
Avista IRP Total 20 Year Cost



Performing stochastic analysis on two key variables of weather and price in our demand analysis provided a statistically supported approach to evaluate and confirm the findings reached from our scenario analysis with respect to adequacy and reasonableness of our weather planning standard and our selected natural gas price forecast. This alternative analytical perspective provides us better confidence in our conclusions and helps us stress test our assumption, thereby mitigating analytical risks.

REGULATORY REQUIREMENTS

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

- Examined a range of demand forecasts
- Examined feasible means of meeting demand with both supply-side and demand-side resources
- Treated supply-side and demand-side resources equally
- Described our long-term plan for meeting expected demand growth
- Described our plan for resource acquisitions between planning cycles
- Taken planning uncertainties into consideration
- Involved the public in the planning process
- We have addressed the applicable requirements throughout this document. Appendix 2.2 lists the specific requirements and guidelines of each jurisdiction and describes our compliance in detail

We are also required to consider risks and uncertainties throughout our planning and analysis. Our approach in addressing this requirement was to identify factors that could cause significant deviation from our Expected Case planning conclusions. We employed dynamic demand analytical methods and incorporated sensitivity analysis on various demand drivers that impacted demand forecast assumptions. From this, we created 17 demand sensitivities and modeled five demand scenario alternatives, which incorporated differing customer growth, use per customer, weather and price elasticity assumptions.

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

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

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

CONCLUSION

The High Growth and Low Growth Case demand analysis provides a sufficient range for evaluating possible demand trajectories relative to our Expected Case. Based on this analysis we feel comfortable that we have sufficient time to plan for forecasted resource needs. Even under a very extreme growth scenario our first forecasted deficiency does not occur until 2029. We recognize that many things could happen between now and when our resource needs occur, therefore we will carefully monitor our demand trends and continually updated and evaluate all demand side and supply side alternatives.

CHAPTER 8 ■ DISTRIBUTION PLANNING

OVERVIEW

Avista’s integrated resource planning encompasses evaluation of safe, economical, and reliable full-path delivery of natural gas from basin to burner tip. Securing adequate natural gas supply and ensuring sufficient pipeline transportation capacity to our city gates become secondary issues if the distribution system behind the city gates is not adequately planned and becomes severely constrained. An important part of the planning process is to forecast future local demand growth, determine potential areas of distribution system constraints, analyze possible solutions, and estimate costs for eliminating constraints.

Analyzing our resource needs to this point has focused on ensuring adequate capacity to our city gates, especially during a peak event (i.e. “Is there adequate volume for a peak day?”). Distribution planning focuses on “Is there adequate pressure during a peak hour?” Despite this altered perspective distribution planning shares many of the same goals, objectives, risks and solutions.

Avista’s natural gas distribution system consists of approximately 5,400 miles of distribution main pipelines in Washington, 3,000 miles in Idaho and 3,500 miles in Oregon 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 our distribution system. System pressure is maintained by pressure regulating stations that utilize pipeline pressures from the interstate transportation pipelines before natural gas enters our distribution networks.

DISTRIBUTION SYSTEM PLANNING

Avista conducts two primary types of evaluations in its distribution system planning efforts to determine the need for resource additions including distribution system reinforcements and expansions. Reinforcements are upgrades in existing infrastructure or new system additions that increase system capacity, reliability and safety. Expansions are new system additions to accommodate new demand. Collectively we refer to these as distribution enhancements.

Ongoing evaluations of each distribution network in our four primary service territories are conducted to identify strategies for addressing local distribution requirements resulting from customer growth. Customer growth assessments are made based on many factors including our IRP demand forecasts, monitoring of gate station flows and other system metering, ongoing communication with construction staff and local area management regarding new service requests, field personnel discussion and inquiries from major developers.

Additionally, Avista regularly conducts integrity assessments of its distribution systems. This type of ongoing system evaluation can also indicate distribution upgrading requirements, as a result of system maintenance needs rather than customer and load growth. In some cases, however, the timing for system integrity upgrades can coincide with growth related expansion requirements.

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

NETWORK DESIGN FUNDAMENTALS

Natural gas distribution networks rely on pressure differentials to flow gas from one place to another. When pressures are the same on both ends of a pipe the gas does not move. When gas is removed from a point on the network the pressure at that point drops lower than the pressure upstream in the network. Gas then moves from the higher pressure in the network to the point of removal attempting to equalize the pressure throughout the network. If gas removed is not sufficiently replaced by new gas entering the network the pressure differential will decrease, flow will stall and the network could run out of pressure.

Therefore, it is important to design a distribution network so that the intake pressure (from gate stations and/or regulator stations) within the network is high enough to maintain an adequate pressure differential when gas leaves the network.

Not all gas flows equally throughout a network. Certain points within the network can constrain flow and thus restrict overall network capacity. Network constraints can occur over time as demand requirements on the network 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 significantly aided by computer modeling to perform network demand studies. Demand studies have evolved with technology in the past decade to become a highly technical and powerful means for analyzing the performance of a distribution system. Using a pipeline fluid flow formula, a specified parameter of each pipe element can be simultaneously solved. A variety of 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 produced closely resemble actual system behavior.

Avista conducts network load studies using GL Noble Denton's SynerGEE® software. This computer-based modeling tool allows users to analyze and interpret solutions graphically. Appendix 8.1 describes in detail our computer modeling methodology while Appendix 8.2 provides an example load study presentation including graphical interface and output examples.

DETERMINING PEAK DEMAND

Avista's distribution network is comprised of high pressure (90-500 psig) and intermediate pressure (5-60 psig) mains. For ease of maintenance and operation, safety to the public, reliable service and cost considerations, intermediate networks operate at a relatively low pressure. Avista operates its intermediate networks at a maximum operating pressure of 60 pounds per square inch gauge (psig). Since the majority of distribution systems operate through relatively small diameter pipes, there is essentially no line-pack capability for managing hourly demand fluctuations.

Core demand typically has a morning peaking period between 6 a.m. and 10 a.m. and an evening peaking period between 5 p.m. and 9 p.m. The peak hour demand for these customers can be as much as 50% above the hourly average of the daily demand. Because of the importance of responding to hourly peaking in the distribution system, planning capacity requirements for our distribution systems are based on peak hour demand[1]. Included in Appendix 8.1 is the detailed methodology Avista uses for determining peak demand.

DISTRIBUTION SYSTEM ENHANCEMENTS

Computer-aided demand studies facilitate modeling numerous "what if" demand forecasting scenarios, constraint identification and corresponding optimum combination of pipe modification and pressure modification solutions to maintain adequate pressures throughout the network over time.

Distribution system enhancements do not reduce demand nor do they create additional supply. However, they can increase the overall capacity of a distribution pipeline system while utilizing existing gate station supply points. The three broad categories of distribution enhancement solutions are pipelines, regulators and compression.

PIPELINES

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

Pipeline solutions consist of looping, upsizing and uprating.

Pipeline looping is the most common method of increasing capacity within an existing distribution system. It involves constructing new pipe parallel to an existing pipeline that has, or may become, a constraint point. Constraint points inhibit flow capacities downstream of the constraint creating inadequate pressures during periods of high demand. When the parallel line is connected to the system this second alternative path allows natural gas flow to bypass the original constraint point and bolster downstream pressures. Looping can also be accomplished by connecting mains that were not previously connected. The feasibility of looping a pipeline is primarily dependent upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt and steep or rocky terrain can greatly increase the cost to amounts that are unjustifiable so that other alternative solutions offer a more cost effective solution.

Pipeline upsizing is simply replacing existing pipe with a larger size pipe. The increased pipe capacity relative to surface area of the pipe results in less friction and therefore a lower pressure drop. This option is usually pursued when there is damaged pipe or pipe integrity issues exist. If the existing pipe is otherwise in satisfactory condition looping is usually pursued, allowing the existing pipe to remain in use.

Pipeline uprating involves increasing 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 system facilities. However, safety considerations and pipe regulations may prohibit feasibility or lengthen the time before completion of this option. Also, increasing line pressure may produce leaks and other pipeline damage creating unanticipated costly repairs. A thorough review is conducted to ensure integrity before pressure is increased.

REGULATORS

Regulators or regulator stations are used to reduce pipeline pressure at various stages within the distribution system. The primary purpose of regulation is to provide a specified and constant outlet pressure before gas continues its downstream travel to a city's distribution system, customer's property or gas appliance. Regulators also ensure that flow requirements are met at a desired pressure regardless of pressure fluctuations upstream of the regulator. Regulators can be found at city gate stations, district regulators stations, farm taps and customer services.

COMPRESSION

Compressor stations present a capacity enhancing option for pipelines with significant gas flow and the ability to operate at higher pressures. For pipelines experiencing a relatively high and constant flow of gas a single, large volume compressor can be installed in the optimal position along the pipeline to boost downstream pressure.

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

Compressors can be a cost effective, feasible option to resolving system constraints; however, regulatory and environmental approvals to install a station, along with engineering and construction time can be a significant deterrent. Also, adding compressor stations within a distribution system typically involves considerable capital expenditure. Based on our detailed knowledge of our distribution system, we do not have any foreseeable plans to add compressors to our distribution network.

CONSERVATION RESOURCES

Included in our evaluation of distribution system constraints is consideration of targeted conservation resources that could reduce or delay distribution system enhancements. We are mindful; however, that the consumer is still the ultimate decision-maker regarding the purchase of a conservation measure. Because of this, we attempt to influence these decisions but we do not depend on estimates of peak day demand reductions from conservation to eliminate near-term distribution system constraint areas. Over longer-term planning we do recognize that targeted conservation programs provide a cumulative benefit that offsets potential constraint areas and may be an effective strategy.

PLANNING RESULTS

Table 8.1 summarizes the cost of major distribution system enhancement projects which address future growth-related system constraints as well as system integrity issues and the anticipated timing of these expenditures. These proposed projects are preliminary estimates of timing and costs of major reinforcement solutions. The scope and needs of these projects can evolve over time with new information requiring ongoing reassessment. Actual solutions may be different due to differences in actual growth patterns and/or construction conditions from those assumed in the initial assessment.

The following discussion provides further information on our key near-term projects:

East Medford Reinforcement – Previous IRP and distribution planning analysis identified a near term resource deficiency driven by forecasted local growth. To remedy the deficiency, increased gas deliveries will likely be needed from the TransCanada Pipeline source at Phoenix Road Gate Station in southeast Medford. To facilitate distribution receipt of the increased gas volumes, a new HP gas line encircling Medford to the east and tying into an existing high-pressure line in White City will improve delivery capacity and provide a much needed reinforcement in the East Medford area.

This has been a multi-phase project spanning multiple years. As forecasted needs have changed over time, and with no immediate resource need, completing the final phase of the project has been delayed. Other factors may drive completion of the project including, reliability needs, flexibility of gas supply management, and optimizing synergies of other construction projects and thereby reducing cost of the project. We will continue to evaluate forecasts and assess the most appropriate timing for completion of the project.

U.S. 2 North Spokane Reinforcement – This project will reinforce the area north of Spokane along U.S. Highway 2. This mixed-use area with residential, commercial and industrial demand experiences low pressure during winter at unpredictable times given varied demand profiles of the diverse customer base. Completion of this reinforcement will improve pressures in the U.S. 2 North Kaiser area. Approximately 8,000 feet of HP steel gas main will be installed in a newly established easement along U.S. Highway 2.

Chase Rd Gate Station, Post Falls, ID – This gate station will allow Avista to split the large load at the Rathdrum Gate Station. Approximately 18,000 feet of high-pressure line will be built to connect Chase Rd Gate Station to the existing high pressure. This gate station will also give Avista the opportunity to feed the growing Post Falls and Coeur d’Alene areas from the north.

TABLE 8.1 DISTRIBUTION PLANNING CAPITAL PROJECTS

		2015	2016	2017	2018
Projects	*East Medford Reinforcement	$0	$0	$0	$5,000,000
	Goldendale HP	$3,500,000	$0	$0	$0
	NSC Greene ST HP	$0	$0	$0	$1,500,000
	Rathdrum Prairie HP Gas Reinforcement	$100,000	$4,900,000	$5,000,000	$0
	*Reinforcement, Hwy 2 Kaiser	$1,300,000	$0	$0	$0
	Spokane St Bridge Gas	$1,000,000	$0	$0	$0

*Details of project described in IRP

Table 8.2 summarizes the city gate stations that have been identified as being over utilized or under capacity. Estimated cost, year, and the plan to remediate the capacity concern are also mentioned.

TABLE 8.2 CITY GATE STATION UPGRADES

Location	Gate Stn	Project to Remediate	Cost	Year
Athol, ID	Athol #219	TBD	-	2019+
Genesee, ID	Genesee #320	TBD	-	2019+
Rathdrum, ID	*Chase Rd	Chase Rd Gate Stn & Hayden Ave HP Main	$5.4M	2014
CDA (East), ID	CDA East #221	Rathdrum Prairie HP Gas Reinforcement	$10M	2016-17
Post Falls, ID	McGuire #213			
CDA (West), ID	Post Falls & CDA West			
Colton, WA	Colton #316	TBD	-	2019+
Sutherlin, OR	Sutherlin #2626	TBD	-	2019+
La Grande, OR	La Grande #815 & Union #817	Union HP Connector	$3M	2019+

*Details of project described in IRP

CONCLUSION

Avista's goal is to maintain its distribution systems reliably and cost effectively to deliver natural gas to every customer. This goal is achieved with the aid of computer modeling, which increases the capacity and reliability of the distribution system by identifying specific areas within the system that may require changes.

The ability to meet the goal of reliable cost effective gas delivery is also enhanced through the localized distribution planning enabling coordinated targeting of distribution projects that are responsive to detailed customer growth patterns.

CHAPTER 9 ■ ACTION PLAN

2013-2014 ACTION PLAN REVIEW

ACTION ITEM

We will actively monitor our demand looking for indications of deviations away from our Expected Case.

RESULTS

Forecast to actual analysis gives us comfort that our modeling techniques are producing forecasts that track actual demand. We have not seen recent activity that supports a material deviation away from expected results.

ACTION ITEM

Continued enhancement of our gate station analysis will also be completed to assess if there are individual gate station deficiencies that are masked by our aggregated IRP analysis. Should any deficiencies be identified we will discuss findings and potential solutions with Commission Staff. We will continue to coordinate analytic efforts between Gas Supply, Gas Engineering, and the intrastate pipelines to perform gate station analysis and if deficiencies are identified seek least cost solutions.

RESULTS

We are in the process of completing the analysis of our gates in Oregon on the NWP system. As we complete the analysis any deficiencies will be communicated along with solutions for rectifying the deficiencies to Commission Staff. We will then look at gates along the GTN system.

ACTION ITEM

Avista filed in Oregon, Washington and Idaho to suspend natural gas DSM programs due to the low avoided costs in the 2012 IRP. Over the next two to three years, Avista will be watching natural gas prices as a sign post for the cost-effectiveness of DSM programs. Should prices move significantly Avista will again be proactive in seeking to reinstate a full complement of our natural gas DSM programs.

RESULTS

Idaho approved the filing and natural gas DSM programs were suspended. In Oregon, DSM programs were allowed to continue for a two year period. During that time, Avista will evaluate program costs, and develop a separate program for low income participants. In Washington, DSM programs were also allowed to continue for a limited period and the test for evaluating cost effectiveness was changed from the total resource cost to the utility cost test.

ACTION ITEM

Pursue the possibility of a regional elasticity study through the Northwest Gas Association or possibly the American Gas Association.

RESULTS

There is a wide spread belief that energy consumers will reduce their consumption if prices rise. However, how much of a response will occur can be debated. To better understand this belief we have reviewed historic research on price elasticity. The analysis shows a wide range of results from statistically significant to statistically insignificant and even positive in some cases.

We have contacted the Northwest Gas Association and they have agreed to help facilitate a process should we decide to move forward with a regional price elasticity study. We are in the process of assessing the scope of work to be completed, estimated cost, and regional interest of the results of the study. When and if we have garnered enough interest we will commence a study.

2015-2016 ACTION PLAN

The decade long recession significantly impacted the expected long term customer growth in our service territory. This reduction in demand has created no resource needs in our Expected Case within the planning horizon. Analysis of further scenarios shows, that even in our most robust growth case, we do not have a resource deficiency until very late in the 20 year forecast.

With no immediate needs, we have time to fully evaluate current resources and potential future resources. We will continue to optimize underutilized resource to recover value for our customers and reduce their costs until resources are needed to meet changing demand needs.

Avista remains committed to offering cost-effective conservation measures as a way for customers to reduce their energy bills and promote a cleaner environment. Like our 2012 IRP, the low price of natural gas has reduced the amount of cost-effective measures. Based on our latest conservation potential assessment which incorporates the lower avoided costs, we are targeting 128,700 Dth of first year savings in Washington, 22,800 Dth of first year savings in Idaho and 16,100 Dth of savings in Oregon.

We will comply with current Commission findings try to increase the cost effectiveness of measures within the portfolio by reducing administration and audit costs, analyzing non-natural gas benefits, and measure lives. We will monitor natural gas prices as signpost for increasing avoided costs. Should avoided costs increase we will evaluate our demand side programs for cost-effectiveness and be proactive in submitting to resume our natural gas demand side management options.

Completion of the gate station analysis to assess any resource deficiencies masked by aggregated IRP analysis. Should deficiencies be identified we will discuss findings and potential solutions with Commission Staff. We 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.

ONGOING ACTION ITEMS

- Monitor actual demand for indications of growth exceeding our forecast to respond aggressively to address potential accelerated 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. This information will be provided in Avista’s updates to each commission staff at least biannually.
- Continue to monitor supply resource trends including the availability and price of natural gas to the regions, exporting LNG, Canadian natural gas imports and interprovincial

consumption, regional plans for gas-fired generation and its affect on pipeline availability, as well as regional pipeline and storage infrastructure plans.

- Monitor new resource lead time requirements relative to when resources are needed to preserve resource option flexibility.
- Regularly meet with Commission Staff members 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.

Chapter 10 ■ 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.

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.

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
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

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
Cost and benefits that are not reflected in the price paid for goods or services.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)
The government agency charged with the regulation and oversight of interstate natural gas pipelines, wholesale electric rates and hydroelectric licensing; the FERC regulates the interstate pipelines with which 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 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.

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 found in Louisiana that is widely recognized as the most important pricing point in the United States. It is also the trading hub for the New York Mercantile Exchange (NYMEX).

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 customer needs at a reasonable price.

JACKSON PRAIRIE
An underground storage project jointly owned by Avista Corp., Puget Sound Energy, and NWP; the project is a naturally occurring aquifer near Chehalis, Washington, which is located some 1,800 feet beneath the surface and capped with a very thick layer of dense shale.

LIQUEFACTION
Any process in which natural gas is converted 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 that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.

LINEAR PROGRAMMING
A mathematical method of solving problems by means of linear functions where the multiple variables involved are subject to constraints; this method is utilized in the SENDOUT® Gas Model.

LOAD DURATION CURVE
An array of daily send outs observed that is sorted from highest send out day to lowest to demonstrate both the 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. Can be 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.

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 be used to supplement firm contracts during times of high demand or to displace other volumes when it is cost-effective to do so; 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 and is 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.

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.

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 that could potentially install a conservation measure did so without consideration of market barriers such as cost and customer awareness.

THERM
A unit of heating value used with natural gas that is equivalent to 100,000 British thermal units (BTU); also approximately equivalent to 100 cubic feet of natural gas.

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, Nevada; 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 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