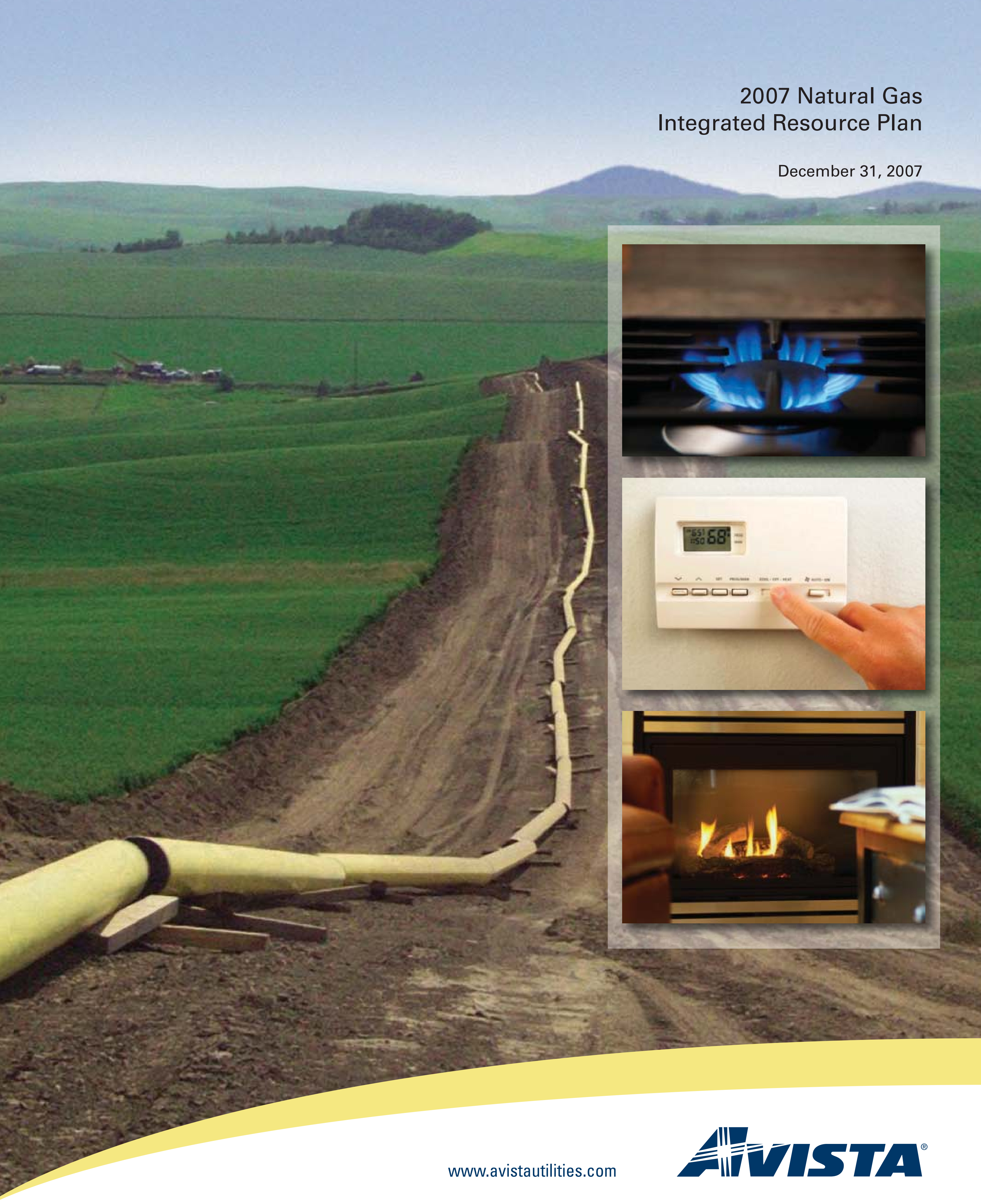

2007 Natural Gas Integrated Resource Plan

December 31, 2007

www.avistautilities.com

AVISTA®

COVER PHOTOS

- Avista's investment in natural gas growth crosses the Palouse region of Southeast Washington, serving Washington State University.
- Key components of natural gas efficiency include a gas cooktop, a programmable thermostat and a gas fireplace.

SPECIAL THANKS TO OUR TALENTED VENDORS FROM THE SPOKANE AREA WHO PRODUCED THIS IRP:

Ross Printing Company

Thinking Cap Design

Printed on recycled paper.

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SAFE HARBOR STATEMENT

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

For a further discussion of these factors and other important factors, please refer to our reports filed with the Securities and Exchange Commission which are available on our website at www.avistacorp.com. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events.

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2007 IRP KEY MESSAGES

- In our Expected Case, Avista has sufficient natural gas resources in Oregon until 2011-2012 and in Washington and Idaho until 2014-2015. Peak day resource deficits begin in these years and are driven primarily by projected average demand growth of 2 percent per year and average natural gas customer growth of 2.4 percent.

- To meet our near term resource deficits in Oregon, we have identified preferred solutions. For the Klamath Falls service territory we intend to purchase the Klamath Falls Lateral from Northwest Pipeline (NWP) enabling us to meet demand in our Expected Case throughout the planning horizon. For the Medford service territory, ongoing distribution system enhancements combined with expansion of Gas Transmission Northwest's (GTN's) Medford Lateral should also meet long term demand in our Expected Case.

- Avista has a diversified portfolio of natural gas resources, including owned and contracted storage, firm capacity rights on five pipelines and commodity 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 plans to meet the identified resource deficits with demand-side management measures and firm resources, including distribution system enhancements and pipeline transportation capacity.

- The major change from the 2006 IRP to the 2007 IRP is the lower demand forecast. This reduction was driven mainly by a lower economic growth rate and lower use per customer than previously forecasted in our service territories.

- There are many risks to consider over the planning horizon. Some of the modeled and non-modeled risks analyzed include price elasticity, growth rates, lead-times and cost overruns on resource construction, legislation on environmental externalities, availability of supply and weather.

- Demand-Side Management efforts include a review and implementation of customer programs, including residential space and water heating efficiency, wall, floor and window audits and replacement programs, and commercial and industrial natural gas efficiency programs, among others. Avista has implemented an energy efficiency initiative called the "Heritage Project." It builds on the company's long-time commitment to energy conservation and efficiency, introducing new products and services to increase customer's energy savings.

- The market for natural gas supply has dramatically changed over the last several years as the commodity market has transitioned from a regionally-based market to a national or perhaps global market. The elevated prices and increased volatility have influenced the way we plan in the short-term and in the long-term. Our natural gas procurement plan seeks to competitively acquire natural gas supplies while reducing exposure to short-term price volatility, using a number of tools such as financial hedging and storage.

- The Integrated Resource Plan identifies and establishes an action plan that will steer the company toward the risk adjusted, least-cost method of providing service to our natural gas customers. Included in this action plan are efforts to improve modeling, evaluation of our planning standard, further research into supply-side resource options and goals for demand-side management.

AVISTA'S ELECTRIC AND NATURAL GAS SERVICE AREAS

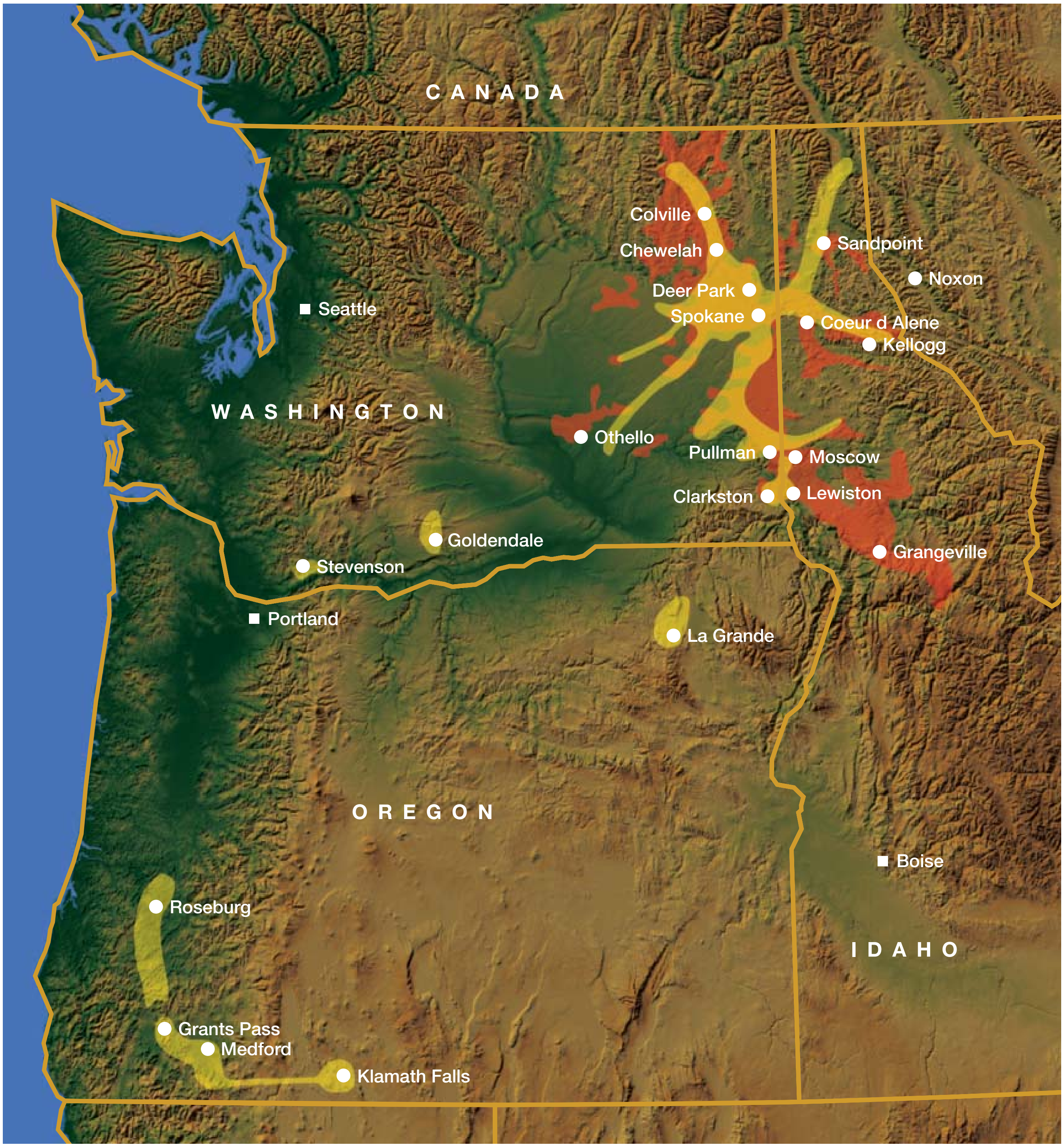
AS OF DECEMBER 31, 2006:

RETAIL ELECTRIC CUSTOMERS BY STATE

Washington:	227,700
Idaho:	117,700
Total Electric:	345,400

RETAIL NATURAL GAS CUSTOMERS BY STATE

Washington:	140,900
Idaho:	69,800
Oregon:	93,900
Total Natural Gas:	304,600



Electric Service Areas

Natural Gas Service Areas

1. EXECUTIVE SUMMARY

Avista's 2007 Natural Gas Integrated Resource Plan (IRP) identifies a strategic natural gas resource portfolio that meets future demand requirements. The foundation for integrated resource planning is the demand planning criteria utilized for the development of demand forecasts. The formal exercise of bringing together forecasts of customer demand with comprehensive analyses of resource options, including supply-side and demand-side measures, is valuable to the company, its customers and regulatory commissions for long-range planning.

Avista submits an IRP to the public utility commissions in Idaho, Washington and Oregon every two years as required by state regulation[1]. The company has 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 various resource options and as a process to establish a plan of action for resource decisions. Through ongoing and evolving investigation and research, we may determine that alternative resources are more cost-effective than those resources selected in this IRP. We will continue to review and refine our knowledge of resource options and will act to secure these least-cost options when appropriate.

The IRP identifies and establishes an action plan to steer the company toward the least-cost method of providing service to our natural gas customers. There are a number of factors that must be considered within the context of least-cost, including an assessment of risks associated with each alternative. Therefore, actions resulting from the IRP process represent risk-adjusted, least-cost results, which we refer to as best cost/risk resources.

Avista's management and stakeholders in the Technical Advisory Committee (TAC) play a key role and have a significant impact in guiding the plan to its conclusions. TAC members include customers, Commission Staff, consumer advocates, academics, utility peers, governmental agencies and other interested parties (a list of TAC members is in Appendix 1.1). The TAC provides important input on modeling, planning assumptions and the general direction of the planning process.

IRP PROCESS AND STAKEHOLDER INVOLVEMENT

Preparation of the IRP is a coordinated effort by several departments within the company and includes input from Commission Staff, customers and other stakeholders. Topics leading to the development of the IRP include natural gas sales forecasts, demand-side management, distribution planning, supply-side resources and computer modeling tools, resulting in an integrated resource portfolio.

[1] In Washington, 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 No. 89-507, 07-002 and UM1056. Chapter 6 of this document details these requirements.

To facilitate stakeholder involvement in the 2007 IRP, the company sponsored four TAC meetings. The first meeting convened on May 2, 2007, and the last meeting was held on Aug. 14, 2007. A broad spectrum of people was invited to each meeting. The meetings focused on specific planning topics, reviewed the status and progress of planning activities and solicited ongoing input on the IRP development. A draft of this IRP was provided to TAC members on Sept. 6, 2007. We gained valuable input from the TAC interaction and appreciate the positive contribution of the participants.

MODELING APPROACH

We applied our SENDOUT® model (a linear programming model widely used to solve natural gas supply and transportation optimization questions) to develop the best cost/risk resource mix for the 20-year planning period. Using a present value revenue requirement (PVRR) methodology, this model performs 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; and
- demand-side management.

Additionally, we have incorporated VectorGas™, a module within SENDOUT®, to simulate weather and price uncertainty. VectorGas™ generates "draws" which are single data sets (heating degree-days for weather and/or prices), which can be optimized in SENDOUT® to provide a probability distribution of results from which decisions can be made. Some examples of the analyses VectorGas™ provides include:

- probability distributions of price and weather;
- probability distributions of costs (i.e. system cost, storage costs and commodity costs);
- resource mix (optimally sizing a contract or asset level for various and competing resources); and
- hedging percentages.

DEMAND AND SCENARIOS

Our approach to demand forecasting focuses on customer growth and use per customer as the base components of demand. We considered various factors that influence these components, including population and employment trends, age and income demographics, natural gas prices, price elasticity and use per customer trends. We used this information to develop low, medium and high customer growth scenarios crossed with low, medium and high price scenarios. Based on input from the TAC, three main cases were selected for further review. Table 1.1 summarizes the three cases, including the customer growth and price elasticity assumptions included in the scenarios. Throughout this document these three cases are referenced as the Expected Case, the High Demand Case and the Low Demand Case. The high and low cases do not represent the maximum or minimum bounds of possible cases, but frame a broad range of likely demand scenarios that could occur.

Table 1.1 - Demand Scenarios

High Demand Case – High demand and low price scenario. 50% increase in customer growth and a price elasticity adjustment to demand coefficients (-.13).	**Expected Case** – Base demand and mid price scenario. Static use per customer over the planning horizon.	**Low Demand Case** – Low demand and high price scenario. 50% decrease in customer growth and a price elasticity adjustment to demand coefficients (-.13).

The demand forecast from the Expected Case revealed:

- The number of system-wide core customers is expected to increase from an average of 315,200 in 2007-2008 to 494,900 in 2026-2027. This is an annual average growth rate of 2.4 percent.
- Average day, system-wide core demand, net of model-selected demand-side management measures, is projected to increase from an average of 95,400 Dekatherms per day (Dth/day) in 2007-2008 to 139,500 Dth/day in 2026-2027. This is an annual average growth rate of 2 percent.
- Coincidental peak day, system-wide core demand, net of model-selected demand-side management measures, is projected to increase from a peak of 361,900 Dth/day in 2007-2008 to 535,700 Dth/day in 2026-2027. This is a growth rate of over 2.1 percent in peak day requirements.

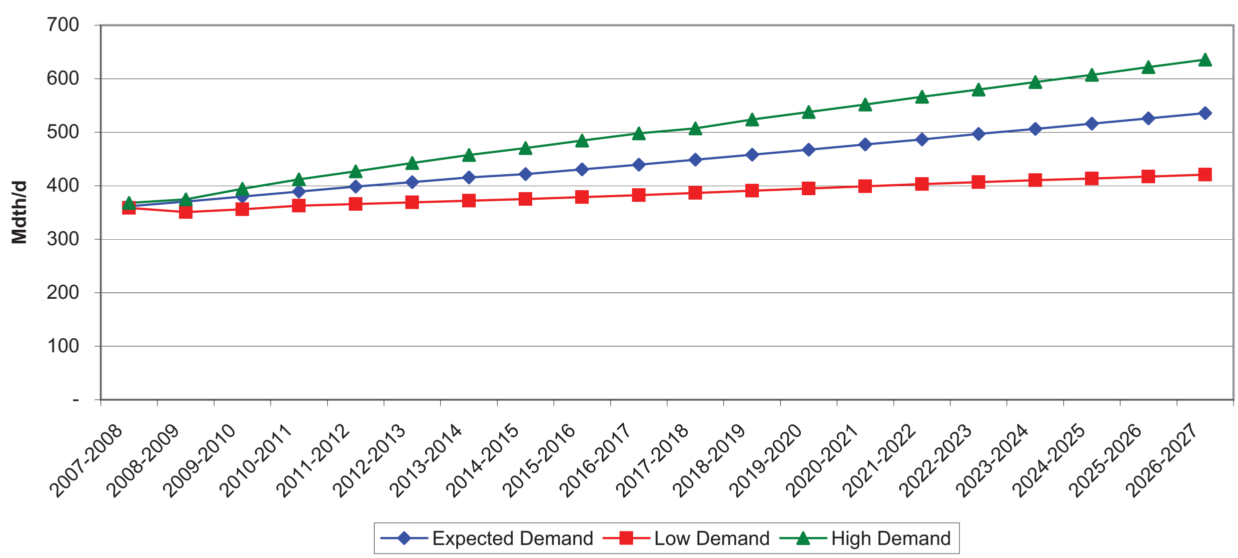
Details of the demand forecast for our High and Low Demand cases can be found in Appendix 2.4

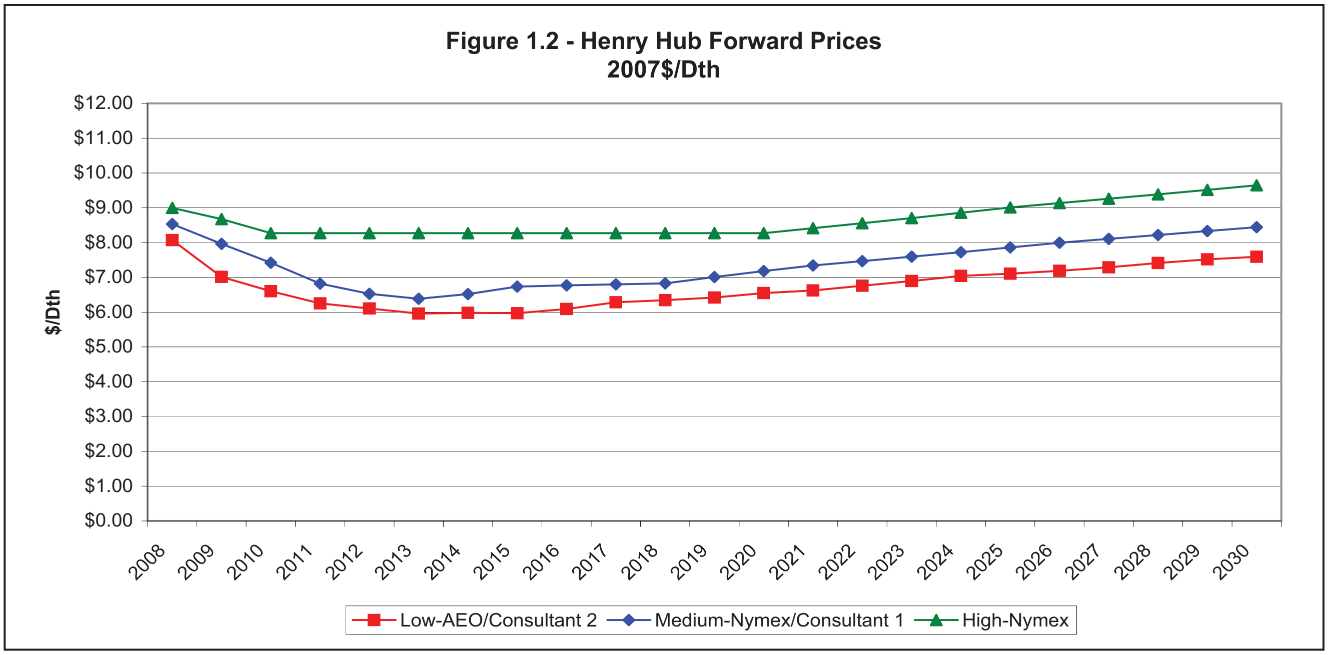
Figure 1.1 shows forecasted system-wide average peak day demand per year for the three main scenarios over the planning horizon.

NATURAL GAS PRICE FORECASTS

The natural gas market has dramatically changed over the last several years as it has transitioned from a regional to a national or perhaps global market. Regional and national natural gas prices since 2005 have experienced increased volatility. Demand growth, natural gas use for electric generation, hurricane activity and other weather events are believed to be some of the reasons for the increased price volatility. Additionally, the continuing trend of heightened oil price volatility from geopolitical and global supply/demand issues remains an influence. The industry has also observed higher natural gas price levels since 2005. This new price level stems from the tight production and productive capacity balance, as well as the increasing costs of natural gas production. Although we do not believe that we can accurately predict future prices for the 20-year horizon of this IRP, we have reviewed several price forecasts from credible sources, and we have selected high, medium and low price forecasts to represent reasonable pricing possibilities. Figure 1.2 depicts the selected price forecasts.

Figure 1.1 - System Wide Peak Day Demand
(Net of DSM Savings)





RESOURCES

Avista has a diversified portfolio of natural gas supply resources, including owned and contracted storage, firm capacity rights on five pipelines and contracts to purchase natural gas from several different supply basins. In our IRP process we model a number of conservation measures or programs that reduce demand if they prove to be cost effective. We also model incremental pipeline transportation, storage options, distribution enhancements and various forms of liquefied natural gas (LNG) storage or service.

DEMAND-SIDE MANAGEMENT

Avista actively promotes and offers energy-efficiency programs to our natural gas customers. These demand-side management (DSM) programs are one component of a comprehensive strategy to provide our customers with a best cost/risk energy resource. The IRP is an opportunity to evaluate this resource mix to refine approaches to the management of both supply-side and demand-side management resources.

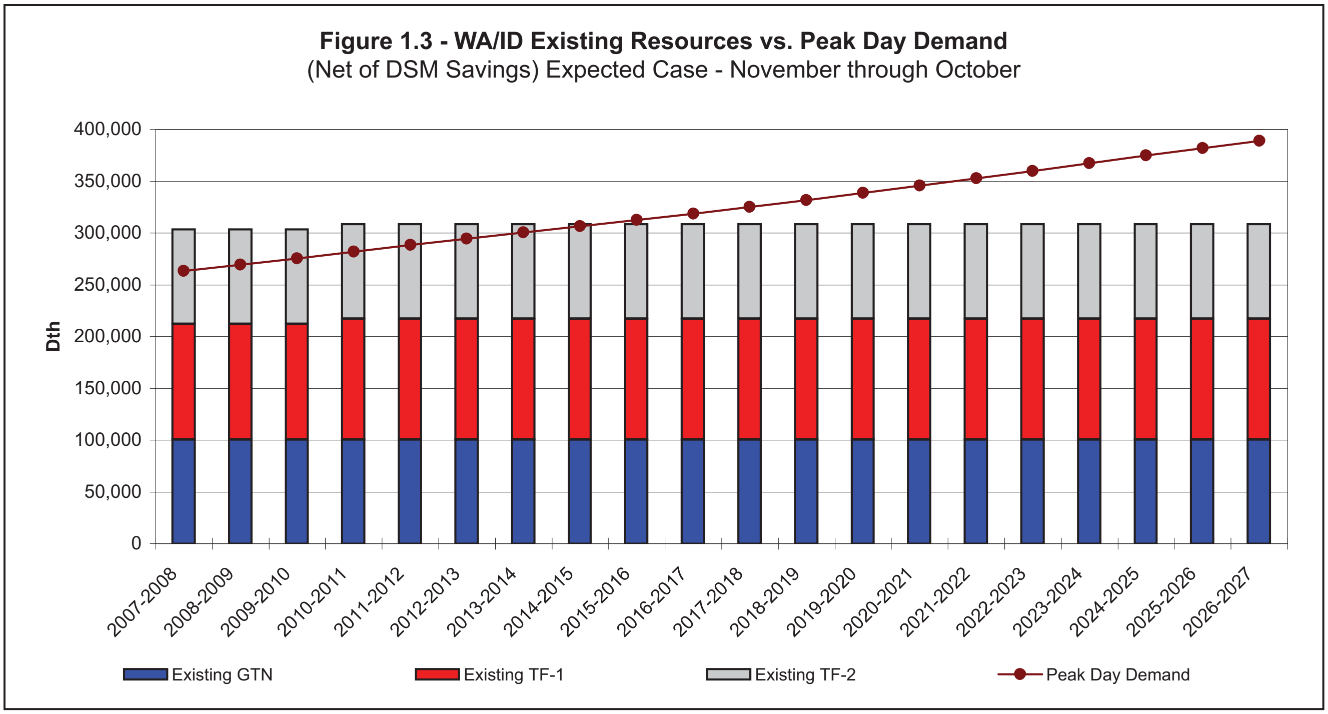
Based on the projected natural gas prices and the estimated cost of alternative supply resources, the SENDOUT® model selected certain DSM measures for further review and implementation.

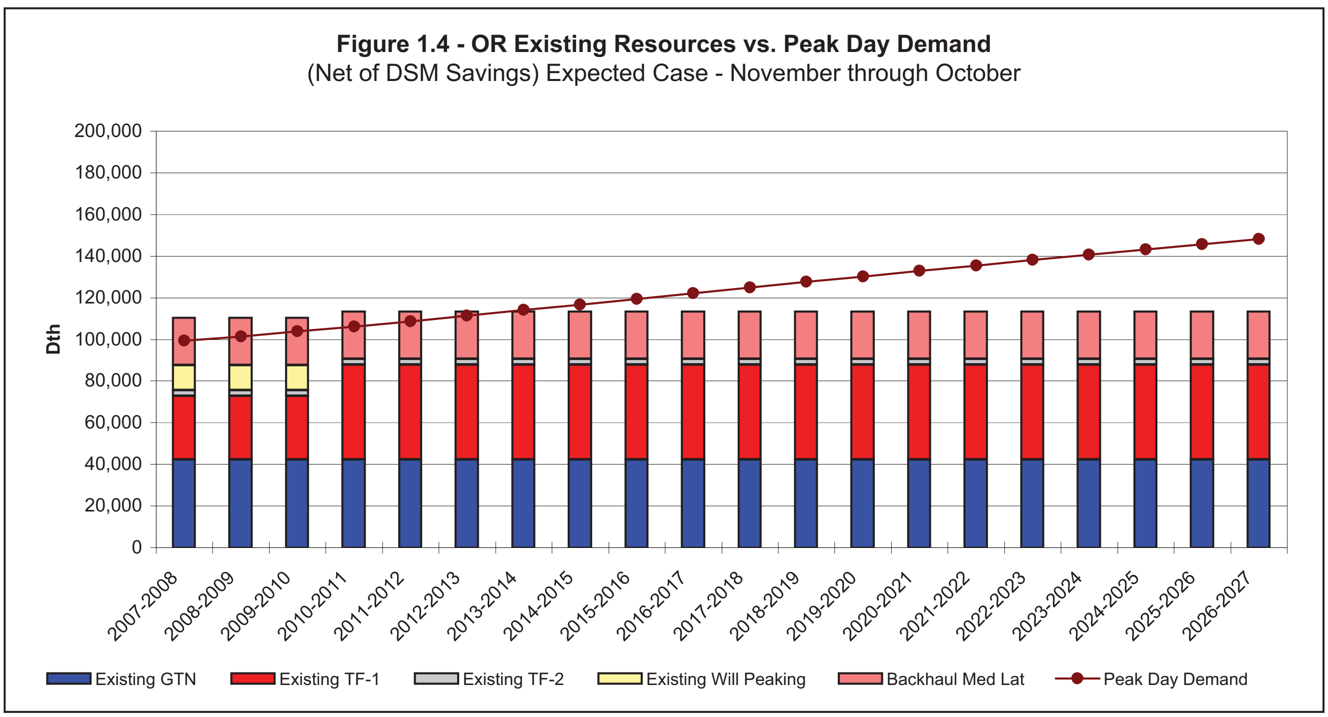
RESOURCE NEEDS

The SENDOUT® model was run utilizing existing resources and the three demand cases to determine if resource deficiencies exist during the planning period.

In the Expected Case for Washington and Idaho, the first deficiency is in 2014-2015. Given this timing, we have sufficient time to carefully monitor, plan and take action on potential resource additions. We also plan to define and analyze sub-regions within this broad region for potential resource needs that may materialize earlier than 2014-2015.

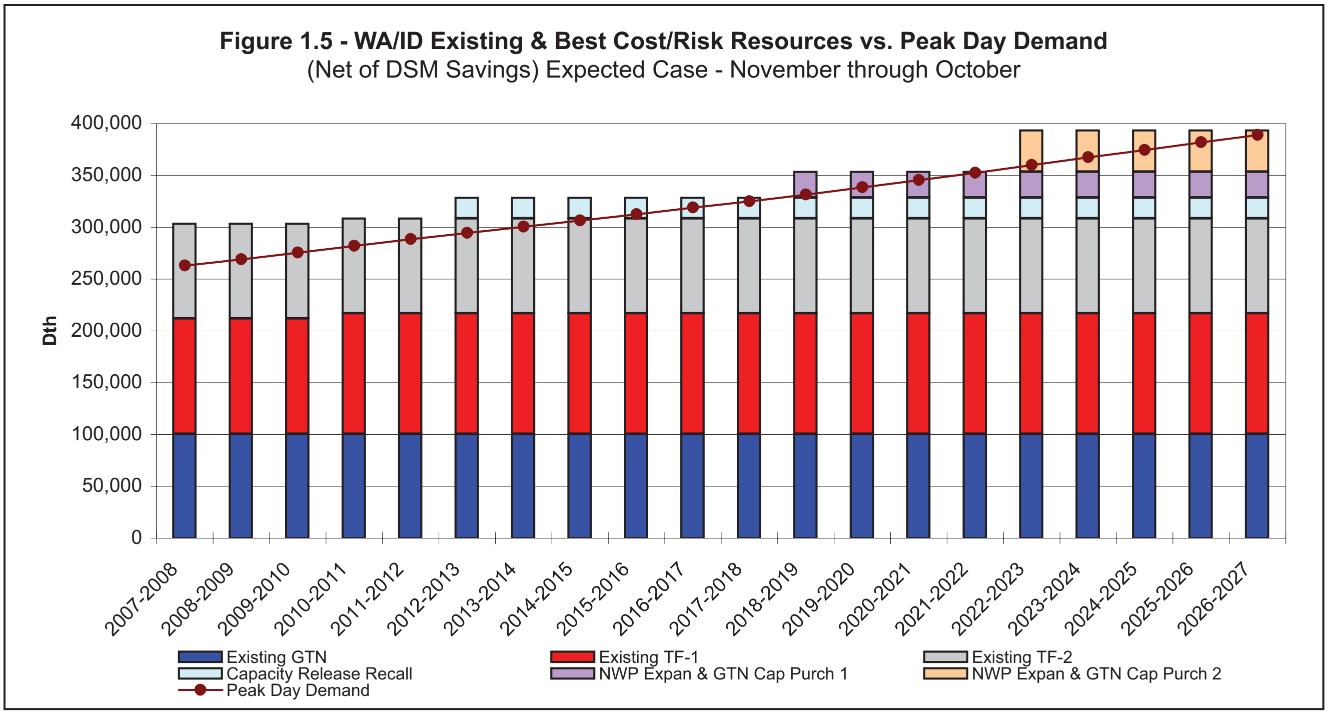
In the Expected Case for Oregon, the first capacity deficiency is in Klamath Falls in 2011-2012. The other Oregon areas become capacity deficient in 2013-2014. Given this timing, we are actively assessing our Action Plan around potential resource additions.

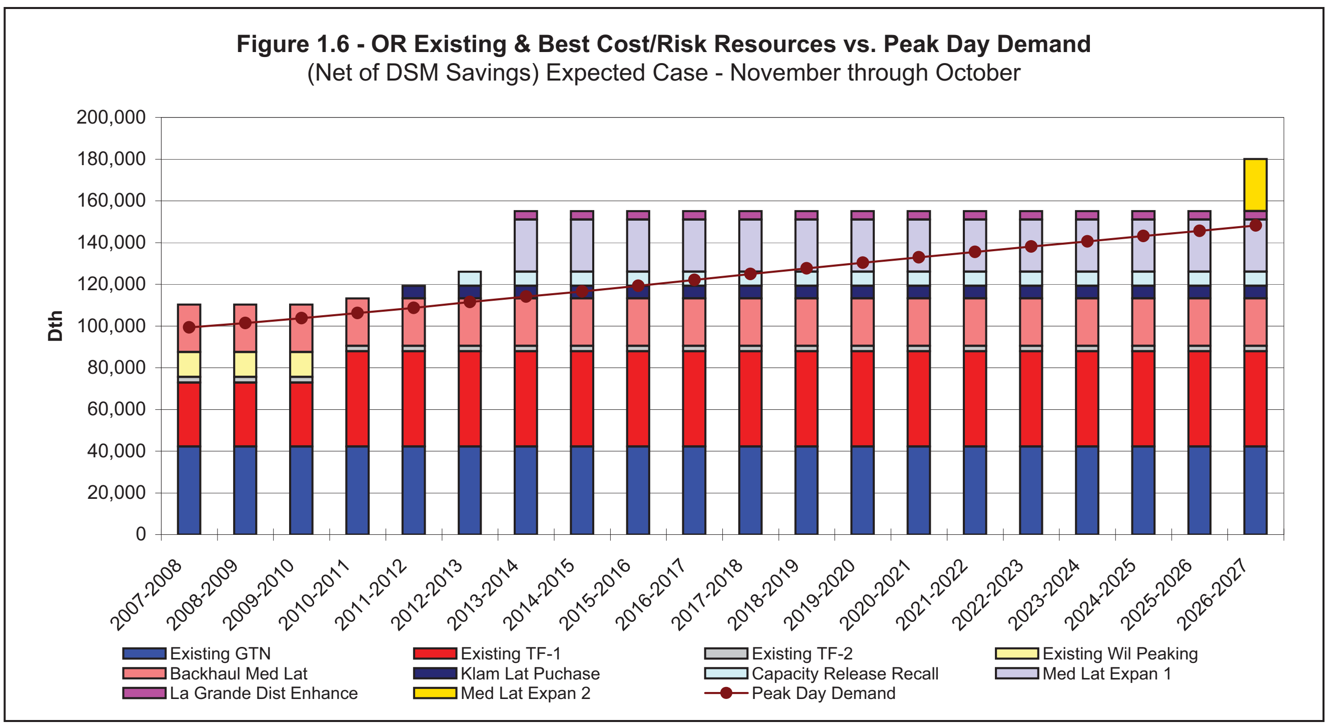




Figures 1.3 and 1.4 compare existing peak day resources to expected peak day demand and show the timing and extent of resource deficiencies for the Expected Case.

We identified possible resource options and placed those options into the SENDOUT® model to select the best cost/risk incremental resources over the 20-year planning horizon.





Figures 1.5 and 1.6 depict the best cost/risk portfolio selected by SENDOUT® to meet the identified capacity deficiencies.

As indicated in Figures 1.5 and 1.6, for Washington/Idaho and Oregon, after DSM savings the model shows a general preference for incremental transportation resources from existing supply basins to resolve capacity deficiencies.

SUMMARY OF KEY FINDINGS AND ACTION ITEMS

Our 2008-2009 Action Plan outlines the activities developed by our staff with advice from management and TAC members. These actions, in many instances, have already begun and will be completed in the next two years. The purpose of these action items is to position the company to provide the best cost/risk resource portfolio, and to support and improve IRP planning. Key components of the Action Plan include:

- Refine our specific resource acquisition action plans for Klamath Falls and Medford service areas that address the projected unserved demand in 2011-2012 and 2013-2014, respectively. For the Klamath Falls service territory, we intend to purchase the Klamath Falls Lateral. For the Medford service territory, our ongoing distribution system enhancements combined with an expansion of the Medford Lateral is our planned resource solution.
- Research and refine the evaluation of resource alternatives, including implementation risk factors and timelines, updated cost estimates, and feasibility assessments, targeting options for the service territories with nearer term unserved demand exposure.
- Explore non-traditional resources to address our needle-peaking requirements. This review will emphasize potential structured transactions with neighboring utilities and other market participants that leverage existing regional infrastructure as an alternative to incremental infrastructure additions.
- Reevaluate our current peak day weather planning standard to ascertain if it still provides the best risk-adjusted methodology for resource planning.
- Continue our pursuit of cost effective demand-side solutions to reduce demand. In Oregon demand-side measures are targeted to reduce demand by 350,000 therms in the first year. In Washington and Idaho, demand-side measures are targeted to reduce demand by over 1,425,000 therms in the first year.
- Define and analyze sub regions within the Washington/Idaho region for potential resource needs that may materialize earlier than the broader region indicates.
- Integrate the VectorGas™ module in our SENDOUT® modeling software to strengthen our ability to analyze demand impacts under varying weather and price scenarios as well as conduct sensitivity analysis to identify, quantify and manage risk around these demand influencing components.
- Continue to assess methods for capturing additional value related to existing storage assets, including methods of optimizing recently recalled capacity.

2. DEMAND FORECAST

OVERVIEW

Avista served an average of 299,300 core natural gas customers (firm, non transportation customers) with 31,887,000 Dth of natural gas in 2006. By 2026, Avista projects that it will have approximately 500,000 core natural gas customers with an annual demand of over 53,700,000 Dth. In Washington, the number of customers is projected to increase at an average annual rate of 2 percent, with demand growing at 1.9 percent per year. In Oregon, the number of customers is projected to increase at an average annual rate of 2.5 percent, with demand growing at 2.3 percent per year. In Idaho, the number of customers is projected to increase at an average annual rate of 3 percent, with demand growing at 3 percent per year.

We presented our natural gas forecast to the TAC in May 2007. This forecast was completed in April 2007, and it had assumptions and results that were driven by national and service area economic forecasts. Based on discussions with the TAC about impacts from natural gas rate increases on use per customer trends, we revised use per customer assumptions downward for this IRP.

Avista manages its demand forecast through two distinct operating divisions – North and South:

- The North Operating Division covers about 26,000 square miles, primarily in eastern Washington and northern Idaho. More than 840,000 people live in Avista's Washington/Idaho service area. It includes urban areas, farm and timberlands, as well as 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. area and Coeur d'Alene, Idaho.

The North Operating Division consists of about 74 miles of natural gas transmission mains and 5,000 miles of natural gas distribution mains. Natural gas is received at more than 40 points along interstate pipelines and distributed to more than 210,000 residential, commercial and industrial customers.

- The South Operating Division serves five counties in Oregon. The population of this area is over 480,000. The South Operating Division includes urban areas, farms and timberlands. The Medford, Ashland and Grants Pass area, located in Jackson and Josephine Counties, is the largest single area in Oregon served by Avista, with a regional population of approximately 280,000. The South Operating Division consists of about 67 miles of natural gas transmission mains and 2,000 miles of natural gas distribution mains. Natural gas is received at more than 20 points along interstate pipelines and distributed to more than 90,000 residential, commercial and industrial customers.

DEMAND FORECAST METHODOLOGY

For this IRP, we used our SENDOUT® model to produce forecasted demand. The key demand forecast inputs are forecasts of the number of customers, demand coefficients and heating degree-days. The daily demand forecasts are calculated per the formula in Table 2.1.

This calculation is performed daily for each firm customer class and demand area. The customer classes are residential, commercial and firm industrial. The demand areas are Medford, Roseburg, Klamath Falls, La Grande, Ore. and the eastern Washington/northern Idaho area. The climate and economy in each of these five areas vary enough to make a meaningful difference in the demand profiles for these areas.

Due to the volatility in natural gas prices, and based on discussions with the TAC, we have incorporated price elasticity when determining use per customer. Avista participated in a national price elasticity study conducted by the American Gas Association (AGA). The AGA provided jurisdiction-specific price elasticity estimates to local distribution companies, and we have incorporated these estimates into our analysis. For the Expected Case there is no adjustment made for price elasticity, as this case assumes no change in use per customer over the planning horizon. For our High and Low Demand cases a price elasticity factor of negative 0.13 was used to adjust the demand coefficients[2].

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 described in this chapter include existing efficiency standards and normal market acceptance levels. Incremental

Table 2.1 - SENDOUT® Demand Calculation

	# of Customers	X	Daily Dth / Base Usage / Customer	
		Plus		
# of Customers	X	Daily Dth / Degree-Day / Customer	X	# of Daily Degree-Days

[2] This means that if natural gas prices increase by 10 percent, we would expect customer demand to decrease 1.3 percent (all other factors being equal). Similarly, a 10 percent decrease in natural gas prices would stimulate a 1.3 percent increase in natural gas consumption.

conservation measures modeled are described in the Demand-Side Management chapter.

CUSTOMER FORECASTS

The foundation of any demand forecast is based on the number and types of customers expected over the planning horizon. We developed our customer forecast by starting with national economic forecasts and then drilling down into regional economies. Population growth expectations and employment are the key drivers in regional economies and in ultimately estimating natural gas customers. Avista contracts with Global Insight, Inc. for long-term regional economic forecasts. A description of the Global Insight forecasts is found in Appendix 2.1. We combined this data, along with company-specific knowledge about sub-regional construction activity, trends and historical data to develop the 20-year customer forecast.

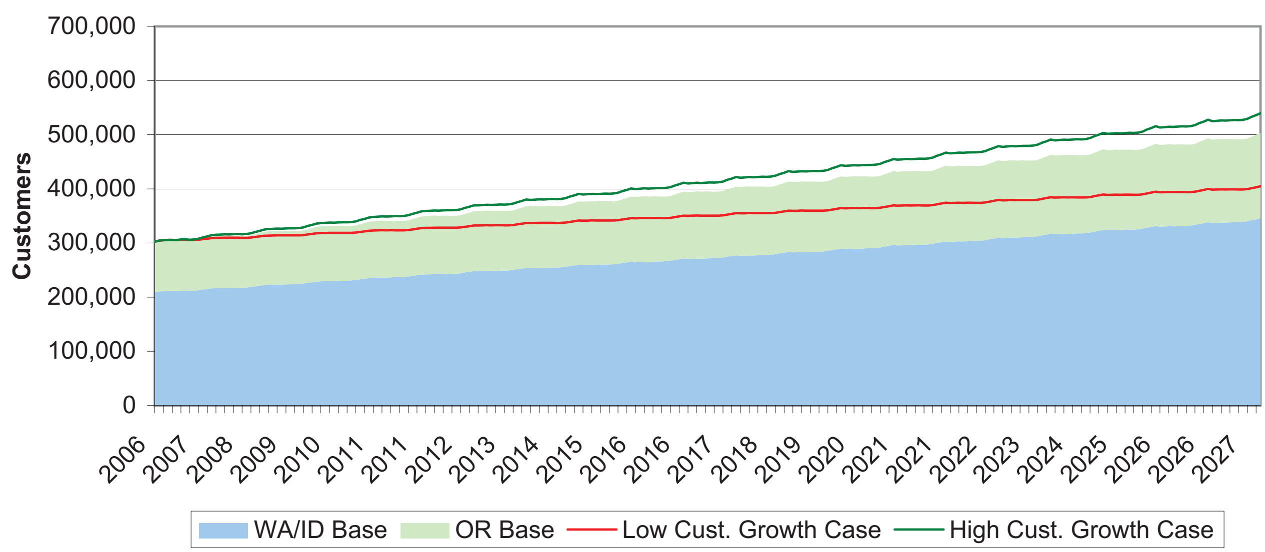
Forecasting customer growth is an inexact science, so it is important to consider alternatives to this forecast. We developed two additional outcomes for consideration in this IRP. During the last 25 years, customer growth during five-year periods has ranged between one-half and one-and-a-half times the 25-year average customer growth rate. Since both patterns have been observed in the past, Avista has created low and high customer growth scenarios with these parameters. The three customer growth forecasts are shown in Figure 2.1. Detailed customer count data, by region and by class, for all three scenarios can be found in Appendix 2.2.

SUB-AREA FORECASTING AND PLANNING

In response to an action item in our previous IRP, we have incorporated sub-area core customer forecasting for each municipality and unincorporated county throughout the three-state service area. This includes 56 governmental subdivisions (called "town codes") in Washington, 26 governmental subdivisions in Idaho and 37 governmental subdivisions in Oregon.

The annual growth for each state is allocated so that the total equals the sum of the parts. These 119 separate town code forecasts are used by the gas distribution engineering group for optimizing decisions within these geographic sub-areas facilitating integrated forecasting

Figure 2.1 - Customer Growth Scenarios
(Number of Customers by Year)



and planning within the company (see further discussion in Chapter 4-Distribution Planning).

HEATING DEGREE-DAY DATA

Heating degree-day data is obtained from the National Oceanic and Atmospheric Administraion (NOAA) 30-year weather study spanning 1971-2000. For Oregon, Avista uses four weather stations, corresponding to the areas where natural gas services are provided. Heating degree-day weather patterns between these areas are uncorrelated. For the eastern Washington and northern Idaho portions of Avista's service area, weather data for the Spokane Airport are used, as heating degree-day monthly weather patterns within that region are correlated. Actual heating degree-day weather is discussed in more detail in Chapter 6-Integrated Resource Portfolio and the actual heating degree-days used in SENDOUT® are found in Appendix 6.1.

USE PER CUSTOMER

Use per customer forecasts are based on daily heating degree-days, which shape customer use with the seasons' variation. We use multiple regressions to compute coefficients by customer classes. The regression includes a non-heat amount (the constant in the regression often referred to as base-load) and three variables for heating degree-days. The first heating degree-day coefficient is the shoulder-month estimate. This includes heating degree-days for the months of April, May, June, September and October. Summer heating degree-days are excluded during the air-conditioning months. The second heating degree-day coefficient is the winter-period estimate. This variable includes degree-days for December, January and February. The third variable is for March and November. We have found that the November and March months are more sensitive to heating degree-days than the shoulder months, but less sensitive than the December through February period. The regression calculations producing these coefficients can be found in Appendix 2.3.

The shoulder-month regression coefficient is about one-half the winter-period coefficient. This means that a shoulder-month heating degree-day produces about one-half as many therms per customer as a winter-period heating degree-day. The coefficients are estimated separately for each area.

Table 2.2 - Demand Coefficients

	Non-Heat Dth/Cust/Day	Shoulder Dth/Cust/Day	Nov. & Mar. Dth/Cust/Day	Dec.-Jan.-Feb. Dth/Cust/Day
Residential – WA/ID	0.0488	0.0059	0.0091	0.0104
Commercial – WA/ID	0.3456	0.0297	0.0458	0.0543
Industrial – WA/ID	7.0856	0.0734	0.1130	0.1497
Residential – Medford	0.0442	0.0073	0.0101	0.0117
Commercial – Medford	0.3412	0.0348	0.0483	0.0475
Industrial – Medford	0.0346	0.0583	0.0809	0.0807
Residential – Roseburg	0.0465	0.0077	0.0099	0.0117
Commercial – Roseburg	0.3637	0.0387	0.0499	0.0512
Industrial – Roseburg	15.5022	0.4377	0.5648	0.4248
Residential – Klamath Falls	0.0318	0.0041	0.0067	0.0084
Commercial – Klamath Falls	0.3488	0.0217	0.0355	0.0372
Industrial – Klamath Falls	0.0892	0.0285	0.0466	0.0548
Residential – La Grande	0.0299	0.0057	0.0102	0.0122
Commericial – La Grande	0.2623	0.0257	0.0455	0.0508
Industrial – La Grande	56.0680	n/a	n/a	n/a

(Each coefficient is significant at the 95 percent level)

VALIDATION OF COEFFICIENT AND CUSTOMER GROWTH INFORMATION

The regression-derived heating degree-day coefficients are average responses derived over a forecasted 60-month period. These coefficients are compared to recalibrated coefficients which are derived from a backcast of actual demand over the previous 12 months. These recalibrated coefficients (see Table 2.2) are input into the SENDOUT® model to produce a demand forecast. This demand forecast is compared to the regression coefficient derived forecast for reasonableness.

With respect to the customer growth assumptions, residential customer growth is proportional to population growth, and commercial customer growth is proportional to employment growth. This ensures that the company-specific customer forecasts are aligned with the regional and national economic forecasts.

DEMAND FORECAST

Increased natural gas price volatility has made it more difficult to project (or predict) future natural gas prices. We acknowledge changing price levels influence usage, so we incorporated a price elasticity of demand factor into our model to allow use per customer to vary as our natural gas price forecast changes (See Table 2.3). From our participation in the American Gas Association's price elasticity study, we received regional elasticity factors which compared favorably to our past estimates. Based on this corroboration, we used a factor of negative 0.13 in our process.

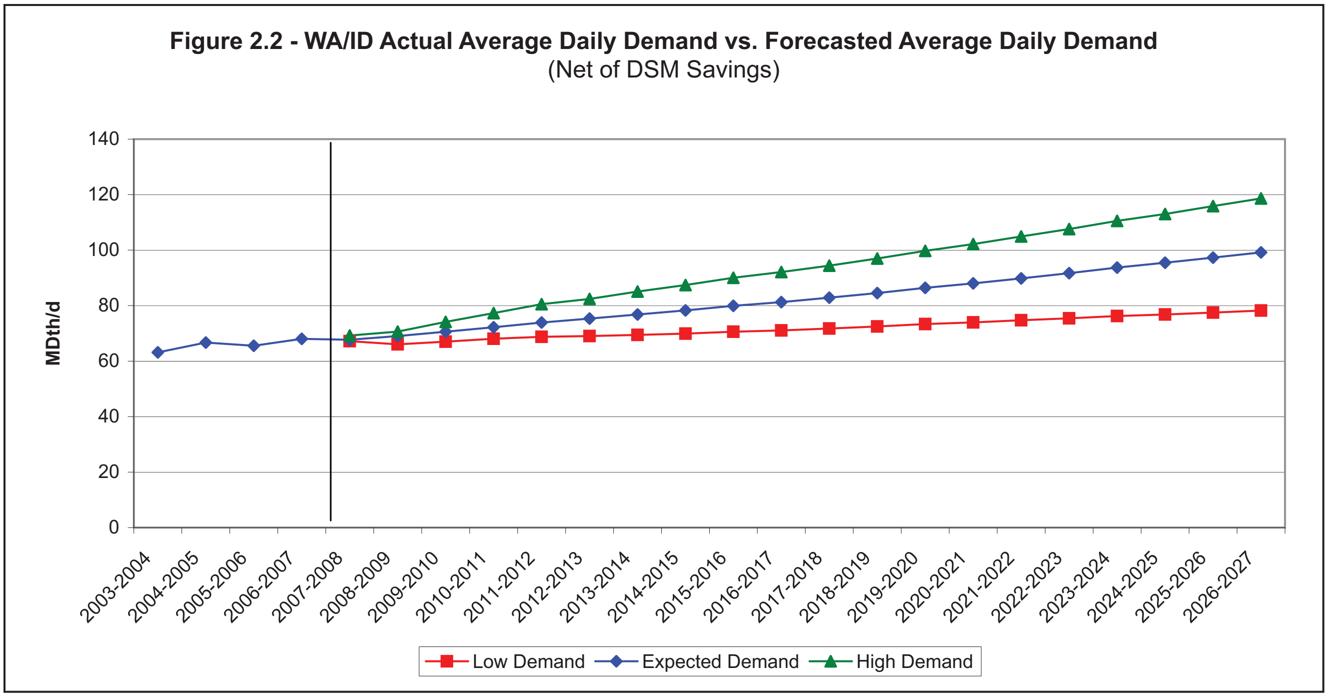
This means that if natural gas prices increase by 10 percent, we would expect customer demand to decrease 1.3 percent (all other factors being equal). Similarly, a 10 percent decrease in natural gas prices would stimulate a 1.3 percent increase in gas consumption. (The price-related elasticity factors are calculated for the High and Low Demand scenarios by indexing the prices to 2007 and applying the negative 0.13 to the percentage) We calculated customer response for each scenario by adjusting the demand coefficients shown in Table 2.2 by the specific price-related elasticity factors. The High and Low Demand forecasts utilize the elasticity assumption and the natural gas price curves discussed in Chapter 6, Figure 6.14

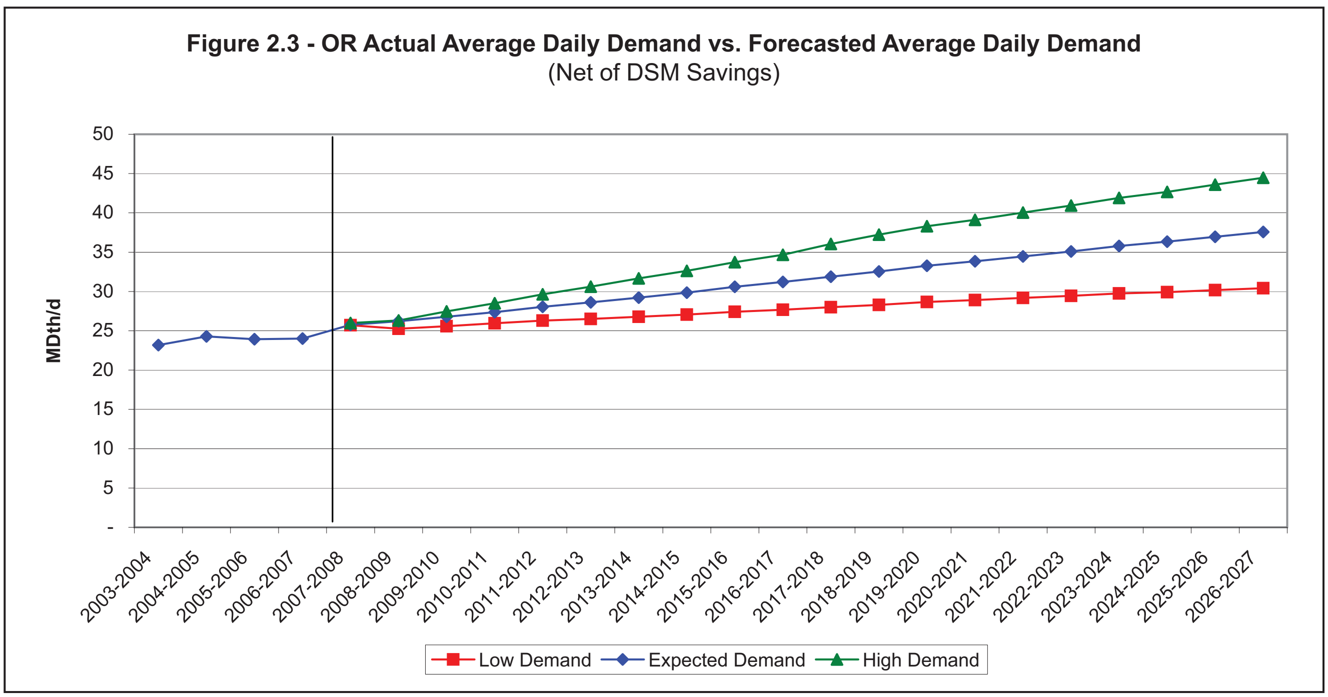
DEMAND SCENARIOS

Our approach to demand forecasting focuses on customer growth and use per customer as the base components of demand. Other factors that influence these components were considered, such as population and employment trends, age and income demographics, natural gas prices, price elasticity and use per customer trends. Three main cases were selected for further analysis. Table 2.3 summarizes the three cases, including the customer growth and price elasticity assumptions. The High and Low Demand cases do not represent the maximum and minimum bounds of possible cases, but frame a broad range of scenarios that could occur.

Table 2.3 - Demand Scenarios

High Demand Case – High demand and low price scenario. 50% increase in customer growth and a price elasticity adjustment to demand coefficients (-.13).	**Expected Case** – Base demand and mid price scenario. Static use per customer over the planning horizon.	**Low Demand Case** – Low demand and high price scenario. 50% decrease in customer growth and a price elasticity adjustment to demand coefficients (-.13).

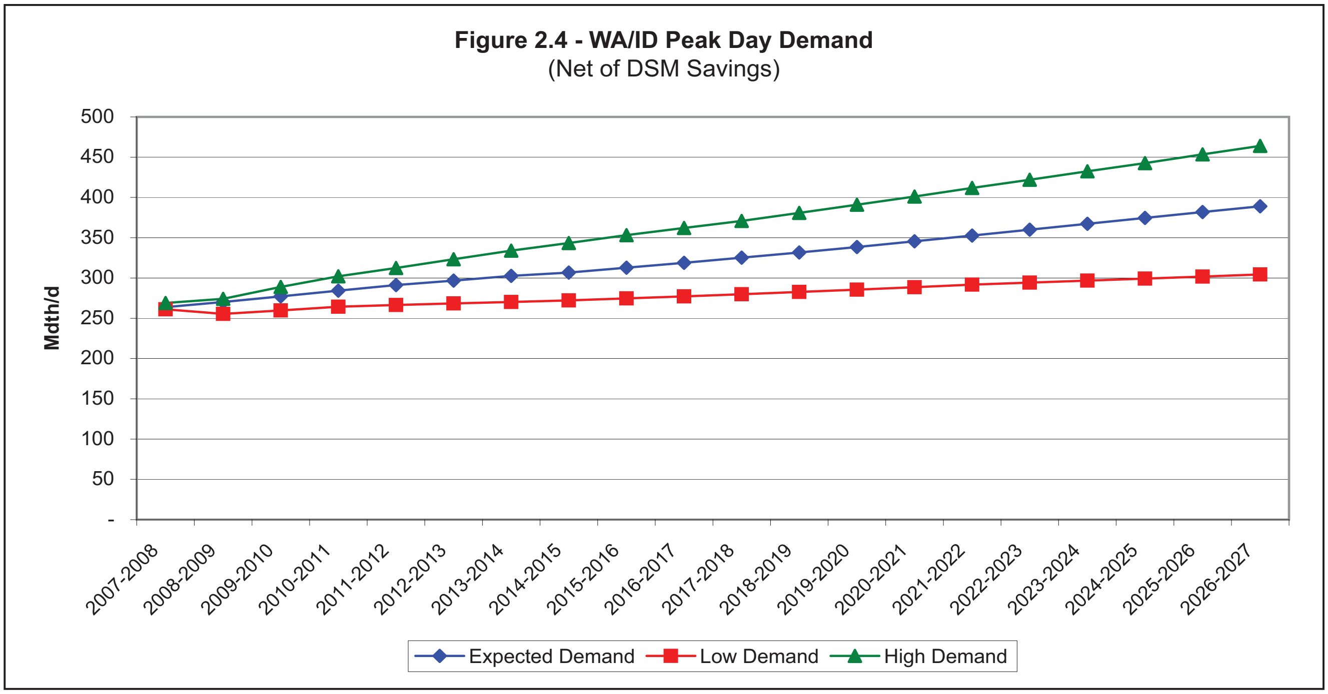




RESULTS

Figures 2.2 and 2.3 show Washington/Idaho and Oregon historical and forecasted demand for the Expected, Low and High Demand cases on an *average* daily basis for each year.

Figures 2.4 and 2.5 show Washington/Idaho and Oregon forecasted demand for the Expected, Low and High Demand cases on a *peak day* basis for each year.



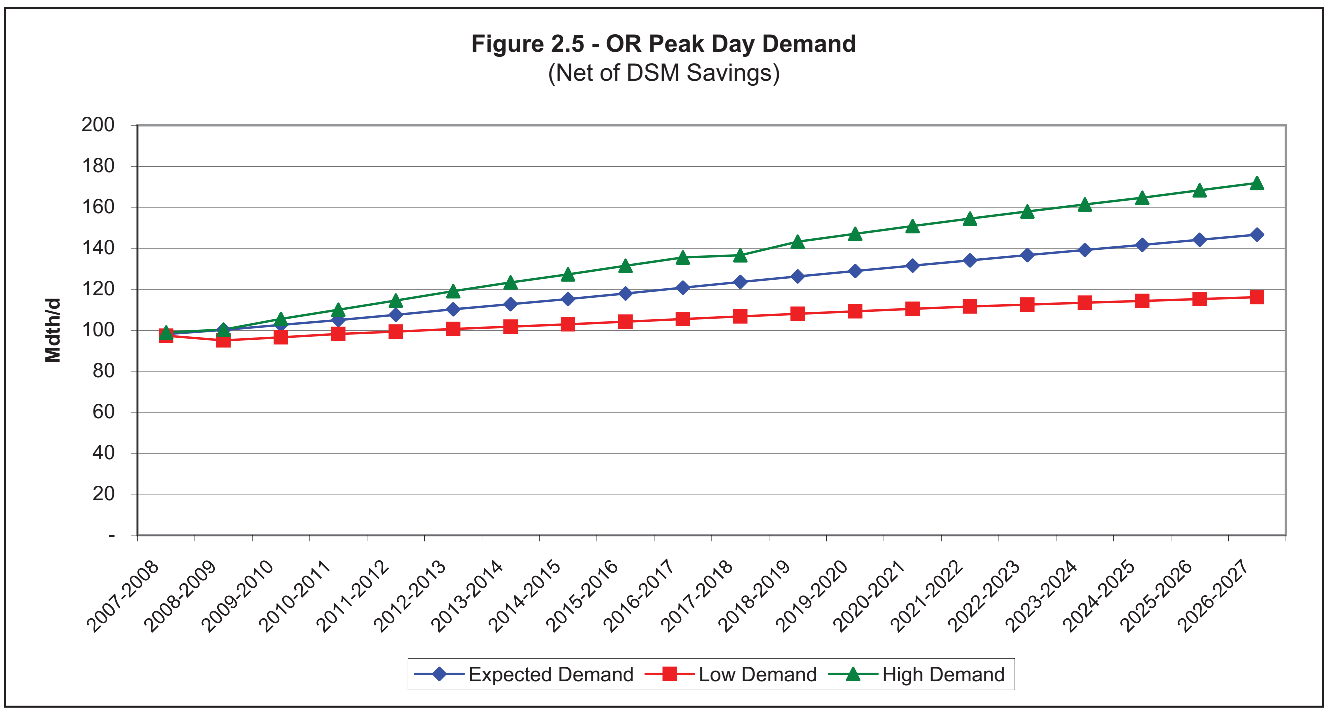


Table 2.4 depicts annual average demand percentage increases by class of customer and area for the Expected, Low and High Demand cases for the 20-year planning period.

Additional detailed data depicting annual and peak day demand data is in Appendix 2.4.

Table 2.4 - Annual Average Demand Percentage Increases
November 2007 through October 2028

Area	Residential	Commercial	Firm Industrial	Total
Expected Case				
Klamath Falls	2.38%	1.37%	0.00%	1.82%
La Grande	1.43%	0.47%	0.00%	0.87%
Medford	3.57%	1.63%	0.00%	2.01%
Medford NWP	2.60%	1.34%	n/a	2.01%
Roseburg	2.60%	1.34%	n/a	2.60%
OR Sub-total	2.52%	1.23%	0.00%	1.99%
Spokane Both	2.37%	2.26%	1.16%	2.03%
Spokane GTN	2.37%	2.26%	1.16%	2.04%
Spokane NWP	2.37%	2.26%	1.16%	2.04%
WA/ID Sub-total	2.37%	2.26%	1.16%	2.04%
Expected Case Total	2.44%	1.74%	0.58%	2.02%
Low Demand Case				
Klamath Falls	1.32%	0.73%	0.00%	0.76%
La Grande	0.76%	0.24%	0.00%	0.23%
Medford	2.08%	0.88%	0.00%	0.91%
Medford NWP	1.46%	0.72%	n/a	0.91%
Roseburg	1.46%	0.72%	n/a	1.29%
OR Sub-total	1.42%	0.66%	0.00%	0.89%
Spokane Both	1.33%	1.26%	0.64%	0.83%
Spokane GTN	1.33%	1.26%	0.64%	0.84%
Spokane NWP	1.33%	1.26%	0.64%	0.84%
WA/ID Sub-total	1.33%	1.26%	0.64%	0.83%
Low Demand Case Total	1.37%	0.96%	0.32%	0.85%
High Demand Case				
Klamath Falls	3.26%	1.94%	0.00%	2.56%
La Grande	2.03%	0.69%	0.00%	1.17%
Medford	4.74%	2.28%	0.00%	2.79%
Medford NWP	3.72%	2.05%	n/a	2.80%
Roseburg	3.72%	2.05%	n/a	3.53%
OR Sub-total	3.50%	1.80%	0.00%	2.74%
Spokane Both	3.23%	3.08%	1.60%	2.87%
Spokane GTN	3.23%	3.08%	1.60%	2.87%
Spokane NWP	3.23%	3.08%	1.60%	2.87%
WA/ID Sub-total	3.23%	3.08%	1.60%	2.87%
High Demand Case Total	3.36%	2.44%	0.80%	2.84%

ACTION ITEMS

The above approach to forecasting demand uses a deterministic modeling methodology. Although it provides a reasonable basis for developing demand cases, we are also examining the capabilities of VectorGas™, a Monte Carlo simulation module of our SENDOUT® modeling software which facilitates modeling of price and weather uncertainty. We intend to use this tool to refine our forecasting capability with a focus on developing sensitivity analysis to identify, quantify and manage risk around price and weather as determinants of natural gas demand. Chapter 6 discusses VectorGas™ in more detail, including preliminary alternative modeling results.

We will also study ways to further refine our ability to model demand by region. Town code forecasting was the first step in enhancing our demand forecasting. We now want to explore incorporating these town code forecasts into regions for analysis in SENDOUT® especially within the Washington/Idaho division to investigate potential resource needs that may materialize earlier than the broader region indicates.

CONCLUSION

Through the scenario planning process, we have considered the potential demand impacts of both changing natural gas prices and a changing economy. The result of those considerations is a reasonable range of outcomes with respect to core consumption of natural gas. While we recognize that the actual level of demand is dependent on a variety of factors, reviewing a range of potential outcomes allows us to plan more effectively as economic or pricing conditions change.

3. DEMAND-SIDE MANAGEMENT

OVERVIEW

Avista's DSM function is organizationally split into a North division (Washington and Idaho), and a South division (Oregon). The Oregon division is segmented into four delivery areas while the Washington/ Idaho division is one delivery area consistent with SENDOUT® modeling requirements.

The analysis in this IRP is the first step in identifying cost-effective natural gas efficiency measures. Following this analysis we will review the DSM portfolio and incorporate refinements and additional analysis of measures, revisions to existing and prospective program plans, and the potential termination of measures that are determined to be no longer cost-effective. This process includes a determination of the optimal approach to each identified cost-effective measure to include the potential for cooperative acquisition or market transformation efforts.

It is possible that there will be measures selected in this IRP that will subsequently be determined to be unsuitable in the company's DSM portfolio based on post-IRP analysis, implementation planning and program planning efforts. It is also possible that programs could be developed for measures rejected by this IRP as a result of the same process. Though the IRP is our best opportunity to comprehensively reevaluate the DSM portfolio and its integration into the overall resource mix, it is necessary to incorporate an ongoing implementation planning process to make the best resource decisions.

Avista is committed to achieving all natural gas-efficiency measures that can be cost-effectively acquired through intervention. This commitment supersedes any numerical goals established within the IRP or the company's implementation planning efforts.

METHODOLOGY

The development of a methodology for evaluating DSM within the IRP was based on four key requirements. The analysis must:

- provide a comprehensive evaluation of all significant natural gas-efficiency options that are commercially available;
- evaluate natural gas-efficiency options in an interactive process with supply-side options;
- maximize portfolio net total resource value;
- deliver meaningful and actionable analytical results for the DSM implementation planning process.

The methodology adopted to fulfill these requirements has four phases:

- **Measure identification and characterization** – We first identified all existing DSM programs, measures considered in previous IRPs, and other concepts evaluated or considered in the last two years;
- **Preliminary evaluation** – We then calculated the levelized total resource cost of each measure (including non-energy benefits as offsets to measure cost), ranked the measures, and categorized them as follows:
  - Oregon-mandated residential measures ("must take" measures);
  - Clearly cost-effective measures ("green" measures);
  - Clearly non-cost-effective measures ("red" measures);
  - All remaining measures ("yellow" measures).
- **SENDOUT® testing** – The "must take" and "green" measures were loaded into SENDOUT® as mandatory programs to be automatically selected. "Yellow" measures were input and evaluated by SENDOUT® against other supply-side resource options. We also input into SENDOUT® an indexed estimate of unique

measures (predominately achieved through a customized application of the site-specific program) that cannot be characterized for testing within SENDOUT®. Finally, "red" measures are excluded from SENDOUT® analysis.

- **Acquisition goal development** – In the last phase, we augmented the results of SENDOUT® with estimates of resource acquisition that cannot be characterized and modeled in SENDOUT®. The final result is the resource acquisition level used in implementation planning efforts. Additional analysis, implementation planning, development of regional and ad hoc partnerships, and local DSM program implementation efforts are initiated from the findings in this IRP. These efforts may modify the findings contained in this IRP based on improved information and the timely assessment of DSM opportunities.

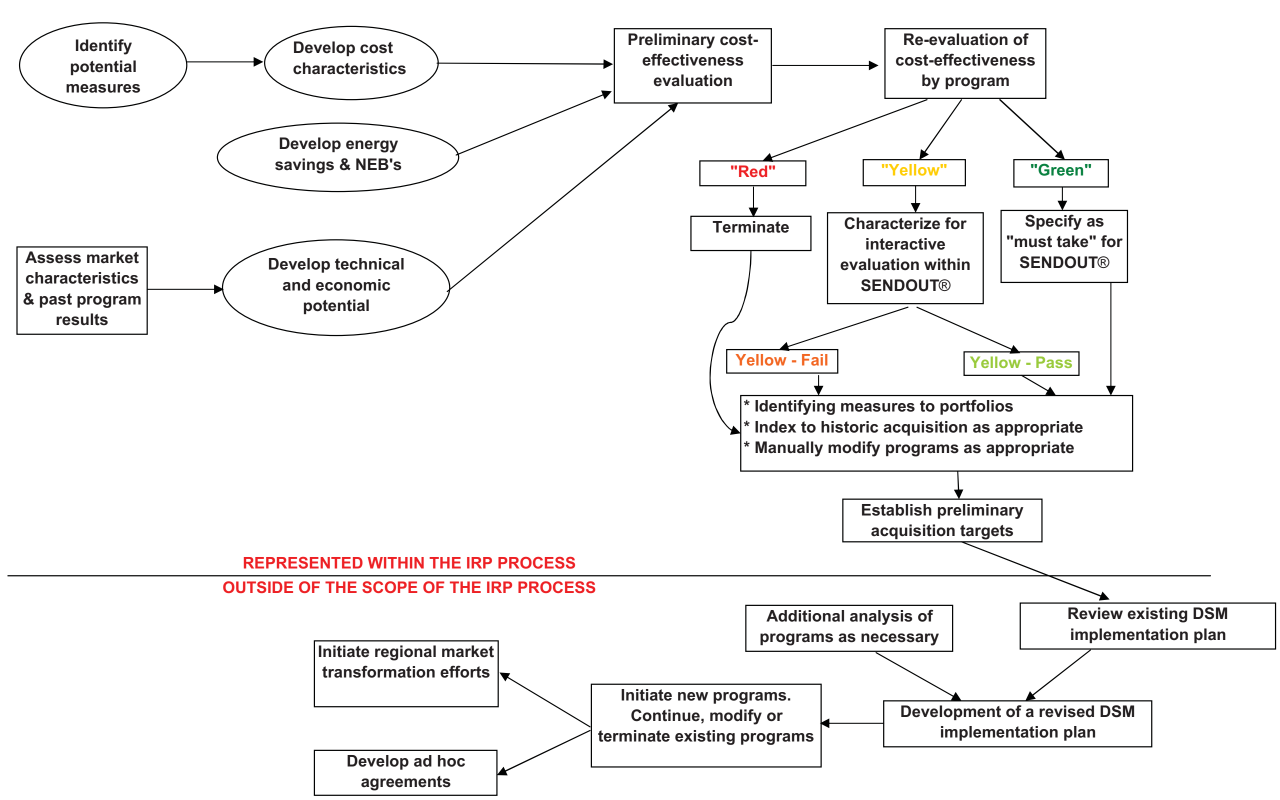
The DSM methodology is summarized in the flowchart in Figure 3.1. Details of each phase follows.

PHASE ONE: MEASURE IDENTIFICATION AND CHARACTERIZATION

We updated previous IRP research, provided by RLW Analytics, with new information regarding measure cost and energy savings and augmented that measure list with additional measures not previously evaluated. A total of 43 residential and 47 non-residential measures were tested for this IRP. This represents an expansion of the number of measures tested from the 2006 IRP given that each of these measures was generally unique, rather than defined as new construction, replacement-before-burnout or replacement-after-burnout.

A summary of the measures that were tested is contained in Appendix 6.9. Energy efficiency, incremental cost and

Figure 3.1 - Integration of DSM within the IRP



other measure characteristics were generally evaluated in comparison to industry standards or code minimums, whichever was higher.

Each tested measure included an assessment of the acquirable resource potential. These estimates were based on early projections of the best implementation approach for particular technologies, market segments and the expected growth of those markets. These projections could require significant revision based on further development of these program plans during the implementation planning process, and on opportunities created by interactions and packaging options created by the mix of programs included in the final analysis.

The energy savings data for weather-sensitive measures were adjusted for the four Oregon delivery areas (Medford, Klamath, Roseburg and La Grande) and the one delivery area in the North division (Washington/Idaho) service territory based on heating degree-day data appropriate to each geographic area.

Avista DSM engineers, program implementers and analysts developed estimates of incremental measure costs, measure lives, energy savings, and other inputs and assumptions in the evaluation process. Great care was taken to ensure symmetric treatment of the costs and benefits of base case and high-efficiency scenarios for each measure given that resource selection is known to be highly sensitive to errors in these assumptions.

The potential energy savings per unit does not include consideration for customer "take-back" (e.g. increased usage in response to the reduced incremental cost of end-use as a result of higher efficiency). The energy savings of individual measures will be reviewed again in the program planning phase to determine if there is any need for reducing the per-unit savings to account for interactive effects between measures.

Program implementation staff estimated incremental non-incentive utility costs for each measure. Since it was assumed that there would be a substantial portfolio of measures passing the total resource cost (TRC) test, the incremental utility cost was generally low or zero. This reflects the incremental utility administrative cost associated with incorporating an individual DSM measure or program into a pre-existing portfolio of cost-

effective programs. This approach has been previously presented to the TAC and others as a "sub-TRC" test, as it excludes one cost element (fixed non-incentive utility cost) that is typically included in a full calculation of the TRC test.

Incremental measure cost was based on the customer cost over and above the assumed base case for new construction and replacement options. Replacement measures were evaluated based on the assumption that the existing equipment was in a state of imminent failure (within one year of a physical failure that would render the equipment uneconomic to repair).

Discussions in preparation for program design often identified the targeting of replacement-shortly-before-burnout as an attractive market segment given the greatly reduced likelihood of customer installation of efficient equipment when the customer is without water or space heating. This topic and its relationship to technical and economic potential therm acquisition will be revisited later in the IRP, and during implementation planning and program development.

Climatic differences between delivery areas was one of the key elements applied to leverage the measurement and evaluation efforts among the two divisions and eight delivery areas. The estimated savings of weather-dependent efficiency measures are generally dependent on the heating degree-days of each delivery area (see Table 3.1), though they are also influenced by the end-use inventory, floor stock vintage and prevailing energy codes.

Table 3.1 - Heating Degree-Days by Delivery Area

	ANNUAL HDDs
Oregon	
Klamath Falls	7,135
LaGrande	6,654
Meford	4,766
Roseburg	4,240
Washington/Idaho	
Spokane	7,097

HDDs: Heating degree-days

We have traditionally adopted a conservative approach to the treatment of non-energy benefits or costs. Those non-energy impacts that are quantifiable in a reasonably rigorous manner were incorporated into the analysis as an adjustment to the incremental cost of the measure. This assumes that part of the premium that the customer is purchasing in the incremental cost of a high-efficiency end-use is for the acquisition of the non-energy benefit. (An adverse non-energy impact would be represented as a negative non-energy benefit). The incremental cost attributable to the energy-efficiency component of the purchase is only that which is over the sum of the base case cost and the net value of the non-energy benefit. Non-energy benefits reduce the cost associated with the energy-efficiency investment. Within the set of measures analyzed for this IRP, the primary quantifiable non-energy benefits were from measures with significant water savings.

PHASE TWO: PRELIMINARY EVALUATION

Based on the incremental customer cost, incremental non-incentive utility cost, incremental annual energy savings, measure life and the application of a discount rate consistent with the IRP process, a levelized "sub-TRC" cost was calculated for each measure. Detailed information on each program can be found in Appendix 6.10. This calculation allowed for the comparison of costs across measures with varying measure lives, and was the foundation for the measure and program selection and portfolio optimization.

This analysis was supplemented with estimates of the full TRC levelized costs (including those that were not incremental to the program) to provide estimates of long-term portfolio cost-effectiveness. This information was used as a diagnostic tool to understand the magnitude and cost-effectiveness of a portfolio, including fully loaded non-incentive utility costs. The sub-TRC calculations drove decisions regarding the incorporation of individual measures into programs or into the overall portfolio.

This preliminary evaluation used a spreadsheet model to permit easy data manipulation. This process identified data elements that were out of the norm or in need of further research, the calculation of a number of different diagnostic statistics and testing measures and programs under alternative approaches to program planning. It also reduced the effort necessary to reformat the results of each program entered into SENDOUT®.

In the final analysis, a levelized TRC was calculated for each measure. This became the most critical element in determining the future treatment of the measure in the IRP analysis. Those measures which were either mandated in Oregon or were so clearly cost-effective that they were certain to be adopted by SENDOUT® were labeled and manually incorporated into the model. Those annual load shape measures (e.g. residential water heating-type load shapes) with a levelized TRC of $0.50 or less were considered clearly cost-effective or "green" in our color-coding methodology. Winter load shape measures (e.g. residential space heating-type load shapes) with a levelized TRC of $0.60 or less were considered "green" in the methodology.

In contrast with the "green" and "must take" resource options that were manually included into the resource selection, there were also measures that were so clearly cost-ineffective that further analysis was unnecessary. Those annual load shape measures with a levelized TRC of $1.00 or more ($1.20 or more for winter load shape measures) were excluded from further consideration. These have been characterized as the "red" programs.

The avoided cost levels established for this categorization of DSM measures was based on a combination of past avoided cost levels and expectations of the avoided cost level to be developed through SENDOUT® modeling. This is a subjective process. Retrospective errors in the avoided cost bandwidths used in this categorization will be corrected in the more detailed and actionable assessment during the DSM implementation process immediately following the completion of the IRP.

The manual inclusion or omission of measures is necessary to limit the number of options incorporated in the linear programming process performed by SENDOUT®. Each additional resource option adds exponentially to the model's calculation time. Given that each DSM measure needs to be subdivided into eight delivery areas for the model, the wholesale inclusion of all of the original DSM options would have made the SENDOUT® analysis an exceptionally difficult or perhaps impossible task.

Forty-two measures were designated as "green" and manually incorporated into the final SENDOUT® Washington/Idaho portfolio. An additional 21 "yellow" measures were individually tested, all of which were accepted by SENDOUT® in 2007/2008 and beyond. The remaining 27 "red" measures were excluded from further consideration.

Table 3.2 summarizes the mandated or tested measures for Washington/Idaho. Therms have been adjusted upward for customer load growth prior to being entered into SENDOUT®.

Table 3.2 - Program Categorization Matrix WA/ID

	Residential Measures	Non-residential Measures
Mandated	0	0
"Green" measures	15	27
"Yellow" measures	13	8
"Red" measures	15	12
	Residential Therms	**Non-residential Therms**
Mandated	0	0
"Green" measures	581,968	70,088
"Yellow" measures	471,773	4,658
"Red" measures	NA	NA

There were four mandated residential measures in Oregon and an additional 42 "green" measures manually incorporated into the portfolio. These measures include pre-rinse sprayers, a measure which is currently being pursued with a known goal and impending sunset date, which necessitated an adjustment to the SENDOUT® results to establish a meaningful goal. Fifteen measures were designated "yellow" for explicit testing within SENDOUT®. Nine measures passed in all delivery areas, five passed in some delivery areas and one failed in all delivery areas in 2007/2008. The remaining 19 "red" measures were not tested in SENDOUT®. Table 3.3 summarizes the mandated or tested measures for Oregon.

Table 3.3 - Program Categorization Matrix OR

	Residential Measures	Non-residential Measures
Mandated	4	0
"Green" measures	13	29
"Yellow" measures	6	9
"Red" measures	10	9
	Residential Therms	**Non-residential Therms**
Mandated	18,510	0
"Green" measures	82,380	94,070
"Yellow" measures	14,922	2,461
"Red" measures	NA	NA

Passing and many non-passing measures are reviewed in the DSM implementation process. The development of measure packages, improved information and refinement of implementation plans can influence the cost-effectiveness of measures.

PHASE THREE: SENDOUT® TESTING

Based on the preceding measure characterization and categorization, the process of preparing the data for SENDOUT® testing consisted of:

1. collapsing all "mandated" and "green" measure categorizations into two line items for winter and annual load shape measures;
2. specifying all "yellow" categorized measures for SENDOUT®;
3. translating all measures to be incorporated into SENDOUT® (including those included on a "must take" basis) into the units appropriate for the model.

This process is more challenging than the summary indicates. The DSM modules of resource planning linear programs are notable for their lack of user-friendliness and marginal technical support. Errors in unit specification or documentation of the program can easily result in meaningless results for the entire resource integration effort.

To minimize the potential for errors in this process we performed preliminary testing of the model by running SENDOUT® using measures with known results. Two "green" and two "red" measures from each division were incorporated in test runs. As expected, the two "green" measures were accepted by the model and the two "red" measures were rejected. In addition to providing confidence that the measures were being correctly specified this also confirmed that the avoided cost break-points used to distinguish "green", "yellow" and "red" categorizations were within reason.

The SENDOUT®-accepted DSM resources are summarized in table 3.4. The results do not include the existing pre-rinse sprayer program or non-residential site-specific measures that were unable to be characterized for input into SENDOUT®. These measures are incorporated in the next phase of the IRP process, along with other adjustments, to develop annual therm acquisition goals.

Table 3.4 - SENDOUT® DSM Results
(calendar year 2008)

	WA/ID	Oregon
Total adopted measures	1,106,912	123,491
Adopted non-residential measures	75,792	26,498
Total adopted measures	1,182,704	149,989

PHASE FOUR: ACQUISITION GOAL DEVELOPMENT

This final phase is critical to translating SENDOUT® results into a product that can be used for calendar years 2008 and 2009 detailed DSM implementation planning, as well as for longer-term and higher-level business planning over a 10-year horizon. Additions and modifications to the raw SENDOUT® results are required for several reasons.

The greatest modification necessary is the addition to SENDOUT® results of resource acquisition expected for measures that could not be characterized within SENDOUT®. This consists primarily of non-residential measures pursued through the site-specific programs of both divisions. Site-specific programs have been designed to be all-inclusive, so any natural gas-efficiency measure qualifies for the program in some fashion. Direct financial incentives are contingent upon minimum project simple-payback criteria in the North division and a TRC cost-effectiveness test in the South division. Generally speaking, all projects have the potential for receiving technical assistance and many qualify for direct financial assistance.

The site-specific program acquisition was addressed by establishing a historical baseline for site-specific program results and modifying those results for past and future growth. These throughput expectations were based on the forecast embedded in the SENDOUT® assumptions. Initial review indicated that the differences in growth between delivery areas and customer segment (residential vs. non-residential) were sufficiently immaterial to justify the use of a single 2.8 percent customer growth rate assumption.

Based on this approach, we expect site-specific acquisition of 903,000 therms in the North division and 56,800 therms in the South division. These estimates incorporate consideration of the significantly different nature of our Oregon non-residential customer base; that the retail customers in Oregon are smaller-sized companies and generally non-industrial. We are in the process of enhancing our Oregon infrastructures capability to acquire resources through the site-specific program by redeploying existing utility staff, establishing relationships with outside energy auditors, the Energy Trust of Oregon and trade ally networks.

The North division site-specific program has been a highly successful component of the overall portfolio. There is relatively little ability to enhance this capability, though active and real-time management is necessary to shift the focus toward new opportunities in this market. The expected therm acquisition is based on a three-year (2004 through 2006 inclusive) historical level adjusted for customer growth.

A final adjustment must be made to the non-residential sector to eliminate the duplication of resource opportunities between the all-inclusive site-specific program and the measures accepted in the SENDOUT® modeling. Both divisions permit and pursue acquisition of all cost-effective, non-residential measures through the appropriate program. Thus, some of the measures incorporated into the SENDOUT® model, either on a "must take" or an explicitly tested manner, are duplicative of resource acquisition incorporated into the estimates of site-specific resource acquisition. Based on a review of the SENDOUT® accepted measures and the expectations of site-specific program targets, we estimated that 5 percent of the Oregon and 20 percent of the Washington/Idaho future site-specific therm acquisition were included in the SENDOUT® analysis. These amounts are subjective, to the extent that they involve projecting the future site-specific program target markets and success within those markets. Ultimately an adjustment in the amounts indicated above was made to the overall non-residential throughput of each jurisdiction to avoid double-counting non-residential opportunities.

As noted in Table 3.4, pre-rinse sprayers were removed from the SENDOUT® results due to the pre-existing program for that measure in both divisions. Implementation of both programs has been outsourced, and it provides the opportunity to exchange a lower-efficiency sprayer head with the code-complying higher-efficiency replacement. This has been designed as a two-year program to accelerate the retirement of sprayers that are not in compliance with new code standards. The North division program is scheduled to end in 2007 and was not tested in SENDOUT®. The Oregon program terminates in 2008 and was tested and accepted in SENDOUT® but removed from the results for separate treatment to ensure that the program termination dates align with the calendar year goals to be established as part of this IRP.

There has been no attempt to adjust either division for price elasticity. This is because the lack of precedent for increases in retail rates of the magnitude we have seen, the complicated lag effects and the effect of both of these on the inventory of cost-effective efficiency opportunities in the market make it virtually impossible to develop any adjustment that can be applied with confidence. Additionally, there is inadequate evidence to determine with any certainty the effects of retail prices on the throughput of DSM programs versus simple reductions in consumption of non-utility sponsored efficiency measures.

The results of the SENDOUT® model required a minor revision to translate into the calendar year implementation planning and budgeting cycle used for DSM operations. Additionally, a customer growth rate consistent with that applied in the IRP was used to adjust historical numbers to reflect current potential and to increase future potentials of programs that were outside the scope of SENDOUT® (e.g. the site-specific program).

An application of the SENDOUT® results and modifications for site-specific and pre-rinse sprayer programs for the first two years (the years prior to the next IRP opportunity to revisit DSM potentials) are summarized in Table 3.5.

Table 3.5 - Results of Acquirable Resource Potential
(CY 2008 and CY 2009)

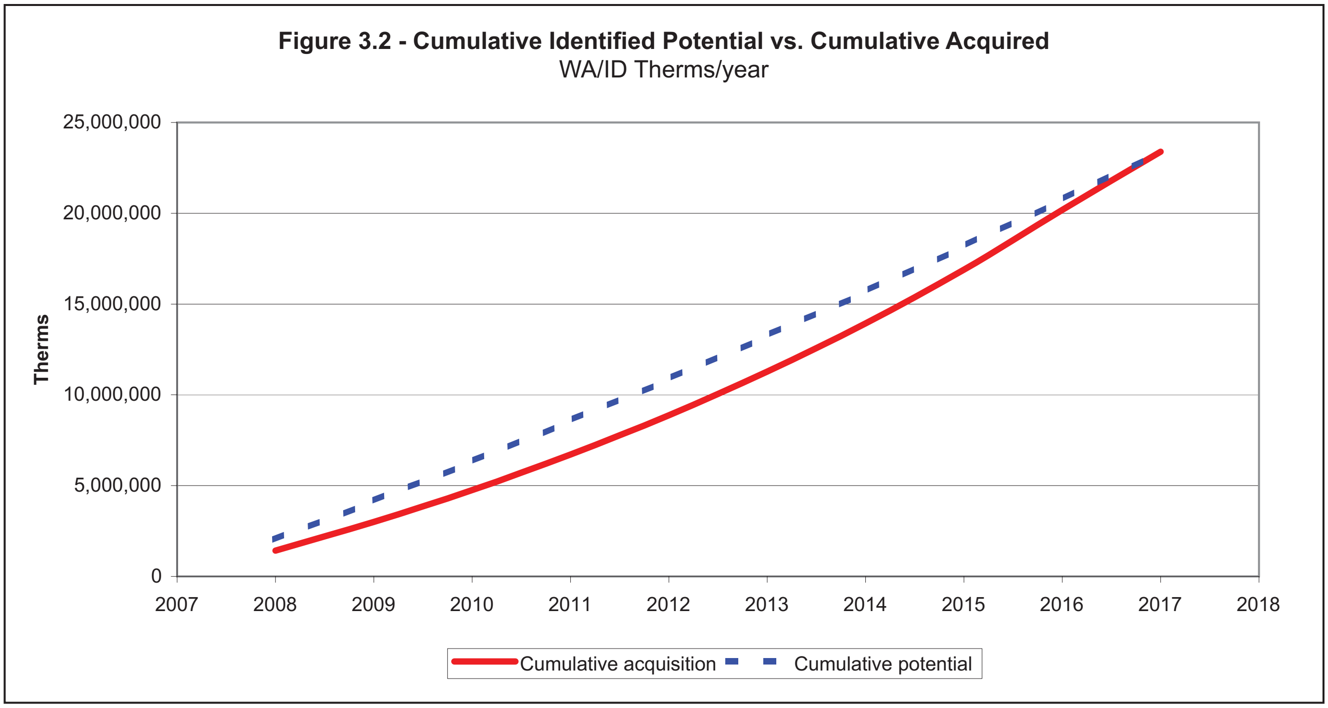
	WA/ID CY 2008	WA/ID CY 2009
SENDOUT®-accepted residential programs	1,106,912	1,176,325
SENDOUT®-accepted non-residential programs	75,792	77,914
Estimated site-specific acquisition	902,837	928,116
Adjustment for non-res program duplication	-60,634	-62,331
Estimated pre-rinse sprayer acquisition	0	0
TOTAL	**2,024,908**	**2,120,024**
	Oregon CY 2008	**Oregon CY 2009**
SENDOUT®-accepted residential programs	123,491	140,381
SENDOUT®-accepted non-residential programs	26,498	27,240
Estimated site-specific acquisition	56,808	58,399
Adjustment for non-res program duplication	-2,650	-2,724
Estimated pre-rinse sprayer acquistion	70,400	0
Enhanced commercial / industrial delivery	75,000	75,000
TOTAL	**349,548**	**298,295**

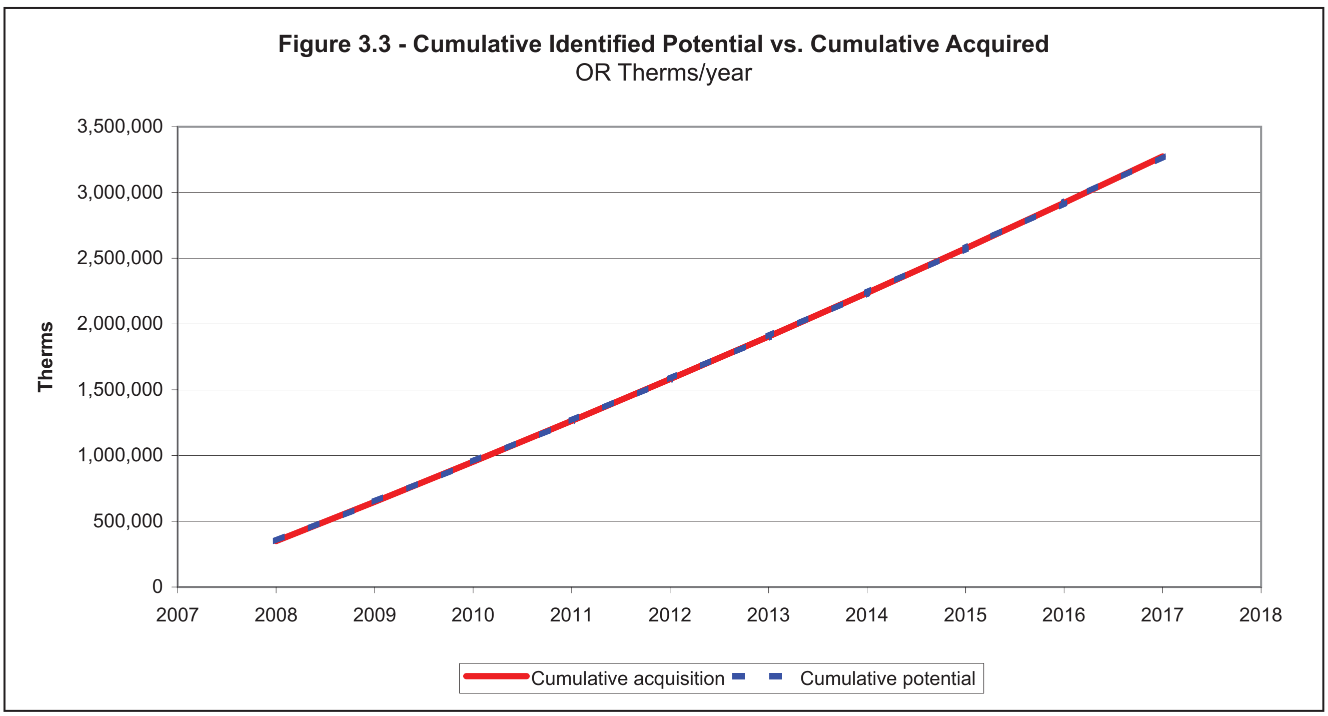
The Washington/Idaho potential is in excess of the current acquisition goal of 1,062,000 therms developed in the 2006 IRP. It is also substantially above the recent acquisition history of 1,111,000 therms per year (based on the 2004-2006 acquisition, inclusively). The potential increase in costs associated with such a large increase in infrastructure necessary to accommodate the 84 percent increase from previous acquisition to meet this identified potential is concerning. Consequently, we have resolved to meet all cumulative potential identified in this IRP over the long-term (10-year) planning cycle with a gradual ramping of program activity. We determined it was possible to establish an 11 percent constraint on the annual increase while simultaneously achieving this objective. This increase is in excess of customer growth but ensures that the infrastructure growth can be managed more carefully and without undue inflation of acquisition costs associated with rapid growth.

Application of this 11 percent annual growth constraint results in a summary of annual and cumulative acquisition and identified DSM potential as listed in Table 3.6.

Table 3.6 - Annual and Cumulative DSM Acquisition and Potential

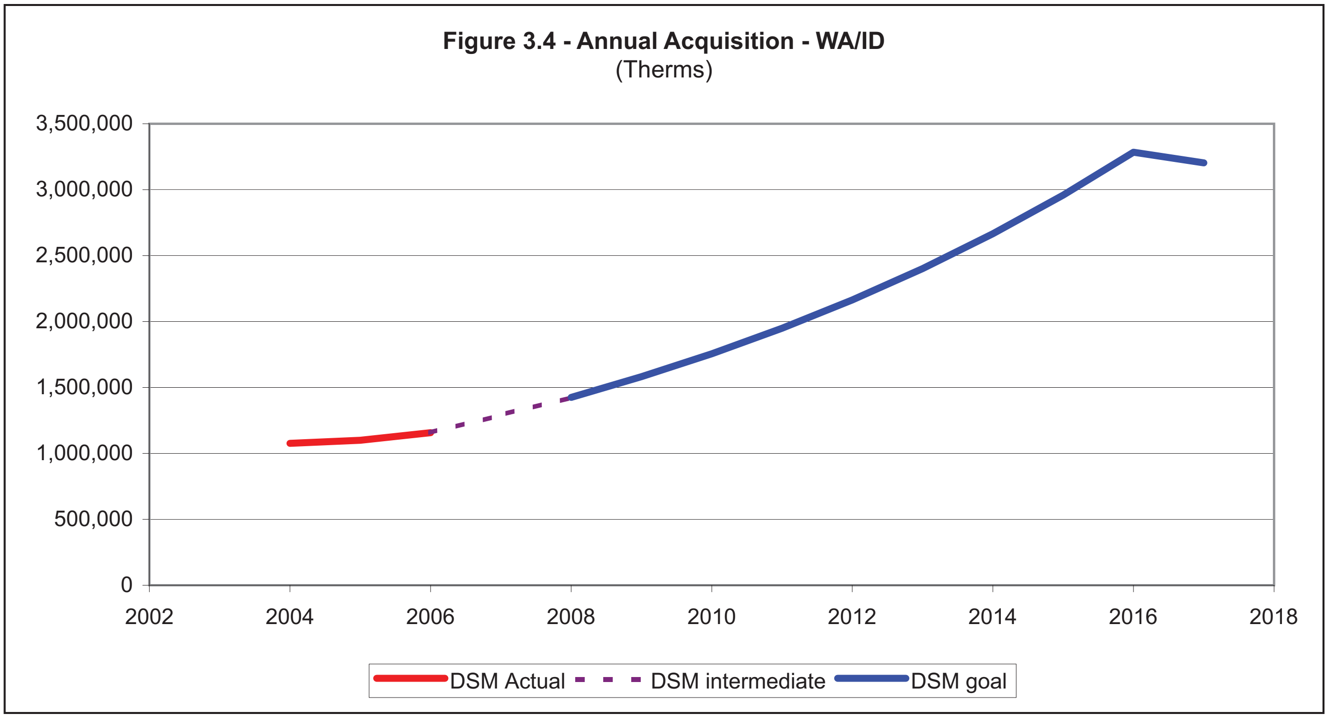
Calendar Year	DSM Potential	Cumulative Potential	DSM Goal	Cumulative Goal
Washington / Idaho				
CY 2008	2,024,908	2,047,645	1,425,070	1,425,070
CY 2009	2,120,024	4,144,932	1,581,828	3,006,898
CY 2010	2,179,385	6,324,317	1,755,829	4,762,727
CY 2011	2,240,408	8,564,724	1,948,970	6,711,698
CY 2012	2,303,139	10,867,863	2,163,357	8,875,055
CY 2013	2,367,627	13,235,490	2,401,326	11,276,381
CY 2014	2,433,921	15,669,411	2,665,472	13,941,853
CY 2015	2,502,070	18,171,481	2,958,674	16,900,527
CY 2016	2,572,128	20,743,609	3,284,128	20,184,655
CY 2017	2,644,148	23,387,757	3,203,102	23,387,757
Oregon				
Calendar Year	**DSM Potential**	**Cumulative Potential**	**DSM Goal**	**Cumulative Goal**
CY 2008	349,548	349,548	349,548	349,548
CY 2009	298,295	647,843	298,295	647,843
CY 2010	304,548	952,391	304,548	952,391
CY 2011	310,975	1,263,366	310,975	1,263,366
CY 2012	317,582	1,580,948	317,582	1,580,948
CY 2013	324,375	1,905,323	324,375	1,905,323
CY 2014	331,357	2,236,680	331,357	2,236,680
CY 2015	338,535	2,575,215	338,535	2,575,215
CY 2016	345,914	2,921,129	345,914	2,921,129
CY 2017	353,500	3,274,629	353,500	3,274,629





The Washington/Idaho potential and acquisition identified in Figure 3.2 indicates that we will fully acquire identified DSM potential over the 10-year planning cycle within the 11 percent annual ramp-up constraint.

The annual ramp-up constraint was not a factor in the Oregon jurisdiction. The full identified potential is being acquired in each year of the long-term planning cycle (see figure 3.3).



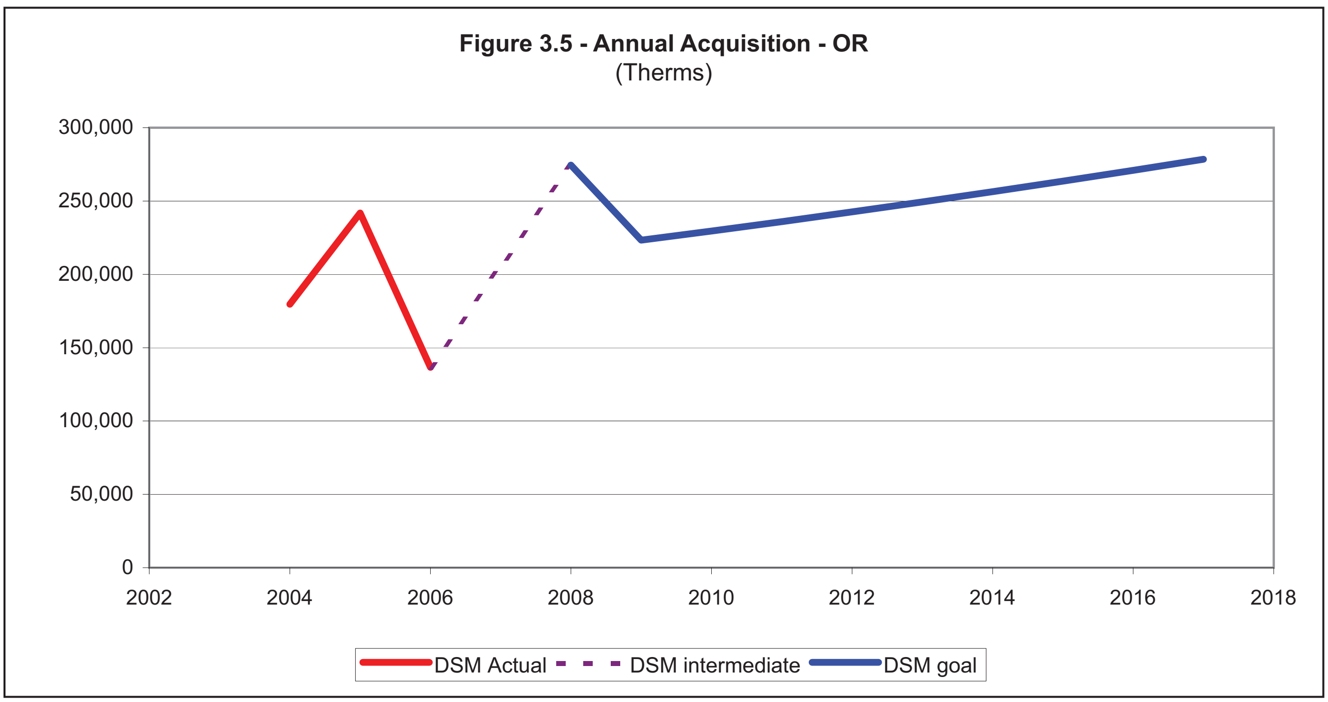


Figure 3.4 shows historical, current and projected Washington and Idaho DSM therm acquisitions. The chart illustrates the gradual ramp-up of DSM activity for the first nine years of the planning cycle. In the tenth year, the cumulative acquisition catches up to the cumulative identified potential of the projection.

The illustration in Figure 3.5 shows historical, current and projected Oregon DSM therm acquisitions. The acquisitions are somewhat choppy primarily because of the start up and sunset of the pre-rinse sprayer program (a 70,400 therm annual impact) in 2007 through 2008 followed by the gradual growth of acquisition to match the identified potential of each year.

The IRP resource analysis is, as previously mentioned, the starting point for the implementation planning process. The following discussion of Avista's DSM programs and how the IRP results will be incorporated into DSM operations is a preview of the effort that will immediately follow the completion of the 2007 IRP.

THE HERITAGE PROJECT

Based on the expected need for future electric generation resources and the growing potential for both electric and natural gas efficiency opportunities, Avista launched a wholesale ramp-up of DSM activity in late 2006. Although this ramp-up, known as the Heritage Project, initially had an electric-efficiency focus the opportunities for leveraging this implementation plan for natural gas-efficiency purposes has not been overlooked. As a consequence the project has been expanded to cover all three jurisdictions served by Avista.

The Heritage Project significantly increased the infrastructure capabilities and outreach efforts of Avista's DSM effort. In the year since the launch of this effort the company has successfully:

- incorporated electric transmission and distribution efficiencies into the portfolio of opportunities;
- launched a combined long-term customer outreach plan to communicate natural gas and electric-efficiency messages;
- augmented the residential portfolio with additional measures offered on a short-term basis; and
- improved rural delivery efforts by launching a rotating geographic saturation implementation program.

These additional efforts overlay a core organizational structure that has a proven history of delivering cost-effective energy-efficiency resources.

OREGON DSM PORTFOLIO

Avista's residential measures are available to approximately 79,000 customers (Avista Rate Schedule 410) with an annual consumption of 48 million therms. The commercial measures are available to 10,600 mostly small-to-medium-sized customers (Avista Rate Schedules 420 and 424) with an annual consumption of approximately 76 million therms. The largest segment of qualified commercial customers use natural gas for space, water heating and cooking with an average consumption of 2,600 therms each.

The measures offer a mix of currently cost effective measures and market transformation measures which are expected to be cost-effective over time. The combined residential and commercial therm goal for 2008 is 349,547 and 298,296 for 2009. Details on individual measures such as measure life, levelized TRC, unit goal and therm goal can be found in Appendix 6.10.

RESIDENTIAL MEASURES

Our residential measures consist of site specific and prescriptive proposals. The residential portfolio is a mix of currently cost effective measures and market transformation measures which are expected to be cost-effective over time. The residential therm goal is 123,491 in 2008 and 140,381 in 2009.

Our residential site specific program is primarily focused on cost effective shell measures. Changes made to the program in early 2007 include higher incentive levels, removal of all non cost effective measures, and requiring window upgrades to be included with at least one other major measure. Additional changes to this program will be considered in 2008. Table 3.7 shows current residential shell program requirements.

Table 3.7 - Avista Residential Shell Program Requirements

Shell Component	Program Requirement
Attic Insulation	R-38
Floor Insulation	R-19
Wall Insulation	R-11
Windows	U-35

We will survey customers who received a home energy audit, but did not follow through on any recommendations. The information from this survey will be used to evaluate current incentive levels, messaging on collateral material and frequency of customer contact. We will also increase our contract audit staff and support staff to facilitate additional customer participation.

In addition to the site specific program, we offer several prescriptive incentives. In early 2007, we added tankless water heaters, high-efficiency direct vent space heaters, external chimney dampers, and programmable thermostats to our list of prescriptive measures. Existing measures include high efficiency forced air furnaces and tank water heaters.

Measures currently not offered that are cost effective based on SENDOUT® results, will be evaluated further to determine their viability for inclusion in our prescriptive offerings. With the exception of high efficiency tank water heaters, all current measures are cost effective in the SENDOUT® model.

In the majority of cases, water heaters are replaced on "burn out" with the high efficiency models costing about $120 more than standard efficiency models. Product availability is also an issue in this situation. For this reason, we feel that in order to affect the incremental cost and maintain availability, high efficiency tank water heaters should be retained as a market transformation program in 2008 and 2009.

We believe that building a strong trade ally network is the best way to promote the acceptance of high-efficiency gas equipment. Our trade allies include HVAC dealers, plumbers, retailers, manufacturers, distributors, builders and developers. We have increased staffing levels to meet our trade ally objectives and will continue to monitor program activity to ensure adequate resources.

We also partner with the Energy Trust of Oregon (ETO) in several market transformation programs. These programs include Energy Star new construction, Energy Star manufactured homes and high-efficiency washing machines. We will continue to evaluate these programs annually to determine their effectiveness and appropriateness for our rate payers.

COMMERCIAL MEASURES

Prior to 2007, our commercial measures were site-specific offerings only. In early 2007, we added several cost effective prescriptive measures. Those measures

Table 3.8 - Summary of 2006 Natural Gas Efficiency Program Results

Program	Res Shell	Res Shell	Res S/H	C/I efficiency
Measure life	30 years	15 years	25 years	18 years
Incentive per unit	variable	$50	$200	variable
TRC cost per unit	variable	$50	$496	variable
Therm savings per unit	variable	27	64.4	variable
Annual target therm savings	62,500	8,397	180,450	99,818
2006 actual therm savings	70,802	6,858	123,750	14,693

include: high-efficiency space heating equipment, Energy Star® gas fryers, three pan gas steam cookers and high-efficiency gas rack ovens.

The commercial therm acquisition goal for 2008 is 155,656 for site specific and prescriptive measures, plus 70,400 therms from the pre-rinse sprayer program for a total of 226,056 therms. With the scheduled completion of the pre-rinse sprayer offering in 2008, the goal for 2009 is 157,915 therms.

We developed the pre-rinse sprayer offering, with implementation services provided by Lockheed Martin, with the goal of installing 400 sprayer units in 2007 and 400 more units in 2008. The measure offers the customer the option to have a code-complying unit directly installed into their facility in return for the retirement of a non complying unit. This approach to accelerating retirement of the units that are not in compliance with current code was one of the most cost-effective resources identified in the 2006 IRP.

We also expect to add a number of new prescriptive measures in 2008. Measures under consideration include cost effective shell measures, tank and tankless high-efficiency water heaters, as well as other measures found to be cost effective and appropriate for inclusion as prescriptive measures. Measures with low acquirable potential, technologies new to the marketplace or where natural gas is used for process, will be evaluated on a site specific basis.

We believe that by adding additional prescriptive measures, the program will be more accessible to customers and easier to manage with less cost. It is anticipated that this will result in higher participation levels in the small to medium sized customer segments. Measures not included in the prescriptive program will be evaluated on a site specific basis.

As a result, we will increase our efforts to identify cost effective, site specific opportunities with our larger commercial customers. We will reallocate resources toward this initiative.

In addition, we will look at the viability of a market transformation program for commercial kitchens. Initial indications point to cost and availability as factors in the decision not to install Energy Star appliances. Depending on the preliminary evaluation scheduled for early 2008, a commercial kitchen program could be launched in the second or third quarter.

We will also continue to look for opportunities to work cooperatively with the ETO where site specific efficiency projects, with gas and electric savings potential, are identified. We will also work closely with local land-use planners and energy consultants on new commercial projects in order to influence energy efficiency decisions during the design phase.

CLIMATE

The Oregon service territory is subdivided into four separate service districts primarily based on climatic differences. These four areas, from warmest to coldest, are Roseburg, Medford, La Grande and Klamath Falls. The annual heating degree-days used in this IRP (discussed in Chapter 6) for the four service districts are shown in Table 3.9.

Table 3.9 - Annual Heating Degree-Days by Service District

Roseburg	4,240
Medford	4,766
LaGrande	6,654
Klamath Falls	7,135

There is a significant difference (71 percent) in heating degree-days from the warmest to the coldest Oregon district.

To determine the seasonal pattern of energy savings of heating-related efficiency measures (weatherization and space heating measures), the monthly heating degree-day patterns of Medford were ascribed to each service territory's annual heating degree-day level. This monthly pattern is represented in Figure 3.10.

Table 3.10 - Annual Distribution of Heating Degree Days (HDDs)

Month	Percent of Annual HDDs
January	16.9%
February	12.9%
March	11.6%
April	8.5%
May	4.6%
June	1.5%
July	0.2%
August	0.3%
September	2.1%
October	7.0%
November	13.5%
December	21.1%

MEASURE DEVELOPMENT

Based on the results of the 2004 natural gas IRP, we launched a commercial cooking measure and a short-term 2007-2008 measure to accelerate the replacement of pre-rinse sprayheads. Additionally a residential top-mounted fireplace damper measure has been launched as a result of opportunities identified after the previous IRP was completed.

We will also look at the best fit for program implementation. Implementation options could include a combined effort between Avista's North and South divisions, additional staffing, Energy Trust of Oregon (ETO), trade partners, and if developed, a gas Northwest Energy Efficiency Alliance (NEEA). Additional avenues for implementation will be evaluated as they are identified.

There are presently no near-term plans to expand the Oregon DSM portfolio to include demand-response programs. An Idaho electric demand-response pilot project is currently underway to test the technical ability and residential customer acceptance of remotely controllable thermostats. At present this pilot is limited to controlling the thermostat for space cooling load during times of electric peak load. If this is successful, there is the possibility that the capabilities of the thermostat could be expanded to address space heating peaks as well, assuming that the value of avoiding or deferring natural gas distribution capacity warrants such an expansion. Given the seasonal nature of the testing of this program, such an expansion is likely to be several years in the future.

IMPACT OF EVIRONMENTAL COSTS ON OREGON DSM MEASURES

To the extent that natural gas-efficiency measures reduce overall end-use demand, there will be reductions in emissions resulting from the compression needed for transmission as well as at the end-use itself. Of all the emissions, carbon dioxide could have the greatest impact on the company. A national carbon tax or green house gas cap-and-trade system would be the most likely mechanism for passing through the costs of emissions.

If a carbon tax were imposed, more DSM resources would become cost-effective. A carbon tax at the $8 per ton level would add $0.07 cents per therm to supply side resources. A $40 per ton tax adds approximately $0.35 cents per therm. At this level, marginal non-cost-effective measures could become cost-effective.

WASHINGTON/IDAHO DSM PORTFOLIO

Avista offers a portfolio of electric and natural gas efficiency measures to Washington and Idaho customers. Electric efficiency measures have been available since 1978. Natural gas efficiency measures have been offered without interruption since 2001 and periodically prior to that time based on cost-effective opportunities within the market.

A non-binding external oversight group, the External Energy Efficiency ("Triple-E") Board, was established to provide guidance for the implementation of DSM measures. This board is provided with a quarterly written update, convenes twice a year and receives a comprehensive annual evaluation of DSM acquisition and cost-effectiveness.

Avista's Rate Schedule 190 provides the regulatory guidelines for the implementation of the natural gas DSM measures. This tariff prescribes a set of tiered, direct financial incentives, as illustrated in Table 3.11, based on the customer simple payback of the measure.

Table 3.11 - WA/ID Rate Schedule 190 Incentive Tiers

Customer Simple Payback	Incentive per 1st yr Therm
Zero to 17 months	$0.00
18 to 48 months	$2.00
49 to 71 months	$2.50
72 months or more	$3.00

Incentives are capped at 50 percent of incremental measure cost in Idaho and 30 percent of incremental measure cost in Washington.

Selected exceptions to these tiered incentives allow the company flexibility to respond to unexpected or unique opportunities. This flexibility includes an additional set of tiered incentives, permitting higher incentives for the development of new technologies and market transformation efforts.

The original 2001 Schedule 190 tariff established an annual goal of 240,000 first-year therms. Almost immediately upon launch of the renewed gas-efficiency program, commodity-driven escalations in retail rates and spillover effects from an emergency electric-efficiency response during the 2001 Western energy crisis drove acquisition well beyond these levels. Initial concerns that this higher level of acquisition may be unsustainable proved to be unfounded. A reassessment of the market in the 2006 Gas IRP process resulted in the establishment of a 1,062,000 annual therm goal. This goal has proven to be marginally achievable in the years following the 2001 energy crisis.

It is likely that detailed business planning will result in recommendations for revisions to the incentive levels, caps and applicable markets, and technologies as part of an overall strategy to meet the commitments made for increased long-term resource acquisition identified in this IRP.

Funding for the natural gas efficiency programs is derived through a surcharge on retail rates authorized under Schedule 191. This surcharge was increased from an amount equal to approximately 0.50 percent of retail rates to 1.50 percent of retail rates in 2006. The increase was necessary to eliminate a persistent imbalance of tariff rider revenues and natural gas program expenditures; an imbalance that began with the 2001 crisis and grew during the period of increasing commodity costs. For the majority of this period, over 90 percent of the gas DSM funding was going directly to customer incentives required under Schedule 190.

Only those customers contributing to the program funding through Avista Rate Schedule 191 are eligible to receive financial incentives. This limits availability to core natural gas customers. Periodically we claim the acquisition of natural gas savings from transport customers if those efficiencies result from involvement in a project that is tightly interwoven with an electric-efficiency project that was being evaluated and funded under the company's electric DSM program.

Our energy-efficiency offerings within Washington and Idaho are a closely related mix of electric and natural gas measures. In 2006, the natural gas share of the total BTU savings from the overall portfolio was 42 percent. This share shifts depending on resource opportunities, retail rates, technical advancements and customer interest. DSM implementation efforts in Washington and Idaho are further subdivided into three different portfolios; (1) the commercial/industrial portfolio, (2) the residential portfolio and (3) the limited income residential portfolio. The approaches to the implementation of these three portfolios differ significantly in recognition of the differences in these markets.

COMMERCIAL/INDUSTRIAL PORTFOLIO

This portfolio is characterized by its all-encompassing approach to this market. Any natural gas efficiency measure qualifies for assistance through this portfolio. Incentives are offered based on the previously described tiered incentive structure applied to each individual project.

This approach to the market ensures that unique and unexpected efficiency measures are never excluded from acquisition through utility programs. The company restricts the development of prescriptive programs to measures and applications that are reasonably uniform in their energy savings and cost characteristics. This has generally not been found to be the case for even relatively common natural gas DSM measures. (Several prescriptive electric DSM programs have been developed for the commercial/industrial market).

In 2006, the company acquired 695,535 therms from this portfolio (60 percent of the total acquisition of all three portfolios). Twenty-five percent of the total non-interactive energy (electric and natural gas) acquisition within this portfolio is attributable to therm savings. Several multifamily housing measures are incorporated in the commercial/industrial portfolio due to the non-residential electric and natural gas rate schedules that many of these customers are billed. Many of the multifamily measures evaluated as part of this IRP analysis (e.g. pool and spa water heating efficiencies in multifamily housing) will be forwarded to the commercial/industrial portfolio segment for further evaluation.

Large projects, resulting in incentives of $100,000 or larger, are disclosed to the Triple-E board to provide them with the information necessary to provide oversight of DSM programs.

RESIDENTIAL PORTFOLIO

Due to the large volume and relatively small size of individual projects, the residential portfolio is exclusively composed of prescriptive programs. In 2006, this portfolio was responsible for the acquisition of 382,355 first-year therms (7 percent of the total portfolio). Of the non-interactive total energy (electric and natural gas) savings in 2006 from this portfolio, 14 percent are attributable to therm savings.

Incentives for residential programs are calculated based on the application of the measure in a typical residential home. Calculations are made in accordance with Avista Rate Schedule 190 tiered incentives with appropriate modifications for potential differences in application, multiple measure programs and rounding for purposes of offering a customer and trade ally-friendly program. The prescriptive residential programs currently available are outlined in Table 3.12.

Table 3.12 - WA/ID Prescriptive Residential Gas Measures

High-efficiency natural gas furnace ($200 for AFUE 90% or better)
High-efficiency natural gas boiler ($200 for AFUE of 85% or better)
High-efficiency natural gas water heater ($25 for EF 0.60 (50 gallon) or 0.62 (40 gallon) or better
Ceiling insulation (14 cents/SF for an added R10 or more)
Attic insulation (14 cents/SF for an added R-10 or more)
Floor insulation (14 cents/SF for an added R-10 or more)
Wall insulation (14 cents/SF for an added R-10 or more)
High-efficiency windows (70 cents/SF of window for U-.35 or better)

Avista is continuing an outreach effort targeted for residential customers. The outreach effort is geared toward improving residential natural gas-efficiency by providing a continuing educational message regarding behavioral effects on energy use as well as driving customers to improve the efficiency of key natural gas appliances.

This new online outreach, auditing and education program will be followed up with a measurement and evaluation effort intended to provide the information necessary to determine therm (and kWh) acquisition and cost-effectiveness as well as management information necessary for evaluating ongoing program improvements.

LIMITED-INCOME RESIDENTIAL PORTFOLIO

Avista's Washington and Idaho limited income programs are implemented in cooperation with six community action partnership (CAP) agencies. These CAP agencies are awarded an annual funding contract specifying the maximum funding amounts and the conditions for program implementation. Contracts can be revised on 30 days' notice, a provision that allows Avista to reallocate funds among the CAP agencies during the year to maximize their value to the customer base.

The CAP agencies and 2006 funding levels are summarized in Table 3.13. These amounts include a $200,000 increase above calendar year 2005 funding.

The distribution of funding for the limited income segment is intended to provide the maximum flexibility possible. This permits agencies to respond to unexpected urgent needs and energy-efficiency opportunities that may not have been anticipated when the annual contracts were signed.

As part of this flexibility, the CAP agencies are permitted to expend their contractual funding on either electric or natural gas-efficiency measures. The funding available includes an allowable 15 percent remuneration to the agency for administrative and outreach costs. Up to 15 percent of the funds can be expended for health and human safety measures with an emphasis on the safe use of energy, and maintenance and repairs necessary to ensure the longevity of installed efficiency measures and continued habitability of the home.

The limited income residential segment delivered 78,729 first-year therms to the overall natural gas DSM program in 2006. This therm acquisition represented 3 percent of the total BTUs acquired by the combined electric and natural gas programs.

AVISTA DSM COMMITMENT

We recognize our obligation to meet the resource needs of customers in the most cost-effective manner. The delivery of natural gas efficiency programs is anticipated to represent an increasing portion of the optimal natural gas resource portfolio. The IRP process is an opportunity to comprehensively review the natural gas efficiency program portfolio and make the revisions necessary to meet those commitments in the future.

This document summarizes a broad evaluation of applicable natural gas efficiency opportunities and

Table 3.13 - WA/ID Community Action Program Contracts

Spokane Neighborhood Action Program (Spokane area)	$539,812
Community Action Agency (Idaho and Washington)	$447,772
Pullman Community Action (Whitman County)	$83,048
Grant County/North Columbia CAA (Grant County area)	$72,667
Northeast Rural Resources	$71,107
Klickitat CAA (Goldendale/Stevenson)	$2,330

identifies those worthy of testing against all other possible resources to assist us in making decisions about which of those natural gas efficiency resources are suitable to carry forward into program development.

We solicited comments from key stakeholders regarding the selection, characterization and testing of natural gas efficiency opportunities within the IRP process. After much discussion and some revision, the general consensus of those stakeholders was that this approach was sufficient to represent natural gas efficiency opportunities within the IRP.

We also agreed that it is cost-effective and appropriate to substantially ramp-up Oregon natural gas DSM programs, as well as reconsider the approach to the implementation of those programs. This analysis has also established a tentative goal far in excess of previous commitments represented in Washington and Idaho Schedule 190 and slightly above recent acquisition levels.

Complete agreement was not possible regarding the likely customer reaction to several components of the enhanced Oregon natural gas DSM portfolio. There is concern that market barriers will constrain participation. We remain open to alternative approaches to overcoming those market barriers to include enhanced outreach efforts, revised incentives, innovative marketing of natural gas efficiency programs and cooperative arrangements with other agents in the market, with particular attention to other natural gas utilities, the Energy Trust of Oregon and regional market transformation organizations with an interest in natural gas efficiency.

We are committed to maintaining a collaborative relationship with all stakeholders who may contribute to the improvement of natural gas DSM efforts as programs are further developed and launched. Additional metrics will be developed to improve the active management of these programs over time, as well as to provide better benchmarks for determining the regulatory prudence of these programs.

We recognize that this commitment to acquiring all cost-effective natural gas-efficiency potential is not limited by the therm acquisition goals established within this IRP. The implementation of the results of this planning effort will be sufficiently flexible to realize those opportunities even if they are in excess of expectations. Human and financial resources will be made available to the extent necessary to achieve the cost-effective potential without regard to those goals.

UPDATING AVOIDED COSTS FOR APPLICATION TO DSM

Upon recognition of this IRP, we will make the necessary modifications to the avoided costs to be applied to DSM projects and submit the appropriate filing for review. This revision will affect the cost-effectiveness analysis used within the business planning process, the calculation of cost-effectiveness within the DSM Annual Report and the TRC analysis performed on individual non-residential site-specific projects.

COOPERATIVE REGIONAL PROGRAMS

Avista has and remains interested in testing the viability of a regional market transformation approach to the acquisition of natural gas-efficiency potential. This model has proven successful in Northwest electric markets as evidenced by the success of the Northwest Energy Efficiency Alliance (NEEA) over the past 11 years. We believe that this approach will be particularly successful in residential markets. Though recent efforts at partnering with NEEA and establishing limited ad hoc regional efforts have been unsuccessful, we will continue to seek alliances with other Northwest utilities to advance this concept.

ACTION ITEMS

The completion of the IRP analysis is the midpoint, not the end point, of a larger reassessment of the DSM resource portfolio. The IRP analysis presented indicates a set of cost-effective measures and acquirable resource potential for a future DSM portfolio. Further evaluation is required to facilitate the development of program plans and to incorporate them into a DSM implementation plan. Following detailed investigation of the natural gas-efficiency technologies identified as cost-effective, we will incorporate these programs into our Heritage Project ramp-up of energy-efficiency efforts.

Based on the analytical process described in this chapter, we estimate first-year energy savings goals of approximately 350,000 therms in Oregon. In the WA/ID service territory we estimate first-year energy savings goals of approximately 1,425,000 therms. This commitment represents a 34 percent increase in annual resource acquisition which will require a significant ramp-up in DSM efforts. In the Washington and Idaho jurisdictions, it is likely that revisions to Schedule 190 will be necessary if we are to achieve the acquisition commitment. The DSM implementation planning process will address the specifics of how we can aggressively increase acquisition without incurring undue increases in costs attributable to the rapid ramp-up.

As part of the implementation planning process, we will calculate all individually-evaluated measures and other measures for their cost-effectiveness in each of the individual Oregon subdivisions as well as within the Washington/Idaho division.

We recognize the obligation to achieve all natural gas-efficiency resources available through the intervention of cost-effective utility programs. There are many new efficiency opportunities in the market, however, considerable uncertainty remains regarding the customer response to these programs. This uncertainty does not preclude us from pursuing the planned aggressive ramp-up of natural gas-efficiency programs. Additionally, we have, and will actively seek, opportunities for new or enhanced resource acquisition through the development of cooperative regional programs.

One of the results of the IRP process is a 20-year forecast of monthly avoided costs for each of our geographic areas. The detailed nature of these avoided costs makes it possible to continue to evaluate measures and programs as technology and markets change before the next IRP process. This is of value in determining program cost-effectiveness based on updated inputs, revised program plans and the ability to determine the value of targeting specific markets. Avoided cost determination is discussed

in detail in Chapter 7. We will file our cost-effectiveness limits (CEL's) based upon the avoided costs derived from this IRP process.

Additionally, we are investigating the applicability of recently completed quantifications of electric distribution capacity, the customer value of risk reduction and greenhouse gas emissions to determine if similar quantifications are possible for our natural gas system.

CONCLUSION

This IRP provides Avista the necessary resource analysis to proceed to the further development and implementation of natural gas efficiency programs. Avista's 2006 natural gas IRP identified a goal of 441,000 therms in Oregon based on information available at that time. Current evaluations of energy savings from high-efficiency natural gas furnaces are significantly lower than previous assumptions, which, when applied to the 2006 IRP goal, would reduce the previous goal to 390,000 therms. The 2007 IRP has identified an acquirable potential that is 10 percent lower than the previous IRP. This decrease in the estimate of acquirable potential does not diminish the company's continuing commitment to address the unique issues inherent in our Oregon service territory through an increased focus on the non-residential sector. These enhancements will include additional utility infrastructure, partnerships with the Energy Trust of Oregon and continuing our work on developing regional market transformation collaboration.

4. DISTRIBUTION PLANNING

OVERVIEW

The primary goal of distribution system planning is to design for present needs and to plan for future expansion to serve demand growth. This allows the company to satisfy current demand-serving requirements while taking steps toward meeting future needs. Distribution system planning identifies potential problems and areas of the distribution system that require reinforcement. By knowing when and where pressure problems may occur, the necessary reinforcements can be incorporated into normal maintenance. Thus, more costly "reactive" and emergency solutions can be avoided.

An action item from the 2006 IRP was to explore a gate station forecasting system to determine projected customer growth in smaller geographic areas. Our evaluation produced a system that utilizes town codes as the forecasting unit. A town code is an unincorporated area within a county or a municipality within a county served by Avista. Distribution Planning has incorporated town code growth rates to generate area-specific load growth for each distribution forecast model thus integrating planning efforts.

COMPUTER MODELING

When designing new main extensions, computer modeling can help determine the optimum size facilities for present and future needs. Undersized facilities are costly to replace and oversized facilities incur unnecessary expenses to the company and its customers.

THEORY AND APPLICATION OF STUDY

Natural gas network load studies have evolved in the last decade to become a highly technical and useful means of analyzing the operation 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 solutions obtained closely represent actual system behavior.

Avista conducts network load studies using Advantica's SynerGEE® software. This computer-based modeling tool allows users to analyze and interpret solutions graphically.

CREATING A MODEL

To properly study the distribution system, all natural gas main information is entered (length, pipe roughness and diameter) into the model. "Main" refers to all pipelines supplying services.

Nodes (points where natural gas enters or leaves the system) are placed at all pipe intersections, beginnings and ends of mains, changes in pipe diameter/material and to identify all large commercial and industrial customers. A model element connects two nodes together. Therefore, a "to node" and a "from node" will represent an element between those two nodes. Almost all of the elements in a model are pipes.

Regulators are treated like adjustable valves in which the downstream pressure is set to a known value. Although specific regulator types can be entered for realistic behavior, the expected flow passing through the actual regulator is determined and the modeled regulator is forced to accommodate such flows.

FLUID MECHANICS OF THE MODEL

Pipe flow equations are used to determine the relationships between flow, pressure drop, diameter and pipe length. For all models, the fundamental flow equation is used due to its demonstrated reliability.

Efficiency factors are used to account for the equivalent resistance of valves, fittings and angle changes within the distribution system. Starting with a 95 percent factor, the efficiency can be changed to fine tune the model to match field results.

Pipe roughness, along with flow conditions, creates a friction factor for all pipes within a system. Each pipe may have a unique friction factor, minimizing computational errors associated with generalized friction values.

LOAD DATA

All studies are considered steady state, meaning all natural gas entering the distribution system must equal the natural gas exiting the distribution system at any given time.

Customer loads are obtained from Avista's customer billing system and converted to an algebraic format so loads can be generated for various conditions.

In the event of a peak day or an extremely cold weather condition, it is assumed that all curtailable loads are interrupted. Therefore, the models are conducted with only core loads.

DETERMINING MAXIMUM HOURLY USAGE

Determining Base Load

Base loads are not temperature dependent; they remain relatively constant regardless of temperature. A reasonable base load can be calculated from customer billing information. The billing month, which has the lowest amount of heating degree-days is usually August. Usage during this month will reflect nearly all natural gas loads exclusive of space heating.

By determining the amount of days in the billing period and applying a peaking factor, the peak hourly base load of each customer can be estimated as shown in Table 4.1.

Determining Heat Load

A heat load will be proportional to heating degree-days (HDDs); at zero HDD, the load will be zero. Heat load can be reasonably calculated from customer billing information. The billing month with the greatest consumption is usually January. This month reflects maximum space heating as well as non-space heating loads.

Table 4.1 - Determining Base Load

$$\text{Customer Usage Summer Billing Period} \times \frac{1}{\text{Days in Billing Period}} \times \text{0.0625[1]} = \text{Peak Hourly Base Load}$$

Table 4.2 - Determining Heat Load

$$\left\{ \text{Customer Usage Winter Billing Period} - \text{Customer Usage Summer Billing Period} \right\} \times \frac{1}{\text{Winter Billing Period Degree Days}} \times \text{Peak HDDs} \times \text{0.0625[1]} = \text{Peak Hourly Heat Load}$$

Customers' usage for January (winter) billing, minus usage for August (summer) billing, leaves a reasonable estimate for heat load. This load can be divided by the number of HDDs that occurred in January, leaving usage per HDD. Customer needs can be calculated by applying the peaking factor, resulting in a peak hourly heat load per HDD. This is shown in Table 4.2.

Determining Peak Hourly Load

The peak hourly load for a customer is estimated by adding the hourly base load and the hourly heat load for a peak temperature. This estimate reflects highest system hourly demands, as shown in Table 4.3.

This method differs from the approach that we use for IRP peak day load planning. The primary reason for this difference is the importance of responding to hourly peaking in the distribution system, while IRP resource planning focuses on peak day requirements to the citygate.

APPLYING LOADS

Having estimated the peak loads for all customers in a particular service area, the model can be loaded. The first step is to assign each load to the respective node or element.

GENERATING LOADS

Temperature-based and non-temperature-based loads are established for each node or element, so loads can be varied based on any temperature (HDD). This is necessary to evaluate the difference in flow and pressure due to different weather conditions.

GEOGRAPHIC INFORMATION SYSTEM (GIS)

We recently converted our natural gas facility maps to GIS. While a GIS can provide a variety of map products, its power lies in its analytical capability. A GIS consists of three components: spatial operations, data association and map production.

Table 4.3 - Determining Peak Hourly Load

$$\text{Peak Hourly Base Load} + \text{Peak Hourly Heat Load} = \text{Peak Hourly Load}$$

[1]The average residential customer's peak usage was found to be 6.25 percent of the total daily load. This peaking factor was estimated by studying the ratio of the peak hourly flow and the total daily flow at the pipeline gate stations (result = 6.25 percent of total daily load) in past years (1994-99). The peaking factor is periodically discussed with other utilities and has been consistent with other utilities of similar size.

A GIS allows analysts to conduct spatial operations. A spatial operation is possible if a facility displayed on a map maintains a relationship to other facilities. Spatial relationships allow analysts to perform a multitude of queries, including:

- identify electric customers adjacent to natural gas mains who are not currently using natural gas;
- display the ratio of customers to length of pipe in Emergency Operating Procedure zones (geographical areas defined by the number of customers and their safety in the event of an emergency); and
- classify high-pressure pipeline proximity criteria.

The second component of a GIS is data association. This allows analysts to model relationships between facilities displayed on a map to tabular information in a database. Databases store facility information such as pipe size, pipe material, pressure rating or related information (e.g., customer databases, equipment databases and work management systems). Data association allows interactive queries within a map-like environment.

Finally, a GIS provides a means to create maps of existing facilities in different scales, projections and displays. In addition, the results of a comparative or spatial analysis can be presented pictorially. This allows users to present abstract analyses in a more intuitive context.

BUILDING SynerGEE® MODELS FROM A GIS

A GIS can provide additional benefits through the ease of creation and maintenance of load studies. Avista can create load studies from a GIS based on tabular data (attributes) installed during the mapping process.

MAINTENANCE USING A GIS

A GIS helps maintain the existing distribution facility by allowing a design to be initiated on a GIS. Currently, design jobs for the company's natural gas system are managed through Avista's Facility Management (AFM) tool. This system is being integrated with GIS, allowing jobs to be designed directly within a GIS. Once completed, the information is submitted to GIS and the facility is immediately updated. This eliminates the need to convert physical maps to a GIS at a later date. Because the facility is updated on GIS, load studies can remain current by refreshing the analysis.

DEVELOPING A PRESENT CASE LOAD STUDY

In order for any model to have accuracy, a present case model has to be developed that reflects what the system was doing when downstream pressures and flows are known. To establish the present case, pressure charts located throughout the distribution system are used. Pressure charts plot pressure (some include temperature) versus time over several days. Various locations recording simultaneously are used to validate the model. Customer loads on SynerGEE® are generated to correspond with actual temperatures recorded on the pressure charts. An accurate model's downstream pressures will match the corresponding location's field pressure chart. Efficiency factors are fine-tuned to further refine the model's pressures.

Since telemetry at the gate stations record hourly flow, temperature and pressure, these values are used to validate the model. All loads are representative of the average daily temperature and are defined as hourly flows. If the load generating method is accurate, all natural gas entering the actual system (physical) equals total natural gas demand solved by the simulated system (model).

DEVELOPING A PEAK CASE LOAD STUDY

Using calculated peak loads, a model can be analyzed to identify the behavior during a peak day. The efficiency factors established in the present case are used throughout subsequent models.

ANALYZING RESULTS

After a model has been balanced, several features within the SynerGEE® model are used to translate results. Color plots are generated to depict flow direction, pressure, pipe diameter and gradient with specific break points. Attributes of reinforcement can be queried by visual inspection. When user edits are completed and the model is rebalanced, pressure changes can be visually displayed, helping identify optimum reinforcements.

An optimum reinforcement will have the largest pressure increase per unit length. Reinforcements can also be deferred and occasionally eliminated through load mitigation of DSM efforts.

PLANNING CRITERIA

In most instances, models resulting in node pressures below 15 psig (pounds per square inch) indicate a likelihood of distribution low pressure and therefore necessitate reinforcements. For most Avista distribution systems, a minimum of 15 psig will ensure deliverability as natural gas exits the distribution mains and travels through service pipelines to a customer's meter. Some Avista distribution areas operate at lower pressures and are assigned a minimum pressure of 5 psig for model results. Given a lower operating pressure, service pipelines in such areas are sized accordingly to maintain reliability.

DETERMINING MAXIMUM CAPACITY FOR A SYSTEM

Using a peak day model, loads can be prorated at intervals until area pressures drop to 15 psig. At that point, the total amount of natural gas entering the system equals the maximum capacity before new construction is necessary. The difference between natural gas entering the system in this scenario and a peak day model is the maximum additional capacity that can be added to the system.

Since the approximate natural gas usage for the average customer is known, it can be determined how many new customers can be added to the distribution system before necessitating system reinforcements. The above models and procedures are utilized with new construction proposals or pipe reinforcements to determine a potential increase in facilities.

Table 4.4 - Capital Reinforcement Projects with Estimated Costs in 2006$

Project Description	State	2007	2008	2009	2010	2011
East Medford	OR	$5,799,667	$5,000,000	$6,000,000		
Glendale Gas Conv	OR	$1,420,002				
Diamond Lake Reinforcement	OR	$1,300,087	$1,700,000	$2,100,000		
Merlin Gate Station Rebuild	OR	$472,821				
Grants Pass South Side Reinforcement	OR	$304,845	$250,000			
Gekelar Road, LaGrande	OR	$150,285				
N-S Freeway/Gas	WA	$150,000	$75,000	$50,000	$50,000	$50,000
Bridging the Valley	WA	$50,000	$100,000	$100,000	$100,000	$100,000
Reinforce Gate Station Post Falls-Chase Rd	ID		$1,500,000			
Re-Rte Kettle Falls HP Feeder & Gate Station	WA		$1,300,000	$2,600,000	$2,300,000	
Qualchan Reinforcement, Spokane	WA		$1,200,000			
HP Reinforcement, Sutherlin	OR		$800,000			
Bonners Ferry 4” PE Reinforcement	ID		$250,000			
Reinforcement, Woolard Rd-Yale Rd, Spokane	WA		$250,000			
Altamont & Crosby Road Project, Klamath Falls	OR		$225,000	$100,000	$100,000	
Umpqua River Crossing Fairgrounds, Roseberg	OR		$150,000			
Reinforce Barker Rd Bridge Crossing, Spokane	WA		$150,000			
Relocation 6” HP @ Larson Creek, Medford	OR		$130,000			
US2 N Spo Gas HP Reinforce (Kaiser Prop)	WA		$100,000			
Rebuild J St Reg Station, Roseburg	OR		$100,000			
Grants Pass 8” HP Reinforce Project	OR			$2,000,000		
Elgin Line HP Reinforcement	OR			$1,600,000		
Relocation, Davis Creek, Roseburg	OR			$125,000		
Reinforce Talent Gate Station & Piping	OR			$50,000	$2,500,000	
Cheney 8” HP Feeder Project	WA				$3,600,000	
Reinforce Country Vista to Appleway 6” PE	WA				$250,000	
Reinforce Barker Rd Looping	WA				$100,000	
IMP Pipe Replacements, 2012 Commitment	OR					$830,000
Total WA		$200,000	$3,175,000	$2,750,000	$6,400,000	$150,000
Total ID		$0	$1,750,000	$0	$0	$0
Total OR		$9,447,707	$8,355,000	$11,975,000	$2,600,000	$830,000

FIVE-YEAR FORECASTING

Load study forecasting is done to predict the system’s behavior and reinforcements necessary within the next five years. Various Avista personnel provide information to determine where and why certain areas may experience growth.

By combining information from Avista’s demand forecast, IRP planning efforts, regional growth plans and area developments, proposals for pipeline reinforcements and expansions can be evaluated with SynerGEE®. A current list of management approved proposed reinforcement projects for the company is shown in Table 4.4.

CONCLUSION

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

The ability to meet our goal of reliable and cost-effective gas delivery is also enhanced through the recent integration of customer growth forecasting at the town code level and localized distribution planning. This enables coordinated targeting of distribution projects that are responsive to detailed customer growth patterns.

5. SUPPLY-SIDE RESOURCES

OVERVIEW

Avista's supply philosophy is to reliably provide natural gas to customers with an appropriate balance of price stability and prudent cost. To that end, we continuously evaluate a variety of supply resources and attempt to build a portfolio that is appropriately balanced and diversified to manage risk and achieve cost effectiveness. These include firm and non-firm supplies, firm and interruptible transportation on five interstate pipelines and various storage options. The hedging program resulting from that continuous evaluation addresses physical and financial risks, both of which are covered in this chapter.

This chapter describes natural gas commodity and storage resources, transportation arrangements used to connect those supply resources to Avista's demand regions, and market-related risks and ways that mitigate those risks.

COMMODITY RESOURCES

We have a number of supply options available to serve our core customers. 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.

Avista is located near several liquid hubs and supply basins in Western North America, including Alberta and British Columbia in Canada and the Rocky Mountain region in the United States. Avista's unique access to a diverse group of supply basins, coupled with the diversity of delivery points, allows the company to purchase at lower-priced trading hubs on a given day, subject to operational and contractual constraints.

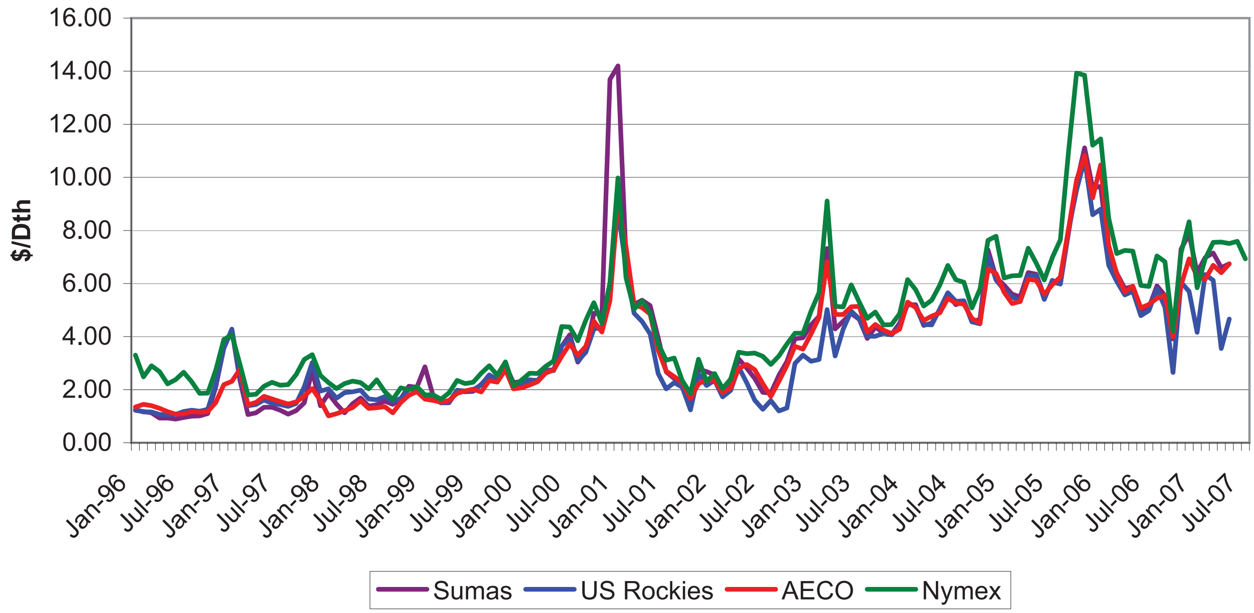
The three major supply points near our service area are Sumas (located north of Seattle at the U.S./Canadian border), AECO (northeast of Spokane in Alberta, Canada) and the Rockies (a number of natural gas production pools in Wyoming, Utah, Colorado and New Mexico). The prices for natural gas at these three supply points generally move together. However the basis differential among the supply points can change depending on market or operational factors, including differences in weather patterns, pipeline constraints and the ability to shift supplies to higher-priced delivery points in the United States or Canada. Based on market information and analysis, we believe there is sufficient liquidity at these three supply points to meet future demand.

Given the ability to transport natural gas to other parts 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 and is widely recognized as the primary natural gas pricing point in the United States. NYMEX futures contracts are priced at Henry Hub. Figure 5.1 illustrates the tight relationship among the various locations and shows historic natural gas prices for physical purchases at Henry Hub, AECO, Sumas and the Rockies.

Procurement of natural gas is typically 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,

Figure 5.1 - January 1996 to July 2007 Monthly Index Nymex/Rockies/Sumas/AECO



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 a standard product.
- **Liquidated Damages** – Most contracts contain provisions for symmetrical penalties for failure to take or supply natural gas according to contract terms.

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 explore a variety of contractual terms and conditions in order to capture the most value from each transaction.

STORAGE RESOURCES

The company is one-third owner, with NWP and Puget Sound Energy (PSE), in the Jackson Prairie Storage Project (Jackson Prairie) for the benefit of its core customers in all three states. Avista has also contracted for service in the Mist underground natural gas storage project for its Oregon customers. Jackson Prairie is an underground reservoir project located near NWP's main line near Chehalis, Wash. Mist is an underground natural gas storage facility located in Mist, Ore., near Portland, Ore.

Storage is a strategic resource due to the company's low load factor. Storage provides the following benefits:

- invaluable peaking capability;
- reduces the need for higher cost annual firm transportation;
- storage injections increase the load factor of existing firm transportation; and
- provides access to normally lower-cost summer supplies.

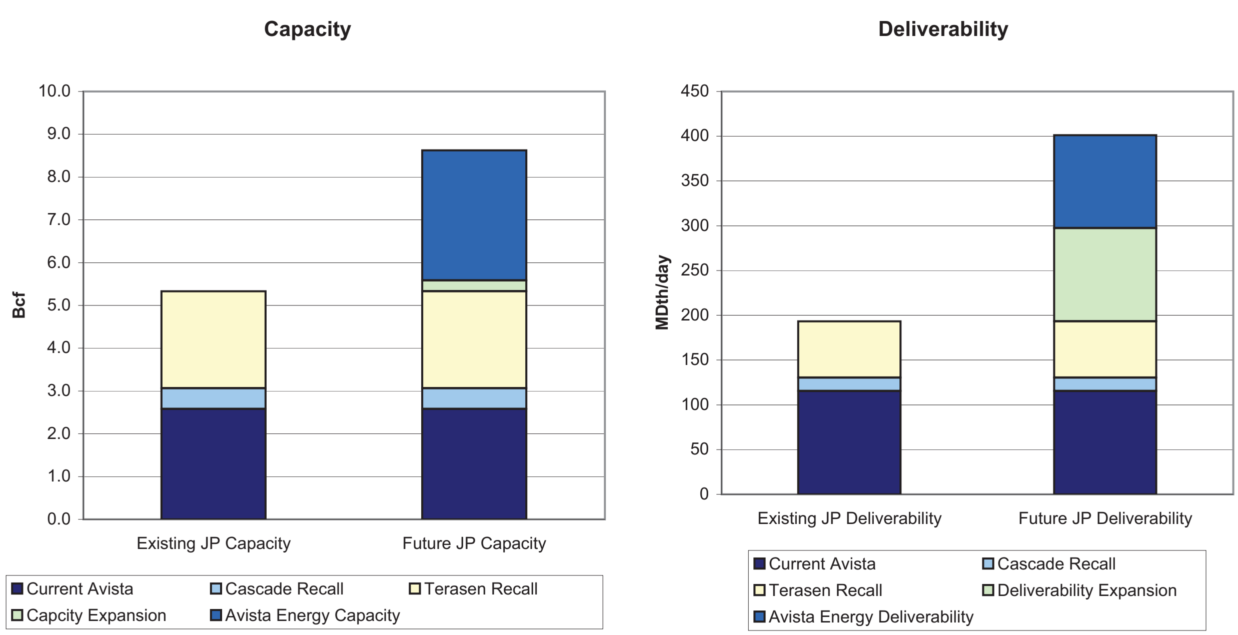
JACKSON PRAIRIE STORAGE PROJECT

In the early 1980s, Avista determined it did not then need its entire Jackson Prairie storage capacity to meet firm system requirements. In 1982, the company released half of its capacity and deliverability at Jackson Prairie to BC Hydro. The primary term of the original contract was set to expire in 1996, with a provision for year-to-year continuation thereafter. The new contract with Terasen, successor to BC Hydro for natural gas operations, has been in place since 1996, with recall provisions after 2000. In April 2006, Avista notified Terasen that this release will be terminated pursuant to the contractual provisions. The recall will be effective April 30, 2008. The recalled Terasen capacity does not include transportation.

In 1999 and again in 2002, Avista participated in capacity expansions of Jackson Prairie with NWP and Puget Sound Energy. It was determined that the additional capacity for core utility customers was not needed at that time, and the expansion went under the management of Avista Energy, Avista's non-regulated energy marketing and trading affiliate. In June 2007, Avista Energy sold substantially all of its energy contracts and ongoing operations to Shell Energy North America, (U.S.), L.P. The sale included Avista Energy's contractual rights to Jackson Prairie through April 30, 2011. After this date, we anticipate recalling these storage rights for use in our utility operations, and have included it in our SENDOUT® model as an incremental storage resource at that time.

The 2002 expansion has been a phased, ongoing project to increase the storage capacity of the field. Beginning in July 2007, concurrent with the Avista Energy/Shell sales transaction, Avista took over the rights to the ongoing 2002 expansion and will utilize this incremental storage capacity. This phase of the expansion is expected to be completed in the fall of 2008. Additionally, the partners in Jackson Prairie are currently expanding the daily withdrawal capability. The target of this expansion is to increase Avista's allocation of daily deliverability by 100 MMcf/day by November 2008.

Figure 5.2 - Jackson Prairie Storage Capacity and Deliverability
Existing and Future Volumes



The Shell-held rights, the capacity expansion and the delivery expansion represent significant incremental future storage-related assets (see figure 5.2). In spring 2007 we discussed a plan for allocation of these rights with the Washington, Oregon and Idaho Commissions Staff recommending an allocation of 75 percent/25 percent between our Washington and Idaho customers and our Oregon customers, respectively. The recommendation was supported in all three jurisdictions.

We continue to evaluate our Jackson Prairie capacity and deliverability requirements to determine if we should negotiate new releases or opportunistically optimize excess storage capacity beyond the benefit currently being captured.

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 territory. Consequently, we have contracted for a sufficient amount of firm pipeline capacity 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 company has many contracts with Northwest Pipeline Corporation (NWP) and Gas Transmission Northwest (GTN) for firm and interruptible transportation to serve our core customers. In addition to this capacity, Avista also contracts for capacity on upstream pipelines to flow natural gas to NWP and GTN. Table 5.1 details the firm transportation/resource services contracted by the company. These contracts are of different vintages, with different expiration dates. However, all have the right to be renewed by Avista. This gives the company and its customers the knowledge that Avista will have available capacity to meet existing core demand now and in the future.

NWP and GTN also provide interruptible transportation service to the company. 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 Dth transported is the same as firm transportation, there are no demand or reservation charges connected with these transportation contracts. Since the marketplace for capacity release of transportation capacity has become so prevalent, the use of interruptible transportation services has diminished. We do not rely on interruptible capacity to meet peak day core demand requirements.

Table 5.1 - Current Available Firm Transportation Resources
Dth/Day

	Avista North		Avista South	
Firm Transportation	***Winter***	***Summer***	***Winter***	***Summer***
NWP TF-1	111,599	111,599	30,638	30,638
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2 (JPSP)	91,200		2,623	
Total	**303,404**	**187,381**	**75,521**	**51,278**
Firm Storage Delivery Capacity				
JPSP (SGS-1)	127,667		2,623	
MIST			15,000	
Total	**127,667**		**17,623**	

*Firm Storage Delivery Capacity utilizes the Firm Transportation capacity.

Table 5.2 - Current Transportation/Storage Rates and Assumptions
Rates in US$/Dth/Day

	Reservation	*Commodity*	*Fuel Rate 3/*	*Rate Change Assumptions*
TransCanada Alberta System Firm Rates -				
Postage Stamp Rates				
AECo/NIT to ABC	0.1230	-	0.00%	Changes every three years
AECo/NIT to ABC Winter Only	0.1538	-	0.00%	Changes every three years
TransCanada BC System Firm Rates -				
Postage Stamp Rates				
ABC to Kingsgate	0.0640	-	1.00%	Changes every three years
GTN FTS-1 Rates 4/ -				
Mileage Based - Representative Example				
Kingsgate to Spokane	0.1166	0.0040	0.38%	Changes every five years
Kingsgate to Medford	0.4190	0.0222	2.10%	Changes every five years
Meford Lateral	0.5481	-	0.00%	Changes every five years
Spectra Energy/Westcoast System Firm Rates -				
Postage Stamp Rates				
Station 2 to Huntington/Sumas	0.3560	-	1.30%	Changes every three years
Williams NWP				
Postage Stamp Rates				
TF-1 1/	0.3798	0.03000	1.82%	Changes every five years
TF-2 1/	0.3798	0.03000	1.82%	Changes every five years
SGS-2F 2/	0.4718	0.01703	0.52%	Changes every five years

1/ TF-1 based upon annual delivery capability. TF-2 based upon approximately 32 days of delivery capability
2/ Not applicable for WA/ID customers
3/ Fuel retained in-kind
4/ GTN rates are the full filed rates. The GTN rate case was settled Oct. 31, 2007.

Forecasting future pipeline rates is difficult, if not impossible. Our assumptions for future rate changes were the result of market information and concurrence by TAC members. GTN filed a rate case in late 2006. The rates in Table 5.2 reflect the rates as filed. Since the drafting of this document, settlement on the GTN rate case has been reached. The settlement was filed with the Federal Energy Regulatory Commission (FERC) on Oct. 31, 2007, but is not yet approved. Beyond this assumption, it is assumed that the pipelines will file to recover costs at rates equal to the GDP.

The company's strategy is to contract for firm transportation to serve core customers should a peak day occur in the near-term planning horizon. Too much firm transportation could keep the company from achieving its goal of being a low-cost energy provider. But too little firm transportation impairs the company's reliability goal. Determining the appropriate level of firm transportation is a complex evaluation of many factors, including the projected number of firm customers and their expected demand on an annual and peak day basis, opportunities for future pipeline or storage expansions, and relative costs between pipelines and their upstream supplies. It is important to maintain an appropriate time cushion, to allow for required lead times for securing new capacity. Also, the ability to release capacity offsets the cost of holding underutilized capacity.

MARKET-RELATED RISKS AND RISK MANAGEMENT

While risk management can be defined in a variety of ways, the IRP 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 (either the transportation capacity or the commodity) to serve core customers.

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

There are three internal organizations that assist in the establishment, reporting and review of Avista's business activities related 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 related matters.
- The Strategic Oversight Group (SOG) 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, Rates and Risk Management departments. While the Natural Gas Supply department is responsible for implementing hedge transactions, the SOG provides input and advice.
- The Natural Gas Coordination Committee involves Natural Gas Supply, Demand-Side Management, Natural Gas Engineering, Rates, Accounting and Natural Gas Operations to ensure that the various departments are maintaining lines of communication and coordinating natural gas-related projects.

MARKET FACTORS AND AVISTA'S PROCUREMENT PLAN

We cannot accurately predict future natural gas prices. The company has designed a natural gas procurement plan that attempts to competitively acquire natural gas supplies while reducing exposure to short-term price volatility. Although the specific provisions of the procurement plan will change as a result of ongoing analysis and experience, the following principles reflect Avista's procurement plan philosophy:

- **Avista employs a diversified approach to hedging** – It is appropriate to hedge over a period of time, and we establish hedge periods within which portions of our future loads are financially hedged. The financial hedges may not be completed at the lowest possible price, but will insulate customers from price spikes. Additionally, we diversify the basins we purchase at and the counterparties we purchase from.
- **Avista establishes a disciplined but flexible approach to hedging** – In addition to establishing hedge periods within which hedges are to be completed, there are also upper- and lower- pricing points. In a rising market, this reduces the company's exposure to extreme price spikes. In a declining market, this encourages the company to capture the value associated with lower prices.
- **Avista regularly reviews its procurement plan in light of current market conditions and opportunities** – Avista has a dynamic plan with ongoing review of the assumptions leading 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 available to help mitigate financial risks. 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 load volatility, whether through option tools available from counterparties or through access to additional storage capacity and/or transportation.

We believe we can strengthen the analysis leading to certain hedges and future modifications to our natural gas procurement plan. VectorGas™ will facilitate the ability to model price and demand uncertainty and model various hedging strategies and evaluate the impacts on cost and volatility of the overall portfolio.

SUPPLY-SIDE OPTIONS

SYSTEM ENHANCEMENTS

In certain instances, the company can facilitate additional peak and base load-serving capabilities through a modification or upgrade of our facilities. These opportunities are geographically specific and require case-by-case study. We have begun a review of several enhancements and preliminary findings indicate that the following opportunities are viable.

- ***NWP Klamath Falls Lateral***
  Avista has the opportunity to purchase and operate the NWP Klamath Falls lateral as a high-pressure distribution system. Although we would incur the capital cost associated with the purchase price, we would be able to avoid current NWP reservation and fuel charges at Klamath Falls and relocate the transportation contract deliverability on NWP to areas where additional deliverability is needed while reducing fuel charges. This solution would also facilitate additional deliveries into the Klamath Falls area off of GTN. This enhancement can likely be completed within six months.

- ***Medford System Enhancement***
  Avista is constructing a high-pressure distribution reinforcement from the GTN system off of the Medford lateral to deliver additional quantities of natural gas off of GTN to Medford. This solution will allow existing supply and capacity to be diverted from Medford on the NWP Grants Pass Lateral to the Roseburg area. Through this enhancement, we can address potential resource shortages in the Medford and Roseburg areas.

- ***La Grande Distribution System Enhancement***
  Avista has the option to enhance the distribution system in the La Grande area with high-pressure distribution looping from an adjacent citygate station such that the distribution system would be reinforced. This solution would allow additional deliveries off of the NWP system to La Grande.

EXISTING STORAGE

Storage allows the company to deliver natural gas supply when needed most. Storage also allows the company to take advantage of summer/winter pricing differentials, as well as provide the company with arbitrage opportunities within individual months. The latter advantages do not offer peak load serving capabilities although they certainly allow the company to offset natural gas supply expenses with these revenues. 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. Storage resources are limited in the Pacific Northwest; however, there are a number of options available.

- ***Jackson Prairie***
  As discussed in the Storage Resources section, Jackson Prairie is a tremendous resource for existing services and expansion opportunities.

  Recently recalled capacity will facilitate peak and winter deliveries at no cost for the storage and very little cost for the transportation in addition to providing ratepayers with the opportunity to capture current arbitrage opportunities that exceed the release revenues that Avista was receiving.

The storage recall and future expansion capacity discussed earlier do not include incremental transportation to our service territory and therefore cannot be considered an incremental peak day resource. However, we will continue to look for swap and transportation release opportunities to fully utilize these additional resources. Even without deliverability, we believe it makes financial sense to fully develop/recall JP capacity to optimize time spreads within the natural gas market and provide net revenue offsets to customer gas costs.

As discussed earlier in this chapter, plans call for some of the JP expansion capacity to be allocated to Oregon customers. This expansion does not currently have transportation so this storage is not currently available for incremental peak resource needs. It is, however, a supply replacement on peak day as well as an arbitrage opportunity. Oregon customers may have the ability to benefit from storage resources for incremental peak needs if future cost-effective pipeline capacity can be acquired.

- ***Mist***

  Avista has also recently added a small amount of storage capacity for its Oregon customers through a three-year storage capacity agreement at the Mist Storage Facility in northwest Oregon.

- ***Plymouth LNG***

  Avista released its rights to Plymouth LNG in part because of the JP capacity release recalls. This peaking resource was costly per unit delivered and 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. In order for this option to become a preferred resource, transportation to and from Plymouth will need to be acquired.

- ***Other Storage***

  Other regional storage facilities exist and may be cost-effective. Additional capacity at Northwest Natural's Mist facility, capacity at Alberta area storage, Questar's Clay Basin facility in Northeast Utah, and Northern California storage are all possibilities. Again, transportation to and from these facilities to Avista's service territory continues to be the largest impediment to contracting for these options. An attractive non-Jackson Prairie resource that we are reviewing is storage potential in Northern California. This concept needs to be further analyzed, although it appears that through backhaul transportation, deliveries could be made to some of the Washington/Idaho and Oregon customers. Storage capacity is periodically available in Northern California as well as transport capacity to and from these locations. Unfortunately, current sellers of storage capacity in Northern California are not offering multi-year contracts or contracts with beginning dates during the timeframes that the company may need these incremental resources.

PIPELINE TRANSPORTATION

Additional firm pipeline transportation resources are viable resource options for the company. Determining the appropriate level, supply source and associated pipeline path, costs and timing as well as 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 is generally a low-cost option given optimization and capacity release opportunities, and it provides for base-load demand. 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.

Many pipelines currently have available pipeline capacity on the mainline portion of their systems. Unfortunately, NWP does not have any available capacity on its mainline or on any of the relevant laterals that serve Avista's service territories. GTN has mainline capacity currently available and may be able to provide additional service to some Washington/Idaho and Oregon customers without an expansion. Further, longer-term permanent capacity release options may be available on both pipelines.

Following are three specific options that provide Avista with flexible existing transportation resources:

- ***Capacity Release Recall***
  Avista's pipeline transportation that is not utilized to serve load can be released to other parties or optimized through buy/sell transactions. Released capacity is 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 a many short-term and several 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.

- ***Willamette Peaking Arrangement***
  We currently have some transportation capacity contingently released to Willamette Industries. As part of this agreement we have the ability to call on this capacity and an associated amount of supply. This contract expires Oct. 31, 2010 and may or may not be renewed.

- ***Utilization of Backhauls***
  On the GTN system, due to the north-to-south flow dynamics and the large amount of natural gas flowing that direction, backhauling supply purchases to Avista's service territory can be done on a firm basis. For example, Avista can purchase cost-effective 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 forward haul transportation from traditional supply sources and paying the associated reservation charges. The GTN system is a mileage-based system so we only pay a fraction of the forward 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. Avista can decrease costs by avoiding fuel charges and full reservation charges on an annual or seasonal basis and/or by avoiding potentially expensive peaking resources.

Pipeline expansions can be 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 the company given that most of the other options discussed in this section require pipeline transportation anyway.

To accurately assess costs and location, feasibility of potential expansion scenarios requires detailed engineering studies by the pipelines. These studies can be expensive and of limited shelf life for projects that might be developed well into the future. Consequently, we employ estimates derived from our knowledge of historical costs, reasonable price escalations and site specific issues that may impact a specific scenario. We combine this knowledge with past information from the pipelines to develop a reasonable basis for our transportation analysis. If and when we determine that additional transportation capacity is necessary, we will request thorough estimates from the appropriate pipeline companies, search the release market for capacity that may include winter-only service and seek capacity on constrained segments. These estimates are costly and will be prudently acquired.

SATELLITE LNG

Company-owned satellite LNG storage is another option that could be constructed within the company's service area. Unlike LNG facilities described earlier, satellite LNG uses natural gas that is trucked to the facilities in liquid form rather than liquefying on site. By locating within the Avista service area and not on the interstate pipelines, Avista could avoid incremental annual pipeline charges.

Estimates for this type of peaking resource look interesting. The company will continue to monitor and evaluate the cost and benefit of satellite LNG as new supply increments while remaining mindful of lead time requirements and environmental issues.

COMPANY-OWNED LNG

LNG facilities could be constructed within the company's service area. By locating within the Avista service area and not on the interstate pipelines, Avista could avoid annual pipeline charges. Such 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 are not cost effective at this time. Although the company is not modeling this option, we will continue to monitor cost effective company-owned LNG storage opportunities.

LARGE-SCALE LNG

There has been considerable national discussion regarding LNG gasification terminals. At today's natural gas prices, LNG can be competitively transported, stored and marketed. Numerous terminals have been proposed in the U.S., Mexico and Canada with seven terminals proposed for Washington, Oregon and British Columbia. Not all of these terminals will advance, and it may be possible that none of the Pacific Northwest terminals will proceed. The siting of LNG terminals is a difficult endeavor. In order for a terminal to advance, it will require economies of scale, the ability to move regasified supplies to markets, a favorable environmental review, favorable public reception, secure LNG supply, long-term output/sales agreements and financing. We have participated in several forums on various regional projects.

Although the Pacific Northwest may not provide sponsors with these requirements, the announcement to construct a pipeline from the proposed Coos Bay LNG facility to Malin, Ore., is encouraging. This pipeline may allow LNG to be directly delivered to Avista's service territory around Roseburg, Medford and Klamath Falls while potentially helping supply other regions via further backhaul or displacement opportunities. We are also monitoring the Bradford Landing/Palomor pipeline project. We have participated in the open seasons of the Coos Bay LNG and Bradwood Landing/ Palomar projects in our region contingently reserving capacity. We continue to monitor developments in this area including the securing of dependable supply which we believe poses a significant challenge for the project sponsors.

Industry experts believe that if additional LNG terminals are built and receive incremental supply, natural gas prices may trend downward or at least become less volatile. These experts also believe that it generally does not matter where the LNG terminals are located because the national natural gas markets are so tightly connected. Even if the Pacific Northwest facilities do not proceed, Avista will likely benefit from increasing amounts of imported LNG nationally.

For this IRP, we are not making large-scale LNG available to the model. This is because LNG in the Pacific Northwest is highly speculative, the region is not considered to be as premium a market as other locations in North America, and because it will take at least five years before this option would move forward in the Pacific Northwest. Each of the price forecasts we have reviewed make assumptions regarding increasing LNG imports to North America, so LNG commodity impacts are imbedded in those forecasts.

We will continue to monitor this option and will take action if a Pacific Northwest terminal begins to look promising.

SUPPLY ISSUES

The market for natural gas has undergone dramatic changes over the last several years, as the commodity market has transitioned from a regionally-based market to a nationally-based, and perhaps globally-based, market. This transition can be attributed to several reasons, including:

- **Supply/Demand Balance** – The balance between production and productive capacity has become tight. The balanced market has increased gas price volatility. Additionally, the cost of production has increased. These production costs keep the market at a price level that is much higher than historical levels.
- **Imports from Canada** – There is an abundance of evidence supporting the assumption that gas will continue to be imported from Canada into the United States. Recently , however, some literature contends supply imports from Canada will diminish greatly or even disappear over the 20-year planning horizon. Since much of our supply comes from the WCSB, the notion that supply could disappear is of concern. We will continue to monitor this situation for signals that indicate increased risk of disrupted supply from Canadian exports.
- **Pipeline constraints** – Although there now may be, or will be in the future, excess pipeline capacity in many parts of the country, the market or delivery portion of most pipelines remains heavily contracted. This is because LDCs and end users such as industrial customers prefer supply certainty. Avista and other consumers in the Pacific Northwest continue to hold all of the NWP capacity and existing lateral capacity on NWP and GTN. Of particular concern to Avista is NWP's Grants Pass Lateral in western Oregon. This lateral is fully contracted, demand is continuing to grow in the demand centers along this lateral, and it is not easily or inexpensively expanded. We also intend to further analyze how this full contracted capacity situation might affect the Spokane lateral or other laterals.

- **Pipeline rate increases** – There is more pipeline capacity from supply sources to markets than is currently needed in many regions in North America. This excess capacity has caused capacity holders with expiring contracts to consider relinquishing this capacity back to the pipelines. Many capacity holders have shown a preference for turn-back transportation contracts where transportation expenses exceed the value of this transportation. The result of this action from a pipeline perspective is to cause affected pipelines to file rate cases to recover some or all of the lost revenues. Distribution companies that rely on firm supplies and transportation will likely continue to hold or may be locked into their long term transportation contracts and may end up paying higher transportation rates depending on the FERC's approach to this issue.
- **Growing national pipeline infrastructure** – Pipeline capacity out of the supply regions has increased in volume and delivery points. As a result, natural gas prices in the Pacific Northwest have become more dependent on demand and prices in regions as far away as the east coast. The Rockies Express pipeline expansion to the Midwest and Eastern markets is expected to further solidify price correlation with these markets.
- **The potential of LNG to be the marginal source of natural gas in the United States** – Several projections indicate that over the next 10 years there will be a growing gap between North American natural gas production and North American demand for natural gas. The consensus is that LNG will fill the gap. Should this occur, there will be global price competition for LNG. We have been, and will continue to be, involved in discussions about LNG as a potential supply resource.

ACTION ITEMS

We will continue to monitor several issues identified in this chapter with respect to commodity, storage, and supply resources. These include:

- tight production/productive capacity;
- pipeline constraints in our region;
- pipeline expansions that move volumes away from our region;
- pipeline cost escalations; and
- large scale LNG activity.

We will also refine our analysis of acquiring or constructing resource alternatives to improve project cost estimating, assessment of project feasibility issues, determination of project siting issues and risks, and increased accuracy of construction/acquisition lead times. Specifically, we will further study these issues with respect to satellite LNG, company owned LNG, pipeline expansions, distribution system enhancements and storage facility diversification.

We will explore creative, non traditional resource possibilities to address our needle peaking exposures with emphasis on potential structured transactions (e.g. transportation and storage exchanges) with neighboring utilities and other market participants that leverage existing regional infrastructure as an alternative to incremental infrastructure additions.

We will continue to assess methods for capturing additional value related to existing storage assets, including methods of optimizing recently recalled releases while implementing its storage strategy of providing balanced storage opportunities. This includes exploring storage diversification options including AECO and Northern California facilities.

We will continue to analyze natural gas procurement practices for strategy enhancing ideas such as basis diversification, storage injection/withdrawal timing and structured products.

There is an abundance of evidence supporting the assumption that gas will continue to be imported from Canada into the United States. However, recently some literature contends supply imports from Canada will diminish greatly or even disappear over the 20 year planning horizon. Since much of our supply comes from the WCSB, the notion that supply could disappear is of concern. We will continue to monitor this situation looking for signals that indicate increased risk of disrupted supply from Canadian exports.

CONCLUSION

Avista is committed to ongoing exploration of supply-side resources that meet our philosophy of providing reliable natural gas service to our customers while balancing price stability and prudent costs. We are mindful that each resource option has unique risks that also must be evaluated in context of a total resource cost which in some cases eliminates them from current modeling consideration. Nonetheless, we are satisfied that the currently viable resource mix options fulfill our supply-side resource analysis objectives.

6. INTEGRATED RESOURCE PORTFOLIO

OVERVIEW

This chapter combines all the previously discussed components of the IRP and the model used for this process to determine if the company is resource deficient during the 20-year planning horizon. This chapter also provides an analysis of potential resource options and displays the model-selected best cost/risk resource options to meet resource deficiencies.

The foundation for integrated resource planning is the demand planning criteria utilized for the development of demand forecasts. Avista currently uses the "coldest day on record" as its planning standard for determining peak day demand. This is consistent with many other natural gas companies and our past IRPs. We intend to reevaluate this standard in the coming months to ascertain if a revision might be appropriate. Many important analytical and judgmental considerations will need to be assessed, including probability studies, reliability and safety implications and potential liability. Currently, we utilize historic peak and average weather data for each demand region for this IRP. It is also important to note that due to our duty to serve, we plan to serve this expected peak for each demand region with firm resources. These firm resources include DSM, 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 the optimization 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. The company 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. These three customer classes are collectively referred to as core customers.

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 tariff filings of the pipelines.

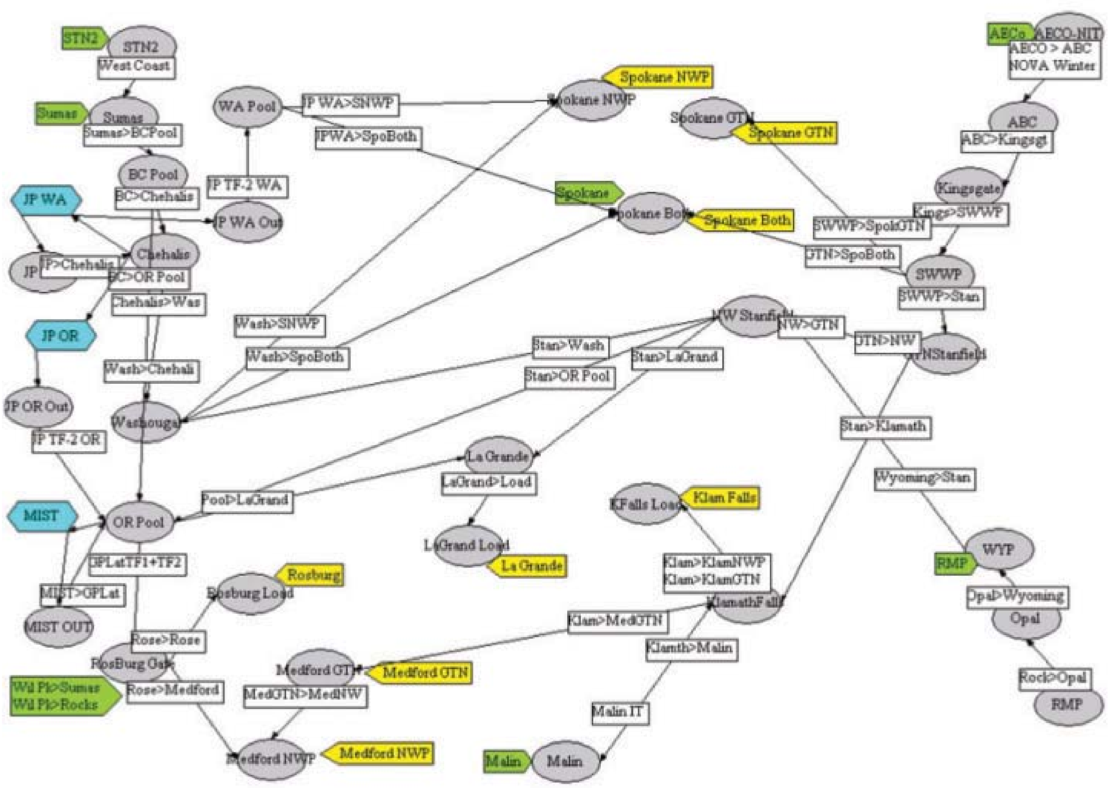
NATURAL GAS RESOURCE MODEL

The natural gas resource optimization model we use is the SENDOUT® Gas Planning System from New Energy Associates (NEA). The SENDOUT® model was purchased in April 1992 and has been used in preparing all IRPs since that time. The company has a long-term maintenance agreement with NEA that allows us to receive updates to the software as enhancements are made. These enhancements encompass software corrections and improvements, and enhancements 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, taking into account physical limitations and contractual constraints. The software looks at thousands of variables and evaluates thousands of possible solutions in order to generate the least-cost solution. Among the variables required by the model are:

- demand data such as customer count forecasts and demand coefficients by customer type (e.g. residential, commercial and industrial);
- heating degree-day (HDD) information;
- 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/

Figure 6.1 - SENDOUT® Model Diagram



withdrawal rates, capacities and costs; and
- demand-side management programs.

An example of some of the information used in the model is illustrated in Figure 6.1, which is the SENDOUT® Model Diagram. This diagram illustrates Avista's current transportation and storage assets, flow paths and constraint points.

The SENDOUT® model also provides a flexible tool to analyze numerous potential scenarios such as:
- pipeline capacity needs and capacity releases;
- effects of different weather patterns on demand;
- effects of natural gas price increases on total natural gas costs;
- storage optimization studies;
- resource mix analysis for demand-side management programs;
- weather pattern testing and analysis;
- analysis of transportation costs;
- avoided cost calculations; and
- short-term planning comparisons.

The latest version of SENDOUT®, released in July 2007, includes VectorGas™ which facilitates the ability to model price and weather uncertainty through Monte Carlo simulation and detailed portfolio optimization techniques that will ultimately produce probability distribution information. Similar to SENDOUT®, there are numerous variables that are entered into VectorGas™. Among the variables required to perform the Monte Carlo analysis are:
- expected monthly heating degree-days by month;
- standard deviation of the monthly heating degree-days;
- monthly minimum and maximum heating degree-days;
- daily HDD pattern (derived from historical data);
- expected monthly gas price by month;
- standard deviation of the monthly gas price;
- monthly minimum and maximum gas price;
- temperature-to-price correlations;
- price-to-price correlations; and
- daily price to temperature coefficients.

This additional software module enhances Avista's analytical capabilities, and we have just begun to explore its capabilities.

ANALYSIS FRAMEWORK

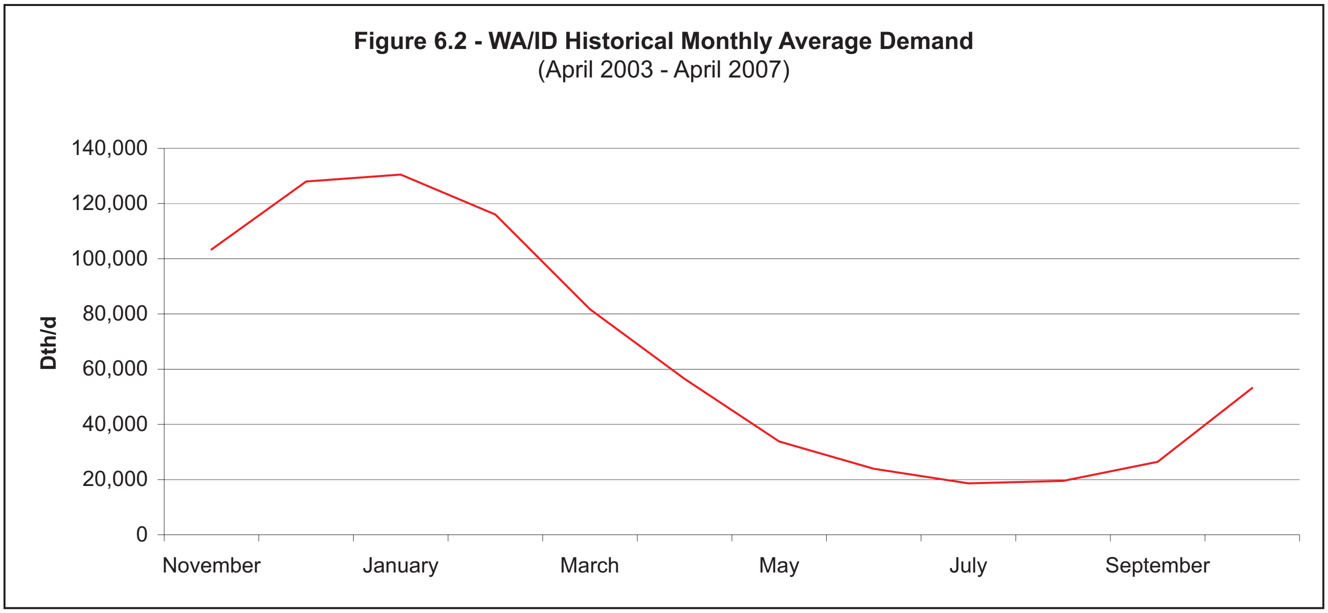
The approach used to analyze Avista's long-range natural gas planning options focuses on the sensitivity of the optimization model to periodic (daily, monthly, seasonal and/or annual) changes in:
- assumptions related to customer growth and customer natural gas usage that ultimately form demand forecasts;
- existing and potential transportation and storage options;
- existing and potential natural gas supply availability and pricing;
- weather assumptions; and
- demand-side management and avoided cost.

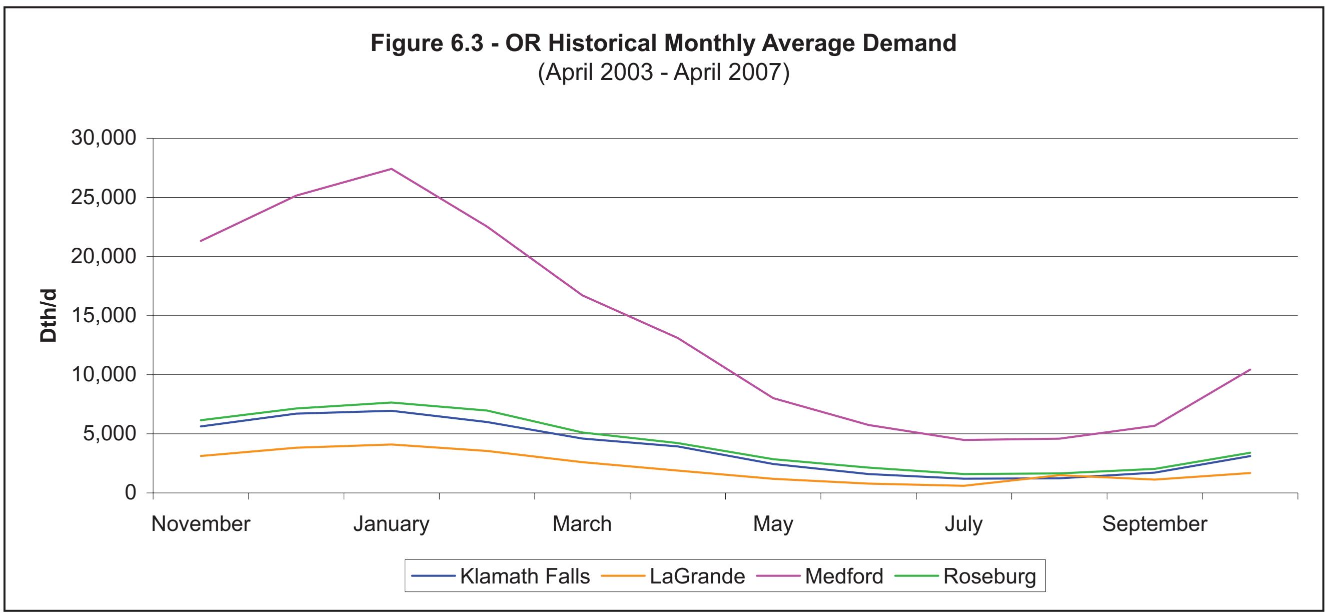
We have reviewed and performed rigorous analysis on each of the aforementioned areas.

DEMAND FORECASTING APPROACH

Avista's demand forecasting approach is described in the Demand Forecast chapter.

We forecasted demand in the SENDOUT® model in five areas due to the existence of distinct weather and demand patterns for each area. The areas within SENDOUT® are Washington/Idaho (further disaggregated to three sub-areas due to pipeline flow limitations), Medford (further disaggregated to two sub-areas due to pipeline flow limitations), Roseburg, Klamath Falls and La Grande. In addition to area distinction, we also modeled demand by customer class





in each of these areas. The relevant customer classes in the Avista service territory for this IRP are residential, commercial and firm industrial sales. Not all classes of customers currently exist or are forecasted to exist in each demand area.

Figures 6.2 and 6.3 show historic non-weather normalized average monthly demand for core customers by region for April 2003 through April 2007.

The SENDOUT® model is used to forecast customer demand, and we have calibrated the demand forecasting component of the SENDOUT® model through a meticulous backcasting process. A backcast uses the algorithm developed for forecasting purposes and applies it to known historical data as a means of testing the validity of that algorithm.

As described in the Demand Forecast chapter, and given experience with customers' price elasticity, we believe

Figure 6.4 - Average vs. Coldest vs. Warmest (84/85 plus 82 HDD, NOAA)
Spokane Weather

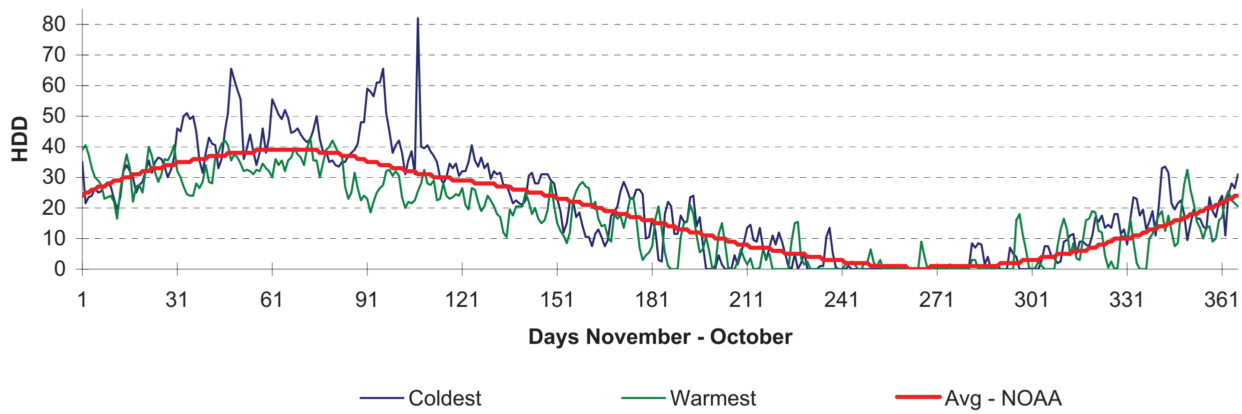
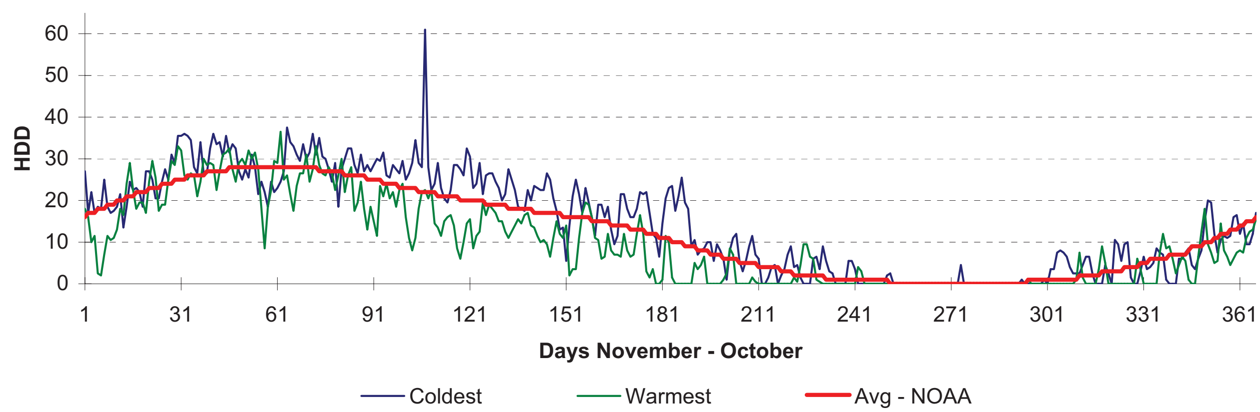


Figure 6.5 - Average vs. Coldest vs. Warmest (63/64 plus 61 HDD, NOAA)
Medford Weather



that it is possible that current and future high prices will continue to impact natural gas demand.

As stated in Chapter 2, we developed three scenarios using low, medium and high customer growth crossed with a price elasticity factor to capture the inverse relationship between price and demand to build our three demand scenarios for this IRP.

WEATHER ASSUMPTIONS

Avista's customer demand reflects a weather dependent customer base, so weather is very important in integrated resource planning. The analysis in this IRP is based on weather data published by the National Oceanic and Atmospheric Administration (NOAA). This is a 30-year weather study spanning 1971-2000. Figures 6.4 and 6.5 show NOAA's 30-year average weather data compared to

Figure 6.6 - NOAA 30-year Average vs. Planning Weather (added 82 HDD on Feb. 15)
Spokane Weather

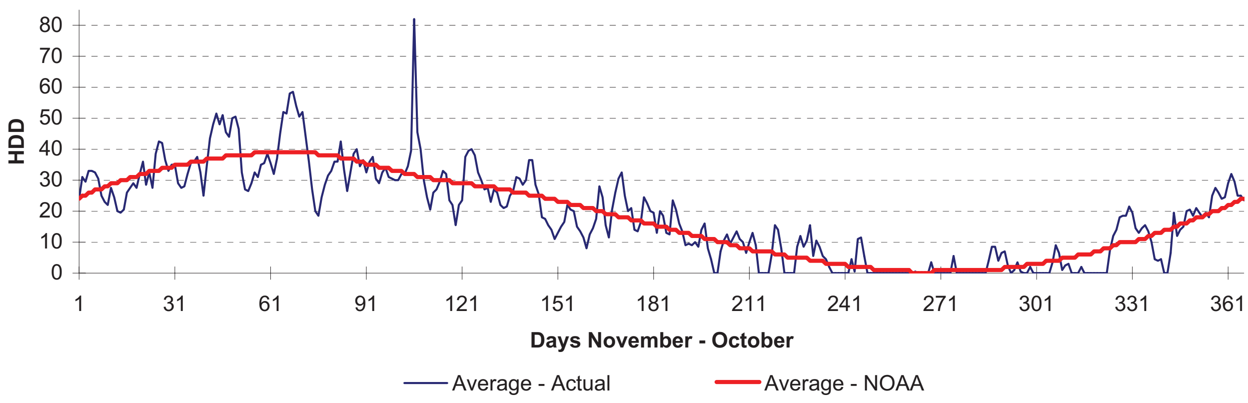
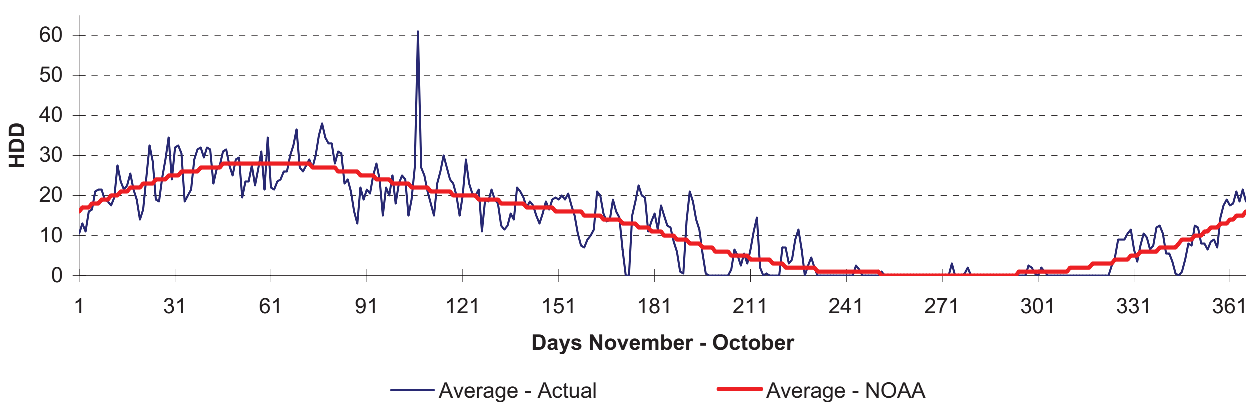


Figure 6.7 - NOAA 30-year Average vs. Planning Weather (added 61 HDD on Feb. 15)
Medford Weather



the coldest and warmest historical planning year for the Spokane and Medford areas. Measurements of historical average weather do not necessarily represent the range of potential future weather patterns, including some days that may differ substantially from that average pattern.

Figures 6.6 and 6.7 compare the NOAA 30-year average weather with a company-selected composite of weather months that form a weather year based on average heating degree-days with the variability of actual weather.

On Dec. 30, 1968, the North Operating Division area experienced the coldest day on record, an 82 heating degree-day for Spokane. This is equal to an average daily temperature of -17 degrees Fahrenheit. This day is used as the peak day for cold conditions in the Washington/ Idaho service area. Only one 82 heating degree-day has been experienced in the last 40 years for this area; however, within that same time period, 80 and 79 heating degree-day events occurred on Dec. 29, 1968, and Dec. 31,1978, respectively.

On Dec. 9, 1972, Medford experienced the coldest day on record, a 61 heating degree-day. This is equal to an average daily temperature of 4 degrees Fahrenheit. This day is used as the peak day for cold conditions in Medford. Medford has experienced only one 61 heating degree-day in the last 40 years; however, it has also experienced 59 and 58 heating degree-day 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 heating degree-day occurred on Dec. 21, 1990, in La Grande a 74 heating degree-day occurred on Dec. 23, 1983, and a 55 heating degree-day occurred in Roseburg on Dec. 22, 1990. As with Washington/Idaho and Medford, these days are used as the peak day for modeling purposes.

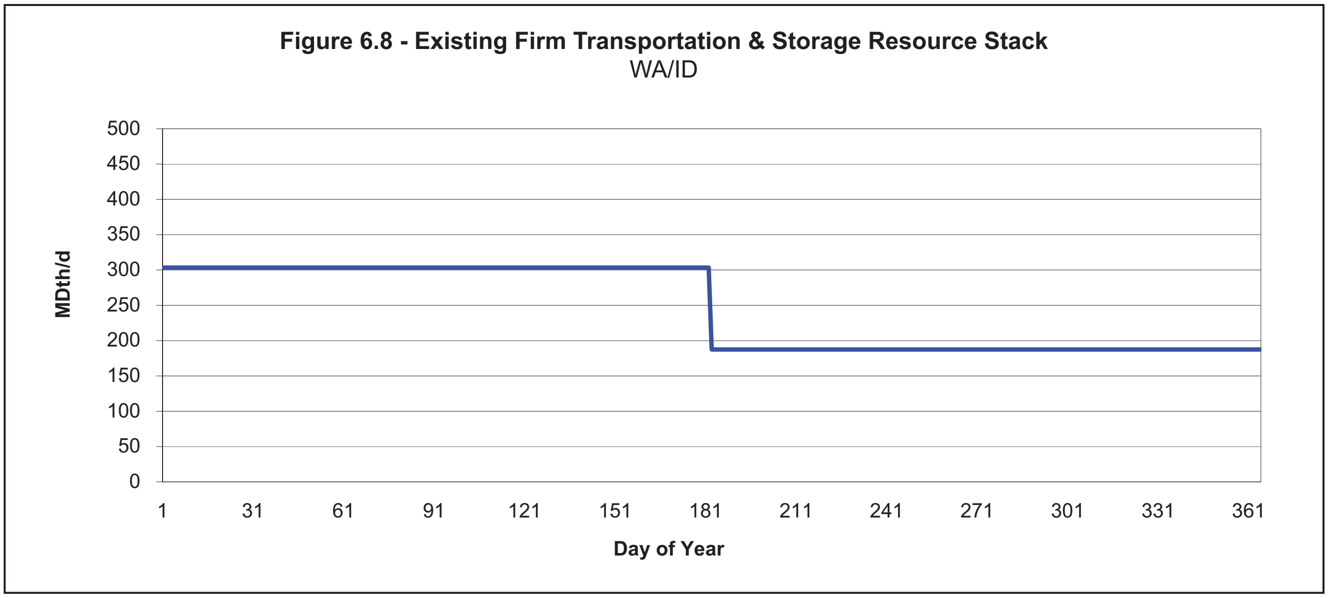
The actual HDDs by area and by day entered into SENDOUT® can be found in Appendix 6.1.

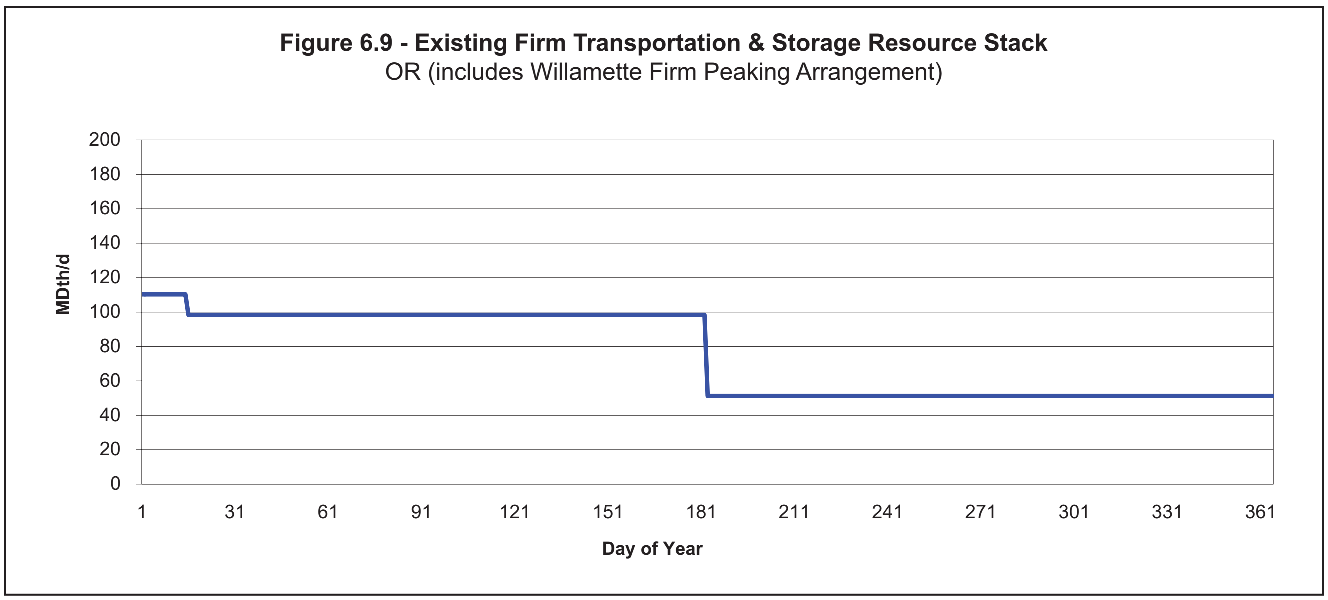
As discussed earlier, we intend to review our peak day weather planning standard to consider whether or not modifications are appropriate. Results and any potential changes will be incorporated in our next IRP. However, one preliminary analysis assessed the relationship between peak day load and the change in 1 HDD which showed that the peak day unserved demand is pushed out one year in each area. Table 6.1 shows the planning standard heating degree-days, the peak day volume by area, and the change between scenarios for the gas year 2011-2012. This is the first year we have unserved demand, in one region, in our Expected Case. This information provides a baseline to understand quantitatively the load implications on each of our service areas for further analysis.

Table 6.1 - Planning Standard Review

2011-2012	Klam Falls	LaGrande	Medford	Roseburg	WA/ID
Planning Standard HDD	72	74	61	55	82
Peak Day Volume	15.15	10.11	65.44	18.03	291.17
Plus One HDD					
Peak Day Volume	15.34	10.24	66.47	18.34	294.48
Change from Standard	0.20	0.13	1.03	0.31	3.31
Plus Two HDD					
Peak Day Volume	15.54	10.37	67.46	18.64	297.78
Change from Standard	0.39	0.26	2.02	0.61	6.61
Less One HDD					
Peak Day Volume	14.96	9.98	64.48	17.74	287.87
Change from Standard	(0.19)	(0.13)	(0.96)	(0.29)	(3.30)
Less Two HDD					
Peak Day Volume	14.76	9.85	63.49	17.44	284.57
Change from Standard	(0.38)	(0.26)	(1.95)	(0.59)	(6.60)

*Removing one HDD moves the unserved demand out one year in each area.





TRANSPORTATION AND STORAGE

Avista's existing transportation and storage resources are described in the Supply-Side Resource chapter (summarized in Table 5.1) and are represented by the firm resource duration curves depicted in Figures 6.8 and 6.9. We consider these firm transportation and storage resources as the starting point for SENDOUT® infrastructure. When modeling future transportation and storage rates, we modified existing rates (summarized in Table 5.2) for expected rate increases and then escalated these rates at the Global Insight inflation rate (see Appendix 6.1). The expected rate increases are based on industry discussions regarding representative pipeline rate cases.

DEMAND-SIDE MANAGEMENT

As discussed in the DSM Chapter, the identification and total resource characterization of available natural gas efficiency measures allows the construction of a natural gas DSM supply curve. This supply curve is a

Figure 6.10 - WA/ID DSM Supply Curve, 2007 / 2008
Representing 63 evaluated non-site-specific measures
Excluding 27 "red" measures that failed preliminary evaluation

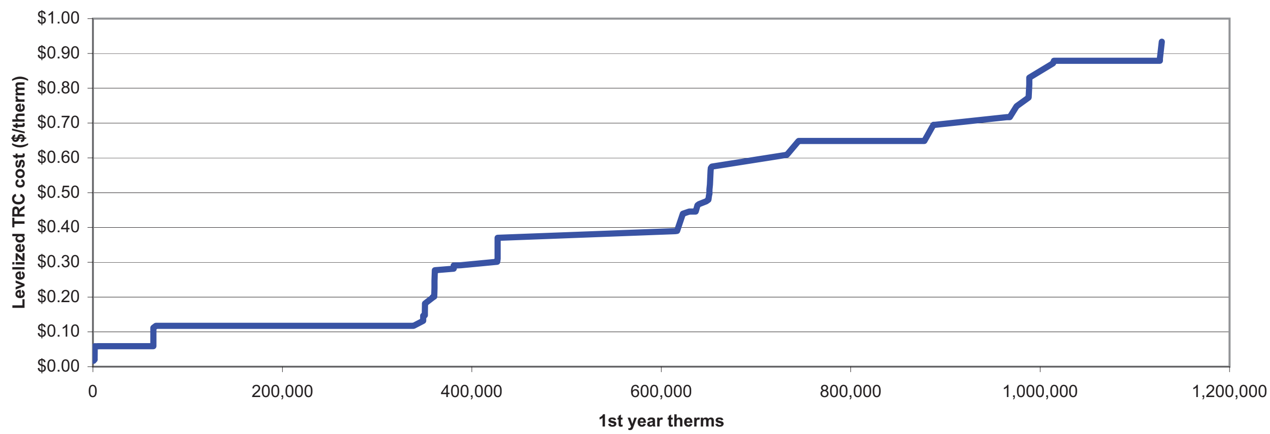
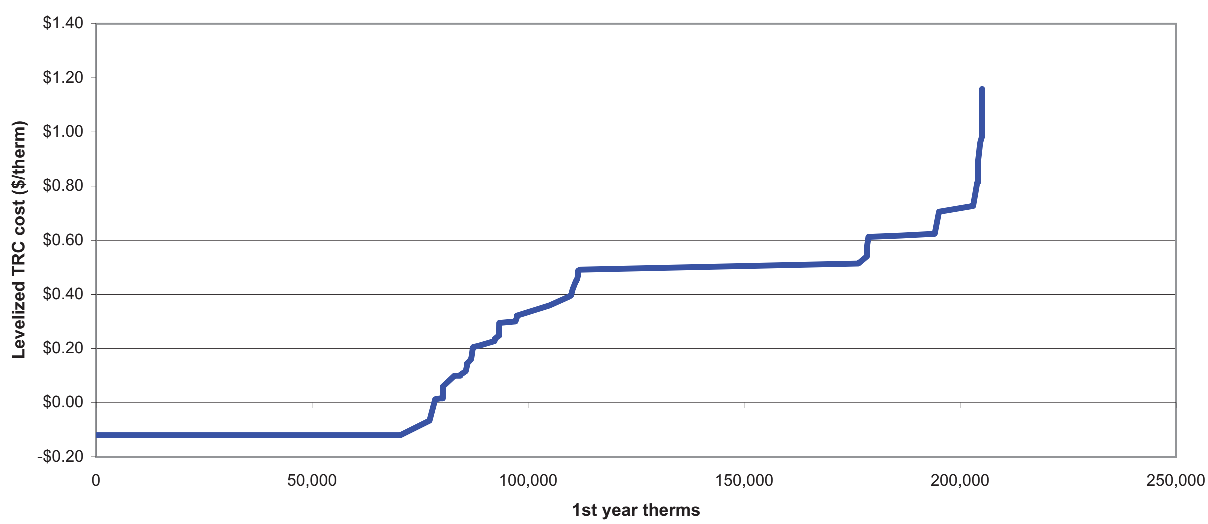


Figure 6.11 - OR DSM Supply Curve, 2007 / 2008
Representing 63 evaluated non-site-specific measures
Excluding 27 "red" measures that failed preliminary evaluation



graphical depiction of the measures in ascending order of total resource cost. The horizontal axis indicates the cumulative resources obtainable at or below that cost. Supply curves are presented for the two divisions (Figures 6.10 and 6.11). These curves represent the cumulative therms of the evaluated measures stacked in ascending order of TRC cost.

SELECTED MEASURES

The list of individual selected measures is incorporated in Appendix 6.9 of this document. Future implementation planning efforts will use these measures as a starting point for more detailed planning, but will also investigate other measures that may have failed preliminary evaluation or SENDOUT® modeling. The implementation plan will also allow for consideration of improvements to the program through the definition of tighter target markets, measure packaging, and climatic and geographic differentials throughout the service territory.

The avoided cost developed in this IRP will be the basis for the implementation planning effort. This allows for consideration or modifications to measures.

DSM ACQUISITION GOALS

Avista is committed to acquiring all cost-effective natural gas-efficiency resources achievable through intervention. This IRP has provided the opportunity for a comprehensive assessment of efficiency opportunities in an analysis that integrates supply-side options as well.

- ***Washington/Idaho DSM Goals***

  Changes in technical opportunities and avoided costs have driven the potential identified in this IRP substantially beyond the 1,062,000 therm level developed in the prior IRP. The proposal for constraining annual growth in the goal to an 11 percent increase, to prevent undue increases in utility acquisition costs, results in a calendar year 2008 goal of 1,425,000 therms. Continuing the 11 percent annual growth rate results in the full acquisition of the identified potential over a 10-year planning cycle.

  Achievement of a persistent 11 percent annual increase in acquisition is likely to require revisions to the Schedule 190 tariff governing natural gas DSM operations. Incentive levels, incentive caps and applicable measures and markets may need to be reviewed to support an implementation plan capable of achieving these long-term goals.

  Other revisions to regulation, infrastructure or DSM operations are likely to be identified in future planning efforts. The company is committed to pursuing a more rapid ramp-up of acquisition if it can be achieved without an undue increase in utility acquisition costs.

- ***Oregon DSM Goals***

  Based on the analysis in this IRP, we believe that a cost-effective annual acquisition of 350,000 first-year therms is achievable through intervention. The identification of this goal does not preclude the addition of other resources that may be identified as cost-effective during later analysis, nor does it preclude the pursuit of unexpected resource acquisition opportunities that may occur between IRP cycles.

NATURAL GAS SUPPLY AVAILABILITY AND PRICING

We attempt to balance the need for both low cost and low volatility with high reliability in our natural gas procurement efforts. The chapter on Supply-Side Resources
describes supply options available to the company.

Regional and national natural gas prices have experienced increased volatility since 2005. Geopolitical and global supply/demand issues have continued to influence oil price volatility and, consequently, natural gas prices given their often correlated relationship. Demand growth, natural gas for electric generation, hurricane activity and other weather events are believed to be some of the reasons for the increased gas price volatility. The industry has also generally observed higher gas price levels since 2005. This new gas price floor stems from the tight production and productive capacity balance, as well as increasing exploration and production costs.

Many factors influence natural gas pricing and volatility in addition to the factors cited above. Examples include regional supply/demand issues, local, regional and national weather, hurricanes/storms or threats of them, storage levels, fuel needs for gas fired generation, infrastructure disruptions, and infrastructure additions (e.g. new pipelines and LNG terminals). Although we monitor these influences on an ongoing basis, we do

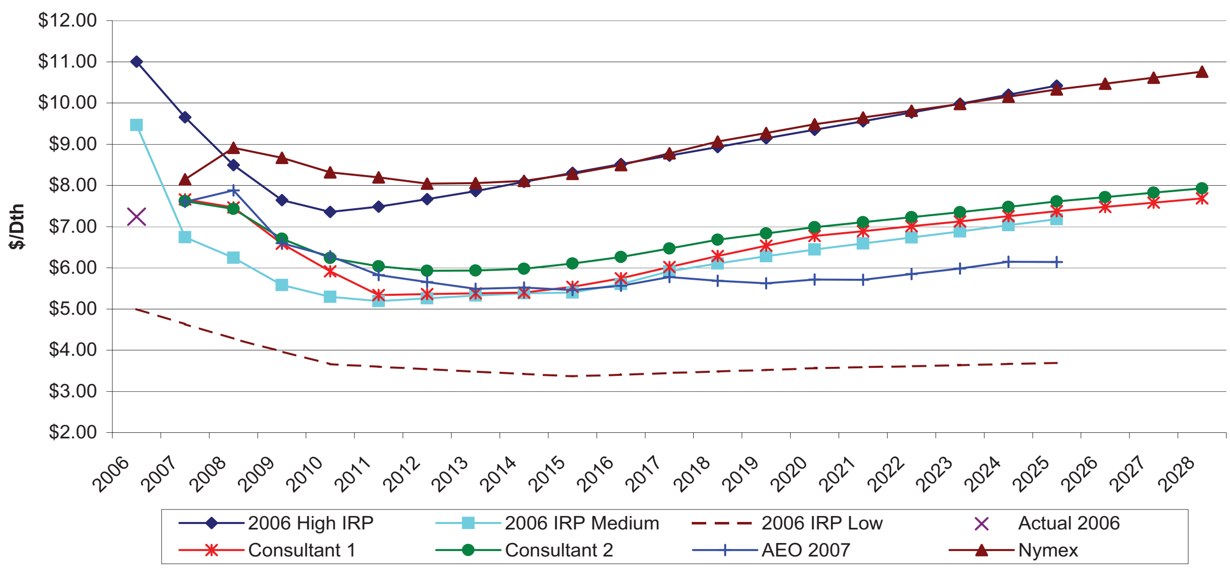


Figure 6.12 - Henry Hub Forward Prices
2006 IRP vs. Current Forecasts
2005$/Dth

not believe that we can accurately predict future prices for the 20-year horizon of this IRP. We have reviewed a variety of price forecasts provided by credible sources and have selected high, medium and low price forecasts to represent the realm of reasonable pricing possibilities. Figure 6.12 depicts the selected price forecasts.

As Figure 6.12 shows, there are many price forecasts with a large variation in overall price levels. Although some of these forecasts are more likely than others, most of them are plausible. Therefore, with the assistance and concurrence of the TAC Committee, we selected high, medium and low price curves to consider possible

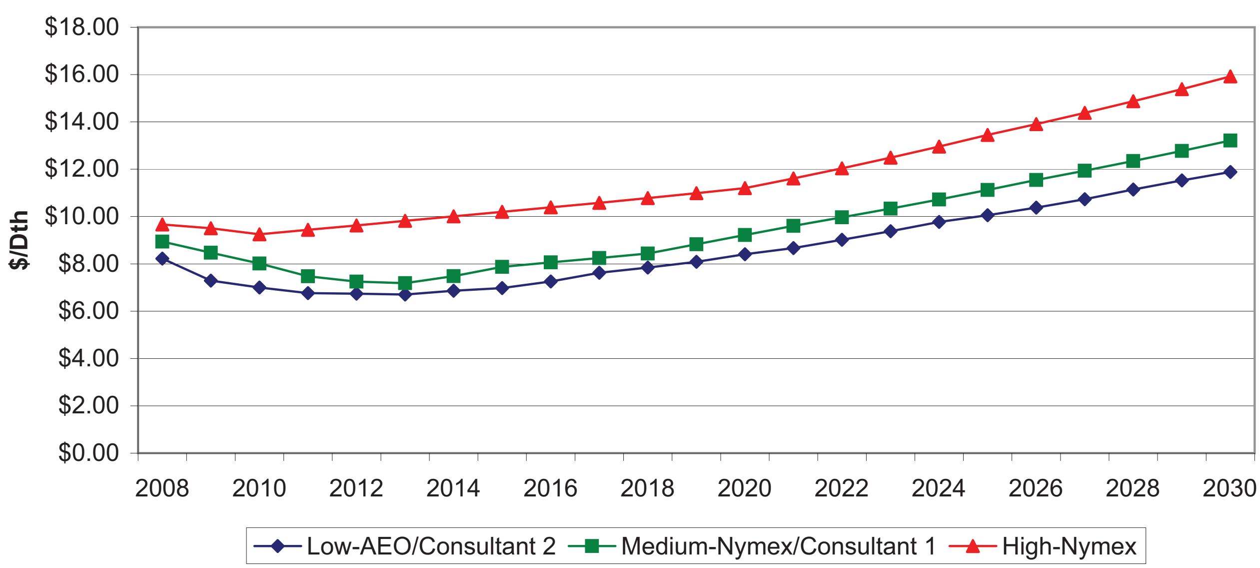
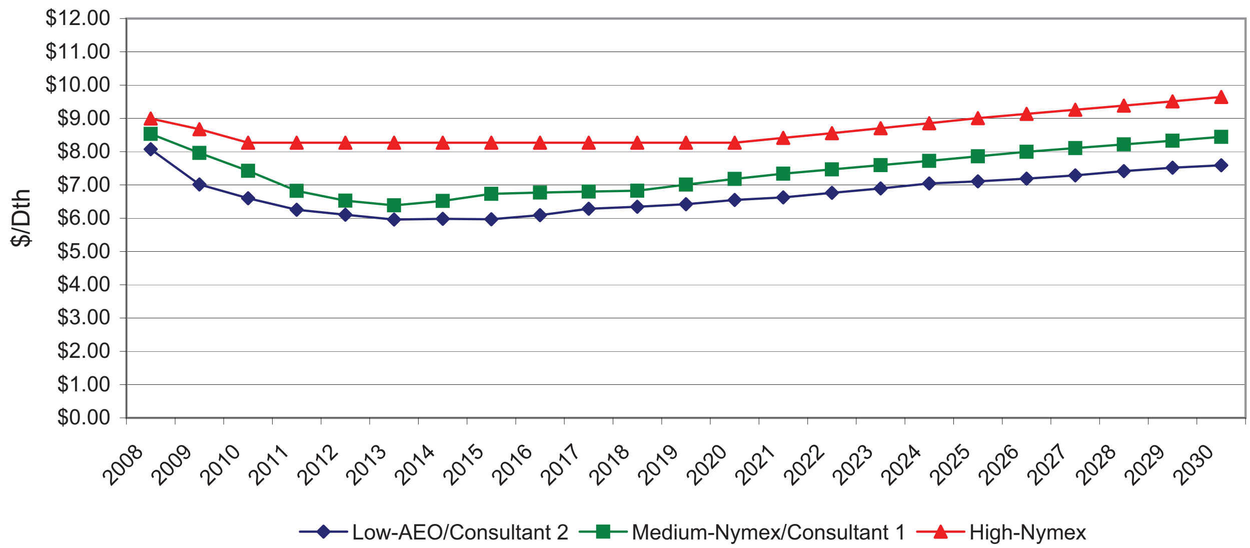


Figure 6.13 - Henry Hub Forward Prices for Avista 2007 IRP
Nominal $/Dth

Figure 6.14 - Henry Hub Forward Prices for Avista 2007 IRP
2007$/Dth



outcomes and the impact that this volatile and high pricing environment might have on planning. These curves are shown in nominal dollars in Figure 6.13 and real dollars in Figure 6.14.

Each of the forecasts illustrated above are at the Henry Hub, which is located in Louisiana just onshore from the Gulf of Mexico. It is the physical location that is widely recognized as the most important pricing point in the United States because of the sheer volume traded on a daily and a spot basis, a forward basis and its proximity to a large portion of United States production. All other producing and market area-pricing points tend to be set off of the Henry Hub as is the New York Mercantile Exchange's (NYMEX) trading hub for futures contracts. Although the Henry Hub influences natural gas prices in the United States and the Pacific Northwest, the physical supply points Sumas, Wash., AECO Alberta, Canada, and the U.S. Rockies ultimately determines Avista's costs. Pricing of these points is set or based upon Henry Hub, although they typically trade at a discount. This discount is commonly referred to as the basis differential. Some of the reasons for the basis differential are a more favorable supply/demand balance in the West, closer physical proximity to these supplies and longer distance from the big demand centers in the Eastern United States.

Since most price forecasters do not forecast regional pricing points, we estimate the basis differential between Henry Hub and the pricing points on which the company relies. As discussed at the TAC meetings, we believe that an average of the most recent differentials is an appropriate estimate of basis differentials, because recent history better represents the current structure of the natural gas market. This structure may change particularly out of the U.S. Rockies producing region; however, at this point in time, it is the best predictor of future differentials. We have adopted Table 6.2 showing the percentage of Henry Hub, for AECO, Sumas and Rockies pricing points. We calculated these percentages by comparing the actual monthly index prices from

Table 6.2 - Basis Differential Assumptions

Pricing Point	AECO	Sumas	Rockies
Percentage	86.0%	87.6%	80.5%

Table 6.3 - Monthly Pricing Allocation

January	February	March	April	May	June
113%	113%	110%	93%	92%	93%
July	**August**	**September**	**October**	**November**	**December**
94%	94%	95%	96%	101%	106%

November 2003 through June 2007. The beginning date for this comparison was chosen because of pipeline expansions that went into service in 2003, which were basis altering expansions.

Each price forecast provides annual (not monthly) prices. For modeling purposes, given Avista's heavily winter-weighted demand profile, it is more appropriate to break these annual figures down to monthly figures. As discussed with the TAC, we believe that utilizing available forward price differentials by month is an appropriate way to compute monthly prices. Table 6.3 depicts the monthly shape that we applied to the annual prices in the price curves.

Appendix 6.1 displays the detailed monthly price data as calculated when the Henry Hub price forecasts are incorporated with the basis and seasonal factor adjustments discussed above.

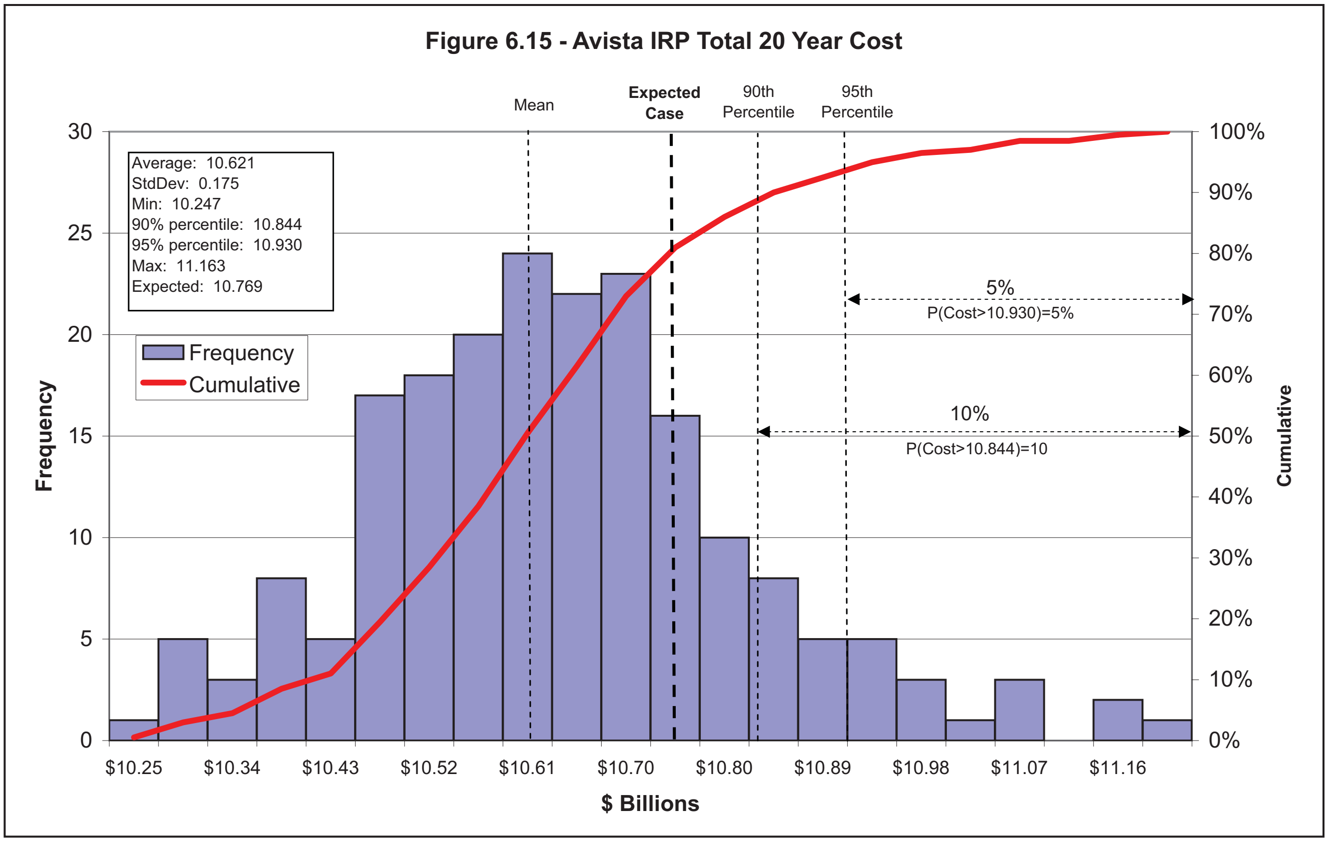
DEMAND FORECASTS AND SENSITIVITIES

As discussed in the Demand Forecast chapter, we have selected three scenarios for detailed analysis to capture a range of possible outcomes over the planning horizon. These scenarios consider the price elasticity effects on the high and low customer growth scenarios. The scenarios are shown in Table 6.4. The customer growth rate figures are further discussed in the Demand Forecast chapter and can be found in Figure 2.1 and Appendix 2.2.

Further demand scenarios can be derived by VectorGas™. By varying the number of heating degree-days by month, differing demand cases can be created. These scenarios can then be run through SENDOUT® to observe how unserved demand varies based on weather. A probability distribution can also be generated showing how likely a particular weather event may be.

Table 6.4 - Demand Scenarios

High Demand Case – High demand and low price scenario. 50% increase in customer growth and a price elasticity adjustment to demand coefficients (-.13).	**Expected Case** – Base demand and mid price scenario. Static use per customer over the planning horizon.	**Low Demand Case** – Low demand and high price scenario. 50% decrease in customer growth and a price elasticity adjustment to demand coefficients (-.13).

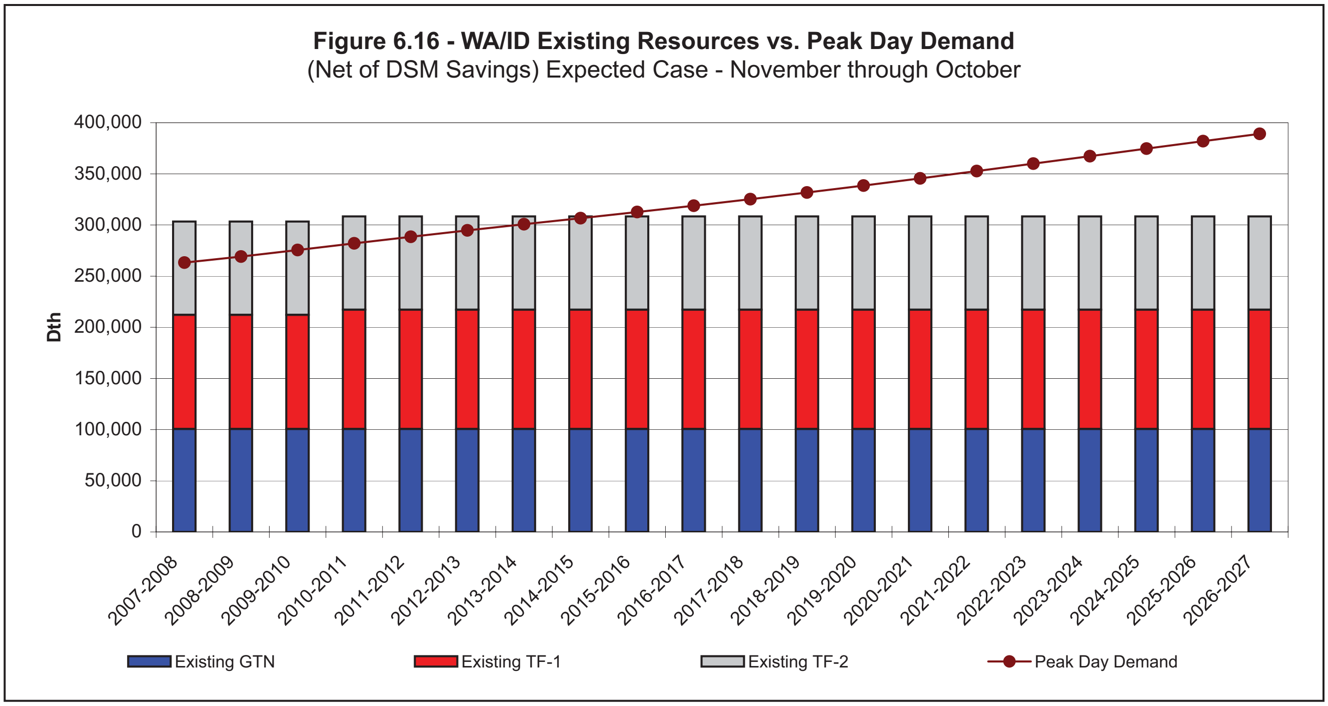


PRELIMINARY RESULTS

Based on our analysis and feedback from the TAC, we generated results from SENDOUT® utilizing expected, High and Low Demand cases and existing transportation and storage resources.

The demand results of these cases are discussed in the Demand Forecast chapter and additional details of these cases are in Appendix 2.4. We believe that these cases explore the realm of reasonable outcomes while minimizing the number of cases analyzed all the way through the conclusion of this IRP process. As we further integrate VectorGas™ into our planning process we will be able to better understand risks around price and weather. We will also be able to determine the frequency of our chosen resource mix.

Through our preliminary use of VectorGas™ a simulation of 200 draws on price alone revealed that the Expected Case total portfolio costs are within the range of occurances. Figure 6.15 shows a histogram of the total portfolio cost of all 200 draws, plus the Expected Case results. This histogram depicts the frequency the total cost of the portfolio occurred among all the draws, the mean of the draws, the standard deviation of the total costs, as well as the total costs from the Expected Case. The figure shows that our Expected Case is within an acceptable range of total costs based on 200 unique pricing scenarios.



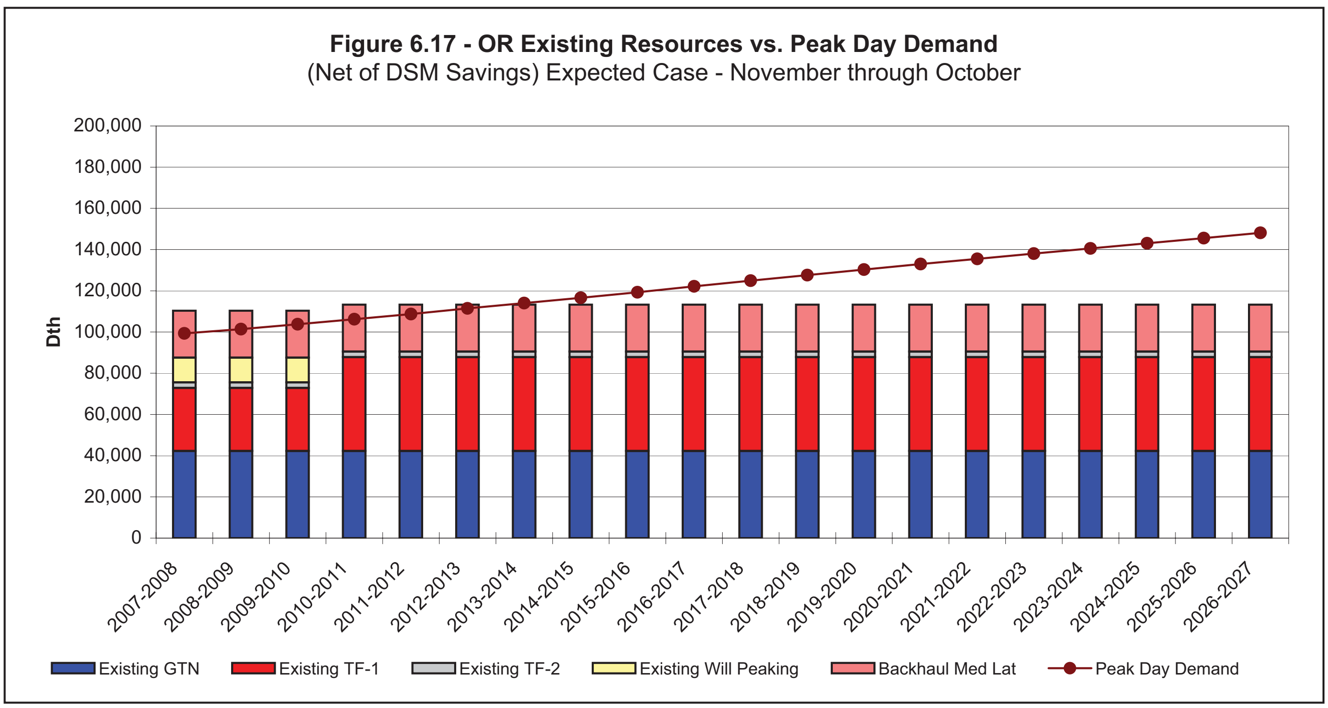


Figure 6.16 and 6.17 graphically represent a regional summary of Expected Case peak day demand compared to existing resources. This comparison shows, on a regional basis, when and how much the company is deficient over the planning horizon. Similar figures for the Low and High Demand cases can be found in Appendix 6.2.

It is important to note that this summarized approach can mask regional deficiencies. Therefore, we prepared

Table 6.5 to provide service area detail which identifies when the company first becomes resource constrained and the amount of that deficiency on that region's peak day. This table also shows the growth in deficiencies over time. Similar figures for the Low and High Demand cases are in Appendix 6.3.

Each case depicts at least one deficiency in at least one demand area during the planning horizon with the first shortages occurring in our smaller service areas. Given that we do not anticipate resource shortages until at least the 2010/2011 heating season in the High Demand case, and given that the Expected Case is not deficient until the 2011/2012 heating season, we have sufficient time to carefully plan and take action on resource additions. Further, the Low Demand case has no resource deficiency until 2019-2020. For this IRP, we attempted to identify all reasonable resource options, given current

Table 6.5 - Peak Day Demand - Served and Unserved (MDth/d)
Before Resource Additions & Net of DSM Savings

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	WA/ID Served	WA/ID Unserved	WA/ID Total
Expected	2007-2008	9.72	-	9.72	263.22	-	263.22
Expected	2008-2009	9.82	-	9.82	269.18	-	269.18
Expected	2009-2010	9.91	-	9.91	275.54	-	275.54
Expected	2010-2011	10.01	-	10.01	282.09	-	282.09
Expected	2011-2012	10.11	-	10.11	288.51	-	288.51
Expected	2012-2013	10.23	-	10.23	294.69	-	294.69
Expected	2013-2014	10.25	0.08	10.33	300.72	-	300.72
Expected	2014-2015	10.25	0.21	10.46	306.60	0.08	306.68
Expected	2015-2016	10.25	0.35	10.60	306.58	6.14	312.72
Expected	2016-2017	10.25	0.47	10.72	306.57	12.22	318.79
Expected	2017-2018	10.25	0.59	10.84	306.61	18.60	325.20
Expected	2018-2019	10.25	0.69	10.95	306.66	25.06	331.72
Expected	2019-2020	10.25	0.81	11.07	305.85	32.68	338.52
Expected	2020-2021	10.25	0.92	11.17	304.98	40.56	345.54
Expected	2021-2022	10.25	1.02	11.27	304.12	48.56	352.69
Expected	2022-2023	10.25	1.11	11.36	303.29	56.72	360.01
Expected	2023-2024	10.25	1.20	11.46	302.47	64.84	367.30
Expected	2024-2025	10.25	1.29	11.55	301.64	73.01	374.65
Expected	2025-2026	10.25	1.37	11.62	300.80	81.10	381.90
Expected	2026-2027	10.25	1.46	11.72	300.00	89.09	389.09

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg WA/ID Total
Expected	2007-2008	13.86	-	13.86	75.77	-	75.77
Expected	2008-2009	14.15	-	14.15	77.48	-	77.48
Expected	2009-2010	14.46	-	14.46	79.43	-	79.43
Expected	2010-2011	14.79	-	14.79	81.41	-	81.41
Expected	2011-2012	15.03	0.11	15.15	83.47	-	83.47
Expected	2012-2013	15.03	0.45	15.48	85.76	-	85.76
Expected	2013-2014	15.03	0.75	15.78	87.24	0.68	87.92
Expected	2014-2015	15.03	1.06	16.09	87.24	2.81	90.05
Expected	2015-2016	15.03	1.39	16.42	87.24	5.06	92.30
Expected	2016-2017	15.03	1.73	16.76	87.24	7.43	94.67
Expected	2017-2018	15.03	2.07	17.10	87.24	9.77	97.01
Expected	2018-2019	15.03	2.40	17.43	87.24	12.00	99.24
Expected	2019-2020	15.03	2.71	17.74	87.24	14.24	101.48
Expected	2020-2021	15.03	3.04	18.07	87.24	16.49	103.73
Expected	2021-2022	15.03	3.35	18.38	87.24	18.63	105.87
Expected	2022-2023	15.03	3.67	18.70	87.24	20.76	108.00
Expected	2023-2024	15.03	3.98	19.02	87.24	22.88	110.12
Expected	2024-2025	15.03	4.30	19.33	87.24	24.98	112.22
Expected	2025-2026	15.03	4.62	19.66	87.24	27.07	114.31
Expected	2026-2027	15.03	4.95	19.98	87.24	29.19	116.43

information, and used the SENDOUT® model to pick the least cost incremental resources.

NEW RESOURCE OPTIONS

When researching resource options, the following considerations are important in determining the appropriateness of potential resources.

Resource Cost

Resource cost is our primary consideration when evaluating resource options although other considerations 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 term 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 anywhere from one to as many as 10 or more years to put in service. Open season processes, planning and permitting, environmental review, design, construction and testing are some of the many aspects that contribute to lead-time requirements for new physical facilities. Recalls of storage or transportation release capacity typically require advance notice of up to two years. Even DSM programs require significant time from program rollout to the point when natural gas savings are realized.

Peak versus Base Load

Our planning efforts include the ability to serve a design or peak day as well as all other demand periods. The company'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. 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

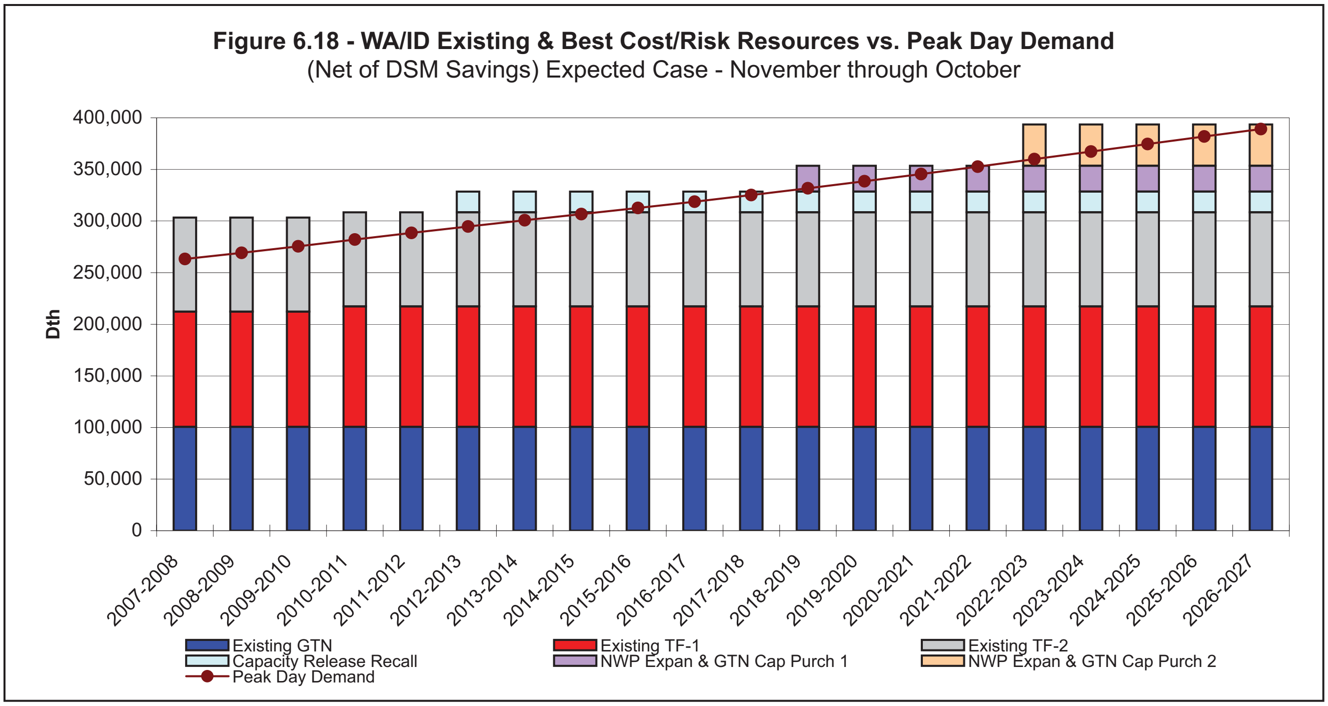
It is paramount that an available resource effectively delivers natural gas to the intended geographical region. Given Avista's separate service territories, it is often impossible to deliver resources from an option such as storage without acquiring additional pipeline transportation.

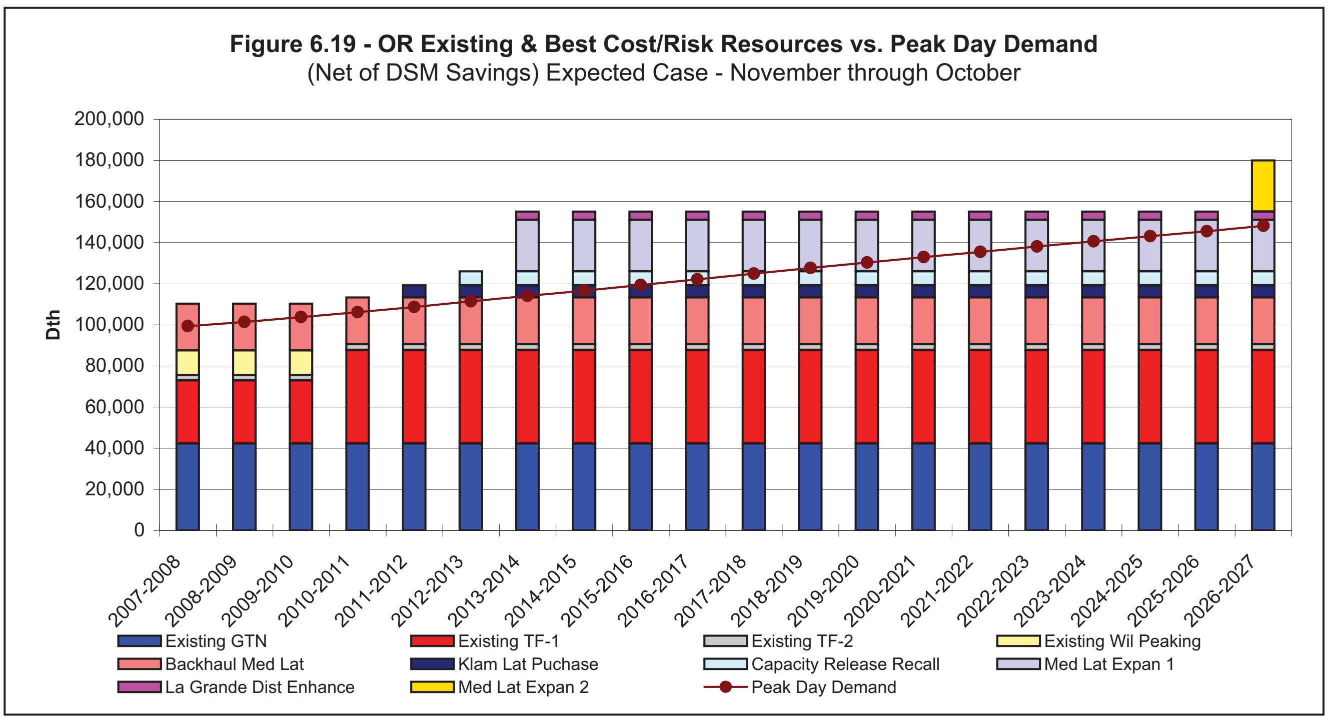
"Lumpiness" of Resource Options

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 resource lumpiness 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 only every few years. This lumpiness provides a cushion for future growth. Given the economy of scale for pipeline construction costs, we are afforded the opportunity to assure that resources are in place to serve future increases in demand.

RESULTS – PORTFOLIO INTEGRATION

After identifying resource options and evaluating them based on the considerations detailed earlier in this chapter (i.e. lead-time, peak vs. base, usefulness, etc.), we focused on how to cost effectively solve resource constraints for the Expected, High and Low Demand cases. In order to answer this question, we entered the risk assessed resource options as described in Chapters 3 and 5 and further detailed in Appendix 6.4, 6.9 and 6.10 into the SENDOUT® model to pick the least cost





approach to meeting resource deficiencies. SENDOUT® compares demand-side and supply-side resources and determines, based on a PVRR analysis, which resource is the least cost.

Figures 6.18 and 6.19 summarize the results of this modeling effort by comparing regional peak day demand against existing and incremental resources for the Expected Case over the 20-year period of the plan.

Figure 6.20 - Load Duration Curve & Resource Stack (with DSM) Average/Actual Weather w/Peak Day
Expected Case - WA/ID

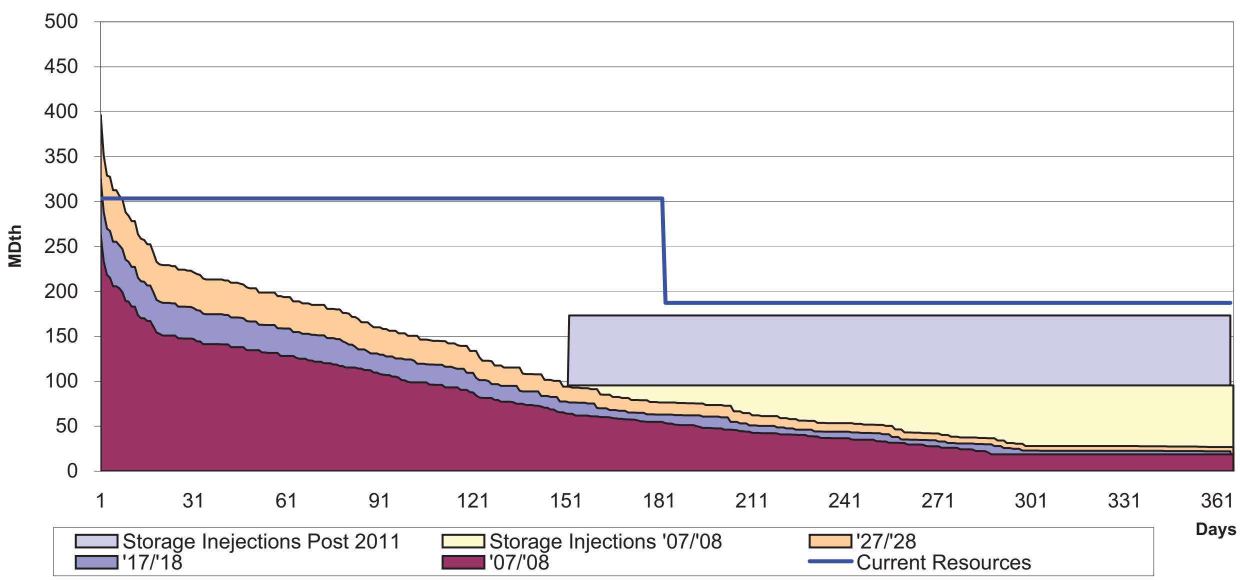
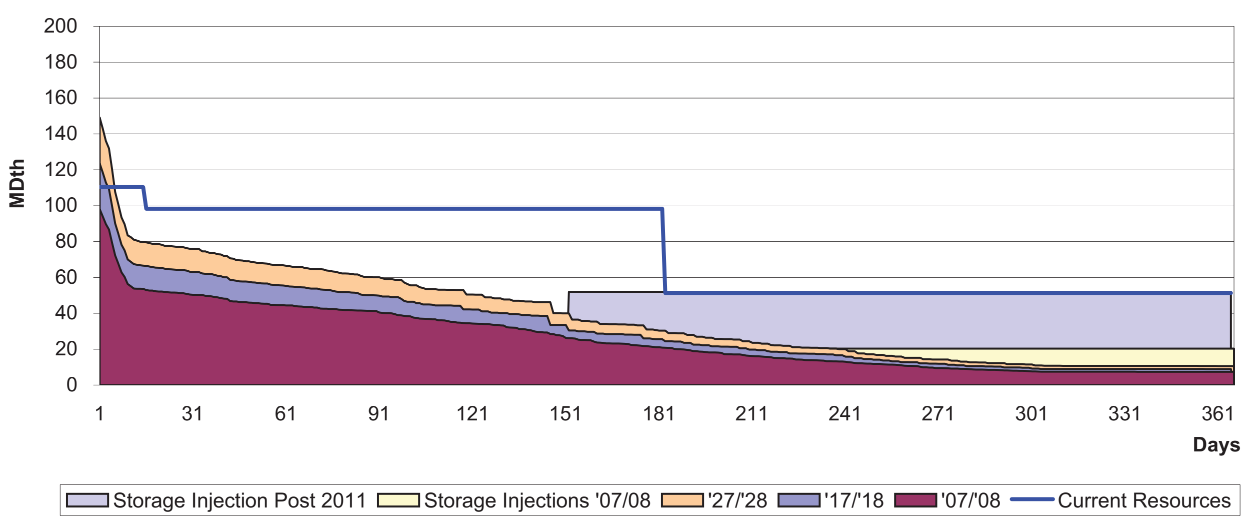


Figure 6.21 - Load Duration Curve & Resource Stack (with DSM) Average/Actual Weather w/Peak Day
Expected Case - OR



Companion figures for the High and Low Demand cases are available in Appendix 6.5.

Figures 6.20 and 6.21 show the load duration curves as well as the current resource stack for the Expected Case. These graphics compare an entire year of demand to the resource stack for that same year. This enables a review of not just peak day sufficiency but allows the opportunity to compare all demand days within that year. Although it appears that there is excess capacity during the non-winter periods, the company utilizes this capacity for storage injections and optimization through capacity releases and buy/sell opportunities. Similar figures for the High and Low Demand cases are in Appendix 6.6.

Table 6.6 - Least Cost Supply-Side Resource Additions Selected by SENDOUT®

Expected Case

Item #	Region	Type	Quantity Dth/d	Timing	Rates/Charges	Notes
Washington/Idaho						
1	WA/ID	Capacity Release	20,078	November 2012	NWP Rate	Capacity out for release is returned back for utility use.
2	WA/ID	Transportation	25,000	November 2018	$4.0 MM Capital Cost Plus Commodity and NWP Transportation Rate	WA/ID area expansions to facilitate the delivery in and around Spokane, Lewiston, etc. from GTN into NWP.
3	WA/ID	Transportation	25,000	November 2018	TransCanada and GTN Transportation Rates Plus Commodity	Provides delivery to Item #2.
4	WA/ID	Transportation	40,000	November 2022	$6.5 MM Capital Cost Plus Commodity and NWP Transportation Rate	WA/ID area expansions to facilitate the delivery in and around Spokane, Lewiston, etc. from GTN into NWP.
5	WA/ID	Transportation	40,000	November 2022	TransCanada and GTN Transportation Rates Plus Commodity	Provides delivery to Item #4
Oregon						
6	OR	Capacity Release	6,700	November 2012	NWP Rate	Capacity out for release is returned back for utility use.
7	Klamath Falls	Purchase	n/a	November 2011	$3MM Capital Cost	Purchase of NWP Klamath pipeline segment. Transportation and fuel cost savings more than offset the revenue requirement and capital cost of the investment. Payoff is approximately 3 years.
8	Klamath Falls	Reclassification	6,000	November 2011	No Incremental Charges	Companion to Item #7. Ownership of lateral allows Avista to operate this lateral as distribution transmission system which provides aproximately. 6,000 Dth/d incremental capacity.
9	Medford/Roseburg	Distribution Enhancement	n/a	November 2013	$14.2MM Capital Cost/$1.9MM Annual Revenue Requirement	Companion item to Item #10 and #12 below.
10	Medford/Roseburg	Transportation	25,000	November 2013	GTN's Med. Lat. Rate	GTN expansion of the Medford Lateral. Assumed current lateral rates, escalated for inflation, for expansion. Item #9 above required to facilitate this option.
11	La Grande	Distribution Enhancement	4,000	November 2013	$3MM Capital Cost/$.420MM Annual Revenue Requirement	
12	Medford/Roseburg	Transportation	25,000	November 2026	GTN's Med. Lat. Rate	GTN expansion of the Medford Lateral. Assumed current lateral rates, escalated for inflation, for expansion. Item #9 above required to facilitate this option.

SENDOUT® considers all resource options (both demand-side and supply-side) entered into the program, determines when and what resources are needed, and rejects options that are not cost effective. These selected resources represent the least cost solution, within given constraints, to serve anticipated customer requirements. Table 6.6 shows the SENDOUT® selected supply-side resources for the Expected Case. Table 6.7 shows the SENDOUT® selected DSM savings for the Expected Case. The High and Low Demand case duration curves can be found in Appendix 6.6 while DSM savings are in Appendix 6.8.

Through ongoing and evolving investigation and research, we may determine that alternative resources are more cost effective than those resources selected in this IRP. We will continue to review and refine our knowledge of resource options and will act to secure these best cost/risk options at the appropriate point in time.

Table 6.7 - Annual Demand, Annual Average Demand and Peak Day Demand
Served by Demand-Side Management

Case	Gas Year	Annual Klamath DSM (MDth)	Daily Klamath DSM (MDth/day)	Peak Day Klamath DSM (MDth/day)	Annual La Grande DSM (MDth)	Daily La Grande DSM (MDth/day)	Peak Day La Grande DSM (MDth/day)	Annual Medford DSM (MDth)	Daily Medford DSM (MDth/day)	Peak Day Medford DSM (MDth/day)	Annual Roseburg DSM (MDth)	Daily Roseburg DSM (MDth/day)	Peak Day Roseburg DSM (MDth/day)
Expected	2007-2008	3.589	0.010	0.030	1.695	0.005	0.010	11.117	0.030	0.080	3.112	0.009	0.020
Expected	2008-2009	7.408	0.020	0.050	3.381	0.009	0.020	22.142	0.060	0.170	6.202	0.017	0.040
Expected	2009-2010	11.112	0.030	0.080	5.072	0.014	0.040	33.214	0.091	0.250	9.303	0.025	0.060
Expected	2010-2011	14.816	0.041	0.100	7.044	0.019	0.050	44.285	0.121	0.330	12.404	0.034	0.080
Expected	2011-2012	18.580	0.051	0.130	8.829	0.024	0.060	55.584	0.152	0.410	15.561	0.043	0.100
Expected	2012-2013	22.223	0.061	0.150	10.566	0.029	0.080	66.427	0.182	0.500	18.607	0.051	0.120
Expected	2013-2014	25.927	0.071	0.180	12.327	0.034	0.090	77.644	0.213	0.580	21.708	0.059	0.150
Expected	2014-2015	29.789	0.081	0.210	14.695	0.040	0.110	92.751	0.253	0.680	25.609	0.070	0.170
Expected	2015-2016	32.318	0.089	0.230	15.868	0.043	0.120	104.962	0.288	0.760	27.237	0.075	0.180
Expected	2016-2017	34.645	0.095	0.250	16.937	0.046	0.130	110.941	0.304	0.830	28.610	0.078	0.200
Expected	2017-2018	37.091	0.101	0.270	18.063	0.049	0.140	117.471	0.321	0.900	30.109	0.082	0.220
Expected	2018-2019	39.481	0.108	0.290	19.181	0.053	0.150	125.588	0.344	0.990	31.605	0.087	0.230
Expected	2019-2020	42.011	0.115	0.320	20.359	0.056	0.160	132.596	0.363	1.060	33.179	0.091	0.250
Expected	2020-2021	44.125	0.121	0.340	21.356	0.058	0.170	137.980	0.377	1.130	35.662	0.097	0.280
Expected	2021-2022	48.821	0.134	0.380	22.407	0.061	0.180	143.930	0.394	1.200	37.075	0.102	0.300
Expected	2022-2023	51.104	0.140	0.410	23.383	0.064	0.190	149.423	0.409	1.270	38.385	0.105	0.320
Expected	2023-2024	53.570	0.147	0.430	24.424	0.067	0.210	155.608	0.426	1.340	39.853	0.109	0.330
Expected	2024-2025	55.672	0.152	0.450	25.334	0.069	0.220	160.410	0.438	1.410	41.006	0.112	0.350
Expected	2025-2026	57.956	0.159	0.480	26.309	0.072	0.230	165.904	0.455	1.480	42.316	0.116	0.370
Expected	2026-2027	60.221	0.165	0.500	27.280	0.075	0.240	171.243	0.469	1.550	43.603	0.119	0.380
Expected	2027-2028	62.673	0.171	0.520	28.324	0.077	0.250	183.044	0.500	1.620	45.051	0.123	0.390

Case	Gas Year	Annual Oregon DSM (MDth)	Daily Oregon DSM (MDth/day)	Peak Day Oregon DSM (MDth/day)	Annual WA/ID DSM (MDth)	Daily WA/ID DSM (MDth/day)	Peak Day WA/ID DSM (MDth/day)	Annual Total System DSM (MDth)	Daily Total System DSM (MDth/day)	Peak Day Total System DSM (MDth/day)
Expected	2007-2008	19.513	0.053	0.140	67.664	0.185	0.470	87.177	0.239	0.610
Expected	2008-2009	39.134	0.107	0.280	134.837	0.368	0.930	173.971	0.475	1.210
Expected	2009-2010	58.701	0.161	0.430	202.255	0.554	1.400	260.956	0.715	1.830
Expected	2010-2011	78.549	0.215	0.560	269.674	0.739	1.860	348.223	0.954	2.420
Expected	2011-2012	98.554	0.269	0.700	338.321	0.924	2.330	436.875	1.194	3.030
Expected	2012-2013	117.824	0.323	0.850	500.544	1.371	3.900	618.368	1.694	4.750
Expected	2013-2014	137.606	0.377	1.000	694.854	1.904	5.770	832.461	2.281	6.770
Expected	2014-2015	162.845	0.445	1.170	881.620	2.409	7.510	1,044.465	2.854	8.680
Expected	2015-2016	180.385	0.494	1.290	1,020.652	2.796	8.720	1,201.038	3.291	10.010
Expected	2016-2017	191.134	0.524	1.410	1,155.248	3.165	9.980	1,346.381	3.689	11.390
Expected	2017-2018	202.734	0.554	1.530	1,232.522	3.368	10.790	1,435.256	3.921	12.320
Expected	2018-2019	215.855	0.591	1.660	1,309.797	3.588	11.600	1,525.652	4.180	13.260
Expected	2019-2020	228.145	0.625	1.790	1,392.710	3.816	12.410	1,620.854	4.441	14.200
Expected	2020-2021	239.124	0.653	1.920	1,464.292	4.001	13.210	1,703.415	4.654	15.130
Expected	2021-2022	252.232	0.691	2.060	1,541.539	4.223	14.020	1,793.772	4.914	16.080
Expected	2022-2023	262.296	0.719	2.190	1,617.415	4.431	14.830	1,879.711	5.150	17.020
Expected	2023-2024	273.454	0.749	2.310	1,700.313	4.658	15.630	1,973.767	5.408	17.940
Expected	2024-2025	282.422	0.772	2.430	1,762.283	4.815	16.420	2,044.705	5.587	18.850
Expected	2025-2026	292.485	0.801	2.560	1,831.275	5.017	17.200	2,123.760	5.819	19.760
Expected	2026-2027	302.348	0.828	2.670	1,900.267	5.206	17.990	2,202.615	6.035	20.660
Expected	2027-2028	319.092	0.872	2.780	1,956.491	5.346	18.770	2,275.584	6.217	21.550

REGULATORY REQUIREMENTS

IRP regulatory requirements in Washington, Oregon and Idaho require several key components in our plan. We must demonstrate we have:

- examined a range of demand forecasts;
- examined feasible means of meeting demand including both supply-side and demand-side resources;
- treated supply-side and demand-side resources equally;
- described our long term plan for meeting expected load growth;
- described our plan for resource acquisitions between planning cycles;
- taken planning uncertainties into consideration; and
- involved the public in the planning process.

Throughout this document, we have addressed the applicable requirements. Recent rulemaking in Oregon has provided further guidance. Order UM 1056 outlines

13 guidelines where we must demonstrate we have addressed the following areas:

- Substantive requirements
- Procedural guidelines
- Plan filing, review and updates
- Plan components
- Transmission (Transportation)
- Conservation
- Demand Response
- Environmental costs
- Direct access loads
- Multi state utilities
- Reliability
- Distributed generation
- Resource acquisition

Appendix 6.11 lists the specific requirements of the guidelines and describes our compliance.

One area that warrants specific discussion is risk and uncertainty. Our approach in addressing this requirement was to identify the factors that could cause significant deviation from our Expected Case planning conclusions. We employed analytical methods for each of our load forecasting assumptions, including use per customer, weather, customer growth rates and price elasticity.

Inadequate consideration or evaluation of these factors could significantly impair the planning process and its effectiveness. We have modeled High and Low Demand alternatives, incorporated price elasticity considerations, performed preliminary analysis on our peak weather planning standard, run simulations in VectorGas™ and integrated customer growth forecasting in distribution planning with town code refinements.

Beyond these direct modeling considerations, we also considered the consequences of insufficient timelines for resource acquisition or development, cost overruns and siting/permitting risks. Infrastructure outages were also identified as a risk area potentially disrupting plan execution. We are exploring ways to better integrate these types of uncertainties into our planning process.

ACTION ITEMS

We will refine our specific resource acquisition action plans for Klamath Falls and Medford service areas that address the projected unserved Expected Case demand in 2011-2012 and 2013-2014, respectively. We will monitor timelines, milestones, status and progress reporting, ongoing plan risk assessment and consideration of alternative actions.

For Klamath Falls we will:

- reassess the necessary operational steps and timing (current estimate six months) to acquire the Klamath Falls Lateral;
- monitor actual demand trends to forecasted demand to refine a target date for initiating the purchase of the lateral.

For Medford we will:

- commission a pipeline expansion study from GTN to identify specific costs and issues;
- monitor actual demand trends to forecasted demand to refine the timing of action plan steps;
- assess the impacts of project timing from possible changes in our weather planning standard.

We will reevaluate our current peak day weather planning standard to ascertain if it still provides the best risk-adjusted methodology in evaluating resource planning.

We will meet regularly with Commission Staff members to provide information on market activities, any material changes to risk management programs, and significant changes in assumptions and/or status of company activity related to the IRP or procurement practices.

CONCLUSION

We have chosen to utilize the Expected Case for our operational planning activities because this case is the most likely outcome given company experience, industry knowledge and our understanding of future 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 reasonably well protected against resource shortages and does not over commit to additional long-term resources. Given the extreme increase and decrease in demand levels over the full planning horizon for the High and Low Demand cases respectively, we believe that these cases are possible but less likely.

Our resource analysis indicates several strategies that should be pursued to fully optimize available resources. The effectiveness of any strategy will be in the flexibility to take advantage of market opportunities. These strategies indicate that:

- Because of the diverse weather within our service territory, a total system supply portfolio should be maintained to provide the greatest flexibility for dispatching resources while maintaining lower supply costs.
- We will continue to benefit from pursuing diversification of our firm transportation sources via GTN and NWP. Flexibility is the key to be able to cost-effectively utilize the lowest priced delivered supply.
- Capacity releases and recalls, both long-term and short-term, should continue to be reviewed periodically.

We will continue to monitor demand levels and peak day requirements for signposts (e.g. greater than expected customer growth) that indicate that demand levels are moving toward another case. We also plan to aggressively model various potential outcomes around price and weather using VectorGas™ to assess demand implications from these factors. We believe that through this analysis and monitoring process, and given that we have sufficient time before potential resource shortages, there is little chance of being surprised by resource shortages.

7. AVOIDED COST DETERMINATION

Avista's avoided cost estimates represent the marginal cost of natural gas usage incremental to the forecasted demand. In other words, avoided cost is the unit cost to serve the next unit of demand during any given period of time. If demand-side management measures reduce customer demand, the company is able to "avoid" certain commodity and transportation costs. This concept is important to assessing the proper value to demand-side management efforts.

METHODOLOGY

To develop avoided cost figures associated with the reduction of incremental natural gas usage, a demand forecast, existing and future supply-side resources and demand-side resources are required. Avista utilizes the SENDOUT® model data used throughout this IRP to produce avoided cost figures. The company assumes the Expected Case as the appropriate data set for the analysis of avoided costs.

SENDOUT® functionality provides marginal cost data by day, month and year for each demand area. This marginal cost data includes the cost of the next unit of supply and the associated transportation charges to move this unit.

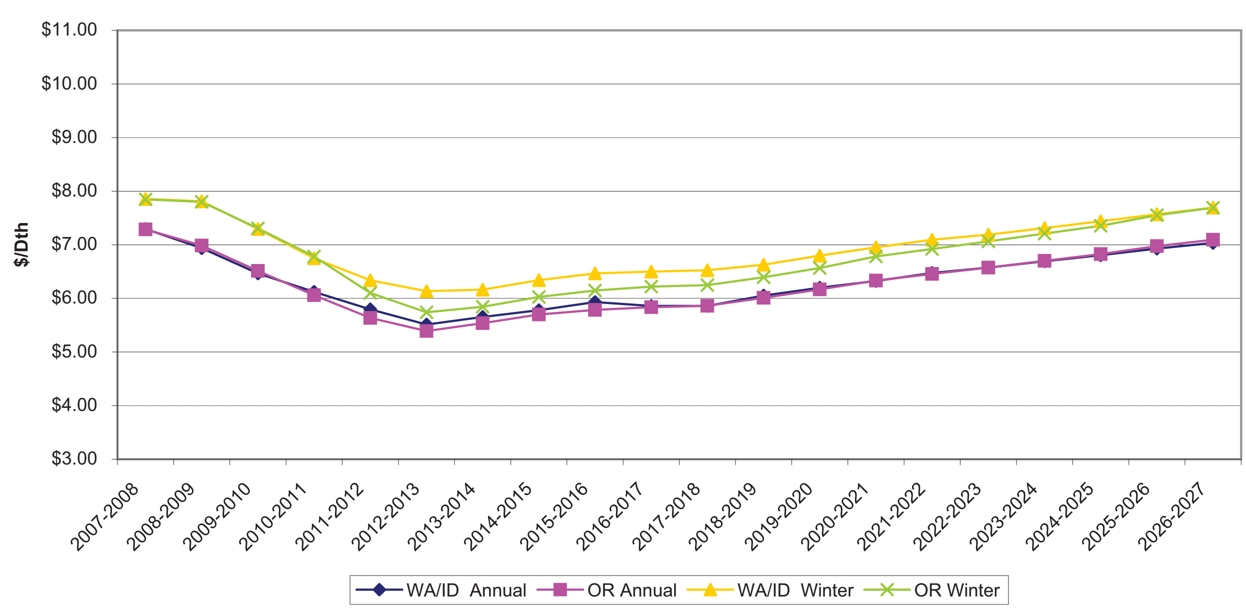
AVOIDED COST DETERMINATIONS

Avista has summarized the SENDOUT® calculated avoided cost data in Appendix 7.1, which has been divided into annual and winter costs and is averaged accordingly. Winter season costs are most appropriate when considering heat related avoided costs. Annual costs are most appropriate when considering non-heat (base load) related avoided costs.

Note that Appendix 7.1 details avoided cost figures for each operating division discussed in this IRP. Also note that figures are stated in real dollars per Dth.

A graphical depiction of the avoided costs for the Washington/Idaho and Oregon areas for annual and winter-only Dth usage is represented in Figure 7.1. These avoided costs exclude environmental externality adders.

Figure 7.1 - Natural Gas Avoided Costs 2007$/Dth
Includes Commodity & Trans. Costs/Excludes Env. Ext. Adder - November through October



ENVIRONMENTAL COSTS AND EXTERNALITIES (OREGON JURISDICTION ONLY)

The methodology employed to develop the avoided costs associated with the reduction of incremental natural gas usage have been based upon the monetary value associated with commodity and transportation costs only. These avoided cost streams do not include environmental externality costs related to the gathering, transmission, distribution or end-use of natural gas.

Per traditional economic theory and industry practice, an environmental externality factor is typically added to the monetary avoided cost when there is an opportunity to displace traditional supply-side resources with an alternative resource lacking adverse environmental impact. Per the requirements established by UM 1056 (see excerpt below) environmental compliance cost adders should be considered when evaluating natural gas resource options.

> UM 1056, Guideline 8 - Environmental Costs
> *"Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides (NO_x), sulfur oxides (SO_2), and mercury (Hg) emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from \$0 - \$40 (1990\$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides (NO_x), sulfur dioxide (SO_2), and mercury (Hg), if applicable."*

Avista's current direct gas distribution system infrastructure does not result in any CO_2, NO_x, SO_2, or Hg emissions. Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems), however, do produce CO_2 emissions via compressors used to pressurize and move natural gas. Accessing CO_2 emissions data on these upstream activities to perform detailed meaningful analysis is challenging but increasingly important given building momentum around legislative developments regarding greenhouse gas emissions and the movement toward the creation of carbon cap-and-trade markets. As these markets develop and mature it may be possible to develop a reasonable quantification of these values. Given the wide diversity of scenarios and current lack of information available from all upstream gas system components, it was not possible to complete a detailed analysis of CO_2 emissions related to upstream natural gas gathering and distribution. However, we have performed analysis on the pipeline transportation infrastructure that we rely on to supply our service territories.

To the extent that natural gas-efficiency programs reduce overall end-use demand, there will be reductions in CO_2 emissions resulting from the compression needed for transmission as well as at the end-use itself. Of all the emissions, carbon dioxide could have the greatest impact on the company. A national carbon tax on greenhouse gas emitting activities would be the most likely mechanism for passing through the costs of emissions. If a carbon tax were to be imposed, more DSM resources would become cost-effective. A carbon tax at the $8 per ton level would add $0.07 cents per therm. A $40 per ton tax adds approximately $0.35 cents per therm. At this level, several of the marginal non-cost-effective measures would become cost-effective.

CONSERVATON COST ADVANTAGE

For this IRP, our natural gas DSM implementation planning process has incorporated a 10 percent environmental externality factor into our assessment of the cost-effectiveness of existing DSM programs. Additionally our assessment of prospective DSM opportunities is based on an avoided cost stream that includes the same consideration of environmental externalities. When appropriate, these evaluations and resource decisions are based on program impacts, markets and environmental impact that are as geographically specific as possible.

ADDITIONAL AVOIDED COST ANALYSIS

Avista will file revised cost-effectiveness limits (CELs) based upon the updated avoided costs available from this IRP process. We are planning on investigating the applicability of recently completed quantifications of electric distribution capacity, the customer value of risk reduction and greenhouse gas emissions to determine if similar quantifications are possible for our natural gas system. It is possible that this analysis will result in a revision to the company's CEL filing in early 2008.

8. ACTION PLAN

2006 ACTION PLAN REVIEW

The 2006 action plan focused on five areas:

- Sales Forecasting
- Supply/Capacity
- Forecasting
- Demand-Side Management
- Distribution Planning

A discussion of the specific action items and the plan results follows.

SALES FORECASTING

Action Item:

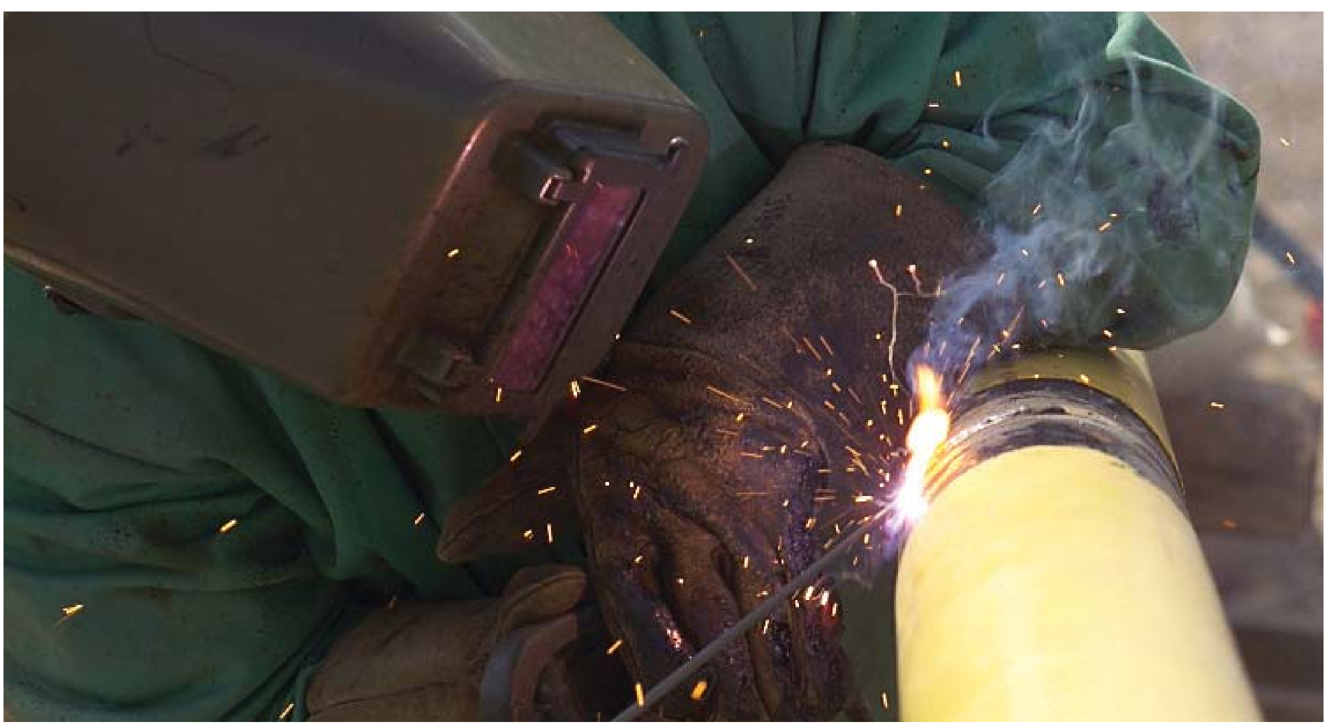
During 2006, we will update customer forecasting models, incorporating the most recent data. The dramatic increase in natural gas retail prices will provide improved information on price elasticity and weather sensitivity coefficients.

We anticipate making two changes to the forecasting methodology, one in 2006 and the other in 2007. We currently use county-level forecasts for eight counties in the three states we serve. During 2006, we will add five counties, two in Washington and three in Idaho. This will help identify differential growth patterns between the core areas (Spokane and Coeur d'Alene) and the more rural and resort areas of the service area.

In 2007, utilizing the data and forecasts from these additional counties, we will develop a "gate-station" forecasting system that will allocate the sales and customer forecast to the various pipeline delivery points in the service area. We anticipate having this system available so that we can utilize the results for the next IRP.

Results:

We now purchase economic forecasts for 15 of the 21 counties we serve. We combined this data with company-specific knowledge to develop our 20 year customer forecast. We have also incorporated sub-area core customer forecasting at the town code level into our customer forecasting process which is utilized in distribution system planning thus integrating our customer forecasting and distribution planning efforts.



SUPPLY/CAPACITY

Action Item:

We will conduct regular meetings with Commission Staff members to provide information on market updates, material changes to our hedging program, and significant changes in assumptions and status of company activity related to the IRP.

We will continue to seek low-cost peaking resources that do not require annual contractual commitments and will investigate acquisition of winter capacity releases from third-party providers.

We will further our understanding of LNG opportunities, including satellite and company-owned LNG resources. We will consider and evaluate the Coos Bay LNG/Pacific Connector Pipeline opportunity.

We will assess methods for capturing additional value related to existing storage assets, including but not limited to recalling some or all of the current releases.

We will further develop its storage strategy with particular focus on storage opportunities for Oregon customers and will research non-Jackson Prairie storage prospects for all customers.

Results:

We have regularly met with Commission Staff members as schedules permitted to provide market updates, material changes to our hedging programs and other IRP related topics.

Thus far we have not identified any cost effective available peaking resources. We will continue to monitor availability of winter capacity releases from third party providers.

Lack of readily available data on company owned LNG resource development has precluded us from significantly advancing our knowledge on specific development details including costs, scalability, permitting and timelines. We will increase our efforts in this area including inquiries of other neighboring utilities that have developed LNG assets and currently have them in their resource portfolio.

With respect to large-scale LNG, we have participated in several forums, conferences and meetings with sponsors on the projects contemplated in our region. We have also participated in the open seasons of two projects in our region contingently reserving capacity. We continue to monitor developments in this area including the securing of dependable supply which we believe poses a significant challenge for project sponsors.

We have recalled our Jackson Prairie storage capacity with Teresen regaining all this capacity on May 1, 2008.

We have identified the current capacity and delivery expansion activity at Jackson Prairie and an expected recall of capacity from Avista Energy in 2011 to develop a storage assets plan that will allocate these storage assets between our Washington/Idaho customers and our Oregon customers on a 75 percent/25 percent ratio. In June 2007, we also acquired term storage capacity rights in the Mist underground storage project in order to serve our Oregon customers.

FORECASTING

Action Item:

We will complete our evaluation of VectorGas™. If purchased, we will utilize VectorGas™ to strengthen Avista's ability to analyze the financial impacts under varying load and price scenarios.

Results:

We have acquired the VectorGas™ module as part of the SENDOUT® software and have begun modeling varying load and price scenarios.

DEMAND-SIDE MANAGEMENT

Action Item:

The DSM analysis that occurred during the IRP process is the launching point for a more detailed investigation of the natural gas-efficiency technologies identified as cost-effective resource options. We initiated this additional evaluation and development of programs in January 2006 with the expectation that program revisions and the launch of new programs will occur in the spring of that same year.

We have explicitly recognized within this IRP the obligation to achieve all natural gas-efficiency resources available through the intervention of cost-effective utility programs. Given the rapid changes within the natural gas market, there are many new efficiency opportunities within the market. Considerable uncertainty remains regarding the customer response to these programs. This uncertainty does not preclude us from pursuing the planned aggressive ramp-up of natural gas-efficiency programs. Additionally, we have and will actively seek opportunities for new or enhanced resource acquisition through the development of cooperative regional programs.

Results:

We have and will continue to actively seek opportunities for developing new DSM programs as well as enhancing existing offerings. The company is on track to meeting our long-term goal of acquiring all cost-effective natural gas resources achievable through utility intervention.

DISTRIBUTION PLANNING

Action Item:

We will continue to utilize computer modeling to facilitate distribution-planning efforts and identify least cost opportunities to meet growth and reinforcement needs. We will determine the benefit and feasibility of using citygate station forecasts as a method for improving distribution planning.

Results:

Our evaluation into refining projected customer growth into smaller geographic areas produced a system that utilizes town code growth rates as the forecasting unit. These smaller, specific-area growth rates facilitate an improved integrated planning effort.

2008-2009 ACTION PLAN

The 2008-2009 action plan is derived from the action items identified in the following chapters:

CHAPTER 2 - DEMAND FORECAST

Action Item:

We will further integrate the VectorGas™ module in our SENDOUT® modeling software to strengthen our ability to analyze the demand impacts under varying weather and price scenarios as well as conduct sensitivity analysis to identify, quantify, and manage risk around these demand influencing components.

Action Item:

We will study ways to further refine our ability to model demand by region. Town code forecasting was the first step in enhancing our demand forecasting. We now want to explore incorporating these town code forecasts into regions for analysis in SENDOUT® especially within the broad Washington/Idaho division to investigate potential resource needs that may materialize earlier than the broader region indicates.

CHAPTER 3 - DEMAND-SIDE MANAGEMENT

Action Item:

The IRP analysis has indicated a set of cost-effective measures and acquirable resource potential for a future DSM portfolio. We have established targets for first-year energy savings goals for 2008 of 1,425,000 therms in WA/ID and 350,000 therms in Oregon. In 2009 the goals for first-year energy savings are 1,581,000 therms in WA/ID and 300,000 therms in Oregon. The completion of the IRP analysis is the midpoint, not the end point, of a larger reassessment of the DSM resource portfolio. Further evaluation is required to facilitate the development of program plans and to incorporate them into an updated DSM implementation plan. Following detailed investigation of the natural gas-efficiency technologies identified as cost-effective resource options, we will incorporate these efforts into the larger Heritage Project ramp-up of Avista's energy-efficiency efforts.

Action Item:

We will file our cost-effectiveness limits (CEL's) based upon the avoided costs derived from this IRP process. Additionally, we are investigating the applicability of recently completed quantifications of electric distribution capacity, the customer value of risk reduction and greenhouse gas emissions to determine if similar quantifications are possible for our natural gas system.

CHAPTER 5 – SUPPLY SIDE RESOURCES

Action Item:

We will continue to monitor several issues identified in this chapter with respect to commodity, storage and supply resources. These include:

- tight production/productive capacity;
- pipeline constraints in our region;
- pipeline expansions that move volumes away from our region;
- pipeline cost escalations; and
- large scale LNG activity.

Action Item:

We will refine our analysis of acquiring or constructing resource alternatives to improve project cost estimating, assessment of project feasibility issues, determination of project siting issues and risks, and improved accuracy of construction/acquisition lead times. Specifically, we will further study these issues with respect to satellite LNG, company owned LNG, pipeline expansions, distribution system enhancements and storage facility diversification. We will explore creative, non-traditional resource possibilities to address our needle peaking exposures with emphasis on potential structured transactions (e.g. transportation and storage exchanges) with neighboring utilities and other market participants that leverage existing regional infrastructure as an alternative to incremental infrastructure additions.

Action Item:

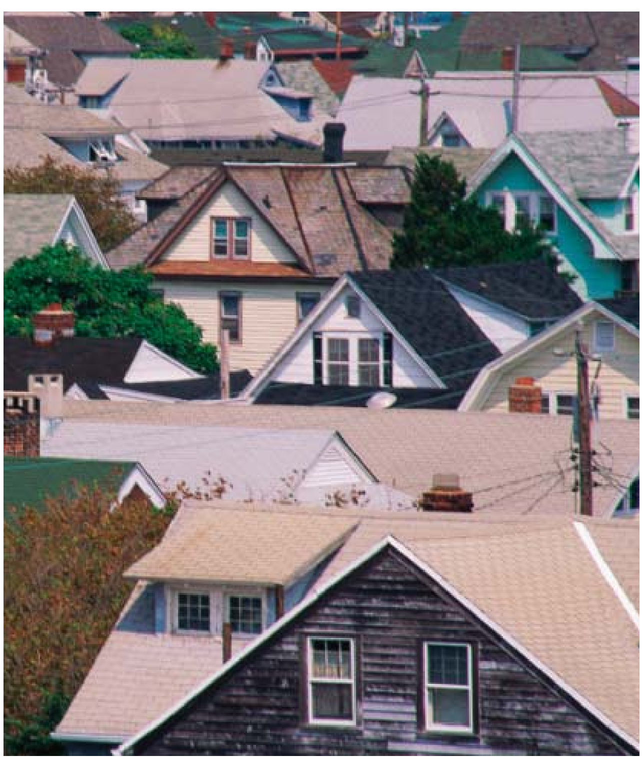
We will continue to assess methods for capturing additional value related to existing storage assets, including methods of optimizing recently recalled releases while implementing its storage strategy of providing balanced storage opportunities. This includes exploring storage diversification options including AECO and Northern California facilities.

Action Item:

We will continue to analyze natural gas procurement practices for strategy enhancing ideas such as basis diversification, storage injection/withdrawal timing and structured products.

Action Item:

Since much of our supply comes from Canadian natural gas exports, the notion that this supply could diminish significantly is of concern. We will continue to monitor the discussion around diminishing Canadian gas exports looking for signals that indicate increased risk of disrupted supply over the 20-year planning horizon.



CHAPTER 6 - INTEGRATED RESOURCE PORTFOLIO

Action Item:

We will refine our specific resource acquisition action plans for Klamath Falls and Medford service areas that address the projected unserved Expected Case demand in 2011-2012 and 2013-2014, respectively. We will monitor timelines, milestones, status and progress reporting, ongoing plan risk assessment and consideration of alternative actions.

For Klamath Falls we will:

- reassess the necessary operational steps and timing (current estimate six months) to acquire the Klamath Falls Lateral; and
- monitor actual demand trends to forecasted demand to refine a target date for initiating the purchase of the lateral.

For Medford we will:

- commission a pipeline expansion study from GTN to identify specific costs and issues;
- monitor actual demand trends to forecasted demand to refine the timing of action steps; and
- assess the impacts of project timing from possible changes in our weather planning standard.

Action Item:

We will reevaluate our current peak day weather standard to ascertain if it still provides the best risk-adjusted methodology in evaluating resource planning.

Action Item:

We will meet regularly with Commission Staff members to provide information on market activities, material changes to risk management programs, and significant changes in assumptions and/or status of company activity related to the IRP or procurement practices.

9. GLOSSARY OF TERMS AND ACRONYMS

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.

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.

Citygate
(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.

Commodity Price
The current price for a supply of natural gas that is charged for each unit of natural gas supplied as determined by market conditions.

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

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

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

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

Demand-Side Resources
Energy resources obtained through assisting customers to reduce their "demand" or use of natural gas.

Demand-Side Management (DSM)
The activity of implementing demand-side measures to minimize customers' energy usage in their facilities.

End User
The ultimate consumer of natural gas; the end user purchases the natural gas for consumption, not for resale or transportation purposes.

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 demand-side management 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.

Firm (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)
One of the five natural gas pipelines the company deals with directly; GTN is headquartered in Portland, Ore., and it is a subsidiary of TransCanada Pipeline; owns and operates a natural gas pipeline that runs from Canada to the Oregon/California border.

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

Global Insight, Inc.
A national economic forecasting company.

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).

Injection
The process of putting natural gas into a storage facility.

Integrated Resource Plan (IRP)
The document that explains Avista's plans and preparations to maintain sufficient resources to meet customer needs at a reasonable price at acceptable risk.

Integrity Management Plan (IMP)
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 (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

Jackson Prairie Storage Project (JP or JPSP)
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 below ground 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 sendouts observed that is sorted from highest sendout 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.

MMcf
A unit of volume equal to a million cubic feet.

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 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 Energy Associates
The developers of the SENDOUT® Gas Planning System.

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

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

NOVA Gas Transmission (NOVA)
See TransCanada Alberta System

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

OPUC
Public Utility Commission of Oregon

Peak Day
A 24-hour period of demand, which is used as a basis for planning peak natural gas capacity requirements. For purposes of this plan, Avista calculates peak day demand based on the coldest day on record.

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.

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

Prescriptive Measures
Efficiency applications that are relatively uniform in their characteristics, in which the utility has the option to define a standardized incentive based upon the typical application of the efficiency measure. This standardized prescriptive incentive takes the place of a customized calculation.

PSIG
Pounds per square inch (guage) – a measure of the pressure at which natural gas is delivered, sometimes referred to as PSI.

Puget Sound Energy
A natural gas local distribution company headquartered in Bellevue, Washington, serving customers in Western and Central Washington.

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 New Energy Associates; a linear programming model used to solve gas supply and transportation optimization questions.

Service Area
Geographic territory in which a utility provides natural gas service to customers.

Shoulder Months
Generally defined as the months of March, April and May (in the spring) or September and October (in the fall) when the temperatures are moderate and customer demand is variable.

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 time spreads; 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.

Tariff
Published regulated rate schedules including general terms and conditions under which a product or service will be supplied.

TF-1
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.

Terasen
A natural gas LDC headquartered in Vancouver, British Columbia, serving customers in Canada. Formerly known as BC Gas.

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 or a municipality within a county.

TransCanada Alberta System (TCPL-AB)
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 five natural gas pipelines Avista deals with directly.

TransCanada BC System (TCPL-BC)
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 US border; one of five natural gas pipelines Avista deals with directly.

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

VectorGas™
A module within SENDOUT® that facilitates the ability to model price and weather uncertainty through Monte Carlo simulation and detailed portfolio optimization techniques.

Weather Normalized
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.

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.

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AVISTA CORPORATION
2007 NATURAL GAS
INTEGRATED RESOURCE PLAN

TABLE OF CONTENTS

TAC Member List

Appendix 1.1

2007 IRP TAC Member List

Name	Organization
Bob Jenks	Oregon CUB
Bonnie Tatom	OPUC
Bruce Folsom	Avista
Bryan Lanspery	IPUC
Dan Kirschner	Northwest Gas Association
Dave Allred	Northwest Pipeline
Dave Sloan	Gas Transmission Northwest
Doug Kilpatrick	WUTC
Elizabeth Klumpp	WCTED
Greg Rahn	Avista
Inara Scott	Northwest Natural
Jon Powell	Avista
Kathy Bernarnd	Cascade Natural Gas Company
Kelly Irvine	Avista
Kerry Shroy	Avista
Ken Boni	Avista
Ken Zimmerman	OPUC
Kevin Christie	Avista
Linda Gervais	Avista
Lynn Anderson	IPUC
Lynn Kittilson	OPUC
Nicolas Garcia	WUTC
Paula Pyron	Northwest Industrial Gas Users
Phillip Popoff	Puget Sound Energy
Randy Barcus	Avista
Scott Russell	Gas Transmission Northwest
Steven Johnson	Washington Attorney General's Office
Terrence Browne	Avista
Terri Carlock	IPUC
Terry Morlan	Northwest Power and Conservation Coucil
Yohannes Mariam	WUTC

Natural Gas Demand Forecast Detail

Appendix 2.1

Appendix 2.1 - Natural Gas Demand Forecast Detail

Overview

Avista presented their 2005 Natural Gas Forecast to the Technical Advisory Committee (TAC). What follows in narrative is the process of preparing the company base customer growth forecast. The first step is a framework-forecast of the national economy, followed by regional economic forecasts consistent with the national outlook. The employment and population forecasts are the key drivers for the natural gas customer forecast.

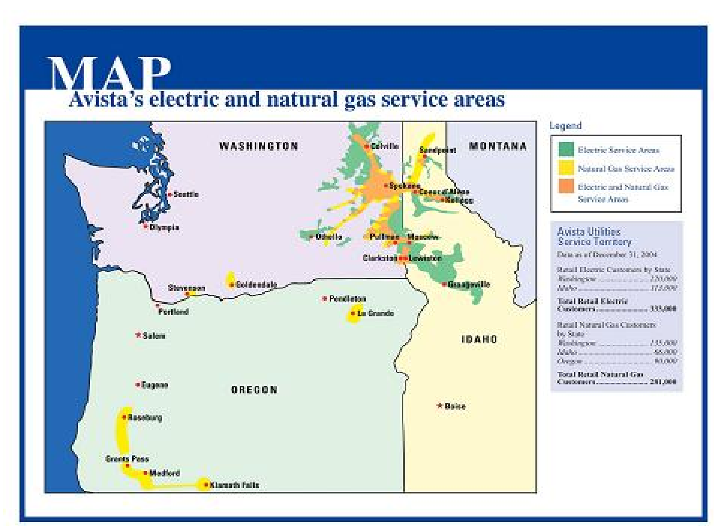
National Economic Outlook

Avista has contracted for national economic forecasts with Global Insight, Inc. for several years. The most recent twenty-five year long term forecast was used as the basis for the 2007 effort. The following narrative has Avista remarks and Global Insight forecasts (used with permission) which are consistent with the presentation at the TAC in May 2007, with a focus on the near term national outlook.

The U.S. Gross Domestic Product is expected to rebound to levels in the 2.5 to 3.0 percent range after a slowdown in 2007. Longer term the rate settles in at 2.5 percent.

Regional Economic Outlook

Avista serves natural gas in eastern Washington, northern Idaho, and in portions of five counties in Oregon. The principal county in Washington is Spokane, while in Idaho there are two counties; Kootenai and Bonner are barometers of service area growth. Kootenai County includes Coeur d'Alene, Post Falls, Hayden and a host of smaller municipalities and Bonner County is anchored by Sandpoint. The primary cities in Spokane County are the City of Spokane, City of Spokane Valley and Liberty Lake. In Oregon, the counties (principal city) of Jackson (Medford), Josephine (Grants Pass), Douglas (Roseburg), Klamath (Klamath Falls) and Union (La Grande) round out the service territory. The map below shows the breadth of the service area.



Global Insight, Inc. has also been providing county-level forecasts to Avista for several years. These forecasts are consistent with and driven by their national forecast.

The economic concepts provided are forecast forward for 30 years. Below we report forecast data ending in the year 2028, the twenty-year horizon.

Overall, the results of the economic forecasts suggest the following impacts on Avista's customer growth: Near term the strength in the construction boom will be mirrored with strong customer growth, while longer term, underlying employment and population growth will drive customer growth.

The following table indicates a listing of 21 counties served by Avista Natural Gas. We purchased economic forecasts for the 15 principal counties.

Table of Counties Served (All or Portions)

Washington	Idaho	Oregon
Adams*	Benewah	Douglas
Asotin	Bonner	Jackson
Franklin*	Boundary	Josephine
Grant*	Latah	Klamath
Klickitat*	Nez Perce	Union
Lincoln*	Shosone	
Skamania*		
Spokane		
Stevens		
Whitman		

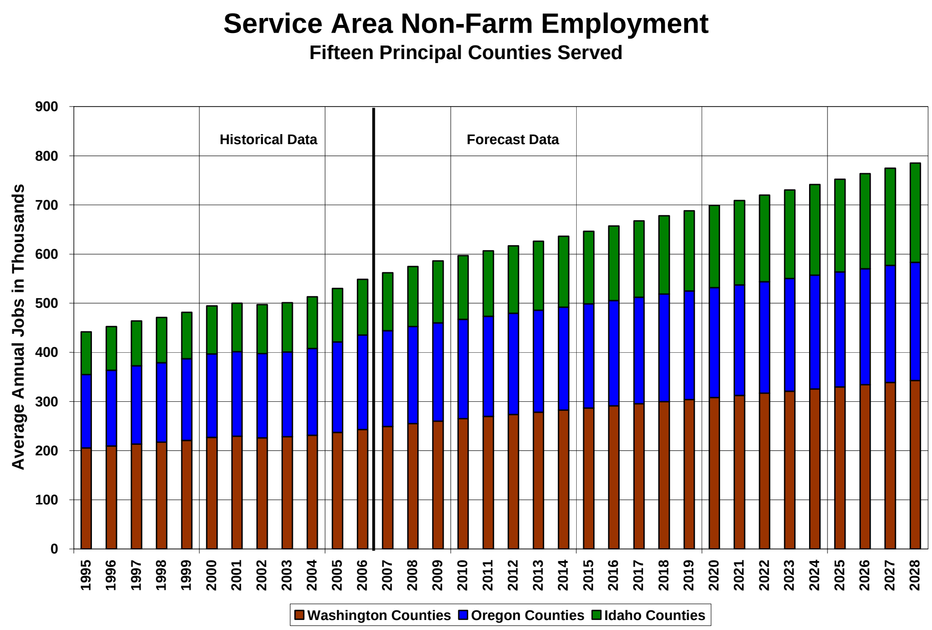
*Did not purchase economic data, few customers served

The charts that follow are the actual employment, population, population age 65 and over, number of households and personal income forecasts used to produce the natural gas forecasts by state, by customer class (residential, commercial and industrial) and by rate schedule (firm – small, medium and large-sized customers).

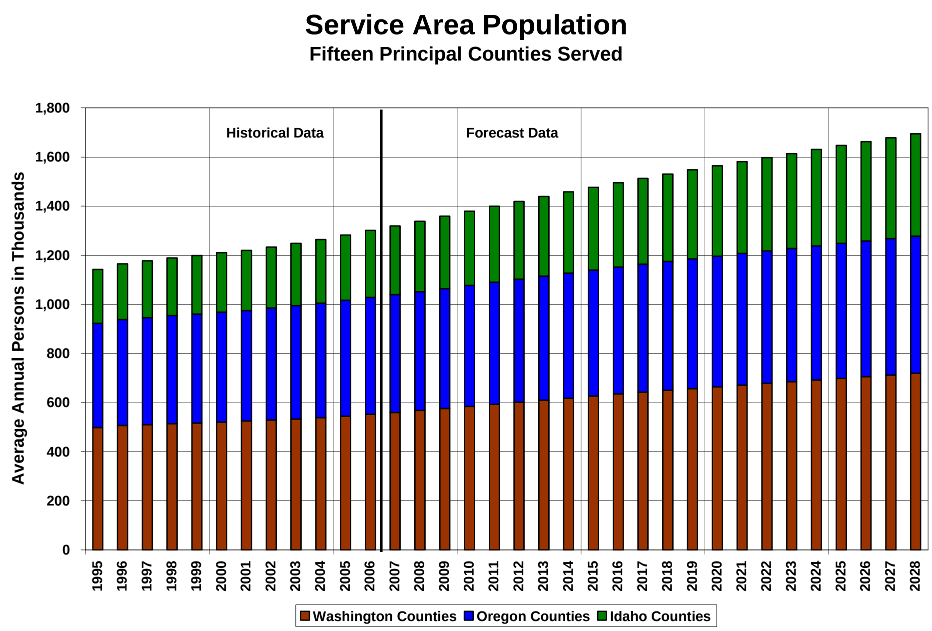
Although the forecasts are prepared in detail by county, the charts aggregate the data by State.

The first chart is Non-Farm Employment. During the last decade, fairly consistent growth in jobs was observed except during the job recession and economy restructuring in the 2001-2002 period. The resumption of job growth in 2003 has accelerated through early 2007, and although expected to moderate it's rate of growth, is expected to grow modestly through the forecast period.

The ten year average compounded growth rate in jobs for these 15 counties was 1.9 percent from 1997-2007, and is forecast to be 1.6 percent for the period 2008-2028.



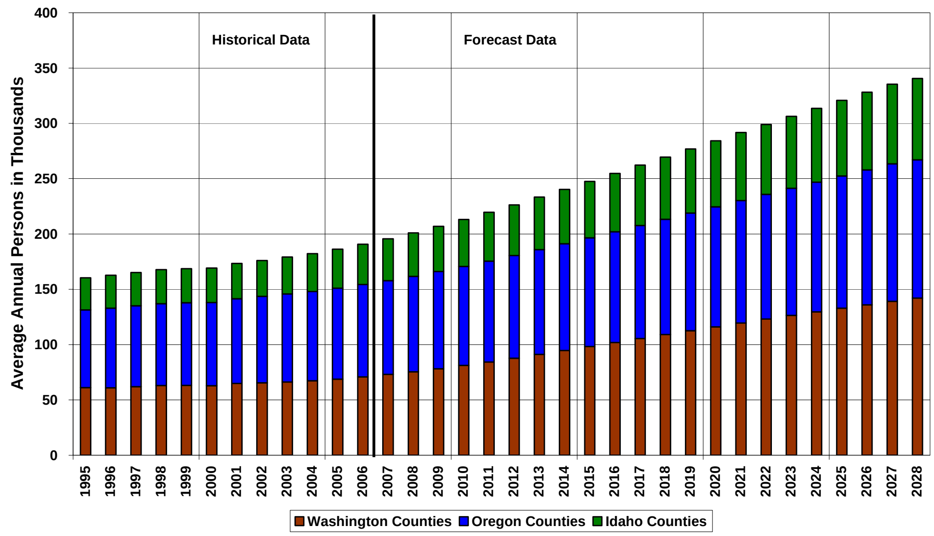
Next is Oregon resident population. Resident population growth was 1.1 percent compounded from 1997-2007, and is expected to rise to 1.2 percent from 2008-2028. Migration into these counties of retirement-age persons is the primary influence on growth.



The next chart is persons 65 years and over. Between 1997 and 2007, the compounded growth rate was 1.7 percent. From 2008 to 2028, it accelerates to 2.7 percent. The 2007 estimate of the percentage of persons 65 and over in Avista's service area is 15 percent. By 2028 this estimate grows to 20 percent.

Service Area 65 and Over Population

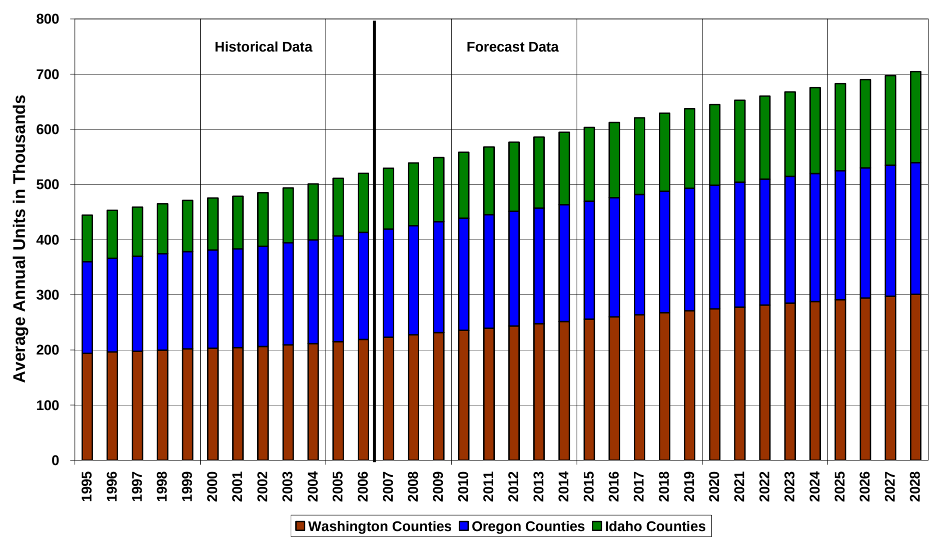
Fifteen Principal Counties Served



The next economic variable used in the preparation of Avista's forecast is number of resident households in the service area. The household growth rate was 1.4 percent from 1997-2007, and is forecast at 1.3 percent for the 2008 to 2028 period.

Service Area Households

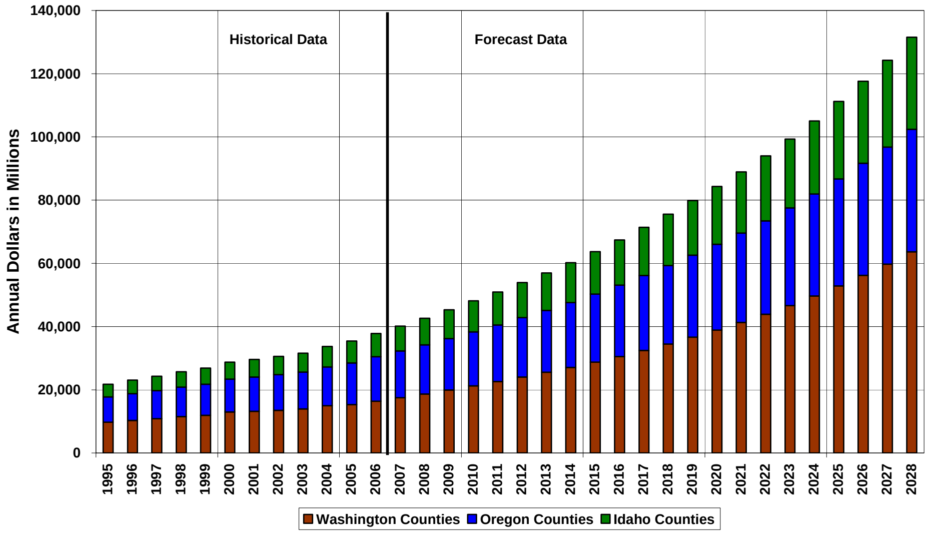
Fifteen Principal Counties Served



The final economic variable used is the estimate of personal income. Besides wage and salary income, personal income includes rental income, transfer payments (like social security from all of the age 65 and over population, plus dividends and interest payments. Between 1997 and 2007, personal income grew at a compounded average rate of 5.2 percent. The forecast period has this growth rate increasing modestly to 5.8 percent, consistent with the proportion of persons 65 years and older and the expectation these individuals will be receiving supplemental payments from retirement sources.

Service Area Personal Income

Fifteen Principal Counties Served



Price Elasticity

Avista participated in a National study of price elasticity conducted for the American Gas Association by a consulting group. As a benefit of our participation, the consultants provided separate price elasticity estimates for each of the three states. The study was discussed at the May 2, 2007 Technical Advisory Committee meeting in Portland, Oregon.

Price Elasticity

American Gas Association, March 2007 Study
Frederick Joutz and Robert P. Trost

Avista Specific Estimates

	Long Run	Short Run
Washington	-0.14	-0.12
Oregon	-0.13	-0.08
Idaho	-0.10	-0.05

Heating Degree Days

Heating degree day data is obtained from the National Weather Service. Avista uses the most recent 30-year period, which goes from 1971-2000. For Oregon, Avista uses four weather stations as the weather basis, corresponding to the areas within which natural gas services are provided, all of which are official National Weather Service stations. Heating degree day weather patterns between these areas are uncorrelated.

At the May 2, 2007 Technical Advisory Committee meeting, Avista presented some data and information regarding trends in heating degree days for its service area. Although not adopting a "Global Warming" baseline for forecasting, our willingness to discuss the subject was well received. It was decided that for this IRP no action on adjusting forecasts for the warmer trends observed in recent years is necessary. However, as this issue continues to garner discussion further analysis will be warranted.

Base Case Forecasts of Customers Served

Base case customer forecasts for residential customers are consistent with our economic forecasts. The relationship has been changing over the last decade, and the forecasts take into account the most recent trends. As shown on the next figure, the number of residential customers per household grew rapidly between 1997 and 2001. About half of this growth was due to fuel switching of existing homes from other heating sources to natural gas.

After 2001, the number of customers switching to natural gas decreased, as the number of homes available to switch declined combined with dramatically higher natural gas retail prices to reduce the market demand.

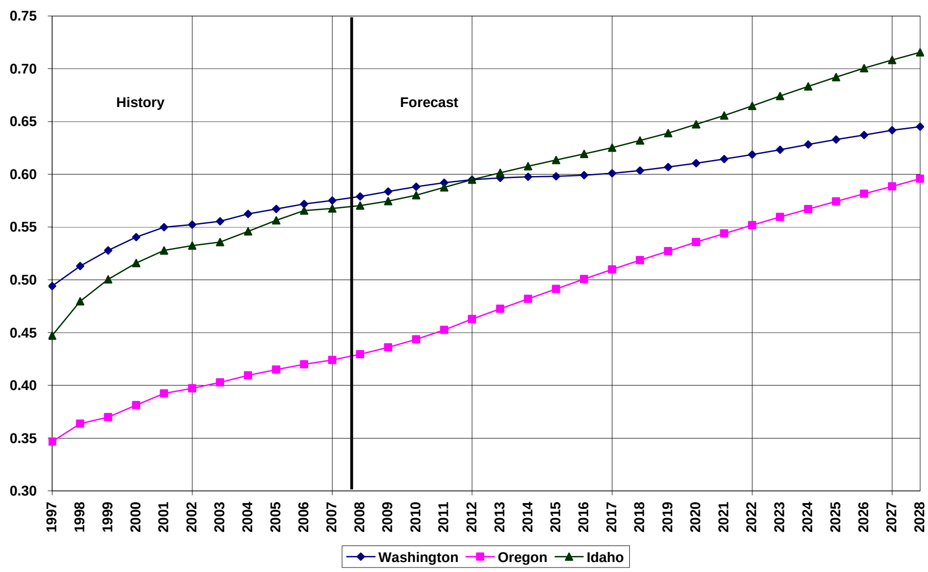
To produce the customer forecast, we look at recent trends in housing construction and the likelihood those homes will be served with natural gas. For example, in Washington, the number of single family homes being constructed has declined, with apartment dwellings taking a larger market share. Multi-family housing has traditionally been served with electricity only, limiting the number of available dwellings for natural gas service.

However, in the areas outside of the urban core of Spokane, including the rest of Washington, much of Idaho and Oregon, housing construction activity has maintained very high levels of single family homes, whether detached-style homes on individual lots or attached-style homes, like duplexes, townhomes, or condominiums. This market is traditionally served with natural gas water and space heat, and many of these homes now are being built with natural gas clothes dryers, gas ranges and ovens and natural gas fire places.

Because growth management laws are in place in all of Avista's natural gas service areas, we assume these construction trends in the urban growth areas will be served with natural gas, and do not anticipate any switching to electricity. We have an effort under way to encourage multi-family builders, who typically are building apartments for rental purposes to include natural gas appliances, but this forecast does not assume this effort will lead to a change in construction practices. We will continue to monitor activity in the multi-family housing segment.

The forecast assumes that the trends of the last five years continue into the future, adjusted for the sharp building cycle presently under way and based on the household forecasts provided by Global Insight. The chart shows the number of residential customers per household. The reason this ratio is increasing in the forecast period is because the ratio of homes being added is higher than the current ratio. This is largely driven by the assumption of nearly 100 percent of new homes having at least one natural gas service. Also, outside of the Medford and Spokane metropolitan areas, the multi-family construction market is very small. The only exception would be in Pullman and Moscow where growth in university enrollments is leading to apartment construction activity in those special areas. To a lesser extent, La Grande, Klamath Falls, and Ashland are seeing student growth-driven apartment construction, but to a small extent.

Residential Customers per Household Trends by State

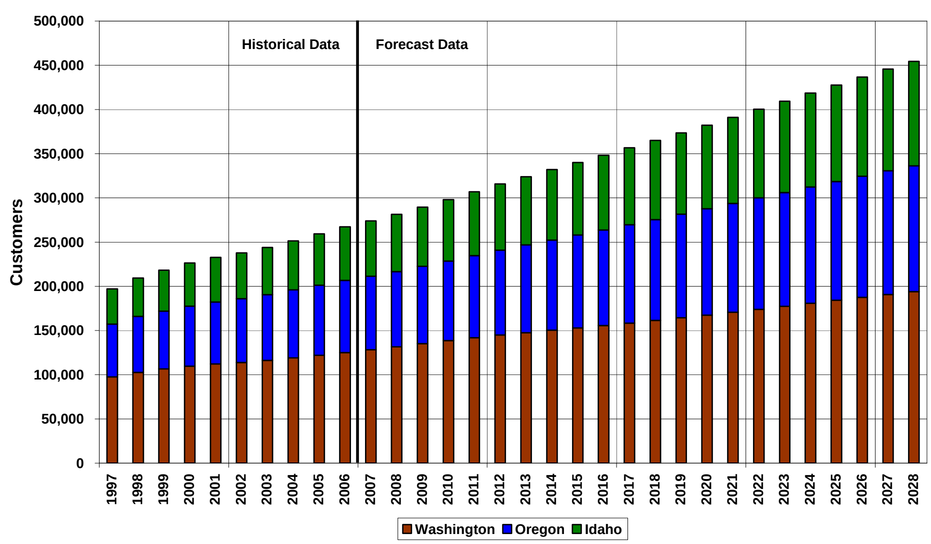


The residential customer forecast is the product of the customers-per-household forecast and the household forecast from Global Insight.

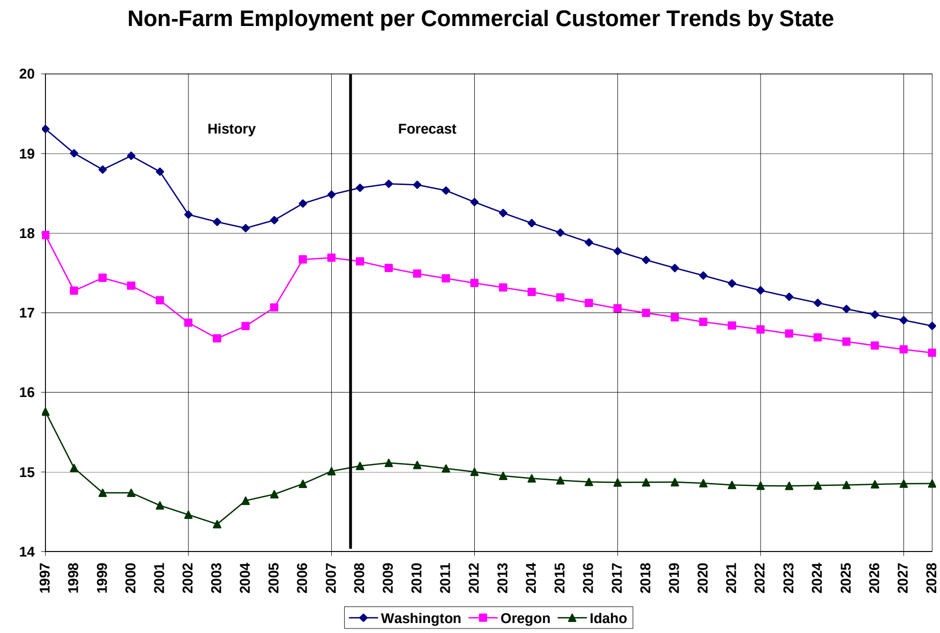
Note: 2007 data includes 4 months actual, 8 months estimated

Residential Customers Served

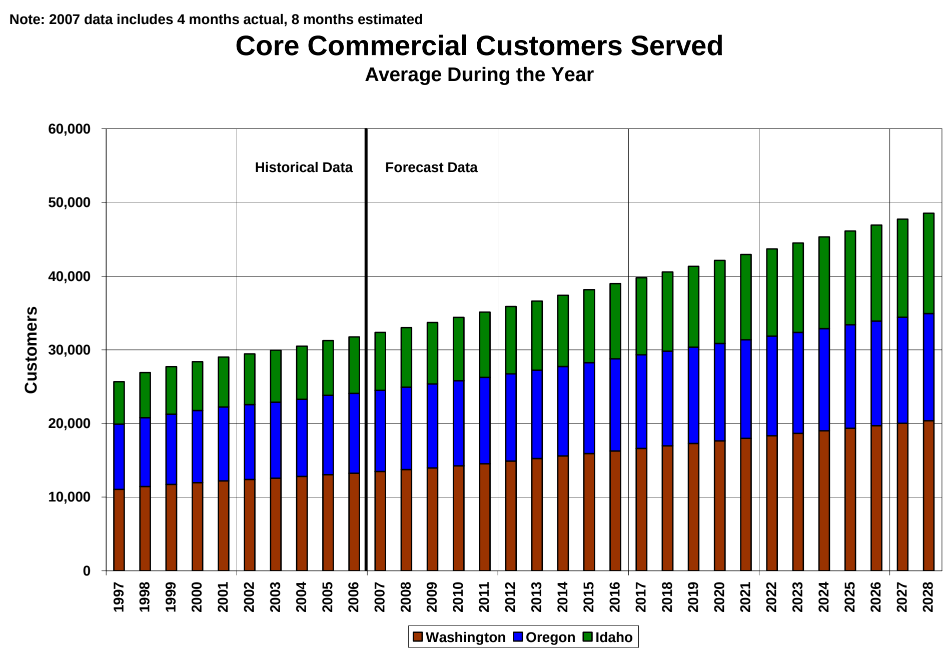
Average During the Year--All Residential Customers are Core Load



Core commercial customers served are based on job forecasts for each county, as well as the number of residential customers. The figure below shows ratio of non-farm workers per commercial customer. The previous ten years show declines in numbers of workers early in the period, followed by a buildup until recently. This build up is due to an increase in the number of big-box retail stores, which have moved from the very large metro areas into the smaller metro areas served by Avista. We believe that build out is largely complete. We do not anticipate new large mall-type complexes will be built in to any great extent. Therefore, in a few more years we expect the number of workers will again begin to decline as smaller shops and strip-mall developments fill into the neighborhood developments. We have taken into account the known shopping areas that have been either permitted or have those proposed that have a high probability of being built in the near term forecast. As shown in the chart, although declines are forecast, they are very modest levels and reflect the particular characteristics of the existing mix of commercial developments in each state.

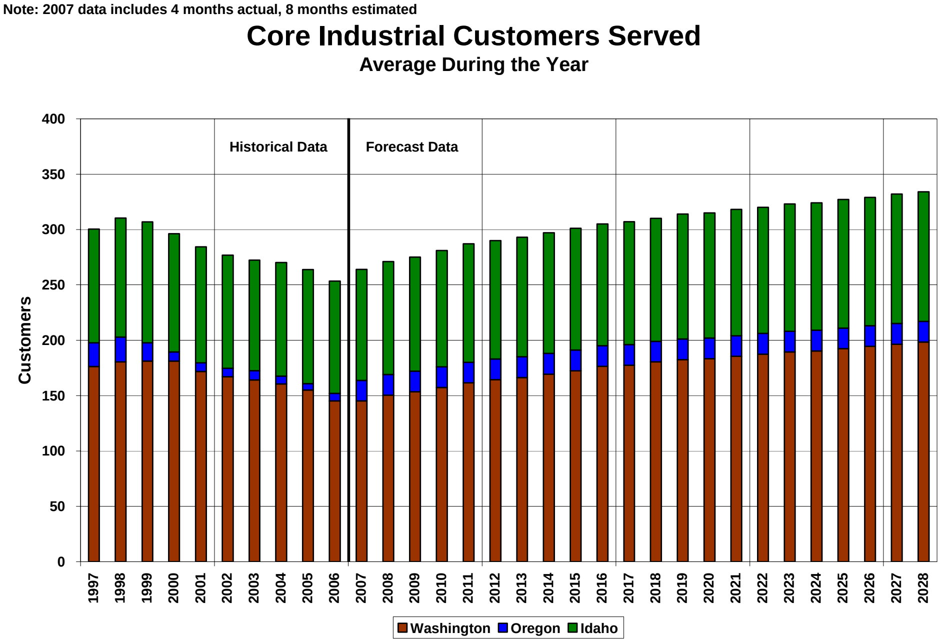


The commercial customer forecast is based on job forecasts multiplied times the forecasted ratio of workers per customer as described above.



Core industrial customers served are based on manufacturing job forecasts for each county. The number of manufacturing workers is expected to be growing slowly over the forecast period, leading to little change in the number of core firm industrial customers.

Note: 2007 data includes 4 months actual, 8 months estimated



Customer Forecast

Appendix 2.2

Appendix 2.2 - Customer Forecast - Number by Region
Expected Case

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-07	193,203	21,592	247	215,042	50,373	6,448	9	56,830	13,163	2,145	2	15,310	13,882	1,606	5	15,493	6,449	882	5	7,336
Dec-07	194,376	21,688	250	216,314	50,851	6,481	9	57,341	13,285	2,153	2	15,440	14,056	1,626	4	15,686	6,514	882	2	7,398
Jan-08	194,726	21,642	248	216,616	51,074	6,498	9	57,581	13,327	2,159	2	15,488	14,110	1,643	4	15,757	6,554	883	1	7,438
Feb-08	194,827	21,768	252	216,847	51,144	6,505	9	57,658	13,367	2,160	2	15,529	14,146	1,654	5	15,805	6,565	883	1	7,449
Mar-08	195,157	21,737	250	217,144	51,241	6,520	9	57,770	13,419	2,163	2	15,584	14,174	1,655	5	15,834	6,555	884	1	7,440
Apr-08	195,051	21,713	250	217,014	51,252	6,487	9	57,748	13,340	2,149	2	15,491	14,134	1,648	5	15,787	6,547	880	1	7,428
May-08	195,373	21,719	250	217,342	51,220	6,491	9	57,720	13,303	2,167	2	15,472	14,039	1,635	5	15,679	6,524	880	2	7,406
Jun-08	195,700	21,751	253	217,704	51,047	6,481	9	57,537	13,219	2,163	2	15,384	13,926	1,631	5	15,562	6,486	881	2	7,369
Jul-08	195,531	21,716	256	217,503	50,866	6,475	9	57,350	13,220	2,158	2	15,380	13,890	1,637	5	15,532	6,363	883	2	7,248
Aug-08	195,802	21,822	253	217,877	50,731	6,479	9	57,219	13,161	2,152	2	15,315	13,785	1,631	5	15,421	6,338	885	3	7,226
Sep-08	196,537	21,910	255	218,702	50,891	6,503	9	57,403	13,127	2,149	2	15,278	13,799	1,640	5	15,444	6,324	888	7	7,219
Oct-08	197,952	21,935	252	220,139	51,263	6,490	9	57,762	13,270	2,152	2	15,424	14,002	1,621	5	15,628	6,450	887	7	7,344
Nov-08	198,723	22,073	254	221,050	51,773	6,573	9	58,355	13,513	2,170	2	15,685	14,232	1,636	5	15,873	6,549	887	5	7,441
Dec-08	199,896	22,169	256	222,321	52,301	6,606	9	58,916	13,635	2,173	2	15,810	14,406	1,656	4	16,066	6,614	887	2	7,503
Jan-09	200,447	22,129	252	222,828	52,374	6,609	9	58,992	13,727	2,203	2	15,932	14,460	1,671	4	16,135	6,654	888	1	7,543
Feb-09	200,548	22,255	256	223,059	52,494	6,616	9	59,119	13,767	2,204	2	15,973	14,496	1,682	5	16,183	6,665	888	1	7,554
Mar-09	200,878	22,224	254	223,356	52,641	6,631	9	59,281	13,819	2,207	2	16,028	14,524	1,683	5	16,212	6,655	889	1	7,545
Apr-09	200,772	22,200	254	223,226	52,702	6,598	9	59,309	13,740	2,193	2	15,935	14,484	1,676	5	16,165	6,647	885	1	7,533
May-09	201,094	22,206	254	223,554	52,720	6,602	9	59,331	13,703	2,211	2	15,916	14,389	1,663	5	16,057	6,624	885	2	7,511
Jun-09	201,421	22,238	257	223,916	52,547	6,592	9	59,148	13,619	2,207	2	15,828	14,276	1,659	5	15,940	6,586	886	2	7,474
Jul-09	201,452	22,203	260	223,915	52,366	6,586	9	58,961	13,670	2,202	2	15,874	14,290	1,665	5	15,960	6,463	888	2	7,353
Aug-09	201,723	22,309	257	224,289	52,231	6,590	9	58,830	13,611	2,196	2	15,809	14,185	1,659	5	15,849	6,438	890	3	7,331
Sep-09	202,458	22,397	259	225,114	52,391	6,614	9	59,014	13,577	2,193	2	15,772	14,199	1,668	5	15,872	6,424	893	7	7,324
Oct-09	203,873	22,422	256	226,551	52,813	6,601	9	59,423	13,720	2,196	2	15,918	14,402	1,649	5	16,056	6,550	892	7	7,449
Nov-09	204,644	22,560	258	227,462	53,373	6,684	9	60,066	13,963	2,214	2	16,179	14,632	1,664	5	16,301	6,649	892	5	7,546
Dec-09	205,817	22,656	260	228,733	53,951	6,717	9	60,677	14,085	2,217	2	16,304	14,806	1,684	4	16,494	6,714	892	2	7,608
Jan-10	206,317	22,665	258	229,240	54,024	6,706	9	60,739	14,227	2,245	2	16,474	14,860	1,697	4	16,561	6,754	892	1	7,647
Feb-10	206,418	22,791	262	229,471	54,144	6,713	9	60,866	14,267	2,246	2	16,515	14,896	1,708	5	16,609	6,765	892	1	7,658
Mar-10	206,748	22,760	260	229,768	54,291	6,728	9	61,028	14,319	2,249	2	16,570	14,924	1,709	5	16,638	6,755	893	1	7,649
Apr-10	206,642	22,736	260	229,638	54,252	6,695	9	60,956	14,240	2,235	2	16,477	14,884	1,702	5	16,591	6,747	889	1	7,637
May-10	206,964	22,742	260	229,966	54,270	6,699	9	60,978	14,203	2,253	2	16,458	14,789	1,689	5	16,483	6,724	889	2	7,615
Jun-10	207,291	22,774	263	230,328	54,097	6,689	9	60,795	14,119	2,249	2	16,370	14,676	1,685	5	16,366	6,686	890	2	7,578
Jul-10	207,422	22,739	266	230,427	53,916	6,683	9	60,608	14,170	2,244	2	16,416	14,740	1,691	5	16,436	6,563	892	2	7,457
Aug-10	207,693	22,845	263	230,801	53,781	6,687	9	60,477	14,111	2,238	2	16,351	14,635	1,685	5	16,325	6,538	894	3	7,435
Sep-10	208,428	22,933	265	231,626	53,941	6,711	9	60,661	14,077	2,235	2	16,314	14,649	1,694	5	16,348	6,524	897	7	7,428
Oct-10	209,843	22,958	262	233,063	54,413	6,698	9	61,120	14,220	2,238	2	16,460	14,852	1,675	5	16,532	6,650	896	7	7,553
Nov-10	210,614	23,096	264	233,974	55,023	6,781	9	61,813	14,463	2,256	2	16,721	15,082	1,690	5	16,777	6,749	896	5	7,650
Dec-10	211,787	23,192	266	235,245	55,651	6,814	9	62,474	14,585	2,259	2	16,846	15,256	1,710	4	16,970	6,814	896	2	7,712
Jan-11	212,288	23,226	264	235,778	55,724	6,792	9	62,525	14,827	2,279	2	17,108	15,360	1,717	4	17,081	6,854	896	1	7,751
Feb-11	212,389	23,352	268	236,009	55,794	6,799	9	62,602	14,867	2,280	2	17,149	15,396	1,728	5	17,129	6,865	896	1	7,762
Mar-11	212,719	23,321	266	236,306	55,941	6,814	9	62,764	14,919	2,283	2	17,204	15,424	1,729	5	17,158	6,855	897	1	7,753
Apr-11	212,613	23,297	266	236,176	55,902	6,781	9	62,692	14,840	2,269	2	17,111	15,384	1,722	5	17,111	6,847	893	1	7,741
May-11	212,935	23,303	266	236,504	55,920	6,785	9	62,714	14,803	2,287	2	17,092	15,289	1,709	5	17,003	6,824	893	2	7,719
Jun-11	213,262	23,335	269	236,866	55,747	6,775	9	62,531	14,719	2,283	2	17,004	15,176	1,705	5	16,886	6,786	894	2	7,682
Jul-11	213,293	23,300	272	236,865	55,566	6,769	9	62,344	14,770	2,278	2	17,050	15,240	1,711	5	16,956	6,663	896	2	7,561
Aug-11	213,564	23,406	269	237,239	55,431	6,773	9	62,213	14,711	2,272	2	16,985	15,135	1,705	5	16,845	6,638	898	3	7,539
Sep-11	214,299	23,494	271	238,064	55,591	6,797	9	62,397	14,677	2,269	2	16,948	15,149	1,714	5	16,868	6,624	901	7	7,532
Oct-11	215,714	23,519	268	239,501	56,113	6,784	9	62,906	14,820	2,272	2	17,094	15,352	1,695	5	17,052	6,750	900	7	7,657
Nov-11	216,485	23,657	270	240,412	56,773	6,867	9	63,649	15,063	2,290	2	17,355	15,582	1,710	5	17,297	6,849	900	5	7,754
Dec-11	217,658	23,753	272	241,683	57,451	6,900	9	64,360	15,185	2,293	2	17,480	15,756	1,730	4	17,490	6,914	900	2	7,816
Jan-12	217,865	23,832	267	241,964	57,640	6,878	9	64,527	15,531	2,316	2	17,849	15,810	1,738	4	17,553	6,960	900	1	7,861
Feb-12	217,968	23,961	271	242,201	57,712	6,885	9	64,606	15,573	2,317	2	17,892	15,847	1,750	5	17,602	6,971	900	1	7,872
Mar-12	218,307	23,930	269	242,506	57,864	6,900	9	64,773	15,627	2,320	2	17,950	15,876	1,751	5	17,632	6,961	901	1	7,863
Apr-12	218,198	23,905	269	242,372	57,824	6,867	9	64,700	15,545	2,306	2	17,853	15,835	1,743	5	17,583	6,953	897	1	7,851
May-12	218,529	23,911	269	242,709	57,842	6,871	9	64,722	15,506	2,325	2	17,832	15,737	1,730	5	17,472	6,930	897	2	7,829
Jun-12	218,864	23,944	272	243,080	57,663	6,861	9	64,533	15,418	2,320	2	17,740	15,621	1,726	5	17,352	6,891	898	2	7,791
Jul-12	218,896	23,908	275	243,079	57,476	6,855	9	64,340	15,471	2,315	2	17,789	15,687	1,732	5	17,424	6,766	900	2	7,668
Aug-12	219,174	24,017	272	243,463	57,337	6,859	9	64,204	15,409	2,309	2	17,721	15,579	1,726	5	17,310	6,741	902	3	7,646
Sep-12	219,929	24,107	274	244,310	57,502	6,883	9	64,394	15,374	2,306	2	17,682	15,593	1,735	5	17,333	6,726	905	7	7,639
Oct-12	221,381	24,133	271	245,784	58,042	6,870	9	64,921	15,524	2,309	2	17,835	15,802	1,716	5	17,523	6,854	904	7	7,766
Nov-12	222,172	24,274	273	246,719	58,725	6,954	9	65,688	15,778	2,328	2	18,108	16,039	1,731	5	17,775	6,955	904	5	7,864
Dec-12	223,376	24,373	275	248,024	59,426	6,987	9	66,422	15,906	2,331	2	18,239	16,218	1,752	4	17,973	7,021	904	2	7,927
Jan-13	223,135	24,438	270	247,843	59,431	6,960	9	66,400	16,202	2,352	2	18,556	16,223	1,759	4	17,986	7,081	904	1	7,986
Feb-13	223,241	24,571	274	248,086	59,506	6,967	9	66,481	16,246	2,354	2	18,601	16,261	1,770	5	18,036	7,093	904	1	7,997
Mar-13	223,588	24,538	272	248,398	59,662	6,982	9	66,654	16,302	2,357	2	18,661	16,290	1,771	5	18,067	7,082	905	1	7,988
Apr-13	223,476	24,513	272	248,261	59,621	6,948	9	66,578	16,216	2,342	2	18,560	16,248	1,764	5	18,017	7,074	901	1	7,976
May-13	223,815	24,519	272	248,606	59,640	6,953	9	66,601	16,176	2,361	2	18,538	16,148	1,751	5	17,903	7,050	901	2	7,953
Jun-13	224,159	24,553	275	248,987	59,455	6,942	9	66,407	16,084	2,357	2	18,442	16,029	1,746	5	17,780	7,011	902	2	7,915
Jul-13	224,191	24,516	278	248,985	59,262	6,936	9	66,208	16,140	2,351	2	18,493	16,096	1,753	5	17,854	6,884	904	2	7,790
Aug-13	224,476	24,628	275	249,379	59,118	6,940	9	66,068	16,075	2,345	2	18,422	15,985	1,746	5	17,737	6,858	906	3	7,767
Sep-13	225,249	24,720	277	250,246	59,289	6,965	9	66,263	16,038	2,342	2	18,382	16,000	1,756	5	17,761	6,844	909	7	7,759
Oct-13	226,736	24,747	274	251,756	59,846	6,952	9	66,806	16,194	2,345	2	18,541	16,214	1,736	5	17,956	6,974	908	7	7,888

Appendix 2.2 - Customer Forecast - Number by Region
Expected Case

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-13	227,546	24,892	276	252,714	60,550	7,037	9	67,595	16,460	2,364	2	18,826	16,457	1,752	5	18,214	7,076	908	5	7,989
Dec-13	228,779	24,993	278	254,050	61,273	7,070	9	68,352	16,593	2,367	2	18,962	16,641	1,772	4	18,417	7,143	908	2	8,053
Jan-14	228,206	25,044	274	253,524	61,172	7,048	9	68,229	16,851	2,391	2	19,244	16,636	1,781	4	18,421	7,187	908	1	8,096
Feb-14	228,314	25,180	278	253,772	61,249	7,055	9	68,314	16,896	2,392	2	19,291	16,675	1,793	5	18,472	7,199	908	1	8,108
Mar-14	228,669	25,147	276	254,091	61,411	7,071	9	68,490	16,955	2,396	2	19,353	16,705	1,794	5	18,504	7,188	909	1	8,098
Apr-14	228,555	25,121	276	253,952	61,368	7,037	9	68,413	16,866	2,381	2	19,249	16,662	1,786	5	18,453	7,180	905	1	8,086
May-14	228,901	25,127	276	254,304	61,388	7,041	9	68,437	16,824	2,400	2	19,225	16,559	1,773	5	18,337	7,156	905	2	8,063
Jun-14	229,253	25,162	279	254,693	61,198	7,030	9	68,237	16,728	2,396	2	19,126	16,436	1,769	5	18,210	7,116	906	2	8,024
Jul-14	229,286	25,124	282	254,692	60,999	7,024	9	68,032	16,786	2,390	2	19,178	16,506	1,775	5	18,286	6,987	908	2	7,897
Aug-14	229,577	25,238	279	255,095	60,851	7,028	9	67,888	16,719	2,384	2	19,105	16,392	1,769	5	18,166	6,961	910	3	7,874
Sep-14	230,367	25,333	281	255,982	61,026	7,053	9	68,089	16,680	2,381	2	19,063	16,407	1,778	5	18,190	6,946	913	7	7,866
Oct-14	231,888	25,360	278	257,527	61,599	7,040	9	68,648	16,843	2,384	2	19,229	16,627	1,758	5	18,390	7,078	912	7	7,997
Nov-14	232,717	25,509	280	258,506	62,324	7,126	9	69,459	17,119	2,403	2	19,524	16,876	1,774	5	18,655	7,182	912	5	8,099
Dec-14	233,978	25,613	282	259,873	63,068	7,160	9	70,237	17,258	2,406	2	19,666	17,064	1,795	4	18,863	7,250	912	2	8,164
Jan-15	233,178	25,650	278	259,106	62,951	7,147	9	70,107	17,533	2,438	2	19,972	17,048	1,808	4	18,860	7,323	913	1	8,237
Feb-15	233,289	25,790	282	259,360	63,030	7,155	9	70,194	17,580	2,439	2	20,021	17,088	1,820	5	18,913	7,335	913	1	8,249
Mar-15	233,651	25,755	280	259,687	63,196	7,170	9	70,376	17,642	2,442	2	20,086	17,119	1,821	5	18,945	7,325	914	1	8,239
Apr-15	233,535	25,729	280	259,544	63,152	7,136	9	70,297	17,548	2,427	2	19,977	17,075	1,813	5	18,893	7,316	910	1	8,227
May-15	233,889	25,735	280	259,904	63,173	7,140	9	70,322	17,504	2,446	2	19,953	16,969	1,800	5	18,774	7,291	910	2	8,203
Jun-15	234,248	25,771	283	260,302	62,977	7,129	9	70,116	17,405	2,442	2	19,849	16,844	1,795	5	18,644	7,251	911	2	8,163
Jul-15	234,282	25,732	286	260,300	62,773	7,123	9	69,905	17,465	2,437	2	19,904	16,915	1,802	5	18,722	7,119	913	2	8,034
Aug-15	234,580	25,849	283	260,712	62,620	7,127	9	69,756	17,396	2,430	2	19,828	16,798	1,795	5	18,599	7,093	915	3	8,010
Sep-15	235,387	25,946	285	261,618	62,801	7,153	9	69,963	17,355	2,427	2	19,784	16,814	1,805	5	18,624	7,078	918	7	8,002
Oct-15	236,941	25,974	282	263,197	63,391	7,139	9	70,539	17,525	2,430	2	19,957	17,039	1,785	5	18,829	7,212	917	7	8,136
Nov-15	237,788	26,126	284	264,198	64,136	7,226	9	71,371	17,812	2,449	2	20,263	17,295	1,801	5	19,100	7,318	917	5	8,240
Dec-15	239,076	26,232	286	265,595	64,902	7,261	9	72,172	17,956	2,453	2	20,411	17,488	1,822	4	19,314	7,388	917	2	8,306
Jan-16	238,249	26,257	282	264,787	64,780	7,257	9	72,046	18,237	2,488	2	20,726	17,461	1,839	4	19,304	7,460	918	1	8,379
Feb-16	238,362	26,399	286	265,047	64,861	7,265	9	72,135	18,286	2,489	2	20,777	17,502	1,851	5	19,358	7,472	918	1	8,391
Mar-16	238,732	26,364	284	265,380	65,032	7,281	9	72,322	18,350	2,492	2	20,844	17,534	1,852	5	19,391	7,461	919	1	8,381
Apr-16	238,613	26,337	284	265,234	64,987	7,246	9	72,241	18,253	2,477	2	20,731	17,488	1,845	5	19,338	7,452	915	1	8,368
May-16	238,975	26,344	284	265,602	65,008	7,250	9	72,267	18,207	2,496	2	20,706	17,380	1,831	5	19,216	7,427	915	2	8,344
Jun-16	239,342	26,380	287	266,008	64,807	7,239	9	72,055	18,104	2,492	2	20,598	17,252	1,826	5	19,083	7,386	916	2	8,304
Jul-16	239,377	26,340	290	266,007	64,596	7,233	9	71,838	18,167	2,487	2	20,655	17,324	1,833	5	19,162	7,252	918	2	8,172
Aug-16	239,681	26,460	287	266,428	64,439	7,237	9	71,685	18,094	2,480	2	20,576	17,205	1,826	5	19,036	7,225	920	3	8,148
Sep-16	240,506	26,559	289	267,354	64,625	7,263	9	71,897	18,052	2,477	2	20,531	17,221	1,836	5	19,062	7,209	923	7	8,140
Oct-16	242,094	26,588	286	268,967	65,232	7,249	9	72,490	18,228	2,480	2	20,710	17,452	1,816	5	19,272	7,347	922	7	8,276
Nov-16	242,959	26,744	288	269,991	65,999	7,338	9	73,346	18,527	2,500	2	21,029	17,713	1,832	5	19,550	7,454	922	5	8,381
Dec-16	244,275	26,852	290	271,418	66,787	7,373	9	74,169	18,677	2,503	2	21,182	17,911	1,853	4	19,768	7,525	922	2	8,449
Jan-17	243,415	26,862	284	270,560	66,596	7,365	9	73,970	18,952	2,535	2	21,488	17,886	1,868	4	19,758	7,581	923	1	8,505
Feb-17	243,530	27,007	288	270,826	66,680	7,372	9	74,061	19,003	2,536	2	21,541	17,928	1,880	5	19,813	7,593	923	1	8,517
Mar-17	243,909	26,972	286	271,166	66,855	7,389	9	74,253	19,069	2,539	2	21,610	17,961	1,881	5	19,847	7,582	924	1	8,507
Apr-17	243,787	26,944	286	271,017	66,809	7,353	9	74,170	18,968	2,524	2	21,494	17,914	1,874	5	19,793	7,573	920	1	8,494
May-17	244,156	26,951	286	271,393	66,830	7,357	9	74,196	18,921	2,544	2	21,467	17,803	1,860	5	19,668	7,548	920	2	8,470
Jun-17	244,531	26,988	289	271,808	66,623	7,346	9	73,979	18,814	2,539	2	21,355	17,672	1,855	5	19,532	7,506	921	2	8,429
Jul-17	244,567	26,947	292	271,806	66,407	7,340	9	73,756	18,879	2,534	2	21,414	17,746	1,862	5	19,613	7,370	923	2	8,295
Aug-17	244,878	27,070	289	272,236	66,246	7,344	9	73,599	18,803	2,527	2	21,332	17,624	1,855	5	19,484	7,342	925	3	8,270
Sep-17	245,720	27,172	291	273,183	66,437	7,370	9	73,816	18,760	2,524	2	21,286	17,640	1,865	5	19,510	7,326	928	7	8,262
Oct-17	247,343	27,201	288	274,831	67,061	7,356	9	74,426	18,943	2,527	2	21,472	17,877	1,844	5	19,726	7,466	927	7	8,400
Nov-17	248,227	27,360	290	275,877	67,850	7,446	9	75,305	19,253	2,547	2	21,802	18,145	1,861	5	20,010	7,575	927	5	8,507
Dec-17	249,572	27,471	292	277,335	68,660	7,482	9	76,151	19,409	2,550	2	21,962	18,347	1,882	4	20,234	7,647	927	2	8,576
Jan-18	248,778	27,463	287	276,527	68,337	7,465	9	75,811	19,644	2,577	2	22,223	18,299	1,894	4	20,197	7,702	927	1	8,630
Feb-18	248,896	27,612	291	276,799	68,423	7,472	9	75,905	19,697	2,578	2	22,277	18,342	1,906	5	20,253	7,714	927	1	8,643
Mar-18	249,283	27,575	289	277,147	68,604	7,489	9	76,101	19,766	2,581	2	22,349	18,375	1,907	5	20,287	7,703	928	1	8,632
Apr-18	249,159	27,547	289	276,994	68,556	7,453	9	76,017	19,662	2,565	2	22,229	18,327	1,899	5	20,232	7,694	924	1	8,619
May-18	249,536	27,554	289	277,379	68,578	7,457	9	76,044	19,613	2,586	2	22,200	18,214	1,885	5	20,104	7,668	924	2	8,594
Jun-18	249,919	27,592	292	277,803	68,366	7,446	9	75,821	19,501	2,581	2	22,084	18,080	1,881	5	19,965	7,626	925	2	8,553
Jul-18	249,956	27,550	295	277,801	68,144	7,439	9	75,592	19,569	2,575	2	22,146	18,156	1,887	5	20,048	7,487	927	2	8,417
Aug-18	250,273	27,676	292	278,241	67,978	7,444	9	75,431	19,491	2,569	2	22,061	18,031	1,881	5	19,916	7,459	929	3	8,392
Sep-18	251,135	27,780	294	279,208	68,174	7,470	9	75,654	19,446	2,565	2	22,013	18,047	1,891	5	19,943	7,444	932	7	8,383
Oct-18	252,793	27,809	291	280,893	68,814	7,456	9	76,279	19,635	2,569	2	22,206	18,289	1,870	5	20,164	7,585	931	7	8,524
Nov-18	253,696	27,972	293	281,962	69,624	7,547	9	77,180	19,957	2,589	2	22,548	18,563	1,886	5	20,454	7,696	931	5	8,633
Dec-18	255,071	28,086	295	283,452	70,455	7,583	9	78,048	20,119	2,592	2	22,713	18,770	1,908	4	20,683	7,769	931	2	8,703
Jan-19	254,242	28,064	291	282,596	70,091	7,563	9	77,664	20,337	2,617	2	22,957	18,699	1,920	4	20,623	7,808	932	1	8,741
Feb-19	254,362	28,216	295	282,874	70,179	7,571	9	77,759	20,392	2,618	2	23,013	18,743	1,932	5	20,680	7,821	932	1	8,753
Mar-19	254,758	28,179	293	283,229	70,364	7,588	9	77,961	20,464	2,622	2	23,087	18,777	1,933	5	20,715	7,809	933	1	8,743
Apr-19	254,631	28,150	293	283,073	70,315	7,551	9	77,875	20,355	2,606	2	22,963	18,728	1,925	5	20,658	7,800	928	1	8,729
May-19	255,016	28,157	293	283,466	70,338	7,555	9	77,902	20,305	2,626	2	22,933	18,612	1,911	5	20,528	7,774	928	2	8,704
Jun-19	255,408	28,196	296	283,900	70,120	7,544	9	77,674	20,189	2,622	2	22,813	18,475	1,906	5	20,386	7,731	929	2	8,662
Jul-19	255,445	28,153	299	283,898	69,893	7,538	9	77,439	20,259	2,616	2	22,877	18,553	1,913	5	20,471	7,590	932	2	8,524
Aug-19	255,770	28,281	296	284,347	69,723	7,542	9	77,274	20,178	2,609	2	22,790	18,425	1,906	5	20,336	7,562	934	3	8,499
Sep-19	256,650	28,388	298	285,336	69,924	7,569	9	77,502	20,132	2,606	2	22,739	18,442	1,916	5	20,363	7,546	937	7	8,490
Oct-19	258,345	28,418	295	287,058	70,581	7,554	9	78,144	20,328	2,609	2	22,939	18,689	1,895	5	20,589	7,690	936	7	8,632

Appendix 2.2 - Customer Forecast - Number by Region
Expected Case

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-19	259,268	28,585	297	288,150	71,411	7,647	9	79,067	20,661	2,630	2	23,293	18,969	1,912	5	20,886	7,802	936	5	8,743
Dec-19	260,673	28,701	299	289,673	72,264	7,684	9	79,956	20,828	2,633	2	23,464	19,181	1,934	4	21,119	7,876	936	2	8,814
Jan-20	260,002	28,689	292	288,982	71,833	7,667	9	79,509	21,041	2,660	2	23,703	19,112	1,947	4	21,062	7,929	936	1	8,866
Feb-20	260,126	28,845	296	289,266	71,923	7,675	9	79,607	21,098	2,661	2	23,761	19,156	1,959	5	21,120	7,942	936	1	8,879
Mar-20	260,530	28,806	294	289,630	72,113	7,692	9	79,813	21,172	2,664	2	23,838	19,191	1,960	5	21,156	7,930	937	1	8,868
Apr-20	260,400	28,777	294	289,470	72,062	7,654	9	79,726	21,060	2,648	2	23,710	19,141	1,952	5	21,099	7,921	933	1	8,855
May-20	260,794	28,784	294	289,872	72,086	7,659	9	79,754	21,007	2,669	2	23,678	19,023	1,937	5	20,966	7,894	933	2	8,829
Jun-20	261,195	28,824	297	290,315	71,862	7,648	9	79,519	20,888	2,664	2	23,555	18,883	1,933	5	20,821	7,851	934	2	8,786
Jul-20	261,233	28,780	300	290,313	71,629	7,641	9	79,279	20,960	2,659	2	23,621	18,962	1,940	5	20,907	7,708	936	2	8,646
Aug-20	261,565	28,911	297	290,773	71,455	7,645	9	79,110	20,877	2,652	2	23,530	18,832	1,933	5	20,770	7,679	938	3	8,620
Sep-20	262,465	29,020	299	291,784	71,661	7,673	9	79,343	20,828	2,648	2	23,479	18,849	1,943	5	20,797	7,663	941	7	8,611
Oct-20	264,198	29,051	296	293,545	72,334	7,658	9	80,001	21,031	2,652	2	23,685	19,102	1,922	5	21,028	7,809	940	7	8,756
Nov-20	265,142	29,221	298	294,662	73,185	7,752	9	80,946	21,376	2,673	2	24,051	19,388	1,939	5	21,331	7,923	940	5	8,868
Dec-20	266,579	29,340	300	296,219	74,059	7,789	9	81,857	21,549	2,676	2	24,228	19,604	1,961	4	21,570	7,999	940	2	8,941
Jan-21	265,962	29,316	294	295,572	73,525	7,757	9	81,291	21,734	2,693	2	24,429	19,524	1,967	4	21,495	8,035	940	1	8,976
Feb-21	266,088	29,475	299	295,862	73,617	7,765	9	81,391	21,793	2,694	2	24,489	19,570	1,980	5	21,555	8,048	940	1	8,989
Mar-21	266,502	29,436	297	296,234	73,811	7,783	9	81,602	21,869	2,698	2	24,569	19,606	1,981	5	21,591	8,036	941	1	8,978
Apr-21	266,369	29,405	297	296,071	73,759	7,745	9	81,513	21,753	2,681	2	24,437	19,555	1,973	5	21,532	8,027	937	1	8,965
May-21	266,772	29,413	297	296,482	73,783	7,749	9	81,542	21,699	2,703	2	24,404	19,434	1,958	5	21,397	8,000	937	2	8,939
Jun-21	267,182	29,453	300	296,935	73,555	7,738	9	81,302	21,576	2,698	2	24,276	19,290	1,953	5	21,249	7,955	938	2	8,895
Jul-21	267,221	29,409	303	296,933	73,316	7,731	9	81,056	21,651	2,692	2	24,345	19,372	1,960	5	21,337	7,811	940	2	8,753
Aug-21	267,560	29,543	300	297,403	73,138	7,736	9	80,883	21,564	2,685	2	24,251	19,238	1,953	5	21,196	7,782	942	3	8,727
Sep-21	268,481	29,654	302	298,437	73,349	7,763	9	81,121	21,514	2,681	2	24,198	19,256	1,963	5	21,225	7,766	945	7	8,718
Oct-21	270,254	29,686	299	300,238	74,038	7,748	9	81,795	21,724	2,685	2	24,411	19,514	1,942	5	21,461	7,913	944	7	8,864
Nov-21	271,220	29,860	301	301,381	74,909	7,843	9	82,761	22,080	2,706	2	24,788	19,806	1,959	5	21,770	8,029	944	5	8,978
Dec-21	272,689	29,981	303	302,974	75,803	7,881	9	83,693	22,259	2,710	2	24,971	20,028	1,982	4	22,013	8,106	944	2	9,051
Jan-22	272,119	29,942	296	302,357	75,167	7,854	9	83,029	22,427	2,732	2	25,161	19,937	1,992	4	21,933	8,141	944	1	9,086
Feb-22	272,248	30,104	301	302,653	75,261	7,862	9	83,132	22,488	2,733	2	25,223	19,984	2,004	5	21,993	8,154	944	1	9,099
Mar-22	272,671	30,064	299	303,034	75,459	7,879	9	83,347	22,566	2,737	2	25,305	20,020	2,006	5	22,031	8,142	945	1	9,088
Apr-22	272,535	30,033	299	302,867	75,407	7,841	9	83,257	22,447	2,720	2	25,169	19,968	1,997	5	21,970	8,133	941	1	9,074
May-22	272,948	30,041	299	303,288	75,431	7,846	9	83,286	22,391	2,742	2	25,134	19,845	1,982	5	21,832	8,106	941	2	9,048
Jun-22	273,367	30,082	302	303,752	75,198	7,834	9	83,041	22,264	2,737	2	25,003	19,698	1,978	5	21,681	8,060	942	2	9,004
Jul-22	273,407	30,037	305	303,750	74,953	7,827	9	82,790	22,341	2,731	2	25,074	19,781	1,985	5	21,771	7,914	944	2	8,860
Aug-22	273,754	30,174	302	304,230	74,771	7,832	9	82,612	22,252	2,724	2	24,977	19,645	1,978	5	21,628	7,885	946	3	8,833
Sep-22	274,697	30,287	304	305,288	74,987	7,860	9	82,856	22,200	2,720	2	24,922	19,663	1,988	5	21,656	7,868	949	7	8,824
Oct-22	276,510	30,319	301	307,131	75,691	7,844	9	83,545	22,417	2,724	2	25,142	19,927	1,966	5	21,898	8,018	948	7	8,973
Nov-22	277,499	30,497	303	308,299	76,582	7,940	9	84,531	22,784	2,745	2	25,531	20,225	1,983	5	22,214	8,135	948	5	9,088
Dec-22	279,002	30,621	305	309,929	77,496	7,979	9	85,484	22,969	2,749	2	25,719	20,451	2,007	4	22,462	8,212	948	2	9,162
Jan-23	278,476	30,567	299	309,342	76,784	7,952	9	84,745	23,109	2,771	2	25,882	20,337	2,016	4	22,357	8,232	948	1	9,181
Feb-23	278,608	30,733	304	309,644	76,880	7,960	9	84,850	23,171	2,772	2	25,946	20,385	2,029	5	22,419	8,245	948	1	9,194
Mar-23	279,041	30,692	302	310,034	77,083	7,978	9	85,070	23,252	2,776	2	26,030	20,422	2,030	5	22,457	8,233	949	1	9,183
Apr-23	278,902	30,660	302	309,864	77,029	7,939	9	84,977	23,129	2,759	2	25,890	20,369	2,022	5	22,396	8,224	945	1	9,169
May-23	279,324	30,668	302	310,294	77,054	7,944	9	85,007	23,072	2,781	2	25,854	20,243	2,007	5	22,255	8,196	945	2	9,143
Jun-23	279,753	30,710	305	310,768	76,815	7,932	9	84,757	22,941	2,776	2	25,719	20,093	2,002	5	22,101	8,150	946	2	9,098
Jul-23	279,794	30,664	308	310,766	76,566	7,925	9	84,500	23,020	2,770	2	25,792	20,178	2,009	5	22,192	8,003	948	2	8,953
Aug-23	280,149	30,804	305	311,258	76,380	7,930	9	84,319	22,928	2,762	2	25,693	20,039	2,002	5	22,046	7,973	950	3	8,926
Sep-23	281,114	30,919	307	312,340	76,600	7,958	9	84,568	22,875	2,759	2	25,636	20,058	2,013	5	22,075	7,956	953	7	8,916
Oct-23	282,970	30,952	304	314,226	77,320	7,943	9	85,272	23,098	2,762	2	25,863	20,326	1,990	5	22,322	8,107	952	7	9,066
Nov-23	283,981	31,134	306	315,421	78,229	8,040	9	86,278	23,477	2,784	2	26,263	20,631	2,008	5	22,644	8,226	952	5	9,183
Dec-23	285,520	31,260	308	317,089	79,163	8,079	9	87,251	23,667	2,788	2	26,457	20,861	2,032	4	22,897	8,304	952	2	9,258
Jan-24	284,832	31,193	300	316,325	78,351	8,054	9	86,414	23,802	2,812	2	26,616	20,725	2,043	4	22,772	8,323	952	1	9,276
Feb-24	284,968	31,362	305	316,635	78,449	8,062	9	86,520	23,866	2,813	2	26,681	20,773	2,056	5	22,835	8,336	952	1	9,289
Mar-24	285,410	31,320	303	317,033	78,656	8,080	9	86,745	23,950	2,817	2	26,768	20,811	2,057	5	22,873	8,324	953	1	9,278
Apr-24	285,268	31,288	303	316,859	78,601	8,041	9	86,651	23,823	2,799	2	26,624	20,757	2,049	5	22,811	8,314	949	1	9,264
May-24	285,700	31,296	303	317,299	78,627	8,045	9	86,681	23,763	2,822	2	26,587	20,629	2,034	5	22,668	8,286	949	2	9,238
Jun-24	286,139	31,339	306	317,784	78,383	8,034	9	86,426	23,629	2,817	2	26,447	20,476	2,029	5	22,510	8,240	950	2	9,192
Jul-24	286,181	31,292	309	317,782	78,129	8,026	9	86,164	23,711	2,810	2	26,523	20,563	2,036	5	22,604	8,091	952	2	9,045
Aug-24	286,544	31,434	306	318,285	77,939	8,031	9	85,979	23,616	2,803	2	26,421	20,421	2,029	5	22,455	8,061	954	3	9,018
Sep-24	287,530	31,553	308	319,391	78,164	8,060	9	86,233	23,561	2,799	2	26,363	20,440	2,040	5	22,485	8,044	958	7	9,008
Oct-24	289,429	31,586	305	321,320	78,898	8,044	9	86,951	23,791	2,803	2	26,596	20,714	2,017	5	22,736	8,197	956	7	9,160
Nov-24	290,463	31,771	307	322,542	79,826	8,143	9	87,978	24,181	2,825	2	27,008	21,024	2,035	5	23,064	8,317	956	5	9,278
Dec-24	292,037	31,900	309	324,247	80,779	8,182	9	88,970	24,377	2,829	2	27,208	21,259	2,059	4	23,322	8,396	956	2	9,354
Jan-25	291,189	31,819	303	323,311	79,893	8,158	9	88,061	24,495	2,855	2	27,352	21,125	2,072	4	23,201	8,414	957	1	9,371
Feb-25	291,327	31,991	308	323,627	79,994	8,166	9	88,169	24,561	2,856	2	27,419	21,174	2,085	5	23,265	8,427	957	1	9,385
Mar-25	291,780	31,949	306	324,034	80,205	8,184	9	88,398	24,647	2,860	2	27,509	21,213	2,087	5	23,304	8,415	958	1	9,374
Apr-25	291,635	31,916	306	323,856	80,149	8,145	9	88,303	24,516	2,843	2	27,361	21,158	2,078	5	23,241	8,405	953	1	9,359
May-25	292,076	31,924	306	324,306	80,174	8,150	9	88,333	24,455	2,865	2	27,322	21,027	2,062	5	23,095	8,377	953	2	9,332
Jun-25	292,525	31,968	309	324,802	79,926	8,138	9	88,073	24,317	2,860	2	27,179	20,872	2,058	5	22,934	8,330	954	2	9,287
Jul-25	292,567	31,920	313	324,800	79,667	8,130	9	87,806	24,401	2,854	2	27,257	20,960	2,065	5	23,030	8,179	957	2	9,138
Aug-25	292,939	32,065	309	325,313	79,473	8,135	9	87,618	24,303	2,846	2	27,152	20,815	2,058	5	22,878	8,149	959	3	9,110
Sep-25	293,947	32,186	311	326,444	79,703	8,164	9	87,876	24,247	2,843	2	27,092	20,835	2,068	5	22,908	8,131	962	7	9,100
Oct-25	295,888	32,220	308	328,416	80,451	8,148	9	88,609	24,483	2,846	2	27,332	21,114	2,046	5	23,164	8,286	961	7	9,254

Appendix 2.2 - Customer Forecast - Number by Region
Expected Case

	WA / ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA / ID Res	WA / ID Com	WA / ID Firm Ind	WA / ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-25	296,946	32,409	310	329,665	81,397	8,248	9	89,655	24,885	2,869	2	27,756	21,430	2,064	5	23,499	8,408	961	5	9,373
Dec-25	298,555	32,541	313	331,408	82,370	8,288	9	90,666	25,086	2,873	2	27,961	21,670	2,088	4	23,761	8,487	961	2	9,450
Jan-26	297,446	32,445	305	330,196	81,448	8,260	9	89,718	25,210	2,897	2	28,109	21,538	2,099	4	23,640	8,489	961	1	9,451
Feb-26	297,588	32,621	310	330,518	81,551	8,269	9	89,828	25,278	2,898	2	28,178	21,588	2,112	5	23,705	8,503	961	1	9,465
Mar-26	298,050	32,577	308	330,935	81,766	8,287	9	90,062	25,366	2,902	2	28,270	21,627	2,114	5	23,746	8,491	962	1	9,454
Apr-26	297,902	32,544	308	330,753	81,709	8,247	9	89,964	25,232	2,884	2	28,118	21,571	2,105	5	23,681	8,481	958	1	9,439
May-26	298,353	32,552	308	331,213	81,735	8,252	9	89,996	25,169	2,907	2	28,078	21,438	2,089	5	23,532	8,452	958	2	9,412
Jun-26	298,811	32,597	311	331,719	81,482	8,240	9	89,731	25,026	2,902	2	27,930	21,280	2,084	5	23,369	8,405	959	2	9,366
Jul-26	298,854	32,548	315	331,717	81,217	8,232	9	89,459	25,113	2,896	2	28,010	21,369	2,092	5	23,466	8,253	961	2	9,216
Aug-26	299,234	32,696	311	332,241	81,020	8,237	9	89,266	25,013	2,888	2	27,903	21,222	2,084	5	23,311	8,222	963	3	9,188
Sep-26	300,264	32,819	313	333,396	81,254	8,266	9	89,529	24,955	2,884	2	27,841	21,242	2,095	5	23,342	8,205	966	7	9,178
Oct-26	302,247	32,854	310	335,410	82,017	8,251	9	90,276	25,198	2,888	2	28,088	21,526	2,072	5	23,603	8,361	965	7	9,333
Nov-26	303,327	33,047	312	336,686	82,982	8,351	9	91,342	25,611	2,911	2	28,524	21,849	2,090	5	23,944	8,483	965	5	9,453
Dec-26	304,970	33,181	315	338,466	83,973	8,392	9	92,373	25,819	2,915	2	28,735	22,093	2,115	4	24,212	8,564	965	2	9,531
Jan-27	303,605	33,070	308	336,983	82,916	8,365	9	91,291	25,914	2,938	2	28,853	21,950	2,126	4	24,080	8,580	965	1	9,546
Feb-27	303,749	33,250	313	337,312	83,020	8,374	9	91,403	25,984	2,939	2	28,924	22,002	2,139	5	24,146	8,594	965	1	9,560
Mar-27	304,221	33,206	311	337,737	83,239	8,392	9	91,641	26,075	2,943	2	29,019	22,042	2,141	5	24,187	8,582	966	1	9,549
Apr-27	304,069	33,172	311	337,552	83,181	8,352	9	91,542	25,936	2,925	2	28,863	21,985	2,132	5	24,121	8,572	962	1	9,534
May-27	304,530	33,180	311	338,021	83,208	8,357	9	91,574	25,872	2,948	2	28,822	21,849	2,116	5	23,970	8,543	962	2	9,507
Jun-27	304,998	33,226	314	338,537	82,950	8,344	9	91,304	25,725	2,943	2	28,670	21,687	2,111	5	23,803	8,495	963	2	9,460
Jul-27	305,042	33,176	318	338,535	82,681	8,337	9	91,027	25,814	2,936	2	28,752	21,779	2,118	5	23,902	8,341	965	2	9,308
Aug-27	305,429	33,327	314	339,070	82,480	8,342	9	90,831	25,711	2,929	2	28,642	21,629	2,111	5	23,745	8,310	967	3	9,280
Sep-27	306,481	33,452	316	340,249	82,718	8,371	9	91,099	25,652	2,925	2	28,578	21,649	2,122	5	23,776	8,292	970	7	9,270
Oct-27	308,504	33,488	313	342,305	83,495	8,355	9	91,860	25,902	2,929	2	28,832	21,939	2,098	5	24,042	8,450	969	7	9,427
Nov-27	309,607	33,684	315	343,606	84,477	8,458	9	92,944	26,326	2,952	2	29,280	22,268	2,117	5	24,390	8,574	969	5	9,548
Dec-27	311,284	33,821	318	345,423	85,486	8,498	9	93,993	26,539	2,956	2	29,497	22,516	2,142	4	24,662	8,655	969	2	9,627

Appendix 2.2 - Customer Forecast - Number by Region
High Growth Case

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-07	195,608	21,927	272	217,807	50,367	6,478	9	56,854	13,207	2,184	2	15,393	13,846	1,595	7	15,448	6,417	896	14	7,327
Dec-07	197,373	22,072	276	219,721	51,082	6,528	9	57,619	13,389	2,196	2	15,587	14,106	1,624	5	15,736	6,514	896	5	7,415
Jan-08	197,899	22,002	273	220,175	51,415	6,553	9	57,978	13,452	2,205	2	15,659	14,187	1,650	5	15,841	6,573	898	2	7,473
Feb-08	198,051	22,192	280	220,523	51,520	6,564	9	58,093	13,512	2,207	2	15,721	14,240	1,666	7	15,913	6,590	898	2	7,489
Mar-08	198,548	22,145	276	220,970	51,665	6,586	9	58,260	13,590	2,211	2	15,803	14,282	1,668	7	15,957	6,575	899	2	7,476
Apr-08	198,388	22,109	276	220,774	51,682	6,537	9	58,227	13,472	2,190	2	15,664	14,223	1,657	7	15,887	6,563	893	2	7,458
May-08	198,873	22,118	276	221,267	51,634	6,543	9	58,186	13,416	2,217	2	15,636	14,081	1,638	7	15,725	6,529	893	5	7,427
Jun-08	199,365	22,167	281	221,812	51,375	6,528	9	57,912	13,290	2,211	2	15,504	13,912	1,632	7	15,551	6,472	895	5	7,371
Jul-08	199,110	22,114	286	221,510	51,104	6,519	9	57,632	13,292	2,204	2	15,498	13,858	1,641	7	15,506	6,288	898	5	7,191
Aug-08	199,518	22,274	281	222,073	50,902	6,525	9	57,436	13,204	2,195	2	15,400	13,702	1,632	7	15,340	6,251	901	8	7,160
Sep-08	200,624	22,406	284	223,314	51,142	6,561	9	57,712	13,153	2,190	2	15,345	13,723	1,645	7	15,375	6,230	905	20	7,155
Oct-08	202,752	22,444	280	225,476	51,698	6,541	9	58,248	13,367	2,195	2	15,563	14,026	1,617	7	15,649	6,418	904	20	7,342
Nov-08	203,912	22,652	283	226,847	52,461	6,666	9	59,135	13,731	2,222	2	15,955	14,369	1,639	7	16,015	6,566	904	14	7,484
Dec-08	205,677	22,797	286	228,759	53,250	6,715	9	59,974	13,913	2,226	2	16,142	14,628	1,669	5	16,303	6,663	904	5	7,572
Jan-09	206,506	22,736	280	229,521	53,359	6,720	9	60,088	14,051	2,273	2	16,326	14,709	1,691	5	16,405	6,723	905	2	7,629
Feb-09	206,657	22,926	286	229,870	53,539	6,730	9	60,278	14,111	2,274	2	16,387	14,763	1,708	7	16,477	6,739	905	2	7,646
Mar-09	207,154	22,879	283	230,316	53,759	6,753	9	60,520	14,189	2,279	2	16,470	14,804	1,709	7	16,521	6,724	906	2	7,632
Apr-09	206,994	22,843	283	230,120	53,850	6,703	9	60,562	14,071	2,258	2	16,330	14,745	1,699	7	16,450	6,712	900	2	7,614
May-09	207,479	22,852	283	230,614	53,877	6,709	9	60,595	14,015	2,285	2	16,302	14,603	1,679	7	16,289	6,678	900	5	7,583
Jun-09	207,971	22,901	288	231,159	53,618	6,694	9	60,321	13,889	2,279	2	16,170	14,434	1,673	7	16,115	6,621	902	5	7,528
Jul-09	208,017	22,848	292	231,157	53,347	6,685	9	60,042	13,966	2,271	2	16,239	14,455	1,682	7	16,145	6,437	905	5	7,347
Aug-09	208,425	23,008	288	231,720	53,146	6,691	9	59,846	13,877	2,262	2	16,141	14,299	1,673	7	15,979	6,400	908	8	7,316
Sep-09	209,531	23,140	291	232,962	53,385	6,727	9	60,121	13,826	2,258	2	16,086	14,320	1,687	7	16,013	6,379	912	20	7,311
Oct-09	211,659	23,178	286	235,123	54,016	6,708	9	60,733	14,041	2,262	2	16,305	14,622	1,659	7	16,288	6,567	911	20	7,498
Nov-09	212,819	23,386	289	236,494	54,853	6,832	9	61,694	14,404	2,289	2	16,696	14,966	1,681	7	16,653	6,715	911	14	7,640
Dec-09	214,584	23,531	292	238,407	55,718	6,882	9	62,608	14,587	2,294	2	16,883	15,225	1,711	5	16,941	6,812	911	5	7,728
Jan-10	215,336	23,544	289	239,169	55,827	6,864	9	62,700	14,800	2,336	2	17,138	15,306	1,730	5	17,041	6,872	911	2	7,785
Feb-10	215,488	23,734	296	239,517	56,006	6,875	9	62,890	14,860	2,338	2	17,199	15,360	1,746	7	17,113	6,888	911	2	7,802
Mar-10	215,984	23,687	292	239,964	56,226	6,897	9	63,132	14,937	2,342	2	17,282	15,401	1,748	7	17,156	6,873	913	2	7,788
Apr-10	215,825	23,651	292	239,768	56,168	6,848	9	63,025	14,819	2,321	2	17,142	15,342	1,737	7	17,086	6,861	907	2	7,770
May-10	216,309	23,660	292	240,262	56,195	6,854	9	63,058	14,764	2,348	2	17,114	15,200	1,718	7	16,925	6,827	907	5	7,739
Jun-10	216,801	23,708	297	240,807	55,936	6,839	9	62,784	14,638	2,342	2	16,982	15,031	1,712	7	16,750	6,770	908	5	7,684
Jul-10	216,998	23,656	302	240,956	55,665	6,830	9	62,504	14,714	2,335	2	17,051	15,127	1,721	7	16,854	6,587	911	5	7,503
Aug-10	217,406	23,816	297	241,518	55,463	6,836	9	62,308	14,626	2,325	2	16,953	14,970	1,712	7	16,689	6,549	914	8	7,472
Sep-10	218,511	23,948	300	242,760	55,703	6,872	9	62,584	14,575	2,321	2	16,898	14,991	1,725	7	16,723	6,529	919	20	7,467
Oct-10	220,640	23,986	296	244,921	56,408	6,852	9	63,270	14,789	2,325	2	17,117	15,294	1,697	7	16,998	6,717	917	20	7,654
Nov-10	221,800	24,194	299	246,292	57,321	6,977	9	64,306	15,153	2,353	2	17,508	15,637	1,719	7	17,363	6,864	917	14	7,796
Dec-10	223,564	24,339	302	248,205	58,260	7,026	9	65,295	15,336	2,357	2	17,695	15,897	1,749	5	17,651	6,961	917	5	7,884
Jan-11	224,318	24,390	299	249,006	58,369	6,994	9	65,372	15,698	2,388	2	18,088	16,052	1,760	5	17,817	7,021	918	2	7,941
Feb-11	224,470	24,580	305	249,355	58,474	7,004	9	65,487	15,758	2,390	2	18,150	16,106	1,777	7	17,889	7,038	918	2	7,957
Mar-11	224,966	24,533	302	249,801	58,693	7,027	9	65,729	15,836	2,394	2	18,232	16,148	1,778	7	17,932	7,023	919	2	7,944
Apr-11	224,807	24,497	302	249,605	58,635	6,977	9	65,621	15,717	2,373	2	18,092	16,088	1,768	7	17,862	7,011	913	2	7,926
May-11	225,291	24,506	302	250,099	58,662	6,983	9	65,654	15,662	2,400	2	18,064	15,946	1,748	7	17,701	6,976	913	5	7,895
Jun-11	225,783	24,554	307	250,644	58,403	6,968	9	65,380	15,536	2,394	2	17,933	15,777	1,742	7	17,527	6,920	915	5	7,839
Jul-11	225,830	24,501	311	250,642	58,133	6,959	9	65,101	15,613	2,387	2	18,001	15,873	1,751	7	17,631	6,736	918	5	7,659
Aug-11	226,237	24,661	307	251,205	57,931	6,965	9	64,905	15,524	2,377	2	17,904	15,716	1,742	7	17,465	6,699	921	8	7,627
Sep-11	227,343	24,794	310	252,447	58,170	7,001	9	65,180	15,473	2,373	2	17,848	15,737	1,756	7	17,500	6,678	925	20	7,623
Oct-11	229,472	24,831	305	254,608	58,951	6,982	9	65,941	15,688	2,377	2	18,067	16,040	1,727	7	17,774	6,866	924	20	7,810
Nov-11	230,631	25,039	308	255,979	59,938	7,106	9	67,053	16,051	2,405	2	18,458	16,383	1,750	7	18,140	7,014	924	14	7,951
Dec-11	232,396	25,184	311	257,892	60,951	7,155	9	68,116	16,234	2,409	2	18,645	16,643	1,780	5	18,428	7,111	924	5	8,040
Jan-12	232,707	25,303	303	258,314	61,234	7,123	9	68,365	16,752	2,444	2	19,198	16,724	1,792	5	18,521	7,179	924	2	8,105
Feb-12	232,863	25,498	310	258,671	61,342	7,133	9	68,484	16,815	2,446	2	19,263	16,779	1,809	7	18,595	7,196	924	2	8,122
Mar-12	233,372	25,450	307	259,129	61,569	7,156	9	68,734	16,896	2,451	2	19,349	16,822	1,810	7	18,639	7,181	925	2	8,108
Apr-12	233,209	25,413	307	258,929	61,509	7,106	9	68,624	16,772	2,429	2	19,203	16,761	1,800	7	18,567	7,169	919	2	8,090
May-12	233,706	25,422	307	259,435	61,537	7,112	9	68,658	16,714	2,457	2	19,173	16,615	1,780	7	18,402	7,134	919	5	8,058
Jun-12	234,211	25,472	311	259,994	61,269	7,097	9	68,375	16,583	2,451	2	19,035	16,441	1,774	7	18,222	7,076	921	5	8,002
Jul-12	234,259	25,418	316	259,993	60,989	7,088	9	68,086	16,663	2,443	2	19,107	16,540	1,783	7	18,329	6,890	924	5	7,818
Aug-12	234,677	25,582	311	260,570	60,780	7,094	9	67,883	16,570	2,434	2	19,006	16,378	1,774	7	18,159	6,852	927	8	7,787
Sep-12	235,812	25,718	315	261,844	61,028	7,130	9	68,167	16,517	2,429	2	18,948	16,400	1,788	7	18,194	6,831	931	20	7,782
Oct-12	237,996	25,757	310	264,062	61,835	7,110	9	68,955	16,741	2,434	2	19,177	16,712	1,759	7	18,477	7,022	930	20	7,971
Nov-12	239,186	25,970	313	265,469	62,856	7,236	9	70,102	17,122	2,461	2	19,585	17,065	1,782	7	18,853	7,172	930	14	8,116
Dec-12	240,997	26,118	316	267,432	63,905	7,287	9	71,200	17,313	2,466	2	19,781	17,332	1,812	5	19,149	7,270	930	5	8,205
Jan-13	240,635	26,217	308	267,160	63,912	7,245	9	71,166	17,757	2,499	2	20,258	17,340	1,823	5	19,167	7,360	929	2	8,291
Feb-13	240,794	26,417	315	267,526	64,024	7,256	9	71,289	17,822	2,501	2	20,325	17,396	1,839	7	19,243	7,377	929	2	8,308
Mar-13	241,316	26,368	311	267,995	64,258	7,279	9	71,546	17,907	2,506	2	20,415	17,441	1,841	7	19,288	7,362	931	2	8,294
Apr-13	241,149	26,330	311	267,790	64,196	7,228	9	71,433	17,778	2,484	2	20,263	17,378	1,830	7	19,215	7,350	924	2	8,276
May-13	241,658	26,339	311	268,308	64,225	7,234	9	71,468	17,717	2,512	2	20,231	17,228	1,810	7	19,045	7,314	924	5	8,243
Jun-13	242,175	26,390	316	268,881	63,949	7,219	9	71,177	17,580	2,506	2	20,087	17,050	1,804	7	18,861	7,255	926	5	8,186
Jul-13	242,224	26,334	321	268,879	63,660	7,210	9	70,879	17,663	2,498	2	20,163	17,151	1,813	7	18,971	7,066	929	5	8,000
Aug-13	242,652	26,502	316	269,471	63,445	7,216	9	70,670	17,567	2,488	2	20,057	16,985	1,804	7	18,796	7,027	932	8	7,967
Sep-13	243,815	26,642	319	270,776	63,700	7,253	9	70,962	17,511	2,484	2	19,997	17,007	1,818	7	18,832	7,006	937	20	7,962
Oct-13	246,052	26,682	315	273,048	64,533	7,233	9	71,774	17,745	2,488	2	20,235	17,327	1,789	7	19,123	7,200	935	20	8,155

Appendix 2.2 - Customer Forecast - Number by Region
High Growth Case

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-13	247,271	26,901	318	274,489	65,585	7,360	9	72,954	18,143	2,517	2	20,661	17,690	1,812	7	19,508	7,353	935	14	8,302
Dec-13	249,126	27,053	321	276,500	66,667	7,411	9	74,086	18,342	2,521	2	20,865	17,964	1,842	5	19,811	7,453	935	5	8,393
Jan-14	248,263	27,131	314	275,707	66,516	7,377	9	73,903	18,728	2,558	2	21,289	17,956	1,856	5	19,817	7,519	935	2	8,456
Feb-14	248,426	27,335	321	276,082	66,631	7,388	9	74,029	18,796	2,560	2	21,358	18,014	1,873	7	19,894	7,536	935	2	8,473
Mar-14	248,960	27,285	318	276,562	66,873	7,412	9	74,293	18,885	2,565	2	21,451	18,059	1,875	7	19,941	7,520	937	2	8,459
Apr-14	248,788	27,246	318	276,352	66,809	7,360	9	74,178	18,750	2,542	2	21,295	17,994	1,864	7	19,865	7,508	931	2	8,441
May-14	249,309	27,256	318	276,882	66,838	7,367	9	74,214	18,687	2,571	2	21,260	17,841	1,844	7	19,691	7,472	931	5	8,408
Jun-14	249,838	27,308	323	277,468	66,554	7,351	9	73,914	18,544	2,565	2	21,111	17,658	1,838	7	19,503	7,412	932	5	8,350
Jul-14	249,888	27,251	328	277,466	66,257	7,342	9	73,608	18,631	2,557	2	21,190	17,762	1,847	7	19,615	7,220	935	5	8,160
Aug-14	250,326	27,423	323	278,072	66,035	7,348	9	73,392	18,531	2,547	2	21,080	17,592	1,838	7	19,436	7,180	939	8	8,127
Sep-14	251,515	27,566	326	279,407	66,298	7,385	9	73,692	18,473	2,542	2	21,017	17,614	1,852	7	19,473	7,159	943	20	8,122
Oct-14	253,803	27,607	321	281,730	67,155	7,365	9	74,529	18,716	2,547	2	21,265	17,943	1,822	7	19,772	7,356	942	20	8,317
Nov-14	255,050	27,831	324	283,205	68,238	7,494	9	75,741	19,130	2,576	2	21,708	18,314	1,845	7	20,167	7,511	942	14	8,466
Dec-14	256,946	27,987	328	285,261	69,351	7,545	9	76,906	19,337	2,581	2	21,920	18,596	1,876	5	20,477	7,613	942	5	8,559
Jan-15	255,743	28,044	321	284,107	69,176	7,526	9	76,712	19,749	2,629	2	22,380	18,571	1,896	5	20,473	7,722	942	2	8,667
Feb-15	255,909	28,254	327	284,491	69,295	7,537	9	76,841	19,820	2,630	2	22,452	18,631	1,914	7	20,551	7,740	942	2	8,684
Mar-15	256,455	28,202	324	284,981	69,543	7,561	9	77,113	19,912	2,635	2	22,549	18,677	1,915	7	20,599	7,724	944	2	8,670
Apr-15	256,280	28,162	324	284,766	69,477	7,509	9	76,995	19,772	2,612	2	22,387	18,611	1,904	7	20,522	7,711	938	2	8,651
May-15	256,812	28,172	324	285,308	69,508	7,515	9	77,032	19,707	2,642	2	22,350	18,454	1,884	7	20,344	7,674	938	5	8,617
Jun-15	257,352	28,226	329	285,907	69,215	7,499	9	76,724	19,558	2,635	2	22,195	18,267	1,877	7	20,151	7,614	939	5	8,558
Jul-15	257,403	28,167	334	285,905	68,909	7,490	9	76,408	19,648	2,627	2	22,277	18,373	1,887	7	20,266	7,417	942	5	8,365
Aug-15	257,851	28,344	329	286,524	68,681	7,496	9	76,187	19,544	2,617	2	22,163	18,199	1,877	7	20,083	7,378	946	8	8,331
Sep-15	259,065	28,490	332	287,888	68,952	7,534	9	76,495	19,484	2,612	2	22,098	18,222	1,892	7	20,120	7,355	950	20	8,325
Oct-15	261,403	28,532	327	290,263	69,834	7,514	9	77,356	19,737	2,617	2	22,356	18,558	1,862	7	20,427	7,556	949	20	8,525
Nov-15	262,677	28,762	331	291,770	70,949	7,644	9	78,602	20,167	2,647	2	22,816	18,939	1,885	7	20,831	7,714	949	14	8,677
Dec-15	264,616	28,921	334	293,871	72,094	7,696	9	79,799	20,383	2,651	2	23,037	19,227	1,917	5	21,149	7,818	949	5	8,771
Jan-16	263,370	28,958	327	292,655	71,911	7,691	9	79,611	20,803	2,705	2	23,510	19,187	1,943	5	21,135	7,926	951	2	8,878
Feb-16	263,541	29,172	334	293,047	72,033	7,702	9	79,744	20,877	2,706	2	23,585	19,248	1,960	7	21,215	7,943	951	2	8,896
Mar-16	264,098	29,120	330	293,548	72,288	7,726	9	80,024	20,973	2,711	2	23,686	19,296	1,962	7	21,264	7,927	952	2	8,881
Apr-16	263,919	29,079	330	293,328	72,220	7,674	9	79,903	20,827	2,688	2	23,517	19,228	1,951	7	21,185	7,914	946	2	8,862
May-16	264,463	29,089	330	293,882	72,252	7,680	9	79,941	20,759	2,718	2	23,479	19,067	1,930	7	21,003	7,877	946	5	8,828
Jun-16	265,015	29,143	335	294,494	71,951	7,664	9	79,624	20,604	2,711	2	23,318	18,875	1,923	7	20,805	7,815	947	5	8,768
Jul-16	265,067	29,084	340	294,491	71,636	7,654	9	79,300	20,698	2,703	2	23,403	18,984	1,933	7	20,924	7,615	951	5	8,571
Aug-16	265,525	29,264	335	295,124	71,401	7,661	9	79,071	20,590	2,693	2	23,285	18,805	1,923	7	20,736	7,575	954	8	8,536
Sep-16	266,765	29,414	339	296,519	71,680	7,699	9	79,388	20,527	2,688	2	23,217	18,829	1,938	7	20,774	7,552	958	20	8,530
Oct-16	269,154	29,457	334	298,945	72,587	7,678	9	80,275	20,790	2,693	2	23,485	19,174	1,908	7	21,088	7,757	957	20	8,733
Nov-16	270,456	29,692	337	300,485	73,734	7,811	9	81,555	21,238	2,723	2	23,963	19,564	1,931	7	21,502	7,917	957	14	8,888
Dec-16	272,436	29,856	340	302,633	74,913	7,864	9	82,786	21,462	2,728	2	24,192	19,859	1,963	5	21,827	8,023	957	5	8,985
Jan-17	271,141	29,870	330	301,341	74,627	7,852	9	82,488	21,873	2,776	2	24,652	19,822	1,986	5	21,813	8,106	958	2	9,067
Feb-17	271,316	30,089	337	301,742	74,752	7,863	9	82,624	21,950	2,778	2	24,730	19,884	2,004	7	21,895	8,125	958	2	9,085
Mar-17	271,885	30,035	333	302,254	75,014	7,888	9	82,911	22,050	2,783	2	24,835	19,933	2,005	7	21,945	8,108	960	2	9,070
Apr-17	271,702	29,994	333	302,029	74,945	7,834	9	82,788	21,898	2,760	2	24,660	19,863	1,994	7	21,864	8,095	953	2	9,050
May-17	272,257	30,004	333	302,595	74,977	7,841	9	82,827	21,828	2,790	2	24,620	19,698	1,973	7	21,678	8,057	953	5	9,015
Jun-17	272,821	30,060	339	303,220	74,668	7,824	9	82,501	21,667	2,783	2	24,452	19,502	1,966	7	21,475	7,994	955	5	8,954
Jul-17	272,875	29,999	344	303,217	74,344	7,815	9	82,168	21,764	2,775	2	24,541	19,613	1,976	7	21,596	7,791	958	5	8,754
Aug-17	273,342	30,184	339	303,865	74,103	7,821	9	81,933	21,652	2,765	2	24,418	19,431	1,966	7	21,404	7,750	961	8	8,719
Sep-17	274,610	30,337	342	305,289	74,389	7,860	9	82,258	21,586	2,760	2	24,348	19,455	1,981	7	21,443	7,727	966	20	8,713
Oct-17	277,051	30,381	337	307,768	75,322	7,839	9	83,170	21,860	2,765	2	24,627	19,808	1,950	7	21,765	7,935	964	20	8,919
Nov-17	278,381	30,621	340	309,342	76,501	7,974	9	84,484	22,325	2,795	2	25,122	20,207	1,975	7	22,189	8,098	964	14	9,077
Dec-17	280,404	30,789	344	311,536	77,713	8,027	9	85,750	22,559	2,800	2	25,361	20,510	2,007	5	22,522	8,206	964	5	9,175
Jan-18	279,210	30,776	335	310,320	77,231	8,002	9	85,242	22,911	2,840	2	25,753	20,437	2,024	5	22,467	8,287	965	2	9,254
Feb-18	279,388	31,000	342	310,730	77,359	8,013	9	85,382	22,990	2,841	2	25,834	20,501	2,042	7	22,551	8,306	965	2	9,272
Mar-18	279,969	30,945	338	311,253	77,629	8,038	9	85,676	23,093	2,847	2	25,942	20,551	2,044	7	22,602	8,289	966	2	9,257
Apr-18	279,783	30,902	338	311,023	77,557	7,984	9	85,550	22,937	2,823	2	25,761	20,480	2,033	7	22,520	8,276	960	2	9,238
May-18	280,350	30,913	338	311,602	77,590	7,990	9	85,590	22,863	2,853	2	25,719	20,311	2,011	7	22,329	8,237	960	5	9,202
Jun-18	280,927	30,970	343	312,240	77,273	7,974	9	85,256	22,697	2,847	2	25,545	20,110	2,005	7	22,122	8,173	961	5	9,140
Jul-18	280,981	30,908	349	312,238	76,941	7,964	9	84,914	22,798	2,838	2	25,638	20,224	2,014	7	22,245	7,967	965	5	8,936
Aug-18	281,459	31,097	343	312,899	76,694	7,971	9	84,673	22,681	2,828	2	25,511	20,037	2,005	7	22,049	7,925	968	8	8,901
Sep-18	282,755	31,254	347	314,355	76,987	8,010	9	85,006	22,613	2,823	2	25,438	20,062	2,019	7	22,089	7,901	972	20	8,894
Oct-18	285,249	31,298	342	316,889	77,944	7,989	9	85,942	22,897	2,828	2	25,727	20,423	1,988	7	22,418	8,113	971	20	9,104
Nov-18	286,608	31,544	345	318,498	79,155	8,125	9	87,289	23,379	2,859	2	26,240	20,832	2,013	7	22,852	8,279	971	14	9,264
Dec-18	288,676	31,715	349	320,740	80,398	8,180	9	88,587	23,621	2,864	2	26,487	21,141	2,046	5	23,192	8,388	971	5	9,364
Jan-19	287,429	31,682	341	319,452	79,854	8,149	9	88,012	23,948	2,902	2	26,852	21,035	2,063	5	23,102	8,446	971	2	9,419
Feb-19	287,610	31,912	348	319,870	79,985	8,161	9	88,155	24,031	2,903	2	26,936	21,100	2,081	7	23,188	8,464	971	2	9,437
Mar-19	288,205	31,855	344	320,405	80,262	8,186	9	88,457	24,137	2,909	2	27,048	21,151	2,083	7	23,241	8,447	973	2	9,422
Apr-19	288,014	31,811	344	320,170	80,188	8,131	9	88,329	23,975	2,884	2	26,861	21,078	2,071	7	23,156	8,434	966	2	9,402
May-19	288,594	31,822	344	320,761	80,222	8,138	9	88,369	23,899	2,916	2	26,817	20,906	2,049	7	22,962	8,395	966	5	9,366
Jun-19	289,183	31,881	350	321,414	79,897	8,121	9	88,027	23,727	2,909	2	26,637	20,700	2,043	7	22,750	8,330	968	5	9,303
Jul-19	289,239	31,817	355	321,411	79,556	8,111	9	87,677	23,831	2,900	2	26,733	20,817	2,053	7	22,876	8,121	971	5	9,097
Aug-19	289,727	32,010	350	322,087	79,303	8,118	9	87,429	23,710	2,889	2	26,602	20,626	2,043	7	22,676	8,078	974	8	9,060
Sep-19	291,051	32,170	353	323,575	79,604	8,158	9	87,770	23,640	2,884	2	26,527	20,651	2,058	7	22,716	8,054	979	20	9,053
Oct-19	293,601	32,216	348	326,164	80,585	8,136	9	88,730	23,934	2,889	2	26,825	21,020	2,026	7	23,053	8,269	977	20	9,266

Appendix 2.2 - Customer Forecast - Number by Region
High Growth Case

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-19	294,990	32,467	351	327,808	81,827	8,275	9	90,110	24,433	2,921	2	27,356	21,438	2,051	7	23,496	8,437	977	14	9,428
Dec-19	297,103	32,642	355	330,100	83,102	8,330	9	91,441	24,684	2,926	2	27,612	21,754	2,084	5	23,844	8,548	977	5	9,530
Jan-20	296,094	32,624	343	329,060	82,458	8,305	9	90,772	25,002	2,966	2	27,971	21,650	2,103	5	23,758	8,626	978	2	9,606
Feb-20	296,280	32,859	350	329,488	82,593	8,317	9	90,918	25,087	2,968	2	28,057	21,717	2,121	7	23,846	8,645	978	2	9,625
Mar-20	296,888	32,801	346	330,035	82,876	8,342	9	91,227	25,198	2,973	2	28,173	21,769	2,123	7	23,899	8,628	979	2	9,609
Apr-20	296,693	32,756	346	329,795	82,801	8,286	9	91,096	25,030	2,949	2	27,981	21,695	2,111	7	23,813	8,614	973	2	9,589
May-20	297,286	32,767	346	330,399	82,836	8,293	9	91,138	24,951	2,981	2	27,934	21,519	2,089	7	23,615	8,575	973	5	9,552
Jun-20	297,888	32,827	351	331,067	82,502	8,276	9	90,787	24,773	2,973	2	27,748	21,309	2,083	7	23,398	8,509	974	5	9,488
Jul-20	297,945	32,762	357	331,064	82,153	8,266	9	90,428	24,881	2,965	2	27,848	21,428	2,093	7	23,527	8,297	978	5	9,279
Aug-20	298,445	32,959	351	331,755	81,893	8,273	9	90,175	24,756	2,954	2	27,712	21,233	2,083	7	23,322	8,253	981	8	9,242
Sep-20	299,799	33,123	355	333,277	82,202	8,313	9	90,524	24,684	2,949	2	27,634	21,259	2,098	7	23,363	8,229	985	20	9,235
Oct-20	302,406	33,170	350	335,925	83,208	8,291	9	91,508	24,987	2,954	2	27,943	21,636	2,066	7	23,708	8,447	984	20	9,451
Nov-20	303,826	33,426	353	337,606	84,480	8,432	9	92,921	25,504	2,986	2	28,492	22,063	2,091	7	24,161	8,618	984	14	9,616
Dec-20	305,987	33,605	357	339,949	85,787	8,487	9	94,283	25,763	2,991	2	28,756	22,386	2,125	5	24,516	8,730	984	5	9,719
Jan-21	305,059	33,569	347	338,975	84,988	8,440	9	93,437	26,040	3,017	2	29,059	22,266	2,133	5	24,405	8,785	983	2	9,770
Feb-21	305,249	33,809	354	339,412	85,126	8,452	9	93,587	26,128	3,019	2	29,148	22,335	2,152	7	24,494	8,804	983	2	9,789
Mar-21	305,871	33,750	351	339,972	85,416	8,478	9	93,903	26,242	3,024	2	29,268	22,388	2,154	7	24,548	8,787	985	2	9,774
Apr-21	305,671	33,704	351	339,726	85,339	8,421	9	93,769	26,068	2,999	2	29,069	22,312	2,142	7	24,460	8,773	979	2	9,753
May-21	306,278	33,716	351	340,345	85,374	8,428	9	93,812	25,987	3,031	2	29,020	22,132	2,120	7	24,258	8,732	979	5	9,716
Jun-21	306,895	33,776	356	341,027	85,033	8,411	9	93,453	25,803	3,024	2	28,829	21,917	2,113	7	24,037	8,666	980	5	9,651
Jul-21	306,953	33,710	361	341,024	84,676	8,401	9	93,086	25,915	3,015	2	28,932	22,039	2,123	7	24,169	8,450	983	5	9,439
Aug-21	307,464	33,911	356	341,731	84,410	8,408	9	92,826	25,785	3,004	2	28,792	21,839	2,113	7	23,959	8,407	987	8	9,401
Sep-21	308,849	34,079	360	343,288	84,725	8,449	9	93,183	25,711	2,999	2	28,712	21,866	2,128	7	24,001	8,382	991	20	9,394
Oct-21	311,516	34,126	354	345,997	85,755	8,427	9	94,191	26,024	3,004	2	29,031	22,251	2,096	7	24,354	8,603	990	20	9,613
Nov-21	312,969	34,389	358	347,716	87,057	8,569	9	95,635	26,558	3,037	2	29,597	22,687	2,121	7	24,816	8,776	990	14	9,780
Dec-21	315,179	34,572	361	350,113	88,395	8,625	9	97,029	26,826	3,042	2	29,870	23,017	2,155	5	25,178	8,890	990	5	9,885
Jan-22	314,321	34,513	350	349,184	87,443	8,585	9	96,037	27,077	3,076	2	30,155	22,882	2,170	5	25,057	8,943	989	2	9,934
Feb-22	314,516	34,757	358	349,631	87,584	8,597	9	96,190	27,168	3,078	2	30,248	22,952	2,189	7	25,148	8,963	989	2	9,954
Mar-22	315,152	34,697	354	350,203	87,881	8,623	9	96,513	27,286	3,083	2	30,371	23,006	2,191	7	25,204	8,945	991	2	9,938
Apr-22	314,948	34,650	354	349,952	87,802	8,566	9	96,377	27,107	3,058	2	30,167	22,929	2,179	7	25,114	8,931	985	2	9,917
May-22	315,569	34,662	354	350,585	87,838	8,573	9	96,420	27,023	3,091	2	30,116	22,745	2,156	7	24,908	8,890	985	5	9,879
Jun-22	316,199	34,724	359	351,283	87,489	8,555	9	96,054	26,833	3,083	2	29,918	22,526	2,149	7	24,682	8,822	986	5	9,814
Jul-22	316,259	34,656	365	351,280	87,124	8,545	9	95,678	26,948	3,074	2	30,024	22,650	2,160	7	24,816	8,604	989	5	9,599
Aug-22	316,782	34,862	359	352,003	86,852	8,552	9	95,413	26,815	3,063	2	29,880	22,446	2,149	7	24,602	8,560	993	8	9,561
Sep-22	318,199	35,033	363	353,595	87,175	8,593	9	95,777	26,738	3,058	2	29,797	22,473	2,165	7	24,645	8,535	997	20	9,553
Oct-22	320,928	35,082	358	356,367	88,228	8,571	9	96,808	27,061	3,063	2	30,127	22,867	2,132	7	25,005	8,759	996	20	9,774
Nov-22	322,414	35,350	361	358,125	89,559	8,715	9	98,283	27,612	3,096	2	30,710	23,312	2,158	7	25,477	8,934	996	14	9,944
Dec-22	324,676	35,537	365	360,577	90,927	8,772	9	99,707	27,888	3,102	2	30,992	23,649	2,193	5	25,847	9,049	996	5	10,050
Jan-23	323,884	35,455	355	359,693	89,861	8,732	9	98,603	28,098	3,135	2	31,235	23,479	2,207	5	25,691	9,079	996	2	10,077
Feb-23	324,083	35,704	362	360,150	90,006	8,745	9	98,759	28,192	3,137	2	31,331	23,550	2,226	7	25,783	9,098	996	2	10,096
Mar-23	324,734	35,643	359	360,736	90,308	8,771	9	99,088	28,313	3,143	2	31,458	23,606	2,228	7	25,841	9,080	997	2	10,080
Apr-23	324,525	35,595	359	360,479	90,228	8,713	9	98,950	28,129	3,117	2	31,247	23,527	2,216	7	25,749	9,066	991	2	10,059
May-23	325,160	35,607	359	361,126	90,265	8,720	9	98,994	28,042	3,150	2	31,194	23,339	2,193	7	25,539	9,025	991	5	10,021
Jun-23	325,806	35,671	364	361,840	89,909	8,702	9	98,620	27,846	3,143	2	30,991	23,116	2,186	7	25,308	8,957	993	5	9,954
Jul-23	325,867	35,601	370	361,838	89,536	8,692	9	98,237	27,965	3,133	2	31,101	23,242	2,196	7	25,445	8,736	996	5	9,737
Aug-23	326,402	35,812	364	362,577	89,258	8,699	9	97,966	27,828	3,122	2	30,952	23,035	2,186	7	25,227	8,691	999	8	9,698
Sep-23	327,852	35,986	368	364,206	89,587	8,741	9	98,337	27,748	3,117	2	30,867	23,062	2,202	7	25,271	8,666	1,004	20	9,690
Oct-23	330,644	36,036	362	367,042	90,663	8,718	9	99,390	28,082	3,122	2	31,206	23,463	2,168	7	25,639	8,892	1,002	20	9,914
Nov-23	332,166	36,309	366	368,841	92,023	8,864	9	100,896	28,649	3,155	2	31,807	23,918	2,195	7	26,119	9,070	1,002	14	10,086
Dec-23	334,480	36,500	370	371,350	93,420	8,922	9	102,351	28,934	3,161	2	32,097	24,262	2,230	5	26,496	9,186	1,002	5	10,194
Jan-24	333,446	36,398	357	370,201	92,205	8,884	9	101,098	29,136	3,197	2	32,335	24,058	2,247	5	26,310	9,214	1,002	2	10,219
Feb-24	333,650	36,653	364	370,667	92,352	8,897	9	101,258	29,232	3,199	2	32,433	24,130	2,266	7	26,404	9,234	1,002	2	10,239
Mar-24	334,316	36,590	360	371,266	92,661	8,923	9	101,594	29,357	3,205	2	32,563	24,187	2,268	7	26,462	9,216	1,004	2	10,222
Apr-24	334,102	36,542	360	371,004	92,579	8,865	9	101,453	29,167	3,178	2	32,347	24,106	2,256	7	26,369	9,202	998	2	10,201
May-24	334,752	36,554	360	371,666	92,617	8,872	9	101,498	29,078	3,212	2	32,292	23,915	2,233	7	26,154	9,160	998	5	10,162
Jun-24	335,412	36,619	366	372,396	92,253	8,854	9	101,117	28,876	3,205	2	32,083	23,687	2,226	7	25,920	9,091	999	5	10,095
Jul-24	335,474	36,548	371	372,393	91,873	8,843	9	100,725	28,999	3,195	2	32,196	23,816	2,236	7	26,059	8,868	1,002	5	9,875
Aug-24	336,021	36,762	366	373,149	91,589	8,851	9	100,449	28,857	3,184	2	32,043	23,605	2,226	7	25,837	8,823	1,006	8	9,836
Sep-24	337,505	36,941	369	374,815	91,925	8,893	9	100,828	28,775	3,178	2	31,956	23,633	2,242	7	25,881	8,797	1,010	20	9,828
Oct-24	340,361	36,991	364	377,716	93,023	8,870	9	101,902	29,119	3,184	2	32,305	24,042	2,208	7	26,256	9,026	1,009	20	10,055
Nov-24	341,917	37,270	368	379,555	94,411	9,018	9	103,437	29,703	3,218	2	32,923	24,505	2,235	7	26,746	9,205	1,009	14	10,228
Dec-24	344,285	37,465	371	382,121	95,836	9,076	9	104,921	29,996	3,223	2	33,222	24,855	2,270	5	27,130	9,323	1,009	5	10,337
Jan-25	343,008	37,342	361	380,711	94,512	9,041	9	103,561	30,173	3,263	2	33,438	24,655	2,290	5	26,950	9,350	1,009	2	10,361
Feb-25	343,217	37,602	369	381,187	94,662	9,053	9	103,724	30,272	3,265	2	33,539	24,729	2,310	7	27,046	9,370	1,009	2	10,381
Mar-25	343,898	37,538	365	381,800	94,977	9,080	9	104,066	30,401	3,271	2	33,674	24,786	2,312	7	27,105	9,352	1,010	2	10,364
Apr-25	343,679	37,488	365	381,532	94,893	9,021	9	103,923	30,205	3,244	2	33,452	24,704	2,299	7	27,010	9,337	1,004	2	10,343
May-25	344,343	37,501	365	382,209	94,932	9,028	9	103,969	30,114	3,278	2	33,394	24,509	2,276	7	26,792	9,295	1,004	5	10,304
Jun-25	345,018	37,567	370	382,955	94,561	9,010	9	103,580	29,906	3,271	2	33,179	24,277	2,269	7	26,553	9,225	1,006	5	10,236
Jul-25	345,082	37,494	376	382,952	94,173	8,999	9	103,181	30,032	3,261	2	33,296	24,409	2,279	7	26,695	9,000	1,009	5	10,014
Aug-25	345,641	37,713	370	383,725	93,883	9,006	9	102,899	29,886	3,250	2	33,138	24,193	2,269	7	26,469	8,954	1,012	8	9,974
Sep-25	347,158	37,895	374	385,427	94,227	9,050	9	103,285	29,802	3,244	2	33,048	24,222	2,285	7	26,514	8,928	1,017	20	9,965
Oct-25	350,078	37,947	369	388,393	95,346	9,026	9	104,381	30,156	3,250	2	33,408	24,639	2,251	7	26,896	9,159	1,015	20	10,195

Appendix 2.2 - Customer Forecast - Number by Region
High Growth Case

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-25	351,668	38,231	372	390,272	96,761	9,176	9	105,945	30,757	3,284	2	34,043	25,111	2,278	7	27,395	9,341	1,015	14	10,370
Dec-25	354,089	38,430	376	392,894	98,214	9,235	9	107,458	31,059	3,290	2	34,351	25,468	2,314	5	27,786	9,460	1,015	5	10,480
Jan-26	352,421	38,285	364	391,071	96,837	9,194	9	106,040	31,244	3,326	2	34,572	25,271	2,330	5	27,606	9,463	1,015	2	10,480
Feb-26	352,634	38,550	372	391,556	96,990	9,207	9	106,205	31,345	3,328	2	34,676	25,346	2,350	7	27,703	9,483	1,015	2	10,501
Mar-26	353,330	38,485	368	392,183	97,311	9,234	9	106,554	31,478	3,334	2	34,814	25,405	2,352	7	27,764	9,465	1,017	2	10,484
Apr-26	353,106	38,434	368	391,909	97,226	9,174	9	106,409	31,277	3,307	2	34,586	25,321	2,339	7	27,667	9,450	1,010	2	10,463
May-26	353,785	38,447	368	392,600	97,265	9,181	9	106,455	31,182	3,342	2	34,526	25,122	2,316	7	27,445	9,408	1,010	5	10,423
Jun-26	354,474	38,515	374	393,363	96,887	9,163	9	106,059	30,969	3,334	2	34,305	24,886	2,308	7	27,201	9,337	1,012	5	10,354
Jul-26	354,540	38,441	379	393,360	96,492	9,152	9	105,652	31,098	3,325	2	34,425	25,020	2,319	7	27,346	9,110	1,015	5	10,130
Aug-26	355,111	38,664	374	394,149	96,196	9,159	9	105,365	30,948	3,313	2	34,263	24,800	2,308	7	27,115	9,064	1,019	8	10,090
Sep-26	356,660	38,849	377	395,887	96,546	9,203	9	105,758	30,862	3,307	2	34,171	24,829	2,325	7	27,161	9,038	1,023	20	10,081
Oct-26	359,643	38,902	372	398,916	97,687	9,179	9	106,875	31,226	3,313	2	34,541	25,254	2,290	7	27,551	9,271	1,022	20	10,313
Nov-26	361,268	39,192	376	400,836	99,130	9,330	9	108,469	31,844	3,348	2	35,194	25,735	2,317	7	28,060	9,454	1,022	14	10,490
Dec-26	363,740	39,395	379	403,514	100,612	9,391	9	110,011	32,155	3,354	2	35,510	26,099	2,354	5	28,458	9,574	1,022	5	10,601
Jan-27	361,685	39,228	369	401,283	99,032	9,351	9	108,392	32,297	3,388	2	35,688	25,887	2,370	5	28,262	9,599	1,022	2	10,622
Feb-27	361,903	39,499	377	401,778	99,188	9,364	9	108,561	32,402	3,390	2	35,795	25,963	2,391	7	28,361	9,619	1,022	2	10,643
Mar-27	362,612	39,432	373	402,418	99,515	9,392	9	108,916	32,538	3,396	2	35,936	26,023	2,392	7	28,422	9,601	1,023	2	10,626
Apr-27	362,384	39,381	373	402,138	99,428	9,331	9	108,768	32,332	3,369	2	35,702	25,938	2,380	7	28,324	9,586	1,017	2	10,605
May-27	363,077	39,394	373	402,844	99,468	9,338	9	108,815	32,235	3,404	2	35,641	25,735	2,355	7	28,098	9,543	1,017	5	10,565
Jun-27	363,781	39,462	378	403,622	99,083	9,320	9	108,412	32,015	3,396	2	35,413	25,494	2,348	7	27,849	9,472	1,019	5	10,495
Jul-27	363,847	39,387	384	403,619	98,680	9,309	9	107,998	32,148	3,386	2	35,537	25,631	2,359	7	27,997	9,242	1,022	5	10,268
Aug-27	364,430	39,615	378	404,424	98,380	9,316	9	107,705	31,994	3,375	2	35,371	25,407	2,348	7	27,762	9,195	1,025	8	10,228
Sep-27	366,012	39,804	382	406,197	98,736	9,360	9	108,105	31,905	3,369	2	35,276	25,437	2,365	7	27,808	9,169	1,030	20	10,219
Oct-27	369,056	39,857	377	409,290	99,897	9,336	9	109,243	32,279	3,375	2	35,656	25,870	2,330	7	28,206	9,404	1,028	20	10,453
Nov-27	370,715	40,153	380	411,248	101,366	9,490	9	110,865	32,915	3,410	2	36,327	26,360	2,357	7	28,724	9,589	1,028	14	10,632
Dec-27	373,238	40,360	384	413,982	102,875	9,551	9	112,434	33,234	3,416	2	36,652	26,731	2,394	5	29,130	9,711	1,028	5	10,744

Appendix 2.2 - Customer Forecast - Number by Region
Low Growth Case

	WA / ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA / ID Res	WA / ID Com	WA / ID Firm Ind	WA / ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-07	191,905	21,468	253	213,625	50,069	6,403	9	56,481	13,071	2,163	2	15,236	13,775	1,602	6	15,382	6,422	882	6	7,310
Dec-07	192,493	21,516	254	214,263	50,307	6,420	9	56,736	13,132	2,167	2	15,300	13,861	1,611	5	15,478	6,454	882	3	7,339
Jan-08	192,668	21,493	253	214,414	50,418	6,428	9	56,856	13,153	2,170	2	15,324	13,888	1,620	5	15,513	6,474	883	2	7,358
Feb-08	192,719	21,556	255	214,530	50,453	6,432	9	56,894	13,173	2,170	2	15,345	13,906	1,625	6	15,537	6,479	883	2	7,364
Mar-08	192,885	21,540	254	214,679	50,502	6,439	9	56,950	13,199	2,172	2	15,372	13,920	1,626	6	15,552	6,474	883	2	7,359
Apr-08	192,831	21,528	254	214,614	50,507	6,423	9	56,939	13,159	2,165	2	15,326	13,900	1,622	6	15,528	6,470	881	2	7,353
May-08	192,993	21,531	254	214,778	50,491	6,425	9	56,925	13,141	2,174	2	15,317	13,853	1,616	6	15,474	6,459	881	3	7,343
Jun-08	193,157	21,548	256	214,960	50,405	6,420	9	56,834	13,099	2,172	2	15,273	13,797	1,614	6	15,416	6,440	882	3	7,324
Jul-08	193,072	21,530	257	214,859	50,315	6,417	9	56,741	13,099	2,169	2	15,271	13,779	1,617	6	15,401	6,379	883	3	7,264
Aug-08	193,208	21,583	256	215,047	50,247	6,419	9	56,675	13,070	2,166	2	15,238	13,727	1,614	6	15,346	6,366	884	4	7,254
Sep-08	193,577	21,627	257	215,461	50,327	6,431	9	56,767	13,053	2,165	2	15,220	13,734	1,618	6	15,358	6,359	885	8	7,252
Oct-08	194,286	21,640	255	216,181	50,513	6,424	9	56,946	13,124	2,166	2	15,292	13,835	1,609	6	15,449	6,422	885	8	7,315
Nov-08	194,673	21,709	256	216,638	50,767	6,466	9	57,242	13,246	2,175	2	15,423	13,949	1,616	6	15,571	6,471	885	6	7,362
Dec-08	195,261	21,758	257	217,276	51,030	6,482	9	57,521	13,306	2,177	2	15,485	14,035	1,626	5	15,667	6,504	885	3	7,391
Jan-09	195,537	21,737	255	217,530	51,066	6,484	9	57,559	13,352	2,192	2	15,547	14,062	1,634	5	15,701	6,524	885	2	7,410
Feb-09	195,588	21,801	257	217,646	51,126	6,487	9	57,623	13,372	2,193	2	15,567	14,080	1,639	6	15,725	6,529	885	2	7,416
Mar-09	195,753	21,785	256	217,795	51,200	6,495	9	57,703	13,398	2,194	2	15,595	14,094	1,640	6	15,740	6,524	885	2	7,411
Apr-09	195,700	21,773	256	217,729	51,230	6,478	9	57,717	13,359	2,187	2	15,548	14,074	1,636	6	15,716	6,520	883	2	7,405
May-09	195,862	21,776	256	217,894	51,239	6,480	9	57,728	13,340	2,196	2	15,539	14,027	1,630	6	15,662	6,509	883	3	7,395
Jun-09	196,026	21,792	258	218,076	51,153	6,475	9	57,637	13,298	2,194	2	15,495	13,971	1,628	6	15,604	6,490	884	3	7,377
Jul-09	196,041	21,775	259	218,075	51,062	6,472	9	57,544	13,324	2,192	2	15,518	13,978	1,631	6	15,614	6,428	885	3	7,316
Aug-09	196,177	21,828	258	218,263	50,995	6,474	9	57,479	13,294	2,189	2	15,485	13,926	1,628	6	15,559	6,416	886	4	7,306
Sep-09	196,546	21,872	259	218,677	51,075	6,486	9	57,570	13,277	2,187	2	15,467	13,933	1,632	6	15,570	6,409	887	8	7,304
Oct-09	197,255	21,885	257	219,397	51,285	6,480	9	57,774	13,349	2,189	2	15,540	14,033	1,623	6	15,662	6,472	887	8	7,367
Nov-09	197,642	21,954	258	219,854	51,564	6,521	9	58,095	13,470	2,198	2	15,670	14,148	1,630	6	15,784	6,521	887	6	7,414
Dec-09	198,230	22,002	259	220,492	51,853	6,538	9	58,399	13,531	2,199	2	15,732	14,234	1,640	5	15,880	6,553	887	3	7,443
Jan-10	198,481	22,007	258	220,746	51,889	6,532	9	58,430	13,602	2,213	2	15,817	14,261	1,647	5	15,913	6,573	887	2	7,462
Feb-10	198,531	22,070	261	220,862	51,949	6,536	9	58,493	13,622	2,214	2	15,838	14,279	1,652	6	15,937	6,579	887	2	7,468
Mar-10	198,697	22,054	259	221,011	52,022	6,543	9	58,574	13,648	2,215	2	15,865	14,293	1,653	6	15,951	6,574	888	2	7,463
Apr-10	198,644	22,042	259	220,945	52,003	6,527	9	58,538	13,608	2,208	2	15,819	14,273	1,649	6	15,928	6,570	886	2	7,457
May-10	198,805	22,045	259	221,110	52,012	6,529	9	58,549	13,590	2,217	2	15,809	14,226	1,643	6	15,874	6,558	886	3	7,447
Jun-10	198,969	22,061	261	221,292	51,925	6,524	9	58,458	13,548	2,215	2	15,765	14,170	1,641	6	15,816	6,539	886	3	7,429
Jul-10	199,035	22,044	263	221,341	51,835	6,521	9	58,365	13,573	2,213	2	15,788	14,202	1,644	6	15,851	6,478	887	3	7,368
Aug-10	199,171	22,097	261	221,529	51,768	6,523	9	58,299	13,544	2,210	2	15,756	14,149	1,641	6	15,796	6,466	888	4	7,358
Sep-10	199,539	22,141	262	221,943	51,848	6,535	9	58,391	13,527	2,208	2	15,737	14,156	1,645	6	15,807	6,459	890	8	7,356
Oct-10	200,249	22,154	261	222,663	52,083	6,528	9	58,620	13,598	2,210	2	15,810	14,257	1,636	6	15,899	6,522	889	8	7,419
Nov-10	200,635	22,223	262	223,120	52,387	6,570	9	58,965	13,720	2,219	2	15,941	14,372	1,643	6	16,020	6,571	889	6	7,466
Dec-10	201,223	22,272	263	223,758	52,700	6,586	9	59,295	13,781	2,220	2	16,003	14,458	1,653	5	16,116	6,603	889	3	7,495
Jan-11	201,475	22,289	262	224,025	52,736	6,575	9	59,321	13,901	2,231	2	16,134	14,510	1,657	5	16,172	6,623	889	2	7,514
Feb-11	201,525	22,352	264	224,141	52,771	6,579	9	59,359	13,921	2,231	2	16,155	14,528	1,662	6	16,196	6,629	889	2	7,520
Mar-11	201,691	22,336	263	224,290	52,844	6,586	9	59,440	13,947	2,233	2	16,182	14,542	1,663	6	16,210	6,624	890	2	7,515
Apr-11	201,638	22,324	263	224,224	52,825	6,570	9	59,404	13,908	2,226	2	16,135	14,522	1,659	6	16,187	6,620	888	2	7,509
May-11	201,799	22,327	263	224,389	52,834	6,572	9	59,415	13,889	2,235	2	16,126	14,475	1,653	6	16,133	6,608	888	3	7,499
Jun-11	201,963	22,343	264	224,571	52,748	6,567	9	59,323	13,847	2,233	2	16,082	14,418	1,651	6	16,075	6,589	888	3	7,480
Jul-11	201,979	22,326	266	224,570	52,658	6,564	9	59,230	13,873	2,230	2	16,105	14,450	1,654	6	16,110	6,528	889	3	7,420
Aug-11	202,114	22,379	264	224,758	52,590	6,566	9	59,165	13,843	2,227	2	16,073	14,398	1,651	6	16,054	6,516	890	4	7,410
Sep-11	202,483	22,423	265	225,172	52,670	6,578	9	59,257	13,826	2,226	2	16,054	14,405	1,655	6	16,066	6,509	892	8	7,408
Oct-11	203,193	22,436	264	225,892	52,930	6,571	9	59,510	13,898	2,227	2	16,127	14,506	1,646	6	16,157	6,571	891	8	7,471
Nov-11	203,579	22,505	265	226,349	53,259	6,613	9	59,881	14,019	2,236	2	16,257	14,620	1,653	6	16,279	6,621	891	6	7,518
Dec-11	204,167	22,553	266	226,987	53,597	6,629	9	60,235	14,080	2,238	2	16,320	14,707	1,663	5	16,375	6,653	891	3	7,547
Jan-12	204,271	22,593	263	227,127	53,691	6,618	9	60,318	14,253	2,249	2	16,504	14,734	1,667	5	16,406	6,676	891	2	7,569
Feb-12	204,323	22,658	265	227,246	53,727	6,622	9	60,358	14,274	2,250	2	16,526	14,752	1,673	6	16,431	6,681	891	2	7,575
Mar-12	204,493	22,642	264	227,399	53,803	6,629	9	60,441	14,301	2,252	2	16,554	14,767	1,673	6	16,446	6,676	892	2	7,570
Apr-12	204,438	22,630	264	227,332	53,783	6,613	9	60,405	14,259	2,244	2	16,506	14,746	1,670	6	16,422	6,672	890	2	7,564
May-12	204,604	22,633	264	227,501	53,792	6,615	9	60,416	14,240	2,254	2	16,496	14,698	1,663	6	16,367	6,661	890	3	7,553
Jun-12	204,772	22,649	266	227,687	53,703	6,610	9	60,322	14,196	2,252	2	16,450	14,640	1,661	6	16,307	6,641	890	3	7,535
Jul-12	204,788	22,631	267	227,687	53,610	6,607	9	60,225	14,223	2,249	2	16,474	14,673	1,664	6	16,342	6,579	891	3	7,473
Aug-12	204,928	22,686	266	227,879	53,540	6,609	9	60,158	14,192	2,246	2	16,440	14,619	1,661	6	16,286	6,567	892	4	7,463
Sep-12	205,306	22,731	267	228,304	53,623	6,621	9	60,252	14,174	2,244	2	16,421	14,626	1,666	6	16,297	6,560	894	8	7,461
Oct-12	206,034	22,744	265	229,043	53,892	6,614	9	60,515	14,249	2,246	2	16,497	14,730	1,656	6	16,392	6,623	893	8	7,524
Nov-12	206,431	22,815	266	229,512	54,232	6,656	9	60,897	14,376	2,255	2	16,633	14,848	1,664	6	16,517	6,673	893	6	7,573
Dec-12	207,034	22,865	267	230,167	54,582	6,673	9	61,263	14,440	2,257	2	16,698	14,937	1,674	5	16,616	6,706	893	3	7,602
Jan-13	206,914	22,898	265	230,076	54,584	6,659	9	61,252	14,588	2,268	2	16,857	14,939	1,678	5	16,622	6,736	893	2	7,631
Feb-13	206,967	22,964	267	230,198	54,621	6,663	9	61,293	14,609	2,268	2	16,880	14,958	1,683	6	16,647	6,742	893	2	7,637
Mar-13	207,141	22,948	266	230,354	54,699	6,670	9	61,379	14,638	2,270	2	16,910	14,973	1,684	6	16,662	6,737	894	2	7,632
Apr-13	207,085	22,935	266	230,286	54,679	6,653	9	61,341	14,595	2,263	2	16,859	14,952	1,680	6	16,638	6,733	891	2	7,626
May-13	207,255	22,938	266	230,459	54,688	6,655	9	61,353	14,574	2,272	2	16,848	14,902	1,673	6	16,581	6,721	891	3	7,615
Jun-13	207,427	22,955	267	230,650	54,596	6,650	9	61,256	14,529	2,270	2	16,800	14,843	1,671	6	16,520	6,701	892	3	7,596
Jul-13	207,443	22,937	269	230,649	54,500	6,647	9	61,156	14,556	2,267	2	16,826	14,876	1,674	6	16,556	6,638	893	3	7,534
Aug-13	207,586	22,993	267	230,846	54,428	6,649	9	61,087	14,524	2,264	2	16,790	14,821	1,671	6	16,498	6,625	894	4	7,523
Sep-13	207,974	23,039	268	231,281	54,513	6,662	9	61,184	14,506	2,263	2	16,770	14,828	1,676	6	16,510	6,618	896	8	7,521
Oct-13	208,719	23,053	267	232,039	54,791	6,655	9	61,455	14,584	2,264	2	16,850	14,935	1,666	6	16,607	6,683	895	8	7,586

Appendix 2.2 - Customer Forecast - Number by Region
Low Growth Case

	WA / ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA / ID Res	WA / ID Com	WA / ID Firm Ind	WA / ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-13	209,126	23,126	268	232,519	55,142	6,697	9	61,848	14,716	2,274	2	16,992	15,056	1,674	6	16,735	6,734	895	6	7,635
Dec-13	209,744	23,176	269	233,189	55,502	6,714	9	62,225	14,783	2,275	2	17,060	15,147	1,684	5	16,836	6,767	895	3	7,665
Jan-14	209,456	23,202	267	232,925	55,452	6,703	9	62,164	14,911	2,287	2	17,201	15,145	1,689	5	16,838	6,789	895	2	7,686
Feb-14	209,511	23,270	269	233,050	55,490	6,707	9	62,206	14,934	2,288	2	17,224	15,164	1,694	6	16,864	6,795	895	2	7,692
Mar-14	209,689	23,254	268	233,210	55,571	6,715	9	62,294	14,964	2,290	2	17,255	15,179	1,695	6	16,880	6,789	896	2	7,687
Apr-14	209,631	23,241	268	233,140	55,550	6,697	9	62,256	14,919	2,282	2	17,203	15,157	1,691	6	16,854	6,785	894	2	7,681
May-14	209,805	23,244	268	233,317	55,559	6,700	9	62,268	14,898	2,292	2	17,191	15,106	1,685	6	16,796	6,773	894	3	7,670
Jun-14	209,981	23,261	270	233,512	55,465	6,694	9	62,168	14,850	2,290	2	17,142	15,045	1,683	6	16,734	6,753	894	3	7,651
Jul-14	209,998	23,242	271	233,511	55,366	6,691	9	62,066	14,879	2,287	2	17,168	15,080	1,686	6	16,771	6,689	895	3	7,587
Aug-14	210,144	23,300	270	233,713	55,292	6,693	9	61,994	14,846	2,284	2	17,131	15,023	1,683	6	16,711	6,676	896	4	7,576
Sep-14	210,540	23,347	271	234,158	55,379	6,706	9	62,094	14,826	2,282	2	17,110	15,031	1,687	6	16,724	6,669	898	8	7,575
Oct-14	211,303	23,361	269	234,933	55,665	6,699	9	62,373	14,907	2,284	2	17,193	15,140	1,677	6	16,823	6,735	897	8	7,640
Nov-14	211,719	23,436	270	235,424	56,026	6,742	9	62,777	15,045	2,293	2	17,341	15,264	1,685	6	16,955	6,786	897	6	7,689
Dec-14	212,351	23,488	271	236,110	56,397	6,759	9	63,165	15,114	2,295	2	17,411	15,358	1,695	5	17,058	6,820	897	3	7,720
Jan-15	211,950	23,507	269	235,725	56,339	6,753	9	63,101	15,252	2,311	2	17,565	15,350	1,702	5	17,057	6,857	897	2	7,756
Feb-15	212,005	23,577	271	235,853	56,378	6,756	9	63,144	15,275	2,311	2	17,589	15,370	1,708	6	17,083	6,863	897	2	7,762
Mar-15	212,187	23,559	270	236,016	56,461	6,764	9	63,234	15,306	2,313	2	17,621	15,385	1,708	6	17,099	6,857	898	2	7,757
Apr-15	212,129	23,546	270	235,945	56,439	6,747	9	63,195	15,259	2,305	2	17,567	15,363	1,705	6	17,073	6,853	896	2	7,751
May-15	212,306	23,549	270	236,125	56,449	6,749	9	63,207	15,238	2,315	2	17,555	15,311	1,698	6	17,014	6,841	896	3	7,740
Jun-15	212,486	23,567	272	236,325	56,352	6,744	9	63,105	15,188	2,313	2	17,503	15,248	1,696	6	16,950	6,821	896	3	7,720
Jul-15	212,503	23,548	273	236,324	56,250	6,741	9	62,999	15,218	2,310	2	17,530	15,284	1,699	6	16,988	6,755	897	3	7,656
Aug-15	212,652	23,607	272	236,531	56,174	6,743	9	62,926	15,183	2,307	2	17,492	15,226	1,696	6	16,927	6,742	899	4	7,644
Sep-15	213,057	23,655	273	236,985	56,264	6,755	9	63,028	15,163	2,305	2	17,471	15,233	1,701	6	16,939	6,734	900	8	7,642
Oct-15	213,836	23,669	271	237,777	56,558	6,749	9	63,315	15,248	2,307	2	17,557	15,345	1,691	6	17,042	6,801	900	8	7,709
Nov-15	214,261	23,746	272	238,279	56,930	6,792	9	63,731	15,391	2,317	2	17,710	15,472	1,698	6	17,176	6,854	900	6	7,760
Dec-15	214,907	23,799	273	238,980	57,311	6,809	9	64,130	15,463	2,318	2	17,784	15,568	1,709	5	17,282	6,889	900	3	7,791
Jan-16	214,492	23,811	271	238,574	57,250	6,808	9	64,067	15,603	2,336	2	17,941	15,555	1,718	5	17,278	6,925	900	2	7,827
Feb-16	214,549	23,883	273	238,705	57,291	6,811	9	64,111	15,628	2,337	2	17,966	15,575	1,723	6	17,304	6,930	900	2	7,833
Mar-16	214,735	23,865	272	238,872	57,376	6,819	9	64,205	15,660	2,338	2	18,000	15,591	1,724	6	17,321	6,925	901	2	7,828
Apr-16	214,675	23,852	272	238,799	57,353	6,802	9	64,164	15,611	2,331	2	17,944	15,569	1,720	6	17,294	6,921	899	2	7,821
May-16	214,856	23,855	272	238,983	57,364	6,804	9	64,177	15,588	2,341	2	17,931	15,515	1,713	6	17,234	6,908	899	3	7,810
Jun-16	215,040	23,873	274	239,187	57,264	6,799	9	64,071	15,537	2,338	2	17,877	15,451	1,711	6	17,168	6,888	899	3	7,790
Jul-16	215,058	23,853	275	239,186	57,159	6,795	9	63,963	15,568	2,336	2	17,906	15,487	1,714	6	17,207	6,821	900	3	7,724
Aug-16	215,210	23,913	274	239,397	57,080	6,798	9	63,887	15,532	2,332	2	17,866	15,428	1,711	6	17,145	6,808	901	4	7,713
Sep-16	215,624	23,963	275	239,862	57,173	6,810	9	63,993	15,511	2,331	2	17,844	15,436	1,716	6	17,157	6,800	903	8	7,711
Oct-16	216,420	23,978	273	240,671	57,476	6,803	9	64,288	15,599	2,332	2	17,933	15,551	1,706	6	17,262	6,868	902	8	7,778
Nov-16	216,854	24,056	274	241,184	57,858	6,848	9	64,715	15,748	2,342	2	18,092	15,681	1,714	6	17,400	6,922	902	6	7,830
Dec-16	217,514	24,111	275	241,900	58,251	6,865	9	65,125	15,823	2,344	2	18,169	15,779	1,724	5	17,508	6,957	902	3	7,862
Jan-17	217,082	24,115	272	241,470	58,156	6,861	9	65,026	15,960	2,360	2	18,322	15,767	1,732	5	17,504	6,985	903	2	7,890
Feb-17	217,141	24,188	274	241,603	58,197	6,865	9	65,071	15,985	2,361	2	18,348	15,787	1,738	6	17,531	6,991	903	2	7,896
Mar-17	217,330	24,170	273	241,774	58,285	6,873	9	65,167	16,019	2,362	2	18,383	15,804	1,738	6	17,548	6,985	903	2	7,891
Apr-17	217,269	24,157	273	241,699	58,262	6,855	9	65,126	15,968	2,355	2	18,325	15,780	1,735	6	17,521	6,981	901	2	7,884
May-17	217,454	24,160	273	241,888	58,272	6,858	9	65,139	15,945	2,365	2	18,311	15,725	1,728	6	17,459	6,968	901	3	7,872
Jun-17	217,642	24,179	275	242,096	58,169	6,852	9	65,030	15,891	2,362	2	18,255	15,660	1,725	6	17,391	6,947	902	3	7,852
Jul-17	217,660	24,158	277	242,095	58,061	6,849	9	64,919	15,923	2,360	2	18,285	15,697	1,729	6	17,431	6,880	903	3	7,785
Aug-17	217,816	24,220	275	242,311	57,981	6,851	9	64,841	15,886	2,356	2	18,244	15,636	1,725	6	17,367	6,866	904	4	7,774
Sep-17	218,239	24,271	276	242,786	58,076	6,864	9	64,949	15,864	2,355	2	18,221	15,644	1,730	6	17,380	6,858	905	8	7,772
Oct-17	219,052	24,286	274	243,612	58,387	6,857	9	65,253	15,955	2,356	2	18,314	15,762	1,720	6	17,488	6,928	905	8	7,840
Nov-17	219,496	24,366	275	244,137	58,780	6,902	9	65,691	16,110	2,366	2	18,479	15,895	1,728	6	17,629	6,982	905	6	7,893
Dec-17	220,170	24,422	277	244,868	59,184	6,920	9	66,113	16,188	2,368	2	18,558	15,996	1,739	5	17,740	7,018	905	3	7,926
Jan-18	219,772	24,417	274	244,463	59,024	6,911	9	65,944	16,306	2,381	2	18,689	15,972	1,745	5	17,722	7,045	905	2	7,952
Feb-18	219,831	24,492	276	244,599	59,066	6,915	9	65,991	16,332	2,382	2	18,716	15,993	1,751	6	17,750	7,051	905	2	7,958
Mar-18	220,025	24,474	275	244,774	59,156	6,923	9	66,089	16,366	2,384	2	18,752	16,010	1,751	6	17,767	7,046	905	2	7,953
Apr-18	219,963	24,459	275	244,697	59,132	6,905	9	66,047	16,314	2,376	2	18,692	15,986	1,748	6	17,739	7,041	903	2	7,947
May-18	220,152	24,463	275	244,890	59,143	6,907	9	66,060	16,290	2,386	2	18,678	15,930	1,740	6	17,676	7,028	903	3	7,935
Jun-18	220,344	24,482	276	245,103	59,038	6,902	9	65,949	16,234	2,384	2	18,620	15,863	1,738	6	17,607	7,007	904	3	7,914
Jul-18	220,362	24,461	278	245,102	58,927	6,899	9	65,835	16,268	2,381	2	18,651	15,901	1,741	6	17,648	6,938	905	3	7,846
Aug-18	220,522	24,524	276	245,322	58,845	6,901	9	65,754	16,229	2,377	2	18,608	15,838	1,738	6	17,582	6,924	906	4	7,834
Sep-18	220,954	24,577	278	245,808	58,942	6,914	9	65,865	16,206	2,376	2	18,584	15,847	1,743	6	17,596	6,916	907	8	7,832
Oct-18	221,785	24,591	276	246,652	59,261	6,907	9	66,177	16,301	2,377	2	18,680	15,967	1,733	6	17,705	6,987	907	8	7,902
Nov-18	222,238	24,673	277	247,189	59,665	6,952	9	66,626	16,462	2,388	2	18,851	16,103	1,741	6	17,850	7,042	907	6	7,955
Dec-18	222,927	24,730	278	247,936	60,079	6,971	9	67,059	16,542	2,389	2	18,934	16,206	1,752	5	17,963	7,079	907	3	7,989
Jan-19	222,512	24,719	276	247,507	59,898	6,960	9	66,867	16,651	2,402	2	19,055	16,171	1,758	5	17,933	7,098	907	2	8,007
Feb-19	222,572	24,796	278	247,646	59,942	6,964	9	66,915	16,679	2,402	2	19,083	16,193	1,764	6	17,962	7,104	907	2	8,013
Mar-19	222,770	24,777	277	247,824	60,034	6,973	9	67,016	16,714	2,404	2	19,121	16,210	1,764	6	17,980	7,098	908	2	8,008
Apr-19	222,707	24,762	277	247,746	60,009	6,954	9	66,973	16,660	2,396	2	19,058	16,185	1,760	6	17,951	7,094	905	2	8,001
May-19	222,900	24,766	277	247,943	60,021	6,957	9	66,986	16,635	2,407	2	19,044	16,128	1,753	6	17,887	7,081	905	3	7,989
Jun-19	223,096	24,786	279	248,161	59,912	6,951	9	66,872	16,578	2,404	2	18,984	16,059	1,751	6	17,816	7,059	906	3	7,968
Jul-19	223,115	24,764	280	248,160	59,799	6,948	9	66,756	16,612	2,401	2	19,016	16,098	1,754	6	17,858	6,990	907	3	7,900
Aug-19	223,278	24,829	279	248,385	59,714	6,950	9	66,673	16,572	2,398	2	18,972	16,035	1,751	6	17,791	6,975	908	4	7,887
Sep-19	223,719	24,882	280	248,881	59,815	6,963	9	66,787	16,549	2,396	2	18,947	16,043	1,756	6	17,805	6,967	910	8	7,885
Oct-19	224,569	24,897	278	249,744	60,142	6,956	9	67,107	16,647	2,398	2	19,046	16,166	1,745	6	17,917	7,039	909	8	7,956

Appendix 2.2 - Customer Forecast - Number by Region
Low Growth Case

	WA / ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA / ID Res	WA / ID Com	WA / ID Firm Ind	WA / ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-19	225,032	24,981	279	250,292	60,556	7,002	9	67,567	16,813	2,408	2	19,223	16,305	1,754	6	18,065	7,095	909	6	8,010
Dec-19	225,736	25,039	280	251,056	60,981	7,021	9	68,010	16,897	2,410	2	19,309	16,411	1,765	5	18,181	7,132	909	3	8,044
Jan-20	225,400	25,033	276	250,709	60,766	7,012	9	67,787	17,003	2,423	2	19,428	16,376	1,771	5	18,152	7,158	909	2	8,069
Feb-20	225,462	25,112	279	250,852	60,811	7,016	9	67,836	17,031	2,424	2	19,457	16,398	1,777	6	18,181	7,164	909	2	8,076
Mar-20	225,665	25,092	277	251,034	60,905	7,025	9	67,939	17,068	2,426	2	19,496	16,416	1,778	6	18,199	7,159	910	2	8,070
Apr-20	225,600	25,077	277	250,954	60,880	7,006	9	67,895	17,012	2,418	2	19,432	16,391	1,774	6	18,170	7,154	908	2	8,064
May-20	225,797	25,081	277	251,156	60,892	7,008	9	67,909	16,986	2,428	2	19,416	16,332	1,766	6	18,104	7,141	908	3	8,051
Jun-20	225,998	25,101	279	251,378	60,781	7,003	9	67,792	16,926	2,426	2	19,354	16,262	1,764	6	18,032	7,119	908	3	8,030
Jul-20	226,017	25,079	281	251,377	60,664	6,999	9	67,673	16,962	2,423	2	19,387	16,302	1,768	6	18,075	7,048	909	3	7,960
Aug-20	226,184	25,145	279	251,608	60,578	7,002	9	67,588	16,921	2,419	2	19,342	16,237	1,764	6	18,007	7,034	910	4	7,948
Sep-20	226,635	25,200	280	252,115	60,681	7,015	9	67,705	16,897	2,418	2	19,316	16,246	1,769	6	18,020	7,026	912	8	7,946
Oct-20	227,504	25,215	279	252,998	61,016	7,008	9	68,033	16,998	2,419	2	19,419	16,371	1,759	6	18,135	7,098	911	8	8,018
Nov-20	227,977	25,301	280	253,558	61,440	7,055	9	68,504	17,170	2,430	2	19,602	16,514	1,767	6	18,286	7,155	911	6	8,073
Dec-20	228,698	25,360	281	254,339	61,876	7,073	9	68,958	17,256	2,432	2	19,690	16,621	1,778	5	18,405	7,193	911	3	8,107
Jan-21	228,388	25,348	278	254,014	61,609	7,057	9	68,676	17,349	2,440	2	19,791	16,581	1,781	5	18,368	7,211	911	2	8,124
Feb-21	228,452	25,428	280	254,160	61,655	7,061	9	68,726	17,378	2,441	2	19,821	16,604	1,787	6	18,397	7,217	911	2	8,130
Mar-21	228,659	25,409	279	254,347	61,752	7,070	9	68,831	17,416	2,443	2	19,861	16,622	1,788	6	18,415	7,212	912	2	8,125
Apr-21	228,592	25,393	279	254,265	61,726	7,051	9	68,786	17,358	2,434	2	19,794	16,597	1,784	6	18,386	7,207	910	2	8,118
May-21	228,795	25,397	279	254,471	61,738	7,053	9	68,801	17,331	2,445	2	19,778	16,537	1,777	6	18,319	7,193	910	3	8,106
Jun-21	229,000	25,417	281	254,698	61,624	7,048	9	68,681	17,270	2,443	2	19,714	16,465	1,774	6	18,245	7,171	910	3	8,084
Jul-21	229,020	25,395	282	254,697	61,505	7,044	9	68,559	17,307	2,440	2	19,749	16,506	1,778	6	18,289	7,099	911	3	8,014
Aug-21	229,190	25,462	281	254,933	61,417	7,047	9	68,472	17,264	2,436	2	19,702	16,439	1,774	6	18,219	7,085	912	4	8,001
Sep-21	229,652	25,518	282	255,452	61,522	7,060	9	68,591	17,239	2,434	2	19,675	16,448	1,779	6	18,233	7,077	914	8	7,999
Oct-21	230,541	25,534	280	256,355	61,865	7,053	9	68,927	17,343	2,436	2	19,782	16,576	1,769	6	18,351	7,150	913	8	8,072
Nov-21	231,025	25,622	281	256,928	62,299	7,100	9	69,408	17,521	2,447	2	19,970	16,722	1,777	6	18,505	7,208	913	6	8,127
Dec-21	231,762	25,683	282	257,727	62,745	7,119	9	69,873	17,611	2,449	2	20,061	16,832	1,788	5	18,625	7,246	913	3	8,162
Jan-22	231,476	25,663	279	257,417	62,428	7,106	9	69,542	17,694	2,460	2	20,156	16,787	1,793	5	18,585	7,264	913	2	8,179
Feb-22	231,541	25,744	281	257,566	62,475	7,110	9	69,593	17,725	2,461	2	20,187	16,810	1,800	6	18,615	7,270	913	2	8,185
Mar-22	231,753	25,724	280	257,757	62,574	7,118	9	69,701	17,764	2,462	2	20,228	16,828	1,800	6	18,634	7,264	914	2	8,180
Apr-22	231,685	25,709	280	257,673	62,547	7,099	9	69,656	17,704	2,454	2	20,160	16,802	1,796	6	18,604	7,260	912	2	8,173
May-22	231,892	25,713	280	257,884	62,559	7,102	9	69,670	17,676	2,465	2	20,143	16,741	1,789	6	18,535	7,246	912	3	8,160
Jun-22	232,102	25,733	282	258,117	62,443	7,096	9	69,548	17,613	2,462	2	20,077	16,668	1,786	6	18,460	7,223	912	3	8,139
Jul-22	232,122	25,711	284	258,116	62,321	7,092	9	69,423	17,651	2,459	2	20,113	16,709	1,790	6	18,505	7,151	913	3	8,067
Aug-22	232,296	25,779	282	258,357	62,231	7,095	9	69,334	17,607	2,456	2	20,065	16,641	1,786	6	18,433	7,136	914	4	8,054
Sep-22	232,768	25,836	283	258,888	62,338	7,108	9	69,456	17,581	2,454	2	20,037	16,650	1,792	6	18,448	7,128	916	8	8,052
Oct-22	233,678	25,853	281	259,812	62,689	7,101	9	69,799	17,689	2,456	2	20,147	16,782	1,781	6	18,568	7,202	915	8	8,125
Nov-22	234,173	25,942	282	260,398	63,133	7,149	9	70,291	17,873	2,467	2	20,341	16,930	1,789	6	18,725	7,261	915	6	8,182
Dec-22	234,927	26,004	284	261,215	63,589	7,168	9	70,766	17,965	2,469	2	20,435	17,042	1,801	5	18,848	7,299	915	3	8,217
Jan-23	234,663	25,977	280	260,920	63,234	7,155	9	70,398	18,035	2,480	2	20,516	16,986	1,806	5	18,796	7,309	915	2	8,226
Feb-23	234,730	26,060	283	261,073	63,282	7,159	9	70,450	18,066	2,480	2	20,548	17,009	1,812	6	18,827	7,315	915	2	8,233
Mar-23	234,947	26,040	282	261,268	63,383	7,168	9	70,559	18,106	2,482	2	20,591	17,028	1,813	6	18,846	7,309	916	2	8,227
Apr-23	234,877	26,024	282	261,182	63,356	7,148	9	70,513	18,045	2,474	2	20,520	17,002	1,809	6	18,816	7,305	914	2	8,220
May-23	235,089	26,028	282	261,398	63,368	7,151	9	70,528	18,016	2,485	2	20,503	16,939	1,801	6	18,746	7,291	914	3	8,208
Jun-23	235,304	26,049	283	261,636	63,250	7,145	9	70,403	17,951	2,482	2	20,435	16,865	1,799	6	18,669	7,268	914	3	8,185
Jul-23	235,324	26,026	285	261,635	63,125	7,141	9	70,276	17,990	2,479	2	20,472	16,907	1,802	6	18,714	7,195	915	3	8,113
Aug-23	235,503	26,096	283	261,882	63,033	7,144	9	70,185	17,945	2,475	2	20,422	16,838	1,799	6	18,642	7,180	916	4	8,100
Sep-23	235,986	26,154	285	262,425	63,142	7,158	9	70,309	17,918	2,474	2	20,394	16,847	1,804	6	18,656	7,171	918	8	8,097
Oct-23	236,917	26,171	283	263,370	63,501	7,150	9	70,660	18,029	2,475	2	20,507	16,980	1,793	6	18,779	7,247	917	8	8,172
Nov-23	237,424	26,262	284	263,970	63,954	7,199	9	71,162	18,218	2,486	2	20,707	17,132	1,802	6	18,939	7,306	917	6	8,229
Dec-23	238,195	26,325	285	264,806	64,420	7,218	9	71,647	18,313	2,488	2	20,804	17,247	1,813	5	19,065	7,345	917	3	8,265
Jan-24	237,851	26,291	281	264,423	64,015	7,205	9	71,229	18,381	2,500	2	20,883	17,179	1,819	5	19,003	7,354	917	2	8,274
Feb-24	237,919	26,376	283	264,578	64,064	7,210	9	71,283	18,413	2,501	2	20,916	17,203	1,825	6	19,034	7,361	917	2	8,280
Mar-24	238,141	26,355	282	264,778	64,167	7,218	9	71,395	18,454	2,503	2	20,959	17,222	1,826	6	19,053	7,355	918	2	8,275
Apr-24	238,069	26,339	282	264,691	64,140	7,199	9	71,348	18,391	2,494	2	20,887	17,195	1,822	6	19,022	7,350	916	2	8,268
May-24	238,286	26,343	282	264,911	64,152	7,201	9	71,363	18,361	2,505	2	20,869	17,131	1,814	6	18,951	7,336	916	3	8,255
Jun-24	238,506	26,365	284	265,155	64,031	7,195	9	71,236	18,294	2,503	2	20,799	17,055	1,812	6	18,873	7,313	916	3	8,232
Jul-24	238,527	26,341	286	265,154	63,904	7,192	9	71,105	18,335	2,500	2	20,837	17,098	1,815	6	18,919	7,239	917	3	8,159
Aug-24	238,709	26,413	284	265,406	63,810	7,194	9	71,013	18,288	2,496	2	20,786	17,028	1,812	6	18,845	7,224	919	4	8,146
Sep-24	239,204	26,472	285	265,961	63,922	7,208	9	71,139	18,260	2,494	2	20,757	17,037	1,817	6	18,860	7,215	920	8	8,143
Oct-24	240,156	26,489	283	266,928	64,288	7,201	9	71,497	18,375	2,496	2	20,873	17,173	1,806	6	18,985	7,291	920	8	8,219
Nov-24	240,674	26,582	285	267,541	64,750	7,250	9	72,009	18,570	2,507	2	21,079	17,328	1,815	6	19,148	7,351	920	6	8,277
Dec-24	241,464	26,647	286	268,396	65,225	7,269	9	72,504	18,667	2,509	2	21,179	17,444	1,827	5	19,276	7,390	920	3	8,313
Jan-25	241,038	26,606	282	267,926	64,784	7,258	9	72,050	18,726	2,522	2	21,251	17,378	1,833	5	19,216	7,399	920	2	8,321
Feb-25	241,108	26,693	285	268,085	64,834	7,262	9	72,105	18,759	2,523	2	21,284	17,402	1,840	6	19,248	7,406	920	2	8,328
Mar-25	241,335	26,671	284	268,289	64,939	7,271	9	72,219	18,802	2,525	2	21,329	17,421	1,841	6	19,268	7,400	920	2	8,322
Apr-25	241,262	26,655	284	268,200	64,911	7,251	9	72,171	18,737	2,516	2	21,255	17,394	1,836	6	19,236	7,395	918	2	8,315
May-25	241,483	26,659	284	268,426	64,924	7,253	9	72,186	18,707	2,527	2	21,236	17,329	1,829	6	19,163	7,381	918	3	8,302
Jun-25	241,708	26,681	285	268,674	64,800	7,247	9	72,057	18,637	2,525	2	21,164	17,252	1,826	6	19,084	7,358	919	3	8,279
Jul-25	241,729	26,657	287	268,673	64,671	7,244	9	71,924	18,679	2,522	2	21,203	17,296	1,830	6	19,131	7,283	920	3	8,205
Aug-25	241,916	26,730	285	268,931	64,574	7,246	9	71,830	18,631	2,518	2	21,151	17,224	1,826	6	19,056	7,267	921	4	8,192
Sep-25	242,421	26,790	287	269,498	64,689	7,261	9	71,958	18,603	2,516	2	21,121	17,233	1,832	6	19,071	7,259	922	8	8,189
Oct-25	243,395	26,808	285	270,487	65,062	7,253	9	72,324	18,721	2,518	2	21,241	17,372	1,820	6	19,198	7,336	922	8	8,266

Appendix 2.2 - Customer Forecast - Number by Region
Low Growth Case

	WA / ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA / ID Res	WA / ID Com	WA / ID Firm Ind	WA / ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-25	243,925	26,902	286	271,113	65,534	7,303	9	72,845	18,921	2,529	2	21,452	17,530	1,829	6	19,364	7,396	922	6	8,324
Dec-25	244,732	26,969	287	271,987	66,018	7,322	9	73,349	19,022	2,531	2	21,555	17,649	1,841	5	19,495	7,436	922	3	8,361
Jan-26	244,176	26,920	283	271,380	65,559	7,309	9	72,877	19,083	2,543	2	21,629	17,583	1,847	5	19,435	7,437	922	2	8,361
Feb-26	244,247	27,009	286	271,541	65,610	7,313	9	72,932	19,117	2,544	2	21,663	17,608	1,853	6	19,467	7,444	922	2	8,368
Mar-26	244,479	26,987	285	271,750	65,717	7,322	9	73,048	19,161	2,546	2	21,709	17,628	1,854	6	19,487	7,438	922	2	8,362
Apr-26	244,404	26,970	285	271,659	65,689	7,302	9	73,000	19,094	2,537	2	21,633	17,600	1,850	6	19,455	7,433	920	2	8,355
May-26	244,630	26,974	285	271,889	65,702	7,304	9	73,015	19,063	2,549	2	21,613	17,533	1,842	6	19,381	7,419	920	3	8,342
Jun-26	244,860	26,997	287	272,144	65,576	7,298	9	72,883	18,992	2,546	2	21,540	17,455	1,839	6	19,300	7,395	921	3	8,319
Jul-26	244,882	26,972	288	272,143	65,444	7,295	9	72,747	19,035	2,543	2	21,580	17,499	1,843	6	19,348	7,319	922	3	8,244
Aug-26	245,072	27,047	287	272,406	65,345	7,297	9	72,652	18,985	2,539	2	21,526	17,426	1,839	6	19,271	7,304	923	4	8,231
Sep-26	245,589	27,108	288	272,985	65,462	7,312	9	72,783	18,956	2,537	2	21,495	17,436	1,845	6	19,286	7,295	924	8	8,228
Oct-26	246,583	27,126	286	273,995	65,842	7,304	9	73,155	19,077	2,539	2	21,618	17,577	1,833	6	19,416	7,373	924	8	8,305
Nov-26	247,125	27,223	287	274,635	66,323	7,354	9	73,686	19,283	2,551	2	21,836	17,738	1,842	6	19,586	7,434	924	6	8,364
Dec-26	247,949	27,290	288	275,527	66,817	7,374	9	74,200	19,387	2,553	2	21,941	17,859	1,855	5	19,719	7,474	924	3	8,401
Jan-27	247,264	27,235	285	274,784	66,291	7,361	9	73,661	19,434	2,564	2	22,001	17,788	1,860	5	19,653	7,482	924	2	8,408
Feb-27	247,336	27,325	288	274,949	66,343	7,365	9	73,717	19,469	2,565	2	22,036	17,814	1,867	6	19,686	7,489	924	2	8,415
Mar-27	247,573	27,303	286	275,162	66,452	7,375	9	73,835	19,515	2,567	2	22,083	17,834	1,867	6	19,707	7,483	924	2	8,409
Apr-27	247,497	27,286	286	275,069	66,423	7,354	9	73,786	19,446	2,558	2	22,005	17,805	1,863	6	19,674	7,478	922	2	8,402
May-27	247,728	27,290	286	275,304	66,436	7,357	9	73,802	19,414	2,569	2	21,985	17,738	1,855	6	19,599	7,464	922	3	8,389
Jun-27	247,962	27,313	288	275,563	66,308	7,351	9	73,667	19,340	2,567	2	21,909	17,657	1,853	6	19,516	7,440	923	3	8,366
Jul-27	247,984	27,288	290	275,562	66,173	7,347	9	73,529	19,385	2,563	2	21,950	17,703	1,856	6	19,565	7,363	924	3	8,290
Aug-27	248,179	27,364	288	275,831	66,073	7,349	9	73,432	19,333	2,560	2	21,895	17,628	1,853	6	19,487	7,348	925	4	8,277
Sep-27	248,706	27,427	289	276,422	66,192	7,364	9	73,565	19,304	2,558	2	21,863	17,638	1,858	6	19,502	7,339	927	8	8,274
Oct-27	249,721	27,444	288	277,453	66,579	7,356	9	73,944	19,428	2,560	2	21,990	17,783	1,847	6	19,635	7,417	926	8	8,352
Nov-27	250,274	27,543	289	278,105	67,069	7,407	9	74,485	19,640	2,571	2	22,214	17,946	1,856	6	19,807	7,479	926	6	8,411
Dec-27	251,115	27,612	290	279,017	67,572	7,428	9	75,008	19,747	2,573	2	22,322	18,070	1,868	5	19,943	7,520	926	3	8,449

Demand Coefficients

Appendix 2.3

Regression--Residential WA & ID

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	0.0301	0.0023	12.9224	2.68657E-30
	NHDDD	0.0094	0.0001	63.6034	7.2305E-169
	NQDDD	0.0019	0.0001	14.9808	1.07403E-37

a Dependent Variable: RNDT

Regression--Residential WA & ID		Calibration Correction (%)	Final
Base	**0.0301**	1.6196	**0.0488**
Shoulder	**0.0094**	0.6304	**0.0059**
Dec-Jan-Feb	**0.0112**	0.9259	**0.0104**
Nov & Mar	**0.0094**	0.9702	**0.0091**

Regression--Commercial WA & ID

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	0.2134	0.0113	18.8746	6.91553E-52
	NHDDD	0.0472	0.0007	65.9534	5.1129E-173
	NQDDD	0.0115	0.0006	19.0984	1.06953E-52

a Dependent Variable: CNDT

Regression--Commercial WA & ID		Calibration Correction (%)	Final
Base	**0.2134**	1.6196	**0.3456**
Shoulder	**0.0472**	0.6304	**0.0297**
Dec-Jan-Feb	**0.0587**	0.9259	**0.0543**
Nov & Mar	**0.0472**	0.9702	**0.0458**

Regression--Firm Industrial WA & ID

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	4.3748	0.080897048	54.07863783	1.4517E-150
	NHDDD	0.1164	0.005117407	22.75515098	1.0506E-65
	NQDDD	0.0452	0.004309456	10.4915236	6.02302E-22

a Dependent Variable: INDT

Regression--Firm Industrial WA & ID		Calibration Correction (%)	Final
Base	**4.3748**	1.6196	**7.0854**
Shoulder	**0.1164**	0.6304	**0.0734**
Dec-Jan-Feb	**0.1617**	0.9259	**0.1497**
Nov & Mar	**0.1164**	0.9702	**0.1130**

Regression--Residential Medford

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	0.0376	0.0015	25.6122	1.85684E-75
	MHDDD	0.0095	0.0001	67.2378	3.1236E-175
	MQDDD	0.0017	0.0001	13.5006	2.35291E-32

a Dependent Variable: RMDT

Regression--Residential Medford		Calibration Correction (%)	Final
Base	**0.0376**	1.1754	**0.0442**
Shoulder	**0.0095**	0.7691	**0.0073**
Dec-Jan-Feb	**0.0112**	1.0440	**0.0117**
Nov & Mar	**0.0095**	1.0680	**0.0101**

Regression--Commercial Medford

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	0.2903	0.0155	18.7306	2.30114E-51
	MHDDD	0.0452	0.0015	30.4767	4.51413E-91
	MQDDD	0.0002	0.0013	0.1656	0.868594306

a Dependent Variable: CMDT

Regression--Commercial Medford		Calibration Correction (%)	Final
Base	**0.2903**	1.1754	**0.3412**
Shoulder	**0.0452**	0.7691	**0.0348**
Dec-Jan-Feb	**0.0455**	1.0440	**0.0475**
Nov & Mar	**0.0452**	1.0680	**0.0483**

Regression--Firm Industrial Medford

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	0.029406813	0.028566584	1.029412998	0.304170887
	MHDDD	0.075782114	0.002736531	27.69276501	2.71243E-82
	MQDDD	0.001501534	0.002462884	0.609664908	0.54257646

a Dependent Variable: CMDT

Regression--Firm Industrial Medford		Calibration Correction (%)	Final
Base	**0.0294**	1.1754	**0.0346**
Shoulder	**0.0758**	0.7691	**0.0583**
Dec-Jan-Feb	**0.0773**	1.0440	**0.0807**
Nov & Mar	**0.0758**	1.0680	**0.0809**

Regression--Residential Roseburg

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	0.0359	0.0012	28.9895	1.958E-86
	RHDDD	0.0106	0.0001	79.6055	8.2663E-195
	RQDDD	0.0013	0.0001	10.7946	5.92577E-23

a Dependent Variable: RRDT

Regression--Residential Roseburg		Calibration Correction (%)	Final
Base	**0.0359**	1.2964	**0.0465**
Shoulder	**0.0106**	0.7245	**0.0077**
Dec-Jan-Feb	**0.0119**	0.9789	**0.0117**
Nov & Mar	**0.0106**	0.9349	**0.0099**

Regression--Commercial Roseburg

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	0.2805	0.0163	17.2281	6.81002E-46
	RHDDD	0.0534	0.0018	30.3715	9.5193E-91
	RQDDD	-0.0011	0.0016	-0.6839	0.494595161

a Dependent Variable: CRDT

Regression--Commercial Roseburg		Calibration Correction (%)	Final
Base	**0.2805**	1.2964	**0.3637**
Shoulder	**0.0534**	0.7245	**0.0387**
Dec-Jan-Feb	**0.0523**	0.9789	**0.0512**
Nov & Mar	**0.0534**	0.9349	**0.0499**

Regression--Firm Industrial Roseburg

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	11.9581	0.1814	65.9241	5.7476E-173
	RHDDD	0.6041	0.0196	30.8542	3.13865E-92
	RQDDD	-0.1701	0.0177	-9.6239	3.91227E-19

a Dependent Variable: IRDT

Regression--Firm Industrial Roseburg		Calibration Correction (%)	Final
Base	**11.9581**	1.2964	**15.5025**
Shoulder	**0.6041**	0.7245	**0.4377**
Dec-Jan-Feb	**0.4340**	0.9789	**0.4249**
Nov & Mar	**0.6041**	0.9349	**0.5648**

Regression--Residential Klamath Falls

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	0.0137	0.0031	4.4168	1.43108E-05
	KHDDD	0.0079	0.0002	41.3221	2.0409E-121
	KQDDD	0.0020	0.0002	13.1000	6.29945E-31

a Dependent Variable: RKDT

Regression--Residential Klamath Falls		Calibration Correction (%)	Final
Base	**0.0137**	2.3155	**0.0318**
Shoulder	**0.0079**	0.5186	**0.0041**
Dec-Jan-Feb	**0.0099**	0.8426	**0.0084**
Nov & Mar	**0.0079**	0.8476	**0.0067**

Regression--Commercial Klamath Falls

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	0.1506	0.0266	5.6723	3.49963E-08
	KHDDD	0.0419	0.0016	25.6776	1.12342E-75
	KQDDD	0.0023	0.0013	1.7302	0.08469882

a Dependent Variable: CKDT

Regression--Commercial Klamath Falls		Calibration Correction (%)	Final
Base	**0.1506**	2.3155	**0.3488**
Shoulder	**0.0419**	0.5186	**0.0217**
Dec-Jan-Feb	**0.0442**	0.8426	**0.0372**
Nov & Mar	**0.0419**	0.8476	**0.0355**

Regression--Firm Industrial Klamath Falls

Coefficients

Model		Unstandardized Coefficients B	Std. Error	t	Sig.
1	(Constant)	0.038518325	0.03941458	0.977260814	0.329280619
	KHDDD	0.054989665	0.002420898	22.71457399	1.45482E-65
	KQDDD	0.010036591	0.00197617	5.078808335	6.92943E-07

a Dependent Variable: CKDT

Regression--Firm Industrial Klamath Falls		Calibration Correction (%)	Final
Base	**0.0385**	2.3155	**0.0892**
Shoulder	**0.0550**	0.5186	**0.0285**
Dec-Jan-Feb	**0.0650**	0.8426	**0.0548**
Nov & Mar	**0.0550**	0.8476	**0.0466**

Regression--Residential La Grande

Coefficients

Model		Unstandardized Coefficients		t	Sig.
		B	Std. Error		
1	(Constant)	0.0145	0.0047	3.0840	0.002245712
	LHDDD	0.0091	0.0003	29.1164	7.7838E-87
	LQDDD	0.0018	0.0003	6.9195	3.06602E-11
a	Dependent Variable: RLDT				

Regression--Residential La Grande		Calibration Correction (%)	Final
Base	**0.0145**	2.0591	**0.0299**
Shoulder	**0.0091**	0.6308	**0.0057**
Dec-Jan-Feb	**0.0109**	1.1194	**0.0122**
Nov & Mar	**0.0091**	1.1161	**0.0102**

Regression--Commercial La Grande

Coefficients

Model		Unstandardized Coefficients		t	Sig.
		B	Std. Error		
1	(Constant)	0.1274	0.0226	5.6466	4.00306E-08
	LHDDD	0.0407	0.0015	27.1824	1.22582E-80
	LQDDD	0.0046	0.0013	3.6881	0.000271162
a	Dependent Variable: CLDT				

Regression--Commercial La Grande		Calibration Correction (%)	Final
Base	**0.1274**	2.0591	**0.2623**
Shoulder	**0.0407**	0.6308	**0.0257**
Dec-Jan-Feb	**0.0454**	1.1194	**0.0508**
Nov & Mar	**0.0407**	1.1161	**0.0455**

Regression--Firm Industrial La Grande

Coefficients

Model		Unstandardized Coefficients		t	Sig.
		B	Std. Error		
1	(Constant)	27.2292	1.6612	16.3912	7.75936E-43
	LHDDD	-1.1588	0.1104	-10.4999	5.65102E-22
	LQDDD	0.3679	0.0923	3.9869	8.54086E-05
a	Dependent Variable: ILDT				

Regression--Firm Industrial La Grande		Calibration Correction (%)	Final
Base	**27.2292**	2.0591	**56.0676**
Shoulder	**(1.1588)**	0.6308	**-**
Dec-Jan-Feb	**(0.7909)**	1.1194	**-**
Nov & Mar	**(1.1588)**	1.1161	**-**

Detailed Demand Data

Appendix 2.4

Appendix 2.4 - A
Annual Avg. Demand (MDth/d)
(Net of DSM Savings)

Area	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017
Expected Case										
Klam Falls	3.81	3.88	3.96	4.05	4.14	4.21	4.28	4.36	4.46	4.54
La Grande	2.43	2.45	2.47	2.49	2.51	2.53	2.55	2.58	2.61	2.64
Medford GTN	10.41	10.61	10.85	11.09	11.38	11.61	11.85	12.11	12.41	12.66
Medford NWP	4.68	4.77	4.87	4.98	5.11	5.22	5.33	5.44	5.58	5.69
Roseburg	4.24	4.32	4.43	4.55	4.70	4.83	4.96	5.10	5.27	5.42
OR Sub-Total	25.56	26.02	26.58	27.16	27.84	28.40	28.97	29.60	30.33	30.95
Spokane	40.49	41.37	42.38	43.42	44.53	45.29	46.23	46.77	47.75	48.56
Spokane GTN	5.59	5.71	5.85	5.99	6.14	6.25	6.36	6.46	6.59	6.70
Spokane NWP	23.74	24.25	24.85	25.46	26.12	26.57	27.01	27.44	28.02	28.49
WA/ID Sub-Total	69.81	71.33	73.07	74.87	76.79	78.11	79.60	80.67	82.36	83.75
Expected Case Total	95.37	97.35	99.65	102.03	104.63	106.51	108.58	110.27	112.69	114.70
High Case										
Klam Falls	3.82	3.88	4.05	4.21	4.37	4.50	4.63	4.75	4.90	5.02
La Grande	2.70	2.70	2.77	2.81	2.86	2.91	2.95	2.99	3.04	3.08
Medford GTN	10.48	10.66	11.16	11.59	12.08	12.48	12.89	13.29	13.75	14.12
Medford NWP	4.71	4.79	5.01	5.21	5.43	5.61	5.79	5.97	6.18	6.35
Roseburg	**4.30**	**4.38**	**4.60**	**4.80**	**5.05**	**5.26**	**5.48**	**5.70**	**5.96**	**6.18**
OR Sub-Total	**26.01**	**26.40**	**27.59**	**28.63**	**29.79**	**30.75**	**31.75**	**32.72**	**33.83**	**34.75**
Spokane	41.32	42.15	44.25	46.14	47.70	49.22	50.81	52.24	53.82	55.07
Spokane GTN	5.70	5.82	6.11	6.37	6.64	6.84	7.06	7.24	7.43	7.60
Spokane NWP	24.22	24.72	25.95	27.06	27.97	28.87	29.80	30.65	31.57	32.31
WA/ID Sub-Total	**71.24**	**72.69**	**76.30**	**79.56**	**82.31**	**84.93**	**87.67**	**90.12**	**92.82**	**94.99**
High Case Total	**97.25**	**99.09**	**103.89**	**108.19**	**112.09**	**115.68**	**119.42**	**122.84**	**126.65**	**129.74**
Low Case										
Klam Falls	3.76	3.69	3.74	3.79	3.83	3.86	3.89	3.93	3.97	4.01
La Grande	2.47	2.41	2.43	2.45	2.45	2.46	2.47	2.48	2.49	2.51
Medford GTN	10.29	10.11	10.25	10.40	10.54	10.63	10.74	10.85	11.00	11.11
Medford NWP	4.62	4.54	4.60	4.67	4.74	4.78	4.83	4.88	4.94	4.99
Roseburg	4.22	4.15	4.22	4.29	4.36	4.42	4.48	4.54	4.63	4.69
OR Sub-Total	**25.37**	**24.91**	**25.23**	**25.60**	**25.93**	**26.15**	**26.40**	**26.68**	**27.04**	**27.31**
Spokane	40.11	39.41	39.99	40.62	41.02	41.19	41.43	41.74	42.16	42.43
Spokane GTN	5.53	5.44	5.52	5.61	5.66	5.69	5.72	5.76	5.82	5.86
Spokane NWP	**23.52**	**23.11**	**23.45**	**23.82**	**24.06**	**24.16**	**24.35**	**24.49**	**24.74**	**24.90**
WA/ID Sub-Total	**69.17**	**67.96**	**68.96**	**70.05**	**70.73**	**71.04**	**71.50**	**71.99**	**72.73**	**73.19**
Low Case Total	**94.53**	**92.86**	**94.19**	**95.65**	**96.66**	**97.18**	**97.91**	**98.68**	**99.77**	**100.50**

Appendix 2.4 - A
Annual Avg. Demand (MDth/d)
(Net of DSM Savings)

Area	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
Expected Case										
Klam Falls	4.71	4.80	4.87	4.96	5.04	5.13	5.20	5.29	5.38	5.46
La Grande	2.69	2.72	2.74	2.76	2.79	2.81	2.83	2.85	2.87	2.88
Medford GTN	13.20	13.50	13.73	13.99	14.24	14.53	14.74	14.98	15.22	15.50
Medford NWP	5.93	6.07	6.17	6.29	6.40	6.53	6.62	6.73	6.84	6.96
Roseburg	5.72	5.88	6.02	6.17	6.31	6.47	6.61	6.77	6.92	7.08
OR Sub-Total	**32.25**	**32.98**	**33.54**	**34.16**	**34.77**	**35.46**	**36.00**	**36.62**	**37.23**	**37.89**
Spokane	50.53	51.65	52.62	53.70	54.82	56.04	57.07	58.20	59.31	60.56
Spokane GTN	6.98	7.13	7.26	7.41	7.57	7.74	7.88	8.03	8.19	8.36
Spokane NWP	29.65	30.30	30.87	31.51	32.16	32.88	33.48	34.14	34.80	35.53
WA/ID Sub-Total	**87.15**	**89.08**	**90.75**	**92.63**	**94.55**	**96.66**	**98.43**	**100.37**	**102.29**	**104.44**
Expected Case Total	**119.40**	**122.06**	**124.29**	**126.78**	**129.33**	**132.12**	**134.44**	**136.99**	**139.52**	**142.33**
High Case										
Klam Falls	5.14	5.26	5.39	5.50	5.62	5.73	5.85	5.96	6.09	6.21
La Grande	3.11	3.15	3.18	3.22	3.25	3.28	3.30	3.33	3.35	3.38
Medford GTN	14.41	14.90	15.33	15.66	16.03	16.38	16.78	17.07	17.43	17.78
Medford NWP	6.48	6.69	6.89	7.04	7.20	7.36	7.54	7.67	7.83	7.99
Roseburg	6.40	6.62	6.86	7.06	7.27	7.48	7.71	7.91	8.13	8.35
OR Sub-Total	**35.53**	**36.62**	**37.65**	**38.47**	**39.37**	**40.24**	**41.18**	**41.94**	**42.84**	**43.71**
Spokane	56.44	57.96	59.62	61.08	62.71	64.31	66.07	67.56	69.25	70.90
Spokane GTN	7.79	8.00	8.23	8.43	8.66	8.88	9.12	9.32	9.56	9.78
Spokane NWP	33.11	34.00	34.98	35.83	36.79	37.73	38.76	39.63	40.62	41.59
WA/ID Sub-Total	**97.35**	**99.96**	**102.83**	**105.33**	**108.15**	**110.92**	**113.95**	**116.51**	**119.43**	**122.27**
High Case Total	**132.88**	**136.58**	**140.48**	**143.80**	**147.52**	**151.15**	**155.14**	**158.45**	**162.28**	**165.98**
Low Case										
Klam Falls	4.04	4.08	4.12	4.15	4.19	4.22	4.25	4.27	4.31	4.34
La Grande	2.52	2.53	2.54	2.55	2.56	2.56	2.57	2.57	2.58	2.58
Medford GTN	11.23	11.36	11.52	11.61	11.71	11.81	11.94	12.00	12.10	12.19
Medford NWP	5.05	5.10	5.17	5.21	5.26	5.31	5.37	5.40	5.44	5.48
Roseburg	4.77	4.84	4.92	4.98	5.05	5.11	5.18	5.24	5.30	5.37
OR Sub-Total	**27.61**	**27.91**	**28.26**	**28.50**	**28.77**	**29.01**	**29.31**	**29.49**	**29.72**	**29.96**
Spokane	42.85	43.28	43.80	44.19	44.65	45.06	45.56	45.89	46.31	46.73
Spokane GTN	5.92	5.98	6.05	6.10	6.16	6.22	6.29	6.34	6.39	6.45
Spokane NWP	25.15	25.40	25.71	25.93	26.20	26.44	26.73	26.93	27.17	27.42
WA/ID Sub-Total	**73.92**	**74.65**	**75.56**	**76.22**	**77.01**	**77.73**	**78.58**	**79.15**	**79.87**	**80.61**
Low Case Total	**101.53**	**102.57**	**103.82**	**104.71**	**105.78**	**106.74**	**107.89**	**108.64**	**109.60**	**110.57**

Appendix 2.4 - B

Annual Avg. Demand (MDth/d)

By Class (Net of DSM Savings)

	2007/2008				2008/2009			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	2.24	1.57	0.00	3.81	2.28	1.59	0.00	3.88
La Grande	1.36	0.91	0.16	2.43	1.38	0.91	0.16	2.45
Medford GTN	6.27	4.13	-	10.41	6.42	4.19	-	10.61
Medford NWP	2.82	1.86	-	4.68	2.88	1.88	-	4.77
Roseburg	2.21	1.98	0.04	4.24	2.27	2.01	0.04	4.32
OR Sub-Total	**14.90**	**10.45**	**0.20**	**25.56**	**15.23**	**10.58**	**0.21**	**26.02**
Spokane Both	23.63	15.49	1.37	40.49	24.18	15.79	1.40	41.37
Spokane GTN	3.26	2.14	0.19	5.59	3.34	2.18	0.19	5.71
Spokane NWP	13.85	9.08	0.80	23.74	14.18	9.26	0.82	24.25
WA/ID Sub-Total	**40.74**	**26.70**	**2.36**	**69.81**	**41.69**	**27.23**	**2.41**	**71.33**
Expected Case Total	**55.64**	**37.16**	**2.57**	**95.37**	**56.93**	**37.81**	**2.61**	**97.35**
High Case								
Klam Falls	2.25	1.57	0.01	3.82	2.29	1.59	0.01	3.88
La Grande	1.36	0.92	0.42	2.70	1.37	0.92	0.42	2.70
Medford GTN	6.31	4.17	-	10.48	6.45	4.21	-	10.66
Medford NWP	2.83	1.87	-	4.71	2.90	1.89	-	4.79
Roseburg	**2.23**	**2.02**	**0.04**	**4.30**	**2.29**	**2.04**	**0.04**	**4.38**
OR Sub-Total	**14.98**	**10.56**	**0.47**	**26.01**	**15.29**	**10.65**	**0.47**	**26.40**
Spokane Both	24.03	15.77	1.52	41.32	24.57	16.04	1.55	42.15
Spokane GTN	**3.31**	**2.18**	**0.21**	**5.70**	**3.39**	**2.21**	**0.21**	**5.82**
Spokane NWP	**14.09**	**9.25**	**0.89**	**24.22**	**14.41**	**9.40**	**0.91**	**24.72**
WA/ID Sub-Total	**41.43**	**27.20**	**2.62**	**71.24**	**42.36**	**27.65**	**2.67**	**72.69**
High Case Total	**56.41**	**37.75**	**3.09**	**97.25**	**57.65**	**38.30**	**3.14**	**99.09**
Low Case								
Klam Falls	2.21	1.55	0.01	3.76	2.16	1.52	0.01	3.69
La Grande	1.35	0.91	0.21	2.47	1.31	0.88	0.22	2.41
Medford GTN	6.20	4.09	-	10.29	6.09	4.02	-	10.11
Medford NWP	2.78	1.84	-	4.62	2.74	1.81	-	4.54
Roseburg	2.19	1.99	0.04	4.22	2.15	1.96	0.04	4.15
OR Sub-Total	**14.72**	**10.38**	**0.26**	**25.37**	**14.45**	**10.19**	**0.26**	**24.91**
Spokane Both	23.37	15.35	1.39	40.11	22.93	15.09	1.39	39.41
Spokane GTN	3.22	2.12	0.19	5.53	3.16	2.08	0.19	5.44
Spokane NWP	**13.70**	**9.00**	**0.82**	**23.52**	**13.45**	**8.85**	**0.81**	**23.11**
WA/ID Sub-Total	**40.29**	**26.47**	**2.40**	**69.17**	**39.54**	**26.02**	**2.40**	**67.96**
Low Case Total	**55.01**	**36.86**	**2.66**	**94.53**	**53.99**	**36.21**	**2.66**	**92.86**

Appendix 2.4 - B

Annual Avg. Demand (MDth/d)

By Class (Net of DSM Savings)

	2009/2010				2010/2011			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	2.34	1.61	0.00	3.96	2.41	1.63	0.00	4.05
La Grande	1.40	0.91	0.16	2.47	1.41	0.91	0.16	2.49
Medford GTN	6.61	4.24	-	10.85	6.80	4.29	-	11.09
Medford NWP	2.97	1.91	-	4.87	3.06	1.93	-	4.98
Roseburg	2.35	2.04	0.04	4.43	2.44	2.07	0.04	4.55
OR Sub-Total	**15.66**	**10.72**	**0.21**	**26.58**	**16.12**	**10.83**	**0.21**	**27.16**
Spokane Both	24.80	16.15	1.43	42.38	25.42	16.54	1.46	43.42
Spokane GTN	3.42	2.23	0.20	5.85	3.51	2.28	0.20	5.99
Spokane NWP	14.55	9.47	0.84	24.85	14.91	9.69	0.85	25.46
WA/ID Sub-Total	**42.76**	**27.85**	**2.46**	**73.07**	**43.85**	**28.51**	**2.51**	**74.87**
Expected Case Total	**58.42**	**38.57**	**2.66**	**99.65**	**59.97**	**39.34**	**2.72**	**102.03**
High Case								
Klam Falls	2.41	1.64	0.01	4.05	2.53	1.67	0.01	4.21
La Grande	1.42	0.93	0.42	2.77	1.45	0.94	0.42	2.81
Medford GTN	6.82	4.34	-	11.16	7.16	4.43	-	11.59
Medford NWP	3.06	1.95	-	5.01	3.21	1.99	-	5.21
Roseburg	2.43	2.12	0.04	4.60	2.59	2.18	0.04	4.80
OR Sub-Total	**16.14**	**10.98**	**0.47**	**27.59**	**16.94**	**11.22**	**0.47**	**28.63**
Spokane Both	25.86	16.78	1.60	44.25	27.02	17.46	1.66	46.14
Spokane GTN	3.57	2.31	0.22	6.11	3.73	2.41	0.23	6.37
Spokane NWP	15.17	9.84	0.94	25.95	15.85	10.23	0.97	27.06
WA/ID Sub-Total	**44.60**	**28.93**	**2.77**	**76.30**	**46.60**	**30.10**	**2.86**	**79.56**
High Case Total	**60.74**	**39.91**	**3.24**	**103.89**	**63.54**	**41.32**	**3.33**	**108.19**
Low Case								
Klam Falls	2.19	1.54	0.01	3.74	2.24	1.55	0.01	3.79
La Grande	1.33	0.89	0.22	2.43	1.34	0.89	0.22	2.45
Medford GTN	6.20	4.05	-	10.25	6.32	4.08	-	10.40
Medford NWP	2.78	1.82	-	4.60	2.84	1.84	-	4.67
Roseburg	2.20	1.98	0.04	4.22	2.25	2.00	0.04	4.29
OR Sub-Total	**14.70**	**10.27**	**0.26**	**25.23**	**14.98**	**10.36**	**0.26**	**25.60**
Spokane Both	23.27	15.31	1.41	39.99	23.63	15.56	1.43	40.62
Spokane GTN	3.21	2.11	0.19	5.52	3.26	2.15	0.20	5.61
Spokane NWP	13.65	8.98	0.83	23.45	13.86	9.12	0.84	23.82
WA/ID Sub-Total	**40.13**	**26.40**	**2.43**	**68.96**	**40.75**	**26.83**	**2.46**	**70.05**
Low Case Total	**54.82**	**36.68**	**2.69**	**94.19**	**55.73**	**37.19**	**2.73**	**95.65**

Appendix 2.4 - B

Annual Avg. Demand (MDth/d)

By Class (Net of DSM Savings)

	2011/2012				2012/2013			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	2.49	1.65	0.00	4.14	2.54	1.66	0.00	4.21
La Grande	1.43	0.92	0.16	2.51	1.46	0.92	0.16	2.53
Medford GTN	7.04	4.34	-	11.38	7.24	4.38	-	11.61
Medford NWP	3.16	1.95	-	5.11	3.25	1.97	-	5.22
Roseburg	2.55	2.10	0.04	4.70	2.66	2.13	0.04	4.83
OR Sub-Total	**16.68**	**10.96**	**0.20**	**27.84**	**17.14**	**11.05**	**0.21**	**28.40**
Spokane Both	26.06	16.98	1.48	44.53	26.43	17.37	1.49	45.29
Spokane GTN	3.60	2.34	0.20	6.14	3.65	2.40	0.21	6.25
Spokane NWP	15.29	9.96	0.87	26.12	15.51	10.18	0.88	26.57
WA/ID Sub-Total	**44.95**	**29.28**	**2.55**	**76.79**	**45.58**	**29.95**	**2.58**	**78.11**
Expected Case Total	**61.63**	**40.24**	**2.76**	**104.63**	**62.73**	**41.00**	**2.78**	**106.51**
High Case								
Klam Falls	2.66	1.71	0.01	4.37	2.75	1.74	0.01	4.50
La Grande	1.49	0.95	0.42	2.86	1.53	0.96	0.42	2.91
Medford GTN	7.55	4.53	-	12.08	7.88	4.60	-	12.48
Medford NWP	3.39	2.04	-	5.43	3.54	2.07	-	5.61
Roseburg	2.77	2.23	0.04	5.05	2.94	2.28	0.04	5.26
OR Sub-Total	**17.86**	**11.46**	**0.47**	**29.79**	**18.64**	**11.64**	**0.47**	**30.75**
Spokane Both	27.79	18.21	1.70	47.70	28.64	18.87	1.72	49.22
Spokane GTN	3.89	2.51	0.23	6.64	4.00	2.60	0.24	6.84
Spokane NWP	16.30	10.68	0.99	27.97	16.80	11.06	1.01	28.87
WA/ID Sub-Total	**47.98**	**31.40**	**2.92**	**82.31**	**49.43**	**32.53**	**2.97**	**84.93**
High Case Total	**65.84**	**42.87**	**3.39**	**112.09**	**68.07**	**44.17**	**3.44**	**115.68**
Low Case								
Klam Falls	2.27	1.56	0.01	3.83	2.29	1.56	0.01	3.86
La Grande	1.35	0.89	0.21	2.45	1.36	0.89	0.22	2.46
Medford GTN	6.44	4.11	-	10.54	6.51	4.12	-	10.63
Medford NWP	2.89	1.85	-	4.74	2.93	1.85	-	4.78
Roseburg	2.31	2.01	0.04	4.36	2.35	2.02	0.04	4.42
OR Sub-Total	**15.25**	**10.42**	**0.26**	**25.93**	**15.45**	**10.44**	**0.26**	**26.15**
Spokane Both	23.78	15.79	1.44	41.02	23.78	15.96	1.45	41.19
Spokane GTN	3.28	2.18	0.20	5.66	3.28	2.20	0.20	5.69
Spokane NWP	13.96	9.26	0.84	24.06	13.96	9.36	0.85	24.16
WA/ID Sub-Total	**41.02**	**27.23**	**2.48**	**70.73**	**41.02**	**27.52**	**2.49**	**71.04**
Low Case Total	**56.28**	**37.64**	**2.74**	**96.66**	**56.47**	**37.96**	**2.76**	**97.18**

Appendix 2.4 - B

Annual Avg. Demand (MDth/d)

By Class (Net of DSM Savings)

	2013/2014				2014/2015			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	2.60	1.68	0.00	4.28	2.66	1.70	0.00	4.36
La Grande	1.47	0.92	0.16	2.55	1.50	0.92	0.16	2.58
Medford GTN	7.44	4.41	-	11.85	7.65	4.46	-	12.11
Medford NWP	3.34	1.98	-	5.33	3.44	2.01	-	5.44
Roseburg	2.76	2.16	0.04	4.96	2.87	2.19	0.04	5.10
OR Sub-Total	**17.62**	**11.15**	**0.21**	**28.97**	**18.11**	**11.28**	**0.21**	**29.60**
Spokane Both	26.92	17.80	1.52	46.23	27.02	18.22	1.54	46.77
Spokane GTN	3.69	2.45	0.21	6.36	3.74	2.51	0.21	6.46
Spokane NWP	15.69	10.43	0.89	27.01	15.86	10.68	0.90	27.44
WA/ID Sub-Total	**46.31**	**30.68**	**2.61**	**79.60**	**46.62**	**31.41**	**2.65**	**80.67**
Expected Case Total	**63.93**	**41.83**	**2.82**	**108.58**	**64.73**	**42.69**	**2.86**	**110.27**
High Case								
Klam Falls	2.86	1.77	0.01	4.63	2.95	1.80	0.01	4.75
La Grande	1.57	0.96	0.42	2.95	1.60	0.97	0.42	2.99
Medford GTN	8.21	4.68	-	12.89	8.53	4.76	-	13.29
Medford NWP	3.69	2.10	-	5.79	3.83	2.14	-	5.97
Roseburg	3.11	2.33	0.04	5.48	3.27	2.39	0.04	5.70
OR Sub-Total	**19.43**	**11.85**	**0.47**	**31.75**	**20.19**	**12.06**	**0.47**	**32.72**
Spokane Both	29.49	19.56	1.76	50.81	30.24	20.21	1.79	52.24
Spokane GTN	4.12	2.70	0.24	7.06	4.20	2.79	0.25	7.24
Spokane NWP	17.30	11.47	1.03	29.80	17.75	11.85	1.05	30.65
WA/ID Sub-Total	**50.91**	**33.73**	**3.03**	**87.67**	**52.19**	**34.84**	**3.09**	**90.12**
High Case Total	**70.34**	**45.58**	**3.50**	**119.42**	**72.38**	**46.90**	**3.56**	**122.84**
Low Case								
Klam Falls	2.32	1.57	0.01	3.89	2.35	1.58	0.01	3.93
La Grande	1.36	0.89	0.22	2.47	1.37	0.89	0.22	2.48
Medford GTN	6.61	4.13	-	10.74	6.70	4.15	-	10.85
Medford NWP	2.97	1.86	-	4.83	3.01	1.87	-	4.88
Roseburg	2.40	2.03	0.04	4.48	2.45	2.05	0.04	4.54
OR Sub-Total	**15.66**	**10.48**	**0.26**	**26.40**	**15.89**	**10.53**	**0.26**	**26.68**
Spokane Both	23.81	16.17	1.46	41.43	23.91	16.37	1.47	41.74
Spokane GTN	3.29	2.23	0.20	5.72	3.30	2.26	0.20	5.76
Spokane NWP	14.02	9.48	0.86	24.35	14.03	9.59	0.86	24.49
WA/ID Sub-Total	**41.12**	**27.87**	**2.52**	**71.50**	**41.24**	**28.22**	**2.53**	**71.99**
Low Case Total	**56.78**	**38.35**	**2.78**	**97.91**	**57.13**	**38.75**	**2.80**	**98.68**

Appendix 2.4 - B

Annual Avg. Demand (MDth/d)

By Class (Net of DSM Savings)

	2015/2016				2016/2017			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	2.73	1.73	0.00	4.46	2.78	1.75	0.00	4.54
La Grande	1.52	0.93	0.16	2.61	1.55	0.93	0.16	2.64
Medford GTN	7.88	4.53	-	12.41	8.08	4.59	-	12.66
Medford NWP	3.54	2.04	-	5.58	3.63	2.06	-	5.69
Roseburg	2.99	2.24	0.04	5.27	3.10	2.28	0.04	5.42
OR Sub-Total	**18.67**	**11.46**	**0.20**	**30.33**	**19.13**	**11.61**	**0.21**	**30.95**
Spokane Both	27.51	18.68	1.56	47.75	27.92	19.06	1.57	48.56
Spokane GTN	3.80	2.58	0.22	6.59	3.86	2.63	0.22	6.70
Spokane NWP	16.15	10.95	0.91	28.02	16.39	11.18	0.92	28.49
WA/ID Sub-Total	**47.47**	**32.20**	**2.69**	**82.36**	**48.17**	**32.87**	**2.71**	**83.75**
Expected Case Total	**66.13**	**43.66**	**2.89**	**112.69**	**67.30**	**44.48**	**2.92**	**114.70**
High Case								
Klam Falls	3.05	1.85	0.01	4.90	3.13	1.88	0.01	5.02
La Grande	1.64	0.98	0.42	3.04	1.68	0.98	0.42	3.08
Medford GTN	8.89	4.86	-	13.75	9.18	4.95	-	14.12
Medford NWP	3.99	2.19	-	6.18	4.12	2.22	-	6.35
Roseburg	3.46	2.46	0.04	5.96	3.62	2.52	0.04	6.18
OR Sub-Total	**21.03**	**12.33**	**0.47**	**33.83**	**21.73**	**12.56**	**0.47**	**34.75**
Spokane Both	31.08	20.91	1.83	53.82	31.75	21.48	1.85	55.07
Spokane GTN	4.30	2.88	0.25	7.43	4.39	2.96	0.25	7.60
Spokane NWP	18.24	12.26	1.07	31.57	18.64	12.59	1.08	32.31
WA/ID Sub-Total	**53.62**	**36.06**	**3.15**	**92.82**	**54.77**	**37.03**	**3.18**	**94.99**
High Case Total	**74.65**	**48.39**	**3.62**	**126.65**	**76.50**	**49.59**	**3.65**	**129.74**
Low Case								
Klam Falls	2.37	1.59	0.01	3.97	2.40	1.60	0.01	4.01
La Grande	1.39	0.89	0.21	2.49	1.40	0.89	0.22	2.51
Medford GTN	6.82	4.18	-	11.00	6.90	4.20	-	11.11
Medford NWP	3.07	1.88	-	4.94	3.10	1.89	-	4.99
Roseburg	2.51	2.08	0.04	4.63	2.56	2.09	0.04	4.69
OR Sub-Total	**16.16**	**10.62**	**0.26**	**27.04**	**16.36**	**10.69**	**0.26**	**27.31**
Spokane Both	24.08	16.60	1.48	42.16	24.17	16.77	1.49	42.43
Spokane GTN	3.33	2.29	0.20	5.82	3.34	2.31	0.21	5.86
Spokane NWP	14.14	9.73	0.87	24.74	14.20	9.83	0.87	24.90
WA/ID Sub-Total	**41.55**	**28.63**	**2.55**	**72.73**	**41.71**	**28.92**	**2.56**	**73.19**
Low Case Total	**57.71**	**39.25**	**2.82**	**99.77**	**58.07**	**39.61**	**2.83**	**100.50**

Appendix 2.4 - B

Annual Avg. Demand (MDth/d)

By Class (Net of DSM Savings)

	2017/2018				2018/2019			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	2.84	1.78	0.00	4.63	2.90	1.80	0.00	4.71
La Grande	1.57	0.94	0.16	2.67	1.59	0.94	0.16	2.69
Medford GTN	8.28	4.65	-	12.93	8.49	4.71	-	13.20
Medford NWP	3.72	2.09	-	5.81	3.81	2.12	-	5.93
Roseburg	3.21	2.32	0.04	5.57	3.32	2.36	0.04	5.72
OR Sub-Total	**19.63**	**11.78**	**0.21**	**31.61**	**20.12**	**11.93**	**0.21**	**32.25**
Spokane Both	28.46	19.48	1.59	49.53	29.02	19.90	1.61	50.53
Spokane GTN	3.93	2.69	0.22	6.84	4.01	2.75	0.22	6.98
Spokane NWP	16.71	11.42	0.93	29.06	17.03	11.67	0.94	29.65
WA/ID Sub-Total	**49.10**	**33.59**	**2.74**	**85.43**	**50.06**	**34.32**	**2.77**	**87.15**
Expected Case Total	**68.73**	**45.37**	**2.94**	**117.04**	**70.18**	**46.25**	**2.98**	**119.40**
High Case								
Klam Falls	3.21	1.92	0.01	5.14	3.30	1.95	0.01	5.26
La Grande	1.71	0.98	0.42	3.11	1.74	0.99	0.42	3.15
Medford GTN	9.40	5.01	-	14.41	9.78	5.12	-	14.90
Medford NWP	4.22	2.25	-	6.48	4.39	2.30	-	6.69
Roseburg	3.78	2.58	0.04	6.40	3.95	2.63	0.04	6.62
OR Sub-Total	**22.32**	**12.74**	**0.47**	**35.53**	**23.15**	**13.00**	**0.47**	**36.62**
Spokane Both	32.51	22.06	1.87	56.44	33.37	22.69	1.90	57.96
Spokane GTN	4.49	3.04	0.26	7.79	4.61	3.13	0.26	8.00
Spokane NWP	19.09	12.93	1.10	33.11	19.59	13.30	1.11	34.00
WA/ID Sub-Total	**56.09**	**38.04**	**3.22**	**97.35**	**57.57**	**39.11**	**3.28**	**99.96**
High Case Total	**78.41**	**50.78**	**3.69**	**132.88**	**80.72**	**52.11**	**3.75**	**136.58**
Low Case								
Klam Falls	2.42	1.62	0.01	4.04	2.45	1.63	0.01	4.08
La Grande	1.41	0.90	0.22	2.52	1.41	0.90	0.22	2.53
Medford GTN	**7.00**	**4.24**	**-**	**11.23**	**7.09**	**4.27**	**-**	**11.36**
Medford NWP	**3.14**	**1.90**	**-**	**5.05**	**3.19**	**1.91**	**-**	**5.10**
Roseburg	2.61	2.11	0.04	4.77	2.67	2.13	0.04	4.84
OR Sub-Total	**16.59**	**10.76**	**0.26**	**27.61**	**16.81**	**10.84**	**0.26**	**27.91**
Spokane Both	24.38	16.97	1.50	42.85	24.60	17.18	1.51	43.28
Spokane GTN	3.37	2.34	0.21	5.92	3.40	2.37	0.21	5.98
Spokane NWP	14.32	9.95	0.88	25.15	14.45	10.07	0.88	25.40
WA/ID Sub-Total	**42.07**	**29.27**	**2.58**	**73.92**	**42.44**	**29.61**	**2.60**	**74.65**
Low Case Total	**58.65**	**40.03**	**2.84**	**101.53**	**59.25**	**40.45**	**2.86**	**102.57**

Appendix 2.4 - B

Annual Avg. Demand (MDth/d)

By Class (Net of DSM Savings)

	2019/2020				2020/2021			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	2.97	1.83	0.00	4.80	3.02	1.85	0.00	4.87
La Grande	1.61	0.95	0.16	2.72	1.63	0.95	0.16	2.74
Medford GTN	8.72	4.79	-	13.50	8.90	4.84	-	13.73
Medford NWP	3.92	2.15	-	6.07	4.00	2.17	-	6.17
Roseburg	3.44	2.40	0.04	5.88	3.55	2.43	0.04	6.02
OR Sub-Total	**20.66**	**12.11**	**0.20**	**32.98**	**21.10**	**12.23**	**0.21**	**33.54**
Spokane Both	29.65	20.38	1.62	51.65	30.21	20.78	1.63	52.62
Spokane GTN	4.10	2.81	0.22	7.13	4.17	2.87	0.22	7.26
Spokane NWP	17.41	11.95	0.95	30.30	17.74	12.18	0.96	30.87
WA/ID Sub-Total	**51.16**	**35.14**	**2.79**	**89.08**	**52.12**	**35.82**	**2.81**	**90.75**
Expected Case Total	**71.82**	**47.25**	**2.99**	**122.06**	**73.22**	**48.05**	**3.02**	**124.29**
High Case								
Klam Falls	3.40	1.99	0.01	5.39	3.48	2.01	0.01	5.50
La Grande	1.77	1.00	0.42	3.18	1.80	1.00	0.42	3.22
Medford GTN	10.11	5.22	-	15.33	10.37	5.29	-	15.66
Medford NWP	4.54	2.35	-	6.89	4.66	2.38	-	7.04
Roseburg	4.12	2.69	0.04	6.86	4.28	2.73	0.04	7.06
OR Sub-Total	**23.94**	**13.25**	**0.47**	**37.65**	**24.58**	**13.42**	**0.47**	**38.47**
Spokane Both	34.34	23.37	1.92	59.62	35.19	23.95	1.94	61.08
Spokane GTN	4.74	3.22	0.26	8.23	4.86	3.30	0.27	8.43
Spokane NWP	20.15	13.70	1.12	34.98	20.65	14.04	1.13	35.83
WA/ID Sub-Total	**59.23**	**40.30**	**3.30**	**102.83**	**60.70**	**41.29**	**3.34**	**105.33**
High Case Total	**83.17**	**53.55**	**3.77**	**140.48**	**85.28**	**54.72**	**3.81**	**143.80**
Low Case								
Klam Falls	2.48	1.64	0.01	4.12	2.50	1.64	0.01	4.15
La Grande	1.42	0.90	0.21	2.54	1.43	0.90	0.22	2.55
Medford GTN	7.21	4.31	-	11.52	7.28	4.33	-	11.61
Medford NWP	3.24	1.93	-	5.17	3.27	1.94	-	5.21
Roseburg	2.73	2.15	0.04	4.92	2.77	2.16	0.04	4.98
OR Sub-Total	**17.07**	**10.93**	**0.26**	**28.26**	**17.26**	**10.98**	**0.26**	**28.50**
Spokane Both	24.87	17.42	1.51	43.80	25.07	17.59	1.52	44.19
Spokane GTN	3.44	2.40	0.21	6.05	3.46	2.43	0.21	6.10
Spokane NWP	14.61	10.21	0.89	25.71	14.72	10.31	0.89	25.93
WA/ID Sub-Total	**42.92**	**30.03**	**2.61**	**75.56**	**43.26**	**30.33**	**2.62**	**76.22**
Low Case Total	**59.99**	**40.96**	**2.87**	**103.82**	**60.52**	**41.31**	**2.88**	**104.71**

Appendix 2.4 - B

Annual Avg. Demand (MDth/d)

By Class (Net of DSM Savings)

	2021/2022				2022/2023			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	3.08	1.87	0.00	4.96	3.14	1.89	0.00	5.04
La Grande	1.65	0.95	0.16	2.76	1.67	0.96	0.16	2.79
Medford GTN	9.09	4.89	-	13.99	9.28	4.96	-	14.24
Medford NWP	4.08	2.20	-	6.29	4.17	2.23	-	6.40
Roseburg	3.66	2.46	0.04	6.17	3.77	2.50	0.04	6.31
OR Sub-Total	**21.57**	**12.38**	**0.21**	**34.16**	**22.04**	**12.53**	**0.21**	**34.77**
Spokane Both	30.85	21.21	1.64	53.70	31.51	21.65	1.66	54.82
Spokane GTN	4.26	2.93	0.23	7.41	4.35	2.99	0.23	7.57
Spokane NWP	18.11	12.44	0.96	31.51	18.50	12.69	0.97	32.16
WA/ID Sub-Total	**53.22**	**36.58**	**2.83**	**92.63**	**54.36**	**37.33**	**2.86**	**94.55**
Expected Case Total	**74.79**	**48.96**	**3.04**	**126.78**	**76.40**	**49.86**	**3.06**	**129.33**
High Case								
Klam Falls	3.56	2.05	0.01	5.62	3.65	2.08	0.01	5.73
La Grande	1.82	1.00	0.42	3.25	1.85	1.01	0.42	3.28
Medford GTN	10.65	5.38	-	16.03	10.92	5.46	-	16.38
Medford NWP	4.79	2.42	-	7.20	4.91	2.46	-	7.36
Roseburg	4.45	2.78	0.04	7.27	4.61	2.83	0.04	7.48
OR Sub-Total	**25.27**	**13.63**	**0.47**	**39.37**	**25.93**	**13.84**	**0.47**	**40.24**
Spokane Both	36.16	24.59	1.95	62.71	37.12	25.21	1.98	64.31
Spokane GTN	4.99	3.39	0.27	8.66	5.13	3.48	0.27	8.88
Spokane NWP	21.22	14.42	1.15	36.79	21.79	14.78	1.16	37.73
WA/ID Sub-Total	**62.38**	**42.40**	**3.37**	**108.15**	**64.04**	**43.47**	**3.41**	**110.92**
High Case Total	**87.65**	**56.03**	**3.84**	**147.52**	**89.97**	**57.31**	**3.88**	**151.15**
Low Case								
Klam Falls	2.53	1.65	0.01	4.19	2.55	1.66	0.01	4.22
La Grande	1.44	0.90	0.22	2.56	1.44	0.90	0.22	2.56
Medford GTN	7.37	4.34	-	11.71	7.44	4.37	-	11.81
Medford NWP	3.31	1.95	-	5.26	3.34	1.96	-	5.31
Roseburg	2.83	2.18	0.04	5.05	2.88	2.19	0.04	5.11
OR Sub-Total	**17.47**	**11.04**	**0.26**	**28.77**	**17.65**	**11.09**	**0.26**	**29.01**
Spokane Both	**25.32**	**17.80**	**1.53**	**44.65**	**25.55**	**17.98**	**1.53**	**45.06**
Spokane GTN	3.50	2.46	0.21	6.16	3.53	2.48	0.21	6.22
Spokane NWP	14.87	10.44	0.89	26.20	15.00	10.54	0.90	26.44
WA/ID Sub-Total	**43.69**	**30.69**	**2.63**	**77.01**	**44.09**	**31.00**	**2.64**	**77.73**
Low Case Total	**61.17**	**41.73**	**2.89**	**105.78**	**61.74**	**42.09**	**2.91**	**106.74**

Appendix 2.4 - B

Annual Avg. Demand (MDth/d)

By Class (Net of DSM Savings)

	2023/2024				2024/2025			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	3.20	1.92	0.00	5.13	3.26	1.94	0.00	5.20
La Grande	1.69	0.96	0.16	2.81	1.70	0.97	0.16	2.83
Medford GTN	9.50	5.03	-	14.53	9.65	5.08	-	14.74
Medford NWP	4.27	2.26	-	6.53	4.34	2.29	-	6.62
Roseburg	3.89	2.54	0.04	6.47	4.00	2.57	0.04	6.61
OR Sub-Total	**22.55**	**12.71**	**0.20**	**35.46**	**22.95**	**12.85**	**0.21**	**36.00**
Spokane Both	32.24	22.13	1.67	56.04	32.85	22.54	1.68	57.07
Spokane GTN	4.45	3.05	0.23	7.74	4.54	3.11	0.23	7.88
Spokane NWP	18.93	12.98	0.98	32.88	19.28	13.21	0.98	33.48
WA/ID Sub-Total	**55.62**	**38.16**	**2.87**	**96.66**	**56.68**	**38.86**	**2.90**	**98.43**
Expected Case Total	**78.17**	**50.87**	**3.08**	**132.12**	**79.62**	**51.71**	**3.10**	**134.44**
High Case								
Klam Falls	3.74	2.11	0.01	5.85	3.81	2.15	0.01	5.96
La Grande	1.87	1.01	0.42	3.30	1.89	1.02	0.42	3.33
Medford GTN	11.22	5.56	-	16.78	11.44	5.64	-	17.07
Medford NWP	5.04	2.50	-	7.54	5.14	2.53	-	7.67
Roseburg	4.78	2.89	0.04	7.71	4.93	2.94	0.04	7.91
OR Sub-Total	**26.64**	**14.07**	**0.47**	**41.18**	**27.20**	**14.27**	**0.47**	**41.94**
Spokane Both	38.20	25.88	1.99	66.07	39.09	26.45	2.01	67.56
Spokane GTN	5.27	3.57	0.27	9.12	5.40	3.65	0.28	9.32
Spokane NWP	22.42	15.17	1.17	38.76	22.94	15.51	1.18	39.63
WA/ID Sub-Total	**65.89**	**44.63**	**3.43**	**113.95**	**67.43**	**45.61**	**3.47**	**116.51**
High Case Total	**92.53**	**58.70**	**3.90**	**155.14**	**94.63**	**59.88**	**3.94**	**158.45**
Low Case								
Klam Falls	2.57	1.67	0.01	4.25	2.59	1.68	0.01	4.27
La Grande	1.45	0.90	0.21	2.57	1.45	0.91	0.22	2.57
Medford GTN	7.54	4.40	-	11.94	7.59	4.42	-	12.00
Medford NWP	**3.39**	**1.98**	**-**	**5.37**	**3.41**	**1.99**	**-**	**5.40**
Roseburg	**2.93**	**2.21**	**0.04**	**5.18**	**2.97**	**2.23**	**0.04**	**5.24**
OR Sub-Total	**17.88**	**11.17**	**0.26**	**29.31**	**18.01**	**11.22**	**0.26**	**29.49**
Spokane Both	25.82	18.20	1.54	45.56	25.99	18.35	1.54	45.89
Spokane GTN	3.57	2.51	0.21	6.29	3.59	2.53	0.21	6.34
Spokane NWP	15.16	10.67	0.90	26.73	15.26	10.76	0.90	26.93
WA/ID Sub-Total	**44.55**	**31.38**	**2.65**	**78.58**	**44.85**	**31.64**	**2.66**	**79.15**
Low Case Total	**62.43**	**42.55**	**2.91**	**107.89**	**62.85**	**42.86**	**2.92**	**108.64**

Appendix 2.4 - B

Annual Avg. Demand (MDth/d)

By Class (Net of DSM Savings)

	2025/2026				2026/2027			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	3.32	1.97	0.00	5.29	3.38	2.00	0.00	5.38
La Grande	1.72	0.97	0.16	2.85	1.73	0.97	0.16	2.87
Medford GTN	9.84	5.15	-	14.98	10.01	5.21	-	15.22
Medford NWP	4.42	2.32	-	6.73	4.50	2.34	-	6.84
Roseburg	4.11	2.61	0.04	6.77	4.23	2.65	0.04	6.92
OR Sub-Total	**23.40**	**13.01**	**0.21**	**36.62**	**23.85**	**13.18**	**0.21**	**37.23**
Spokane Both	33.52	22.99	1.69	58.20	34.17	23.44	1.71	59.31
Spokane GTN	4.63	3.17	0.23	8.03	4.72	3.23	0.24	8.19
Spokane NWP	19.67	13.48	0.99	34.14	20.05	13.74	1.00	34.80
WA/ID Sub-Total	**57.82**	**39.64**	**2.92**	**100.37**	**58.94**	**40.41**	**2.94**	**102.29**
Expected Case Total	**81.22**	**52.65**	**3.12**	**136.99**	**82.79**	**53.59**	**3.15**	**139.52**
High Case								
Klam Falls	3.90	2.18	0.01	6.09	3.99	2.22	0.01	6.21
La Grande	1.91	1.02	0.42	3.35	1.93	1.03	0.42	3.38
Medford GTN	11.71	5.73	-	17.43	11.96	5.82	-	17.78
Medford NWP	5.26	2.58	-	7.83	5.37	2.62	-	7.99
Roseburg	5.10	3.00	0.04	8.13	5.26	3.05	0.04	8.35
OR Sub-Total	**27.87**	**14.50**	**0.47**	**42.84**	**28.51**	**14.74**	**0.47**	**43.71**
Spokane Both	40.12	27.11	2.03	69.25	41.09	27.75	2.06	70.90
Spokane GTN	5.54	3.74	0.28	9.56	5.67	3.83	0.28	9.78
Spokane NWP	23.54	15.89	1.19	40.62	24.11	16.27	1.20	41.59
WA/ID Sub-Total	**69.20**	**46.74**	**3.50**	**119.43**	**70.88**	**47.85**	**3.54**	**122.27**
High Case Total	**97.07**	**61.24**	**3.97**	**162.28**	**99.39**	**62.58**	**4.01**	**165.98**
Low Case								
Klam Falls	2.61	1.69	0.01	4.31	2.63	1.70	0.01	4.34
La Grande	1.45	0.91	0.22	2.58	1.46	0.91	0.22	2.58
Medford GTN	7.66	4.44	-	12.10	7.73	4.47	-	12.19
Medford NWP	3.44	2.00	-	5.44	3.47	2.01	-	5.48
Roseburg	3.02	2.24	0.04	5.30	3.07	2.26	0.04	5.37
OR Sub-Total	**18.18**	**11.28**	**0.26**	**29.72**	**18.36**	**11.34**	**0.26**	**29.96**
Spokane Both	26.22	18.54	1.55	46.31	26.44	18.74	1.55	46.73
Spokane GTN	3.62	2.56	0.21	6.39	3.65	2.58	0.21	6.45
Spokane NWP	15.39	10.87	0.91	27.17	15.53	10.99	0.91	27.42
WA/ID Sub-Total	**45.23**	**31.97**	**2.67**	**79.87**	**45.62**	**32.31**	**2.68**	**80.61**
Low Case Total	**63.42**	**43.25**	**2.93**	**109.60**	**63.98**	**43.65**	**2.94**	**110.57**

Appendix 2.4 - C
Annual Demand Total (MDth)
By Class (Net of DSM Savings)

	2007/2008				2008/2009			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	819.10	574.41	1.60	1,395.11	833.83	580.85	1.59	1,416.27
La Grande	498.01	332.29	58.14	888.45	503.05	332.31	58.09	893.45
Medford GTN	2,295.64	1,513.18	-	3,808.81	2,342.47	1,528.87	-	3,871.34
Medford NWP	1,031.37	679.86	-	1,711.24	1,052.41	686.95	-	1,739.36
Rosburg	809.71	725.26	15.28	1,550.25	828.25	733.18	15.23	1,576.66
OR Sub-Total	**5,453.83**	**3,825.01**	**75.02**	**9,353.86**	**5,560.02**	**3,862.16**	**74.91**	**9,497.08**
Spokane Both	**8,648.11**	**5,668.88**	**501.97**	**14,818.96**	**8,825.15**	**5,763.99**	**509.20**	**15,098.34**
Spokane GTN	1,193.09	781.91	69.24	2,044.24	1,217.76	795.03	70.23	2,083.02
Spokane NWP	5,070.64	3,323.14	294.26	8,688.03	5,175.46	3,378.89	298.50	8,852.85
WA/ID Sub-Total	**14,911.84**	**9,773.93**	**865.46**	**25,551.24**	**15,218.37**	**9,937.91**	**877.94**	**26,034.21**
Base Case Total	**20,365.67**	**13,598.94**	**940.48**	**34,905.10**	**20,778.38**	**13,800.06**	**952.84**	**35,531.29**
High Case								
Klam Falls	821.92	575.58	2.16	1,399.66	834.43	579.98	2.15	1,416.56
La Grande	498.07	337.83	153.91	989.80	498.95	334.13	153.79	986.87
Medford GTN	2,309.08	1,525.04	-	3,834.13	2,353.66	1,535.94	-	3,889.60
Medford NWP	1,037.41	685.20	-	1,722.61	1,057.44	690.12	-	1,747.57
Rosburg	816.43	740.28	15.28	1,571.99	835.52	746.40	15.16	1,597.08
OR Sub-Total	**5,482.91**	**3,863.93**	**171.34**	**9,518.19**	**5,580.00**	**3,886.57**	**171.10**	**9,637.67**
Spokane Both	**8,793.36**	**5,773.17**	**555.72**	**15,122.25**	**8,966.99**	**5,853.20**	**566.09**	**15,386.28**
Spokane GTN	1,213.13	796.30	76.65	2,086.08	1,237.32	807.34	78.08	2,122.74
Spokane NWP	5,155.78	3,384.27	325.77	8,865.82	5,258.61	3,431.19	331.85	9,021.64
WA/ID Sub-Total	**15,162.27**	**9,953.75**	**958.13**	**26,074.15**	**15,462.92**	**10,091.72**	**976.02**	**26,530.66**
High Case Total	**20,645.18**	**13,817.68**	**1,129.48**	**35,592.34**	**21,042.92**	**13,978.29**	**1,147.12**	**36,168.33**
Low Case								
Klam Falls	807.83	567.51	1.95	1,377.29	788.71	556.05	1.94	1,346.70
La Grande	493.33	332.21	78.66	904.21	479.57	322.53	78.55	880.65
Medford GTN	2,268.04	1,497.93	-	3,765.97	2,222.51	1,466.64	-	3,689.15
Medford NWP	1,018.97	673.02	-	1,691.99	998.52	658.99	-	1,657.51
Rosburg	800.02	729.47	15.28	1,544.76	786.11	715.23	15.09	1,516.42
OR Sub-Total	**5,388.19**	**3,800.14**	**95.89**	**9,284.21**	**5,275.41**	**3,719.44**	**95.58**	**9,090.43**
Spokane Both	**8,552.62**	**5,619.89**	**509.29**	**14,681.80**	**8,368.53**	**5,508.71**	**507.44**	**14,384.68**
Spokane GTN	1,179.92	775.16	70.25	2,025.32	1,154.77	759.82	69.99	1,984.59
Spokane NWP	5,014.66	3,294.42	298.55	8,607.63	4,907.78	3,229.24	297.47	8,434.49
WA/ID Sub-Total	**14,747.19**	**9,689.47**	**878.09**	**25,314.75**	**14,431.09**	**9,497.77**	**874.90**	**24,803.75**
Low Case Total	**20,135.38**	**13,489.61**	**973.98**	**34,598.97**	**19,706.50**	**13,217.21**	**970.48**	**33,894.19**

Appendix 2.4 - C
Annual Demand Total (MDth)
By Class (Net of DSM Savings)

	2009/2010				2010/2011			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	855.13	588.71	1.59	1,445.43	880.99	595.00	1.59	1,477.59
La Grande	509.72	333.23	58.09	901.04	516.40	333.83	58.09	908.31
Medford GTN	2,411.29	1,548.49	-	3,959.78	2,482.40	1,565.43	-	4,047.83
Medford NWP	1,083.33	695.79	-	1,779.13	1,115.28	703.44	-	1,818.72
Rosburg	856.40	745.63	15.23	1,617.26	889.72	756.01	15.23	1,660.96
OR Sub-Total	**5,715.89**	**3,911.85**	**74.91**	**9,702.64**	**5,884.80**	**3,953.71**	**74.91**	**9,913.41**
Spokane Both	**9,051.04**	**5,895.55**	**520.33**	**15,466.92**	**9,279.48**	**6,035.43**	**532.28**	**15,847.20**
Spokane GTN	1,249.16	813.18	71.77	2,134.11	1,280.91	832.47	73.42	2,186.81
Spokane NWP	5,308.93	3,456.01	305.02	9,069.96	5,443.89	3,538.01	312.03	9,293.93
WA/ID Sub-Total	**15,609.13**	**10,164.75**	**897.11**	**26,670.99**	**16,004.28**	**10,405.92**	**917.73**	**27,327.93**
Base Case Total	**21,325.02**	**14,076.60**	**972.02**	**36,373.63**	**21,889.07**	**14,359.63**	**992.64**	**37,241.34**
High Case								
Klam Falls	878.71	598.71	2.15	1,479.57	923.80	611.02	2.15	1,536.97
La Grande	516.50	340.07	153.79	1,010.37	530.02	343.45	153.79	1,027.26
Medford GTN	2,488.80	1,583.63	-	4,072.43	2,611.86	1,618.75	-	4,230.61
Medford NWP	1,118.16	711.58	-	1,829.74	1,173.44	727.39	-	1,900.84
Rosburg	888.46	773.84	15.22	1,677.53	944.20	794.24	15.25	1,753.69
OR Sub-Total	**5,890.63**	**4,007.84**	**171.17**	**10,069.64**	**6,183.31**	**4,094.86**	**171.20**	**10,449.37**
Spokane Both	**9,440.50**	**6,124.69**	**585.60**	**16,150.79**	**9,861.85**	**6,372.11**	**606.17**	**16,840.13**
Spokane GTN	1,302.88	844.78	80.77	2,228.43	1,361.24	878.91	83.61	2,323.76
Spokane NWP	5,537.23	3,590.34	343.28	9,470.85	5,785.28	3,735.38	355.34	9,875.99
WA/ID Sub-Total	**16,280.61**	**10,559.81**	**1,009.65**	**27,850.07**	**17,008.37**	**10,986.40**	**1,045.12**	**29,039.88**
High Case Total	**22,171.24**	**14,567.65**	**1,180.82**	**37,919.71**	**23,191.68**	**15,081.26**	**1,216.31**	**39,489.25**
Low Case								
Klam Falls	800.93	560.91	1.94	1,363.77	816.47	565.46	1.94	1,383.86
La Grande	483.98	323.73	78.55	886.26	489.31	324.93	78.55	892.79
Medford GTN	2,261.65	1,478.58	-	3,740.23	2,305.16	1,490.62	-	3,795.78
Medford NWP	1,016.10	664.39	-	1,680.49	1,035.65	669.82	-	1,705.48
Rosburg	801.58	722.48	15.11	1,539.17	820.83	729.42	15.13	1,565.38
OR Sub-Total	**5,364.24**	**3,750.09**	**95.60**	**9,209.93**	**5,467.41**	**3,780.25**	**95.62**	**9,343.28**
Spokane Both	**8,492.49**	**5,589.13**	**514.02**	**14,595.64**	**8,623.80**	**5,680.51**	**521.81**	**14,826.12**
Spokane GTN	1,172.12	770.91	70.90	2,013.93	1,190.48	783.52	71.97	2,045.97
Spokane NWP	4,981.50	3,276.39	301.32	8,559.21	5,059.52	3,329.95	305.89	8,695.37
WA/ID Sub-Total	**14,646.10**	**9,636.44**	**886.23**	**25,168.78**	**14,873.79**	**9,793.98**	**899.68**	**25,567.45**
Low Case Total	**20,010.35**	**13,386.53**	**981.83**	**34,378.70**	**20,341.21**	**13,574.23**	**995.30**	**34,910.73**

Appendix 2.4 - C
Annual Demand Total (MDth)
By Class (Net of DSM Savings)

	2011/2012				2012/2013			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	909.66	602.39	1.60	1,513.65	928.26	605.75	1.59	1,535.60
La Grande	525.09	335.59	58.14	918.82	531.27	335.13	58.09	924.48
Medford GTN	2,576.91	1,589.31	-	4,166.22	2,641.76	1,597.23	-	4,238.98
Medford NWP	1,157.74	714.20	-	1,871.94	1,186.88	717.78	-	1,904.66
Rosburg	933.86	769.74	15.28	1,718.89	969.57	776.81	15.23	1,761.61
OR Sub-Total	**6,103.26**	**4,011.24**	**75.02**	**10,189.52**	**6,257.73**	**4,032.70**	**74.91**	**10,365.34**
Spokane Both	**9,539.17**	**6,215.68**	**541.39**	**16,296.24**	**9,645.37**	**6,340.65**	**545.48**	**16,531.51**
Spokane GTN	1,316.99	857.33	74.68	2,249.00	1,331.72	874.57	75.24	2,281.54
Spokane NWP	5,597.19	3,643.54	317.37	9,558.10	5,659.84	3,716.94	319.77	9,696.55
WA/ID Sub-Total	**16,453.34**	**10,716.55**	**933.44**	**28,103.33**	**16,636.94**	**10,932.16**	**940.49**	**28,509.59**
Base Case Total	**22,556.60**	**14,727.79**	**1,008.46**	**38,292.85**	**22,894.67**	**14,964.86**	**1,015.39**	**38,874.93**
High Case								
Klam Falls	971.90	625.67	2.16	1,599.73	1,005.25	633.85	2.15	1,641.25
La Grande	546.03	347.88	153.91	1,047.82	557.88	348.88	153.79	1,060.56
Medford GTN	2,762.34	1,659.76	-	4,422.10	2,875.47	1,678.47	-	4,553.95
Medford NWP	1,241.05	745.25	-	1,986.30	1,291.88	754.39	-	2,046.27
Rosburg	1,013.76	817.49	15.33	1,846.58	1,072.62	832.21	15.29	1,920.13
OR Sub-Total	**6,535.08**	**4,196.06**	**171.40**	**10,902.53**	**6,803.10**	**4,247.81**	**171.24**	**11,222.15**
Spokane Both	**10,171.28**	**6,665.50**	**620.56**	**17,457.34**	**10,452.28**	**6,886.45**	**628.26**	**17,966.99**
Spokane GTN	1,423.27	919.57	85.59	2,428.43	1,458.28	950.04	86.66	2,494.97
Spokane NWP	5,967.21	3,907.47	363.77	10,238.46	6,132.86	4,037.02	368.29	10,538.17
WA/ID Sub-Total	**17,561.76**	**11,492.54**	**1,069.93**	**30,124.22**	**18,043.41**	**11,873.50**	**1,083.21**	**31,000.13**
High Case Total	**24,096.83**	**15,688.60**	**1,241.32**	**41,026.75**	**24,846.52**	**16,121.31**	**1,254.45**	**42,222.28**
Low Case								
Klam Falls	830.90	569.76	1.95	1,402.61	837.12	569.86	1.94	1,408.91
La Grande	493.81	325.88	78.66	898.36	495.56	324.76	78.55	898.87
Medford GTN	2,355.42	1,503.86	-	3,859.28	2,377.45	1,502.20	-	3,879.66
Medford NWP	1,058.23	675.81	-	1,734.04	1,068.91	675.15	-	1,744.06
Rosburg	843.67	736.89	15.18	1,595.75	858.64	738.02	15.13	1,611.80
OR Sub-Total	**5,582.04**	**3,812.20**	**95.79**	**9,490.03**	**5,637.69**	**3,810.00**	**95.62**	**9,543.30**
Spokane Both	**8,705.29**	**5,779.86**	**526.84**	**15,011.99**	**8,679.87**	**5,826.71**	**528.17**	**15,034.75**
Spokane GTN	1,201.84	797.22	72.67	2,071.73	1,198.55	803.65	72.85	2,075.06
Spokane NWP	5,107.83	3,388.20	308.84	8,804.87	5,093.85	3,415.66	309.62	8,819.13
WA/ID Sub-Total	**15,014.96**	**9,965.29**	**908.35**	**25,888.59**	**14,972.27**	**10,046.02**	**910.64**	**25,928.93**
Low Case Total	**20,597.00**	**13,777.49**	**1,004.14**	**35,378.62**	**20,609.96**	**13,856.02**	**1,006.26**	**35,472.23**

Appendix 2.4 - C
Annual Demand Total (MDth)
By Class (Net of DSM Savings)

	2013/2014				2014/2015			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	950.09	611.88	1.59	1,563.56	971.92	619.30	1.59	1,592.81
La Grande	538.24	335.83	58.09	932.15	546.86	336.72	58.09	941.66
Medford GTN	2,715.47	1,610.56	-	4,326.03	2,791.34	1,628.74	-	4,420.07
Medford NWP	1,219.99	723.93	-	1,943.92	1,254.08	732.14	-	1,986.22
Rosburg	1,007.64	786.98	15.23	1,809.85	1,047.29	799.94	15.23	1,862.46
OR Sub-Total	**6,431.43**	**4,069.17**	**74.91**	**10,575.51**	**6,611.48**	**4,116.84**	**74.91**	**10,803.23**
Spokane Both	**9,825.79**	**6,495.56**	**553.03**	**16,874.38**	**9,862.20**	**6,648.76**	**561.00**	**17,071.96**
Spokane GTN	1,348.59	895.94	76.28	2,320.80	1,363.70	917.25	77.38	2,358.33
Spokane NWP	5,728.47	3,807.75	324.19	9,860.41	5,788.83	3,897.73	328.86	10,015.42
WA/ID Sub-Total	**16,902.84**	**11,199.25**	**953.50**	**29,055.59**	**17,014.74**	**11,463.74**	**967.24**	**29,445.71**
Base Case Total	**23,334.27**	**15,268.42**	**1,028.40**	**39,631.10**	**23,626.22**	**15,580.58**	**1,042.15**	**40,248.94**
High Case								
Klam Falls	1,042.14	645.18	2.15	1,689.46	1,076.09	656.93	2.15	1,735.17
La Grande	571.36	351.13	153.79	1,076.29	584.85	352.88	153.79	1,091.53
Medford GTN	2,997.84	1,708.19	-	4,706.03	3,115.03	1,737.33	-	4,852.36
Medford NWP	1,346.86	767.79	-	2,114.64	1,399.51	780.93	-	2,180.44
Rosburg	1,134.62	851.58	15.30	2,001.51	1,194.72	872.24	15.30	2,082.26
OR Sub-Total	**7,092.81**	**4,323.88**	**171.25**	**11,587.94**	**7,370.20**	**4,400.31**	**171.25**	**11,941.75**
Spokane Both	**10,762.81**	**7,140.88**	**641.34**	**18,545.03**	**11,037.78**	**7,376.36**	**653.74**	**19,067.88**
Spokane GTN	1,503.76	985.16	88.46	2,577.37	1,533.58	1,017.65	90.17	2,641.40
Spokane NWP	6,315.84	4,186.19	375.96	10,877.98	6,477.97	4,324.25	383.23	11,185.45
WA/ID Sub-Total	**18,582.41**	**12,312.22**	**1,105.76**	**32,000.39**	**19,049.33**	**12,718.26**	**1,127.14**	**32,894.73**
High Case Total	**25,675.22**	**16,636.10**	**1,277.00**	**43,588.33**	**26,419.53**	**17,118.57**	**1,298.39**	**44,836.48**
Low Case								
Klam Falls	846.56	572.14	1.94	1,420.63	856.00	575.10	1.94	1,433.04
La Grande	498.20	324.73	78.55	901.48	501.86	324.67	78.55	905.08
Medford GTN	2,412.25	1,507.82	-	3,920.07	2,447.26	1,514.81	-	3,962.06
Medford NWP	1,083.76	677.64	-	1,761.41	1,099.49	680.86	-	1,780.35
Rosburg	876.28	742.50	15.13	1,633.92	895.00	748.03	15.13	1,658.16
OR Sub-Total	**5,717.05**	**3,824.84**	**95.62**	**9,637.50**	**5,799.60**	**3,843.47**	**95.62**	**9,738.69**
Spokane Both	**8,689.03**	**5,900.46**	**532.52**	**15,122.00**	**8,725.53**	**5,973.80**	**536.48**	**15,235.81**
Spokane GTN	1,200.04	813.75	73.45	2,087.23	1,205.29	823.98	74.00	2,103.27
Spokane NWP	5,118.17	3,458.56	312.17	8,888.90	5,122.51	3,502.06	314.49	8,939.06
WA/ID Sub-Total	**15,007.23**	**10,172.76**	**918.14**	**26,098.13**	**15,053.33**	**10,299.83**	**924.97**	**26,278.14**
Low Case Total	**20,724.28**	**13,997.60**	**1,013.76**	**35,735.63**	**20,852.93**	**14,143.31**	**1,020.59**	**36,016.83**

Appendix 2.4 - C
Annual Demand Total (MDth)
By Class (Net of DSM Savings)

	2015/2016				2016/2017			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	998.05	631.98	1.60	1,631.63	1,016.07	639.74	1.59	1,657.41
La Grande	558.05	339.64	58.14	955.83	564.79	340.41	58.09	963.29
Medford GTN	2,885.20	1,657.50	-	4,542.70	2,947.56	1,674.17	-	4,621.74
Medford NWP	1,296.25	745.11	-	2,041.36	1,324.27	752.65	-	2,076.92
Rosburg	1,093.85	819.85	15.28	1,928.98	1,130.56	832.25	15.23	1,978.04
OR Sub-Total	**6,831.40**	**4,194.08**	**75.02**	**11,100.50**	**6,983.25**	**4,239.23**	**74.91**	**11,297.39**
Spokane Both	**10,070.40**	**6,836.08**	**570.96**	**17,477.44**	**10,191.07**	**6,957.97**	**573.80**	**17,722.83**
Spokane GTN	1,391.02	942.91	78.75	2,412.69	1,407.88	959.72	79.14	2,446.75
Spokane NWP	5,911.87	4,007.56	334.70	10,254.12	5,983.51	4,079.03	336.36	10,398.90
WA/ID Sub-Total	**17,373.29**	**11,786.54**	**984.42**	**30,144.25**	**17,582.45**	**11,996.72**	**989.31**	**30,568.48**
Base Case Total	**24,204.69**	**15,980.62**	**1,059.44**	**41,244.75**	**24,565.71**	**16,235.95**	**1,064.21**	**41,865.87**
High Case								
Klam Falls	1,115.50	675.32	2.16	1,792.98	1,143.38	686.93	2.15	1,832.46
La Grande	601.56	357.03	153.91	1,112.50	611.79	357.96	153.79	1,123.55
Medford GTN	3,253.38	1,779.93	-	5,033.31	3,349.46	1,805.91	-	5,155.37
Medford NWP	1,461.66	800.12	-	2,261.78	1,504.83	811.84	-	2,316.67
Rosburg	1,265.05	901.54	15.35	2,181.94	1,320.18	920.76	15.29	2,256.23
OR Sub-Total	**7,697.15**	**4,513.94**	**171.42**	**12,382.51**	**7,929.65**	**4,583.39**	**171.24**	**12,684.27**
Spokane Both	**11,374.24**	**7,653.64**	**668.83**	**19,696.71**	**11,588.07**	**7,839.88**	**673.69**	**20,101.64**
Spokane GTN	1,572.70	1,055.82	92.25	2,720.78	1,600.57	1,081.37	92.92	2,774.86
Spokane NWP	6,676.19	4,486.82	392.07	11,555.07	6,802.44	4,596.02	394.92	11,793.38
WA/ID Sub-Total	**19,623.13**	**13,196.28**	**1,153.15**	**33,972.56**	**19,991.08**	**13,517.26**	**1,161.53**	**34,669.88**
High Case Total	**27,320.28**	**17,710.22**	**1,324.57**	**46,355.07**	**27,920.73**	**18,100.65**	**1,332.77**	**47,354.15**
Low Case								
Klam Falls	869.17	582.29	1.95	1,453.40	875.13	585.10	1.94	1,462.17
La Grande	507.55	326.69	78.66	912.91	509.53	326.48	78.55	914.56
Medford GTN	2,497.00	1,530.23	-	4,027.23	2,519.46	1,534.79	-	4,054.25
Medford NWP	1,121.84	687.88	-	1,809.73	1,131.93	690.03	-	1,821.96
Rosburg	918.96	759.46	15.18	1,693.60	934.39	764.14	15.13	1,713.66
OR Sub-Total	**5,914.53**	**3,886.55**	**95.79**	**9,896.87**	**5,970.43**	**3,900.55**	**95.62**	**9,966.60**
Spokane Both	**8,813.28**	**6,076.77**	**542.33**	**15,432.38**	**8,822.85**	**6,121.93**	**542.97**	**15,487.75**
Spokane GTN	1,217.63	838.18	74.80	2,130.61	1,219.16	844.41	74.89	2,138.46
Spokane NWP	5,174.93	3,562.45	317.92	9,055.30	5,181.44	3,588.94	318.29	9,088.68
WA/ID Sub-Total	**15,205.84**	**10,477.40**	**935.05**	**26,618.29**	**15,223.45**	**10,555.28**	**936.15**	**26,714.88**
Low Case Total	**21,120.37**	**14,363.95**	**1,030.84**	**36,515.15**	**21,193.88**	**14,455.83**	**1,031.77**	**36,681.48**

Appendix 2.4 - C
Annual Demand Total (MDth)
By Class (Net of DSM Savings)

	2017/2018				2018/2019			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	1,038.13	648.88	1.59	1,688.60	1,059.46	657.70	1.59	1,718.75
La Grande	572.99	342.03	58.09	973.11	580.41	343.56	58.09	982.06
Medford GTN	3,023.38	1,697.47	-	4,720.85	3,098.48	1,720.03	-	4,818.51
Medford NWP	1,358.33	763.17	-	2,121.50	1,392.07	773.35	-	2,165.42
Rosburg	1,171.89	846.62	15.23	2,033.74	1,212.82	860.26	15.23	2,088.31
OR Sub-Total	**7,164.73**	**4,298.17**	**74.91**	**11,537.80**	**7,343.25**	**4,354.89**	**74.91**	**11,773.05**
Spokane Both	**10,387.89**	**7,111.67**	**579.35**	**18,078.91**	**10,590.60**	**7,265.06**	**586.90**	**18,442.56**
Spokane GTN	1,435.03	980.92	79.91	2,495.86	1,462.99	1,002.08	80.95	2,546.02
Spokane NWP	6,098.88	4,169.15	339.62	10,607.66	6,217.71	4,259.10	344.04	10,820.85
WA/ID Sub-Total	**17,921.80**	**12,261.75**	**998.88**	**31,182.43**	**18,271.30**	**12,526.24**	**1,011.90**	**31,809.43**
Base Case Total	**25,086.53**	**16,559.91**	**1,073.79**	**42,720.23**	**25,614.55**	**16,881.13**	**1,086.80**	**43,582.48**
High Case								
Klam Falls	1,173.43	699.01	2.15	1,874.59	1,205.30	711.81	2.15	1,919.25
La Grande	622.49	359.36	153.79	1,135.65	633.39	361.39	153.79	1,148.57
Medford GTN	3,430.20	1,830.06	-	5,260.26	3,568.26	1,869.38	-	5,437.64
Medford NWP	1,541.10	822.74	-	2,363.84	1,603.13	840.45	-	2,443.58
Rosburg	1,379.41	940.50	15.28	2,335.19	1,440.92	960.70	15.27	2,416.89
OR Sub-Total	**8,146.64**	**4,651.66**	**171.22**	**12,969.52**	**8,451.00**	**4,743.73**	**171.21**	**13,365.94**
Spokane Both	**11,867.77**	**8,052.40**	**682.13**	**20,602.30**	**12,180.76**	**8,280.14**	**693.74**	**21,154.64**
Spokane GTN	1,639.15	1,110.68	94.09	2,843.91	1,682.32	1,142.09	95.69	2,920.10
Spokane NWP	6,966.40	4,720.62	399.87	12,086.89	7,149.88	4,854.14	406.68	12,410.69
WA/ID Sub-Total	**20,473.32**	**13,883.69**	**1,176.09**	**35,533.10**	**21,012.95**	**14,276.37**	**1,196.11**	**36,485.43**
High Case Total	**28,619.96**	**18,535.36**	**1,347.30**	**48,502.62**	**29,463.95**	**19,020.10**	**1,367.32**	**49,851.37**
Low Case								
Klam Falls	884.69	589.65	1.94	1,476.28	893.88	594.04	1.94	1,489.85
La Grande	512.98	327.25	78.55	918.79	516.07	327.96	78.55	922.58
Medford GTN	2,554.43	1,546.24	-	4,100.67	2,589.07	1,557.32	-	4,146.39
Medford NWP	1,147.64	693.87	-	1,841.51	1,163.20	698.77	-	1,861.97
Rosburg	953.92	771.36	15.13	1,740.40	973.26	778.14	15.13	1,766.53
OR Sub-Total	**6,053.65**	**3,928.37**	**95.62**	**10,077.64**	**6,135.47**	**3,956.23**	**95.62**	**10,187.32**
Spokane Both	**8,899.07**	**6,195.58**	**546.36**	**15,641.01**	**8,978.17**	**6,269.02**	**550.35**	**15,797.54**
Spokane GTN	1,229.67	854.57	75.36	2,159.60	1,240.58	864.70	75.91	2,181.19
Spokane NWP	5,226.13	3,632.14	320.28	9,178.55	5,272.49	3,675.21	322.62	9,270.32
WA/ID Sub-Total	**15,354.87**	**10,682.29**	**942.01**	**26,979.16**	**15,491.25**	**10,808.93**	**948.88**	**27,249.05**
Low Case Total	**21,408.52**	**14,610.66**	**1,037.63**	**37,056.80**	**21,626.72**	**14,765.16**	**1,044.50**	**37,436.37**

Appendix 2.4 - C
Annual Demand Total (MDth)
By Class (Net of DSM Savings)

	2019/2020				2020/2021			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	1,085.74	669.33	1.60	1,756.66	1,103.02	674.36	1.59	1,778.96
La Grande	590.19	346.17	58.14	994.51	595.73	346.53	58.09	1,000.35
Medford GTN	3,190.98	1,751.80	-	4,942.78	3,246.93	1,764.82	-	5,011.75
Medford NWP	1,433.63	787.68	-	2,221.30	1,458.76	793.57	-	2,252.33
Rosburg	1,260.39	878.10	15.28	2,153.77	1,295.48	886.18	15.23	2,196.89
OR Sub-Total	**7,560.93**	**4,433.08**	**75.02**	**12,069.03**	**7,699.92**	**4,465.45**	**74.91**	**12,240.28**
Spokane Both	**10,853.28**	**7,458.48**	**592.22**	**18,903.99**	**11,027.27**	**7,582.90**	**595.29**	**19,205.46**
Spokane GTN	1,499.23	1,028.76	81.69	2,609.67	1,523.21	1,045.92	82.11	2,651.25
Spokane NWP	6,371.74	4,372.50	347.17	11,091.41	6,473.69	4,445.46	348.96	11,268.11
WA/ID Sub-Total	**18,724.25**	**12,859.75**	**1,021.08**	**32,605.07**	**19,024.17**	**13,074.29**	**1,026.36**	**33,124.82**
Base Case Total	**26,285.18**	**17,292.83**	**1,096.10**	**44,674.10**	**26,724.09**	**17,539.74**	**1,101.27**	**45,365.11**
High Case								
Klam Falls	1,243.29	727.58	2.16	1,973.02	1,269.43	735.04	2.15	2,006.62
La Grande	646.87	364.49	153.91	1,165.27	655.23	364.79	153.79	1,173.82
Medford GTN	3,698.92	1,912.29	-	5,611.21	3,784.12	1,932.34	-	5,716.47
Medford NWP	1,661.83	859.78	-	2,521.61	1,700.11	868.83	-	2,568.95
Rosburg	1,509.68	985.53	15.31	2,510.52	1,562.36	997.87	15.25	2,575.48
OR Sub-Total	**8,760.58**	**4,849.67**	**171.38**	**13,781.64**	**8,971.25**	**4,898.88**	**171.20**	**14,041.33**
Spokane Both	**12,566.73**	**8,553.70**	**701.34**	**21,821.77**	**12,844.25**	**8,741.75**	**706.45**	**22,292.45**
Spokane GTN	1,735.57	1,179.83	96.74	3,012.13	1,773.83	1,205.76	97.44	3,077.04
Spokane NWP	7,376.18	5,014.53	411.13	12,801.84	7,538.82	5,124.79	414.13	13,077.73
WA/ID Sub-Total	**21,678.48**	**14,748.05**	**1,209.21**	**37,635.74**	**22,156.90**	**15,072.30**	**1,218.02**	**38,447.22**
High Case Total	**30,439.06**	**19,597.73**	**1,380.59**	**51,417.38**	**31,128.15**	**19,971.18**	**1,389.22**	**52,488.55**
Low Case								
Klam Falls	907.11	598.71	1.95	1,507.77	912.79	599.99	1.94	1,514.72
La Grande	521.06	329.68	78.66	929.41	522.50	329.31	78.55	930.36
Medford GTN	2,638.10	1,576.40	-	4,214.50	2,657.63	1,579.31	-	4,236.95
Medford NWP	1,185.23	707.26	-	1,892.49	1,194.01	708.50	-	1,902.51
Rosburg	997.71	787.37	15.18	1,800.26	1,012.41	789.84	15.13	1,817.38
OR Sub-Total	**6,249.21**	**3,999.42**	**95.79**	**10,344.42**	**6,299.34**	**4,006.96**	**95.62**	**10,401.92**
Spokane Both	**9,103.92**	**6,375.04**	**553.59**	**16,032.55**	**9,151.75**	**6,421.46**	**554.72**	**16,127.94**
Spokane GTN	1,257.94	879.32	76.36	2,213.61	1,264.52	885.72	76.51	2,226.76
Spokane NWP	5,346.26	3,737.38	324.52	9,408.16	5,374.25	3,764.62	325.18	9,464.05
WA/ID Sub-Total	**15,708.12**	**10,991.74**	**954.46**	**27,654.32**	**15,790.53**	**11,071.80**	**956.42**	**27,818.75**
Low Case Total	**21,957.33**	**14,991.16**	**1,050.25**	**37,998.74**	**22,089.86**	**15,078.76**	**1,052.04**	**38,220.67**

Appendix 2.4 - C
Annual Demand Total (MDth)
By Class (Net of DSM Savings)

	2021/2022				2022/2023			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	1,124.98	682.38	1.59	1,808.95	1,146.57	690.83	1.59	1,838.99
La Grande	602.84	347.93	58.09	1,008.86	609.25	349.42	58.09	1,016.75
Medford GTN	3,318.22	1,786.37	-	5,104.58	3,388.30	1,808.71	-	5,197.01
Medford NWP	1,490.79	803.30	-	2,294.09	1,522.28	813.38	-	2,335.65
Rosburg	1,336.54	898.59	15.23	2,250.36	1,377.23	911.53	15.23	2,303.98
OR Sub-Total	**7,873.37**	**4,518.56**	**74.91**	**12,466.84**	**8,043.62**	**4,573.86**	**74.91**	**12,692.39**
Spokane Both	**11,259.63**	**7,742.90**	**599.70**	**19,602.23**	**11,501.64**	**7,902.69**	**605.25**	**20,009.58**
Spokane GTN	1,555.27	1,067.99	82.72	2,705.97	1,588.65	1,090.03	83.48	2,762.16
Spokane NWP	6,609.90	4,539.27	351.55	11,500.72	6,751.77	4,632.97	354.80	11,739.54
WA/ID Sub-Total	**19,424.80**	**13,350.16**	**1,033.96**	**33,808.93**	**19,842.06**	**13,625.68**	**1,043.54**	**34,511.28**
Base Case Total	**27,298.17**	**17,868.73**	**1,108.87**	**46,275.77**	**27,885.68**	**18,199.54**	**1,118.45**	**47,203.67**
High Case								
Klam Falls	1,301.15	746.43	2.15	2,049.73	1,332.13	757.92	2.15	2,092.20
La Grande	665.39	366.58	153.79	1,185.76	673.79	368.16	153.79	1,195.74
Medford GTN	3,888.08	1,963.14	-	5,851.22	3,986.87	1,993.50	-	5,980.36
Medford NWP	1,746.82	882.72	-	2,629.53	1,791.20	896.40	-	2,687.60
Rosburg	1,622.79	1,015.93	15.25	2,653.96	1,681.26	1,034.09	15.24	2,730.58
OR Sub-Total	**9,224.22**	**4,974.79**	**171.19**	**14,370.21**	**9,465.24**	**5,050.06**	**171.18**	**14,686.48**
Spokane Both	**13,199.09**	**8,975.75**	**713.26**	**22,888.09**	**13,550.13**	**9,202.34**	**721.83**	**23,474.30**
Spokane GTN	1,822.78	1,238.04	98.38	3,159.20	1,871.19	1,269.29	99.56	3,240.05
Spokane NWP	7,746.82	5,261.98	418.12	13,426.92	7,952.61	5,394.83	423.12	13,770.56
WA/ID Sub-Total	**22,768.69**	**15,475.77**	**1,229.76**	**39,474.21**	**23,373.93**	**15,866.47**	**1,244.51**	**40,484.91**
High Case Total	**31,992.91**	**20,450.56**	**1,400.95**	**53,844.42**	**32,839.17**	**20,916.52**	**1,415.70**	**55,171.39**
Low Case								
Klam Falls	922.23	603.66	1.94	1,527.83	929.81	606.91	1.94	1,538.65
La Grande	525.34	329.90	78.55	933.79	527.04	330.01	78.55	935.59
Medford GTN	2,689.76	1,585.48	-	4,275.24	2,717.01	1,593.97	-	4,310.98
Medford NWP	1,208.44	713.04	-	1,921.48	1,220.68	716.90	-	1,937.58
Rosburg	1,031.70	795.84	15.13	1,842.67	1,049.53	801.17	15.12	1,865.82
OR Sub-Total	**6,377.47**	**4,027.92**	**95.62**	**10,501.01**	**6,444.06**	**4,048.96**	**95.61**	**10,588.63**
Spokane Both	**9,243.05**	**6,496.94**	**556.80**	**16,296.78**	**9,326.24**	**6,562.78**	**559.67**	**16,448.69**
Spokane GTN	1,277.12	896.13	76.80	2,250.05	1,288.59	905.22	77.20	2,271.00
Spokane NWP	5,427.77	3,808.88	326.40	9,563.05	5,476.54	3,847.50	328.08	9,652.12
WA/ID Sub-Total	**15,947.93**	**11,201.96**	**959.99**	**28,109.89**	**16,091.37**	**11,315.49**	**964.95**	**28,371.81**
Low Case Total	**22,325.41**	**15,229.88**	**1,055.61**	**38,610.90**	**22,535.43**	**15,364.45**	**1,060.55**	**38,960.44**

Appendix 2.4 - C
Annual Demand Total (MDth)
By Class (Net of DSM Savings)

	2023/2024				2024/2025			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	1,172.48	702.48	1.60	1,876.56	1,188.55	709.56	1.59	1,899.71
La Grande	617.31	352.05	58.14	1,027.51	621.31	352.49	58.09	1,031.88
Medford GTN	3,475.63	1,840.58	-	5,316.21	3,523.21	1,855.34	-	5,378.54
Medford NWP	1,561.51	827.74	-	2,389.25	1,582.89	834.40	-	2,417.29
Rosburg	1,425.15	928.97	15.28	2,369.39	1,459.33	939.15	15.23	2,413.71
OR Sub-Total	**8,252.08**	**4,651.82**	**75.02**	**12,978.92**	**8,375.29**	**4,690.94**	**74.91**	**13,141.13**
Spokane Both	**11,800.31**	**8,101.26**	**610.22**	**20,511.79**	**11,991.38**	**8,226.55**	**613.22**	**20,831.16**
Spokane GTN	1,629.85	1,117.42	84.17	2,831.44	1,656.20	1,134.70	84.58	2,875.48
Spokane NWP	6,926.90	4,749.39	357.71	12,034.00	7,038.86	4,822.86	359.48	12,221.19
WA/ID Sub-Total	**20,357.06**	**13,968.07**	**1,052.10**	**35,377.23**	**20,686.44**	**14,184.11**	**1,057.28**	**35,927.83**
Base Case Total	**28,609.14**	**18,619.89**	**1,127.12**	**48,356.16**	**29,061.73**	**18,875.05**	**1,132.19**	**49,068.96**
High Case								
Klam Falls	1,367.41	773.11	2.16	2,142.68	1,390.34	783.39	2.15	2,175.88
La Grande	684.18	370.88	153.91	1,208.97	689.41	371.37	153.79	1,214.57
Medford GTN	4,105.71	2,034.75	-	6,140.46	4,174.37	2,056.89	-	6,231.26
Medford NWP	1,844.59	914.97	-	2,759.56	1,875.44	924.96	-	2,800.40
Rosburg	1,748.75	1,057.46	15.28	2,821.49	1,798.24	1,072.65	15.22	2,886.11
OR Sub-Total	**9,750.64**	**5,151.18**	**171.34**	**15,073.16**	**9,927.80**	**5,209.26**	**171.16**	**15,308.21**
Spokane Both	**13,980.67**	**9,473.34**	**728.89**	**24,182.91**	**14,268.64**	**9,656.03**	**734.35**	**24,659.02**
Spokane GTN	1,930.59	1,306.67	100.47	3,337.73	1,970.30	1,331.87	101.15	3,403.32
Spokane NWP	8,205.04	5,553.72	426.99	14,185.75	8,373.80	5,660.83	429.89	14,464.53
WA/ID Sub-Total	**24,116.30**	**16,333.74**	**1,256.35**	**41,706.39**	**24,612.75**	**16,648.74**	**1,265.38**	**42,526.87**
High Case Total	**33,866.95**	**21,484.91**	**1,427.69**	**56,779.55**	**34,540.54**	**21,858.00**	**1,436.54**	**57,835.08**
Low Case								
Klam Falls	941.07	612.55	1.95	1,555.57	944.28	614.03	1.94	1,560.25
La Grande	530.19	331.16	78.66	940.02	529.82	330.46	78.55	938.83
Medford GTN	2,759.69	1,610.47	-	4,370.16	2,769.89	1,611.64	-	4,381.53
Medford NWP	1,239.86	724.36	-	1,964.21	1,244.44	724.92	-	1,969.36
Rosburg	1,072.23	810.12	15.16	1,897.51	1,084.72	812.49	15.10	1,912.31
OR Sub-Total	**6,543.04**	**4,088.67**	**95.77**	**10,727.48**	**6,573.14**	**4,093.54**	**95.59**	**10,762.28**
Spokane Both	**9,450.13**	**6,660.95**	**562.52**	**16,673.59**	**9,487.16**	**6,698.63**	**563.19**	**16,748.98**
Spokane GTN	1,305.69	918.76	77.59	2,302.03	1,310.79	923.95	77.68	2,312.42
Spokane NWP	5,549.20	3,905.07	329.75	9,784.03	5,570.87	3,927.18	330.15	9,828.20
WA/ID Sub-Total	**16,305.01**	**11,484.78**	**969.85**	**28,759.65**	**16,368.82**	**11,549.76**	**971.02**	**28,889.60**
Low Case Total	**22,848.05**	**15,573.45**	**1,065.62**	**39,487.13**	**22,941.96**	**15,643.30**	**1,066.61**	**39,651.88**

Appendix 2.4 - C
Annual Demand Total (MDth)
By Class (Net of DSM Savings)

	2025/2026				2026/2027			
Area	**Residential**	**Commercial**	**Firm Industrial**	**Total**	**Residential**	**Commercial**	**Firm Industrial**	**Total**
Expected Case								
Klam Falls	1,210.41	718.98	1.59	1,930.98	1,232.50	728.20	1.59	1,962.29
La Grande	626.56	354.02	58.09	1,038.67	632.22	355.56	58.09	1,045.87
Medford GTN	3,589.93	1,878.83	-	5,468.76	3,654.17	1,902.78	-	5,556.95
Medford NWP	1,612.87	845.00	-	2,457.86	1,641.73	855.77	-	2,497.49
Rosburg	1,501.43	953.19	15.23	2,469.84	1,543.45	966.85	15.23	2,525.53
OR Sub-Total	**8,541.19**	**4,750.01**	**74.91**	**13,366.11**	**8,704.06**	**4,809.16**	**74.91**	**13,588.13**
Spokane Both	**12,233.24**	**8,390.51**	**617.63**	**21,241.38**	**12,470.65**	**8,554.48**	**623.19**	**21,648.31**
Spokane GTN	1,689.55	1,157.32	85.19	2,932.06	1,722.30	1,179.93	85.96	2,988.19
Spokane NWP	7,180.64	4,919.00	362.06	12,461.69	7,319.81	5,015.14	365.32	12,700.26
WA/ID Sub-Total	**21,103.43**	**14,466.83**	**1,064.88**	**36,635.14**	**21,512.75**	**14,749.55**	**1,074.46**	**37,336.76**
Base Case Total	**29,644.61**	**19,216.84**	**1,139.79**	**50,001.24**	**30,216.81**	**19,558.71**	**1,149.36**	**50,924.89**
High Case								
Klam Falls	1,422.14	796.85	2.15	2,221.15	1,454.71	809.94	2.15	2,266.79
La Grande	697.21	373.29	153.79	1,224.30	705.00	375.34	153.79	1,234.13
Medford GTN	4,272.44	2,090.73	-	6,363.17	4,364.14	2,124.66	-	6,488.81
Medford NWP	1,919.50	940.20	-	2,859.70	1,960.70	955.45	-	2,916.15
Rosburg	1,860.40	1,093.22	15.21	2,968.84	1,921.32	1,113.01	15.21	3,049.54
OR Sub-Total	**10,171.69**	**5,294.29**	**171.16**	**15,637.14**	**10,405.88**	**5,378.40**	**171.15**	**15,955.42**
Spokane Both	**14,642.42**	**9,894.13**	**741.24**	**25,277.79**	**14,998.50**	**10,129.47**	**750.30**	**25,878.27**
Spokane GTN	2,021.85	1,364.71	102.07	3,488.64	2,070.97	1,397.18	103.28	3,571.42
Spokane NWP	8,592.91	5,800.43	433.80	14,827.14	8,801.65	5,938.41	438.94	15,179.00
WA/ID Sub-Total	**25,257.19**	**17,059.28**	**1,277.11**	**43,593.58**	**25,871.12**	**17,465.06**	**1,292.52**	**44,628.70**
High Case Total	**35,428.88**	**22,353.57**	**1,448.26**	**59,230.72**	**36,277.00**	**22,843.46**	**1,463.67**	**60,584.12**
Low Case								
Klam Falls	952.45	617.53	1.94	1,571.92	960.26	621.25	1.93	1,583.44
La Grande	531.01	330.53	78.55	940.09	532.49	330.78	78.55	941.81
Medford GTN	2,795.13	1,620.53	-	4,415.66	2,820.67	1,630.05	-	4,450.72
Medford NWP	1,255.78	728.95	-	1,984.73	1,267.25	733.24	-	2,000.49
Rosburg	1,102.95	818.25	15.10	1,936.30	1,121.46	824.21	15.09	1,960.77
OR Sub-Total	**6,637.32**	**4,115.80**	**95.58**	**10,848.70**	**6,702.13**	**4,139.52**	**95.57**	**10,937.22**
Spokane Both	**9,568.92**	**6,768.00**	**565.12**	**16,902.03**	**9,650.95**	**6,839.12**	**567.56**	**17,057.63**
Spokane GTN	1,322.06	933.52	77.95	2,333.53	1,333.38	943.33	78.28	2,354.99
Spokane NWP	5,618.79	3,967.87	331.27	9,917.94	5,666.88	4,009.58	332.71	10,009.17
WA/ID Sub-Total	**16,509.77**	**11,669.39**	**974.34**	**29,153.50**	**16,651.21**	**11,792.04**	**978.55**	**29,421.79**
Low Case Total	**23,147.10**	**15,785.19**	**1,069.92**	**40,002.21**	**23,353.34**	**15,931.56**	**1,074.12**	**40,359.01**

Appendix 2.4 D
Peak Day Demand - 11/2007 - 10/2027 (Net of DSM Savings)
Peak Day = February 15

Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Rosburg	Oregon	Spokane Both	Spokane GTN	Spokane NWP	WA/ID	Total
Base											
2007-2008	10.76	9.72	26.84	12.06	12.87	72.25	152.66	21.06	89.50	263.22	335.46
2008-2009	10.97	9.82	27.42	12.32	13.19	73.71	156.11	21.54	91.53	269.18	342.89
2009-2010	11.21	9.91	28.07	12.61	13.55	75.35	159.79	22.05	93.70	275.54	350.89
2010-2011	11.48	10.01	28.71	12.90	13.94	77.04	163.58	22.57	95.94	282.09	359.14
2011-2012	11.72	10.11	29.44	13.23	14.41	78.92	167.30	23.09	98.13	288.51	367.43
2012-2013	11.95	10.23	30.13	13.54	14.85	80.69	170.87	23.58	100.23	294.69	375.38
2013-2014	12.18	10.33	30.80	13.84	15.28	82.44	174.37	24.07	102.29	300.72	383.16
2014-2015	12.43	10.46	31.51	14.16	15.76	84.31	177.81	24.55	104.32	306.68	390.99
2015-2016	12.68	10.60	32.24	14.49	16.26	86.27	181.31	25.03	106.38	312.72	398.99
2016-2017	12.94	10.72	32.98	14.82	16.76	88.22	184.82	25.52	108.45	318.79	407.01
2017-2018	13.19	10.84	33.69	15.14	17.23	90.08	188.54	26.03	110.63	325.20	415.28
2018-2019	13.42	10.95	34.39	15.45	17.70	91.91	192.32	26.55	112.85	331.72	423.63
2019-2020	13.67	11.07	35.10	15.77	18.18	93.79	196.27	27.10	115.16	338.52	432.31
2020-2021	13.90	11.17	35.77	16.08	18.63	95.55	200.33	27.66	117.55	345.54	441.09
2021-2022	14.14	11.27	36.44	16.37	19.10	97.33	204.48	28.23	119.98	352.69	450.01
2022-2023	14.38	11.36	37.10	16.67	19.56	99.07	208.73	28.82	122.47	360.01	459.08
2023-2024	14.61	11.46	37.75	16.96	20.03	100.81	212.96	29.40	124.95	367.30	468.11
2024-2025	14.86	11.55	38.39	17.25	20.51	102.56	217.22	29.99	127.44	374.65	477.21
2025-2026	15.11	11.62	39.04	17.54	20.99	104.30	221.42	30.57	129.91	381.90	486.20
2026-2027	15.35	11.72	39.66	17.82	21.47	106.02	225.59	31.14	132.35	389.09	495.11
High											
2007-2008	10.84	9.86	27.06	12.16	13.07	72.99	155.95	21.51	91.43	268.89	341.87
2008-2009	10.99	9.84	27.48	12.35	13.33	73.99	158.95	21.93	93.20	274.08	348.07
2009-2010	11.52	10.15	28.91	12.99	14.09	77.65	167.59	23.12	98.28	288.99	366.64
2010-2011	12.01	10.37	30.09	13.52	14.79	80.79	175.14	24.17	102.72	302.02	382.81
2011-2012	12.47	10.60	31.40	14.10	15.59	84.17	181.09	25.20	106.21	312.50	396.67
2012-2013	12.85	10.81	32.54	14.62	16.32	87.14	187.41	26.03	109.93	323.37	410.51
2013-2014	13.26	11.00	33.67	15.13	17.04	90.10	193.52	26.90	113.52	333.95	424.05
2014-2015	13.64	11.21	34.76	15.62	17.76	92.99	199.08	27.59	116.79	343.45	436.44
2015-2016	14.03	11.43	35.91	16.13	18.54	96.05	204.78	28.29	120.14	353.21	449.26
2016-2017	14.40	11.59	36.96	16.61	19.26	98.83	209.99	28.99	123.21	362.19	461.02
2017-2018	14.72	11.74	37.90	17.03	19.91	101.31	215.05	29.69	126.17	370.91	472.22
2018-2019	15.07	11.88	38.95	17.50	20.62	104.03	220.80	30.48	129.55	380.83	484.86
2019-2020	15.43	12.05	39.98	17.97	21.32	106.76	226.65	31.29	132.97	390.91	497.66
2020-2021	15.76	12.18	40.92	18.39	21.96	109.20	232.54	32.10	136.43	401.06	510.27
2021-2022	16.10	12.32	41.87	18.82	22.64	111.75	238.77	32.96	140.08	411.80	523.55
2022-2023	16.42	12.44	42.78	19.23	23.29	114.15	244.72	33.78	143.57	422.06	536.22
2023-2024	16.74	12.55	43.67	19.62	23.95	116.53	250.78	34.62	147.12	432.51	549.04
2024-2025	17.07	12.65	44.52	20.01	24.60	118.84	256.68	35.43	150.57	442.67	561.51
2025-2026	17.42	12.76	45.46	20.43	25.31	121.38	262.92	36.29	154.22	453.43	574.81
2026-2027	17.78	12.88	46.33	20.82	25.99	123.80	269.08	37.14	157.84	464.05	587.86
Low											
2007-2008	10.58	9.69	26.50	11.91	12.79	71.47	151.44	20.89	88.79	261.11	332.59
2008-2009	10.33	9.41	25.93	11.65	12.54	69.87	148.15	20.44	86.87	255.47	325.33
2009-2010	10.48	9.49	26.34	11.83	12.75	70.90	150.59	20.78	88.31	259.69	330.58
2010-2011	10.66	9.58	26.77	12.03	13.01	72.05	153.28	21.15	89.90	264.33	336.39
2011-2012	10.77	9.62	27.11	12.18	13.23	72.92	154.57	21.33	90.66	266.56	339.48
2012-2013	10.87	9.68	27.42	12.32	13.43	73.72	155.61	21.48	91.29	268.38	342.10
2013-2014	10.97	9.72	27.73	12.46	13.64	74.52	156.55	21.61	92.06	270.22	344.74
2014-2015	11.08	9.77	28.05	12.61	13.86	75.37	157.83	21.79	92.61	272.22	347.59
2015-2016	11.20	9.83	28.39	12.76	14.10	76.28	159.24	21.99	93.45	274.67	350.95
2016-2017	11.32	9.89	28.74	12.91	14.34	77.19	160.66	22.19	94.29	277.13	354.33
2017-2018	11.43	9.94	29.06	13.05	14.56	78.05	162.25	22.40	95.22	279.87	357.92
2018-2019	11.53	9.99	29.39	13.20	14.79	78.90	163.86	22.63	96.17	282.66	361.55
2019-2020	11.63	10.04	29.72	13.34	15.00	79.74	165.56	22.86	97.16	285.59	365.33
2020-2021	11.73	10.08	30.04	13.49	15.22	80.56	167.31	23.10	98.19	288.60	369.16
2021-2022	11.84	10.13	30.31	13.62	15.44	81.35	169.10	23.35	99.24	291.69	373.04
2022-2023	11.92	10.15	30.55	13.73	15.63	81.98	170.58	23.55	100.10	294.23	376.22
2023-2024	12.00	10.16	30.80	13.84	15.82	82.62	172.03	23.75	100.96	296.74	379.37
2024-2025	12.08	10.18	31.02	13.94	16.01	83.24	173.50	23.96	101.82	299.27	382.51
2025-2026	12.17	10.19	31.25	14.05	16.21	83.87	174.92	24.15	102.65	301.72	385.60
2026-2027	12.26	10.21	31.48	14.15	16.41	84.52	176.47	24.37	103.56	304.39	388.91

Appendix 2.4 D

Peak Day Demand - 11/2007 - 10/2027 (Net of DSM Savings)

Peak Day = December 20

Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Rosburg	Oregon	Spokane Both	Spokane GTN	Spokane NWP	WA/ID	Total
Base											
2007-2008	13.86	8.48	41.02	18.43	16.33	**98.12**	125.17	17.27	73.38	**215.81**	**313.94**
2008-2009	14.15	8.57	42.00	18.87	16.62	**100.21**	128.21	17.69	75.17	**221.07**	**321.28**
2009-2010	14.46	8.66	43.05	19.34	17.06	**102.58**	131.40	18.13	77.06	**226.59**	**329.17**
2010-2011	14.80	8.74	44.10	19.81	17.53	**104.98**	134.74	18.59	79.02	**232.35**	**337.33**
2011-2012	15.15	8.82	45.18	20.30	18.04	**107.48**	138.09	19.06	80.99	**238.14**	**345.62**
2012-2013	15.48	8.91	46.35	20.82	18.64	**110.20**	141.01	19.46	82.71	**243.17**	**353.38**
2013-2014	15.78	9.01	47.41	21.30	19.21	**112.71**	143.66	19.83	84.26	**247.75**	**360.46**
2014-2015	16.09	9.10	48.48	21.79	19.78	**115.25**	146.09	20.18	85.71	**251.98**	**367.22**
2015-2016	16.42	9.22	49.61	22.29	20.40	**117.94**	149.01	20.57	87.43	**257.01**	**374.95**
2016-2017	16.76	9.34	50.79	22.82	21.05	**120.77**	151.97	20.98	89.17	**262.13**	**382.89**
2017-2018	17.10	9.45	51.96	23.35	21.70	**123.56**	155.05	21.41	90.97	**267.43**	**391.00**
2018-2019	17.43	9.55	53.07	23.85	22.32	**126.22**	158.21	21.84	92.83	**272.88**	**399.10**
2019-2020	17.74	9.64	54.19	24.35	22.93	**128.86**	161.42	22.28	94.71	**278.41**	**407.28**
2020-2021	18.07	9.75	55.31	24.86	23.56	**131.55**	164.77	22.75	96.67	**284.19**	**415.75**
2021-2022	18.38	9.84	56.38	25.34	24.15	**134.09**	168.23	23.22	98.70	**290.16**	**424.24**
2022-2023	18.70	9.93	57.43	25.81	24.75	**136.63**	171.76	23.71	100.77	**296.24**	**432.87**
2023-2024	19.02	10.01	58.48	26.28	25.35	**139.14**	175.38	24.21	102.89	**302.48**	**441.62**
2024-2025	19.33	10.09	59.51	26.74	25.97	**141.63**	178.99	24.71	105.01	**308.70**	**450.33**
2025-2026	19.66	10.17	60.52	27.20	26.59	**144.14**	182.62	25.21	107.13	**314.96**	**459.10**
2026-2027	19.98	10.24	61.55	27.66	27.22	**146.65**	186.20	25.70	109.23	**321.13**	**467.78**
High											
2007-2008	13.89	8.70	41.24	18.53	16.55	**98.91**	127.41	17.58	74.70	**219.69**	**318.60**
2008-2009	14.09	8.69	42.00	18.87	16.70	**100.36**	129.90	17.92	76.16	**223.98**	**324.34**
2009-2010	14.80	8.96	44.27	19.89	17.63	**105.56**	136.80	18.88	80.22	**235.90**	**341.46**
2010-2011	15.41	9.15	46.19	20.75	18.47	**109.98**	142.94	19.72	83.83	**246.49**	**356.47**
2011-2012	16.06	9.34	48.14	21.62	19.36	**114.53**	147.90	20.57	86.74	**255.21**	**369.73**
2012-2013	16.61	9.51	50.07	22.50	20.35	**119.05**	153.45	21.30	90.00	**264.75**	**383.80**
2013-2014	17.14	9.69	51.89	23.32	21.31	**123.35**	158.76	22.06	93.12	**273.94**	**397.29**
2014-2015	17.63	9.84	53.55	24.06	22.18	**127.25**	163.42	22.64	95.86	**281.92**	**409.18**
2015-2016	18.14	10.02	55.30	24.85	23.15	**131.46**	168.25	23.24	98.70	**290.19**	**421.65**
2016-2017	18.62	10.19	56.99	25.61	24.09	**135.50**	172.57	23.82	101.24	**297.64**	**433.14**
2017-2018	19.08	10.31	56.71	25.49	24.99	**136.58**	176.82	24.41	103.73	**304.95**	**441.53**
2018-2019	19.55	10.46	60.22	27.06	25.91	**143.21**	181.53	25.06	106.49	**313.08**	**456.29**
2019-2020	20.02	10.59	61.84	27.79	26.81	**147.05**	186.39	25.73	109.34	**321.46**	**468.51**
2020-2021	20.48	10.73	63.41	28.49	27.70	**150.81**	191.17	26.39	112.15	**329.70**	**480.51**
2021-2022	20.91	10.85	64.94	29.18	28.56	**154.44**	196.25	27.09	115.12	**338.46**	**492.90**
2022-2023	21.36	10.97	66.39	29.83	29.41	**157.96**	201.25	27.78	118.05	**347.08**	**505.04**
2023-2024	21.78	11.07	67.82	30.48	30.25	**161.40**	206.46	28.50	121.11	**356.07**	**517.47**
2024-2025	22.19	11.16	69.16	31.08	31.09	**164.68**	211.50	29.19	124.06	**364.75**	**529.43**
2025-2026	22.66	11.27	70.64	31.75	32.00	**168.32**	216.91	29.94	127.23	**374.07**	**542.39**
2026-2027	23.13	11.36	72.08	32.39	32.91	**171.87**	222.08	30.65	130.26	**382.98**	**554.85**
Low											
2007-2008	13.70	8.49	40.60	18.24	16.27	**97.29**	124.09	17.12	72.75	**213.96**	**311.26**
2008-2009	13.37	8.25	39.72	17.84	15.88	**95.05**	121.43	16.75	71.20	**209.38**	**304.43**
2009-2010	13.57	8.32	40.36	18.14	16.14	**96.53**	123.40	17.03	72.37	**212.80**	**309.33**
2010-2011	13.80	8.40	41.07	18.46	16.45	**98.17**	125.62	17.33	73.67	**216.62**	**314.79**
2011-2012	13.96	8.43	41.57	18.68	16.69	**99.32**	126.75	17.49	74.34	**218.58**	**317.90**
2012-2013	14.10	8.47	42.11	18.92	16.98	**100.58**	127.75	17.63	74.94	**220.32**	**320.89**
2013-2014	14.24	8.51	42.61	19.14	17.24	**101.74**	128.66	17.76	75.63	**222.05**	**323.79**
2014-2015	14.38	8.55	43.10	19.37	17.51	**102.91**	129.79	17.92	76.15	**223.86**	**326.76**
2015-2016	14.53	8.60	43.62	19.60	17.81	**104.16**	130.99	18.08	76.86	**225.94**	**330.09**
2016-2017	14.68	8.65	44.17	19.85	18.12	**105.47**	132.21	18.26	77.59	**228.06**	**333.53**
2017-2018	14.84	8.70	44.72	20.08	18.43	**106.77**	133.55	18.44	78.37	**230.36**	**337.13**
2018-2019	14.98	8.75	45.24	20.31	18.72	**108.00**	134.91	18.63	79.17	**232.71**	**340.72**
2019-2020	15.11	8.79	45.76	20.54	19.00	**109.20**	136.31	18.82	79.99	**235.12**	**344.31**
2020-2021	15.25	8.83	46.28	20.78	19.30	**110.44**	137.78	19.02	80.85	**237.65**	**348.09**
2021-2022	15.39	8.87	46.73	21.00	19.58	**111.57**	139.29	19.23	81.73	**240.25**	**351.82**
2022-2023	15.50	8.89	47.11	21.17	19.83	**112.50**	140.57	19.41	82.48	**242.46**	**354.96**
2023-2024	15.61	8.91	47.50	21.35	20.07	**113.43**	141.80	19.58	83.20	**244.58**	**358.01**
2024-2025	15.71	8.92	47.86	21.51	20.31	**114.31**	143.10	19.76	83.97	**246.83**	**361.14**
2025-2026	15.83	8.94	48.21	21.67	20.57	**115.22**	144.40	19.94	84.73	**249.07**	**364.29**
2026-2027	15.94	8.95	48.59	21.84	20.83	**116.17**	145.69	20.11	85.49	**251.29**	**367.46**

General Assumptions

Appendix 6.1

Appendix 6.1 – General Assumptions

Utility Natural Gas Escalation Rates*

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
0.8%	9.0%	0.0%	-3.2%	-1.4%	-1.9%	0.2%	0.7%	2.1%	2.6%
2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
3.4%	3.2%	2.3%	2.2%	1.7%	1.7%	1.7%	1.7%	1.7%	1.4%

* Source: Global Insights, Inc 4/26/2007 Forecast.

GDP Inflation Rates*

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1.89%	1.99%	2.07%	2.01%	1.98%	2.01%	1.97%	1.88%	1.85%	1.85%
2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
1.88%	1.92%	1.95%	1.92%	1.96%	1.97%	1.99%	2.00%	1.99%	2.02%

* Source: Global Insights, Inc 4/26/2007 Forecast.

Real Discount Rate = 4.18% - Weighted Average after Tax Cost of Capital (jurisdictionally weighted).

AECO, Sumas, Rockies Prices – See Attached

NYMEX Prices – Were closing 5/9/2007 prices. More current NYMEX prices (11/26/2007) were analyzed and determined that the change was not significant enough to warrant updating.

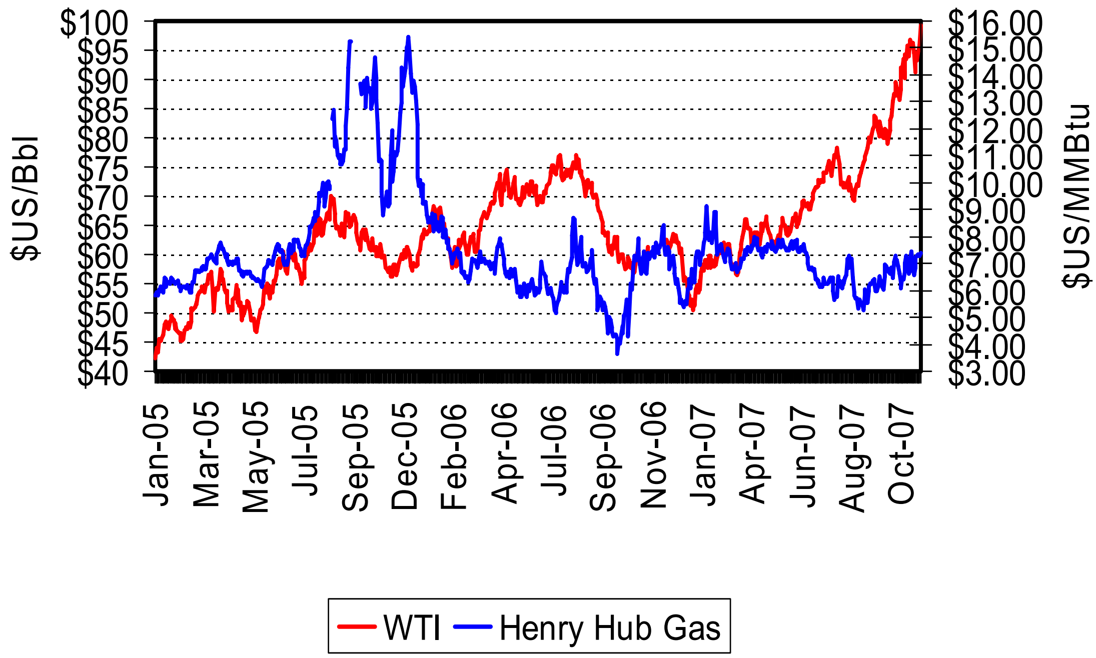
Other Pricing:
Station 2 – Sumas minus $.4172
Malin = AECO plus $.2123
Spokane = AECo plus $.2967

Consultant Price Assumptions

	Consultant 1			Consultant 2			AEO 2007		
	2008	**2010**	**2015**	**2008**	**2010**	**2015**	**2008**	**2010**	**2015**
Forecasted HH Price (2007 $)	$ 8.07	$ 7.06	$ 6.73	$ 7.83	$ 6.58	$ 6.18	$ 8.31	$ 6.62	$ 5.75
US Economic Growth (% GDP)	3.50%	3.20%	3.20%	3.00%	3.00%	3.00%	3.05%	3.01%	3.00%
Total US Gas Demand bcf/d)	63.41	65.86	68.27	60.61	62.06	67.8	63.95	65.8	69.38
EG Demand (bcf\d)	18.6	19.81	21.54	17.93	19.36	25.4	17.44	17.48	19.48
World Oil Prices (2007$)	$ 65.53	$ 61.17	$ 63.93	$ 55.32	$ 52.62	$ 46.87	$ 67.59	$ 60.61	$ 52.59
US Gas Prod. (bcf\d)	53.27	52.45	49.77	48.32	47.78	46.5	53.22	53.21	53.89
LNG Imports (bcf\d)	2.76	5.82	10.28	4.14	6.84	11.8	3.04	4.97	8.19
Net (Canada & Mexico) Imports (bcf\d)	7.47	7.6	8.22	7.78	7.39	9	7.69	7.62	7.30
Mackenzie Delta Pipeline		1 bcf/d in service 2014			In service 2012			1.2 bcf/d in service 2012	
Alaska Pipeline			4 bcf/d in service 2020			In service 2017			3.9 bcf/d in service 2018

Pipeline Rates
Northwest Pipeline – currently settled rates with pipeline rate increases every five years at GDP
GTN – currently filed rates with pipeline rate increases every five years at GDP
Canadian Pipelines – current rates with pipeline rate increases three years at GDP

Natural Gas and WTI Oil Price Relationship:



Heating Degree Days – See Attached

Appendix 6.1
Klamath Falls Heating Degree Days
Source: NOAA with added peak days

Day of Month	January	February	March	April	May	June	July	August	September	October	November	December	
1	48	23	21	13	21	13	4	0	3	12	16	34	
2	37	26	32	21	24	12	8	0	9	9	22	27	
3	31	27	30	27	19	13	13	1	6	8	19	23	
4	38	22	35	22	14	10	15	2	5	8	19	28	
5	29	28	35	23	8	4	15	0	5	8	19	26	
6	23	26	34	30	9	6	12	1	1	9	22	31	
7	29	30	27	27	8	15	7	1	10	8	23	31	
8	27	23	23	21	11	12	5	2	9	22	18	35	
9	39	28	17	14	15	12	4	0	6	24	27	34	
10	42	35	22	10	8	13	3	0	1	21	29	43	
11	39	28	21	10	7	8	0	0	3	24	33	46	
12	41	22	23	25	10	12	0	0	3	25	31	47	
13	34	42	20	29	21	9	0	0	3	21	41	39	
14	29	51	21	20	27	2	3	0	0	23	43	41	
15	26	54	24	18	25	0	0	0	0	31	42	39	
16	35	53	20	34	25	0	0	2	0	24	37	39	
17	38	47	18	27	13	0	0	0	0	16	37	37	
18	40	35	20	25	8	0	0	0	0	12	38	54	
19	41	29	26	25	0	0	0	0	3	16	37	66	
20	41	22	25	32	0	3	0	1	2	15	36	72	
21	43	29	33	31	10	0	0	2	17	17	35	68	
22	36	38	33	25	15	0	0	3	19	13	30	58	
23	36	35	35	20	16	0	0	4	20	15	31	35	
24	31	31	33	26	16	11	0	9	22	21	24	33	
25	34	33	31	20	18	7	0	13	20	27	22	35	
26	29	32	28	19	18	1	1	5	19	22	31	37	
27	35	26	25	13	16	7	0	7	21	23	33	38	
28	34	22	22	12	6	11	0	9	19	16	24	38	
29	27	26	23	8	1	8	0	11	16	17	21	37	
30	32	0	21	2	13	16	0	7	13	16	26	35	
31	39	0	24	0	24	0	0	3	0	17	0	27	
	1083	923	802	629	426	205	90	83	255	540	866	1233	7135

Appendix 6.1
La Grande Heating Degree Days
Source: NOAA with added peak days

Day of Month	January	February	March	April	May	June	July	August	September	October	November	December	
1	35	22	17	23	28	22	1	0	0	10	34	28	
2	39	25	27	22	26	9	0	0	0	10	22	24	
3	41	24	24	23	20	12	0	0	0	11	17	28	
4	52	21	27	18	22	18	0	0	0	13	27	31	
5	66	29	24	14	22	15	0	4	5	14	28	37	
6	56	27	31	18	17	3	1	1	3	11	21	33	
7	39	26	24	11	20	0	2	3	0	5	23	35	
8	30	25	24	11	14	0	0	0	0	3	25	33	
9	25	28	18	11	13	0	0	0	7	14	30	31	
10	24	35	19	14	11	4	0	0	11	17	25	33	
11	34	31	22	22	3	8	0	0	18	18	24	49	
12	30	28	29	22	0	13	0	0	15	14	21	54	
13	27	61	23	24	0	8	0	0	9	12	14	37	
14	31	68	22	26	11	1	0	0	6	13	25	29	
15	33	74	31	14	14	0	0	0	4	9	33	30	
16	33	61	32	21	6	0	0	5	14	7	30	31	
17	34	60	28	19	9	0	5	0	6	11	32	33	
18	35	50	29	22	15	0	0	0	12	19	26	51	
19	33	49	31	22	14	0	0	0	3	15	30	58	
20	34	42	28	12	11	1	8	8	7	19	29	64	
21	31	32	30	6	6	3	9	3	7	21	26	58	
22	35	24	26	0	0	8	0	1	16	24	31	51	
23	34	22	22	23	0	2	0	5	12	21	31	26	
24	35	29	16	26	4	11	0	5	8	24	29	31	
25	34	30	21	19	2	4	4	8	17	28	33	35	
26	34	23	18	25	5	1	1	1	10	23	34	34	
27	32	15	18	18	0	0	4	5	7	18	31	35	
28	27	18	20	21	4	0	7	0	14	19	33	40	
29	24	0	30	23	15	0	0	0	6	26	26	34	
30	24	0	31	28	18	4	0	0	0	20	30	34	
31	31	0	24	0	14	0	0	4	0	24	0	36	
	1072	979	766	558	344	147	42	53	217	493	820	1163	6654

Appendix 6.1
Medford Heating Degree Days
Source: NOAA with added peak days

Day of Month	January	February	March	April	May	June	July	August	September	October	November	December	
1	27	18	28	18	8	7	0	4	0	0	10	22	
2	33	21	22	19	13	7	2	0	0	1	13	23	
3	28	22	20	18	17	4	6	0	0	1	5	22	
4	32	25	20	16	10	9	2	0	0	0	16	26	
5	28	26	21	18	12	13	0	0	0	0	23	30	
6	31	25	11	18	8	9	0	0	0	0	21	26	
7	25	24	19	20	6	6	0	0	0	10	24	30	
8	30	26	18	20	3	0	0	0	0	15	28	25	
9	30	25	21	14	2	0	0	0	0	18	16	29	
10	29	25	19	18	3	0	0	0	7	16	14	22	
11	23	23	18	21	0	0	0	0	5	17	16	28	
12	19	22	12	23	0	0	0	0	4	17	19	28	
13	21	32	11	23	3	0	0	0	2	19	22	32	
14	25	36	12	22	9	0	0	0	0	15	27	28	
15	22	38	15	19	7	2	0	0	0	9	16	21	
16	20	32	14	17	2	6	0	0	0	3	18	16	
17	21	28	22	13	0	3	0	0	0	3	18	19	
18	23	19	21	10	4	3	0	0	0	8	21	50	
19	23	16	19	6	11	0	0	0	3	10	20	59	
20	23	21	17	6	10	0	0	0	10	15	24	61	
21	22	17	18	4	14	0	0	0	10	14	26	56	
22	25	21	17	5	10	0	0	0	5	6	30	55	
23	28	23	15	13	7	0	0	1	2	9	26	34	
24	31	20	13	14	10	0	0	0	2	10	23	34	
25	32	22	15	15	9	0	0	0	0	13	25	30	
26	28	28	18	10	7	0	0	0	2	15	26	28	
27	30	22	16	2	7	0	0	0	3	21	23	32	
28	23	27	19	0	9	0	0	0	6	13	26	29	
29	22	0	19	0	16	0	0	0	4	11	31	29	
30	23	0	19	0	9	0	0	2	4	16	25	31	
31	27	0	20	0	8	0	0	0	0	13	0	33	
	804	684	549	402	234	69	10	7	69	318	632	988	4766

Appendix 6.1
Roseburg Heating Degree Days
Source: NOAA with added peak days

Day of Month	January	February	March	April	May	June	July	August	September	October	November	December	
1	25	25	11	13	7	5	6	0	1	0	15	25	
2	18	27	9	8	2	5	0	0	5	5	17	28	
3	23	23	15	6	14	8	0	0	2	10	19	28	
4	15	18	25	11	15	11	0	0	0	8	15	23	
5	15	11	24	11	16	9	0	0	0	5	20	24	
6	19	23	22	9	12	7	0	0	0	0	19	21	
7	23	25	18	13	15	7	0	0	0	0	16	22	
8	22	23	24	23	15	3	0	3	0	5	13	24	
9	24	26	16	18	13	0	0	0	0	8	14	27	
10	27	27	23	11	9	0	0	0	0	11	14	28	
11	22	25	17	11	13	6	0	0	0	11	11	25	
12	21	20	14	7	5	8	0	0	1	14	15	27	
13	20	32	16	17	0	4	1	0	1	6	12	22	
14	23	37	13	20	6	2	0	0	0	9	13	18	
15	24	42	11	20	13	0	0	0	0	9	17	20	
16	27	34	12	17	14	0	0	0	0	6	18	27	
17	29	28	13	19	16	0	3	0	5	6	17	25	
18	24	16	14	20	15	0	0	0	8	7	16	40	
19	22	14	11	19	7	0	0	0	11	2	17	53	
20	25	12	4	21	5	0	0	0	8	10	26	55	
21	18	15	14	11	0	0	0	0	8	15	23	46	
22	19	14	18	8	0	0	1	4	3	17	14	48	
23	20	26	15	0	0	0	0	4	2	13	14	17	
24	24	21	19	1	0	0	0	1	0	10	13	19	
25	22	17	22	7	7	0	0	0	5	10	12	20	
26	22	11	23	11	1	0	0	0	4	9	18	22	
27	27	10	19	13	0	0	0	0	0	9	21	18	
28	26	21	20	11	0	7	3	0	0	11	28	23	
29	23	0	17	10	0	3	3	0	6	14	25	22	
30	24	0	9	7	5	2	2	0	5	17	29	20	
31	26	0	7	0	1	0	0	0	0	13	0	23	
	699	623	495	373	226	87	19	12	75	270	521	840	4240

Appendix 6.1
WA/ID Heating Degree Days
Source: NOAA with added peak days

Day of Month	January	February	March	April	May	June	July	August	September	October	November	December	
1	35	40	28	23	20	0	9	0	0	14	29	40	
2	40	45	27	26	18	5	6	0	0	18	26	37	
3	39	38	29	23	13	6	0	0	0	21	27	36	
4	33	30	27	26	12	2	0	0	0	15	29	41	
5	29	26	29	24	23	2	0	0	6	16	35	38	
6	38	34	26	25	20	7	0	0	10	12	35	34	
7	38	32	21	25	16	8	0	0	9	12	31	32	
8	38	34	20	22	13	15	0	0	7	7	27	32	
9	35	41	20	18	9	4	2	0	13	7	27	31	
10	35	43	24	20	9	6	5	0	11	7	34	32	
11	34	41	27	24	9	5	1	0	5	17	23	31	
12	34	38	38	18	10	5	0	0	1	14	27	24	
13	33	62	41	19	8	3	0	0	11	12	28	25	
14	38	72	42	16	14	0	0	0	12	20	29	34	
15	47	82	32	19	16	0	0	0	12	22	35	40	
16	46	67	26	18	8	9	0	0	15	23	42	41	
17	44	57	25	20	4	13	0	0	18	21	39	41	
18	41	26	24	20	0	10	0	1	22	13	33	51	
19	37	22	18	21	0	9	0	2	16	13	29	56	
20	38	29	23	22	7	8	6	0	6	12	25	61	
21	36	35	28	18	10	4	10	5	3	16	26	58	
22	36	34	29	10	12	4	6	1	0	16	21	53	
23	36	35	27	6	9	0	0	5	0	15	26	37	
24	35	32	26	13	11	0	0	7	0	20	29	40	
25	34	25	19	10	13	0	0	7	3	23	30	51	
26	42	21	16	5	11	0	0	7	4	23	28	58	
27	46	29	10	14	10	10	0	2	3	26	32	47	
28	41	33	20	17	6	10	1	0	2	30	34	48	
29	38	0	25	20	10	4	0	0	2	29	29	39	
30	40	0	23	15	13	0	0	2	3	30	32	30	
31	33	0	18		9	0	0	3	0	30	0	37	
	1169	1103	788	557	343	149	46	42	194	554	897	1255	7097

Appendix 6.1
Mid Price Case
Real 2007$

		86.0%	87.6%	80.5%
	Nymex	AECo	Sumas	Rockies
2008	8.53	7.34	7.47	6.87
2009	7.96	6.85	6.97	6.41
2010	7.42	6.38	6.50	5.97
2011	6.82	5.87	5.97	5.49
2012	6.53	5.61	5.72	5.25
2013	6.38	5.49	5.59	5.14
2014	6.52	5.61	5.71	5.25
2015	6.73	5.79	5.90	5.42
2016	6.77	5.82	5.93	5.45
2017	6.80	5.85	5.96	5.47
2018	6.83	5.87	5.98	5.50
2019	7.01	6.03	6.14	5.64
2020	7.18	6.17	6.29	5.78
2021	7.34	6.31	6.43	5.91
2022	7.47	6.42	6.54	6.01
2023	7.59	6.53	6.65	6.11
2024	7.72	6.64	6.77	6.22
2025	7.86	6.76	6.88	6.33
2026	8.00	6.88	7.00	6.44
2027	8.11	6.97	7.10	6.53

Seasonal Shape	
January	113%
February	113%
March	110%
April	93%
May	92%
June	93%
July	94%
August	94%
September	95%
October	96%
November	101%
December	106%

AECO		113%	113%	110%	93%	92%	93%	94%	94%	95%	96%	101%	106%
		January	February	March	April	May	June	July	August	September	October	November	December
2008	7.34	8.30	8.29	8.08	6.85	6.74	6.80	6.87	6.92	6.95	7.04	7.42	7.80
2009	6.85	7.75	7.73	7.54	6.39	6.29	6.34	6.41	6.46	6.49	6.57	6.93	7.28
2010	6.38	7.22	7.21	7.03	5.95	5.86	5.91	5.97	6.02	6.05	6.12	6.46	6.78
2011	5.87	6.64	6.63	6.46	5.47	5.38	5.44	5.49	5.53	5.56	5.63	5.93	6.23
2012	5.61	6.35	6.34	6.18	5.24	5.15	5.20	5.25	5.29	5.32	5.38	5.68	5.96
2013	5.49	6.21	6.20	6.05	5.12	5.04	5.09	5.14	5.18	5.20	5.27	5.55	5.84
2014	5.61	6.34	6.33	6.18	5.23	5.15	5.20	5.25	5.29	5.31	5.38	5.67	5.96
2015	5.79	6.55	6.54	6.38	5.40	5.32	5.37	5.42	5.46	5.49	5.55	5.86	6.15
2016	5.82	6.59	6.58	6.41	5.43	5.34	5.39	5.45	5.49	5.52	5.58	5.89	6.19
2017	5.85	6.62	6.61	6.44	5.46	5.37	5.42	5.47	5.51	5.54	5.61	5.91	6.22
2018	5.87	6.64	6.63	6.47	5.48	5.39	5.44	5.50	5.54	5.56	5.63	5.94	6.24
2019	6.03	6.82	6.81	6.64	5.62	5.53	5.58	5.64	5.68	5.71	5.78	6.10	6.41
2020	6.17	6.99	6.97	6.80	5.76	5.67	5.72	5.78	5.82	5.85	5.92	6.24	6.56
2021	6.31	7.14	7.13	6.95	5.89	5.79	5.85	5.91	5.95	5.98	6.05	6.38	6.71
2022	6.42	7.27	7.25	7.07	5.99	5.90	5.95	6.01	6.06	6.09	6.16	6.50	6.83
2023	6.53	7.39	7.38	7.19	6.09	6.00	6.05	6.11	6.16	6.19	6.26	6.61	6.94
2024	6.64	7.52	7.50	7.31	6.20	6.10	6.15	6.22	6.26	6.30	6.37	6.72	7.06
2025	6.76	7.65	7.63	7.44	6.31	6.20	6.26	6.33	6.37	6.41	6.48	6.84	7.18
2026	6.88	7.78	7.77	7.57	6.42	6.31	6.37	6.44	6.48	6.52	6.60	6.96	7.31
2027	6.97	7.89	7.87	7.68	6.50	6.40	6.46	6.53	6.57	6.61	6.69		

Appendix 6.1
Mid Price Case

Sumas		113%	113%	110%	93%	92%	93%	94%	94%	95%	96%	101%	106%
		January	February	March	April	May	June	July	August	September	October	November	December
2008	7.47	8.46	8.44	8.23	6.97	6.86	6.93	7.00	7.05	7.08	7.17	7.56	7.94
2009	6.97	7.89	7.88	7.68	6.51	6.40	6.46	6.53	6.58	6.61	6.69	7.05	7.41
2010	6.50	7.36	7.34	7.16	6.07	5.97	6.02	6.09	6.13	6.16	6.24	6.58	6.91
2011	5.97	6.76	6.75	6.58	5.57	5.48	5.54	5.59	5.63	5.66	5.73	6.04	6.35
2012	5.72	6.47	6.46	6.30	5.33	5.25	5.30	5.35	5.39	5.42	5.48	5.78	6.08
2013	5.59	6.33	6.32	6.16	5.22	5.13	5.18	5.24	5.27	5.30	5.36	5.66	5.94
2014	5.71	6.46	6.45	6.29	5.33	5.24	5.29	5.35	5.39	5.41	5.48	5.78	6.07
2015	5.90	6.67	6.66	6.50	5.50	5.41	5.47	5.52	5.56	5.59	5.66	5.97	6.27
2016	5.93	6.71	6.70	6.53	5.53	5.44	5.49	5.55	5.59	5.62	5.69	6.00	6.30
2017	5.96	6.74	6.73	6.56	5.56	5.47	5.52	5.58	5.62	5.65	5.71	6.02	6.33
2018	5.98	6.77	6.76	6.59	5.58	5.49	5.54	5.60	5.64	5.67	5.74	6.05	6.36
2019	6.14	6.95	6.93	6.76	5.73	5.64	5.69	5.75	5.79	5.82	5.89	6.21	6.53
2020	6.29	7.12	7.10	6.93	5.87	5.77	5.83	5.89	5.93	5.96	6.03	6.36	6.68
2021	6.43	7.28	7.26	7.08	6.00	5.90	5.96	6.02	6.06	6.09	6.17	6.50	6.83
2022	6.54	7.40	7.39	7.20	6.10	6.00	6.06	6.12	6.17	6.20	6.27	6.62	6.95
2023	6.65	7.53	7.51	7.33	6.21	6.11	6.16	6.23	6.27	6.31	6.38	6.73	7.07
2024	6.77	7.66	7.64	7.45	6.31	6.21	6.27	6.33	6.38	6.41	6.49	6.84	7.19
2025	6.88	7.79	7.78	7.58	6.42	6.32	6.38	6.44	6.49	6.52	6.60	6.96	7.32
2026	7.00	7.93	7.91	7.71	6.54	6.43	6.49	6.56	6.61	6.64	6.72	7.08	7.45
2027	7.10	8.03	8.02	7.82	6.63	6.52	6.58	6.65	6.70	6.73	6.81		

Rockies		113%	113%	110%	93%	92%	93%	94%	94%	95%	96%	101%	106%
		January	February	March	April	May	June	July	August	September	October	November	December
2008	6.87	7.77	7.76	7.56	6.41	6.30	6.36	6.43	6.48	6.51	6.59	6.95	7.30
2009	6.41	7.25	7.24	7.06	5.98	5.88	5.94	6.00	6.04	6.07	6.15	6.48	6.81
2010	5.97	6.76	6.75	6.58	5.57	5.48	5.54	5.59	5.63	5.66	5.73	6.04	6.35
2011	5.49	6.21	6.20	6.05	5.12	5.04	5.09	5.14	5.18	5.20	5.27	5.55	5.84
2012	5.25	5.94	5.93	5.78	4.90	4.82	4.87	4.92	4.95	4.98	5.04	5.31	5.58
2013	5.14	5.82	5.81	5.66	4.80	4.72	4.76	4.81	4.85	4.87	4.93	5.20	5.46
2014	5.25	5.94	5.93	5.78	4.90	4.82	4.86	4.91	4.95	4.97	5.03	5.31	5.58
2015	5.42	6.13	6.12	5.97	5.06	4.98	5.02	5.07	5.11	5.14	5.20	5.48	5.76
2016	5.45	6.16	6.15	6.00	5.08	5.00	5.05	5.10	5.14	5.16	5.23	5.51	5.79
2017	5.47	6.19	6.18	6.03	5.11	5.02	5.07	5.12	5.16	5.19	5.25	5.54	5.82
2018	5.50	6.22	6.21	6.05	5.13	5.04	5.09	5.14	5.18	5.21	5.27	5.56	5.84
2019	5.64	6.38	6.37	6.21	5.26	5.18	5.23	5.28	5.32	5.35	5.41	5.71	6.00
2020	5.78	6.54	6.53	6.36	5.39	5.31	5.36	5.41	5.45	5.48	5.54	5.85	6.14
2021	5.91	6.69	6.67	6.51	5.51	5.42	5.48	5.53	5.57	5.60	5.67	5.98	6.28
2022	6.01	6.80	6.79	6.62	5.61	5.52	5.57	5.63	5.67	5.70	5.77	6.08	6.39
2023	6.11	6.92	6.91	6.73	5.70	5.61	5.66	5.72	5.76	5.79	5.86	6.18	6.50
2024	6.22	7.03	7.02	6.85	5.80	5.71	5.76	5.82	5.86	5.89	5.96	6.29	6.61
2025	6.33	7.16	7.15	6.97	5.90	5.81	5.86	5.92	5.97	6.00	6.07	6.40	6.72
2026	6.44	7.28	7.27	7.09	6.01	5.91	5.96	6.03	6.07	6.10	6.17	6.51	6.84
2027	6.53	7.38	7.37	7.19	6.09	5.99	6.05	6.11	6.15	6.19	6.26		

Appendix 6.1
High Price Case
Real 2007$

		86.0%	87.6%	80.5%		
	Nymex	AECo	Sumas	Rockies	Seasonal Shape	
2008	9.00	7.74	7.88	7.24		
2009	8.67	7.46	7.60	6.98	January	113%
2010	8.27	7.11	7.25	6.66	February	113%
2011	8.27	7.11	7.25	6.66	March	110%
2012	8.27	7.11	7.25	6.66	April	93%
2013	8.27	7.11	7.25	6.66	May	92%
2014	8.27	7.11	7.25	6.66	June	93%
2015	8.27	7.11	7.25	6.66	July	94%
2016	8.27	7.11	7.25	6.66	August	94%
2017	8.27	7.11	7.25	6.66	September	95%
2018	8.27	7.11	7.25	6.66	October	96%
2019	8.27	7.11	7.25	6.66	November	101%
2020	8.27	7.11	7.25	6.66	December	106%
2021	8.41	7.24	7.37	6.77		
2022	8.56	7.36	7.50	6.89		
2023	8.70	7.48	7.62	7.01		
2024	8.85	7.62	7.76	7.13		
2025	9.01	7.75	7.89	7.25		
2026	9.13	7.86	8.00	7.35		
2027	9.26	7.96	8.11	7.45		

AECO		113%	113%	110%	93%	92%	93%	94%	94%	95%	96%	101%	106%
		January	February	March	April	May	June	July	August	September	October	November	December
2008	7.74	8.75	8.74	8.52	7.22	7.10	7.17	7.24	7.29	7.33	7.42	7.82	8.22
2009	7.46	8.44	8.43	8.21	6.96	6.85	6.91	6.98	7.03	7.07	7.16	7.54	7.93
2010	7.11	8.05	8.03	7.83	6.64	6.53	6.59	6.66	6.71	6.74	6.82	7.19	7.56
2011	7.11	8.05	8.03	7.83	6.64	6.53	6.59	6.66	6.71	6.74	6.82	7.19	7.56
2012	7.11	8.05	8.03	7.83	6.64	6.53	6.59	6.66	6.71	6.74	6.82	7.19	7.56
2013	7.11	8.05	8.03	7.83	6.64	6.53	6.59	6.66	6.71	6.74	6.82	7.19	7.56
2014	7.11	8.05	8.03	7.83	6.64	6.53	6.59	6.66	6.71	6.74	6.82	7.19	7.56
2015	7.11	8.05	8.03	7.83	6.64	6.53	6.59	6.66	6.71	6.74	6.82	7.19	7.56
2016	7.11	8.05	8.03	7.83	6.64	6.53	6.59	6.66	6.71	6.74	6.82	7.19	7.56
2017	7.11	8.05	8.03	7.83	6.64	6.53	6.59	6.66	6.71	6.74	6.82	7.19	7.56
2018	7.11	8.05	8.03	7.83	6.64	6.53	6.59	6.66	6.71	6.74	6.82	7.19	7.56
2019	7.11	8.05	8.03	7.83	6.64	6.53	6.59	6.66	6.71	6.74	6.82	7.19	7.56
2020	7.11	8.05	8.03	7.83	6.64	6.53	6.59	6.66	6.71	6.74	6.82	7.19	7.56
2021	7.24	8.19	8.17	7.97	6.75	6.64	6.71	6.77	6.82	6.86	6.94	7.32	7.69
2022	7.36	8.33	8.31	8.10	6.87	6.75	6.82	6.89	6.94	6.97	7.06	7.44	7.82
2023	7.48	8.47	8.45	8.24	6.98	6.87	6.93	7.01	7.06	7.09	7.18	7.57	7.95
2024	7.62	8.62	8.60	8.39	7.10	6.99	7.06	7.13	7.18	7.22	7.30	7.70	8.09
2025	7.75	8.77	8.75	8.53	7.23	7.11	7.18	7.25	7.31	7.34	7.43	7.84	8.24
2026	7.86	8.89	8.87	8.65	7.33	7.21	7.28	7.35	7.41	7.45	7.53	7.94	8.35
2027	7.96	9.01	8.99	8.77	7.43	7.31	7.38	7.45	7.51	7.55	7.64		

Appendix 6.1
High Price Case

Sumas

		113%	113%	110%	93%	92%	93%	94%	94%	95%	96%	101%	106%
		January	February	March	April	May	June	July	August	September	October	November	December
2008	7.88	8.92	8.90	8.68	7.35	7.23	7.30	7.38	7.43	7.47	7.56	7.97	8.38
2009	7.60	8.60	8.58	8.37	7.09	6.97	7.04	7.11	7.17	7.20	7.29	7.69	8.08
2010	7.25	8.20	8.18	7.98	6.76	6.65	6.71	6.78	6.83	6.87	6.95	7.33	7.70
2011	7.25	8.20	8.18	7.98	6.76	6.65	6.71	6.78	6.83	6.87	6.95	7.33	7.70
2012	7.25	8.20	8.18	7.98	6.76	6.65	6.71	6.78	6.83	6.87	6.95	7.33	7.70
2013	7.25	8.20	8.18	7.98	6.76	6.65	6.71	6.78	6.83	6.87	6.95	7.33	7.70
2014	7.25	8.20	8.18	7.98	6.76	6.65	6.71	6.78	6.83	6.87	6.95	7.33	7.70
2015	7.25	8.20	8.18	7.98	6.76	6.65	6.71	6.78	6.83	6.87	6.95	7.33	7.70
2016	7.25	8.20	8.18	7.98	6.76	6.65	6.71	6.78	6.83	6.87	6.95	7.33	7.70
2017	7.25	8.20	8.18	7.98	6.76	6.65	6.71	6.78	6.83	6.87	6.95	7.33	7.70
2018	7.25	8.20	8.18	7.98	6.76	6.65	6.71	6.78	6.83	6.87	6.95	7.33	7.70
2019	7.25	8.20	8.18	7.98	6.76	6.65	6.71	6.78	6.83	6.87	6.95	7.33	7.70
2020	7.25	8.20	8.18	7.98	6.76	6.65	6.71	6.78	6.83	6.87	6.95	7.33	7.70
2021	7.37	8.34	8.33	8.12	6.88	6.77	6.83	6.90	6.95	6.99	7.07	7.46	7.83
2022	7.50	8.48	8.47	8.25	6.99	6.88	6.95	7.02	7.07	7.10	7.19	7.58	7.97
2023	7.62	8.63	8.61	8.40	7.11	7.00	7.06	7.14	7.19	7.23	7.31	7.71	8.10
2024	7.76	8.78	8.76	8.54	7.24	7.12	7.19	7.26	7.31	7.35	7.44	7.85	8.24
2025	7.89	8.93	8.91	8.69	7.36	7.24	7.31	7.39	7.44	7.48	7.57	7.98	8.39
2026	8.00	9.05	9.04	8.81	7.46	7.34	7.41	7.49	7.55	7.58	7.67	8.09	8.50
2027	8.11	9.18	9.16	8.93	7.57	7.44	7.52	7.59	7.65	7.69	7.78		

Rockies

		113%	113%	110%	93%	92%	93%	94%	94%	95%	96%	101%	106%
		January	February	March	April	May	June	July	August	September	October	November	December
2008	7.24	8.19	8.18	7.97	6.76	6.65	6.71	6.78	6.83	6.86	6.95	7.32	7.70
2009	6.98	7.90	7.89	7.69	6.51	6.41	6.47	6.54	6.58	6.62	6.70	7.06	7.42
2010	6.66	7.53	7.52	7.33	6.21	6.11	6.17	6.23	6.28	6.31	6.39	6.73	7.08
2011	6.66	7.53	7.52	7.33	6.21	6.11	6.17	6.23	6.28	6.31	6.39	6.73	7.08
2012	6.66	7.53	7.52	7.33	6.21	6.11	6.17	6.23	6.28	6.31	6.39	6.73	7.08
2013	6.66	7.53	7.52	7.33	6.21	6.11	6.17	6.23	6.28	6.31	6.39	6.73	7.08
2014	6.66	7.53	7.52	7.33	6.21	6.11	6.17	6.23	6.28	6.31	6.39	6.73	7.08
2015	6.66	7.53	7.52	7.33	6.21	6.11	6.17	6.23	6.28	6.31	6.39	6.73	7.08
2016	6.66	7.53	7.52	7.33	6.21	6.11	6.17	6.23	6.28	6.31	6.39	6.73	7.08
2017	6.66	7.53	7.52	7.33	6.21	6.11	6.17	6.23	6.28	6.31	6.39	6.73	7.08
2018	6.66	7.53	7.52	7.33	6.21	6.11	6.17	6.23	6.28	6.31	6.39	6.73	7.08
2019	6.66	7.53	7.52	7.33	6.21	6.11	6.17	6.23	6.28	6.31	6.39	6.73	7.08
2020	6.66	7.53	7.52	7.33	6.21	6.11	6.17	6.23	6.28	6.31	6.39	6.73	7.08
2021	6.77	7.66	7.65	7.46	6.32	6.22	6.28	6.34	6.39	6.42	6.50	6.85	7.20
2022	6.89	7.79	7.78	7.59	6.43	6.32	6.38	6.45	6.50	6.53	6.61	6.97	7.32
2023	7.01	7.93	7.91	7.71	6.54	6.43	6.49	6.56	6.61	6.64	6.72	7.09	7.45
2024	7.13	8.06	8.05	7.85	6.65	6.54	6.60	6.67	6.72	6.76	6.84	7.21	7.58
2025	7.25	8.21	8.19	7.99	6.77	6.66	6.72	6.79	6.84	6.87	6.96	7.34	7.71
2026	7.35	8.32	8.31	8.10	6.86	6.75	6.81	6.88	6.93	6.97	7.05	7.44	7.82
2027	7.45	8.43	8.42	8.21	6.95	6.84	6.91	6.98	7.03	7.06	7.15		

Appendix 6.1
Low Price Case
Real 2007$

	Nymex	AECo	Sumas	Rockies
		86.0%	87.6%	80.5%
2008	8.07	6.94	7.07	6.50
2009	7.01	6.03	6.14	5.65
2010	6.60	5.68	5.78	5.31
2011	6.25	5.38	5.48	5.03
2012	6.11	5.25	5.35	4.92
2013	5.96	5.12	5.22	4.80
2014	5.98	5.14	5.24	4.81
2015	5.97	5.13	5.23	4.80
2016	6.09	5.24	5.34	4.90
2017	6.28	5.40	5.50	5.06
2018	6.34	5.46	5.56	5.11
2019	6.42	5.52	5.62	5.17
2020	6.55	5.63	5.73	5.27
2021	6.62	5.70	5.80	5.33
2022	6.76	5.81	5.92	5.44
2023	6.89	5.93	6.04	5.55
2024	7.04	6.06	6.17	5.67
2025	7.11	6.11	6.22	5.72
2026	7.19	6.18	6.30	5.79
2027	7.29	6.27	6.38	5.87

Seasonal Shape	
January	113%
February	113%
March	110%
April	93%
May	92%
June	93%
July	94%
August	94%
September	95%
October	96%
November	101%
December	106%

AECO		January	February	March	April	May	June	July	August	September	October	November	December
		113%	113%	110%	93%	92%	93%	94%	94%	95%	96%	101%	106%
2008	6.94	7.85	7.84	7.64	6.48	6.37	6.43	6.50	6.55	6.58	6.66	7.02	7.38
2009	6.03	6.82	6.81	6.64	5.63	5.54	5.59	5.65	5.69	5.72	5.79	6.10	6.41
2010	5.68	6.42	6.41	6.25	5.30	5.21	5.26	5.31	5.35	5.38	5.44	5.74	6.03
2011	5.38	6.08	6.07	5.92	5.02	4.94	4.98	5.03	5.07	5.10	5.16	5.44	5.72
2012	5.25	5.94	5.93	5.78	4.90	4.82	4.87	4.92	4.95	4.98	5.04	5.31	5.58
2013	5.12	5.80	5.79	5.64	4.78	4.70	4.75	4.80	4.83	4.86	4.91	5.18	5.45
2014	5.14	5.82	5.81	5.66	4.80	4.72	4.77	4.81	4.85	4.88	4.93	5.20	5.47
2015	5.13	5.81	5.80	5.65	4.79	4.71	4.76	4.80	4.84	4.86	4.92	5.19	5.46
2016	5.24	5.93	5.92	5.77	4.89	4.81	4.85	4.90	4.94	4.96	5.02	5.30	5.57
2017	5.40	6.11	6.10	5.95	5.04	4.96	5.01	5.06	5.10	5.12	5.18	5.47	5.74
2018	5.46	6.17	6.16	6.01	5.09	5.01	5.06	5.11	5.14	5.17	5.23	5.52	5.80
2019	5.52	6.25	6.24	6.08	5.15	5.07	5.12	5.17	5.21	5.23	5.30	5.58	5.87
2020	5.63	6.37	6.36	6.20	5.25	5.17	5.22	5.27	5.31	5.34	5.40	5.69	5.98
2021	5.70	6.45	6.44	6.27	5.32	5.23	5.28	5.33	5.37	5.40	5.46	5.76	6.06
2022	5.81	6.58	6.57	6.40	5.42	5.34	5.39	5.44	5.48	5.51	5.58	5.88	6.18
2023	5.93	6.71	6.70	6.53	5.53	5.44	5.49	5.55	5.59	5.62	5.69	6.00	6.30
2024	6.06	6.85	6.84	6.67	5.65	5.56	5.61	5.67	5.71	5.74	5.81	6.13	6.44
2025	6.11	6.91	6.90	6.73	5.70	5.61	5.66	5.72	5.76	5.79	5.86	6.18	6.50
2026	6.18	6.99	6.98	6.81	5.77	5.67	5.73	5.79	5.83	5.86	5.93	6.25	6.57
2027	6.27	7.09	7.08	6.90	5.85	5.75	5.81	5.87	5.91	5.94	6.01		

Appendix 6.1
Low Price Case

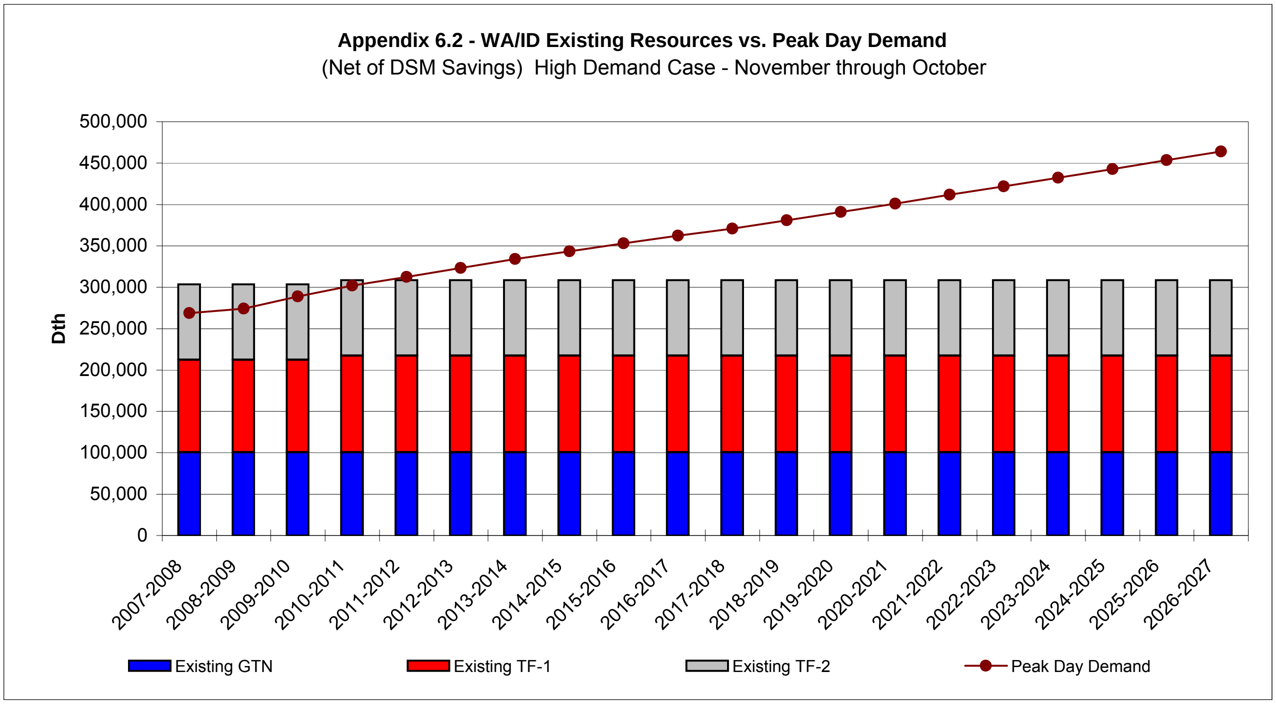
Sumas		113%	113%	110%	93%	92%	93%	94%	94%	95%	96%	101%	106%
		January	February	March	April	May	June	July	August	September	October	November	December
2008	7.07	8.00	7.99	7.79	6.60	6.49	6.55	6.62	6.67	6.70	6.78	7.15	7.51
2009	6.14	6.95	6.94	6.77	5.73	5.64	5.69	5.75	5.79	5.82	5.89	6.21	6.53
2010	5.78	6.54	6.53	6.37	5.39	5.31	5.36	5.41	5.45	5.48	5.55	5.85	6.15
2011	5.48	6.20	6.19	6.03	5.11	5.03	5.08	5.13	5.17	5.19	5.25	5.54	5.82
2012	5.35	6.05	6.04	5.89	4.99	4.91	4.96	5.01	5.04	5.07	5.13	5.41	5.69
2013	5.22	5.90	5.89	5.75	4.87	4.79	4.84	4.88	4.92	4.95	5.01	5.28	5.55
2014	5.24	5.93	5.92	5.77	4.89	4.81	4.85	4.90	4.94	4.97	5.03	5.30	5.57
2015	5.23	5.92	5.91	5.76	4.88	4.80	4.84	4.89	4.93	4.96	5.01	5.29	5.56
2016	5.34	6.04	6.03	5.88	4.98	4.90	4.94	4.99	5.03	5.06	5.12	5.40	5.67
2017	5.50	6.23	6.22	6.06	5.14	5.05	5.10	5.15	5.19	5.22	5.28	5.57	5.85
2018	5.56	6.29	6.28	6.12	5.18	5.10	5.15	5.20	5.24	5.27	5.33	5.62	5.91
2019	5.62	6.36	6.35	6.19	5.25	5.16	5.21	5.26	5.30	5.33	5.39	5.69	5.98
2020	5.73	6.49	6.48	6.32	5.35	5.26	5.31	5.37	5.41	5.44	5.50	5.80	6.10
2021	5.80	6.57	6.56	6.39	5.41	5.33	5.38	5.43	5.47	5.50	5.57	5.87	6.17
2022	5.92	6.70	6.69	6.52	5.53	5.44	5.49	5.54	5.58	5.61	5.68	5.99	6.29
2023	6.04	6.83	6.82	6.65	5.63	5.54	5.60	5.65	5.69	5.72	5.79	6.11	6.42
2024	6.17	6.98	6.97	6.79	5.76	5.66	5.72	5.77	5.82	5.85	5.92	6.24	6.56
2025	6.22	7.04	7.03	6.85	5.81	5.71	5.77	5.83	5.87	5.90	5.97	6.30	6.62
2026	6.30	7.12	7.11	6.93	5.87	5.78	5.83	5.89	5.94	5.97	6.04	6.37	6.69
2027	6.38	7.22	7.21	7.03	5.96	5.86	5.92	5.98	6.02	6.05	6.12		

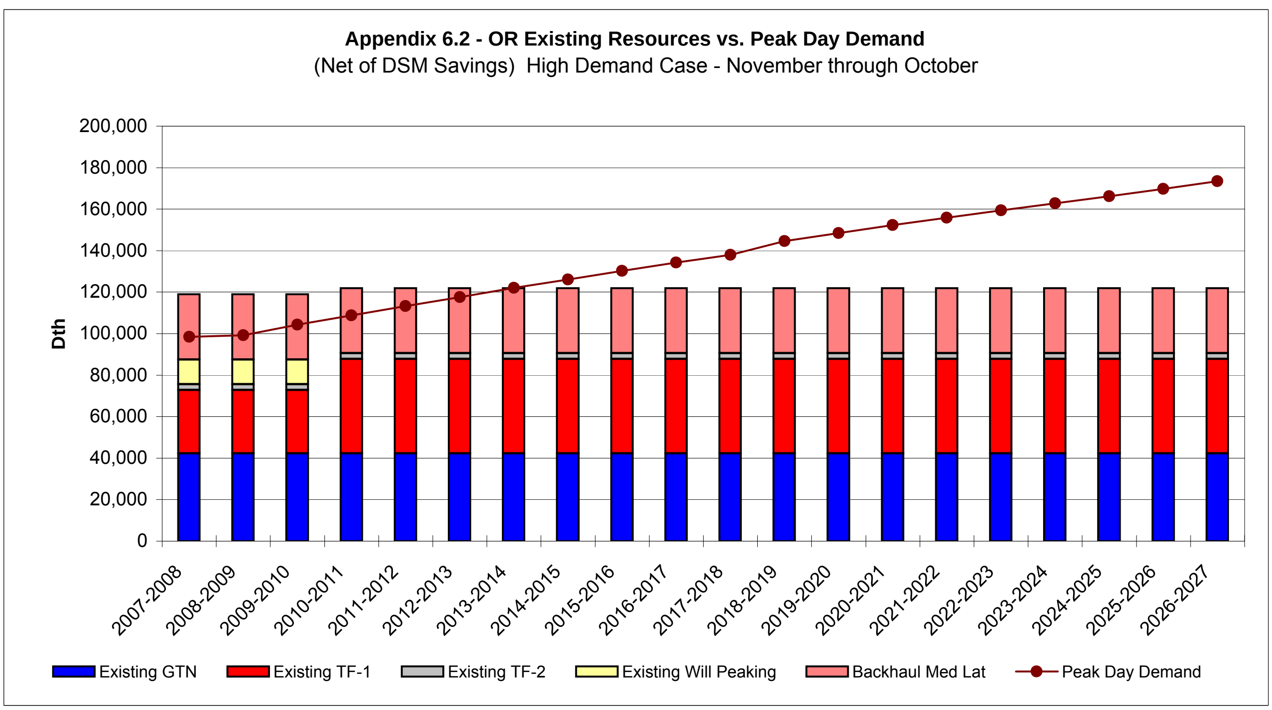
Rockies		113%	113%	110%	93%	92%	93%	94%	94%	95%	96%	101%	106%
		January	February	March	April	May	June	July	August	September	October	November	December
2008	6.50	7.35	7.34	7.15	6.06	5.96	6.02	6.08	6.13	6.16	6.23	6.57	6.91
2009	5.65	6.39	6.38	6.22	5.27	5.18	5.23	5.28	5.32	5.35	5.42	5.71	6.00
2010	5.31	6.01	6.00	5.85	4.96	4.88	4.92	4.97	5.01	5.04	5.10	5.37	5.65
2011	5.03	5.70	5.69	5.54	4.70	4.62	4.66	4.71	4.75	4.77	4.83	5.09	5.35
2012	4.92	5.56	5.55	5.41	4.59	4.51	4.55	4.60	4.64	4.66	4.71	4.97	5.22
2013	4.80	5.43	5.42	5.28	4.47	4.40	4.44	4.49	4.52	4.55	4.60	4.85	5.10
2014	4.81	5.45	5.44	5.30	4.49	4.42	4.46	4.51	4.54	4.56	4.62	4.87	5.12
2015	4.80	5.44	5.43	5.29	4.48	4.41	4.45	4.50	4.53	4.55	4.61	4.86	5.11
2016	4.90	5.55	5.54	5.40	4.57	4.50	4.54	4.59	4.62	4.65	4.70	4.96	5.21
2017	5.06	5.72	5.71	5.57	4.72	4.64	4.69	4.73	4.77	4.79	4.85	5.12	5.38
2018	5.11	5.78	5.77	5.62	4.76	4.69	4.73	4.78	4.82	4.84	4.90	5.17	5.43
2019	5.17	5.85	5.84	5.69	4.82	4.74	4.79	4.84	4.87	4.90	4.96	5.23	5.49
2020	5.27	5.96	5.95	5.80	4.92	4.84	4.88	4.93	4.97	5.00	5.05	5.33	5.60
2021	5.33	6.03	6.02	5.87	4.98	4.90	4.94	4.99	5.03	5.05	5.12	5.39	5.67
2022	5.44	6.16	6.15	5.99	5.08	5.00	5.04	5.09	5.13	5.16	5.22	5.50	5.78
2023	5.55	6.28	6.27	6.11	5.18	5.09	5.14	5.19	5.23	5.26	5.32	5.61	5.90
2024	5.67	6.41	6.40	6.24	5.29	5.20	5.25	5.31	5.35	5.37	5.44	5.73	6.03
2025	5.72	6.47	6.46	6.30	5.34	5.25	5.30	5.35	5.39	5.42	5.49	5.79	6.08
2026	5.79	6.55	6.54	6.37	5.40	5.31	5.36	5.42	5.46	5.48	5.55	5.85	6.15
2027	5.87	6.64	6.63	6.46	5.47	5.39	5.44	5.49	5.53	5.56	5.63		

Existing Resource Comparisons

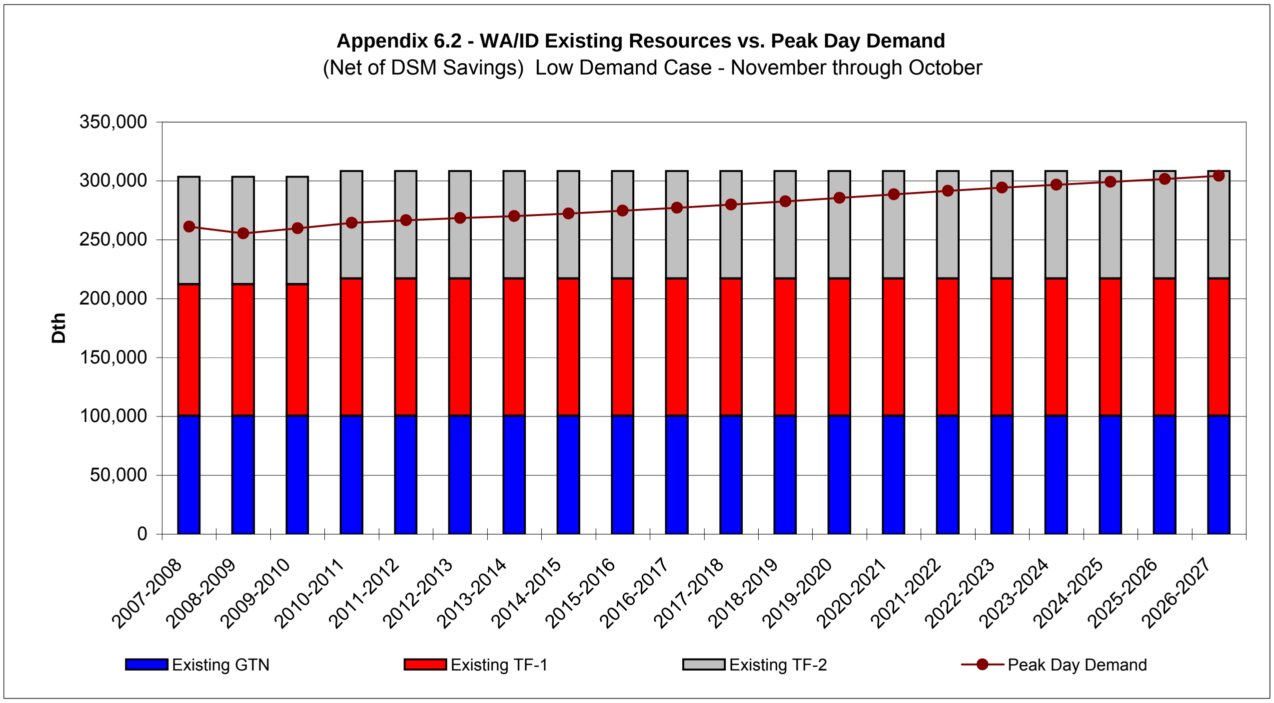
Appendix 6.2

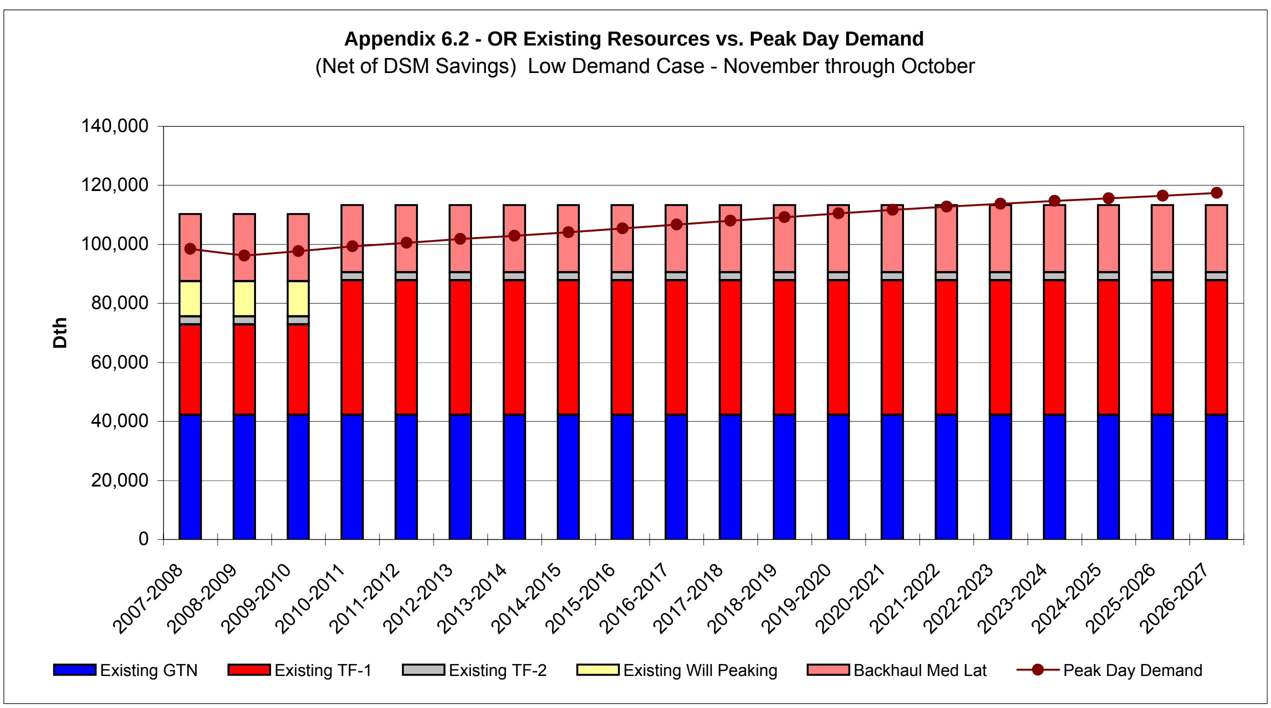
EXISTING RESOURCES





EXISTING RESOURCES





Served and Unserved Demand

Appendix 6.3

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

Before Resource Additions & Net of DSM Savings

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	WA/ID Served	WA/ID Unserved	WA/ID Total
High	2007-2008	9.86	-	9.86	268.89	-	268.89
High	2008-2009	9.84	-	9.84	274.08	-	274.08
High	2009-2010	10.15	-	10.15	288.99	-	288.99
High	2010-2011	10.25	0.12	10.37	302.02	-	302.02
High	2011-2012	10.25	0.35	10.60	307.42	5.08	312.50
High	2012-2013	10.25	0.55	10.81	307.52	15.85	323.37
High	2013-2014	10.25	0.75	11.00	307.67	26.28	333.95
High	2014-2015	10.25	0.96	11.21	307.63	35.82	343.45
High	2015-2016	10.25	1.18	11.43	307.23	45.98	353.21
High	2016-2017	10.25	1.34	11.59	305.66	56.53	362.19
High	2017-2018	10.25	1.48	11.74	302.65	68.27	370.91
High	2018-2019	10.25	1.63	11.88	301.21	79.62	380.83
High	2019-2020	10.25	1.80	12.05	299.82	91.08	390.91
High	2020-2021	10.25	1.93	12.18	298.64	102.42	401.06
High	2021-2022	10.25	2.07	12.32	297.43	114.37	411.80
High	2022-2023	10.25	2.18	12.44	296.29	125.77	422.06
High	2023-2024	10.25	2.29	12.55	295.18	137.33	432.51
High	2024-2025	10.25	2.40	12.65	295.99	146.68	442.67
High	2025-2026	10.25	2.51	12.76	296.85	156.57	453.43
High	2026-2027	10.25	2.63	12.88	297.70	166.35	464.05

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total
High	2007-2008	13.89	-	13.89	74.72	-	74.72
High	2008-2009	14.09	-	14.09	75.36	-	75.36
High	2009-2010	14.80	-	14.80	79.39	-	79.39
High	2010-2011	15.03	0.38	15.41	83.01	-	83.01
High	2011-2012	15.03	1.03	16.06	86.65	-	86.65
High	2012-2013	15.03	1.58	16.61	87.24	2.98	90.22
High	2013-2014	15.03	2.11	17.14	87.24	6.73	93.97
High	2014-2015	15.03	2.59	17.63	87.24	10.04	97.28
High	2015-2016	15.03	3.11	18.14	87.24	13.44	100.68
High	2016-2017	15.03	3.59	18.62	87.24	16.73	103.97
High	2017-2018	15.03	4.04	19.08	87.24	19.95	107.19
High	2018-2019	15.03	4.52	19.55	87.24	25.96	113.20
High	2019-2020	15.03	4.98	20.02	87.24	29.20	116.44
High	2020-2021	15.03	5.44	20.48	87.24	32.36	119.60
High	2021-2022	15.03	5.88	20.91	87.24	35.44	122.68
High	2022-2023	15.03	6.32	21.36	87.24	38.39	125.63
High	2023-2024	15.03	6.75	21.78	87.24	41.30	128.54
High	2024-2025	15.03	7.16	22.19	87.24	44.09	131.33
High	2025-2026	15.03	7.63	22.66	87.24	47.15	134.39
High	2026-2027	15.03	8.10	23.13	87.24	50.13	137.37

Appendix 6.3 - Peak Day Demand - Served and Unserved (MDth/d)
Before Resource Additions & Net of DSM Savings

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	WA/ID Served	WA/ID Unserved	WA/ID Total
Low	2007-2008	9.69	-	9.69	261.11	-	261.11
Low	2008-2009	9.41	-	9.41	255.47	-	255.47
Low	2009-2010	9.49	-	9.49	259.69	-	259.69
Low	2010-2011	9.58	-	9.58	264.33	-	264.33
Low	2011-2012	9.62	-	9.62	266.56	-	266.56
Low	2012-2013	9.68	-	9.68	268.38	-	268.38
Low	2013-2014	9.72	-	9.72	270.22	-	270.22
Low	2014-2015	9.77	-	9.77	272.22	-	272.22
Low	2015-2016	9.83	-	9.83	274.67	-	274.67
Low	2016-2017	9.89	-	9.89	277.13	-	277.13
Low	2017-2018	9.94	-	9.94	279.87	-	279.87
Low	2018-2019	9.99	-	9.99	282.66	-	282.66
Low	2019-2020	10.04	-	10.04	285.59	-	285.59
Low	2020-2021	10.08	-	10.08	288.60	-	288.60
Low	2021-2022	10.13	-	10.13	291.69	-	291.69
Low	2022-2023	10.15	-	10.15	294.23	-	294.23
Low	2023-2024	10.16	-	10.16	296.74	-	296.74
Low	2024-2025	10.18	-	10.18	299.27	-	299.27
Low	2025-2026	10.19	-	10.19	301.72	-	301.72
Low	2026-2027	10.21	-	10.21	304.39	-	304.39

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total
Low	2007-2008	13.70	-	13.70	75.11	-	75.11
Low	2008-2009	13.37	-	13.37	73.44	-	73.44
Low	2009-2010	13.57	-	13.57	74.64	-	74.64
Low	2010-2011	13.80	-	13.80	75.98	-	75.98
Low	2011-2012	13.96	-	13.96	76.94	-	76.94
Low	2012-2013	14.10	-	14.10	78.00	-	78.00
Low	2013-2014	14.24	-	14.24	78.99	-	78.99
Low	2014-2015	14.38	-	14.38	79.98	-	79.98
Low	2015-2016	14.53	-	14.53	81.03	-	81.03
Low	2016-2017	14.68	-	14.68	82.14	-	82.14
Low	2017-2018	14.84	-	14.84	83.23	-	83.23
Low	2018-2019	14.98	-	14.98	84.27	-	84.27
Low	2019-2020	15.03	0.07	15.11	85.31	-	85.31
Low	2020-2021	15.03	0.22	15.25	86.36	-	86.36
Low	2021-2022	15.03	0.36	15.39	87.24	0.07	87.31
Low	2022-2023	15.03	0.47	15.50	87.24	0.87	88.11
Low	2023-2024	15.03	0.57	15.61	87.24	1.68	88.92
Low	2024-2025	15.03	0.68	15.71	87.24	2.44	89.68
Low	2025-2026	15.03	0.80	15.83	87.24	3.21	90.45
Low	2026-2027	15.03	0.91	15.94	87.24	4.03	91.27

Supply-Side Resources

Appendix 6.4

Appendix 6.4 - Supply-Side Resources

Potential Additional Supply Resources

Facility/Location	Annual (Dth)	Daily (Dth) Delivery	Year Avail. 3/	Lead Time	Investment Cost $ (000's)	Variable Cost $ (000's)	Availability
WA/ID							
AECO Supply	Varies	Varies	1	<1 year	n/a	Commodity	Daily
Sumas/Station 2	Varies	Varies	1	<1 year	n/a	Commodity	Daily
Rockies	Varies	Varies	1	<1 year	n/a	Commodity	Daily
WA/ID Satellite LNG #1	25,000	5,000	10	7 years	7,000	Commodity + $1.0MM/yr	Peaking
WA/ID Satellite LNG #2	50,000	10,000	10	7 years	12,000	Commodity + $1.0MM/yr	Peaking
Oregon							
AECO Supply	Varies	Varies	1	<1 year	n/a	Commodity	Daily
Sumas/Station 2 Supply	Varies	Varies	1	<1 year	n/a	Commodity	Daily
Rockies Supply	Varies	Varies	1	<1 year	n/a	Commodity	Daily
Malin Supply	Varies	Varies	1	<1 year	n/a	Commodity	Daily
KFalls Lateral Purchase 2/	0	0	1	<1 year	3,000	none	n/a
KFalls Lateral Enhancement 2/	2,190,000	6,000	1	<1 year	0	Commodity	Annual
La Grande Dist. Enhance. #1	1,460,000	4,000	3	2 years	3,000	Commodity	Annual
Medford Satellite LNG #1	90,000	15,000	5	7 years	14,000	Commodity + $1.5MM/yr	Peaking
Medford Satellite LNG #2	90,000	15,000	10	7 years	14,000	Commodity + $1.5MM/yr	Peaking
California Storage 3/	1,000,000	10,000		<1 year	$2.00 per Dth Inventory	n/a	Peaking
California Storage 3/	1,000,000	10,000		<1 year	$2.00 per Dth Inventory	n/a	Peaking
Roseburg Satellite LNG	90,000	15,000	10	7 years	14,000	Commodity + $1.0MM/yr	Peaking
Klamath Falls Satellite LNG	25,000	5,000	5	7 years	7,000	Commodity + $1.0MM/yr	Peaking
Med. Company Owned LNG	n/a	n/a	n/a	n/a	n/a	n/a	Peaking

1/ Utilizes Malin supply
2/ This column is intended to indicate the first year in which the resource is available. The resource is assumed to be available in each subsequent year
3/ Requires redelivery service via backhauls

Appendix 6.4 - Supply-Side Resources

Potential Contract Demand Expansions/Additions

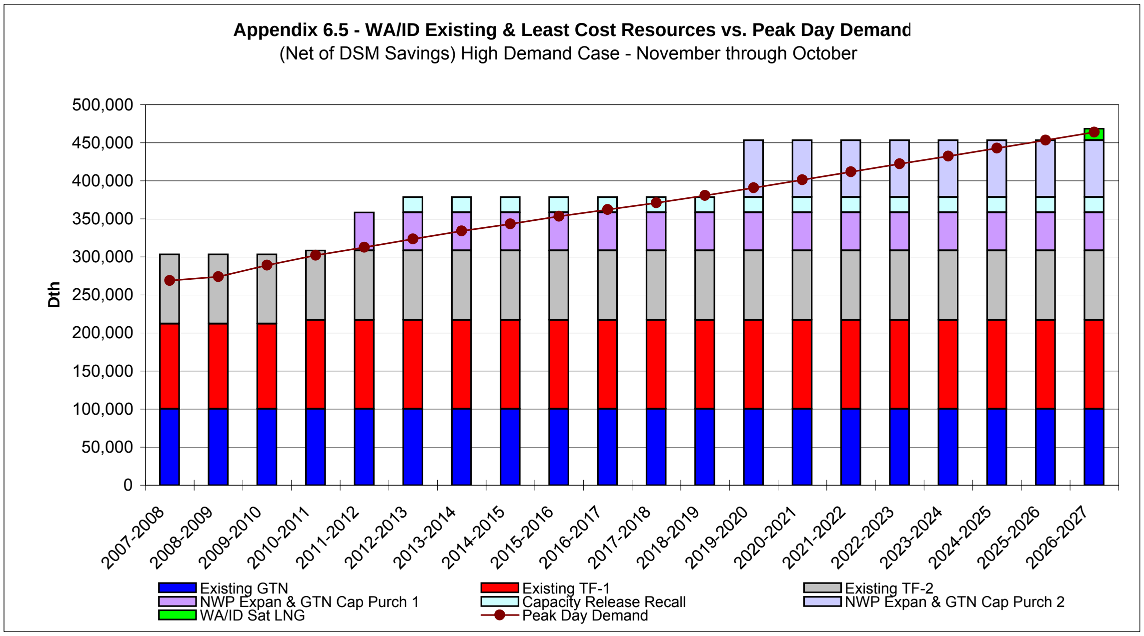
Location	Pipeline/ Facility	Identification	Daily (Dth) Capacity	Year 3/ Available	Lead Time	Capital Cost $ (000's)	Cost Dth 4/	Notes
WA/ID								
NWP Capacity for WA/ID	NWP	NWP Capacity Relesase Recalls	17,000	4	1 year	n/a	NWP Rate	Recall long-term capacity releases - 2012
NWP Zone 20 Spokane Area	NWP	NWP from GTN #1	25,000	4	3 years	4,000	NWP Rate	Expansion to facilitate additional GTN deliveries
NWP Zone 20 Spokane Area	NWP	NWP from GTN #2	25,000	8	3 years	4,300	NWP Rate	Expansion to facilitate additional GTN deliveries
NWP Zone 20 Spokane Area	NWP	NWP from GTN #3	25,000	12	3 years	4,600	NWP Rate	Expansion to facilitate additional GTN deliveries
NWP Zone 20 Spokane Area	NWP	NWP from GTN #4	50,000	4	3 years	8,000	NWP Rate	Expansion to facilitate additional GTN deliveries
NWP Zone 20 Spokane Area	NWP	NWP from GTN #5	75,000	8	3 years	12,000	NWP Rate	Expansion to facilitate additional GTN deliveries
NWP Zone 20 Spokane Area	NWP	NWP from GTN #6	40,000	12	3 years	6,500	NWP Rate	Expansion to facilitate additional GTN deliveries
TransCanada AECO to WA/ID	TC/GTN	AECo to Spokane #1	25,000	1	<1 year	n/a	GTN/TC Rates	Existing available capacity from AECO to Stanfield. GTN capacity assumed to be winter only.
TransCanada AECO to WA/ID	TC/GTN	AECo to Spokane #2	25,000	1	<1 year	n/a	GTN/TC Rates	Existing available capacity from AECO to Stanfield.
TransCanada AECO to WA/ID	TC/GTN	AECo to Spokane #3	25,000	1	<1 year	n/a	GTN/TC Rates	Existing available capacity from AECO to Stanfield. GTN capacity assumed to be winter only.
TransCanada AECO to WA/ID	TC/GTN	AECo to Spokane #4	50,000	1	<1 year	n/a	GTN/TC Rates	Existing available capacity from AECO to Stanfield. GTN capacity assumed to be winter only.
TransCanada AECO to WA/ID	TC/GTN	AECo to Stanfield #5	60,000	1	<1 year	n/a	GTN/TC Rates	Existing available capacity from AECO to Stanfield.
TransCanada AECO to WA/ID	TC/GTN	AECo to Stanfield #6	40,000	1	<1 year	n/a	GTN/TC Rates	Existing available capacity from AECO to Stanfield. GTN capacity assumed to be winter only.
NWP Zone 11 & 20 1/	NWP	NWP JP Transport Expansion #1	25,000	4	4 years	n/a	NWP Rate X 3.0	Transport Expansion for JP to WA/ID
NWP Zone 11 & 20 1/	NWP	NWP JP Transport Expansion #2	50,000	4	4 years	n/a	NWP Rate X 3.0	Transport Expansion for JP to WA/ID
NWP Zone 11 & 20 1/	NWP	NWP JP Transport Expansion #3	100,000	4	4 years	n/a	NWP Rate X 3.0	Transport Expansion for JP to WA/ID
NWP Zone 30,26,20 1/	NWP	NWP Sumas to WA/ID #1	20,000	5	4 years	n/a	NWP Rate X 4.0	Transport Expansion for Sumas to WA/ID
NWP Zone 30,26,20 1/	NWP	NWP Sumas to WA/ID #2	20,000	10	4 years	n/a	NWP Rate X 4.0	Transport Expansion for Sumas to WA/ID
NWP Zone 24 & 20 1/	NWP	NWP Rocks to WA/ID #1	20,000	5	4 years	n/a	NWP Rate X 4.0	Transport Expansion for Rocks to WA/ID
NWP Zone 24 & 20 1/	NWP	NWP Rocks to WA/ID #2	20,000	10	4 years	n/a	NWP Rate X 4.0	Transport Expansion for Rocks to WA/ID
Oregon								
NWP Capacity for OR	NWP	NWP Capacity Relesase Recalls	6,700	4	1 year	n/a	NWP Rate	Recall long-term capacity releases - 2012
Medford Lateral Expansion 2/ 5/	GTN	GTN Med. Lateral Expansion #1	20,000	4	3 years	n/a	Existing GTN Rate	Expansion of Medford lateral with compression. Allows NWP cap. to be redirected to Roseburg
Medford Lateral Expansion 2/ 5/	GTN	GTN Med. Lateral Expansion #1	25,000	4	3 years	n/a	Existing GTN Rate	Expansion of Medford lateral with compression. Allows NWP cap. to be redirected to Roseburg
Medford Lateral Expansion 2/ 5/	GTN	GTN Med. Lateral Expansion #2	20,000	8	3 years	n/a	Existing GTN Rate	Expansion of Medford lateral with compression. Allows NWP cap. to be redirected to Roseburg
Medford Lateral Expansion 2/ 5/	GTN	GTN Med. Lateral Expansion #2	25,000	8	3 years	n/a	Existing GTN Rate	Expansion of Medford lateral with compression. Allows NWP cap. to be redirected to Roseburg
Medford Lateral Expansion 2/ 5/	GTN	GTN Med. Lateral Expansion #3	25,000	12	3 years	n/a	Existing GTN Rate	Expansion of Medford lateral with compression. Allows NWP cap. to be redirected to Roseburg
Med. Lat. Klamath Expansion 2/	GTN	GTN Med. Lateral Expansion #4	5,000	4	3 years	n/a	Existing GTN Rate	Expansion of Medford lateral with compression. Klamath deliveries only
NWP Zone 30,26,16,12,9,8 1/	NWP	NWP Sumas to Medford Exp. #1	20,000	4	4 years	n/a	NWP Rate X 5.0	Transport Expansion for Sumas to Medford
NWP Zone 24,26,16,12,9,8 1/	NWP	NWP Rocks to Medford Exp. #1	20,000	4	4 years	n/a	NWP Rate X 5.0	Transport Expansion for Rocks to Medford
NWP Zone 26,16,12,9,8 1/	NWP	NWP JP to Medford Exp. #1	20,000	4	4 years	n/a	NWP Rate X 3.5	Transport Expansion for JP to Medford
California Storage Transport	CGT/GTN	CA Storage Backhaul #1	10,000	1	<1 year	n/a	CGT, GTN Rates	Current PG&E CGT, GTN mainline and Medford rates. Combined with CA storage above
California Storage Transport	CGT/GTN	CA Storage Backhaul #2	10,000	1	<1 year	n/a	CGT, GTN Rates	Current PG&E CGT, GTN mainline and Medford rates. Combined with CA storage above

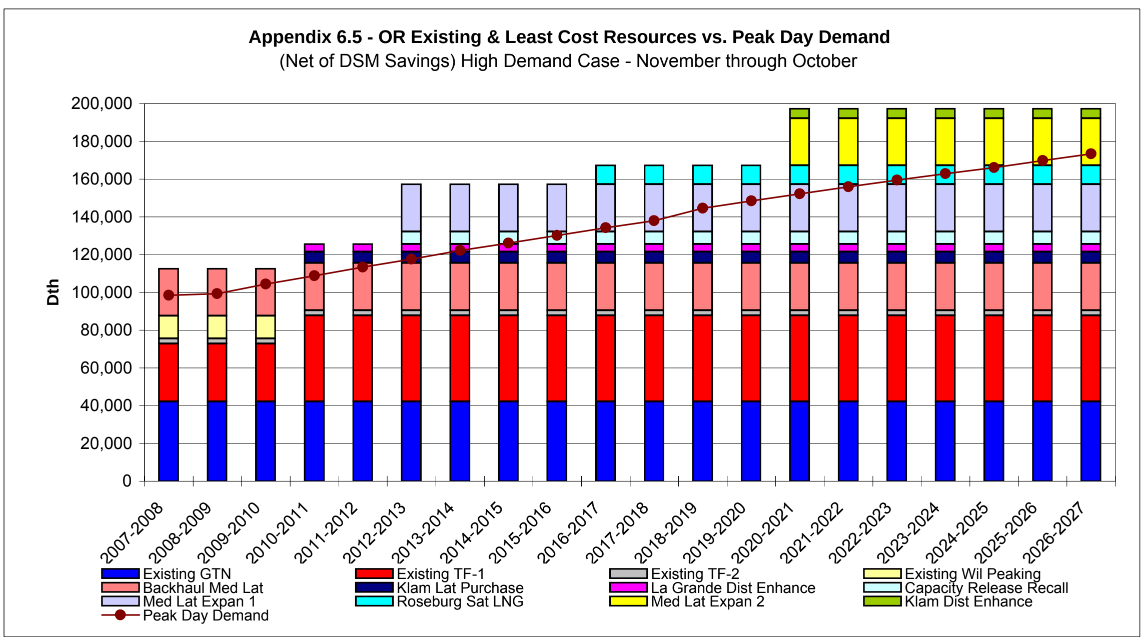
1/ Assumes additional participation in expansion by other customers
2/ Utilizes Malin supply
3/ This column is intended to indicate the first year in which the resource is available. The resource is assumed to be available in each subsequent year until utilized
4/ All existing rates escalated at inflation rate
5/ Requires a distribution system enhancement in Medford area to facilitate expansion deliveries. Avista anticipates this enhancement being completed in 2007 and is driven by Integrity Management related activity in the Medford area. The approximate capital cost of this project is $11MM and will likely be incurred whether or not a GTN Medford lateral expansion is selected by the SENDOUT model for resource additions.
6/ Transportation resources are assumed to be annual contracts. However, to the extent winter only capcity is available the company will pursue those options.

Future Resource Comparisons

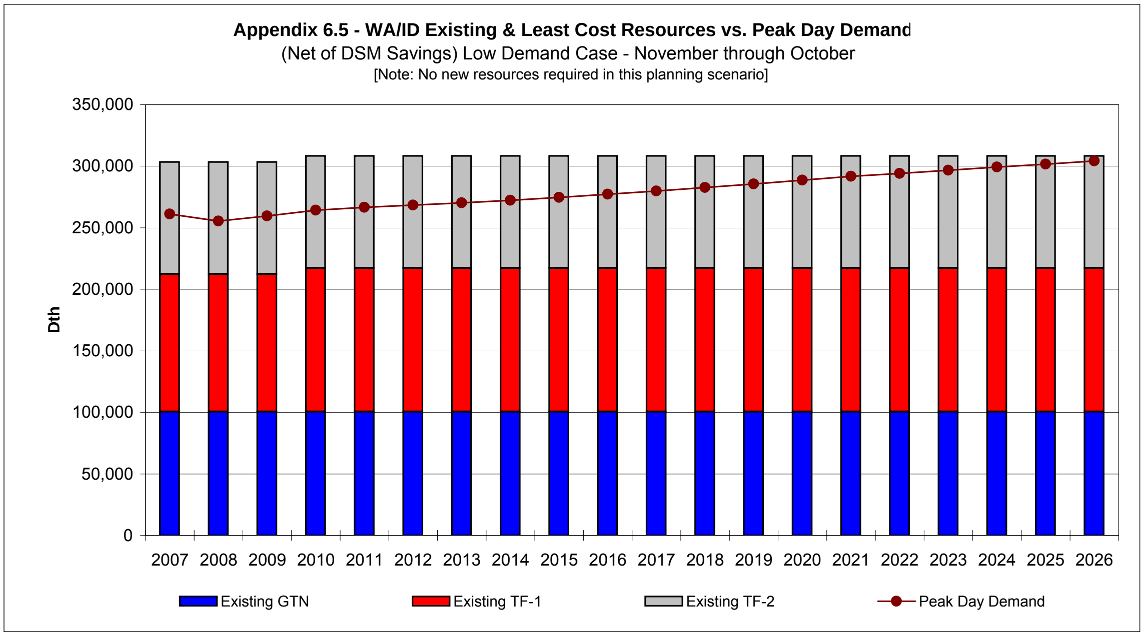
Appendix 6.5

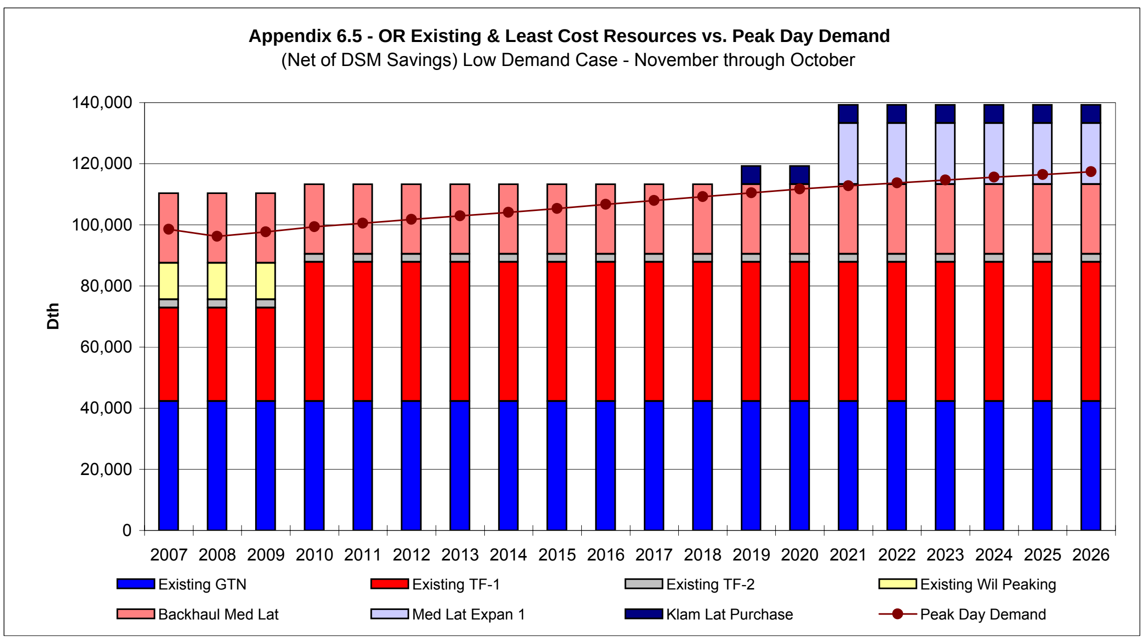
EXISTING AND LEAST COST RESOURCES





EXISTING AND LEAST COST RESOURCES

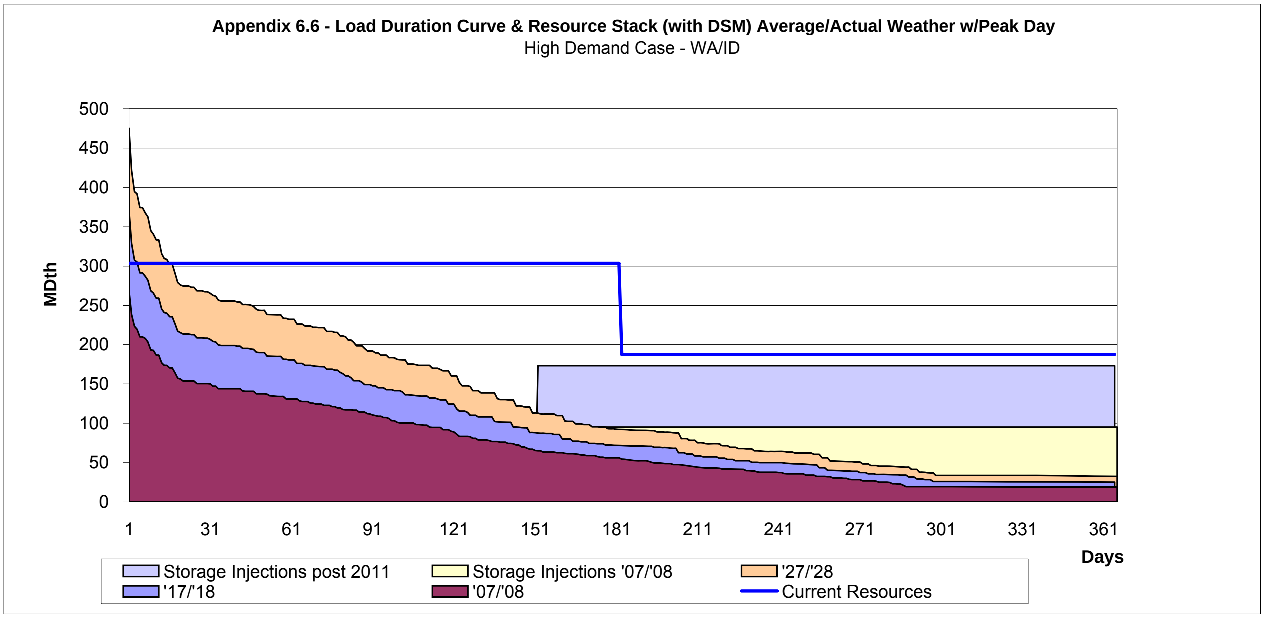


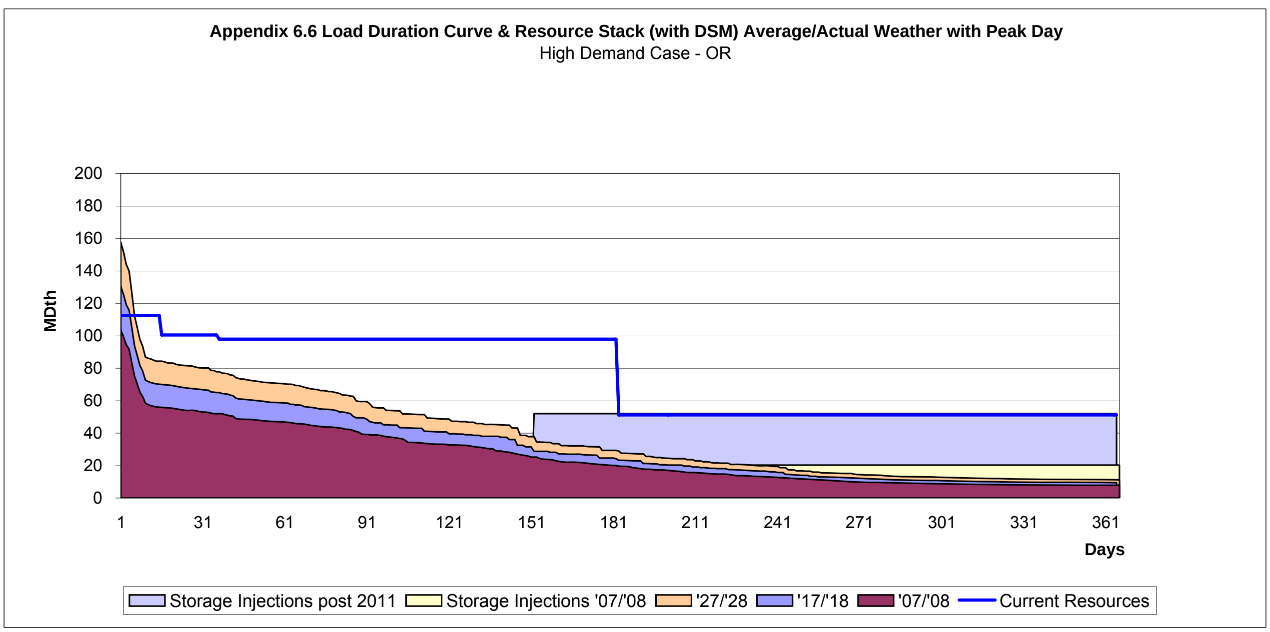


Load Duration Curves

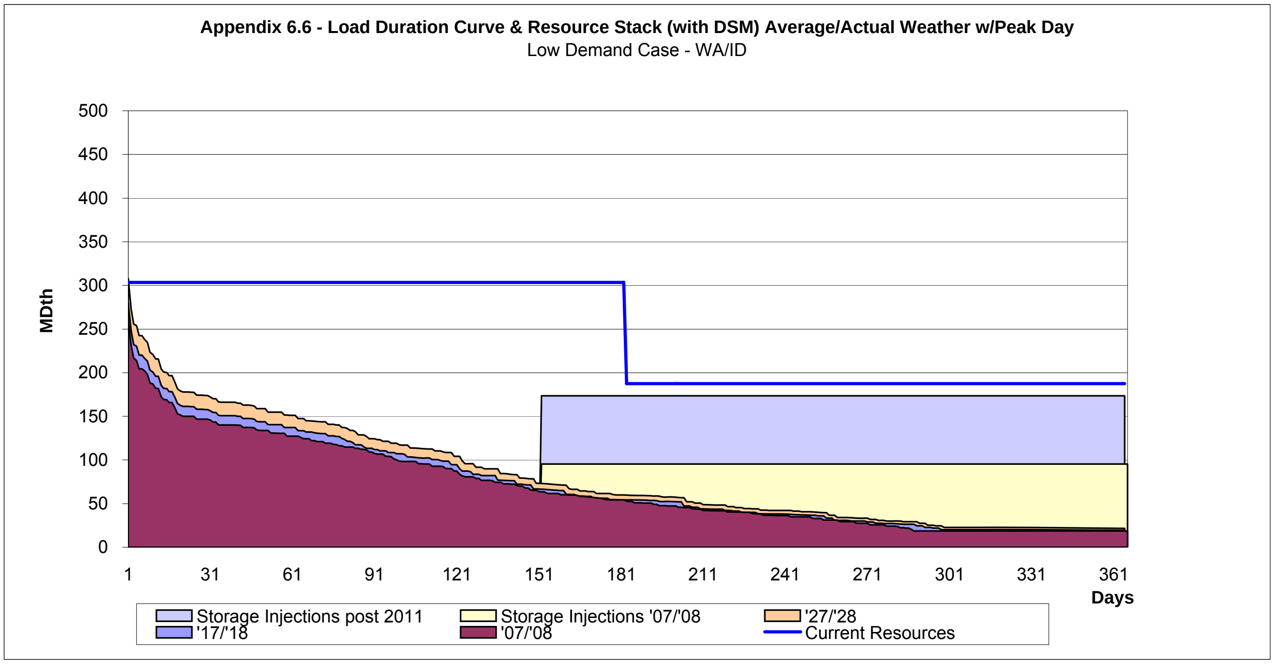
Appendix 6.6

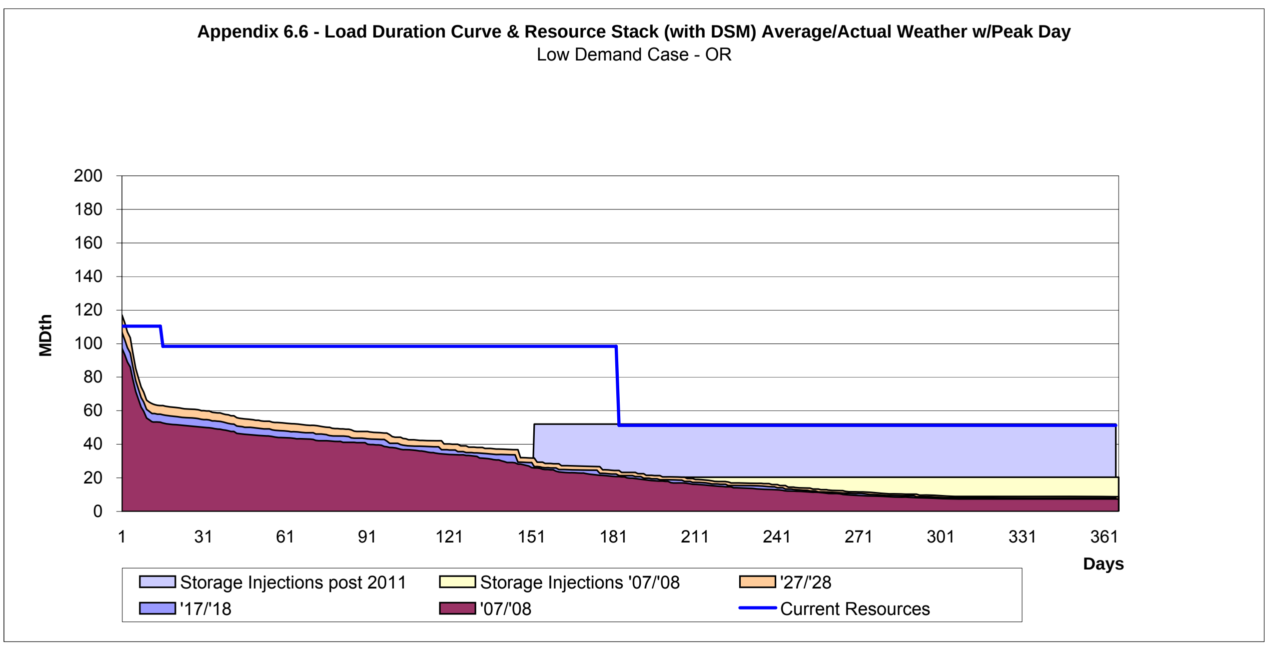
Load Duration Curves





Load Duration Curves





Resource Selections

Appendix 6.7

Appendix 6.7 - Least Cost Supply-Side Resource Additions Selected by SENDOUT®

High Demand Case

Item #	Region	Type	Quantity 2/	Timing	Rates/Charges	Description
Washington/Idaho						
1	WA/ID	Capacity Release	20,078	November 2012	NWP TF-1 Rate	Recall long-term capacity releases - 2012
2	WA/ID	Transportation	50,000 - 75,000	November 2011 & 2019	NWP Expansion Rate	WA/ID area expansions to facilitate the delivery in and around Spokane, Lewiston, etc. from GTN into NWP
3	WA/ID	Transportation	50,000	November 2011	TransCanada Rates from Alberta to Stanfield	Acquisition of existing capacity from Alberta to Stanfield on the TransCanada pipelines. Assumed current transportation rates (escalated for inflation). Assumed winter-only capacity on GTN
4	WA/ID	Transportation	75,000	November 2019	TransCanada Rates from Alberta to Stanfield	Acquisition of existing capacity from Alberta to Stanfield on the TransCanada pipelines. Assumed current transportation rates (escalated for inflation). Assumed winter-only capacity on GTN
5	WA/ID	Satelite LNG	15,000	November 2026	Commodity plus Variable	Provides for peaking services and alleviates the need for further costly pipeline construction.
Oregon						
6	OR	Capacity Release	6,700	November 2012	NWP TF-1 Rate	Recall long-term capacity releases - 2012
7	Klamath Falls	Distribution Enhancement	6,000	November 2010	n/a	Purchase of NWP Klamath pipeline segment. Purchase price is approximately $3 MM capital cost. Purchase may occur as early as 2008/2009 and the price can be allocated towards additional infrastructure. Contract capacity is to be relocated elsewhere.
8	La Grande	Distribution Enhancement	4,000	November 2010	n/a	La Grande distribution system enhancement to install high-pressure distribution system looping from adjacent city gate station such that the La Grande distribution system will be reinforced. The expected capital cost for this enhancement is approximately $3MM
9	Medford/Roseburg	Distribution Enhancement	n/a	November 2012	n/a	Distribution system enhancement to allow more GTN-based deliveries to the Medford area. This will allow Avista to redirect NWP Grants Pass Lateral deliveries from Medford to Roseburg. The expected capital cost for this Integrity Management related activity is approximately $14.2MM.
10	Medford/Roseburg	Transportation	25,000	November 2012	GTN's Med. Lat. Rate	GTN expansion of the Medford Lateral. Assumed current lateral rates, escalated for inflation, for expansion. Item #9 above required to facilitate this option.
11	Medford/Roseburg	Transportation	25,000	November 2020	GTN's Med. Lat. Rate	GTN expansion of the Medford Lateral. Assumed current lateral rates, escalated for inflation, for expansion. Item #9 above required to facilitate this option.
12	Roseburg	Satelite LNG	10,000	November 2016	Commodity plus Variable	Supply alleviates Grants Pass Lateral issues and provides peaking services.
13	Klamath Falls	Trasportation	5,000	November 2020	GTN's Med. Lat. Rate	GTN expansion of the Medford Lateral. Assumed current lateral rates, escalated for inflation, for expansion. Item #7 above required to facilitate this option.

1/ Does not include DSM therm savings. Therms associated withDSM programs included in DSM Appendix.
2/ Quantity Dth/d unless othewise noted

Appendix 6.7 - Least Cost Supply-Side Resource Additions Selected by SENDOUT®

Low Demand Case

Item #	Region	Type	Quantity 2/	Timing	Rates/Charges	Description
Oregon						
1	Klamath Falls	Distribution Enhancement	6,000	Nov-19	n/a	Purchase of NWP Klamath pipeline segment. Purchase price is approximately $3 MM capital cost. Purchase may occur as early as 2008/2009 and the price can be allocated towards additional infrastructure. Contract capacity is to be relocated elsewhere. Not needed for peak needs in this case but provides other core benefits.
2	Medford/Roseburg	Distribution Enhancement	n/a	Nov-21	n/a	Distribution system enhancement to allow more GTN-based deliveries to the Medford area. This will allow Avista to redirect NWP Grants Pass Lateral deliveries from Medford to Roseburg. The expected capital cost
3	Medford/Roseburg	Transportation	20,000	Nov-21	GTN's Med. Lat. Rate	GTN expansion of the Medford Lateral. Assumed current lateral rates, escalated by inflation, for expansion. Item #2 above required to facilitate this option

1/ Does not include DSM therm savings. Therms associated withDSM programs included in DSM Appendix.
2/ Quantity Dth/d unless othewise noted

Demand-Side Management Savings

Appendix 6.8

Appendix 6.8 - Annual and Annual Average Demand Served by Demand-Side Management 1

Case	Gas Year	Annual Klamath DSM (MDth)	Daily Klamath DSM (MDth/d)	Annual LaGrande DSM (MDth)	Daily LaGrande DSM (MDth/d)	Annual Medford DSM (MDth)	Daily Medford DSM (MDth/d)	Annual Roseburg DSM (MDth)	Daily Roseburg DSM (MDth/d)	Annual Oregon DSM (MDth)	Daily Oregon DSM (MDth/d)	Annual WA/ID DSM (MDth)	Daily WA/ID DSM (MDth/d)	Annual Total System DSM (MDth)	Daily Total System DSM (MDth/d)
Expected	**2007-2008**	3.589	0.010	1.695	0.005	11.117	0.030	3.112	0.009	19.513	0.053	67.664	0.185	87.177	0.239
Expected	**2008-2009**	7.408	0.020	3.381	0.009	22.142	0.060	6.202	0.017	39.134	0.107	134.837	0.368	173.971	0.475
Expected	**2009-2010**	11.112	0.030	5.072	0.014	33.214	0.091	9.303	0.025	58.701	0.161	202.255	0.554	260.956	0.715
Expected	**2010-2011**	14.816	0.041	7.044	0.019	44.285	0.121	12.404	0.034	78.549	0.215	269.674	0.739	348.223	0.954
Expected	**2011-2012**	18.580	0.051	8.829	0.024	55.584	0.152	15.561	0.043	98.554	0.269	338.321	0.924	436.875	1.194
Expected	**2012-2013**	22.223	0.061	10.566	0.029	66.427	0.182	18.607	0.051	117.824	0.323	500.544	1.371	618.368	1.694
Expected	**2013-2014**	25.927	0.071	12.327	0.034	77.644	0.213	21.708	0.059	137.606	0.377	694.854	1.904	832.461	2.281
Expected	**2014-2015**	29.789	0.081	14.695	0.040	92.751	0.253	25.609	0.070	162.845	0.445	881.620	2.409	1,044.465	2.854
Expected	**2015-2016**	32.318	0.089	15.868	0.043	104.962	0.288	27.237	0.075	180.385	0.494	1,020.652	2.796	1,201.038	3.291
Expected	**2016-2017**	34.645	0.095	16.937	0.046	110.941	0.304	28.610	0.078	191.134	0.524	1,155.248	3.165	1,346.381	3.689
Expected	**2017-2018**	37.091	0.101	18.063	0.049	117.471	0.321	30.109	0.082	202.734	0.554	1,232.522	3.368	1,435.256	3.921
Expected	**2018-2019**	39.481	0.108	19.181	0.053	125.588	0.344	31.605	0.087	215.855	0.591	1,309.797	3.588	1,525.652	4.180
Expected	**2019-2020**	42.011	0.115	20.359	0.056	132.596	0.363	33.179	0.091	228.145	0.625	1,392.710	3.816	1,620.854	4.441
Expected	**2020-2021**	44.125	0.121	21.356	0.058	137.980	0.377	35.662	0.097	239.124	0.653	1,464.292	4.001	1,703.415	4.654
Expected	**2021-2022**	48.821	0.134	22.407	0.061	143.930	0.394	37.075	0.102	252.232	0.691	1,541.539	4.223	1,793.772	4.914
Expected	**2022-2023**	51.104	0.140	23.383	0.064	149.423	0.409	38.385	0.105	262.296	0.719	1,617.415	4.431	1,879.711	5.150
Expected	**2023-2024**	53.570	0.147	24.424	0.067	155.608	0.426	39.853	0.109	273.454	0.749	1,700.313	4.658	1,973.767	5.408
Expected	**2024-2025**	55.672	0.152	25.334	0.069	160.410	0.438	41.006	0.112	282.422	0.772	1,762.283	4.815	2,044.705	5.587
Expected	**2025-2026**	57.956	0.159	26.309	0.072	165.904	0.455	42.316	0.116	292.485	0.801	1,831.275	5.017	2,123.760	5.819
Expected	**2026-2027**	60.221	0.165	27.280	0.075	171.243	0.469	43.603	0.119	302.348	0.828	1,900.267	5.206	2,202.615	6.035

Appendix 6.8 - Annual and Annual Average Demand Served by Demand-Side Management 1

Case	Gas Year	Annual Klamath DSM (MDth)	Daily Klamath DSM (MDth/d)	Annual LaGrande DSM (MDth)	Daily LaGrande DSM (MDth/d)	Annual Medford DSM (MDth)	Daily Medford DSM (MDth/d)	Annual Roseburg DSM (MDth)	Daily Roseburg DSM (MDth/d)	Annual Oregon DSM (MDth)	Daily Oregon DSM (MDth/d)	Annual WA/ID DSM (MDth)	Daily WA/ID DSM (MDth/d)	Annual Total System DSM (MDth)	Daily Total System DSM (MDth/d)
High	**2007-2008**	3.589	0.010	1.695	0.005	11.117	0.030	3.112	0.009	19.513	0.053	67.664	0.185	87.177	0.239
High	**2008-2009**	7.408	0.020	3.381	0.009	22.142	0.060	6.202	0.017	39.134	0.107	134.837	0.368	173.971	0.475
High	**2009-2010**	11.112	0.030	5.072	0.014	33.214	0.091	9.303	0.025	58.701	0.161	202.255	0.554	260.956	0.715
High	**2010-2011**	14.816	0.041	6.763	0.019	44.285	0.121	12.404	0.034	78.268	0.214	269.674	0.739	347.942	0.953
High	**2011-2012**	18.580	0.051	8.829	0.024	55.584	0.152	15.561	0.043	98.554	0.269	338.321	0.924	436.875	1.194
High	**2012-2013**	22.223	0.061	10.566	0.029	66.427	0.182	18.607	0.051	117.824	0.323	457.131	1.252	574.954	1.575
High	**2013-2014**	25.927	0.071	12.327	0.034	77.508	0.212	21.716	0.059	137.478	0.377	587.382	1.609	724.860	1.986
High	**2014-2015**	29.669	0.081	14.088	0.038	92.245	0.252	25.712	0.070	161.714	0.442	881.074	2.407	1,042.788	2.849
High	**2015-2016**	32.269	0.088	15.848	0.043	105.939	0.290	28.100	0.077	182.157	0.499	1,043.901	2.860	1,226.058	3.359
High	**2016-2017**	34.592	0.095	16.937	0.046	112.107	0.307	29.584	0.081	193.220	0.529	1,129.535	3.095	1,322.755	3.624
High	**2017-2018**	37.030	0.101	18.049	0.049	118.880	0.325	31.168	0.085	205.128	0.560	1,232.522	3.368	1,437.650	3.928
High	**2018-2019**	39.481	0.108	19.181	0.053	125.588	0.344	32.710	0.090	216.960	0.594	1,309.797	3.588	1,526.756	4.183
High	**2019-2020**	42.011	0.115	20.349	0.056	132.596	0.363	34.381	0.094	229.338	0.628	1,392.710	3.816	1,622.047	4.444
High	**2020-2021**	44.125	0.121	21.356	0.058	137.980	0.377	35.662	0.097	239.124	0.653	1,464.292	4.001	1,703.415	4.654
High	**2021-2022**	46.380	0.127	22.407	0.061	143.930	0.394	37.075	0.102	249.791	0.684	1,541.539	4.223	1,791.331	4.908
High	**2022-2023**	51.104	0.140	23.383	0.064	149.423	0.409	38.385	0.105	262.296	0.719	1,617.415	4.431	1,879.711	5.150
High	**2023-2024**	53.570	0.147	24.424	0.067	155.608	0.426	39.853	0.109	273.454	0.749	1,700.313	4.658	1,973.767	5.408
High	**2024-2025**	55.672	0.152	25.334	0.069	160.410	0.438	41.006	0.112	282.422	0.772	1,762.283	4.815	2,044.705	5.587
High	**2025-2026**	57.956	0.159	26.309	0.072	165.904	0.455	42.316	0.116	292.485	0.801	1,831.275	5.017	2,123.760	5.819
High	**2026-2027**	60.221	0.165	27.280	0.075	171.243	0.469	43.603	0.119	302.348	0.828	1,900.267	5.206	2,202.615	6.035

Appendix 6.8 - Annual and Annual Average Demand Served by Demand-Side Management 1

Case	Gas Year	Annual Klamath DSM (MDth)	Daily Klamath DSM (MDth/d)	Annual LaGrande DSM (MDth)	Daily LaGrande DSM (MDth/d)	Annual Medford DSM (MDth)	Daily Medford DSM (MDth/d)	Annual Roseburg DSM (MDth)	Daily Roseburg DSM (MDth/d)	Annual Oregon DSM (MDth)	Daily Oregon DSM (MDth/d)	Annual WA/ID DSM (MDth)	Daily WA/ID DSM (MDth/d)	Annual Total System DSM (MDth)	Daily Total System DSM (MDth/d)
Low	**2007-2008**	3.589	0.010	1.695	0.005	11.117	0.030	3.112	0.009	19.513	0.053	67.664	0.185	87.177	0.239
Low	**2008-2009**	7.408	0.020	3.381	0.009	22.142	0.060	6.202	0.017	39.134	0.107	134.837	0.368	173.971	0.475
Low	**2009-2010**	11.112	0.030	5.072	0.014	33.214	0.091	9.303	0.025	58.701	0.161	202.255	0.554	260.956	0.715
Low	**2010-2011**	14.816	0.041	7.044	0.019	44.285	0.121	12.404	0.034	78.549	0.215	269.674	0.739	348.223	0.954
Low	**2011-2012**	18.580	0.051	8.829	0.024	55.584	0.152	15.561	0.043	98.554	0.269	419.532	1.146	518.087	1.416
Low	**2012-2013**	22.252	0.061	10.566	0.029	68.291	0.187	18.607	0.051	119.716	0.328	603.431	1.653	723.147	1.981
Low	**2013-2014**	26.065	0.071	12.859	0.035	81.157	0.222	22.490	0.062	142.571	0.391	772.054	2.115	914.625	2.506
Low	**2014-2015**	29.840	0.082	14.713	0.040	92.922	0.254	25.702	0.070	163.178	0.446	924.198	2.525	1,087.376	2.971
Low	**2015-2016**	32.415	0.089	15.871	0.043	105.297	0.288	27.316	0.075	180.900	0.496	1,043.901	2.860	1,224.801	3.356
Low	**2016-2017**	34.700	0.095	16.953	0.046	111.453	0.305	28.706	0.079	191.812	0.526	1,155.248	3.165	1,347.060	3.691
Low	**2017-2018**	37.091	0.101	18.067	0.049	119.137	0.326	30.155	0.082	204.450	0.559	1,232.522	3.368	1,436.972	3.926
Low	**2018-2019**	39.481	0.108	19.190	0.053	125.588	0.344	31.605	0.087	215.864	0.591	1,309.797	3.588	1,525.660	4.180
Low	**2019-2020**	42.011	0.115	20.359	0.056	132.596	0.363	34.381	0.094	229.347	0.628	1,392.710	3.816	1,622.057	4.444
Low	**2020-2021**	46.403	0.127	21.356	0.058	137.980	0.377	35.662	0.097	241.402	0.660	1,464.292	4.001	1,705.694	4.660
Low	**2021-2022**	48.821	0.134	22.407	0.061	143.930	0.394	37.075	0.102	252.232	0.691	1,541.539	4.223	1,793.772	4.914
Low	**2022-2023**	51.104	0.140	23.383	0.064	149.423	0.409	38.385	0.105	262.296	0.719	1,617.415	4.431	1,879.711	5.150
Low	**2023-2024**	53.570	0.147	24.424	0.067	155.608	0.426	39.853	0.109	273.454	0.749	1,700.313	4.658	1,973.767	5.408
Low	**2024-2025**	55.672	0.152	25.334	0.069	160.410	0.438	41.006	0.112	282.422	0.772	1,762.283	4.815	2,044.705	5.587
Low	**2025-2026**	57.956	0.159	26.309	0.072	165.904	0.455	42.316	0.116	292.485	0.801	1,831.275	5.017	2,123.760	5.819
Low	**2026-2027**	60.221	0.165	27.280	0.075	176.733	0.484	43.603	0.119	307.837	0.843	1,900.267	5.206	2,208.104	6.050

Demand-Side Management Selected Measures

Appendix 6.9

Appendix 6.9 - Washington/Idaho Preliminary Evaluation Results

Program	WA/ID
Energy Star Pressure SteamerNon-residentialcooking	Must Take
Programmable ThermostatsNon-residentialHVAC	Must Take
Radiant heatNon-residentialHVAC	Must Take
Low Flow ShowerheadsNon-residentialDHW	Must Take
Pool blanketResidentialDHW	Must Take
Programmable ThermostatResidentialHVAC	Must Take
Wall insulationNon-residentialshell	Must Take
Pool blanketNon-residentialpool	Must Take
Pool blanketResidentialDHW	Must Take
horizontal axis clothes washerResidentialappliances	Must Take
CrematoriaNon-residentialcrematoria	Must Take
Programmable ThermostatResidentialHVAC	Must Take
Roof insulationNon-residentialshell	Must Take
Pizza / Deck OvenNon-residentialcooking	Must Take
Warm Up ControlNon-residentialHVAC	Must Take
Coin-Op Gas Clothers DryerNon-residentialappliances	Must Take
Demand control ventilationNon-residentialHVAC	Must Take
Conveyer BroilerNon-residentialcooking	Must Take
CheesemelterNon-residentialcooking	Must Take
SalamanderNon-residentialcooking	Must Take
Tankless Water HeaterNon-residentialDHW	Must Take
Fireplace dampersResidentialshell	Must Take
Vent DamperNon-residentialHVAC	Must Take
Comm. Gas Clothes DryerNon-residentialappliances	Must Take
BoilerNon-residentialDHW	Must Take
Condensing Storage Water HeaterNon-residentialDHW	Must Take
KilnNon-residentialkiln	Must Take
Boiler Tune-upNon-residentialHVAC	Must Take
Duct sealingResidentialHVAC	Must Take
High efficiency boilerResidentialHVAC	Must Take
high Efficiency furnaceResidentialHVAC	Must Take
Walls insulationResidentialshell	Must Take
Window (WA/ID)Residentialshell	Must Take
Attic insulationResidentialshell	Must Take
Duct sealingResidentialHVAC	Must Take
Condensing BoilerNon-residentialDHW	Must Take
Duct insulation retrofitResidentialHVAC	Must Take
Recirculation ControlsNon-residentialDHW	Must Take
CharbroilerNon-residentialcooking	Must Take
Recirculation ControlsNon-residentialHVAC	Must Take
Occupancy sensors for PTAC unitsNon-residentialHVAC	Must Take
Duct insulation retrofitResidentialHVAC	Must Take

Appendix 6.9 - Washington/Idaho Preliminary Evaluation Results

Program	WA/ID
Floor insulationResidentialshell	SENDOUT®
Condensing Tank Water HeaterNon-residentialDHW	SENDOUT®
BBQ / Rotisserie OvenNon-residentialcooking	SENDOUT®
High efficiency furnaceResidentialHVAC	SENDOUT®
Wall insulationResidentialshell	SENDOUT®
Window (WA/ID)Residentialshell	SENDOUT®
Condensing boilerResidentialDHW	SENDOUT®
Condensing boilerResidentialHVAC	SENDOUT®
Air sealing weatherstrippingResidentialshell	SENDOUT®
Air sealing weatherstrippingResidentialshell	SENDOUT®
Floor insulationResidentialshell	SENDOUT®
Tankless water heaterResidentialDHW	SENDOUT®
Convection OvenNon-residentialcooking	SENDOUT®
Coin-op clothes washerNon-residentialappliances	SENDOUT®
Attic insulationResidentialshell	SENDOUT®
Power BurnerNon-residentialHVAC	SENDOUT®
Gas Pool HeaterNon-residentialpool	SENDOUT®
Gas Pool HeaterResidentialHVAC	SENDOUT®
Gas Pool HeaterResidentialHVAC	SENDOUT®
Energy recovery ventilationNon-residentialHVAC	SENDOUT®
Rack / Tray OvenNon-residentialcooking	SENDOUT®
Infrared Fryer GriddleNon-residentialcooking	Screened Out
Combi OvenNon-residentialcooking	Screened Out
Infrared General Purpose FryerNon-residentialcooking	Screened Out
Direct vent gas unit heaterResidentialHVAC	SENDOUT®
Energy Star HomeResidentialwhole home	Screened Out
Direct vent gas unit heaterResidentialHVAC	SENDOUT®
Exterior doorsResidentialshell	Screened Out
Exterior doorsResidentialshell	Screened Out
Revolving OvenNon-residentialcooking	Screened Out
Pipe insulationResidentialDHW	Screened Out
Pipe insulationResidentialDHW	Screened Out
Passive solar water heatingResidentialDHW	Screened Out
Passive solar water heatingResidentialDHW	Screened Out
Oven ConveyerNon-residentialcooking	Screened Out
Window retrofitNon-residentialshell	Screened Out
Solar waterNon-residentialDHW	Screened Out
Salamander (Broiler)Non-residentialcooking	Screened Out
Comm clothes washerNon-residentialappliances	Screened Out
Cheesemelter (broiler)Non-residentialcooking	Screened Out
Gas Spa HeaterNon-residentialpool	Screened Out
Gas Spa HeaterResidentialHVAC	Screened Out
Gas Spa HeaterResidentialHVAC	Screened Out
Open BurnerNon-residentialcooking	Screened Out
Combo boiler (hydronic)ResidentialDHW	Screened Out
Combo boiler (air)ResidentialDHW	Screened Out
Exterior doorsResidentialshell	Screened Out
Exterior doorsResidentialshell	Screened Out

Appendix 6.9 - Oregon Program Preliminary Evaluation Results

Program	Roseburg	Medford	LaGrande	Klamath Falls
Wall insulationResidentialshell	Mandated	Mandated	Mandated	Mandated
Floor insulationResidentialshell	Mandated	Mandated	Mandated	Mandated
Attic insulationResidentialshell	Mandated	Mandated	Mandated	Mandated
Air sealing weatherstrippingResidentialshell	Mandated	Mandated	Mandated	Mandated
Pre-rinse sprayersNon-residentialDHW	Must Take	Must Take	Must Take	Must Take
horizontal axis clothes washerResidentialappliances	Must Take	Must Take	Must Take	Must Take
Energy Star Pressure SteamerNon-residentialcooking	Must Take	Must Take	Must Take	Must Take
Programmable ThermostatsNon-residentialHVAC	Must Take	Must Take	Must Take	Must Take
Radiant heatNon-residentialHVAC	Must Take	Must Take	Must Take	Must Take
Pool blanket - MFHResidentialDHW	Must Take	Must Take	Must Take	Must Take
Programmable ThermostatResidentialHVAC	Must Take	Must Take	Must Take	Must Take
Pool blanket - Non resNon-residentialpool	Must Take	Must Take	Must Take	Must Take
Pool blanket - SFHResidentialDHW	Must Take	Must Take	Must Take	Must Take
CrematoriaNon-residentialcrematoria	Must Take	Must Take	Must Take	Must Take
Wall insulationNon-residentialshell	Must Take	Must Take	Must Take	Must Take
Coin-Op Gas Clothers DryerNon-residentialappliances	Must Take	Must Take	Must Take	Must Take
Pizza / Deck OvenNon-residentialcooking	Must Take	Must Take	Must Take	Must Take
Roof insulationNon-residentialshell	Must Take	Must Take	Must Take	Must Take
Programmable ThermostatResidentialHVAC	Must Take	Must Take	Must Take	Must Take
Conveyer BroilerNon-residentialcooking	Must Take	Must Take	Must Take	Must Take
CheesemelterNon-residentialcooking	Must Take	Must Take	Must Take	Must Take
SalamanderNon-residentialcooking	Must Take	Must Take	Must Take	Must Take
Demand control ventilationNon-residentialHVAC	Must Take	Must Take	Must Take	Must Take
Warm Up ControlNon-residentialHVAC	Must Take	Must Take	Must Take	Must Take
Tankless Water HeaterNon-residentialDHW	Must Take	Must Take	Must Take	Must Take
BoilerNon-residentialDHW	Must Take	Must Take	Must Take	Must Take
KilnNon-residentialkiln	Must Take	Must Take	Must Take	Must Take
Comm. Gas Clothes DryerNon-residentialappliances	Must Take	Must Take	Must Take	Must Take
Condensing Storage Water HeaterNon-residentialDHW	Must Take	Must Take	Must Take	Must Take
High efficiency boilerResidentialDHW	Must Take	Must Take	Must Take	Must Take
Fireplace dampersResidentialshell	Must Take	Must Take	Must Take	Must Take
high Efficiency furnaceResidentialHVAC	Must Take	Must Take	Must Take	Must Take
Vent DamperNon-residentialHVAC	Must Take	Must Take	Must Take	Must Take
Condensing BoilerNon-residentialDHW	Must Take	Must Take	Must Take	Must Take
Duct sealing - SFHResidentialHVAC	Must Take	Must Take	Must Take	Must Take
High efficiency boilerResidentialHVAC	Must Take	Must Take	Must Take	Must Take
CharbroilerNon-residentialcooking	Must Take	Must Take	Must Take	Must Take
Recirculation ControlsNon-residentialDHW	Must Take	Must Take	Must Take	Must Take
Condensing Tank Water HeaterNon-residentialDHW	Must Take	Must Take	Must Take	Must Take
Boiler Tune-upNon-residentialHVAC	Must Take	Must Take	Must Take	Must Take
BBQ / Rotisserie OvenNon-residentialcooking	Must Take	Must Take	Must Take	Must Take
Duct sealing - MFHResidentialHVAC	Must Take	Must Take	Must Take	Must Take
Recirculation ControlsNon-residentialHVAC	Must Take	Must Take	Must Take	Must Take
Duct commissioningResidentialHVAC	Must Take	Must Take	Must Take	Must Take
High efficiency furnaceResidentialHVAC	Must Take	Must Take	Must Take	Must Take
Occupancy sensors for PTAC unitsNon-residentialHVAC	Must Take	Must Take	Must Take	Must Take

Appendix 6.9 - Oregon Program Preliminary Evaluation Results

Program	Roseburg	Medford	LaGrande	Klamath Falls
Convection OvenNon-residentialcooking	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Tankless water heaterResidentialDHW	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Rack / Tray OvenNon-residentialcooking	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Infrared Fryer GriddleNon-residentialcooking	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Gas Pool HeaterNon-residentialpool	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Gas Pool HeaterResidentialHVAC	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Gas Pool HeaterResidentialHVAC	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Energy recovery ventilationNon-residentialHVAC	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Combi OvenNon-residentialcooking	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Infrared General Purpose FryerNon-residentialcooking	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Power BurnerNon-residentialHVAC	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Revolving OvenNon-residentialcooking	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Energy Star HomeResidentialwhole home	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Exterior doorsResidentialshell	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Exterior doorsResidentialshell	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Direct vent gas unit heaterResidentialHVAC	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Direct vent gas unit heaterResidentialHVAC	Screened Out	Screened Out	Screened Out	Screened Out
Window retrofitNon-residentialshell	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Coin-op clothes washerNon-residentialappliances	Screened Out	Screened Out	Screened Out	Screened Out
Passive solar water heatingResidentialDHW	Screened Out	Screened Out	Screened Out	Screened Out
Passive solar water heatingResidentialDHW	Screened Out	Screened Out	Screened Out	Screened Out
Oven ConveyerNon-residentialcooking	Screened Out	Screened Out	Screened Out	Screened Out
Comm clothes washerNon-residentialappliances	Screened Out	Screened Out	Screened Out	Screened Out
Salamander (Broiler)Non-residentialcooking	Screened Out	Screened Out	Screened Out	Screened Out
Solar waterNon-residentialDHW	Screened Out	Screened Out	Screened Out	Screened Out
Cheesemelter (broiler)Non-residentialcooking	Screened Out	Screened Out	Screened Out	Screened Out
Gas Spa HeaterNon-residentialpool	Screened Out	Screened Out	Screened Out	Screened Out
Open BurnerNon-residentialcooking	Screened Out	Screened Out	Screened Out	Screened Out
Combo boiler (hydronic)ResidentialDHW	Screened Out	Screened Out	Screened Out	Screened Out
Gas Spa HeaterResidentialHVAC	Screened Out	Screened Out	Screened Out	Screened Out
Gas Spa HeaterResidentialHVAC	Screened Out	Screened Out	Screened Out	Screened Out
Combo boiler (air)ResidentialDHW	Screened Out	Screened Out	Screened Out	Screened Out
Exterior doorsResidentialshell	Screened Out	Screened Out	Screened Out	Screened Out
Exterior doorsResidentialshell	Screened Out	Screened Out	Screened Out	Screened Out

Demand-Side Management Programs – OR Only

Appendix 6.10

Appendix 6.10 - Oregon Measure Final Status and Resource Acquisition

Measure	Sector	Incremental measure cost	Measure life	Energy savings/unit	Non-Energy benefits	Levelized TRC	2007/2008 Annual acquisition	CY 2008 unit goal	CY 2008 therm goal	CY 2009 unit goal	CY 2009 therm goal	Category	Final status
Wall insulation	Residential	$ 744	45	66	$ -	$ 1.03	1,992	34	2,254	39	2,563	Dark green	Mandated
Air sealing weatherstripping	Residential	$ 250	10	38	$ -	$ 1.03	948	28	1,073	32	1,220	Dark green	Mandated
Floor insulation	Residential	$ 1,244	45	96	$ -	$ 1.19	7,698	91	8,714	103	9,906	Dark green	Mandated
Attic insulation	Residential	$ 666	45	44	$ -	$ 1.38	7,872	201	8,910	229	10,129	Dark green	Mandated
Pre-rinse sprayers	Non-residential	$ 10	5	176	$ 91	$ (0.12)	70,400	400	70,400	-	-	Green	Special pass
Energy Star Pressure Steamer	Non-residential	$ 111	20	643	$ -	$ 0.02	1,286	2	1,290	2	1,326	Green	Spreadsheet pass
Programmable Thermostats	Non-residential	$ 25	20	117	$ -	$ 0.02	1,172	10	1,176	10	1,209	Green	Spreadsheet pass
Radiant heat	Non-residential	$ 25	20	117	$ -	$ 0.02	586	5	588	5	604	Green	Spreadsheet pass
horizontal axis clothes washer	Residential	$ 70	13	17	$ 61	$ 0.07	6,800	453	7,697	515	8,750	Green	Spreadsheet pass
Pool blanket - MFH	Residential	$ 25	20	41	$ -	$ 0.07	0	-	-	-	-	Green	Spreadsheet pass
Programmable Thermostat	Residential	$ 25	20	31	$ -	$ 0.09	0	-	-	-	-	Green	Spreadsheet pass
Pool blanket - Non res	Non-residential	$ 2,200	10	2,720	$ -	$ 0.13	2,720	1	2,729	1	2,805	Green	Spreadsheet pass
Pool blanket - SFH	Residential	$ 1,100	10	1,360	$ -	$ 0.13	1,360	1	1,539	1	1,750	Green	Spreadsheet pass
Crematoria	Non-residential	$ 9,672	30	5,537	$ -	$ 0.17	0	-	-	-	-	Green	Spreadsheet pass
Coin-Op Gas Clothers Dryer	Non-residential	$ 613	11	419	$ 144	$ 0.16	1,257	3	1,261	3	1,296	Green	Spreadsheet pass
Wall insulation	Non-residential	$ 0	30	0	$ -	$ 0.17	1	5	1	5	1	Green	Spreadsheet pass
Pizza / Deck Oven	Non-residential	$ 466	20	256	$ -	$ 0.20	256	1	257	1	264	Green	Spreadsheet pass
Programmable Thermostat	Residential	$ 25	20	12	$ -	$ 0.22	309	28	350	32	398	Green	Spreadsheet pass
Conveyer Broiler	Non-residential	$ 1,182	15	661	$ -	$ 0.22	661	1	663	1	682	Green	Spreadsheet pass
Roof insulation	Non-residential	$ 0	30	0	$ -	$ 0.24	1	5	1	5	1	Green	Spreadsheet pass
Cheesemelter	Non-residential	$ 408	15	203	$ -	$ 0.25	203	1	204	1	209	Green	Spreadsheet pass
Warm Up Control	Non-residential	$ 300	10	180	$ -	$ 0.26	180	1	180	1	185	Green	Spreadsheet pass
Salamander	Non-residential	$ 300	15	137	$ -	$ 0.27	137	1	137	1	141	Green	Spreadsheet pass
Demand control ventilation	Non-residential	$ 1	20	0	$ -	$ 0.30	1	3	1	3	1	Green	Spreadsheet pass
Tankless Water Heater	Non-residential	$ 600	20	211	$ -	$ 0.31	1,055	5	1,058	5	1,088	Green	Spreadsheet pass
Comm. Gas Clothes Dryer	Non-residential	$ 1,586	11	740	$ -	$ 0.31	740	1	742	1	763	Green	Spreadsheet pass
Boiler	Non-residential	$ 11,928	20	3,854	$ -	$ 0.34	3,854	1	3,867	1	3,975	Green	Spreadsheet pass
Condensing Storage Water Heater	Non-residential	$ 848	15	308	$ -	$ 0.34	308	1	309	1	318	Green	Spreadsheet pass
Kiln	Non-residential	$ 199	30	49	$ -	$ 0.39	0	-	-	-	-	Green	Spreadsheet pass
Fireplace dampers	Residential	$ 500	15	150	$ -	$ 0.41	3,748	28	4,243	32	4,823	Green	Spreadsheet pass
Vent Damper	Non-residential	$ 304	12	101	$ -	$ 0.42	0	-	-	-	-	Green	Spreadsheet pass
High efficiency boiler	Residential	$ 160	20	40	$ -	$ 0.44	40	1	45	1	51	Green	Spreadsheet pass
High efficiency space heater	Residential	$ 275	20	64	$ -	$ 0.47	322	6	364	6	414	Green	Spreadsheet pass
Condensing Boiler	Non-residential	$ 36,701	20	7,524	$ -	$ 0.53	7,524	1	7,549	1	7,760	Green	Spreadsheet pass
Recirculation Controls	Non-residential	$ 1,311	10	386	$ -	$ 0.53	386	1	387	1	398	Green	Spreadsheet pass
Boiler Tune-up	Non-residential	$ 100	5	50	$ -	$ 0.51	50	1	50	1	51	Green	Spreadsheet pass
Charbroiler	Non-residential	$ 1,313	15	298	$ -	$ 0.55	298	1	299	1	307	Green	Spreadsheet pass
Duct sealing - SFH	Residential	$ 500	20	94	$ -	$ 0.58	4,687	57	5,305	64	6,031	Green	Spreadsheet pass
High efficiency boiler	Residential	$ 160	20	30	$ -	$ 0.58	30	1	34	1	39	Green	Spreadsheet pass
Condensing Tank Water Heater	Non-residential	$ 3,855	15	771	$ -	$ 0.62	771	1	774	1	795	Green	Spreadsheet pass
BBQ / Rotisserie Oven	Non-residential	$ 1,003	15	198	$ -	$ 0.63	198	1	199	1	204	Green	Spreadsheet pass
Duct sealing - MFH	Residential	$ 300	20	47	$ -	$ 0.70	235	6	266	6	302	Green	Spreadsheet pass
Duct commissioning	Residential	$ 300	20	45	$ -	$ 0.73	449	11	508	13	578	Green	Spreadsheet pass
Recirculation Controls	Non-residential	$ 200	25	26	$ -	$ 0.77	26	1	26	1	27	Green	Spreadsheet pass
High efficiency furnace	Residential	$ 450	20	64	$ -	$ 0.76	64,400	1,132	72,895	1,287	82,865	Green	Spreadsheet pass
Occupancy sensors for PTAC units	Non-residential	$ 200	20	26	$ -	$ 0.86	0	-	-	-	-	Green	Spreadsheet pass
Tankless water heater	Residential	$ 700	15	102	$ -	$ 0.85	7,650	85	8,659	97	9,843	Yellow	SENDOUT pass
Convection Oven	Non-residential	$ 2,696	20	324	$ -	$ 0.91	324	1	325	1	334	Yellow	SENDOUT pass
Rack / Tray Oven	Non-residential	$ 9,709	20	1,013	$ -	$ 1.05	1,013	1	1,016	1	1,045	Yellow	SENDOUT pass
Infrared Fryer Griddle	Non-residential	$ 2,146	20	194	$ -	$ 1.21	194	1	195	1	200	Yellow	SENDOUT pass
Combi Oven	Non-residential	$ 1,667	15	164	$ -	$ 1.26	164	1	165	1	169	Yellow	SENDOUT pass
Power Burner	Non-residential	$ 913	12	101	$ -	$ 1.26	101	1	101	1	104	Yellow	SENDOUT pass
Gas Pool Heater	Non-residential	$ 3,364	20	280	$ -	$ 1.32	280	1	280	1	288	Yellow	SENDOUT pass
Gas Pool Heater, SFH	Residential	$ 3,364	20	280	$ -	$ 1.32	280	1	316	1	360	Yellow	SENDOUT pass
Gas Pool Heater, MFH	Residential	$ 3,364	20	280	$ -	$ 1.32	280	1	316	1	360	Yellow	SENDOUT pass
Energy recovery ventilation	Non-residential	$ 4	20	0	$ -	$ 1.33	2	5	2	5	2	Yellow	SENDOUT pass
Infrared General Purpose Fryer	Non-residential	$ 3,186	15	300	$ -	$ 1.32	300	1	301	1	309	Yellow	SENDOUT pass
Revolving Oven	Non-residential	$ 4,870	20	364	$ -	$ 1.46	364	1	365	1	375	Yellow	SENDOUT pass
Energy Star Home	Residential	$ 2,870	31	145	$ -	$ 1.90	7,272	57	8,231	64	9,357	Yellow	SENDOUT fail
Exterior doors	Residential	$ 100	30	5	$ -	$ 1.95	0	0	0	0	0	Yellow	SENDOUT pass
Exterior doors	Residential	$ 100	30	5	$ -	$ 1.95	0	0	0	0	0	Yellow	SENDOUT pass

	CY 2008 therms	CY 2009 therms
SENDOUT-accepted residential programs	123,491	140,381
SENDOUT-accepted non-residential programs	26,498	27,240
Estimated site-specific acquisition	56,808	58,399
Adjustment for non-res porgram duplication	(2,650)	(2,724)
Estimated pre-rinse sprayer acquisition	70,400	-
Enhanced commercial / industrial delivery	75,000	75,000
	349,547	298,296

Oregon Public Utility Commission IRP Standard and Guidelines

Appendix 6.11

Appendix 6.11 Oregon Public Utility Commission IRP Standard and Guidelines

Guideline Number	Description of Requirement	Fulfillment of Requirement
Guideline 1: Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis.	All resource options including Demand side and Supply side are modeled in SENDOUT utilizing the same common assumptions, approach and methodology.
1.a.2	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	Avista considered a range of resources including demand-side management, distribution system enhancements, interstate pipeline transportation, transport backhauls, and storage options including liquefied natural gas. Chapter 3 and Appendix 6.10 and 6.11 documents Avista's demand-side management resources considered. Chapter 5 and Appendix 6.4 documents supply-side resources. Chapter 6 documents how Avista developed and assessed each of these resources.
1.a.3	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	Avista considered various combinations of technologies, lead times, in-service dates, durations, and locations. Chapter 6 provides details about the modeling methodology and results. Chapter 5 describes resource attributes and Appendix 6.4 summarizes the resources' lead times, in-service dates and locations.
1.a.4	Consistent assumptions and methods should be used for evaluation of all resources.	Appendix 6.1 documents general assumptions used in Avista's SENDOUT® modeling software. All portfolio resources both demand and supply side were evaluated within SENDOUT using the same sets of inputs.
1.a.5	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	Avista applied its after-tax WACC of 4.18% to discount all future resource costs. (See general assumptions at Appendix 6.1)
1.b.1	Risk and uncertainty must be considered. Electric utilities only	Not Applicable
1.b.2	Risk and uncertainty must be considered. Natural gas utilities should consider demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas (GHG) emissions.	After considering the influencers on demand, Avista focused on three scenarios (Table 1.1) for SENDOUT modeling purposes. Demand coefficients were developed for base, shoulder and winter demand (Appendix 2.3) while peak demand was contemplated through modeling a weather planning standard of the coldest day on record (see heating degree day data in Appendix 6.1). Avista evaluated several price forecasts (Figure 6.12) and selected high, medium and low price scenarios for modeling purposes (Figures 6.13 & 6.14).

Guideline Number	Description of Requirement	Fulfillment of Requirement
		Avista also ran Monte Carlo simulations using VectorGas™ for price and weather variables to analyze demand sensitivity and resulting resource timing and selection. Avista considered potential GHG emissions regulatory compliance costs in Chapter 7.
	Utilities should identify in their plans any additional sources of risk and uncertainty.	Avista evaluated additional risks and uncertainties, including the level of DSM achievable potential (Chapter 3). See Chapter 6 for a discussion of the other sources of risk and uncertainty considered but not necessarily modeled for scenario and stochastic risk analysis.
1c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.	Gas utilities are different from electric utilities in the number and combinations of resources available. Gas utilities do not have multiple portfolios of resources. Therefore, Avista considers a resource mix of all the supply side and demand side options as our alternative to portfolios. Avista inputs the supply side and demand side measures into SENDOUT® and allows the model to pick a suite of resources. Each scenario has a different resource mix based on the assumptions of the scenario. Avista evaluated cost/risk tradeoffs for each of the scenarios considered. For example, we considered large scale LNG but after considering the lead time, cost, and assessment of the risks we determined it was not a viable option at this time. See Chapter 6 for the company's risk analysis and determination of the preferred resource mix.
	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	Avista used a 20-year study period for portfolio modeling. Avista contemplated possible costs beyond the planning period that could affect rates including end effects such as infrastructure decommission costs and concluded there were no significant costs reasonably likely to impact rates under different resource selection scenarios.
	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs of all long-lived resources such as power plants, gas storage facilities and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	Avista's SENDOUT modeling software utilizes a PVRR cost metric methodology applied to both long and short-lived resources.
	To address risk, the plan should include at a minimum: 1) Two measures of PVRR risk: one	Avista, through its VectorGas software, modeled 200 scenarios around varying gas price inputs via Monte Carlo iterations developing a distribution of Total 20

Guideline Number	Description of Requirement	Fulfillment of Requirement
	that measures the variability of costs and one that measures the severity of bad outcomes. 2) Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	year cost estimates utilizing SENDOUT's PVRR methodology. Chapter 6 further describes this analysis while Figure 6.15 summarizes this analysis graphically. The variability of costs is plotted against the Expected Case while the scenarios beyond the 95^{th} percentile capture the severity of bad outcomes. Chapter 5 discusses Avista's physical and financial hedging methodology.
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapter 6 and Appendix 6.7 summarizes the results of Avista's cost/risk tradeoff analysis, and describes what criteria the company used to determine what resource combinations provide an appropriate balance between cost and risk.
1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	Avista considered current and expected state and federal energy policies in portfolio modeling. Chapter 6 describes the decision process used to derive portfolios, which includes consideration of state resource policy directions.
Guideline 2: Procedural Requirements		
2a	The public, including other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan.	Chapter 1 provides an overview of the public process and documents the details on public meetings held for the 2007 IRP.
2b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan.	The entire IRP, as well as the Technical Advisory Committee process, includes all of the non-confidential information the company used for portfolio evaluation and selection. Avista also provided stakeholders with non-confidential information to support public meeting discussions via email. The draft plan was also made available on Avista's website for public viewing during this period.
2c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	Avista distributed a draft IRP document for external review to TAC members on September 6, 2007 and requested comments by October 31, 2007. The draft plan was also made available on Avista's website for public viewing during this period.
Guideline 3: Plan Filing, Review and Updates		
3a	Utility must file an IRP within two years of its previous IRP acknowledgement order.	This Plan complies with this requirement as the 2006 Natural Gas IRP was acknowledged on 9/16/06.
3b	Utility must present the results of its filed plan to	Avista will adhere to this guideline.

Guideline Number	Description of Requirement	Fulfillment of Requirement
	the Commission at a public meeting prior to the deadline for written public comment.	
3c - g	These guides discuss Commission comments and acknowledgement and the IRP annual update.	Not applicable.
Guideline 4: Plan Components		
	At a minimum, the plan must include the following elements:	
4a	An explanation of how the utility met each of the substantive and procedural requirements.	The purpose of this table is to comply with this guideline by providing an overview of how Avista met each of the substantive and procedural requirements for a natural gas IRP.
4b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	Avista developed low, medium and high demand growth forecasts for scenario analysis. Stochastic variability of demand was also captured in the risk analysis. Chapter 2 describes the demand forecast data and Chapter 6 provides the scenario and risk analysis results. Appendix 6.1 details major assumptions.
4c	For electric utilities only	Not Applicable
4d	A determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources.	This plan complies with the requirement with resource summaries documented in Figure 1.3 (and duplicated in Figure 6.17) for the expected case. Appendix 6.5 summarizes the high and low demand scenarios. Additionally, figure 6.21 shows that the need for resources primarily occurs on and around the peak day. Appendix 6.6 summarizes the high and low case. Appendix 6.4 details all the supply side options considered and Appendix 6.9 and 6.10 provides details on the demand side options. Table 6.6 identifies the resources selected by the model for the expected case, and Appendix 6.7 details the resources for the high and low cases.
4e	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology	Chapter 3 and Appendix 6.9 and 6.10 identify the demand-side resources and costs included in this IRP. Chapter 6 and Appendix 6.4 identify the supply-side resources and costs.
4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	Chapter 4 discusses the modeling tools, customer growth forecasting and cost-risk considerations used to maintain and plan a reliable gas delivery system. The Chapter also captures a summary of the reliability analysis process demonstrated at the second TAC meeting. Chapter 5 discusses the diversified infrastructure and multiple supply basin approach that acts to mitigate certain reliability risks.
4g	Identification of key assumptions about the future	Appendix 6.1 and Chapter 6 describe the key assumptions and alternative

Guideline Number	Description of Requirement	Fulfillment of Requirement
	(e.g. fuel prices and environmental compliance costs) and alternative scenarios considered.	scenarios used in this IRP.
4h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations - system-wide or delivered to a specific portion of the system.	This Plan documents the development and results for resource options evaluated in this IRP (see also Appendix 6.4, 6.9, and 6.10). See also guideline **1c** for further discussion on resource mix alternatives to portfolios.
4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	We evaluated our candidate portfolio by performing stochastic analysis using VectorGas™ varying price under 200 different scenarios. Additionally, we test the portfolio of options with the use of SENDOUT® under deterministic scenarios where demand and price vary. For resources selected, we assess other risk factors such as varying lead times required and potential for cost overruns outside of the amounts included in the modeling assumptions.
4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results	Avista's four distinct geographic Oregon service territories limit many resource option synergies which inherently reduces available portfolio options. Feasibility uncertainty, lead time variability and uncertain cost escalation around certain resource options also reduce reasonably viable options. Chapter 6 describes resource options reviewed including discussion on uncertainties in lead times and costs as well as viability and resource availability (e.g. LNG). Appendix 6.4 summarizes the potential resource options identifying investment and variable costs, asset availability and lead time requirements while results of resources selected are identified in Table 6.6 as well as graphically presented in Figure 6.19 for the expect case and Appendix 6.5 for High and Low demand cases.
4k	Analysis of the uncertainties associated with each portfolio evaluated	See the responses to 1.b above.
4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers	Avista evaluated cost/risk tradeoffs for each of the risk analysis portfolios considered. Chapter 6 shows the company's portfolio risk analysis, as well as the process and determination of the preferred portfolio.
4m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation	This IRP is presumed to have no inconsistencies.
4n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources,	Chapter 8 presents the 2008-09 IRP Action Plan with focus on the following areas: • Modeling

Guideline Number	Description of Requirement	Fulfillment of Requirement
	regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	• Supply/capacity • Forecasting • Regulatory communication • DSM Goals
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	Not applicable to Avista's gas utility operations.
Guideline 6: Conservation		
6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	In our 2006 IRP, Avista retained the services of RLW Analytics to provide data regarding cost, energy-efficiency and technical potential characteristics for DM measures. Using the information from the work of RLW Analytics as a starting point and incorporating any new information, Avista completes a comprehensive assessment of the potential for utility acquisition of energy-efficiency resources into the regularly-scheduled Integrated Resource Planning process.
6b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	In Avista's Action Plan in Chapter 8 we include our conservation programs annual savings targets and reference to Appendix 6.10 for the program's specific details. A discussion on the treatment of conservation programs is included in Chapter 3 while selection methodology is documented in Chapter 6.
6c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1) determine the amount of conservation resources in the best cost/ risk portfolio without regard to any limits on funding of conservation programs; and 2) identify	Not applicable. See the response for 6.b above.

Guideline Number	Description of Requirement	Fulfillment of Requirement
	the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	Avista has periodically evaluated conceptual approaches to meeting capacity constraints using demand-response and similar voluntary programs. In the past these have failed to be the most cost-effective response to the constraint. Avista is in the process of developing a separate natural gas distribution capacity value as part of the overall avoided cost structure in anticipation of improvements in technology that may allow for the cost-effective use of demand-response options. Avista is currently testing an electric demand-response technology that may be expanded to incorporate natural gas demand-response if suitable equipment can be acquired.
Guideline 8: Environmental Costs		
8	Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for CO2, NOx, SO2, and Hg emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from \$0 - \$40 (1990\$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for NOx, SO2, and Hg, if applicable.	Avista's current direct gas distribution system infrastructure does not result in any CO2, NOx, SO2, or Hg emissions. Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems) do produce CO2 emissions via compressors used to pressurize and move gas throughout the system. The Environmental Externalities discussion in Chapter 7 describes our process for addressing these costs.
Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Not applicable to Avista's gas utility operations.
Guideline 10: Multi-state utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2007 IRP conforms to the multi-state planning approach.

Guideline Number	Description of Requirement	Fulfillment of Requirement
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	Avista analyzes on an integrated basis gas supply, transportation, and storage, along with demand-side resources to reliably meet peak, swing, and base-load system requirements. As stated in Chapter 5, Avista's strategy is to reliably serve our customers on all days, including the peak day. To emphasize our commitment to reliability our assessment of resources favors firm (contractually dependable) resources. Acquisition costs of non-firm resources may be less costly. However, after consideration of risk, these assets do not meet our reliability requirements.
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	Not applicable to Avista's gas utility operations.
Guideline 13: Resource Acquisition		
13a	An electric utility should: identify its proposed acquisition strategy for each resource in its action plan; Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party; identify any Benchmark Resources it plans to consider in competitive bidding.	Not applicable to Avista's gas utility operations.
13b	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	This information will be provided following IRP acknowledgment.

Avoided Cost Determination

Appendix 7.1

Appendix 7.1 - SENDOUT® Marginal Cost Determination by Region - Summary

Expected Case

Figures Include Transportation and Storage, Excludes Environmental Externalities - 2007$/Dth

		Annual						Winter					
Year	Year of Forecast	Klamath Falls	La Grande	Medford	Roseburg	OR Total	WA/ID	Klamath Falls	La Grande	Medford	Roseburg	OR Total	WA/ID
2007/2008	1	$7.37	$7.31	$7.29	$7.31	$7.32	$7.29	$7.99	$7.94	$7.85	$7.94	$7.93	$7.86
2008/2009	2	$7.10	$6.94	$6.99	$6.94	$6.99	$6.94	$8.03	$7.72	$7.80	$7.72	$7.82	$7.81
2009'2010	3	$6.62	$6.48	$6.51	$6.48	$6.52	$6.47	$7.51	$7.25	$7.31	$7.25	$7.33	$7.29
2010/2011	4	$6.15	$6.05	$6.06	$6.05	$6.08	$6.12	$6.95	$6.75	$6.78	$6.75	$6.81	$6.75
2011/2012	5	$5.79	$5.50	$5.64	$5.50	$5.61	$5.80	$6.42	$5.78	$6.10	$5.78	$6.02	$6.34
2012/2013	6	$5.65	$5.15	$5.39	$5.15	$5.34	$5.51	$6.23	$5.26	$5.74	$5.26	$5.62	$6.13
2013/2014	7	$5.73	$5.30	$5.54	$5.30	$5.47	$5.65	$6.26	$5.36	$5.84	$5.36	$5.71	$6.16
2014/2015	8	$5.91	$5.45	$5.70	$5.45	$5.62	$5.78	$6.44	$5.55	$6.03	$5.55	$5.89	$6.34
2015/2016	9	$5.97	$5.55	$5.79	$5.55	$5.72	$5.93	$6.54	$5.69	$6.15	$5.69	$6.02	$6.47
2016/2017	10	$6.00	$5.62	$5.84	$5.62	$5.77	$5.86	$6.57	$5.81	$6.22	$5.81	$6.10	$6.50
2017/2018	11	$6.02	$5.64	$5.86	$5.64	$5.79	$5.86	$6.60	$5.83	$6.25	$5.83	$6.13	$6.53
2018/2019	12	$6.16	$5.80	$6.01	$5.80	$5.94	$6.05	$6.72	$6.00	$6.39	$6.00	$6.28	$6.63
2019/2020	13	$6.32	$5.96	$6.17	$5.96	$6.10	$6.20	$6.89	$6.18	$6.57	$6.18	$6.45	$6.80
2020/2021	14	$6.46	$6.15	$6.33	$6.15	$6.27	$6.32	$7.04	$6.46	$6.78	$6.46	$6.68	$6.95
2021/2022	15	$6.58	$6.27	$6.46	$6.48	$6.45	$6.47	$7.17	$6.60	$6.92	$7.10	$6.95	$7.09
2022/2023	16	$6.69	$6.40	$6.58	$6.61	$6.57	$6.57	$7.30	$6.75	$7.06	$7.26	$7.09	$7.19
2023/2024	17	$6.81	$6.54	$6.70	$6.95	$6.75	$6.69	$7.42	$6.92	$7.21	$7.92	$7.37	$7.31
2024/2025	18	$6.92	$6.67	$6.83	$7.09	$6.88	$6.81	$7.54	$7.09	$7.35	$8.10	$7.52	$7.44
2025/2026	19	$7.05	$6.85	$6.98	$7.26	$7.03	$6.93	$7.67	$7.35	$7.55	$8.36	$7.73	$7.57
2026/20027	20	$7.15	$6.98	$7.09	$7.60	$7.20	$7.04	$7.78	$7.52	$7.69	$9.02	$8.01	$7.69

Appendix 7.1 - SENDOUT® Marginal Cost Determination by Region - Annual

Expected Case

Figures Include Transportation and Storage, Excludes Environmental Externalities - 2007$/Dth

Year	Month	Klam Falls	La Grande	Medford	Roseburg	OR Total	WA/ID
2007	Nov	6.65	6.48	6.53	6.48	6.54	6.46
2007	Dec	7.48	8.01	7.43	8.01	7.73	7.66
2008	Jan	8.73	8.58	8.54	8.58	8.61	8.53
2008	Feb	8.70	8.42	8.48	8.42	8.50	8.42
2008	Mar	8.39	8.20	8.26	8.20	8.26	8.20
2008	Apr	6.75	6.66	6.71	6.66	6.70	6.71
2008	May	6.98	6.88	6.93	6.88	6.92	6.86
2008	Jun	6.61	6.53	6.57	6.53	6.56	6.68
2008	Jul	7.11	7.16	7.11	7.16	7.13	7.03
2008	Aug	7.12	7.03	7.07	7.03	7.06	7.06
2008	Sep	6.79	6.71	6.75	6.71	6.74	6.85
2008	Oct	7.12	7.02	7.07	7.02	7.06	7.06
	Avg.	**7.37**	**7.31**	**7.29**	**7.31**	**7.32**	**7.29**
2008	Nov	7.75	7.53	7.59	7.53	7.60	7.53
2008	Dec	8.23	7.53	7.79	7.53	7.77	8.04
2009	Jan	8.17	8.04	8.00	8.04	8.06	7.98
2009	Feb	8.15	7.85	7.91	7.85	7.94	7.85
2009	Mar	7.84	7.65	7.71	7.65	7.71	7.65
2009	Apr	6.20	6.12	6.16	6.12	6.15	5.44
2009	May	6.47	6.38	6.43	6.38	6.42	6.38
2009	Jun	6.17	6.10	6.14	6.10	6.13	6.24
2009	Jul	6.63	6.68	6.63	6.68	6.66	6.56
2009	Aug	6.64	6.57	6.60	6.57	6.60	6.59
2009	Sep	6.34	6.26	6.30	6.26	6.29	6.39
2009	Oct	6.65	6.57	6.61	6.57	6.60	6.60
	Avg.	**7.11**	**6.94**	**6.99**	**6.94**	**6.99**	**6.94**
2009	Nov	7.26	7.03	7.10	7.03	7.11	7.03
2009	Dec	7.70	7.24	7.39	7.24	7.39	7.52
2010	Jan	7.63	7.51	7.47	7.51	7.53	7.45
2010	Feb	7.62	7.33	7.39	7.33	7.42	7.32
2010	Mar	7.33	7.14	7.20	7.14	7.20	7.14
2010	Apr	5.78	5.70	5.74	5.70	5.73	5.12
2010	May	6.03	5.95	5.99	5.95	5.98	5.95
2010	Jun	5.77	5.70	5.73	5.70	5.72	5.82
2010	Jul	6.18	6.23	6.18	6.23	6.21	6.12
2010	Aug	6.01	5.94	5.97	5.94	5.97	6.02
2010	Sep	5.91	5.84	5.88	5.84	5.87	5.97
2010	Oct	6.21	6.13	6.17	6.13	6.16	6.16
	Avg.	**6.62**	**6.48**	**6.52**	**6.48**	**6.52**	**6.47**
2010	Nov	6.77	6.56	6.62	6.56	6.62	6.56
2010	Dec	7.18	6.98	7.00	6.98	7.03	7.03
2011	Jan	7.03	6.92	6.87	6.92	6.93	6.86
2011	Feb	7.02	6.74	6.80	6.74	6.82	6.74
2011	Mar	6.76	6.57	6.62	6.57	6.63	6.56
2011	Apr	5.33	5.26	5.29	5.26	5.28	5.35
2011	May	5.57	5.50	5.54	5.50	5.53	5.47
2011	Jun	5.60	5.53	5.56	5.53	5.56	5.55
2011	Jul	5.69	5.86	5.69	5.86	5.77	6.52
2011	Aug	5.73	5.66	5.69	5.66	5.68	5.69
2011	Sep	5.43	5.37	5.40	5.37	5.39	5.49
2011	Oct	5.72	5.64	5.68	5.64	5.67	5.67
	Avg.	**6.15**	**6.05**	**6.06**	**6.05**	**6.08**	**6.12**
2011	Nov	6.13	6.02	6.08	6.02	6.06	6.02
2011	Dec	6.45	3.70	5.09	3.70	4.74	6.46
2012	Jan	6.58	6.62	6.58	6.62	6.60	6.56
2012	Feb	6.56	6.32	6.44	6.32	6.41	6.36
2012	Mar	6.39	6.29	6.34	6.29	6.33	6.28
2012	Apr	5.09	5.02	5.06	5.02	5.05	4.93
2012	May	5.30	5.23	5.26	5.23	5.25	5.23
2012	Jun	5.35	5.29	5.32	5.29	5.31	5.31
2012	Jul	5.44	5.61	5.44	5.61	5.52	6.27
2012	Aug	5.48	5.41	5.44	5.41	5.44	5.44
2012	Sep	5.21	5.14	5.17	5.14	5.17	5.26
2012	Oct	5.46	5.39	5.43	5.39	5.42	5.41
	Avg.	**5.79**	**5.50**	**5.64**	**5.50**	**5.61**	**5.79**

Appendix 7.1 - SENDOUT® Marginal Cost Determination by Region - Annual

Expected Case

Figures Include Transportation and Storage, Excludes Environmental Externalities - 2007$/Dth

Year	Month	Klam Falls	La Grande	Medford	Roseburg	OR Total	WA/ID
2012	Nov	5.88	5.77	5.82	5.77	5.81	5.77
2012	Dec	6.18	1.85	4.02	1.85	3.47	6.14
2013	Jan	6.44	6.47	6.44	6.47	6.45	6.42
2013	Feb	6.42	6.16	6.29	6.16	6.25	6.20
2013	Mar	6.26	6.14	6.20	6.14	6.19	6.14
2013	Apr	5.26	4.42	4.84	4.42	4.73	3.51
2013	May	5.21	5.12	5.16	5.12	5.15	5.12
2013	Jun	4.98	4.90	4.94	4.90	4.93	5.01
2013	Jul	5.32	5.50	5.32	5.50	5.41	6.06
2013	Aug	5.37	5.30	5.33	5.30	5.32	5.33
2013	Sep	5.10	5.03	5.06	5.03	5.05	5.14
2013	Oct	5.41	5.25	5.33	5.25	5.31	5.28
	Avg.	**5.65**	**5.16**	**5.40**	**5.16**	**5.34**	**5.51**
2013	Nov	5.75	5.63	5.72	5.63	5.68	5.63
2013	Dec	6.05	2.11	4.11	2.11	3.60	6.02
2014	Jan	6.56	6.61	6.62	6.61	6.60	6.55
2014	Feb	6.55	6.29	6.46	6.29	6.40	6.34
2014	Mar	6.40	6.28	6.37	6.28	6.33	6.28
2014	Apr	5.37	5.02	5.22	5.02	5.16	4.44
2014	May	5.32	5.23	5.30	5.23	5.27	5.23
2014	Jun	5.10	5.00	5.07	5.00	5.04	5.12
2014	Jul	5.44	5.61	5.49	5.61	5.54	6.17
2014	Aug	5.48	5.41	5.47	5.41	5.44	5.44
2014	Sep	5.23	5.13	5.20	5.13	5.17	5.24
2014	Oct	5.53	5.37	5.48	5.37	5.44	5.40
	Avg.	**5.73**	**5.31**	**5.54**	**5.31**	**5.47**	**5.65**
2014	Nov	5.87	5.76	5.84	5.76	5.81	5.76
2014	Dec	6.18	2.29	4.27	2.29	3.76	6.15
2015	Jan	6.78	6.83	6.84	6.83	6.82	6.77
2015	Feb	6.77	6.51	6.67	6.51	6.62	6.55
2015	Mar	6.60	6.48	6.57	6.48	6.53	6.48
2015	Apr	5.55	4.77	5.19	4.77	5.07	4.01
2015	May	5.50	5.40	5.48	5.40	5.44	5.40
2015	Jun	5.28	5.17	5.25	5.17	5.21	5.29
2015	Jul	5.61	5.79	5.67	5.79	5.71	6.34
2015	Aug	5.65	5.59	5.65	5.59	5.62	5.61
2015	Sep	5.41	5.31	5.38	5.31	5.35	5.42
2015	Oct	5.71	5.54	5.65	5.54	5.61	5.57
	Avg.	**5.91**	**5.45**	**5.71**	**5.45**	**5.63**	**5.78**
2015	Nov	6.07	5.95	6.04	5.95	6.00	5.95
2015	Dec	6.37	2.50	4.47	2.50	3.96	6.38
2016	Jan	6.82	6.87	6.88	6.87	6.86	6.81
2016	Feb	6.81	6.69	6.78	6.69	6.74	6.68
2016	Mar	6.63	6.51	6.61	6.51	6.57	6.51
2016	Apr	5.58	5.20	5.42	5.20	5.35	5.01
2016	May	5.52	5.42	5.50	5.42	5.46	5.42
2016	Jun	5.32	5.20	5.28	5.20	5.25	5.31
2016	Jul	5.64	5.82	5.70	5.82	5.75	6.37
2016	Aug	5.69	5.62	5.68	5.62	5.65	5.64
2016	Sep	5.45	5.35	5.42	5.35	5.39	5.46
2016	Oct	5.74	5.57	5.69	5.57	5.64	5.60
	Avg.	**5.97**	**5.56**	**5.79**	**5.56**	**5.72**	**5.93**
2016	Nov	6.10	5.98	6.07	5.98	6.03	5.98
2016	Dec	6.42	2.98	4.72	2.98	4.27	6.42
2017	Jan	6.85	6.90	6.91	6.90	6.89	6.84
2017	Feb	6.84	6.73	6.82	6.73	6.78	6.72
2017	Mar	6.67	6.54	6.64	6.54	6.60	6.54
2017	Apr	5.62	5.23	5.46	5.23	5.39	4.44
2017	May	5.55	5.45	5.53	5.45	5.50	5.45
2017	Jun	5.33	5.25	5.32	5.25	5.29	5.41
2017	Jul	5.67	5.72	5.72	5.72	5.71	5.61
2017	Aug	5.71	5.66	5.70	5.66	5.68	5.70
2017	Sep	5.49	5.41	5.47	5.41	5.44	5.56
2017	Oct	5.78	5.66	5.75	5.66	5.71	5.67
	Avg.	**6.00**	**5.63**	**5.84**	**5.63**	**5.77**	**5.86**

Appendix 7.1 - SENDOUT® Marginal Cost Determination by Region - Annual
Expected Case
Figures Include Transportation and Storage, Excludes Environmental Externalities - 2007$/Dth

Year	Month	Klam Falls	La Grande	Medford	Roseburg	OR Total	WA/ID
2017	Nov	6.12	6.00	6.09	6.00	6.05	6.00
2017	Dec	6.45	3.01	4.76	3.01	4.30	6.45
2018	Jan	6.87	6.93	6.94	6.93	6.92	6.87
2018	Feb	6.86	6.75	6.84	6.75	6.80	6.74
2018	Mar	6.70	6.57	6.67	6.57	6.63	6.57
2018	Apr	5.64	5.26	5.48	5.26	5.41	4.14
2018	May	5.57	5.47	5.55	5.47	5.52	5.47
2018	Jun	5.36	5.27	5.34	5.27	5.31	5.43
2018	Jul	5.70	5.75	5.75	5.75	5.74	5.64
2018	Aug	5.74	5.69	5.73	5.69	5.71	5.73
2018	Sep	5.51	5.44	5.50	5.44	5.47	5.58
2018	Oct	5.80	5.68	5.77	5.68	5.73	5.69
	Avg.	**6.03**	**5.65**	**5.87**	**5.65**	**5.80**	**5.86**
2018	Nov	6.15	6.03	6.12	6.03	6.08	6.03
2018	Dec	6.47	3.30	4.92	3.30	4.50	6.42
2019	Jan	7.06	7.11	7.12	7.11	7.10	7.04
2019	Feb	7.05	6.92	7.02	6.92	6.98	6.92
2019	Mar	6.87	6.74	6.84	6.74	6.80	6.74
2019	Apr	5.78	5.39	5.61	5.39	5.54	5.08
2019	May	5.72	5.61	5.69	5.61	5.66	5.61
2019	Jun	5.51	5.43	5.49	5.43	5.47	5.58
2019	Jul	5.84	5.90	5.90	5.90	5.88	5.78
2019	Aug	5.88	5.83	5.88	5.83	5.85	5.87
2019	Sep	5.71	5.60	5.67	5.60	5.64	5.74
2019	Oct	5.96	5.83	5.92	5.83	5.89	5.84
	Avg.	**6.17**	**5.81**	**6.02**	**5.81**	**5.95**	**6.06**
2019	Nov	6.32	6.19	6.29	6.19	6.25	6.19
2019	Dec	6.64	3.47	5.09	3.47	4.67	6.60
2020	Jan	7.23	7.28	7.29	7.28	7.27	7.22
2020	Feb	7.21	7.08	7.18	7.08	7.14	7.08
2020	Mar	7.04	6.91	7.01	6.91	6.96	6.90
2020	Apr	5.93	5.52	5.75	5.52	5.68	5.09
2020	May	5.86	5.76	5.84	5.76	5.80	5.76
2020	Jun	5.65	5.56	5.63	5.56	5.60	5.72
2020	Jul	5.98	6.05	6.05	6.05	6.03	5.93
2020	Aug	6.03	5.97	6.02	5.97	6.00	6.02
2020	Sep	5.85	5.74	5.81	5.74	5.78	5.88
2020	Oct	6.12	5.99	6.09	5.99	6.05	6.00
	Avg.	**6.32**	**5.96**	**6.17**	**5.96**	**6.10**	**6.20**
2020	Nov	6.46	6.33	6.43	6.33	6.39	6.33
2020	Dec	6.79	4.26	5.56	4.26	5.22	6.76
2021	Jan	7.39	7.44	7.45	7.44	7.43	7.38
2021	Feb	7.38	7.25	7.35	7.25	7.31	7.25
2021	Mar	7.19	7.06	7.16	7.06	7.12	7.06
2021	Apr	6.06	5.64	5.88	5.64	5.81	5.08
2021	May	5.98	5.88	5.96	5.88	5.92	5.88
2021	Jun	5.78	5.69	5.75	5.69	5.73	5.85
2021	Jul	6.12	6.18	6.18	6.18	6.17	6.06
2021	Aug	6.16	6.11	6.16	6.11	6.13	6.15
2021	Sep	5.97	5.86	5.94	5.86	5.91	6.01
2021	Oct	6.26	6.12	6.22	6.12	6.18	6.13
	Avg.	**6.46**	**6.15**	**6.34**	**6.15**	**6.28**	**6.33**
2021	Nov	6.60	6.48	6.57	6.48	6.53	6.48
2021	Dec	6.95	4.45	5.73	6.90	6.01	6.95
2022	Jan	7.52	7.57	7.58	7.57	7.56	7.50
2022	Feb	7.50	7.38	7.47	7.38	7.43	7.37
2022	Mar	7.32	7.19	7.29	7.19	7.25	7.18
2022	Apr	6.16	5.74	5.98	5.74	5.91	5.51
2022	May	6.10	5.99	6.07	5.99	6.04	5.99
2022	Jun	5.89	5.80	5.87	5.80	5.84	5.95
2022	Jul	6.22	6.29	6.29	6.29	6.27	6.16
2022	Aug	6.27	6.22	6.27	6.22	6.25	6.26
2022	Sep	6.12	5.97	6.07	5.97	6.03	6.11
2022	Oct	6.37	6.23	6.33	6.23	6.29	6.24
	Avg.	**6.58**	**6.27**	**6.46**	**6.48**	**6.45**	**6.48**

Appendix 7.1 - SENDOUT® Marginal Cost Determination by Region - Annual

Expected Case

Figures Include Transportation and Storage, Excludes Environmental Externalities - 2007$/Dth

Year	Month	Klam Falls	La Grande	Medford	Roseburg	OR Total	WA/ID
2022	Nov	6.73	6.60	6.70	6.60	6.65	6.60
2022	Dec	7.07	4.73	5.94	7.19	6.23	6.99
2023	Jan	7.64	7.70	7.71	7.70	7.69	7.57
2023	Feb	7.63	7.50	7.60	7.50	7.55	7.49
2023	Mar	7.44	7.31	7.41	7.31	7.37	7.30
2023	Apr	6.27	5.84	6.08	5.84	6.00	5.58
2023	May	6.20	6.09	6.18	6.09	6.14	6.09
2023	Jun	5.98	5.89	5.96	5.89	5.93	6.05
2023	Jul	6.33	6.52	6.39	6.52	6.44	6.31
2023	Aug	6.38	6.32	6.37	6.32	6.35	6.37
2023	Sep	6.24	6.09	6.19	6.09	6.15	6.23
2023	Oct	6.47	6.34	6.44	6.34	6.40	6.34
	Avg.	**6.70**	**6.41**	**6.58**	**6.61**	**6.58**	**6.58**
2023	Nov	6.84	6.71	6.81	6.71	6.77	6.71
2023	Dec	7.18	5.06	6.16	9.97	7.09	7.11
2024	Jan	7.77	7.83	7.84	7.83	7.82	7.71
2024	Feb	7.75	7.62	7.72	7.62	7.68	7.62
2024	Mar	7.56	7.43	7.53	7.43	7.49	7.42
2024	Apr	6.38	5.94	6.19	5.94	6.11	5.72
2024	May	6.30	6.19	6.28	6.19	6.24	6.19
2024	Jun	6.09	6.00	6.07	6.00	6.04	6.15
2024	Jul	6.44	6.63	6.50	6.63	6.55	6.42
2024	Aug	6.48	6.42	6.48	6.42	6.45	6.47
2024	Sep	6.35	6.19	6.29	6.19	6.26	6.33
2024	Oct	6.59	6.45	6.55	6.45	6.51	6.45
	Avg.	**6.81**	**6.54**	**6.70**	**6.95**	**6.75**	**6.69**
2024	Nov	6.95	6.82	6.92	6.82	6.88	6.82
2024	Dec	7.31	5.40	6.39	10.30	7.35	7.23
2025	Jan	7.90	7.96	7.97	7.96	7.95	7.84
2025	Feb	7.88	7.75	7.85	7.75	7.81	7.75
2025	Mar	7.69	7.57	7.67	7.57	7.62	7.56
2025	Apr	6.51	6.06	6.32	6.06	6.24	5.84
2025	May	6.41	6.29	6.38	6.29	6.34	6.29
2025	Jun	6.20	6.10	6.17	6.10	6.14	6.26
2025	Jul	6.55	6.74	6.62	6.74	6.66	6.53
2025	Aug	6.59	6.54	6.59	6.54	6.56	6.58
2025	Sep	6.46	6.30	6.41	6.30	6.37	6.44
2025	Oct	6.70	6.56	6.66	6.56	6.62	6.57
	Avg.	**6.93**	**6.67**	**6.83**	**7.08**	**6.88**	**6.81**
2025	Nov	7.08	6.94	7.05	6.94	7.00	6.94
2025	Dec	7.43	6.17	6.84	11.06	7.87	7.36
2026	Jan	8.03	8.11	8.11	8.11	8.09	7.98
2026	Feb	8.02	7.89	8.00	7.89	7.95	7.89
2026	Mar	7.82	7.70	7.80	7.70	7.76	7.69
2026	Apr	6.62	6.17	6.43	6.17	6.35	5.95
2026	May	6.52	6.40	6.50	6.40	6.46	6.40
2026	Jun	6.30	6.21	6.28	6.21	6.25	6.37
2026	Jul	6.67	6.87	6.73	6.87	6.78	6.65
2026	Aug	6.71	6.65	6.70	6.65	6.68	6.69
2026	Sep	6.57	6.41	6.52	6.41	6.48	6.56
2026	Oct	6.82	6.70	6.79	6.70	6.75	6.70
	Avg.	**7.05**	**6.85**	**6.98**	**7.26**	**7.03**	**6.93**
2026	Nov	7.20	7.06	7.17	7.06	7.12	7.06
2026	Dec	7.56	6.56	7.08	13.87	8.77	7.52
2027	Jan	8.14	8.21	8.21	8.21	8.19	8.08
2027	Feb	8.12	8.01	8.10	8.01	8.06	8.00
2027	Mar	7.93	7.81	7.91	7.81	7.87	7.80
2027	Apr	6.71	6.25	6.51	6.25	6.43	6.03
2027	May	6.62	6.50	6.59	6.50	6.55	6.50
2027	Jun	6.39	6.30	6.37	6.30	6.34	6.46
2027	Jul	6.76	6.96	6.83	6.96	6.88	6.74
2027	Aug	6.80	6.74	6.80	6.74	6.77	6.78
2027	Sep	6.77	6.56	6.69	6.56	6.64	6.68
2027	Oct	6.91	6.79	6.89	6.79	6.85	6.79
	Avg.	**7.16**	**6.98**	**7.10**	**7.59**	**7.21**	**7.04**

Appendix 7.1 - SENDOUT® Marginal Cost Determination by Region - Winter

Expected Case

Figures Include Transportation and Storage, Excludes Environmental Externalities - 2007$/Dth

Year	Month	Klam Falls	La Grande	Medford	Roseburg	OR Total	WA/ID
2007	Nov	6.65	6.48	6.53	6.48	6.54	6.46
2007	Dec	7.48	8.01	7.43	8.01	7.73	7.66
2008	Jan	8.73	8.58	8.54	8.58	8.61	8.53
2008	Feb	8.70	8.42	8.48	8.42	8.50	8.42
2008	Mar	8.39	8.20	8.26	8.20	8.26	8.20
	Avg.	**7.99**	**7.94**	**7.85**	**7.94**	**7.93**	**7.85**
2008	Nov	7.75	7.53	7.59	7.53	7.60	7.53
2008	Dec	8.23	7.53	7.79	7.53	7.77	8.04
2009	Jan	8.17	8.04	8.00	8.04	8.06	7.98
2009	Feb	8.15	7.85	7.91	7.85	7.94	7.85
2009	Mar	7.84	7.65	7.71	7.65	7.71	7.65
	Avg.	**8.03**	**7.72**	**7.80**	**7.72**	**7.82**	**7.81**
2009	Nov	7.26	7.03	7.10	7.03	7.11	7.03
2009	Dec	7.70	7.24	7.39	7.24	7.39	7.52
2010	Jan	7.63	7.51	7.47	7.51	7.53	7.45
2010	Feb	7.62	7.33	7.39	7.33	7.42	7.32
2010	Mar	7.33	7.14	7.20	7.14	7.20	7.14
	Avg.	**7.51**	**7.25**	**7.31**	**7.25**	**7.33**	**7.29**
2010	Nov	6.77	6.56	6.62	6.56	6.62	6.56
2010	Dec	7.18	6.98	7.00	6.98	7.03	7.03
2011	Jan	7.03	6.92	6.87	6.92	6.93	6.86
2011	Feb	7.02	6.74	6.80	6.74	6.82	6.74
2011	Mar	6.76	6.57	6.62	6.57	6.63	6.56
	Avg.	**6.95**	**6.75**	**6.78**	**6.75**	**6.81**	**6.75**
2011	Nov	6.13	6.02	6.08	6.02	6.06	6.02
2011	Dec	6.45	3.70	5.09	3.70	4.74	6.46
2012	Jan	6.58	6.62	6.58	6.62	6.60	6.56
2012	Feb	6.56	6.32	6.44	6.32	6.41	6.36
2012	Mar	6.39	6.29	6.34	6.29	6.33	6.28
	Avg.	**6.42**	**5.79**	**6.11**	**5.79**	**6.03**	**6.34**
2012	Nov	5.88	5.77	5.82	5.77	5.81	5.77
2012	Dec	6.18	1.85	4.02	1.85	3.47	6.14
2013	Jan	6.44	6.47	6.44	6.47	6.45	6.42
2013	Feb	6.42	6.16	6.29	6.16	6.25	6.20
2013	Mar	6.26	6.14	6.20	6.14	6.19	6.14
	Avg.	**6.24**	**5.28**	**5.75**	**5.28**	**5.64**	**6.13**
2013	Nov	5.75	5.63	5.72	5.63	5.68	5.63
2013	Dec	6.05	2.11	4.11	2.11	3.60	6.02
2014	Jan	6.56	6.61	6.62	6.61	6.60	6.55
2014	Feb	6.55	6.29	6.46	6.29	6.40	6.34
2014	Mar	6.40	6.28	6.37	6.28	6.33	6.28
	Avg.	**6.26**	**5.38**	**5.86**	**5.38**	**5.72**	**6.16**
2014	Nov	5.87	5.76	5.84	5.76	5.81	5.76
2014	Dec	6.18	2.29	4.27	2.29	3.76	6.15
2015	Jan	6.78	6.83	6.84	6.83	6.82	6.77
2015	Feb	6.77	6.51	6.67	6.51	6.62	6.55
2015	Mar	6.60	6.48	6.57	6.48	6.53	6.48
	Avg.	**6.44**	**5.57**	**6.04**	**5.57**	**5.91**	**6.34**
2015	Nov	6.07	5.95	6.04	5.95	6.00	5.95
2015	Dec	6.37	2.50	4.47	2.50	3.96	6.38
2016	Jan	6.82	6.87	6.88	6.87	6.86	6.81
2016	Feb	6.81	6.69	6.78	6.69	6.74	6.68
2016	Mar	6.63	6.51	6.61	6.51	6.57	6.51
	Avg.	**6.54**	**5.70**	**6.15**	**5.70**	**6.03**	**6.47**

Appendix 7.1 - SENDOUT® Marginal Cost Determination by Region - Winter

Expected Case

Figures Include Transportation and Storage, Excludes Environmental Externalities - 2007$/Dth

Year	Month	Klam Falls	La Grande	Medford	Roseburg	OR Total	WA/ID
2016	Nov	6.10	5.98	6.07	5.98	6.03	5.98
2016	Dec	6.42	2.98	4.72	2.98	4.27	6.42
2017	Jan	6.85	6.90	6.91	6.90	6.89	6.84
2017	Feb	6.84	6.73	6.82	6.73	6.78	6.72
2017	Mar	6.67	6.54	6.64	6.54	6.60	6.54
	Avg.	**6.57**	**5.82**	**6.23**	**5.82**	**6.11**	**6.50**
2017	Nov	6.12	6.00	6.09	6.00	6.05	6.00
2017	Dec	6.45	3.01	4.76	3.01	4.30	6.45
2018	Jan	6.87	6.93	6.94	6.93	6.92	6.87
2018	Feb	6.86	6.75	6.84	6.75	6.80	6.74
2018	Mar	6.70	6.57	6.67	6.57	6.63	6.57
	Avg.	**6.60**	**5.85**	**6.26**	**5.85**	**6.14**	**6.53**
2018	Nov	6.15	6.03	6.12	6.03	6.08	6.03
2018	Dec	6.47	3.30	4.92	3.30	4.50	6.42
2019	Jan	7.06	7.11	7.12	7.11	7.10	7.04
2019	Feb	7.05	6.92	7.02	6.92	6.98	6.92
2019	Mar	6.87	6.74	6.84	6.74	6.80	6.74
	Avg.	**6.72**	**6.02**	**6.40**	**6.02**	**6.29**	**6.63**
2019	Nov	6.32	6.19	6.29	6.19	6.25	6.19
2019	Dec	6.64	3.47	5.09	3.47	4.67	6.60
2020	Jan	7.23	7.28	7.29	7.28	7.27	7.22
2020	Feb	7.21	7.08	7.18	7.08	7.14	7.08
2020	Mar	7.04	6.91	7.01	6.91	6.96	6.90
	Avg.	**6.89**	**6.19**	**6.57**	**6.19**	**6.46**	**6.80**
2020	Nov	6.46	6.33	6.43	6.33	6.39	6.33
2020	Dec	6.79	4.26	5.56	4.26	5.22	6.76
2021	Jan	7.39	7.44	7.45	7.44	7.43	7.38
2021	Feb	7.38	7.25	7.35	7.25	7.31	7.25
2021	Mar	7.19	7.06	7.16	7.06	7.12	7.06
	Avg.	**7.04**	**6.47**	**6.79**	**6.47**	**6.69**	**6.95**
2021	Nov	6.60	6.48	6.57	6.48	6.53	6.48
2021	Dec	6.95	4.45	5.73	6.90	6.01	6.95
2022	Jan	7.52	7.57	7.58	7.57	7.56	7.50
2022	Feb	7.50	7.38	7.47	7.38	7.43	7.37
2022	Mar	7.32	7.19	7.29	7.19	7.25	7.18
	Avg.	**7.18**	**6.61**	**6.93**	**7.10**	**6.96**	**7.10**
2022	Nov	6.73	6.60	6.70	6.60	6.65	6.60
2022	Dec	7.07	4.73	5.94	7.19	6.23	6.99
2023	Jan	7.64	7.70	7.71	7.70	7.69	7.57
2023	Feb	7.63	7.50	7.60	7.50	7.55	7.49
2023	Mar	7.44	7.31	7.41	7.31	7.37	7.30
	Avg.	**7.30**	**6.77**	**7.07**	**7.26**	**7.10**	**7.19**
2023	Nov	6.84	6.71	6.81	6.71	6.77	6.71
2023	Dec	7.18	5.06	6.16	9.97	7.09	7.11
2024	Jan	7.77	7.83	7.84	7.83	7.82	7.71
2024	Feb	7.75	7.62	7.72	7.62	7.68	7.62
2024	Mar	7.56	7.43	7.53	7.43	7.49	7.42
	Avg.	**7.42**	**6.93**	**7.21**	**7.91**	**7.37**	**7.31**
2024	Nov	6.95	6.82	6.92	6.82	6.88	6.82
2024	Dec	7.31	5.40	6.39	10.30	7.35	7.23
2025	Jan	7.90	7.96	7.97	7.96	7.95	7.84
2025	Feb	7.88	7.75	7.85	7.75	7.81	7.75
2025	Mar	7.69	7.57	7.67	7.57	7.62	7.56
	Avg.	**7.54**	**7.10**	**7.36**	**8.08**	**7.52**	**7.44**
2025	Nov	7.08	6.94	7.05	6.94	7.00	6.94
2025	Dec	7.43	6.17	6.84	11.06	7.87	7.36
2026	Jan	8.03	8.11	8.11	8.11	8.09	7.98
2026	Feb	8.02	7.89	8.00	7.89	7.95	7.89
2026	Mar	7.82	7.70	7.80	7.70	7.76	7.69
	Avg.	**7.67**	**7.36**	**7.56**	**8.34**	**7.73**	**7.57**

Appendix 7.1 - SENDOUT® Marginal Cost Determination by Region - Winter

Expected Case

Figures Include Transportation and Storage, Excludes Environmental Externalities - 2007$/Dth

Year	Month	Klam Falls	La Grande	Medford	Roseburg	OR Total	WA/ID
2026	Nov	7.20	7.06	7.17	7.06	7.12	7.06
2026	Dec	7.56	6.56	7.08	13.87	8.77	7.52
2027	Jan	8.14	8.21	8.21	8.21	8.19	8.08
2027	Feb	8.12	8.01	8.10	8.01	8.06	8.00
2027	Mar	7.93	7.81	7.91	7.81	7.87	7.80
	Avg.	**7.79**	**7.53**	**7.70**	**8.99**	**8.00**	**7.69**