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IDAHO PUBLIC
UTILITIES COMMISSION

AVISTA Corp.

AVU-G-07-04

December 27, 2007

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
Statehouse Mail
W. 472 Washington Street
Boise, Idaho 83720

Dear Ms. Jewell:

RE: Avista Utilities 2007 Natural Gas Integrated Resource Plan

Per IPUC's Integrated Resource Plan Requirements outlined in Case No.U-1500-165, Order No. 22299, Case No.GNR-E-93-1, Order No. 24729 and Case No.GNR-E-93-3, Order No. 25260 , Avista Corporation d/b/a/ Avista Utilities, hereby submits for filing an original, an electronic copy and 7 copies of its 2007 Natural Gas Integrated Resource Plan.

The Company submits the IRP to public utility commissions in Idaho, Washington and Oregon every two years as required by state regulation. 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. The IRP, by identifying and evaluating various resource options and establishing a plan of action for resource decisions, is a significant component in meeting this obligation.

The 2007 Plan is notable for the following:

- The Company's peak day resource deficits in Oregon begin in 2011-2012 and in Washington and Idaho in 2014-2015;

- Deficits are driven primarily by customer and demand growth;

- Lower forecasted demand is the primary change from the 2006 IRP;

- Estimated DSM energy savings goals are 1,425,000 therms in Washington and Idaho and 350,000 therms in Oregon;

Printing costs have been reduced by putting supporting documents on our web site at http://www.avistautilities.com/inside/transmission/irp/gas/

Please direct any questions regarding this report to Greg Rahn at (509) 495-2048.

Sincerely,

Linda Gervais

Linda Gervais
Senior Regulatory Analyst, State and Federal Regulation

c: Brian Lanspery

AVU-G-07-04

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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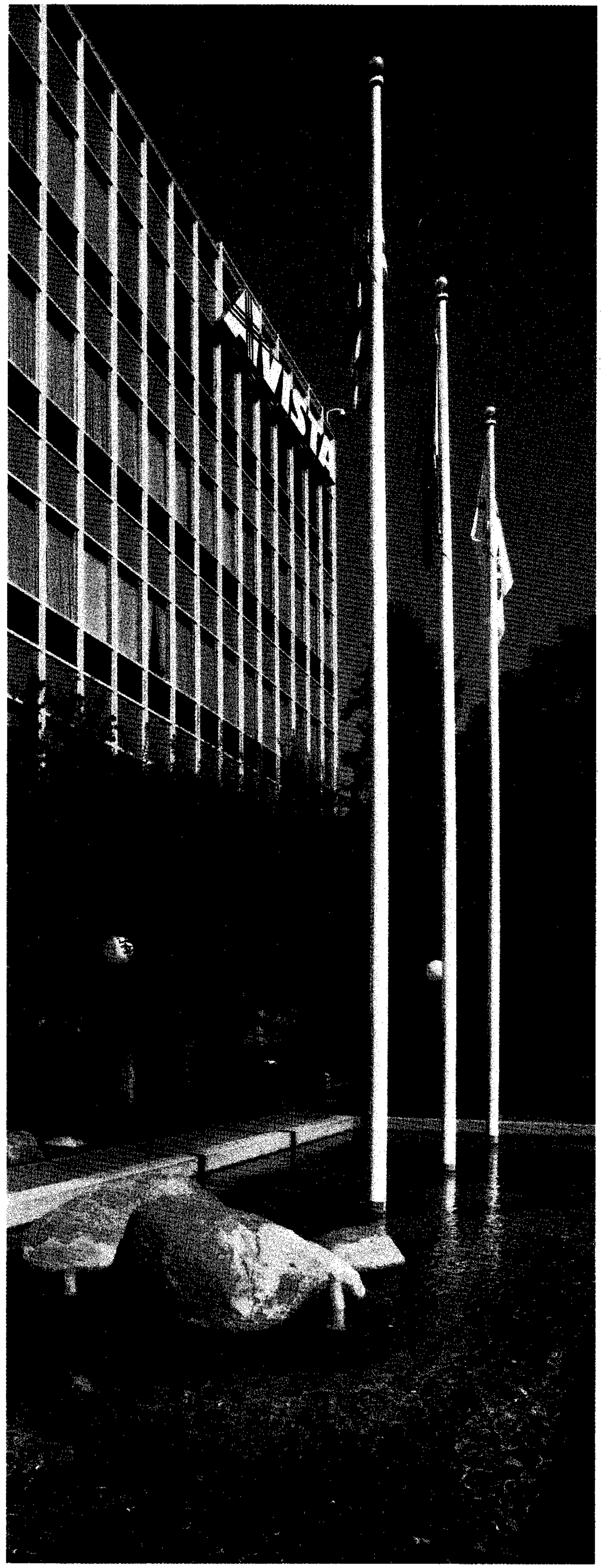

SAFE HARBOR STATEMENT

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

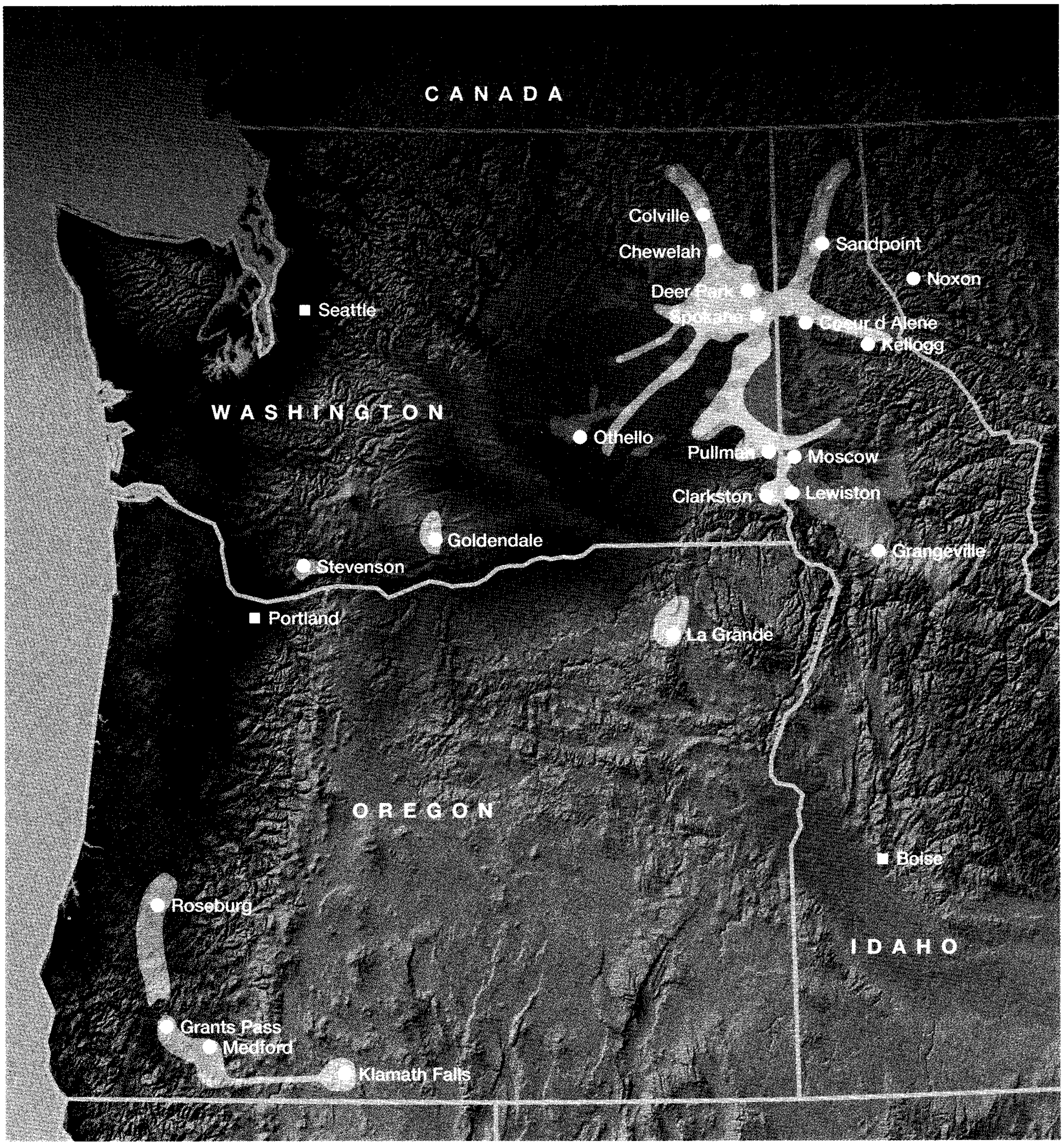
AS OF DECEMBER 31, 2006:

RETAIL ELECTRIC CUSTOMERS BY STATE

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

RETAIL NATURAL GAS CUSTOMERS BY STATE

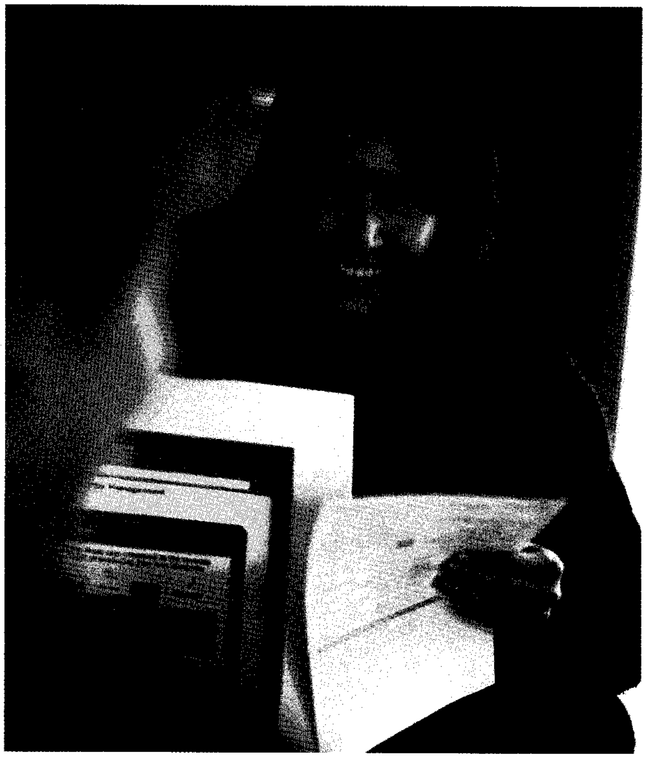
Washington:	140,900
Idaho:	69,800
Oregon:	93,900
Total Natural Gas:	304,600



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.

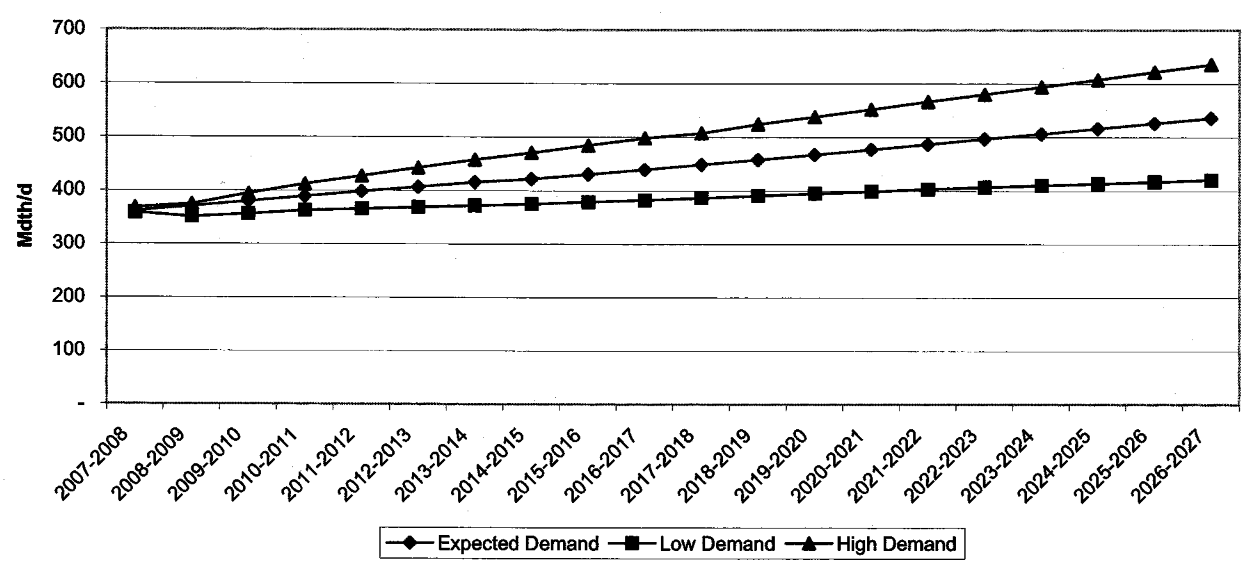
Details of the demand forecast for our High and Low Demand cases can be found in Appendix 2.4

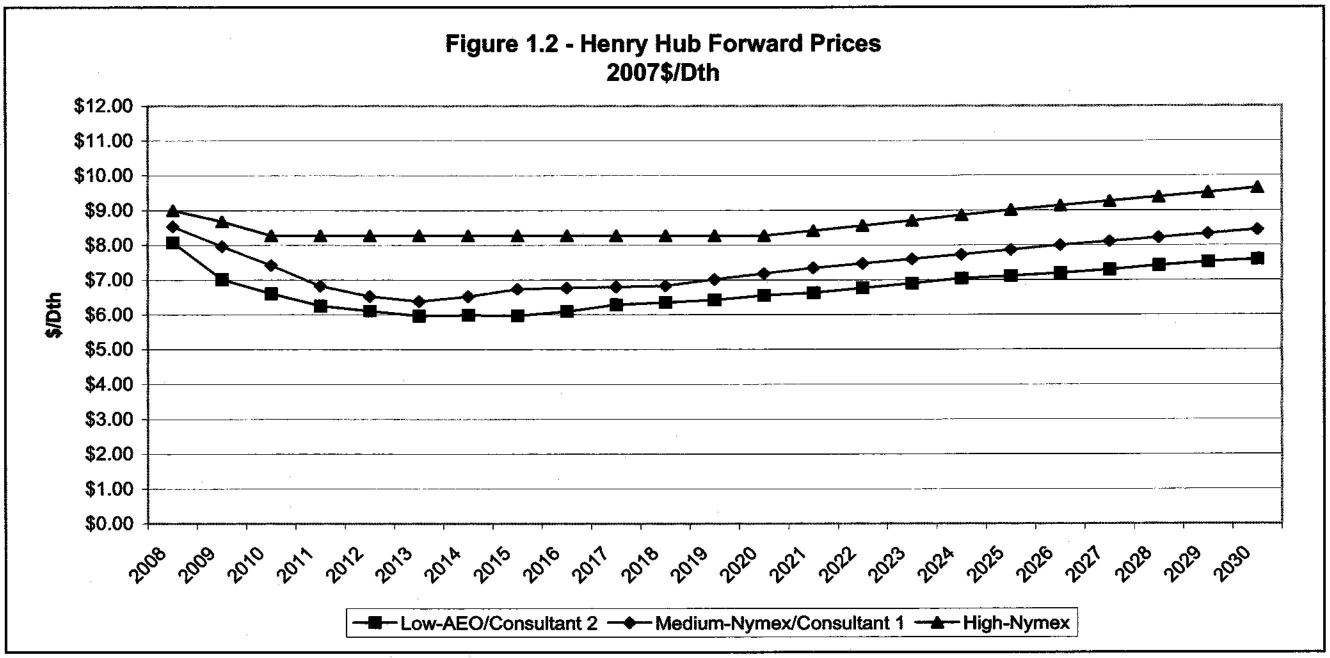
Figure 1.1 shows forecasted system-wide average peak day demand per year for the three main scenarios over the planning horizon.

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.

Figure 1.3 - WA/ID Existing Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case - November through October

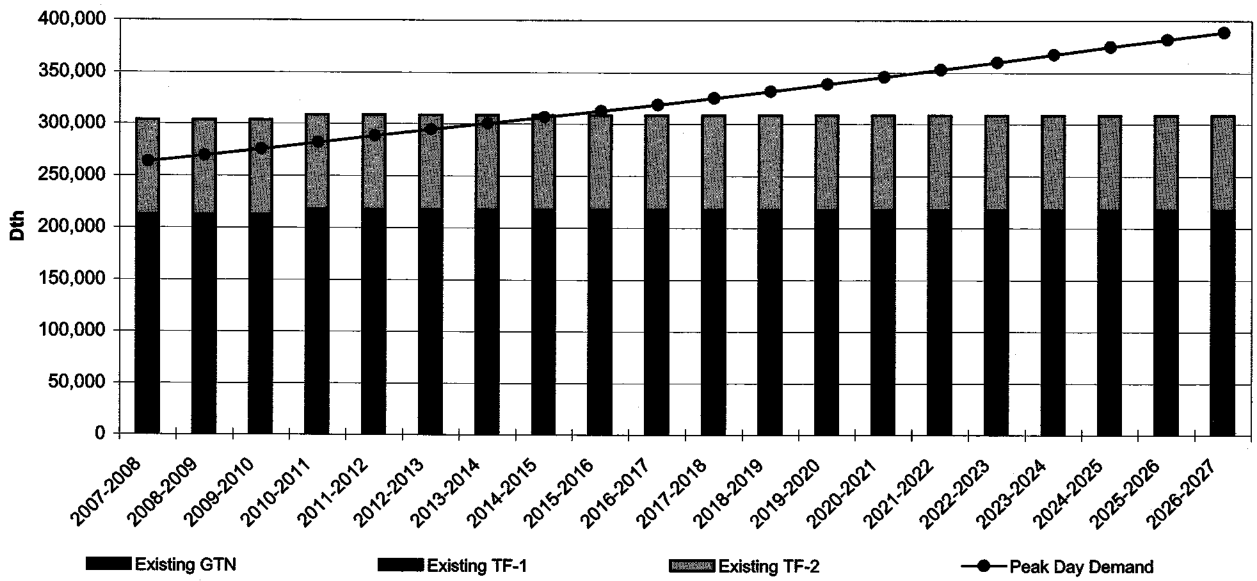
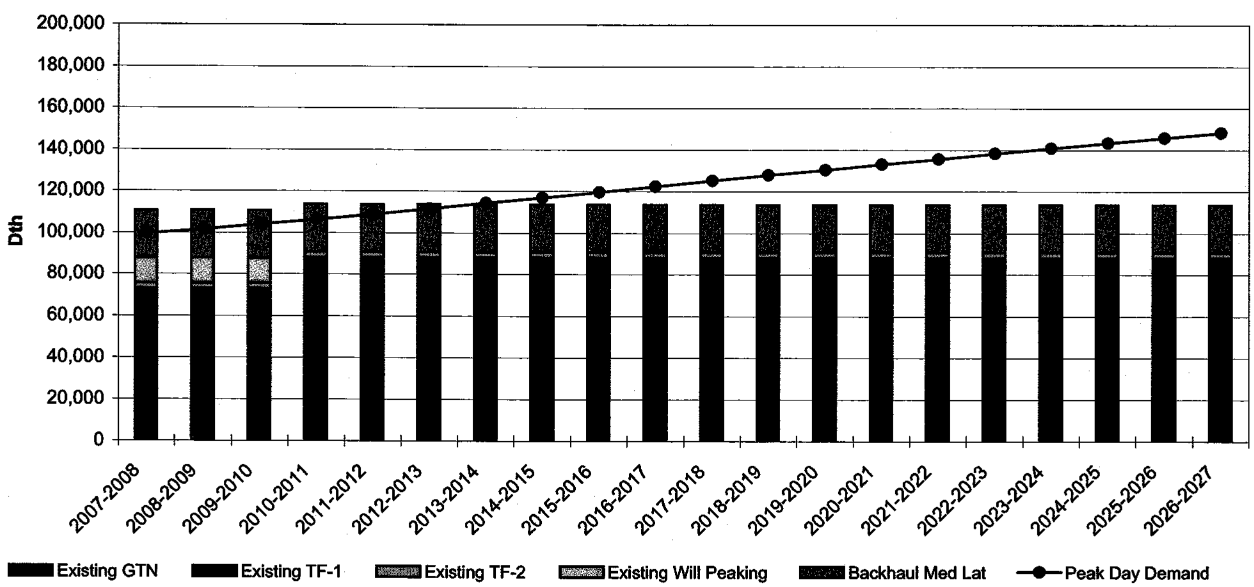
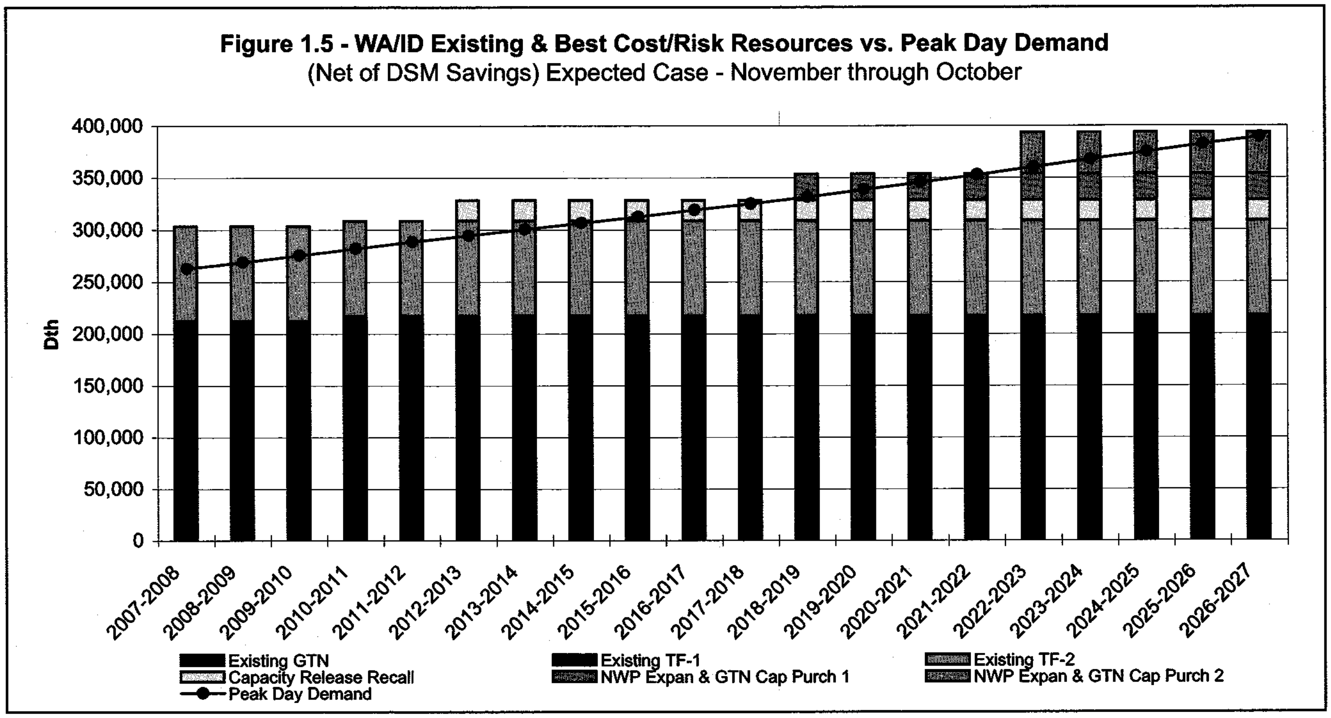


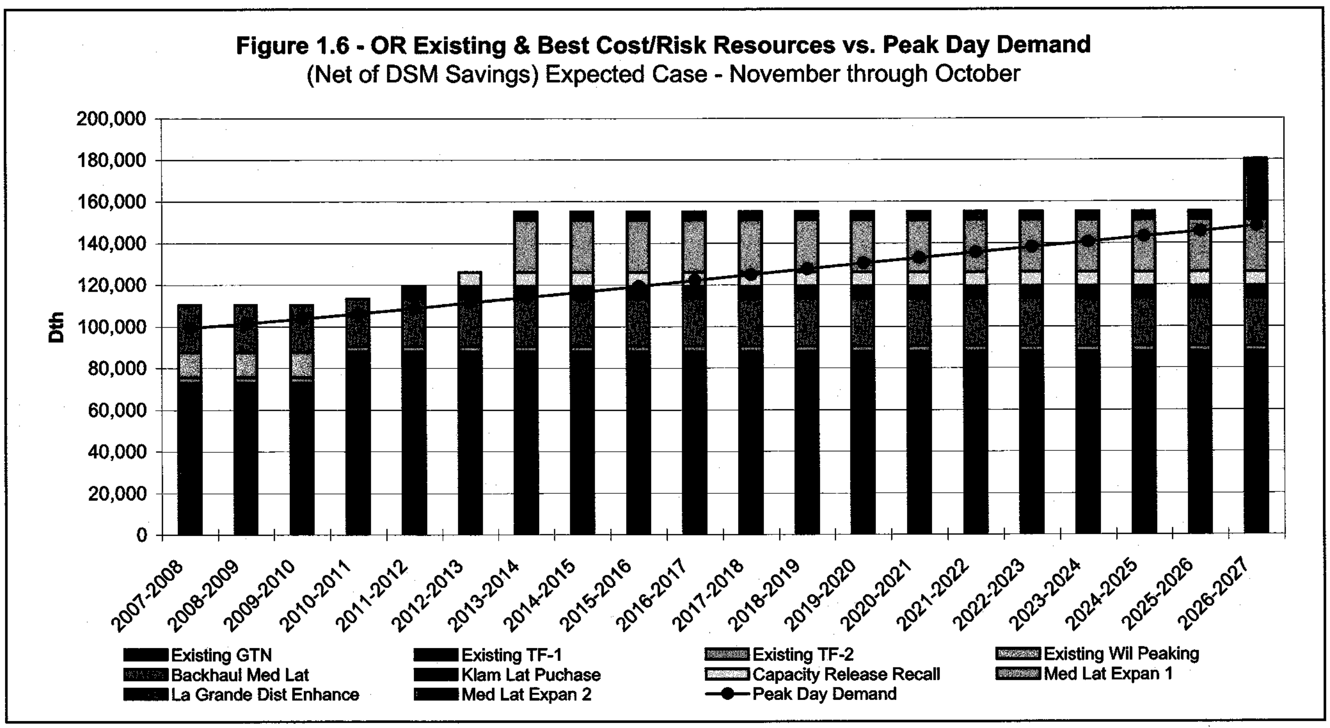
Figure 1.4 - OR Existing Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case - November through October



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

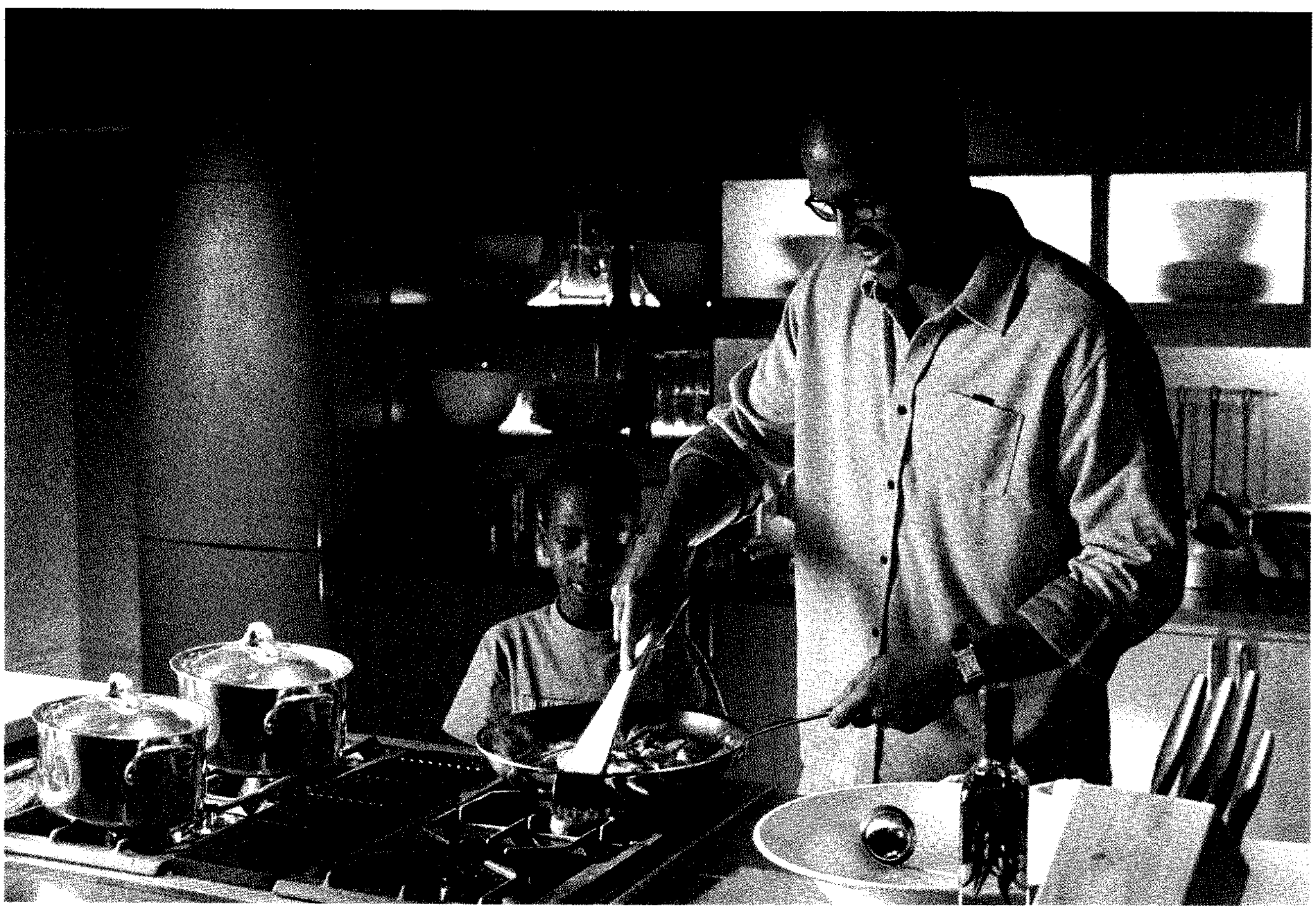
OVERVIEW

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.

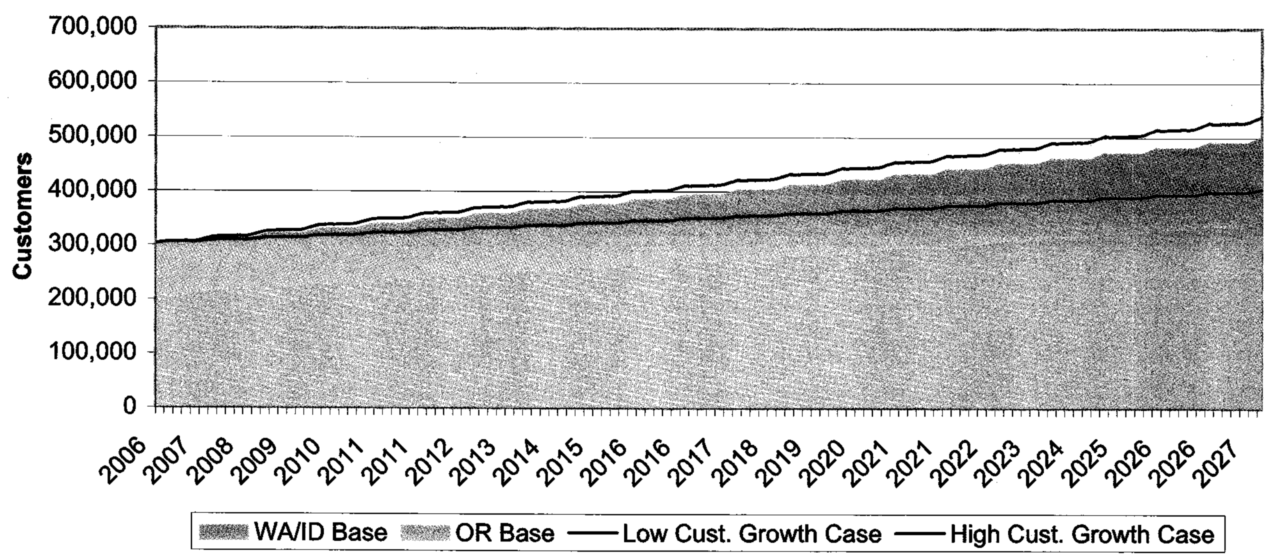
Forecasting customer growth is an inexact science, so it is important to consider alternatives to this forecast. We developed two additional outcomes for consideration in this IRP. During the last 25 years, customer growth during five-year periods has ranged between one-half and one-and-a-half times 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.

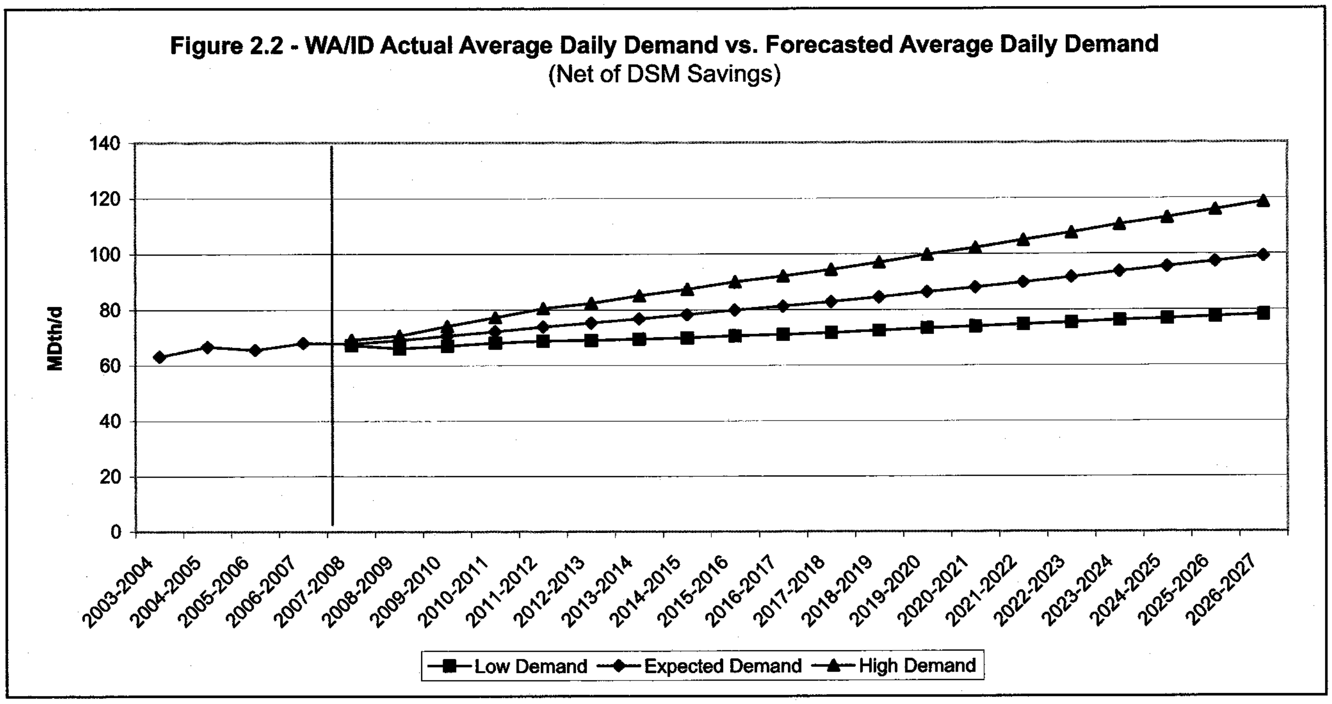
This means that if natural gas prices increase by 10 percent, we would expect customer demand to decrease 1.3 percent (all other factors being equal). Similarly, a 10 percent decrease in natural gas prices would stimulate a 1.3 percent increase in gas consumption. (The price-related elasticity factors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

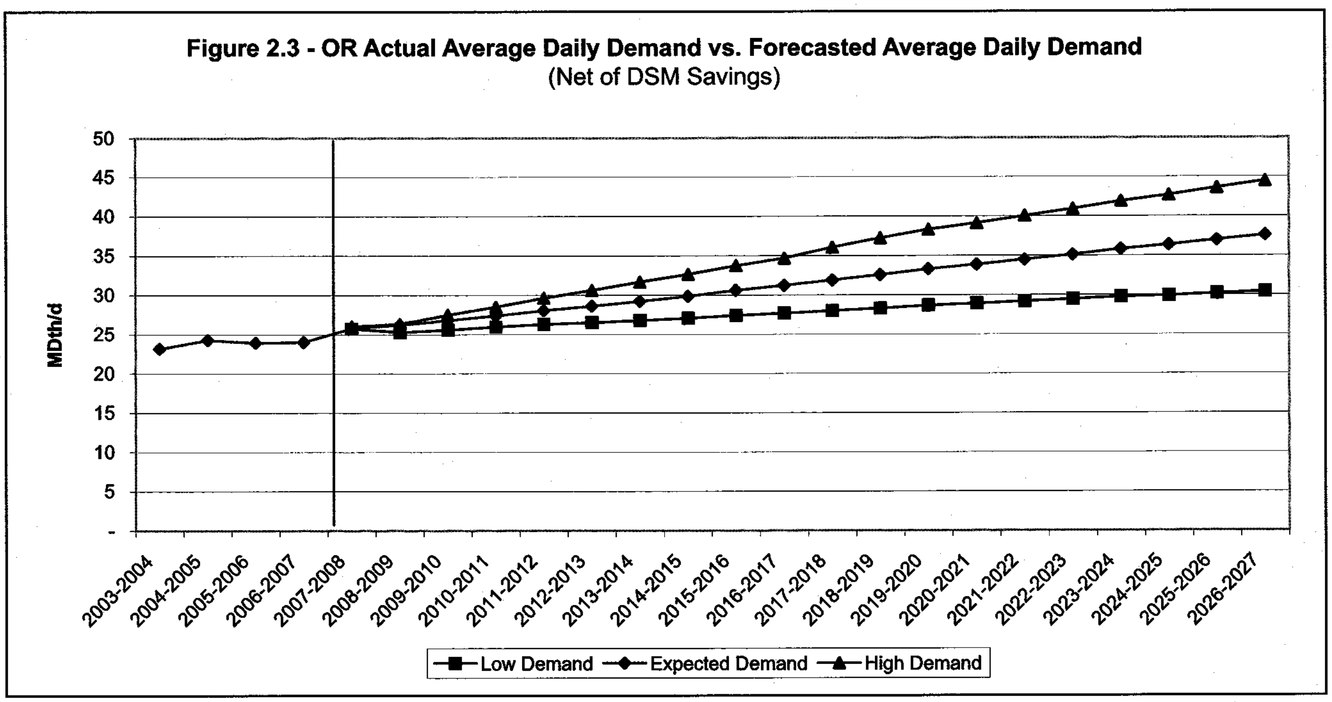
DEMAND SCENARIOS

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).

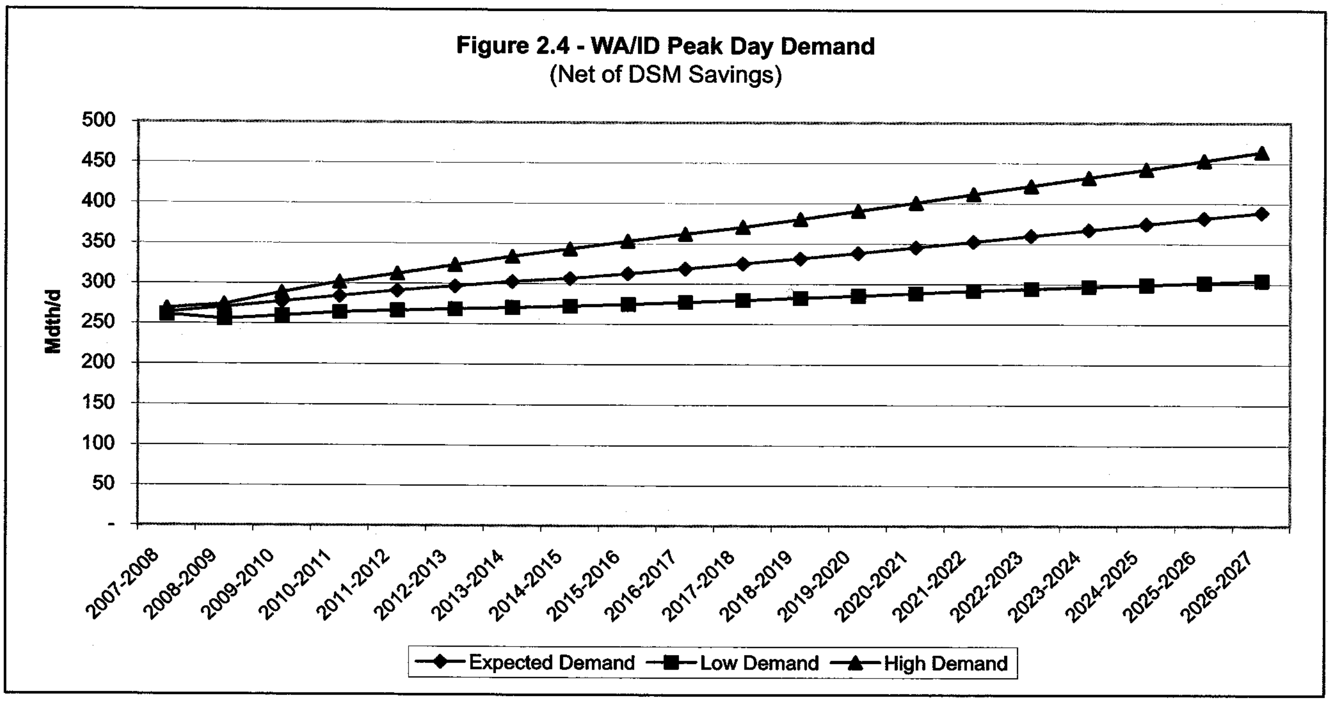




RESULTS

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.



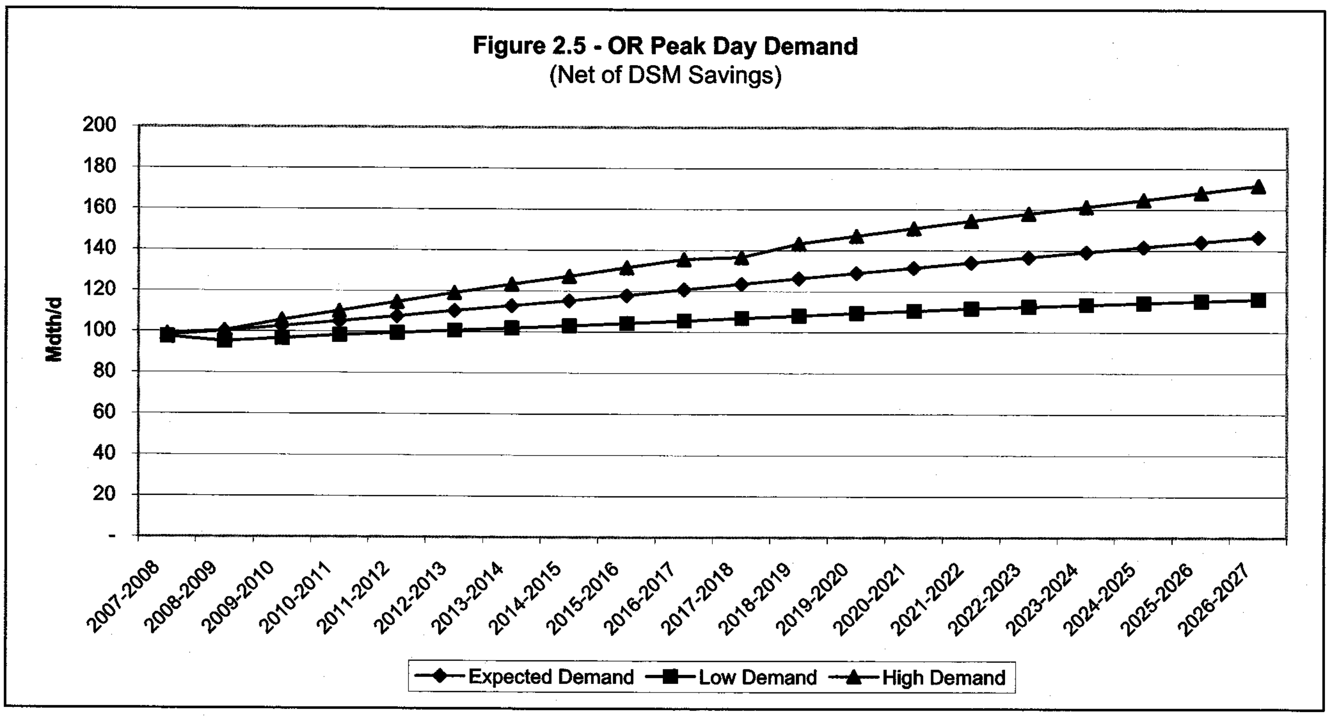


Table 2.4 depicts annual average demand percentage increases by class of customer and area for the Expected, Low and High Demand cases for the 20-year planning period.

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.

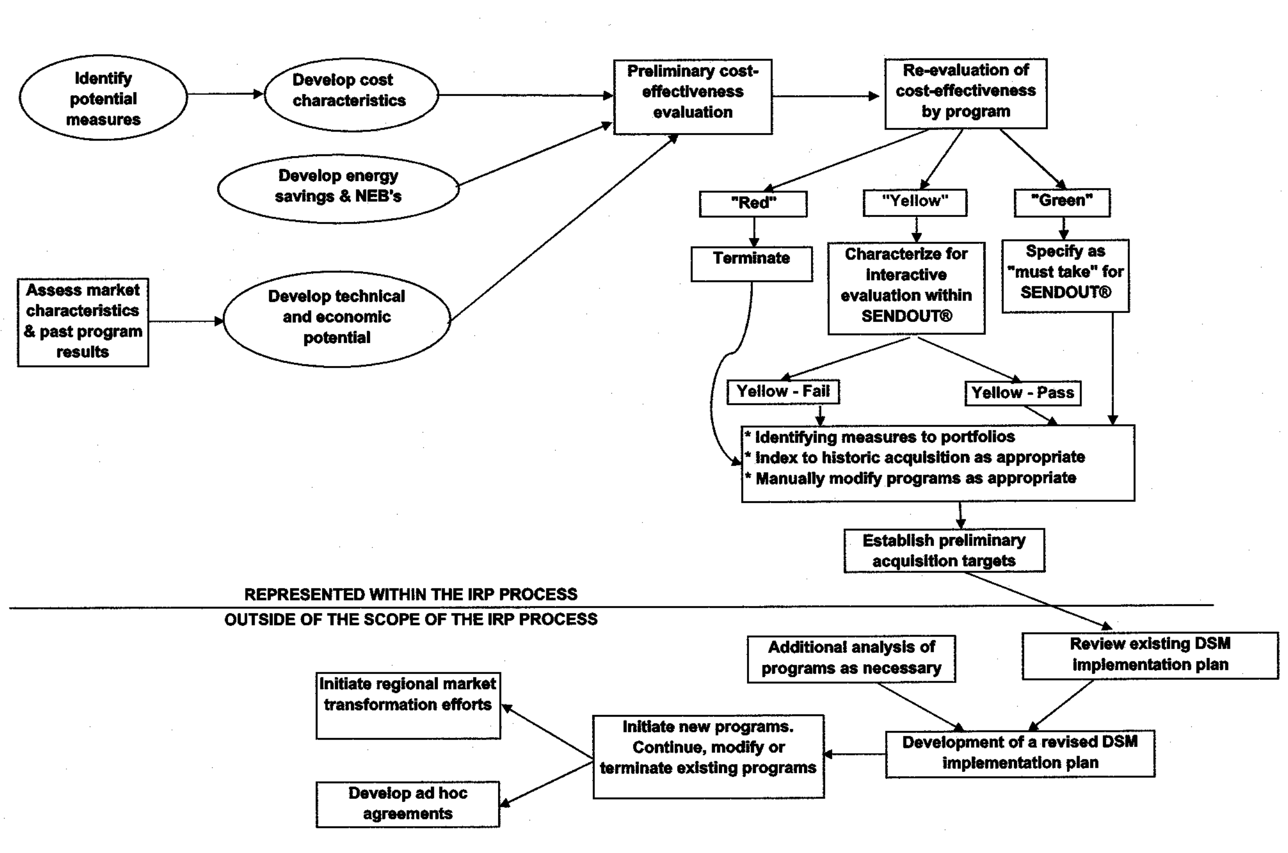
The DSM methodology is summarized in the flowchart in Figure 3.1. Details of each phase follows.

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

Figure 3.2 - Cumulative Identified Potential vs. Cumulative Acquired
WA/ID Therms/year

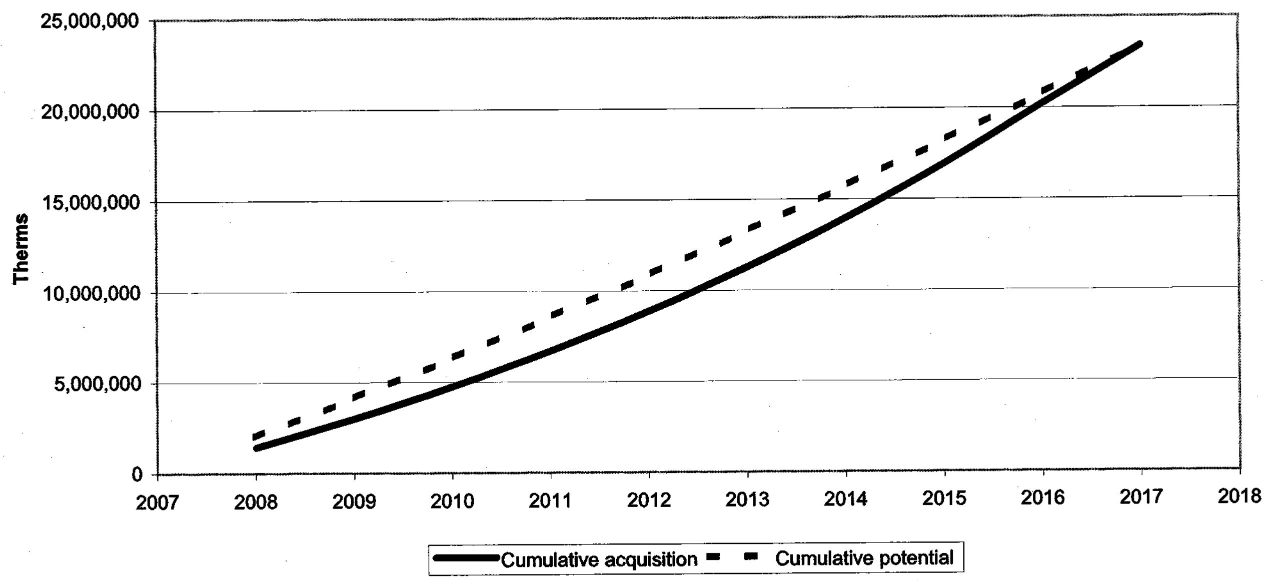
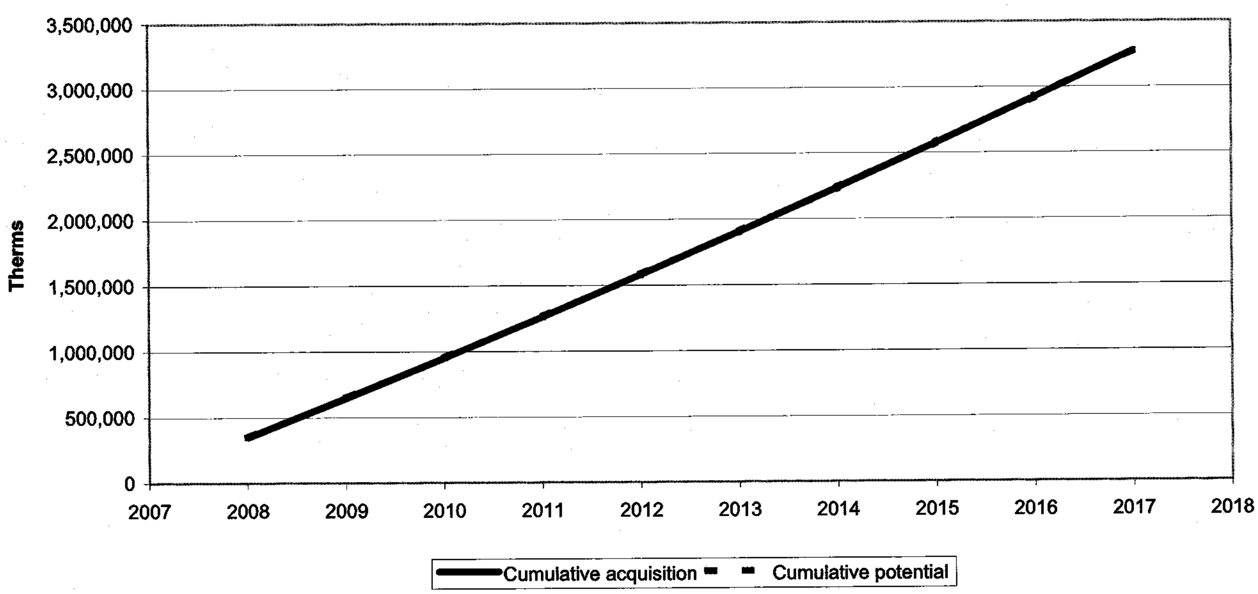
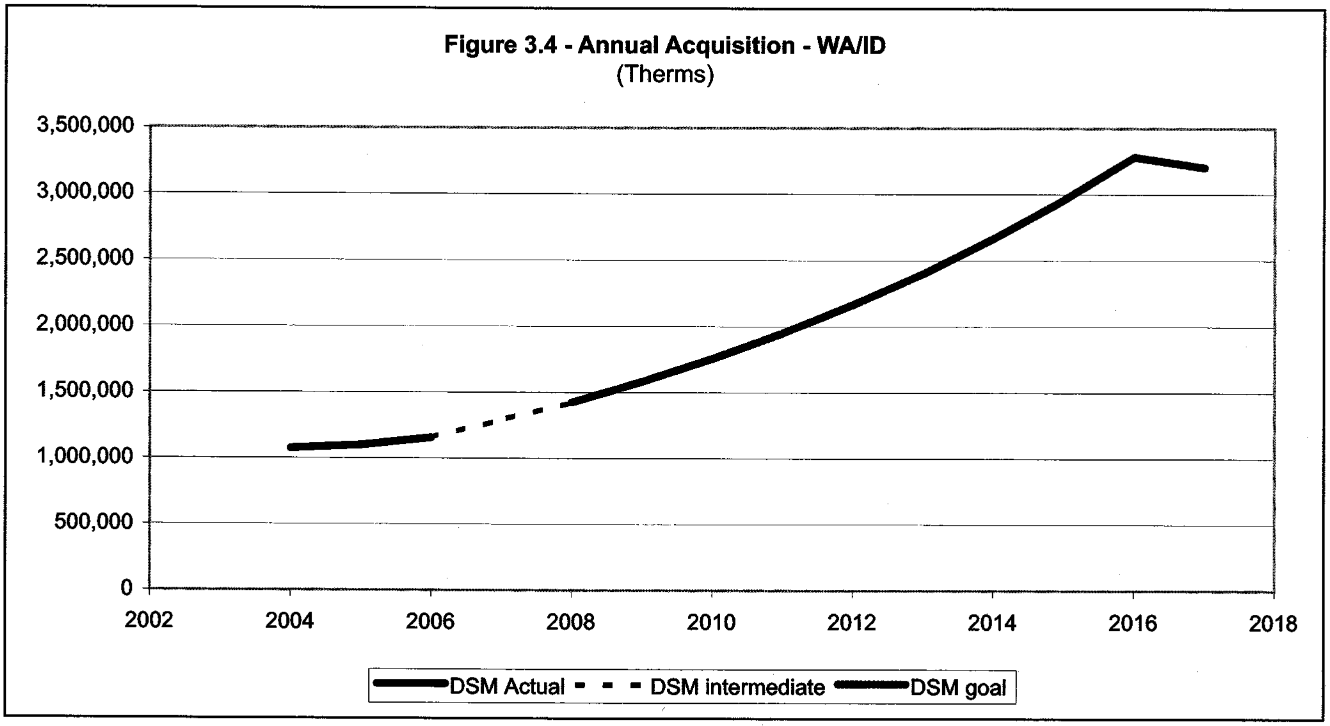


Figure 3.3 - Cumulative Identified Potential vs. Cumulative Acquired
OR Therms/year



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).



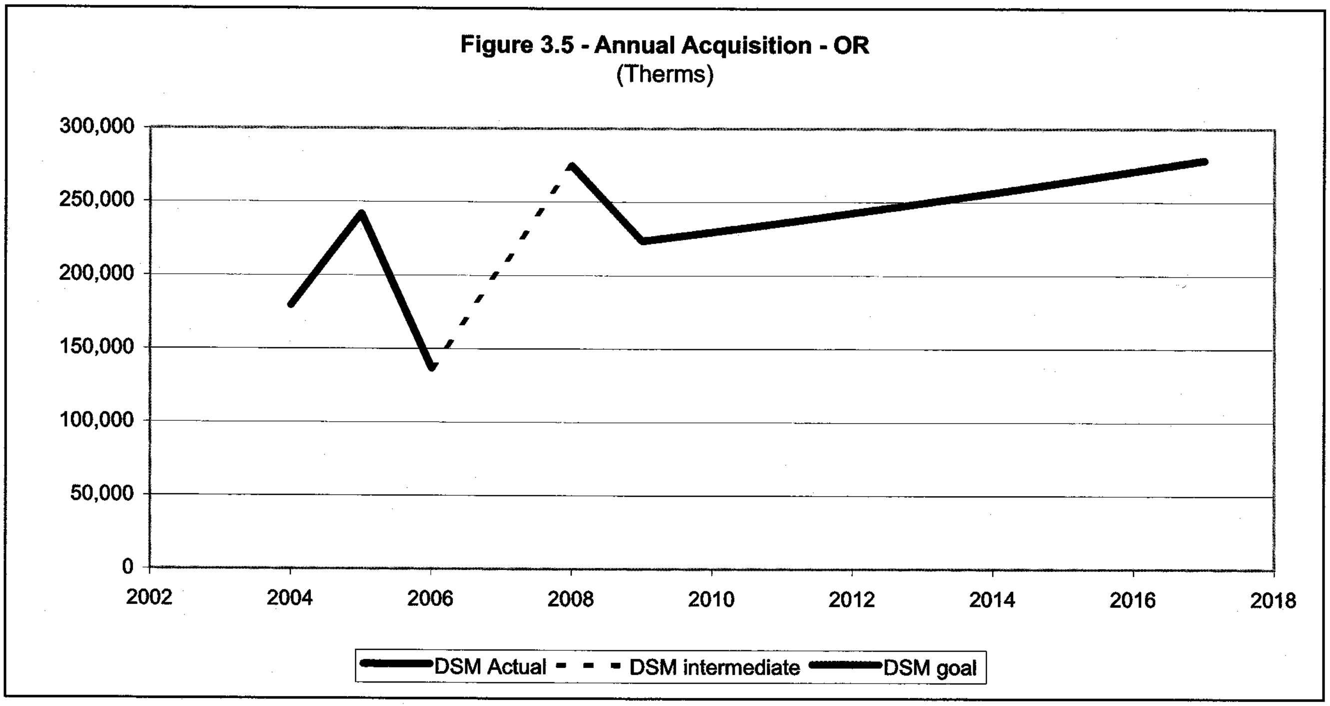


Figure 3.4 shows historical, current and projected Washington and Idaho DSM therm acquisitions. The chart illustrates the gradual ramp-up of DSM activity for the first nine years of the planning cycle. In the tenth year, the cumulative acquisition catches up to the cumulative identified potential of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

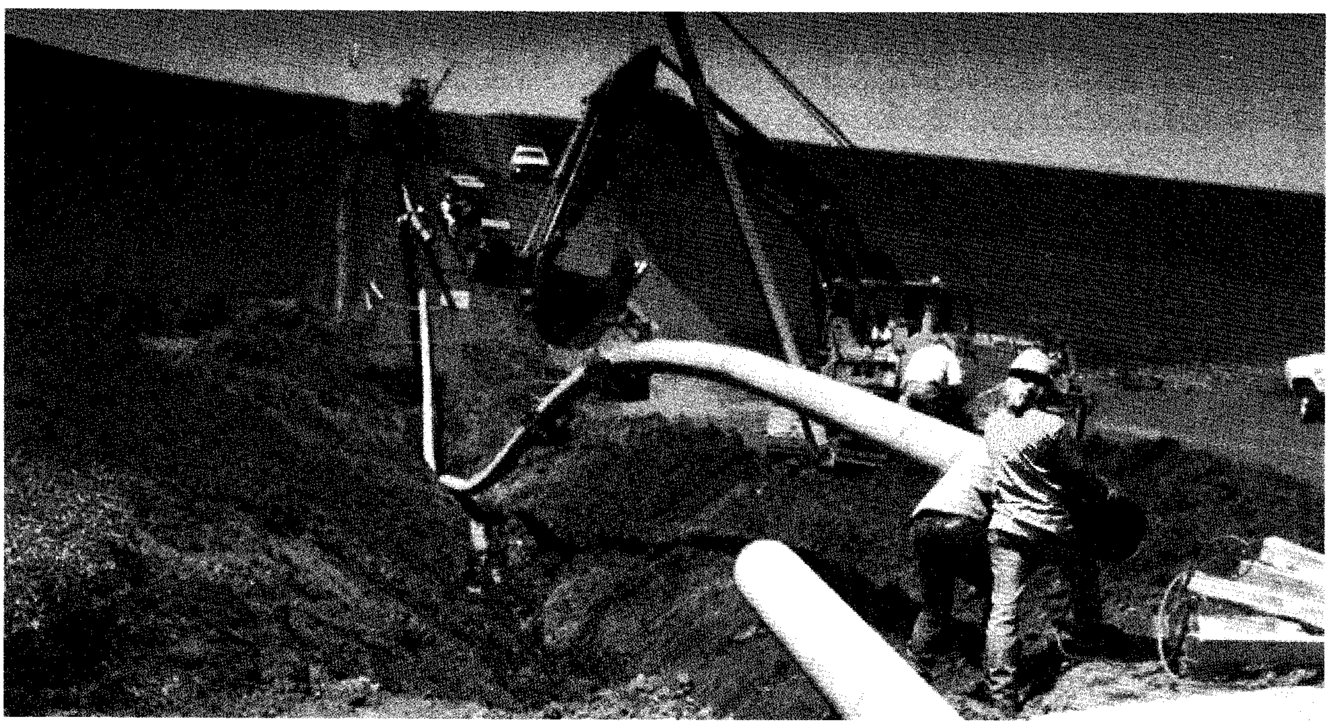
COMPUTER MODELING

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

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

Table 4.2 - Determining Heat Load

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

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.

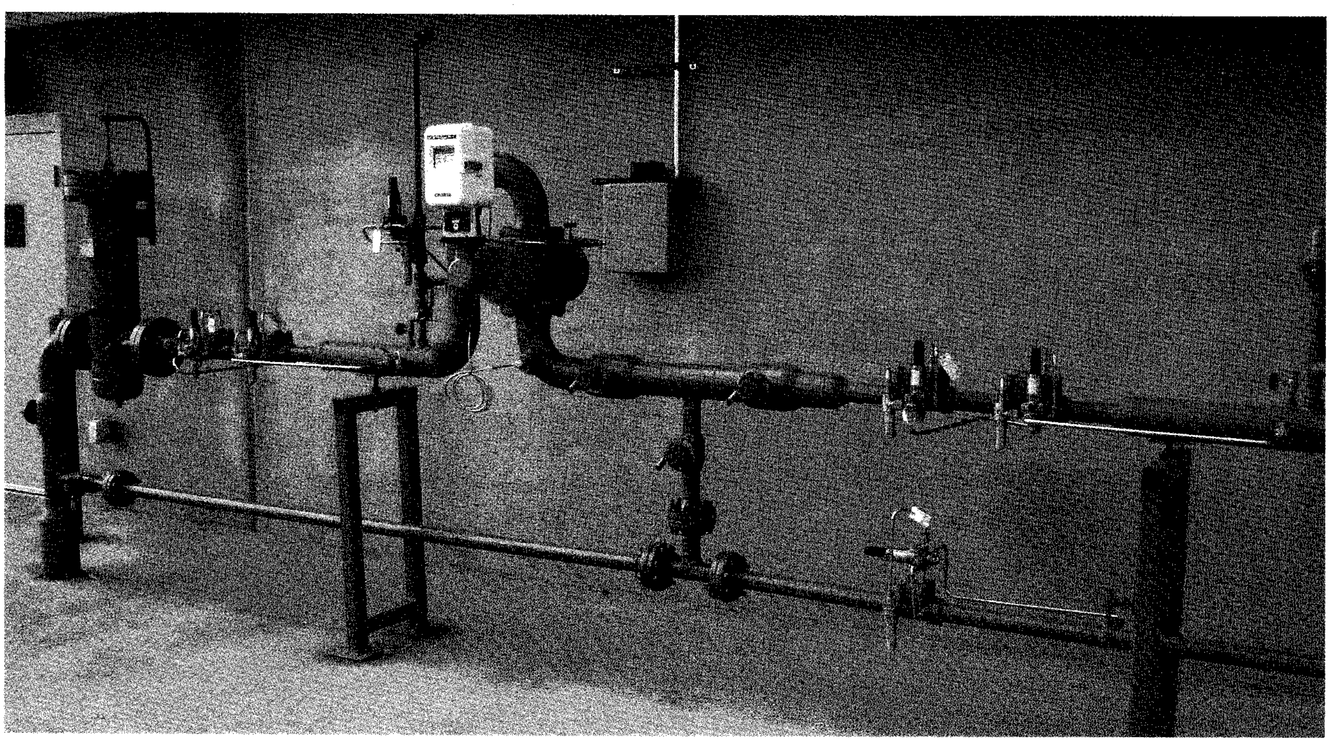


Table 4.4 - Capital Reinforcement Projects with Estimated Costs in 2006$

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.

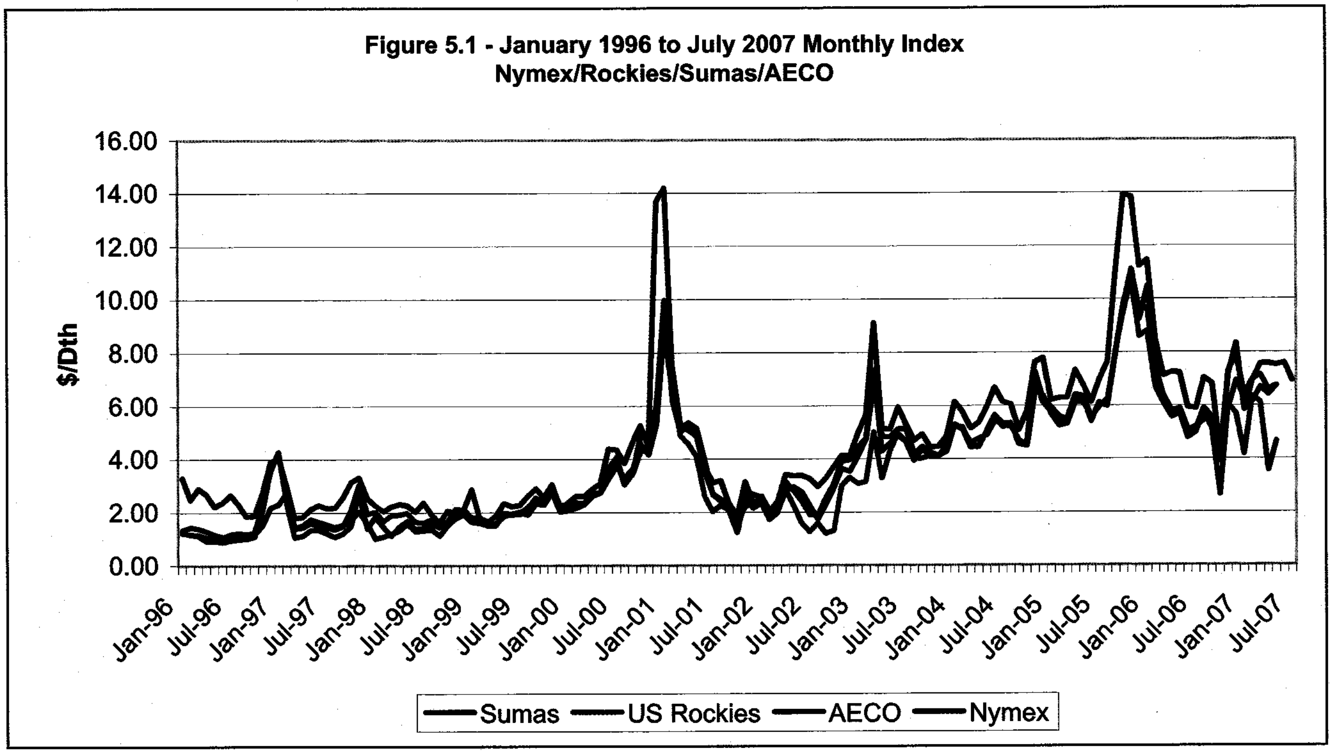
Avista is located near several liquid hubs and supply basins in Western North America, including Alberta and British Columbia in Canada and the Rocky Mountain region in the United States. Avista's unique access to a diverse group of supply basins, coupled with the diversity of delivery points, allows 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,



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.

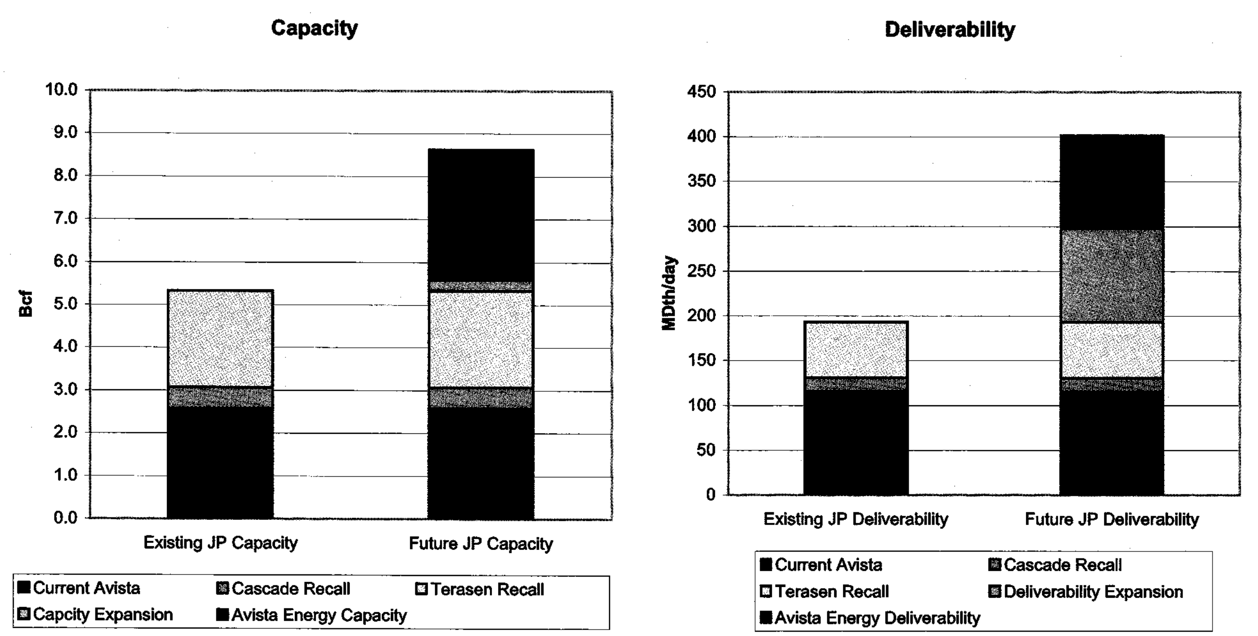
JACKSON PRAIRIE STORAGE PROJECT

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.

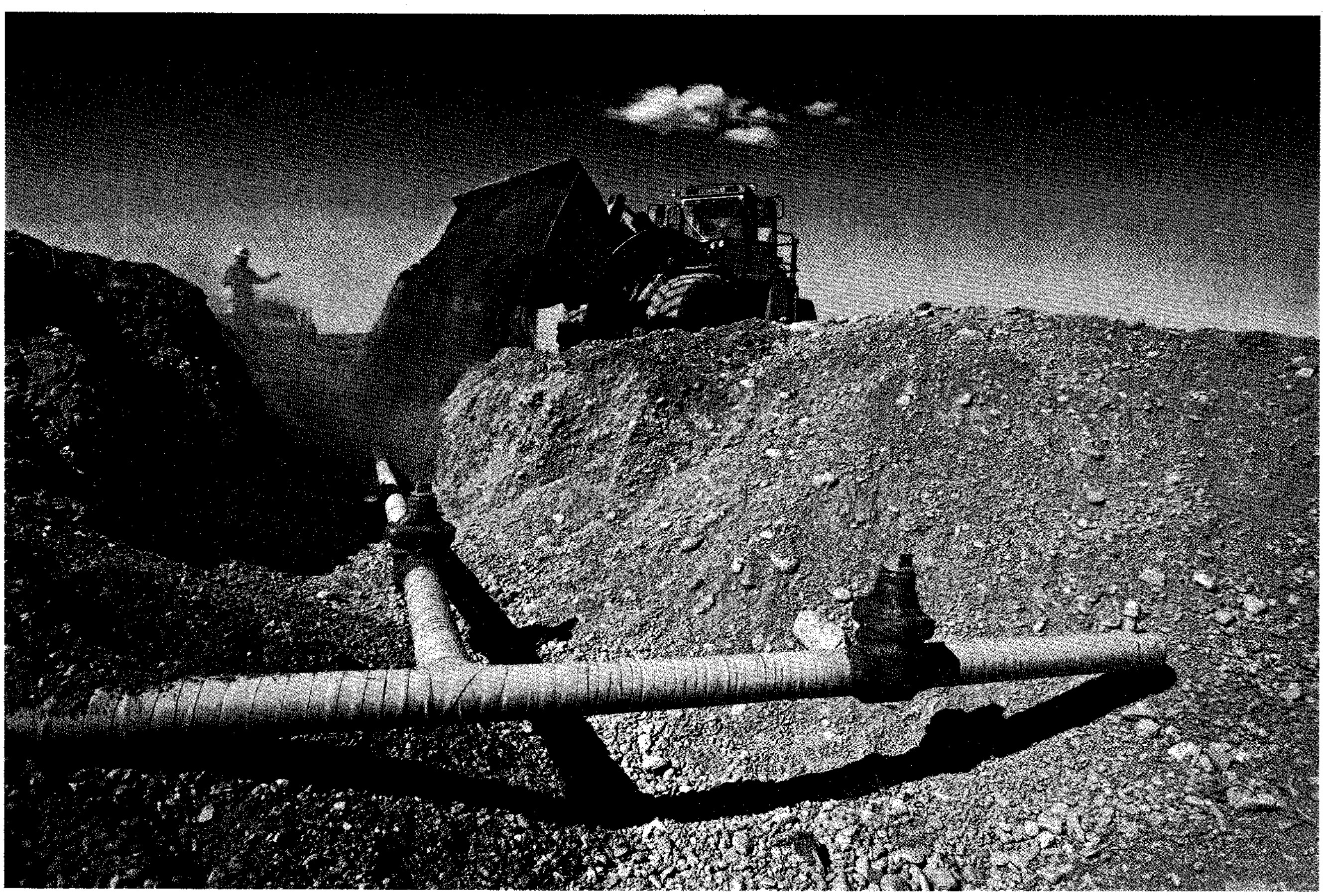
We will continue to assess methods for capturing additional value related to existing storage assets, including methods of optimizing recently recalled releases while implementing its storage strategy of providing balanced storage opportunities. This includes exploring storage diversification options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

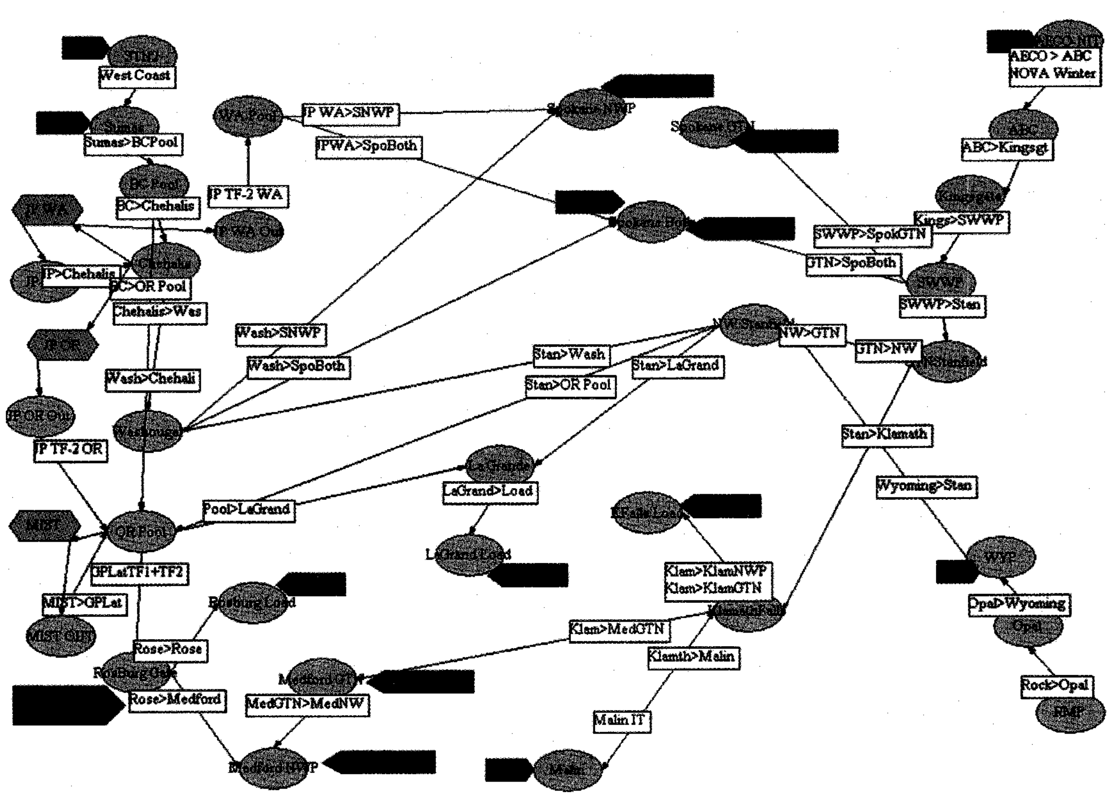
NATURAL GAS RESOURCE MODEL

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

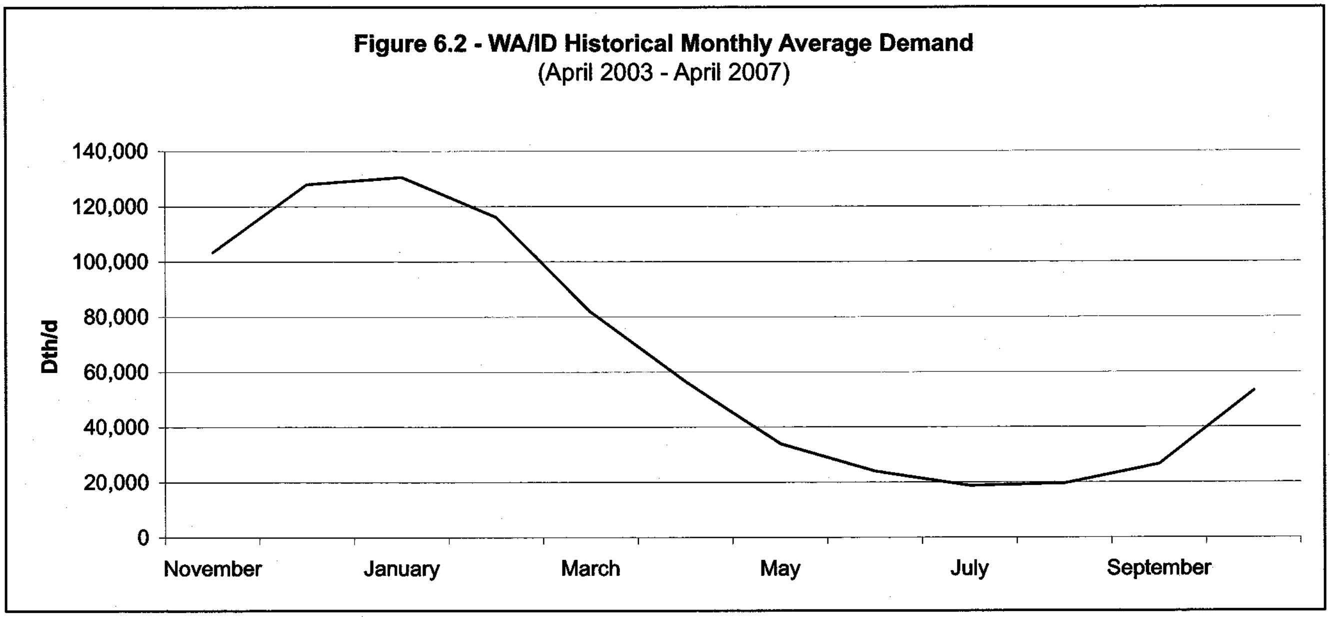
The approach used to analyze Avista's long-range natural gas planning options focuses on the sensitivity of the optimization model to periodic (daily, monthly, seasonal and/or annual) changes in:
- assumptions related to customer growth and customer natural gas usage that ultimately form demand forecasts;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

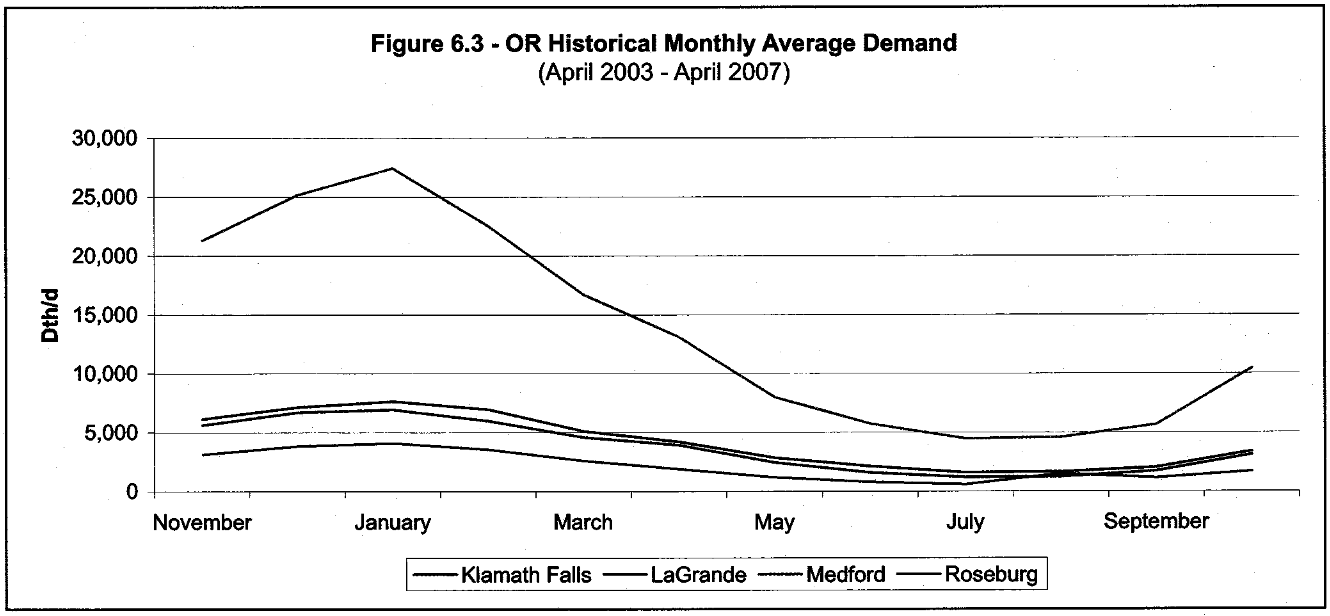
We have reviewed and performed rigorous analysis on each of the aforementioned areas.

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

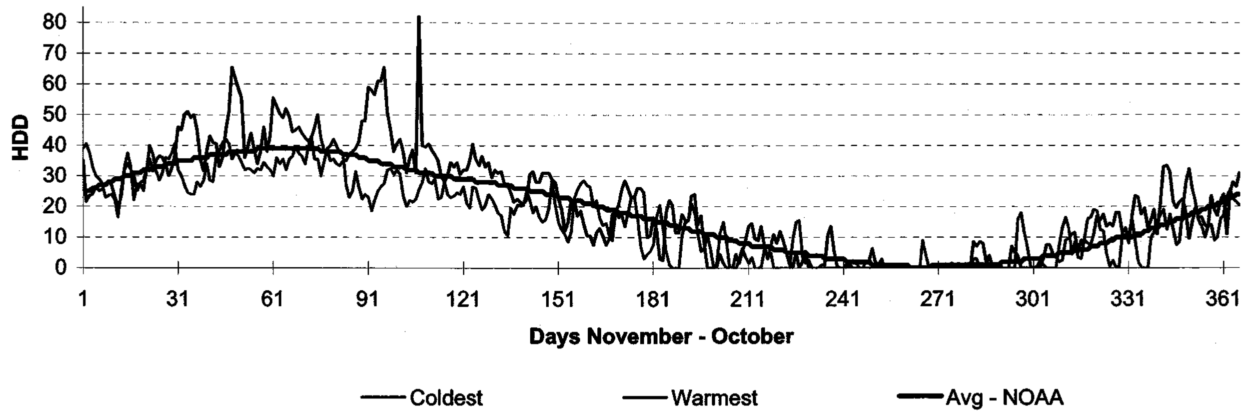
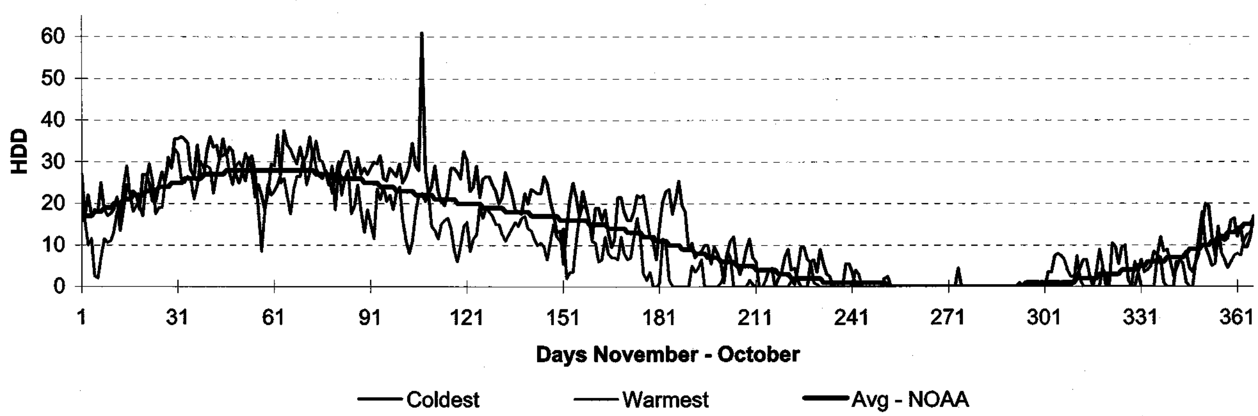


Figure 6.5 - Average vs. Coldest vs. Warmest (63/64 plus 61 HDD, NOAA)
Medford Weather



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

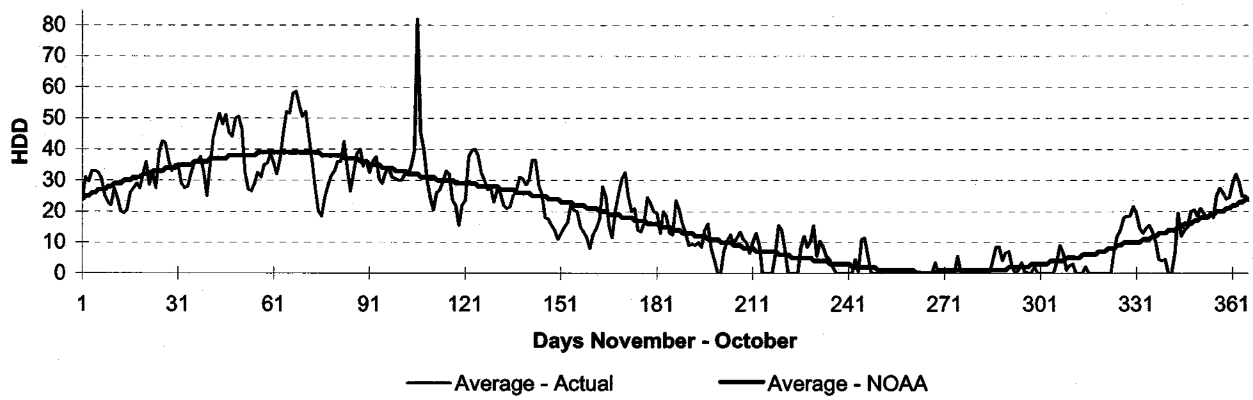
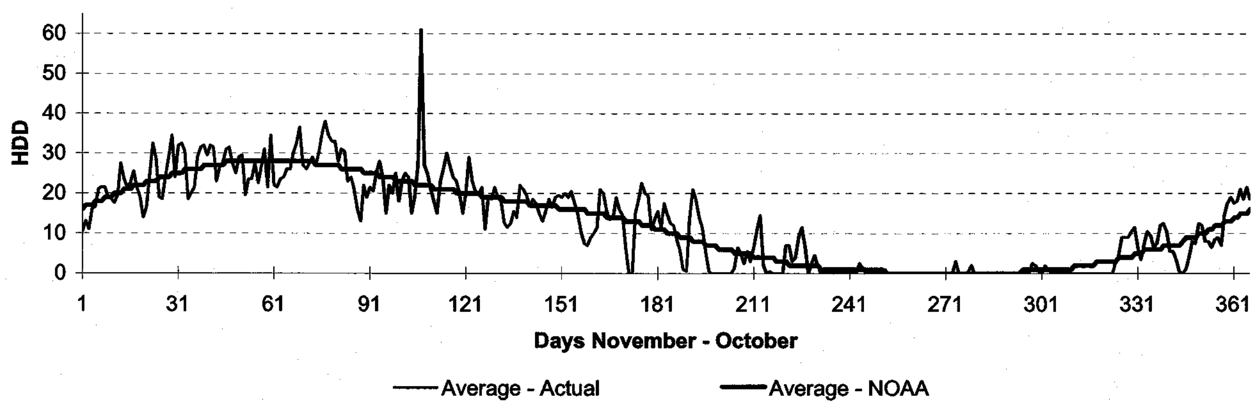


Figure 6.7 - NOAA 30-year Average vs. Planning Weather (added 61 HDD on Feb. 15)
Medford Weather



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.

Figure 6.8 - Existing Firm Transportation & Storage Resource Stack
WA/ID

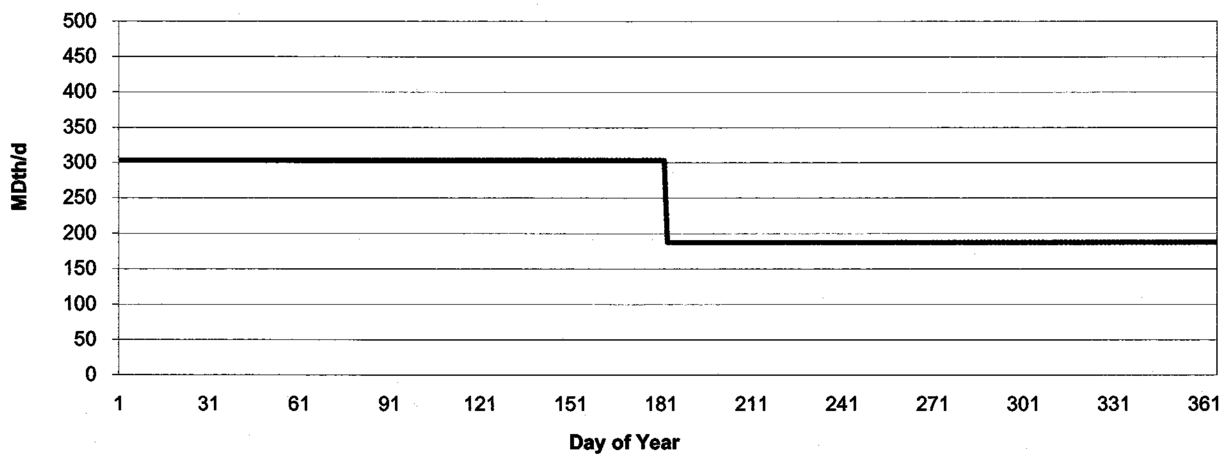


Figure 6.9 - Existing Firm Transportation & Storage Resource Stack
OR (includes Willamette Firm Peaking Arrangement)

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

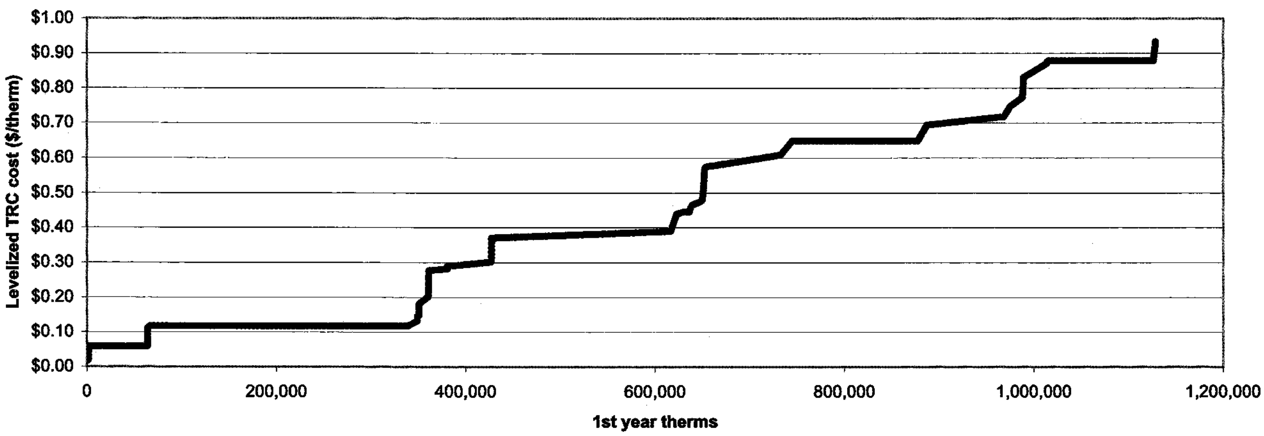
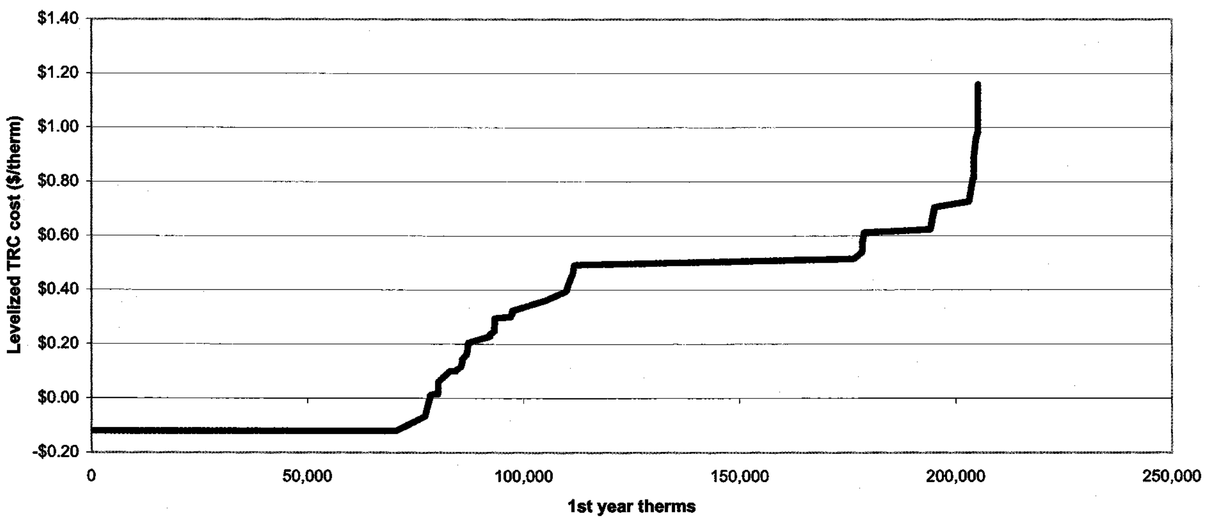


Figure 6.11 - OR DSM Supply Curve, 2007 / 2008
Representing 63 evaluated non-site-specific measures
Excluding 27 "red" measures that failed preliminary evaluation



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***

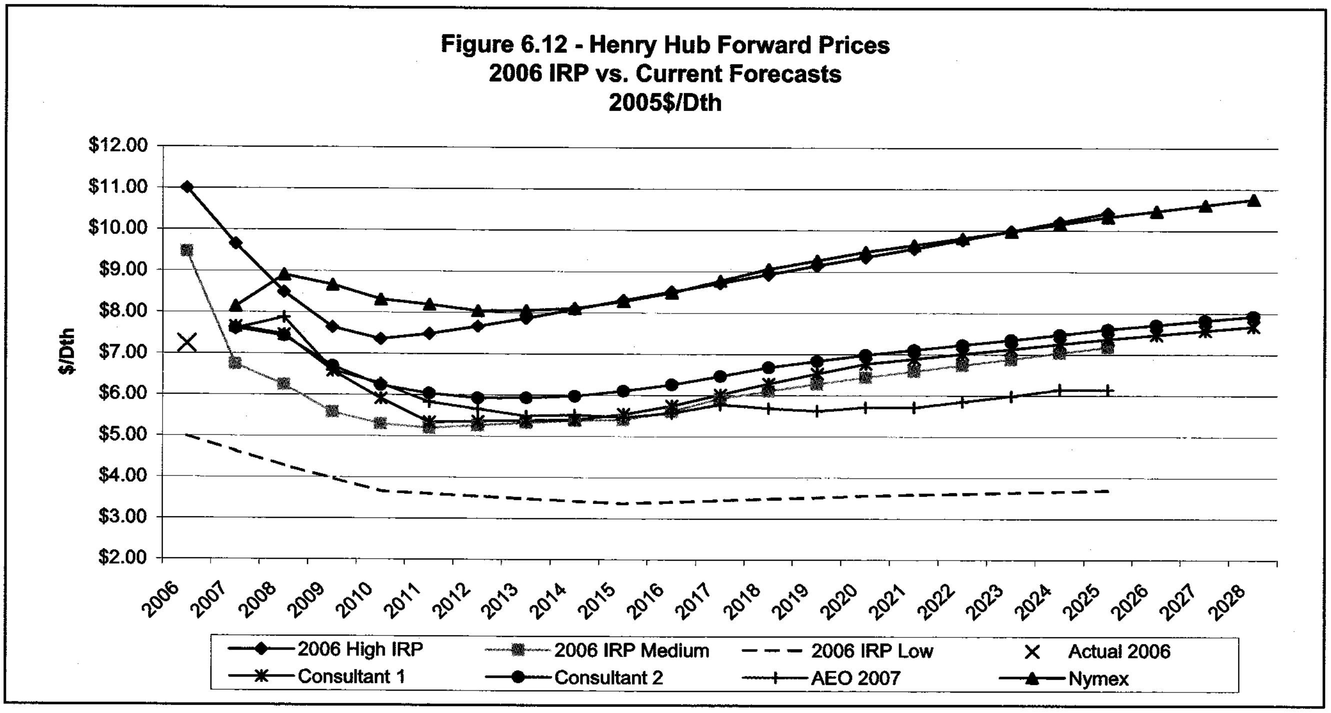
  Based on the analysis in this IRP, we believe that a cost-effective annual acquisition of 350,000 first-year therms is achievable through intervention. The identification of this goal does not preclude the addition of other resources that may be identified as cost-effective during later analysis, nor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



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

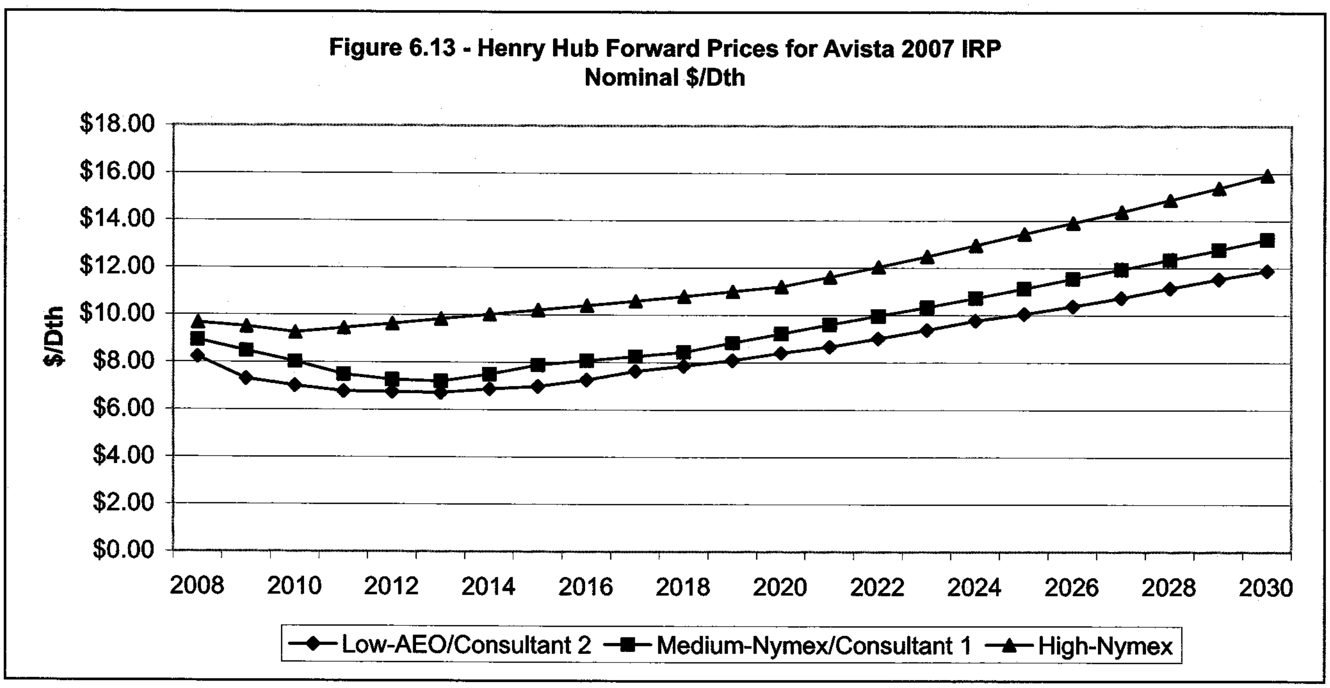
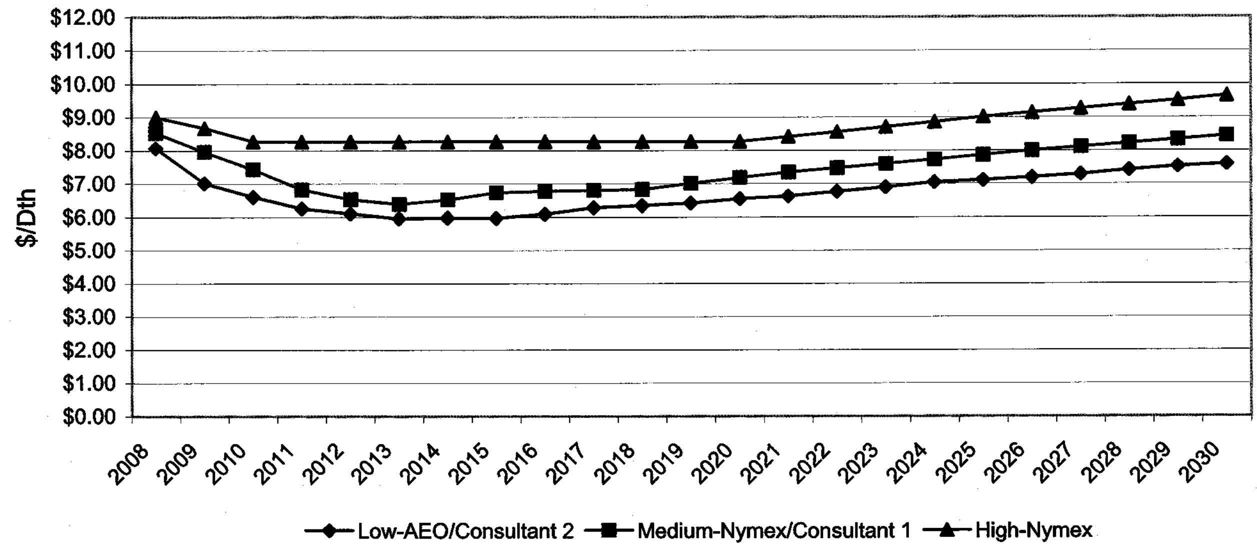


Figure 6.14 - Henry Hub Forward Prices for Avista 2007 IRP
2007$/Dth



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

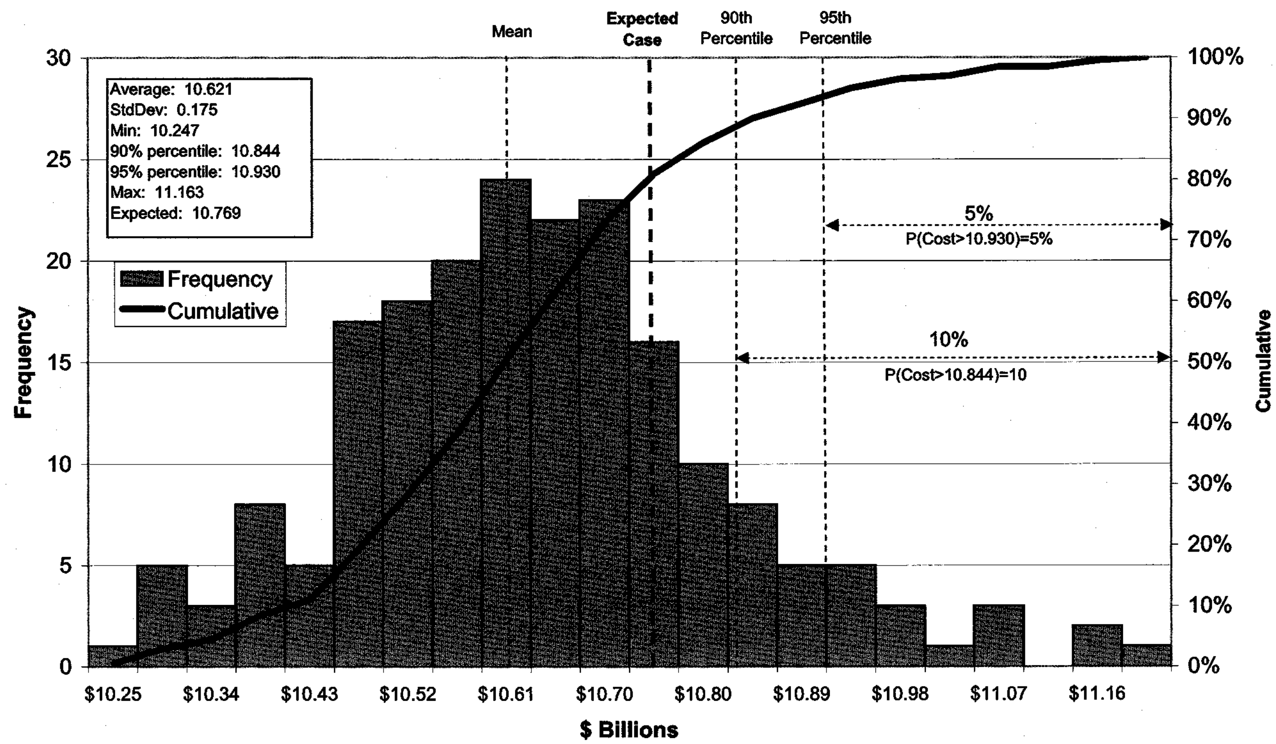
As discussed in the Demand Forecast chapter, we have selected three scenarios for detailed analysis to capture a range of possible outcomes over the planning horizon. These scenarios consider the price elasticity effects on the high and low customer growth scenarios. The scenarios are shown in Table 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).

Figure 6.15 - Avista IRP Total 20 Year Cost



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 ofVectorGas™ 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 - WA/ID Existing Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case - November through October

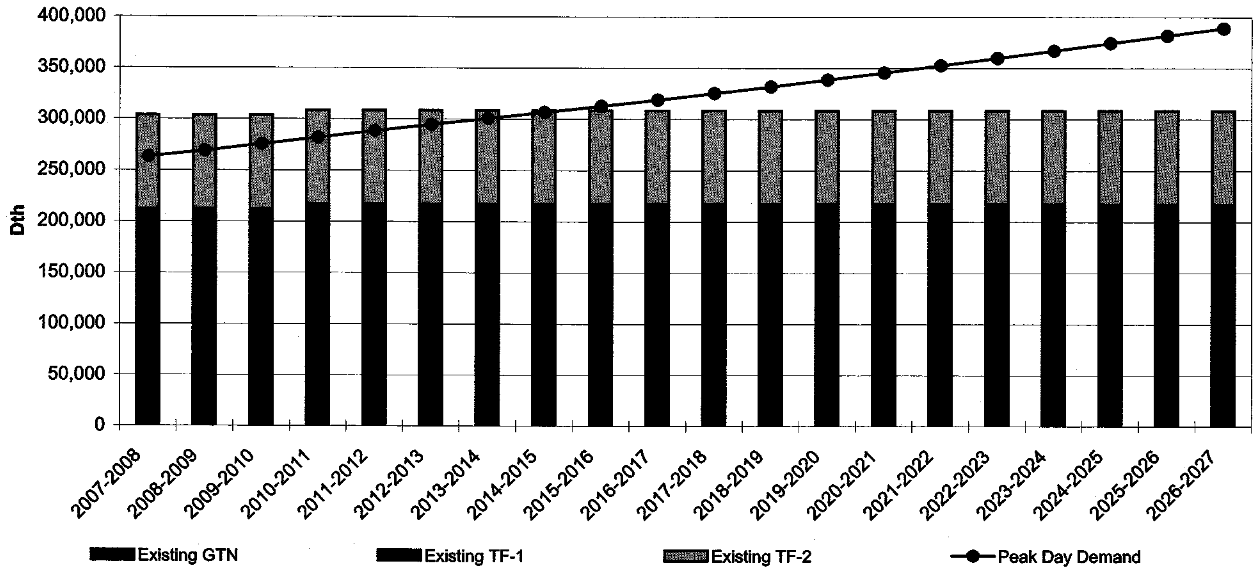


Figure 6.17 - OR Existing Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case - November through October

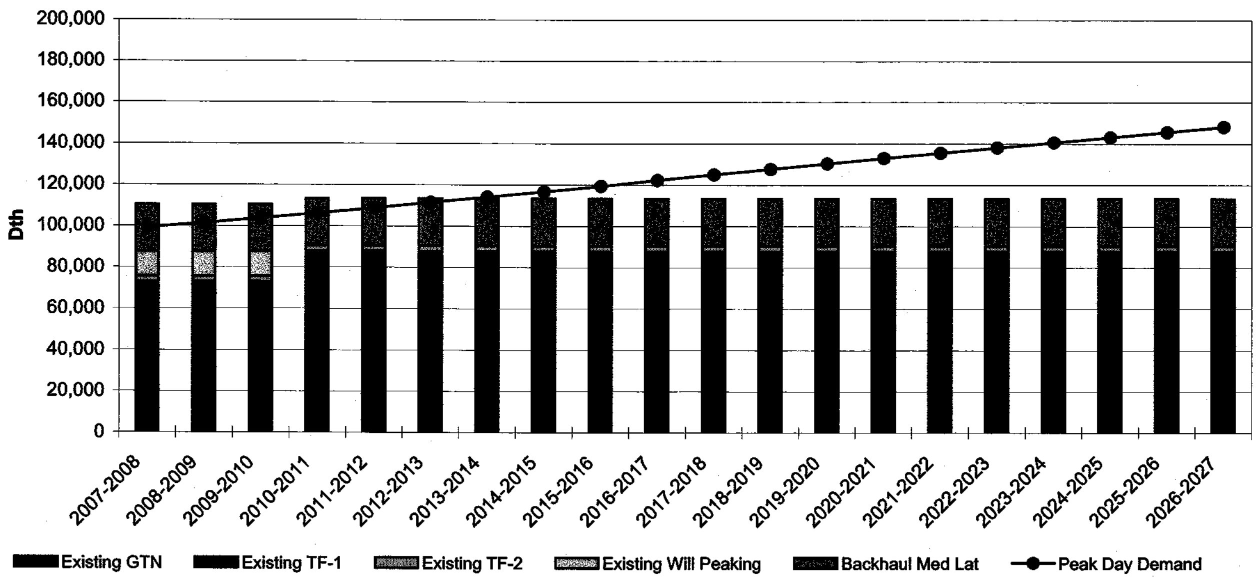


Figure 6.16 and 6.17 graphically represent a regional summary of Expected Case peak day demand compared to existing resources. This comparison shows, on a regional basis, when and how much the company is deficient over the planning horizon. Similar figures for the Low and High Demand cases can be found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

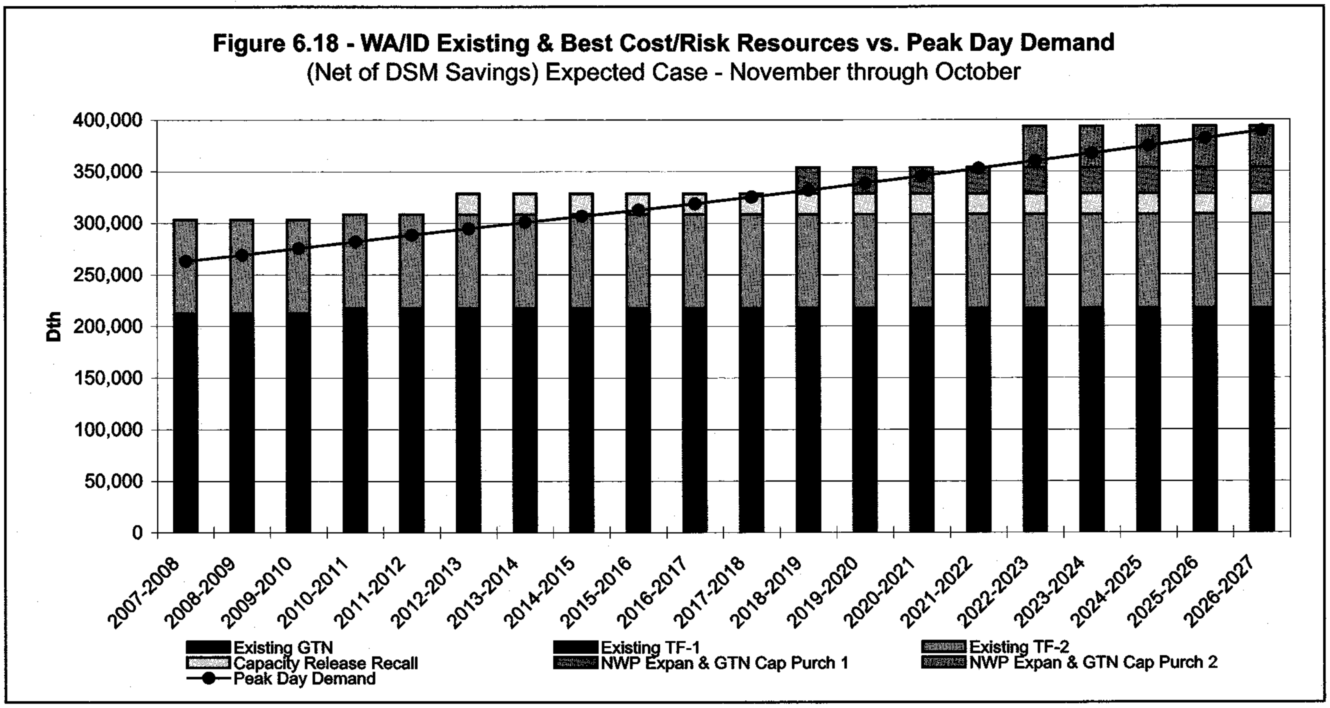
It is paramount that an available resource effectively delivers natural gas to the intended geographical region. Given Avista's separate service territories, it is often impossible to deliver resources from an option such as storage without acquiring additional pipeline transportation.

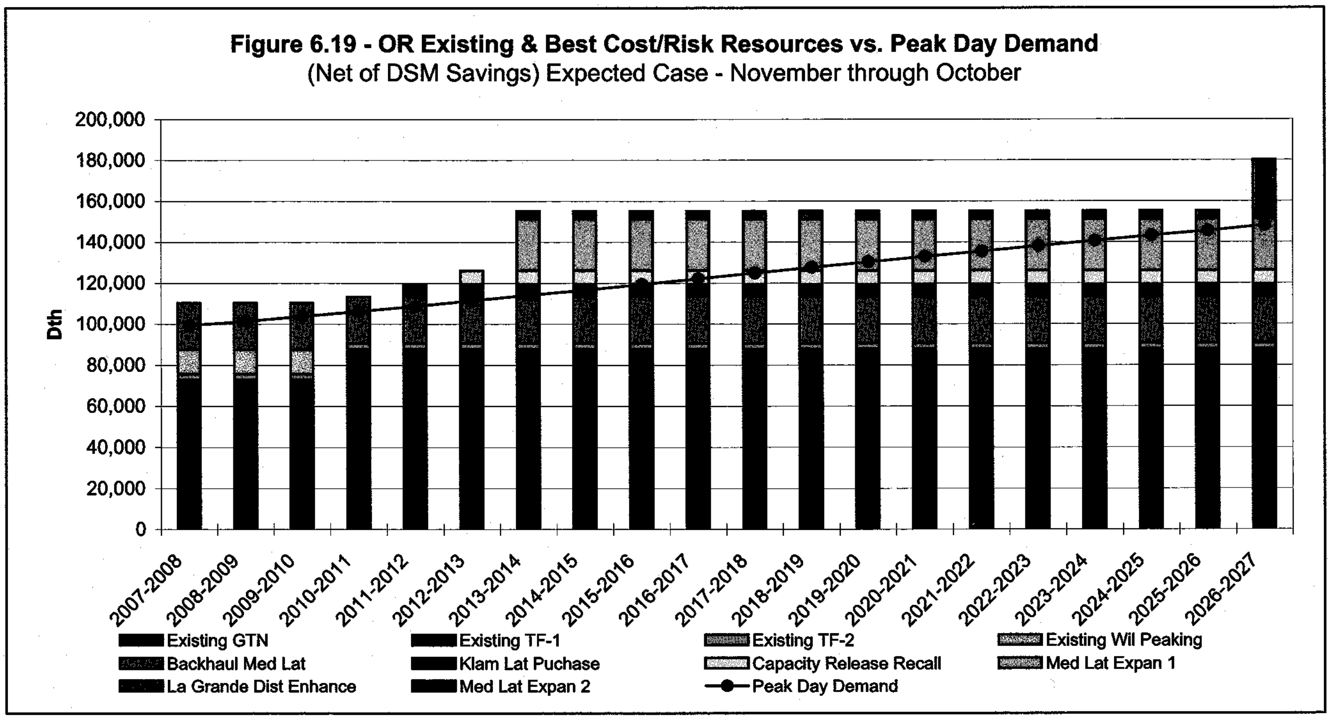
"Lumpiness" of Resource Options

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

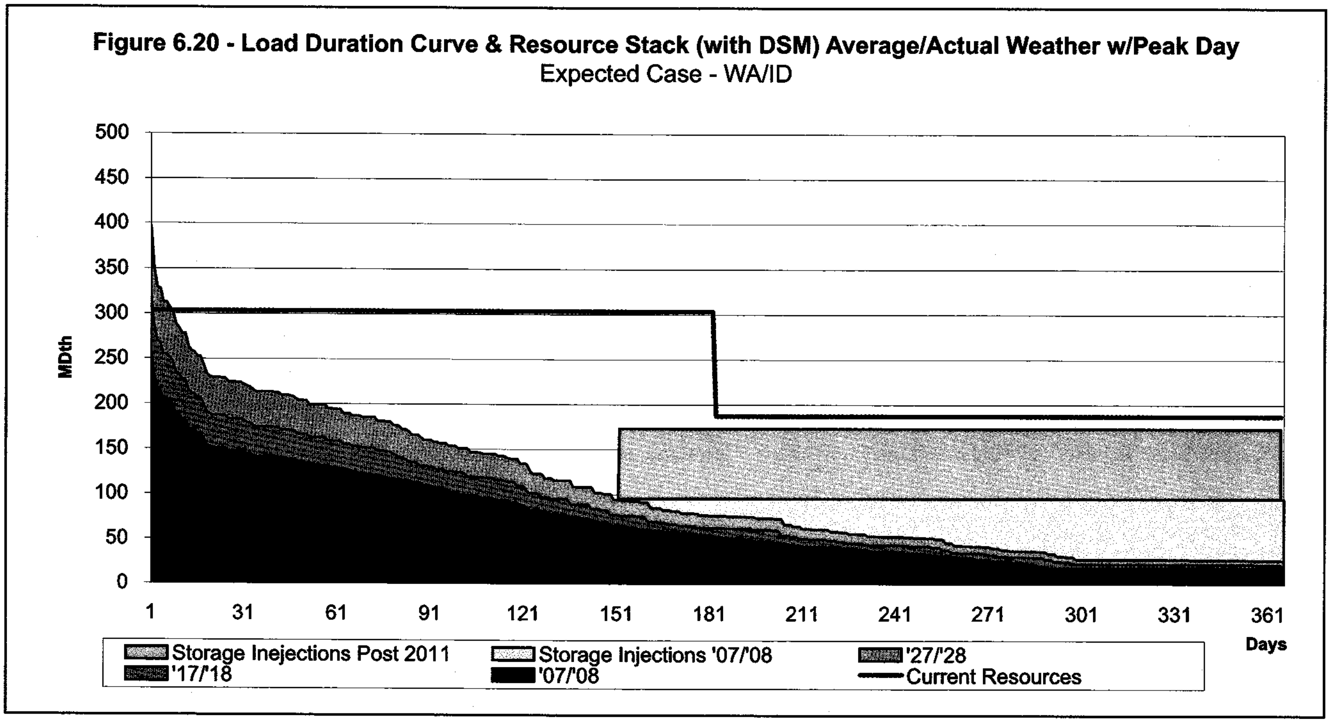
After identifying resource options and evaluating them based on the considerations detailed earlier in this chapter (i.e. lead-time, peak vs. base, usefulness, etc.), we focused on how to cost effectively solve resource constraints for the Expected, High and Low Demand cases. In order to answer this 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

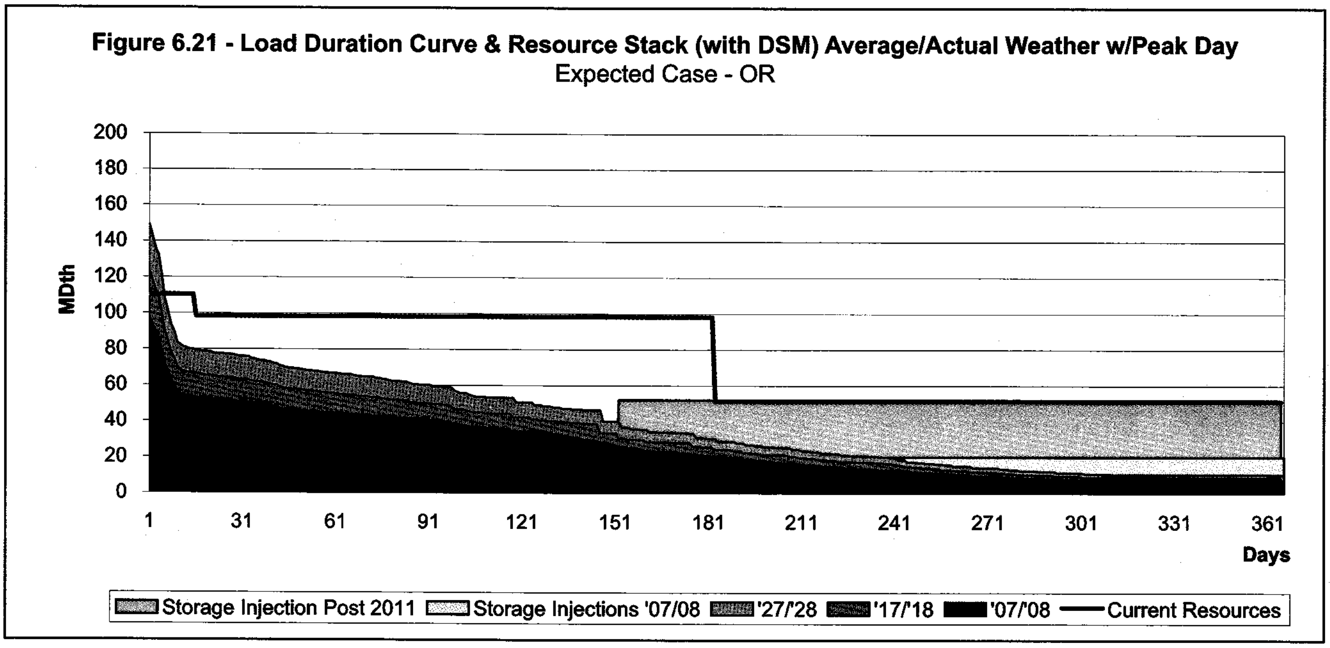




approach to meeting resource deficiencies. SENDOUT® compares demand-side and supply-side resources and determines, based on a PVRR analysis, which resource is the least cost.

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.





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.

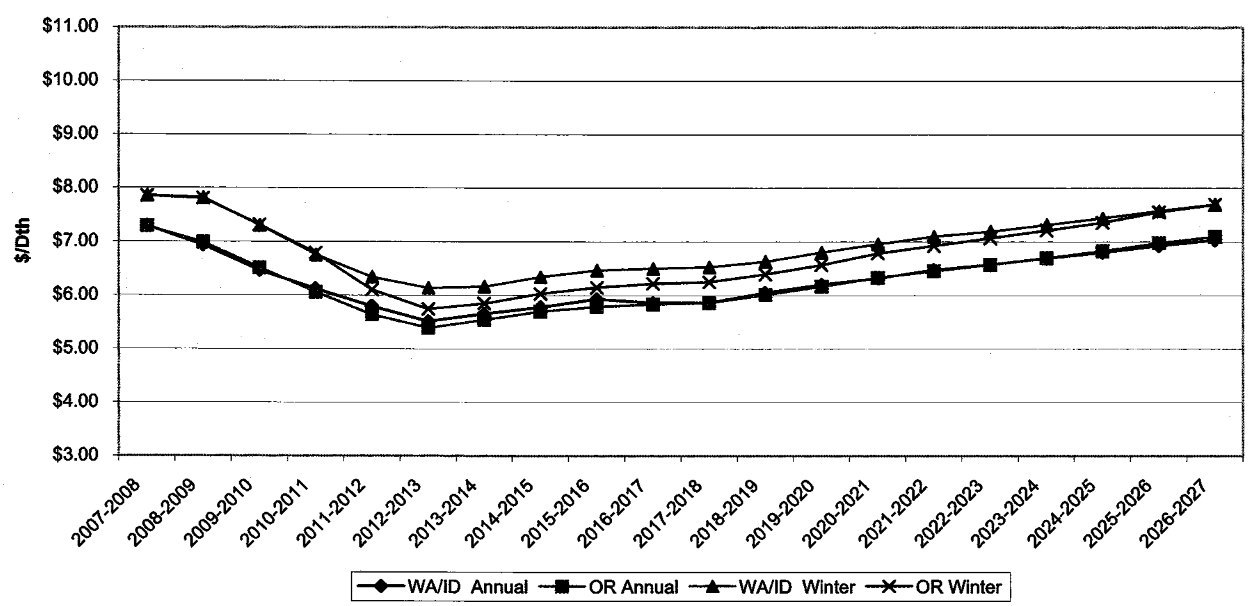
AVOIDED COST DETERMINATIONS

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 ofVectorGas™. 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.

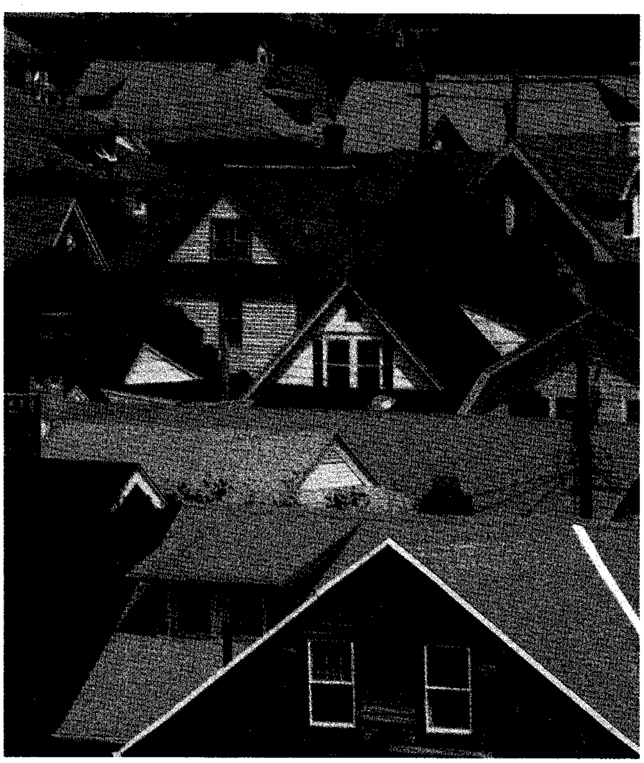
Action Item:

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.