AVISTA®

December 29, 2009

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

AVU-G-09-06

Dear Ms. Jewell:

RE: Avista Utilities 2009 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 2009 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 2009 Plan highlights the following:

- Our philosophy is to reliably provide natural gas to our customer with an appropriate balance of price stability and prudent cost using our portfolio of purchase contracts, storage and firm pipeline capacity rights;

- The Company forecasts sufficient natural gas resources well into the future with resource needs not occurring until 2018-2019 in Oregon and 2022-2023 in Washington and Idaho;

- The major change from the 2007 IRP is a lower demand forecast driven by lower economic growth in our service territories;

- We continue our pursuit of cost effective demand-side management solutions establishing a 2010 goal to reduce demand by 2,193,000 therms in Washington and Idaho and 303,000 therms in Oregon; and

- As forecasted demand is relatively flat, we will monitor actual demand for signs of increased growth which could accelerate resource needs.

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

Sincerely,

Linda Gervais

Linda Gervais
Manager, Regulatory Policy
State and Federal Regulation
Avista Utilities
509-495-4975
linda.gervais@avistacorp.com

c: Matt Elam

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2009

Natural Gas Integrated Resource Plan

December 31, 2009

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Note: Appendices provided under separate cover.

SAFE HARBOR STATEMENT

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

For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission 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.

2009 IRP KEY MESSAGES

- Avista has a diversified portfolio of existing natural gas supply resources including owned and contracted storage, firm capacity rights on six pipelines and purchase contracts from several different supply basins. Our philosophy is to reliably provide natural gas to customers with an appropriate balance of price stability and prudent cost.
- Avista's 2009 Integrated Resource Plan (IRP) forecasts lower demand for all service territories than our 2007 plan. These reductions are driven mainly by lower growth rates in our service territories than originally anticipated as a result of the severe economic downturn during this IRP cycle.
- Additional resource needs do not occur until well into the future. In Oregon, resource deficits occur in 2018-2019 and in Washington and Idaho in 2022-2023. The deficits are driven primarily by demand growth averaging 1.4 percent and 1.0 percent per year in the respective jurisdictions. Customer accounts are expected to grow at an annual average rate of 2.5 percent and 2.2 percent, respectively. Our plan indicates incremental pipeline transportation capacity is the preferred resource to meet the identified needs.
- An important risk with the identified future resource deficits is the relatively flat slope of forecasted demand growth. Implied in this outlook is existing resources will be sufficient for quite some time to meet demand. However, should demand growth accelerate, the steepening of the demand curve could quickly accelerate resource shortages by several years. This "flat demand risk" requires that we closely monitor signs of accelerating demand and carefully evaluate lead times to acquire preferred incremental resources.
- Other risks we evaluated include price elasticity variability, climate change policy uncertainty, long-term availability of supply, weather planning standard alternatives and cost escalation risks/lead times when acquiring resources.
- Conservation programs are an integral component of our IRP process, as these programs result in multiple benefits including reduced customers' bills, reduced supply-side resource needs and reduced greenhouse gas (GHG) emissions. Avista's long-time commitment to energy conservation and efficiency is founded in the belief that these benefits make acquiring cost effective conservation resources the single best strategy for minimizing energy service costs to our customers while promoting a cleaner environment.
- We have identified first-year conservation goals of 2,193,300 therms for our North Division (Washington and Idaho) and 303,300 therms for our South Division (Oregon).
- The IRP identifies and establishes an Action Plan that continues to guide us toward the risk-adjusted, least-cost method of providing service to our natural gas customers. Included in this Action Plan are efforts to improve price elasticity modeling, monitor trends for Canadian natural gas imports, and goals for demand-side management.

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LIST OF ACRONYMS

AGA	American Gas Association
DSM	Demand-Side Management*
Dth	Dekatherm*
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission*
GTN	Gas Transmission Northwest*
GHG	Greenhouse Gas
HDD	Heating Degree Day*
HP	High Pressure
IRP	Integrated Resource Plan*
LNG	Liquified Natural Gas*
Mmbtu	Million British Thermal Units*
NOAA	National Oceanic and Atmospheric Administration*
NPCC	Northwest Power and Conservation Council*
NWP	Williams - Northwest Pipeline*
NYMEX	New York Mercantile Exchange*
Psig	Pounds per Square Inch Gauge*
PVRR	Present Value Revenue Requirement
TAC	Technical Advisory Committee*
TRC	Total Resource Cost
Triple E	External Energy Efficiency Board
WCSB	Western Canadian Sedimentary Basin

* Glossary contains additional information.

CHAPTER 1 – EXECUTIVE SUMMARY

Avista's 2009 Natural Gas Integrated Resource Plan (IRP) identifies a strategic natural gas resource portfolio that meets future customer demand requirements. The formal exercise of bringing together customer demand forecasts with comprehensive analyses of resource options, including supply-side resources and demand-side measures, is valuable to Avista, its customers, Regulatory Commissions and other stakeholders for long-range planning.

The IRP identifies and establishes an Action Plan to steer Avista toward the least-cost method of providing service to our natural gas customers. There are other factors that must be considered besides cost within the context of least-cost planning, including an assessment of risks associated with each alternative as well as environmental and regulatory issues. Actions resulting from the IRP process represent risk-adjusted, least-cost results, which we refer to as best cost/risk resources.

IRP PROCESS AND STAKEHOLDER INVOLVEMENT

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

PLANNING ENVIRONMENT

This IRP was developed during a two-year period in which an international credit crisis severely disrupted the United States and global economy. Long-term effects on the natural gas industry are uncertain, prompting us to consider a wider range of scenarios to evaluate and prepare for a broad spectrum of potential outcomes. We examined key assumptions and historical trends, questioning how they might be impacted by the economic environment which is ambiguous, fluid and evolving. We have sought to perform analysis and modeling that not only looks at "what happened?" but also asks "what if?" to understand possible outcomes. Over time, as more becomes known about this uncertain period, some of our scenarios may differ substantially from subsequent actual results. Nonetheless, the trade-off of examining a broad range of possibilities with stretched assumptions is preferable to a narrower analysis of more-likely outcomes that could completely miss a less probable future.

DEMAND FORECASTS

For this IRP, we define eight demand areas, which are structured around the transportation resources that serve them. These demand areas are aggregated into four service territories (Washington/Idaho, Medford/Roseburg, Oregon, Klamath Falls, Oregon and La Grande, Oregon) and further summarized into two divisions (North and South) for presentation throughout this IRP.

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

Recognizing customers adjust consumption in response to price, we also analyzed factors that influence natural gas prices and demand through price elasticity. These included unconventional natural gas production trends, climate change policies and legislation, Canadian import trends, potential drilling restrictions and alternate price forecasts.

We developed a historical based reference case and conducted sensitivity analysis on key demand drivers by varying assumptions to understand how demand changes. Using this information and incorporating input from the TAC, we formed several alternate demand scenarios for detailed analysis. Table 1.1 summarizes these scenarios, which do not represent the maximum bounds of possible cases, but frame a broad range of potential outcomes. Within this range, we define an Expected Case which we view as the most likely scenario.

Table 1.1 Alternate Demand Scenarios
Expected Case
High Growth, Low Price
Low Growth, High Price
Green Future
Alternate Weather Standard
Supply Constraints

Avista uses the IRP process to develop two primary types of demand forecasts — annual average daily and peak day. Annual average daily demand forecasts are useful for preparing revenue budgets, developing natural gas procurement plans and preparing purchased gas adjustment filings. Peak day demand forecasts are critical for determining the adequacy of existing resources or the timing for new resource acquisitions to meet our customers' natural gas needs in extreme weather conditions. The demand forecasts from the Expected Case revealed:

Annual Average Daily Demand — Average day, system-wide core demand is projected to increase from an average of 96,160 dekatherms per day (Dth/day) in 2009-2010 to 117,660 Dth/day in 2028-2029. This is an annual average growth rate of 1.1 percent and is net of projected conservation savings from DSM programs[1].

Peak Day Demand — Coincidental peak day, system-wide core demand is projected to increase from a peak of 365,720 Dth/day in 2009-2010 to 474,670 Dth/day in 2028-2029. Forecasted non coincidental peak day demand peaks at 341,850 Dth/day in 2009-2010 and increases to 440,630 Dth/day in 2028-2029, a 1.3 percent compounded growth rate in peak day requirements. This is also net of projected conservation savings from DSM programs.

Figure 1.1 shows forecasted system-wide **annual average daily demand** for the six main scenarios modeled over the planning horizon.

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

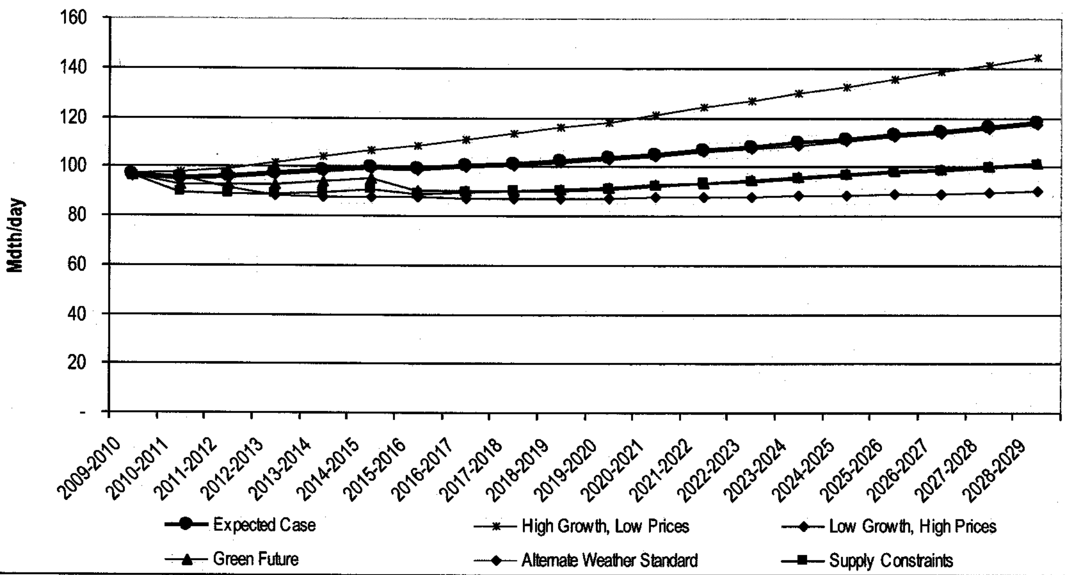
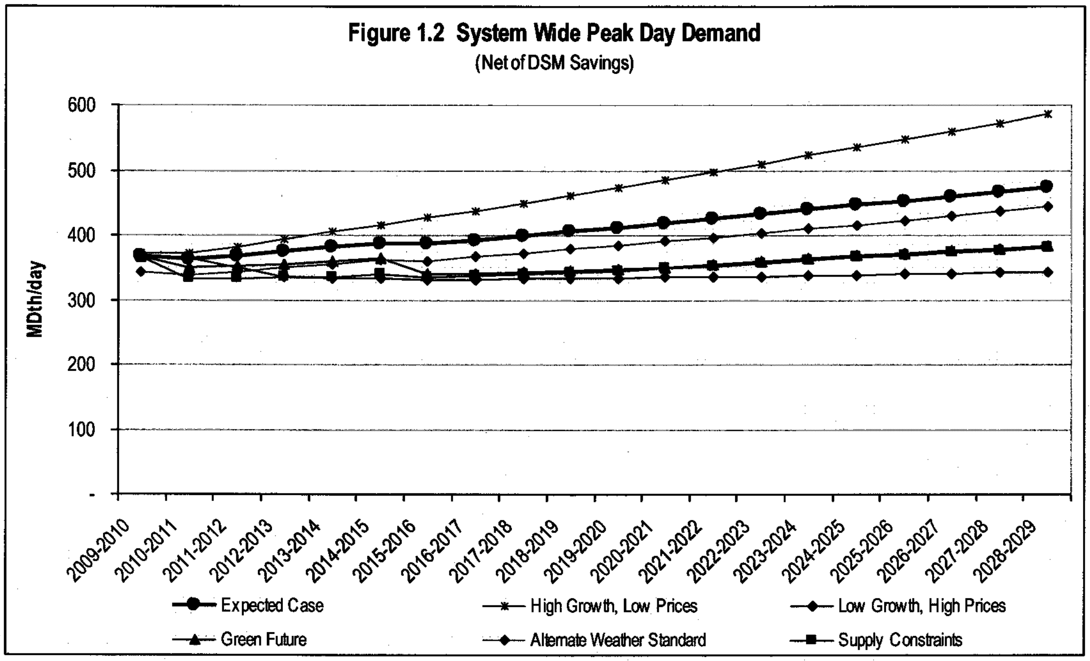


Figure 1.2 shows forecasted system-wide **peak day demand** for the six main scenarios modeled over the planning horizon.

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



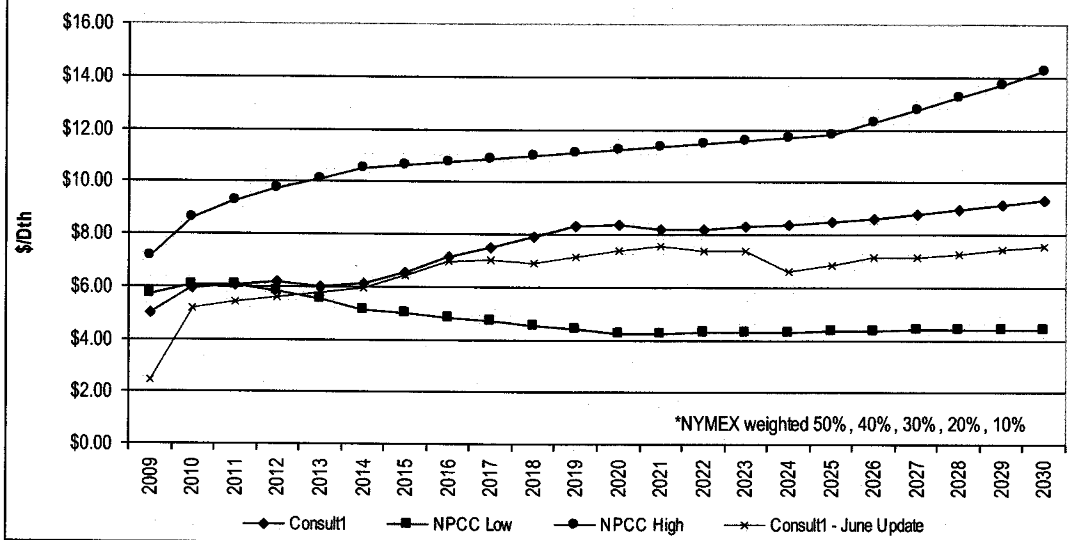
NATURAL GAS PRICE FORECASTS

Natural gas prices are a fundamental component of integrated resource planning. The commodity price is a significant component of the total resource cost of a resource option. This affects the avoided cost threshold for determining cost effectiveness of conservation measures. The price of natural gas influences the consumption of natural gas by customers, so we included price elasticity analysis in our evaluation of demand.

The outlook for natural gas prices has changed dramatically over the recent planning cycle because of several influential events and trends affecting the natural gas industry. Most notable is the severe economic recession triggered by the global credit crisis. Other significant influences include expectations of prolific shale gas production and increased natural gas-fired power generation as anticipated climate change legislation encourages replacement of coal burning power plants. The outlook for these and other factors has evolved rapidly in the midst of significant uncertainty precipitating wide swings and frequent updates to the natural gas price forecasts we monitor.

Although we do not believe we can accurately predict future prices for the 20-year horizon of this IRP, we have reviewed several price forecasts from credible sources and have selected high, medium and low price forecasts to represent aggressive but reasonable pricing possibilities for our analysis. Figure 1.3 depicts the price forecasts used in our IRP. Continuing our theme of stretching modeling assumptions to better prepare for an uncertain environment, the price curves have considerable variation.

Figure 1.3 Henry Hub Price Forecasts for IRP
NYMEX blend first five years*
2009$/Dth



In modeling a consumption response to these price curves, we developed high, medium and low price elasticity response factors to be applied under various scenarios. We have assumed a low response to prices in our Expected Case, partly based on a conservative assumption that tight economic conditions and declining real estate values may deter many customers from investing in long-term capital intensive conservation measures in the near term. We will monitor this assumption over the next IRP cycle and make any necessary adjustments.

EXISTING AND POTENTIAL RESOURCES

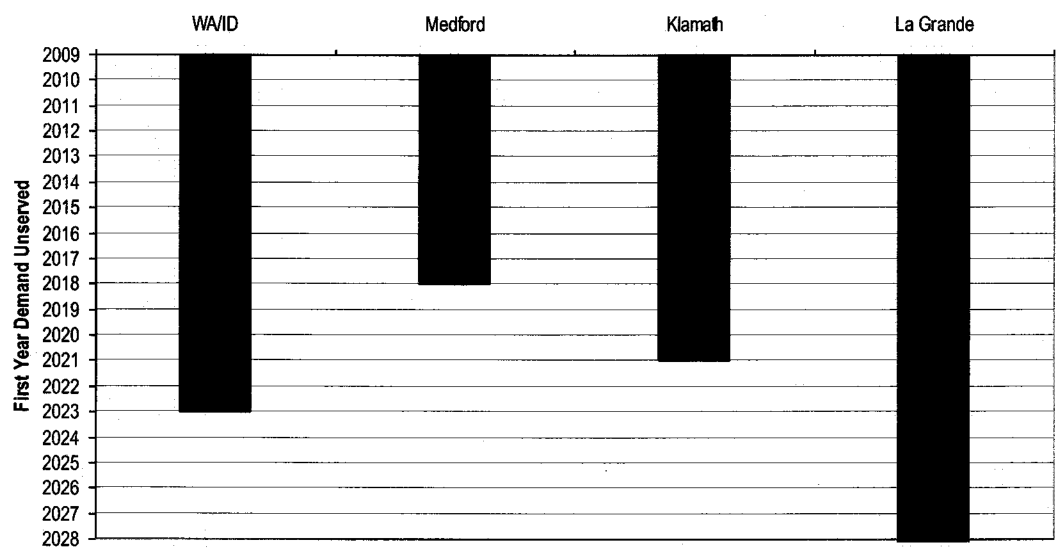
Avista has a diversified portfolio of natural gas supply resources, including contracts to purchase natural gas from several different supply basins, owned and contracted storage enabling flexibility and diversity of supply sources, and firm capacity rights on six pipelines enabling delivery of supply to our service territory city gates. For potential resource additions, we also evaluate incremental pipeline transportation, storage options, distribution enhancements and various forms of liquefied natural gas storage or service.

In our IRP process, we model a number of conservation measures that reduce demand if they prove to be cost effective over the planning horizon. Based on the projected natural gas prices and the estimated cost of alternative supply resources, our computer planning model (SENDOUT®) selects measures for further review and implementation. We actively promote these measures to our customers as one component of a comprehensive strategy to arrive at best cost/risk adjusted resources.

RESOURCE NEEDS

Using our Expected Case demand scenario matched with our Existing Resources supply scenario, we ran the case through the SENDOUT® computer model to determine when the first year peak day demand is not fully served. The results of this portfolio are summarized in Figure 1.4.

Figure 1.4 First Year Peak Demand Not Met With Existing Resources
Expected Case



In the Expected Case for Washington and Idaho, this system first becomes unserved in 2023. In Oregon, the first unserved year is in Medford/Roseburg in 2018 followed by Klamath Falls in 2021. The La Grande system does not go unserved at any time during the 20-year planning horizon.

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

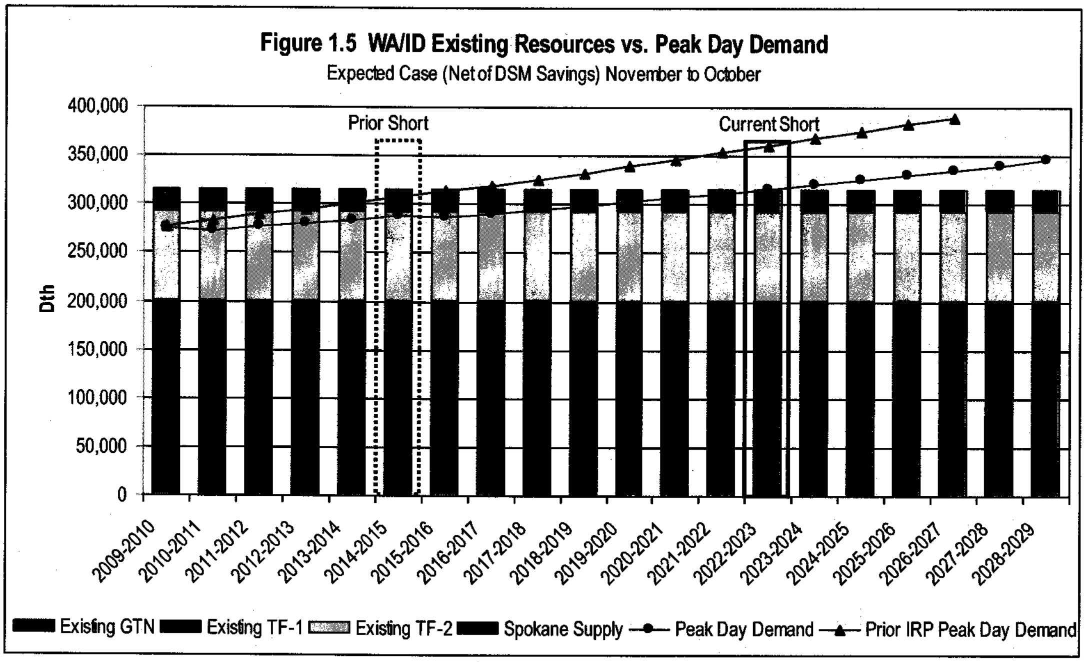


Figure 1.5 WA/ID Existing Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October
Prior Short
Current Short
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
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Existing GTN
Existing TF-1
Existing TF-2
Spokane Supply
Peak Day Demand
Prior IRP Peak Day Demand

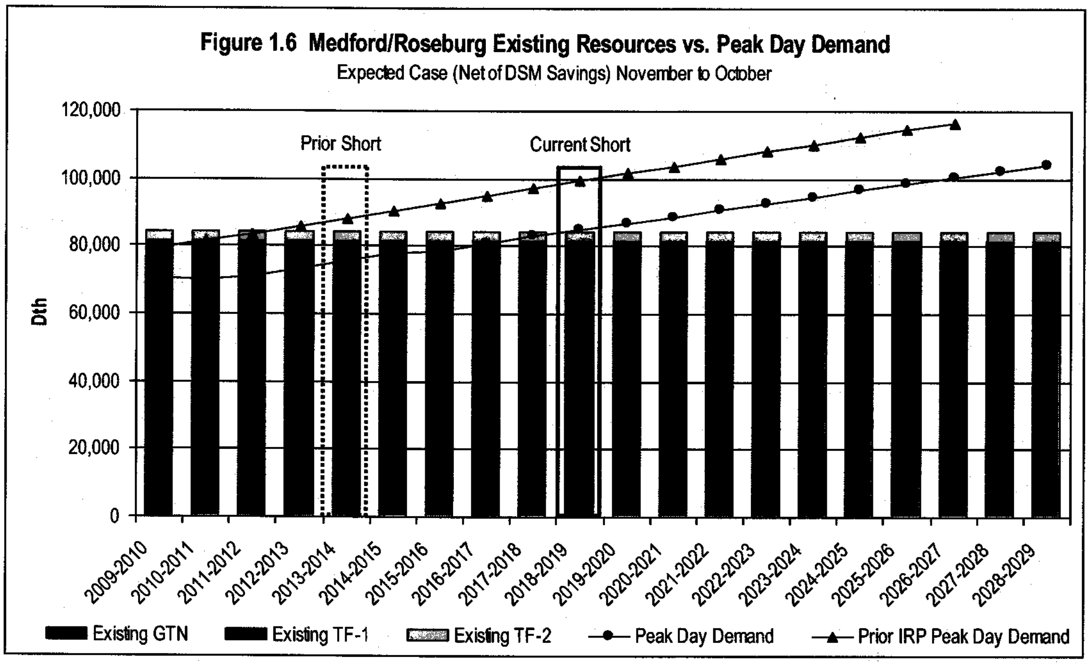
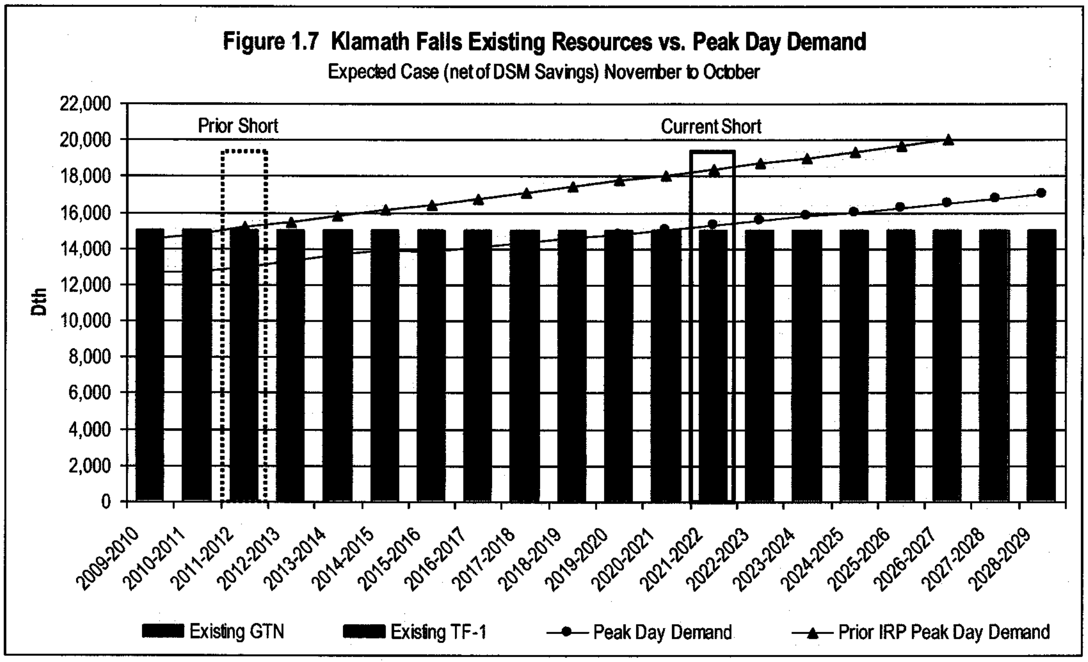
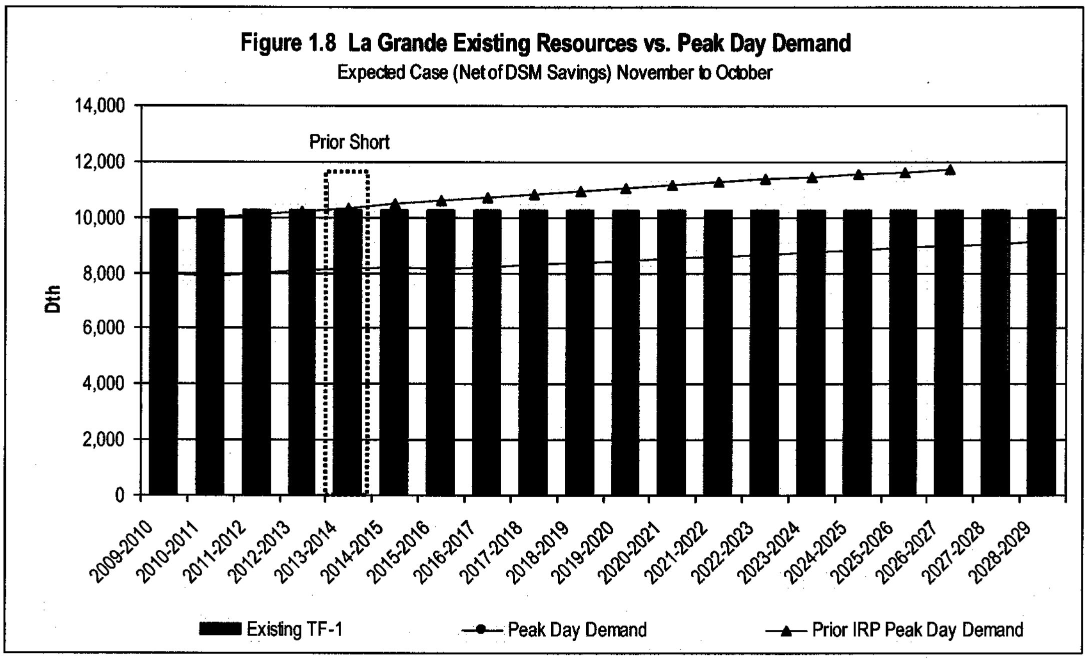
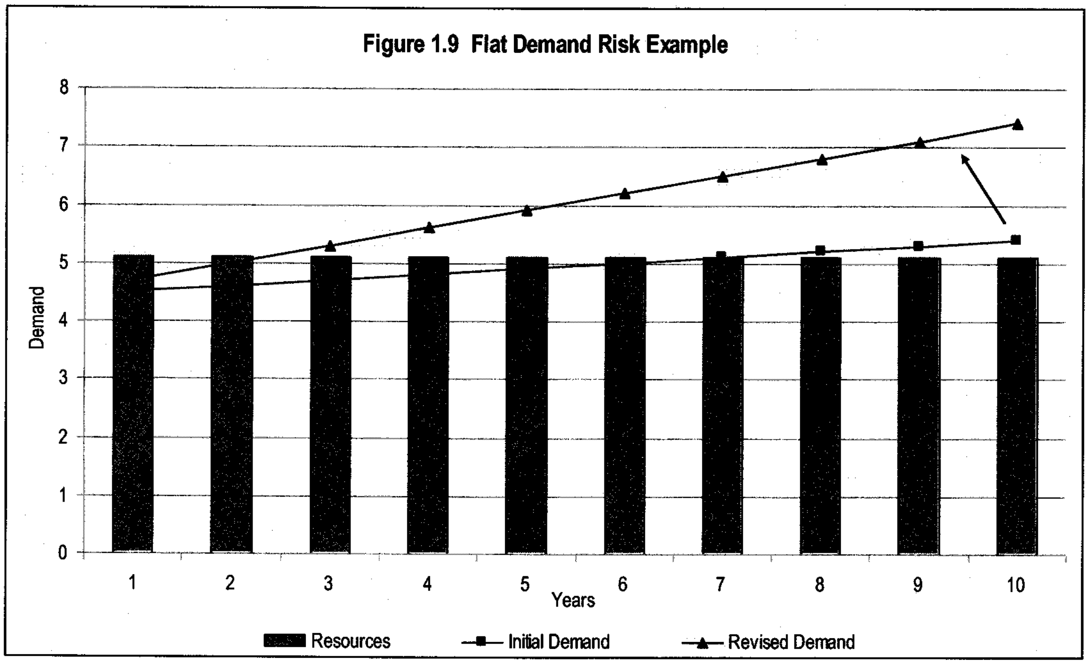


Figure 1.6 Medford/Roseburg Existing Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October
Prior Short
Current Short
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
Existing GTN
Existing TF-1
Existing TF-2
Peak Day Demand
Prior IRP Peak Day Demand



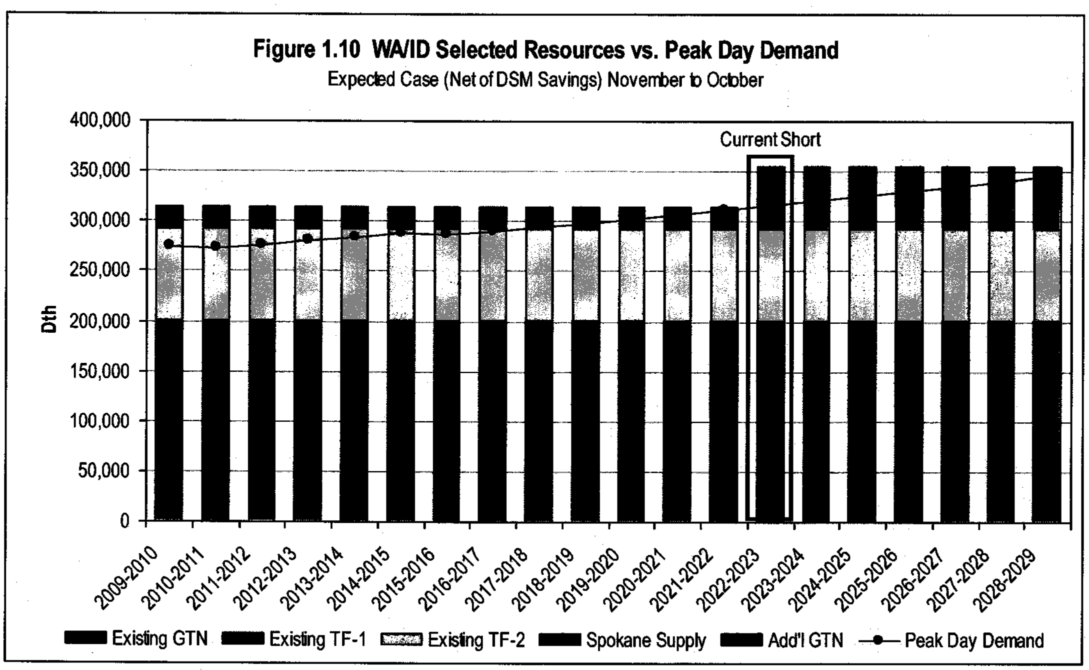


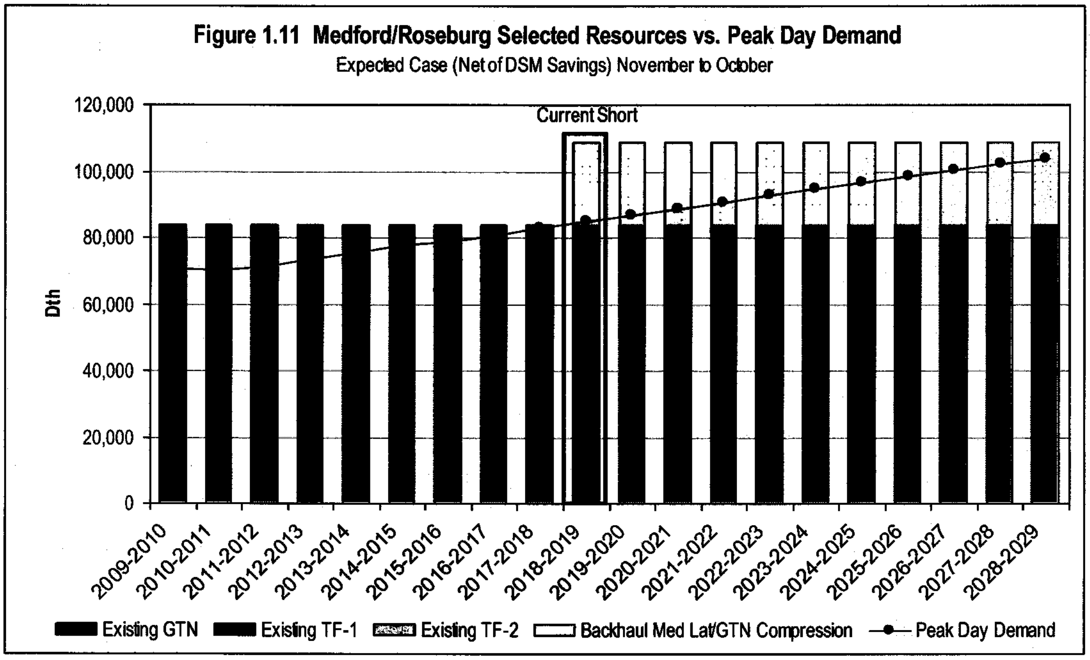
A critical risk with respect to our identified resource shortages is the slope of forecasted demand growth which is almost flat. This outlook implies that existing resources will be sufficient for quite some time to meet demand. However, if demand growth accelerates, the steeper demand curve could quickly accelerate resource shortages by several years. Figure 1.9 is a conceptual diagram that illustrates this risk. In this hypothetical example, a resource shortage does not occur until year eight in the initial demand case. However, the shortage dramatically accelerates by five years under the revised demand case to year three. This "flat demand risk" necessitates close monitoring of accelerating demand as well as careful evaluation of lead times to acquire the preferred incremental resource.

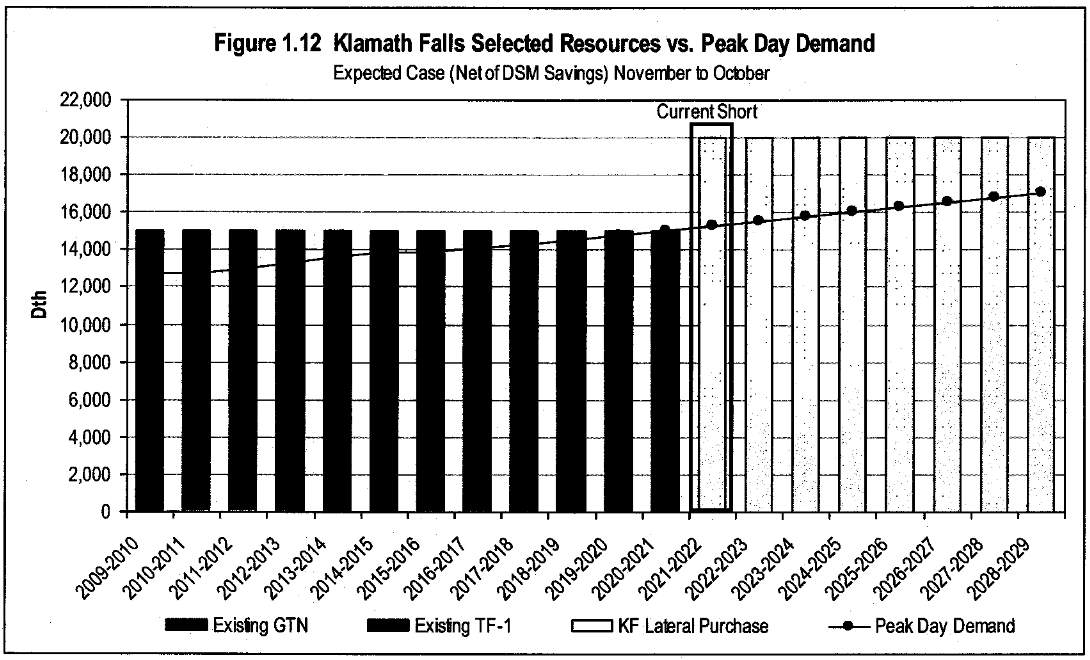


RESOURCE SELECTIONS

The next step is to determine how to resolve resource deficiencies. For this step, we identified possible resource options and placed them into the SENDOUT® model to allow it to select the best cost/risk incremental resources over the 20-year planning horizon. Figures 1.10, 1.11 and 1.12 depict the best cost/risk portfolio selected by SENDOUT® to meet the identified resource shortages. As previously mentioned, the La Grande service territory does not have resource shortages over our planning horizon in the Expected Case.





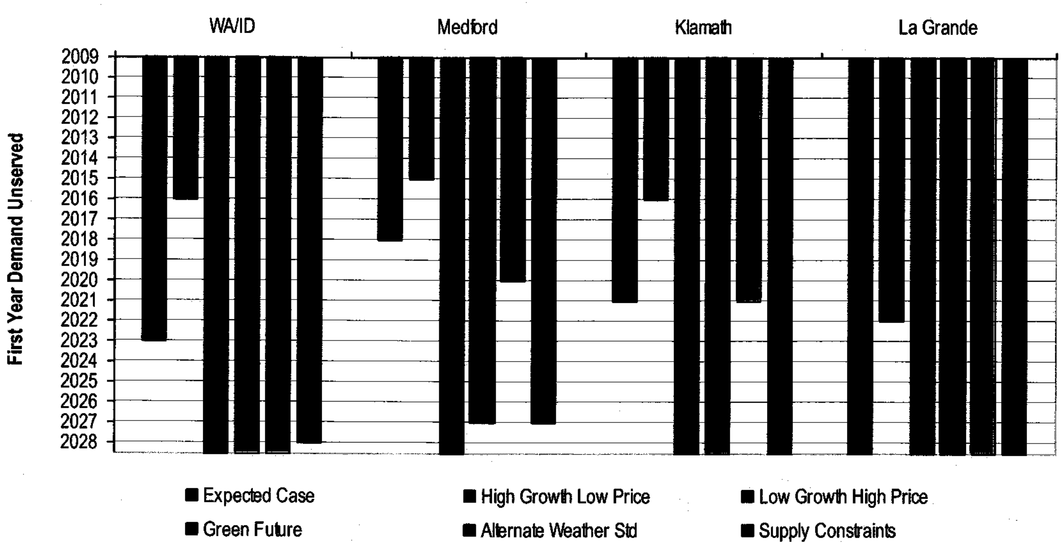


As indicated in the figures, after DSM savings, the model shows a general preference for incremental transportation resources from existing pipelines and supply basins to resolve resource shortages.

ALTERNATE DEMAND SCENARIOS

We performed the same SENDOUT® process for five other demand scenarios, which identified first year unserved dates for each scenario by service territory (Figure 1.13). As expected, the High Growth, Low Price scenario has the most rapid growth and the earliest first year unserved dates. This "steeper" demand somewhat lessens the "flat demand risk" discussed above, but the earlier unserved dates warrant close monitoring of demand trends and resource lead times.

Figure 1.13 First Year Peak Demand Not Met with Existing Resources
Scenario Comparisons



Several scenarios indicate no resource deficiencies over the planning horizon due to very slow or even negative demand growth. A key reason for this is our price elasticity assumptions combined with price forecasts with steep price increases early in the planning horizon. This perfect storm combination produces a significant curtailment in total demand early in the forecast. A key question for these scenarios is whether this early price shock materializes as forecasted and, if so, is demand permanently curtailed as predicted in the price elastic response assumption. This condition also warrants close monitoring and comparison to actual results.

ACTION PLAN

Our 2010-2011 Action Plan outlines activities identified by our IRP team, with advice from management and TAC members, for development and inclusion in the 2011 IRP. The purpose of these action items is to position Avista to provide the best cost/risk resource portfolio and to support and improve IRP planning. Key components of the Action Plan include:

- Monitor actual demand for indications of growth exceeding our forecast to respond aggressively to address potential accelerated resource deficiencies arising from exposure to "flat demand" risk. This includes researching and refining evaluation of resource alternatives, including implementation risk factors and timelines, updated cost estimates, feasibility assessments and targeting options for the service territories with nearer term unserved demand exposure.
- Analyze use per customer data and DSM program results for indications of price elasticity response trends that may have been influenced by evolving economic conditions. Investigate

contemporary analytical sources for information on natural gas price elasticity. Determine if the American Gas Association (AGA) will update its analytical work and/or consider hiring a third-party price elasticity study and assess interest of other utilities in pursuing a regional study.

- Continue cost effective demand-side solutions. In Washington and Idaho, conservation measures are targeted to reduce demand by 2,193,338 therms in the first year (2010). In Oregon, conservation measures are targeted to reduce demand by 303,300 therms in the first year. These goals represent an increase of 25 percent in Washington and Idaho and a nominal decrease of less than 1 percent in Oregon from the 2010 projected goals in the 2007 IRP.
- Research and engage a conservation consultant to perform an updated assessment of technical and achievable potential for conservation in our service territories prior to the 2011 IRP.
- Continue to monitor the discussion around diminishing Canadian natural gas imports and look for signals that indicate increased risk of disrupted supply given much of our supply comes from Canadian sources.
- Explore and evaluate alternative and additional forecasting methodologies for potential inclusion in our next IRP.
- Regularly meet with Commission Staff members to provide information on market activities and significant changes in assumptions and/or status of Avista activities related to the IRP or natural gas procurement practices.

ISSUES AND CHALLENGES

Although we are satisfied with the planning, analysis and conclusions reached in this IRP, we recognize widespread uncertainty results in a heightened risk environment requiring diligent monitoring of the following issues and challenges:

ECONOMIC UNCERTAINTY

The current economic downturn has been dramatic and has impacted near-term trends in economic activity. The potential influence on natural gas demand, DSM, infrastructure developments, commodity prices, credit terms and procurement practices in such an unsettled environment presents many forecasting challenges. Historical relationships may be altered or fundamentally changed. For example, customer changes in natural gas consumption may be driven as much by personal income changes as by natural gas prices. DSM initiatives could be enthusiastically pursued by more customers seeking savings on their energy costs while other customers may forego participation due to personal economic constraints. Tight credit markets, lower regional demand and community opposition could delay pipeline and other infrastructure projects. Alternatively, lower labor, materials and interest costs may prompt accelerated infrastructure investment.

In such an uncertain environment, there is more risk of unanticipated outcomes. Although we sought to capture many of these issues through a wide range of scenarios in our modeling and analysis, monitoring will be required to see how events unfold and if there are outcomes we did not consider, requiring adjustment of our analysis and action.

CLIMATE CHANGE LEGISLATION

Global economic growth earlier in the decade was partly driven by low cost debt and inexpensive energy. The two are not uncorrelated – robust growth usually depends on both. In hindsight, we now see this growth was vulnerable. Debt was improperly priced for risk while energy was underpriced for carbon emissions and other environmental concerns. As prices of debt and energy readjust to reflect these costs, economic growth will face strong headwinds. The emerging political dilemma will be how to facilitate this readjustment in a fragile economic climate.

When we initiated our IRP planning and analysis, federal climate change legislation appeared almost certain to pass with far reaching and long-term implications. We still believe some form of federal climate change legislation is likely to be enacted though the form, extent and timing continue to be uncertain. A cap and trade structure remains the most likely framework for greenhouse gas legislation. Economic issues aside, this complex structure has numerous design issues that must be addressed, including emissions target levels, phase in timeframes, allocation of allowances, availability of offsets, cost mitigation to customers and a host of implementation challenges.

By design, this legislation is meant to substantially alter the energy production and consumption landscape. Inherent in this new landscape is significant uncertainty in market behavior and acceptance, which can profoundly impact resource needs. Additional carbon mitigation costs may slow or reverse end user adoption of natural gas appliances and applications. Direct use initiatives may stall given significant regional hydro and other renewable electric resources will not be burdened with carbon costs. The integration of federal legislation with the regional Western Climate Initiative also remains uncertain. These example issues pose significant modeling and forecasting challenges.

To address these challenges, we worked closely with one of our energy industry consultants, leveraging their monitoring of climate change policy issues and in-depth research to develop our long-term price forecasts. This includes specific alternative price forecast scenarios that separately captured influences of potential carbon emissions legislation. We also conferred with and solicited ideas and feedback from Avista's electric resource planning team and the TAC to develop two carbon emission reduction sensitivities that were ultimately incorporated in each of our modeled scenarios. This provided useful findings and a solid base to continue analysis and monitoring developments in this important sphere going forward.

SEISMIC SUPPLY SHIFTS

The main driver of North American natural gas production growth is now forecast to be unconventional gas, especially shale gas. Several new shale gas fields have been identified with many of the wells delivering impressive results. However, the reality is huge future volumes are being forecast for this resource, yet the long-term estimates for these resources remain relatively untested and unknown. Although we are encouraged by this progress, we will need to be prudently wary as well.

Burgeoning supply from international liquefied natural gas projects, which have been at least a half decade in the making, is just now coming on line. Significant capacity is being added as near-term global demand is diminished from the prospects of a lingering global recession. This, combined with the unconventional gas production supply surge, resulted in an unprecedented rapid collapse in prices. Although beneficial to end users in the near term, this dramatic volatility and uncertainty could cause long-term disruption in production, pipeline and storage capital investment exacerbating boom/bust cycles in the long term.

CONCLUSION

Lower demand since our last IRP as well as slower forecasted demand in our Expected Case indicates no near-term need for additional supply-side resources. This will not diminish our efforts to encourage customer adoption of cost effective conservation measures consistent with our longstanding commitment to acquire demand-side resources. The IRP process has many objectives but foremost is to ensure that proper planning will enable us to continue delivering safe, reliable and economic natural gas service to our customers well into the future. We are confident this plan delivers on that objective.

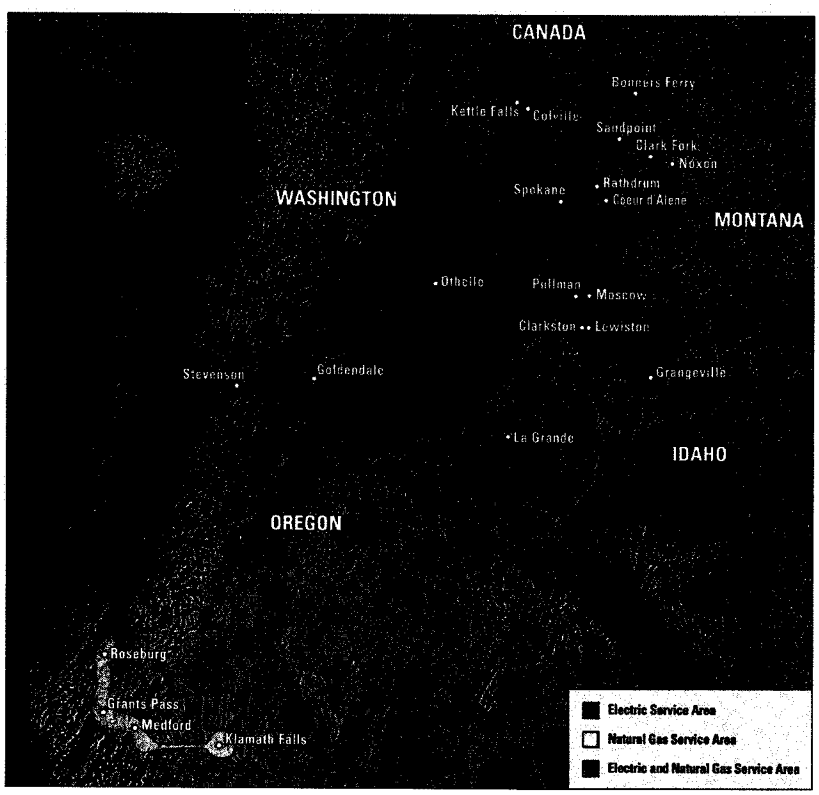
CHAPTER 2 – INTRODUCTION

OUR COMPANY

Avista is involved in the production, transmission and distribution of energy as well as other energy-related businesses. Avista was founded in 1889 as Washington Water Power and has been providing reliable, efficient and competitively priced energy to customers for nearly 120 years.

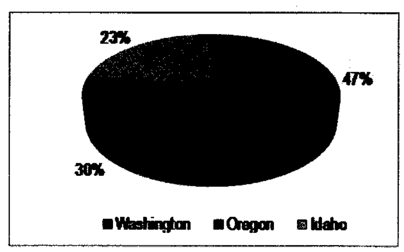
Avista entered the natural gas business with the purchase of Spokane Natural Gas Company in 1958. In 1970, we expanded into natural gas storage with Washington Natural Gas (now Puget Sound Energy) and El Paso Natural Gas (their interest subsequently purchased by Williams - Northwest Pipeline (NWP)) to develop the Jackson Prairie natural gas underground storage facility in Chehalis, Washington. In 1991, we added 63,000 customers with the acquisition of CP National Corporation's Oregon and California properties. Avista subsequently sold the California properties and its 18,000 South Lake Tahoe customers to Southwest Gas in 2005. Avista currently provides natural gas service to over 314,000 customers in eastern Washington, northern Idaho and several communities in northeast and southwest Oregon.

SERVICE TERRITORIES AND NUMBER OF CUSTOMERS



Natural Gas Customers as of Dec. 31, 2008

Washington	145,600
Idaho	73,250
Oregon	95,300
Total	314,150



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

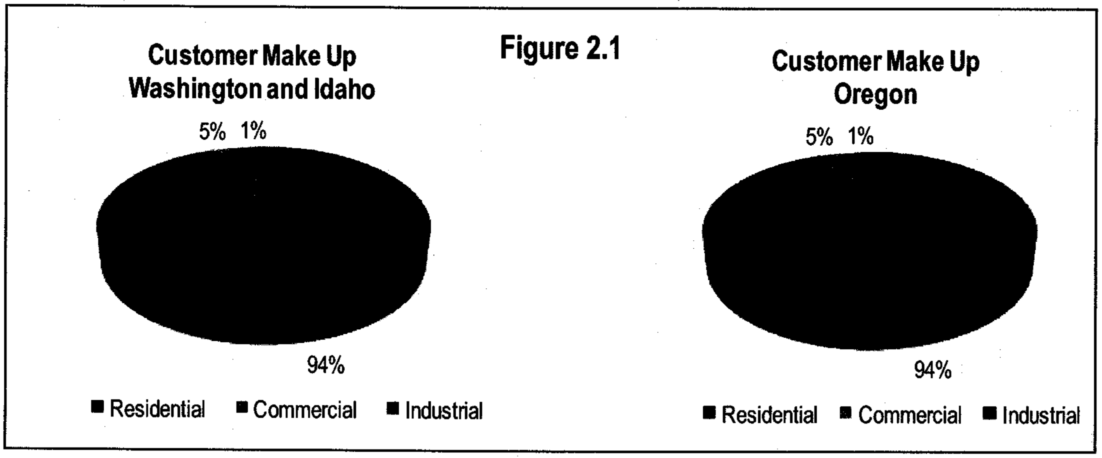
- The North Division covers about 26,000 square miles, primarily in eastern Washington and northern Idaho. Over 840,000 people live in Avista's Washington/Idaho service area. It includes urban areas, farms, timberlands and the Coeur d'Alene mining district. Spokane is the largest metropolitan area with a regional population of approximately 450,000 followed by the Lewiston, Idaho/Clarkston, Washington area and Coeur d'Alene, Idaho. The North Division has about 74 miles of natural gas distribution mains and 5,000 miles of distribution lines. Natural gas is received at more than 40 points along interstate pipelines and distributed to over 219,000 residential, commercial and industrial customers.
- The South Division serves four counties in southwest Oregon and one county in northeast Oregon. The combined population of these two areas is over 480,000 residents. The South Division includes urban areas, farms and timberlands. The Medford, Ashland and Grants Pass area, located in Jackson and Josephine Counties, is the largest single area served by Avista in this division, with a regional population of approximately 280,000 residents. The South Division consists of about 67 miles of natural gas distribution mains and 2,000 miles of distribution lines. Natural gas is received at more than 20 points along interstate pipelines and distributed to over 95,000 residential, commercial and industrial customers.

OUR CUSTOMERS

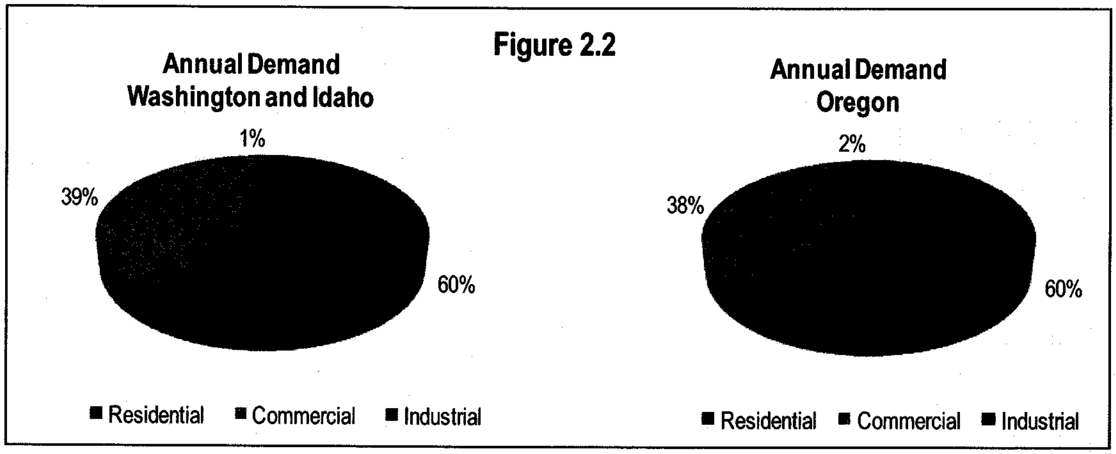
We provide natural gas services to two customer classifications — core and transportation only customers. Core customers purchase natural gas directly from us with delivery to their home or business under a bundled rate. This service implicitly obligates Avista to deliver whatever volume is needed by the customer under firm delivery requirements.

Transportation only customers purchase natural gas from third-parties who deliver their gas to our distribution system. We then deliver this gas to their business charging a distribution rate only. This delivery service can be interrupted by us during periods of high demand by our core customers. Because our transportation only customers purchase their own gas and delivery on our distribution system is non-firm, we exclude these customers from our long-term resource planning analysis.

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



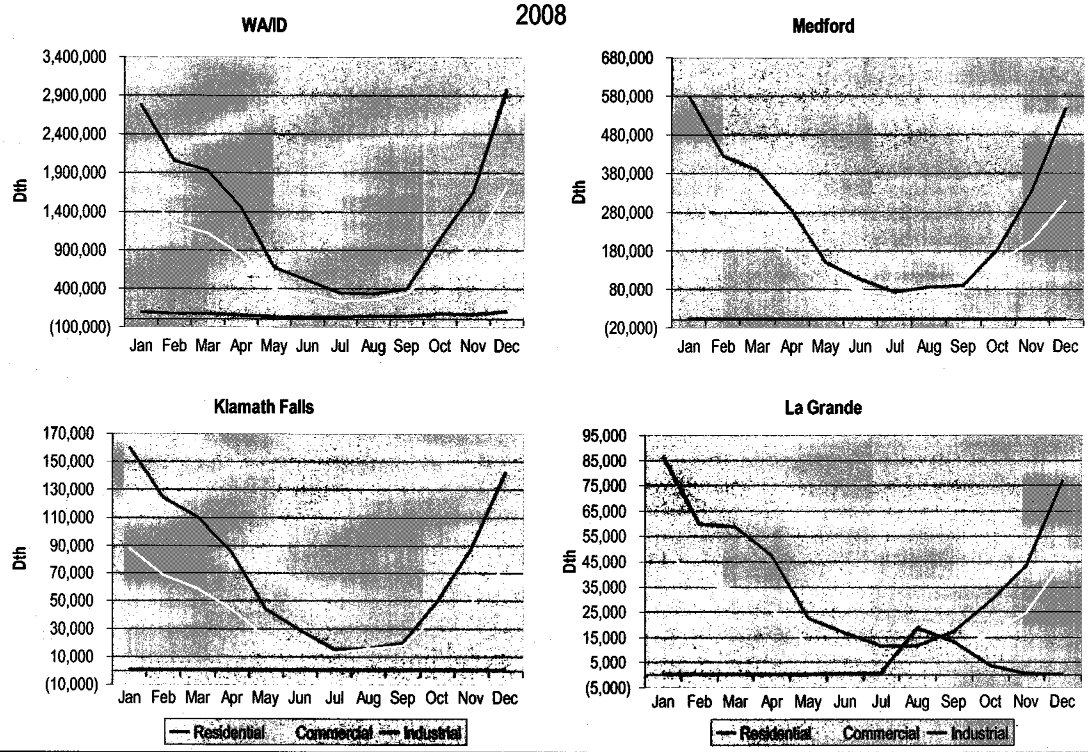
The mix is more balanced between residential and commercial accounts on an annual volume basis (Figure 2.2). Volume consumed by core industrial customers is not significant to the total partly because most industrial companies in our service territories are transportation only customers.



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

Figure 2.3 Seasonal Demand by ServiceTerritory and Customer Class

2008



INTEGRATED RESOURCE PLANNING

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

PURPOSE OF THE IRP

This document has several objectives:

- Provides a comprehensive long-range planning tool;
- Fully integrates forecasted requirements with potential resources;
- Determines the most cost effective, risk-adjusted means for meeting demand requirements; and
- Responds to Washington, Idaho and Oregon rules and orders.

AVISTA'S IRP PROCESS

The IRP process considers:

- Customer growth and usage;
- Weather planning standard;

- DSM opportunities;
- Existing and potential supply-side resource options; and
- Risk.

PUBLIC PARTICIPATION

Members of Avista's TAC play a key role and have a significant impact in development of the IRP. TAC members include Commission Staff, peer utilities, public interest groups, customers, academics, government agencies and other interested parties. 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 process.

Avista sponsored four TAC meetings to facilitate stakeholder involvement in the 2009 IRP. The first meeting convened on April 26, 2009 and the last meeting was held on July 16, 2009. A broad spectrum of stakeholders was represented at each meeting. The meetings focused on specific planning topics, reviewed the status and progress of planning activities and solicited input on the IRP development. A draft of this IRP was provided to TAC members on September 4, 2009. We gained valuable input from the interaction and communication with TAC members and express our thanks and appreciation for their contributions and participation.

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

REGULATORY REQUIREMENTS

Avista submits an IRP to the Public Utility Commissions in Washington, Idaho and Oregon every two years as required by state regulation[1]. We intend to file our plan with all three Commissions on or before December 31, 2009. We have a statutory obligation to provide reliable natural gas service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. We regard the IRP as a means for identifying and evaluating resource options and as a process to establish an Action Plan for resource decisions. Ongoing investigation, analysis and research may cause us to determine that alternative resources are more cost effective than resources selected in this IRP. We will continue to review and refine our understanding of resource options and will act to secure these risk-adjusted, least-cost options when appropriate.

PLANNING MODEL

Consistent with several prior IRPs is SENDOUT®, the computer planning model we use to perform comprehensive and effective natural gas supply planning and analysis. This linear programming-based model is widely used in the industry to solve natural gas supply, storage and transportation

[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 Nos. 07-002, 07-047 and 08-339. Appendix 2.1 provides details of these requirements and how they were met.

optimization problems. This model uses present value revenue requirement (PVRR) methodology to perform least cost optimization based on daily, monthly, seasonal and annual assumptions related to:

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

We have also incorporated the Monte Carlo simulation module within SENDOUT® (formerly called VectorGas™) to simulate weather and price uncertainty. The module uses Monte Carlo functionality to generate simulations of weather and price to provide a probability distribution of results from which decisions can be made. Some examples of the types of analysis Monte Carlo simulation provides include:

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

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

PLANNING ENVIRONMENT

Although we prepare and publish an IRP biannually, the IRP process is ongoing to take into account new information and developments. In "normal" circumstances, the process can become complex as underlying assumptions evolve and impact previously completed analyses. The most recent cycle has been even more challenging because the planning environment has undergone extraordinary changes to the economic and natural gas industry landscape.

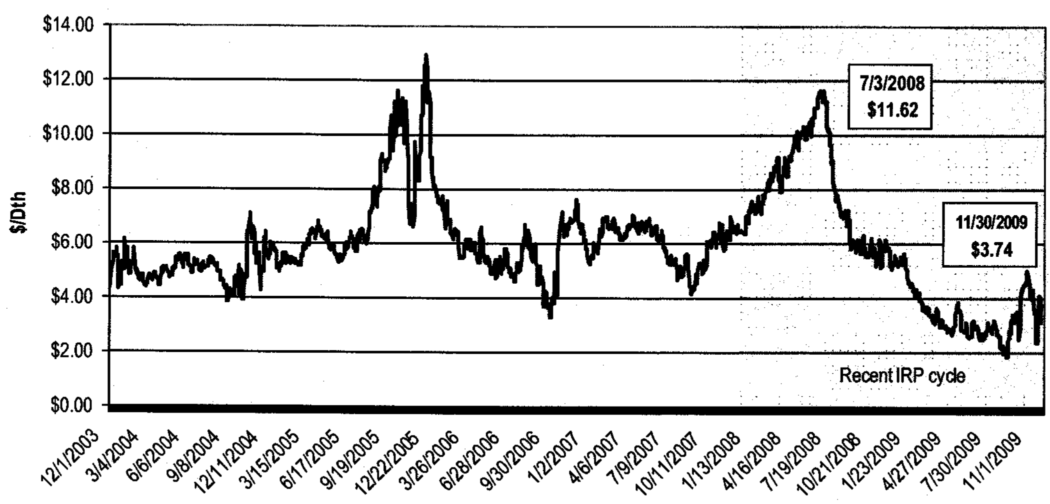
HISTORICAL RECAP

As we completed our 2007 IRP, continued robust global economic activity was pressuring energy commodity prices upward. Natural gas prices were strained by extremely tight production versus production capacity conditions and declining production in the Gulf of Mexico and western Canada. Increased oil sands production consumed an increasing share of western Canada's declining production exacerbating a declining import trend into the United States. At that time there was much discussion that imported liquefied natural gas (LNG) was essential to bridging the supply/demand gap. Higher forecasted prices were predicted to be necessary to lure LNG away from the higher priced European and Asian markets. Further, firming climate change policy generally predicted solid demand growth from increased gas-fired power generation to replace coal burning generation.

Higher prices brought increased investment in natural gas exploration, production and infrastructure. Emerging successes in existing unconventional gas production, especially shale gas, was a primary recipient of this increased investment, particularly in the areas of securing land leases and drilling test wells in new and existing plays throughout North America. With the expectation of strong demand growth came numerous new proposed pipeline projects announced including several to serve the Pacific Northwest.

Strong energy price increases and tight fundamentals also caught the attention of the investment community prompting significant interest in energy commodities and investment inflows into the sector. Prices were bid strongly and by summer 2008, natural gas prices reached all-time highs on a seasonal basis (Figure 2.4).

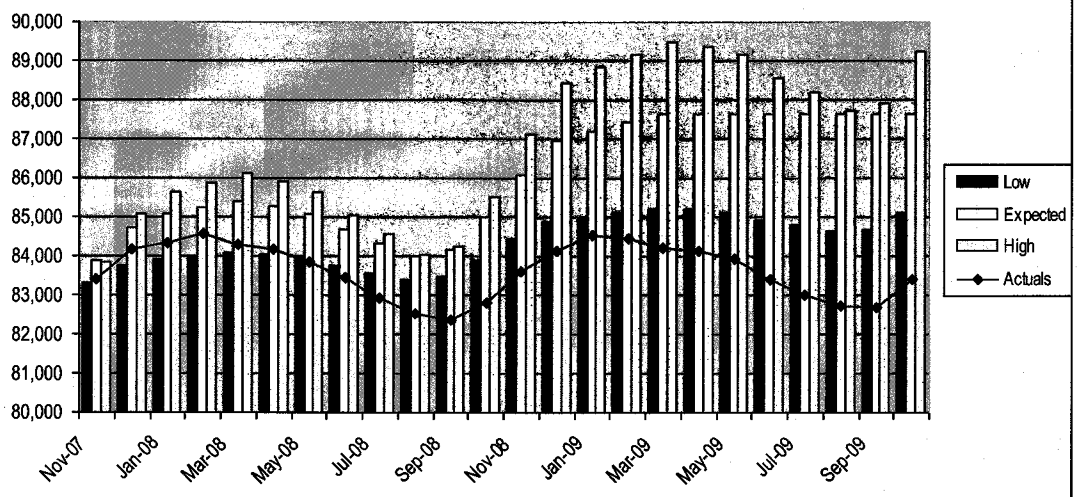
Figure 2.4 Historical Daily Prices
AECO



However, shifting fundamental factors and a slowing economy increasingly contradicted with this price strength. In the second half of 2008 and into 2009, the global credit crisis led to widespread economic disruption and energy demand destruction which dramatically reversed energy market expectations. Energy prices plummeted and uncertainty reigned. Meanwhile, earlier investments in shale exploration and production began delivering prolific results, leading to several upward revisions for predicted future supply sources prompting significant downward revisions to forward price forecasts.

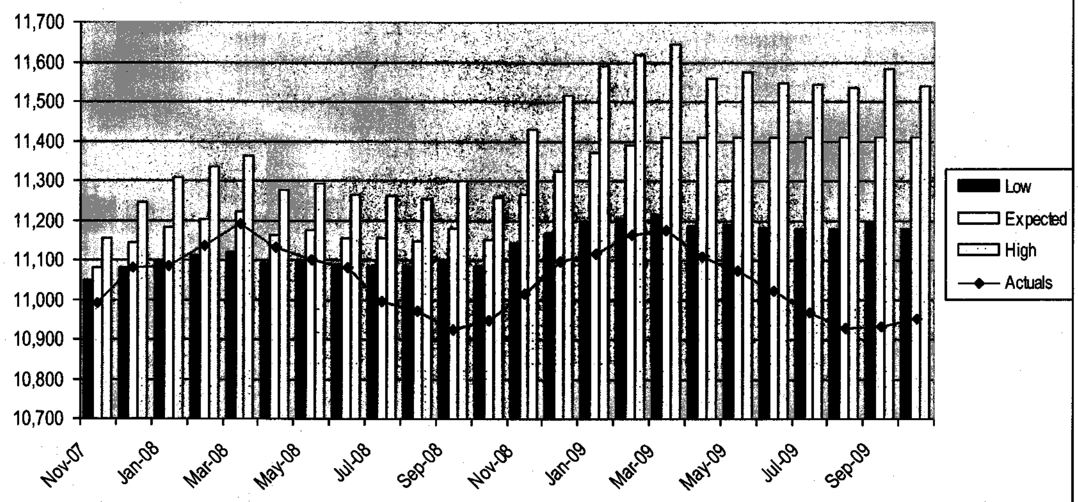
In our own data, we saw a dramatic drop in a key demand metric, customer counts, which began lagging our 2007 IRP forecast. In Oregon, the counts even fell below our low-case projection, raising concern about the severity of the downturn and questions about our underlying modeling assumptions (See Figures 2.5 and 2.6).

Figure 2.5 Customer Count - 2007 IRP vs. Actuals
OR Residential



Note: y-axis doesn't start at zero to better show differences.

Figure 2.6 Customer Count - 2007 IRP vs. Actuals
OR Commercial



Note: y-axis doesn't start at zero to better show differences.

IRP PLANNING STRATEGY

Amid this rapidly changing and uncertain environment, we contemplated our IRP planning strategy. We determined our approach needed to:

- Recognize historical trends may be fundamentally altered;
- Critically review all assumptions;
- Stress test assumptions via sensitivity analysis;
- Pursue a wide spectrum of possible scenarios;

- Develop a flexible analytical framework to accommodate changes; and
- Maintain a long-term perspective.

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

CHAPTER 3 – DEMAND FORECASTS

OVERVIEW

The integrated resource planning process begins with the development of forecasted demand. This was a challenging time to predict future events including preparing demand forecasts. Although historical trends normally provide a reliable baseline, they were used with heightened caution given the dramatic economic disruption we confronted as we prepared and presented this analysis.

The current economic situation is ambiguous, fluid and evolving. Although the economy appears to be stabilizing, long-term effects on the natural gas industry are uncertain, prompting us to consider a wide range of scenarios to evaluate and prepare for a broad spectrum of potential outcomes.

DEMAND AREAS

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

Table 3.1 Geographic Demand Classifications

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

DEMAND FORECAST METHODOLOGY

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

DEMAND MODELING EQUATION

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

Table 3.2 Basic Demand Formula

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

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

Table 3.3 SENDOUT® Demand Formula

of customers **x** Daily Dth of base usage / customer
Plus
of customers **x** Daily Dth of degree day usage / customer **x** # of daily degree days

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

Customer Forecasts

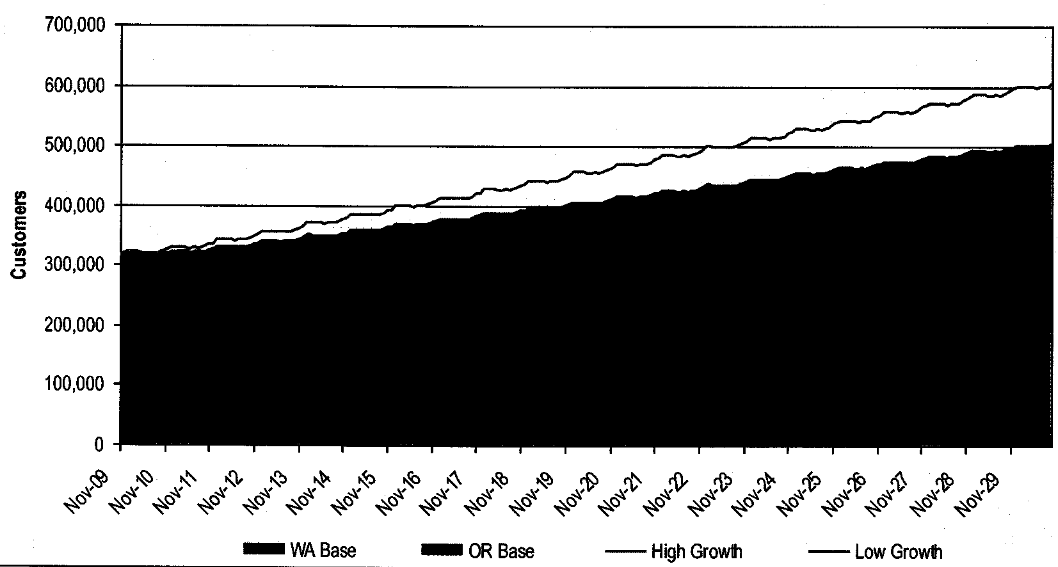
Avista's customer base is segregated into three categories: residential, commercial and industrial. For each of the customer categories, we develop our customer forecasts by starting with national economic forecasts and then drilling down into regional economies. Population growth expectations and employment are key drivers in regional economic forecasts and are useful in estimating natural gas customers. We contract with Global Insight, Inc. for long-term regional economic forecasts. A description of the Global Insight forecasts is found in our customer forecasts detail in Appendix 3.1. We combine this data with local knowledge about sub-regional construction activity, age and other demographic trends and historical data to develop our 20-year customer forecasts.

In response to a previous IRP action item, this IRP incorporates sub-area core customer forecasting for each municipality and unincorporated county area throughout the three-state service area. This includes 56 governmental subdivisions or "town codes" in Washington, 26 in Idaho and 37 in Oregon.

The annual growth for each state is allocated so that the total equals the sum of the parts. These 119 town code forecasts are used by the distribution engineering group for optimizing decisions within these geographic sub-areas and facilitating integrated forecasting and planning within Avista (see further discussion in Chapter 8 – Distribution Planning).

Forecasting customer growth is an inexact science so it is important to consider alternative forecasts. Two alternative forecasts were developed 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, Avista has created low and high customer growth alternatives with these parameters. The three customer growth forecasts are shown in Figure 3.1. Detailed customer count data, by region and by class, for all three scenarios, is in Appendix 3.2.

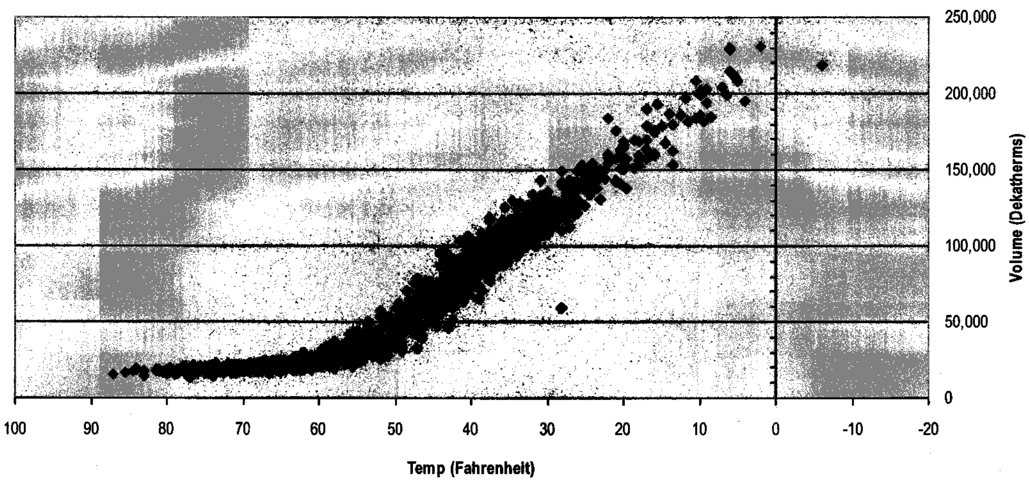
Figure 3.1 Customer Growth Scenarios



Use per Customer Forecast

The goal for a use per customer forecast is to develop base and weather sensitive demand coefficients that can be combined and applied to HDD weather parameters to reflect average use per customer. This produces a very reliable forecast because of the high correlation between usage and temperature as depicted in the example scatter plot in Figure 3.2.

Figure 3.2 - Example Daily Demand vs. Temperature Profile
Washington Idaho



The first step in developing demand coefficients was gathering daily historical gas flow data for all of our city gates. Three years of data were gathered, segregated by service territory/temperature zone and then by month. Weather normalized July and August data was used to calculate base demand coefficients by dividing total usage by total number of customers. Customer class factors were then calculated using allocations based on customer billing data demand ratios.

To derive weather sensitive demand coefficients, for each monthly data subset, we removed base demand from the total and plotted usage by HDD in a scatter plot chart. We then applied linear regression to the data to capture the linear relationship of usage to HDD. The slopes of the resulting lines were our monthly weather sensitive demand coefficients. Again, to derive factors by customer class, we used allocations based on customer billing data demand ratios.

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

The methodology for deriving super peak coefficients was exactly the same as deriving weather sensitive demand coefficients except, instead of forming data subsets by month, a dataset was created using temperature (specifically only very cold temperatures). The line slope from the regression on this data was typically flatter relative to the other monthly weather sensitive demand coefficients. One inherent drawback to this methodology is the lack of sufficient data points to develop a strong linear relationship. More years of data can help, but the older data becomes less and less relevant to current demand relationships.

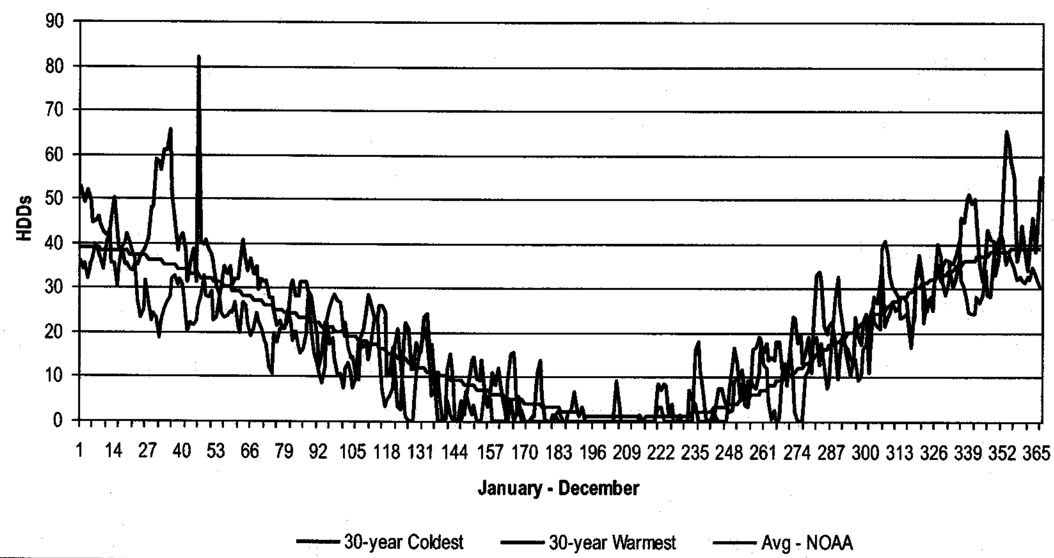
As a final step, to check coefficient reasonableness, we applied the coefficients to actual customer count and weather data to backcast demand. This was compared to actual demand with satisfactory results. The regression calculations and coefficients can be found in Appendix 3.3.

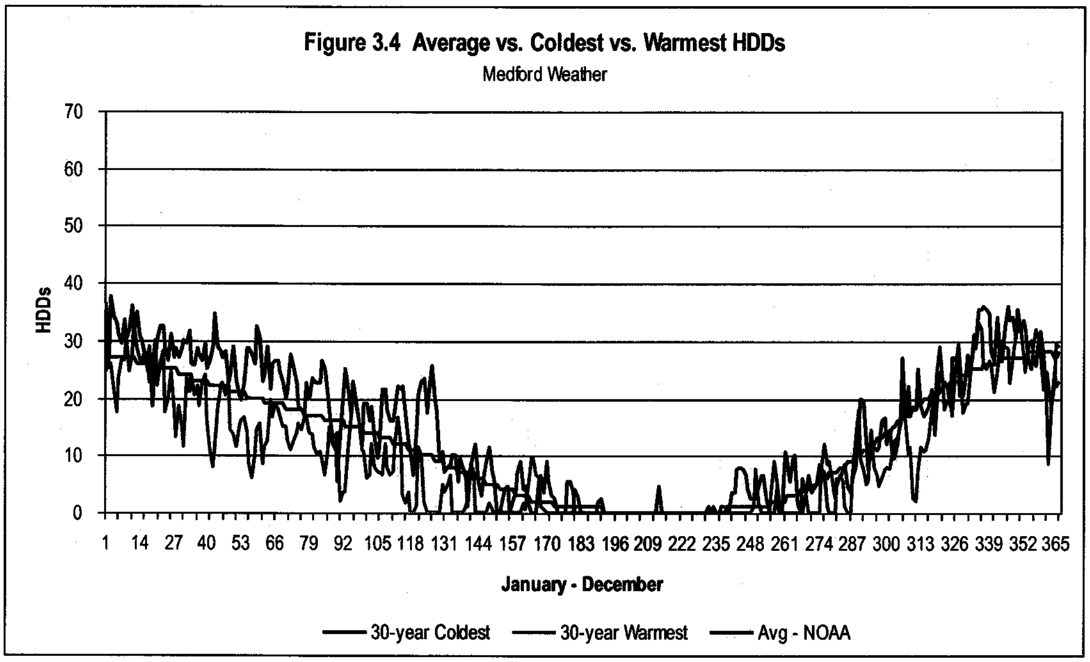
Weather Forecast

The last input in the demand modeling equation is weather (specifically HDDs). We obtain the most current 30 years of daily weather data from the National Oceanic Atmospheric Administration (NOAA), convert it to HDDs and compute an average for each day to develop our weather forecast. For Oregon, we use four weather stations, corresponding to the areas where natural gas services are provided. HDD weather patterns between these areas are uncorrelated. For the eastern Washington and northern Idaho portions of our service area, weather data for the Spokane Airport is used, as HDD weather patterns within that region are correlated.

Figures 3.3 and 3.4 show NOAA's most recent 30-year average weather data in comparison to the coldest and warmest planning year in history 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.

Figure 3.3 Average vs. Coldest vs. Warmest HDDs
Spokane Weather





Figures 3.5 and 3.6 compare the NOAA 30-year average weather with a company-selected composite of weather months that form a weather year based on average HDDs with the variability of actual weather.

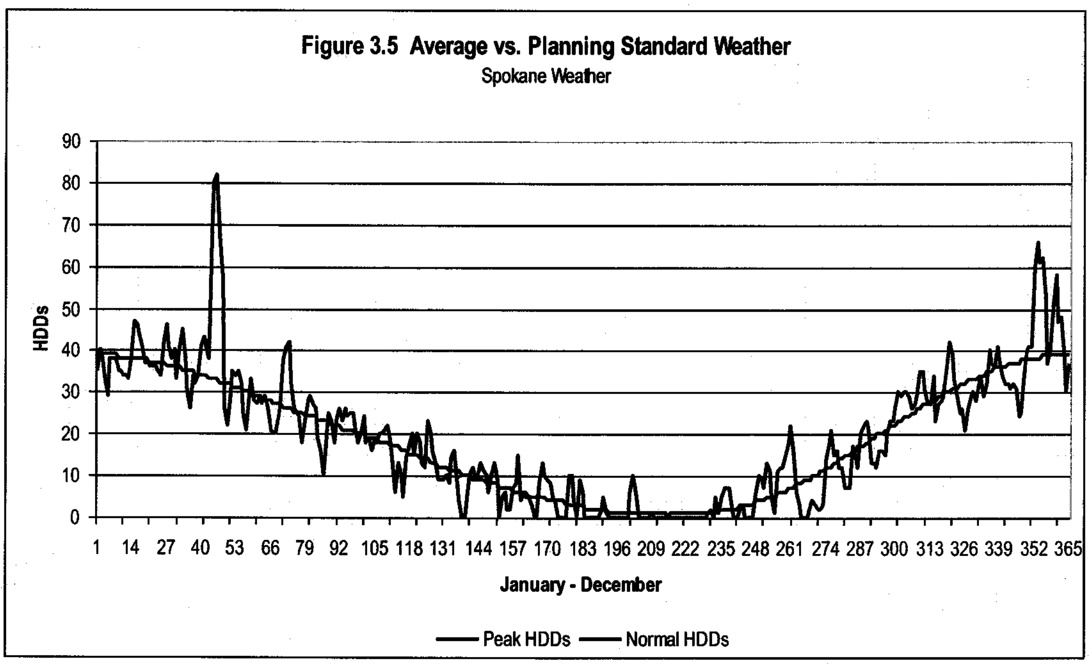
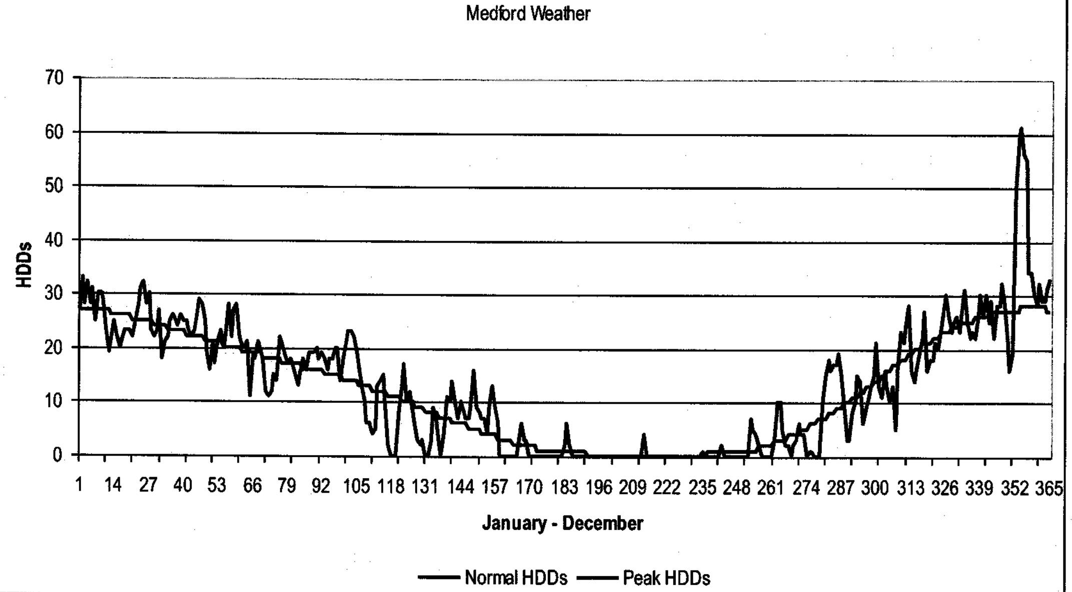


Figure 3.6 Average vs. Planning Standard Weather



The NOAA 30-year average weather (adjusted for global warming-see below) serves as the base weather forecast that is used to prepare the annual average demand forecast. In preparing the peak day demand forecast we adjust average weather to reflect a five-day cold weather event. This consists of adjusting the middle day of the five day cold weather event to the coldest temperature on record for a service territory, as well as adjusting the two days either side of the coldest day to temperatures slightly warmer than the coldest day. For our Washington/Idaho and La Grande service territories, we model this event on and around February 15 each year. For our southwestern Oregon service territories (Medford, Roseburg, Klamath Falls) we model this event on and around December 20 each year.

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

- On Dec. 30, 1968, the Washington/Idaho service area experienced the coldest day on record, an 82 HDD for Spokane. This is equal to an average daily temperature of -17 degrees Fahrenheit. Only one 82 HDD has been experienced in the last 40 years for this area; however, within that same time period, 80 and 79 HDD events occurred on Dec. 29, 1968, and Dec. 31,1978, respectively.
- On Dec. 9, 1972, Medford experienced the coldest day on record, a 61 HDD. This is equal to an average daily temperature of 4 degrees Fahrenheit. Medford has experienced only one 61 HDD in the last 40 years; however, it has also experienced 59 and 58 HDD events on Dec. 8, 1972, and Dec. 21, 1990, respectively.
- The other three areas in Oregon have similar weather data. For Klamath Falls, a 72 HDD occurred on Dec. 21, 1990, in La Grande a 74 HDD occurred on Dec. 23, 1983, and a 55 HDD occurred in Roseburg on Dec. 22, 1990. As with Washington/Idaho and Medford, these days are used as the peak day weather standard for modeling purposes.

The actual HDDs by area and by day entered into SENDOUT® can be found in Appendix 3.4.

For this IRP, we adjusted the NOAA weather data to incorporate estimates for global warming in developing our HDD forecast. This was based on extensive analysis of historical weather data in each of the areas we serve. Adjustments were applied to daily data and include a phase-in over the first ten years of our planning horizon. The effect of the adjustments, all else equal, results in declining annual demand over time. Appendix 3.5 summarizes our historical analysis and adjustment factors.

Although our analysis identified a gradual warming trend in the historical data, we were unable to discern any definitive evidence to support a peak day warming trend. We unsuccessfully searched for potential supporting studies or analysis on the topic and, after discussion with our TAC, determined we would not make warming trend adjustments to our peak day weather events in our HDD forecast. Therefore, our modeling and analysis with respect to peak day planning is unaffected by global warming. Additional information on this topic is in Appendix 3.5.

DEVELOPING A REFERENCE CASE

Significant uncertainty in the planning environment led us to develop a demand forecasting process that could flexibly adapt to a host of alternative demand forecast assumptions. To understand how various alternative assumptions influence forecasted demand, we needed a reference point for comparative analysis. For this we define a reference case demand forecast (Figure 3.7). We stress that this case is not intended to reflect anything other than a simple assumption start point.

Figure 3.7 Reference Case Assumptions

1. Customer annual growth rates:

	Residential	Commercial	Industrial
Washington	1.8%	2.1%	1.2%
Idaho	3.0%	2.5%	0.6%
Oregon	2.7%	1.4%	0%

2. Use per customer coefficients – Flat all classes
3. Weather planning standard – coldest day on record
   - WA/ID 82; Medford 61; Klamath 72; La Grande 74

DYNAMIC DEMAND METHODOLOGY

To address the uncertain planning environment, we identified a demand planning strategy to critically examine a wide range of potential outcomes. The approach developed consisted of:

- Identifying key demand drivers behind natural gas consumption;

- Performing sensitivity analysis on each demand driver; and
- Combining demand drivers under various scenarios to develop alternative potential outcomes for forecasted demand.

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

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

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

Appendix 3.6 schedules the specific sensitivities we identified and the base assumptions we varied to determine the resultant effect on demand relative to our reference case. Sensitivity assumptions reflect incremental adjustments we estimate are not captured in the underlying Reference Case forecast.

Following our testing of the various sensitivities we grouped them into meaningful combinations of demand drivers to develop demand forecasts representing scenarios. Table 3.4 identifies the scenarios we developed. Included is an Expected Case reflecting the demand forecast we believe is most likely. Appendix 3.6 schedules the specific assumptions within the scenarios while Appendix 3.7 contains a detailed description of each scenario.

Table 3.4 Alternate Demand Scenarios
Expected Case
High Growth, Low Price
Low Growth, High Price
Green Future
Alternate Weather Standard
Supply Constraints

PRICE ELASTICITY

With increased natural gas price volatility, it has become difficult to project future natural gas prices. We acknowledge changing price levels influence usage so we incorporate a price elasticity of demand factor into our model to allow use per customer to vary into the future as our natural gas price forecast changes.

Price elasticity is usually expressed as a numerical factor that defines the relationship of a consumer's consumption change in response to price change. Typically, the factor is a negative number as consumers normally reduce their consumption in response to higher prices or will increase their consumption in response to lower prices. For example, a price elasticity factor of negative 0.13 means a 10% price increase will prompt a 1.3% consumption decrease and a 10% price decrease will prompt a 1.3% consumption increase.

We noted complex relationships influence price elasticity and given the challenging economic environment, we questioned whether current behavior might differ from historical trends. Working with the TAC we sought to develop a range of elasticity factors to examine sensitivity of demand to various price elasticity assumptions.

AGA PRICE ELASTICITY STUDY

From our participation in the AGA 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 .13 as our medium case factor to adjust use per customer coefficients. From this base line assumption, we varied the factors to come up with a range of price elasticity responses which was then used in various price influencing demand scenarios (Table 3.5).

Table 3.5 Price Elasticity Assumptions

	Real Price annual increase within 30%	Real Price annual increase exceeds 30%
High	Negative .20	Negative .30
Medium	Negative .13	Negative .13
Low	No response	Negative .06

RESULTS

During 2009-10, our Expected Case demand forecast indicates we will serve an average of 317,700 core natural gas customers with 35,099,000 dekatherms of natural gas. By 2028-29, we project 493,600 core natural gas customers with an annual demand of over 42,944,000 dekatherms. In Washington/Idaho, the number of customers is projected to increase at an average annual rate of 2.2 percent with demand growing at a compounded average annual rate of 1.0 percent. In Oregon, the number of customers is projected to increase at an average annual rate of 2.5 percent, with demand growing 1.4 percent per year.

Figure 3.8 shows system forecasted demand for the Expected, High and Low demand cases on an **average daily basis** for each year[1].

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

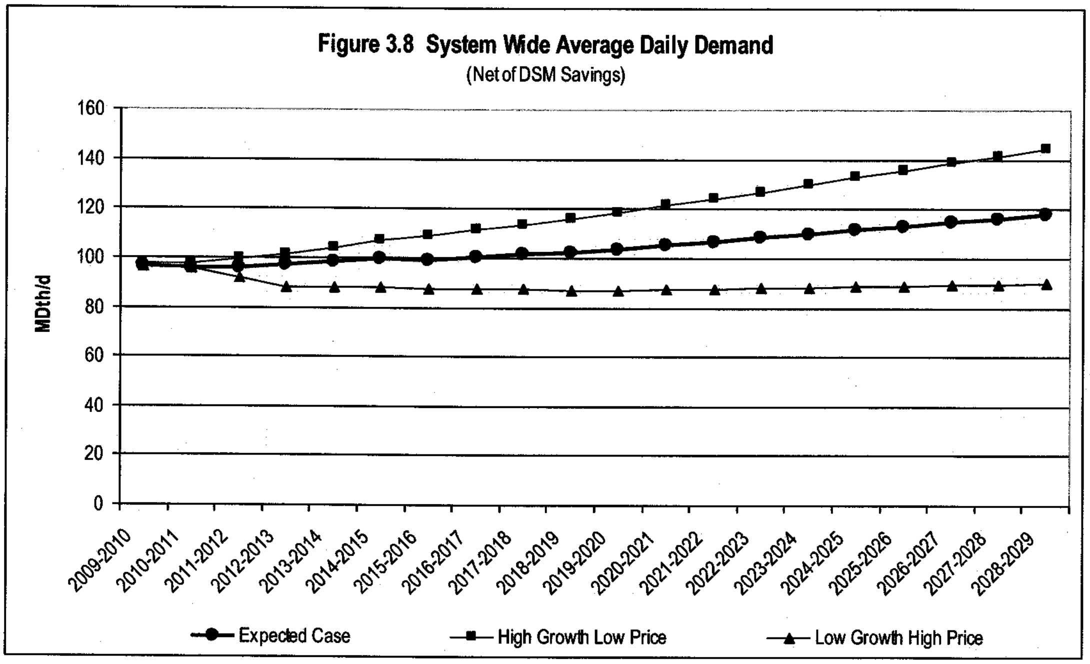
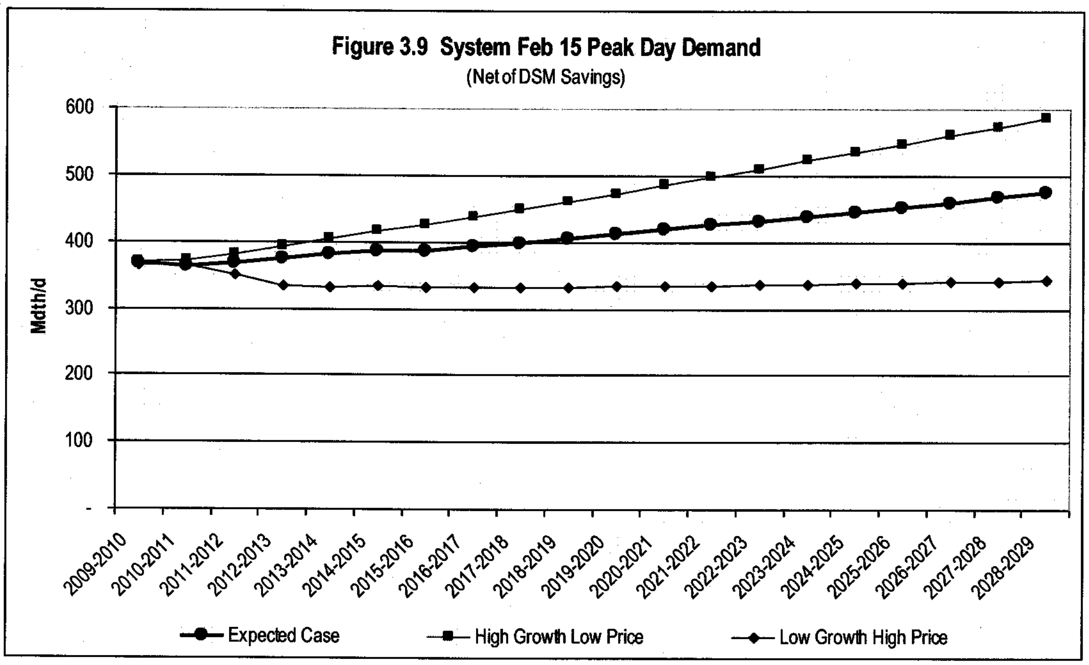


Figure 3.9 shows system forecasted demand for the Expected, High and Low Demand cases on a **peak day basis** for each year.



Detailed data depicting annual and peak day demand data is in Appendix 3.8.

The purpose of the IRP is to balance forecasted demand with existing and new supply alternatives. Since new supply sources include conservation resources, which act as a demand reduction, the demand forecasts prepared and described in this section include existing efficiency standards and normal market acceptance levels. The incremental conservation measures modeled are described in the Demand-Side Resources Chapter.

ACTION ITEM

Our price elasticity analysis raised several issues. First, we noted the AGA factors were derived from annual demand data. This was satisfactory for our annual demand forecasting, but this raised a question whether the factors were applicable to peak demand analysis. We also use the same factors for residential and commercial customer classes even though the AGA factors were derived from residential customer data only.

We also noted that price signals to core customers are lagged and they are often insulated from volatile prices due to their exposure to tariff rates versus wholesale prices. Finally, we noted that the period we were analyzing presented a challenging scenario because of the timing of our price forecasts.

During our planning cycle, prices had reached all-time seasonal highs in summer 2008 but by the beginning of 2009, prices had tumbled to multi-year lows. This dramatic volatility in the wholesale market was not necessarily a price signal to core customers who were on more stable tariff rates.

Our medium price forecast captured very low pricing early in the forecast but included a very steep increase in the second and third years. The medium and high case price elasticity assumptions, when run through the SENDOUT® model, resulted in significant curtailment of demand which was much greater than historical experience.

This curtailment had a cumulative effect and our forecasted demand in some cases took several years to return to our current demand. This raised apprehension that the forecasted curtailment might not occur and our modeled demand could be understated. This, in turn, could distort the timing of actual future resource deficiencies. On the other hand, the customer response could materialize as modeled, resulting in an actual significant demand curtailment.

We discussed this dilemma with the TAC. We decided to use the low price elasticity assumption for our Expected Case and monitor closely actual use per customer data and DSM program results for indications of price elasticity response trends that may have been influenced by evolving economic conditions.

For the coming IRP cycle, we plan to investigate contemporary analytical sources for information on natural gas price elasticity and inquire if the AGA will update its analytical work. We may also consider hiring a third-party price elasticity study and assess interest of other utilities in pursuing a regional study.

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.

CHAPTER 4 – DEMAND-SIDE RESOURCES

OVERVIEW

Demand-side management (DSM) is the activity pursued by an energy utility to influence its customers to reduce their energy consumption or change their patterns of energy use away from peak consumption periods. This usually includes information campaigns and financial incentives to persuade customers to adopt conservation measures. Conservation measures are installations of appliances, products or facility upgrades that result in energy savings. Demand-side resources represent the aggregate energy savings attained from the installation of conservation measures.

Avista has been offering natural gas DSM programs to its customers periodically since 1995. These programs result in multiple benefits including reducing customers' bills, reducing supply-side resource needs and reducing GHG emissions. These benefits make acquiring cost effective demand-side resources a very attractive resource alternative which we believe is the best strategy for minimizing energy service costs to our customers while promoting a cleaner environment.

Since our last IRP, energy policy and legislation activity are placing a high level of awareness and importance on environmental and energy use issues. Spiking energy prices in early 2008 and subsequent economic challenges in latter 2008 and into 2009 have also led to increased public awareness and interest in energy saving measures. In response, Avista is committed to provide the resources to help consumers reduce energy consumption through cost effective conservation programs.

Avista's DSM organization is split into a North Division (Washington and Idaho), and a South Division (Oregon). The North Division is one delivery area while the South Division is further segmented into four delivery areas consistent with our SENDOUT® modeling.

COST EFFECTIVENESS

Cost effectiveness is a fundamental concept to DSM. In simple terms, it is the determination of whether the present value of the energy savings (net of non-energy benefits) for any given conservation measure is greater than the cost to achieve the savings. When making this assessment, it is important to capture all benefits and costs in the evaluation. For example, Avista identifies and quantifies the non-energy benefits of water conservation in high efficiency front loading washing machines as an offset against the avoided cost of that measure. For the South Division, the presence of environmental externalities in supply resources relative to conservation measures is quantified and factored into any comparative cost analysis[1]. Incremental administrative costs are also evaluated for possible inclusion in analyzing conservation measure economics.

[1] Oregon IRP regulations require that a 10% cost advantage accrues to DSM resources relative to supply resources for environmental externalities costs. Appendix 4.4 describes our analysis.

Exceptions to the cost effectiveness rule include conservation measures that are pursued as part of a broader market transformation effort or measures that are mandated or approved by regulators. In some cases, bundling measures may justify inclusion of a non-cost effective measure when the overall bundle of measures is cost effective, otherwise enhancing the non-cost effective measure with cost effective measures while enticing the customer to install more measures.

TYPES OF CONSERVATION MEASURES

Conservation measures that achieve generally uniform year round energy savings independent of weather temperature changes are considered base load measures. Examples include high efficiency water heaters, cooking equipment and front load clothes washers. Measures that are influenced by weather temperature changes are weather sensitive measures which include higher efficiency furnaces, ceiling/wall/floor insulation, weather stripping, insulated windows, duct work improvements (tighter sealing to reduce leaks) and ventilation heat recovery systems (capturing "chimney" heat). Weather sensitive measures are desirable in resource planning, as they save the most energy during the coldest periods thus displacing the more expensive peaking or seasonal supply resources. Weather sensitive measures are often referred to as winter measures and are valued using a higher avoided cost while base load measures are often called annual measures and are valued at a lower avoided cost.

Conservation measures are offered to residential, non-residential and low income customers. Conservation measures offered to residential customers are classified as prescriptive, meaning they have a standardized therm savings which can be generalized across the customer class and all customers receive the same financial incentive for the same measures. Low income customers receive a more holistic, customized approach through six Community Action Agency partnerships. Non-residential customers have access to prescriptive and site-specific conservation measures. Site-specific measures are customized to the facility and have cost and therm savings that are unique to the individual facility.

Finally, some conservation measures in our South Division are offered based on legislation and are therefore designated "mandatory" or "must take" measures in our SENDOUT® modeling tool, which means they are offered to customers without regard to their current cost effectiveness relative to the utility's supply resources. An example of something mandated would be a walk-through energy audit which would not be accompanied with energy savings unless a customer chooses to participate in a program. In addition, a customer may choose to delay participating in a program for many years if they choose to participate at all. In these cases, the audit would be non-cost effective since there is no savings benefit to offset the cost of the audit.

METHODOLOGY

Avista's methodology for evaluating DSM within our IRP is based on four key concepts:

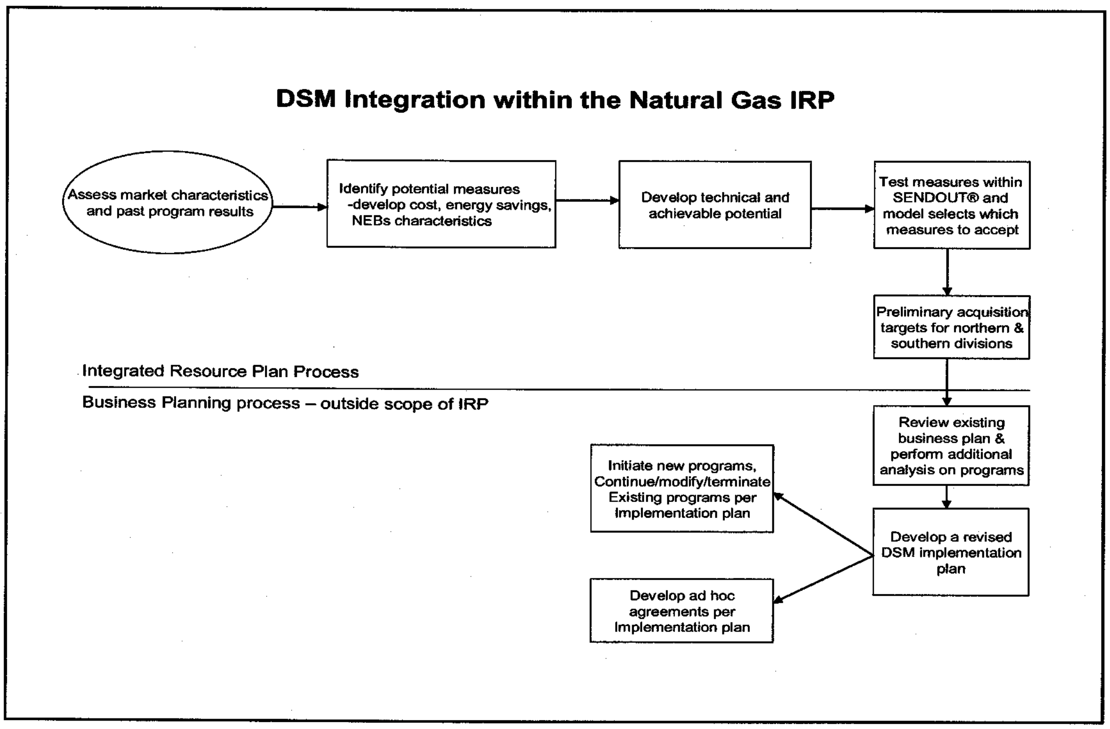
- Provides a comprehensive evaluation of all significant conservation measures that are currently commercially available and emerging measures that are likely to be available in the future;
- Evaluates conservation measures in a process that is interactive with supply-side options;
- Maximizes portfolio net total resource value (we strive to get the most for each dollar spent); and
- Delivers analytical results that are actionable for the DSM implementation planning process[2].

The methodology we adopted to fulfill these concepts has four phases:

- Identifying Technical Potential
- Assessing Achievable Potential
- SENDOUT® Testing
- Conservation Goal Development

The above DSM methodology is summarized in the flowchart in Figure 4.1. Details of each phase follows.

Figure 4.1 DSM Methodology Flowchart



[2] The completion of IRP analysis is not the end point but rather the midpoint of a larger reassessment of the DSM resource portfolio. Appendix 4.1 describes the development of our DSM implementation plan and overall DSM operations.

PHASE ONE: IDENTIFYING TECHNICAL POTENTIAL

Technical potential is an estimate of all energy savings that can theoretically be accomplished if every customer that could potentially install a conservation measure did so without consideration of market barriers such as cost and customer awareness. For example, the "replace on burnout" technical potential for high efficiency water heaters would quantify total savings assuming every existing water heater (gas or electric) within a natural gas service territory would be replaced with a high efficiency model upon an assumed burnout schedule in all cases.

In 2005, Avista contracted with RLW Analytics, a conservation analysis consultant, to independently identify and analyze the potential energy savings for our Oregon service territories. Methodology from their study was extrapolated to Washington and Idaho and served as the initial basis for determining conservation technical potential for all of Avista's natural gas service territories. The energy savings data for weather-sensitive measures were adjusted to incorporate local heating degree day data appropriate to each geographic area. Avista DSM engineers, program implementers and analysts also reviewed the consultant's estimates of incremental measure costs, measure lives, energy savings and other inputs and assumptions, making adjustments when knowledge of local factors differed from the more generalized assumptions used in the study.

Since 2005, we have made adjustments and updates to incorporate new information regarding measure cost and energy savings, augmenting the study with additional measures not previously evaluated. A total of 155 residential and 147 non-residential measures were considered for this IRP. A summary of these measures for both divisions are contained in Appendix 4.2.

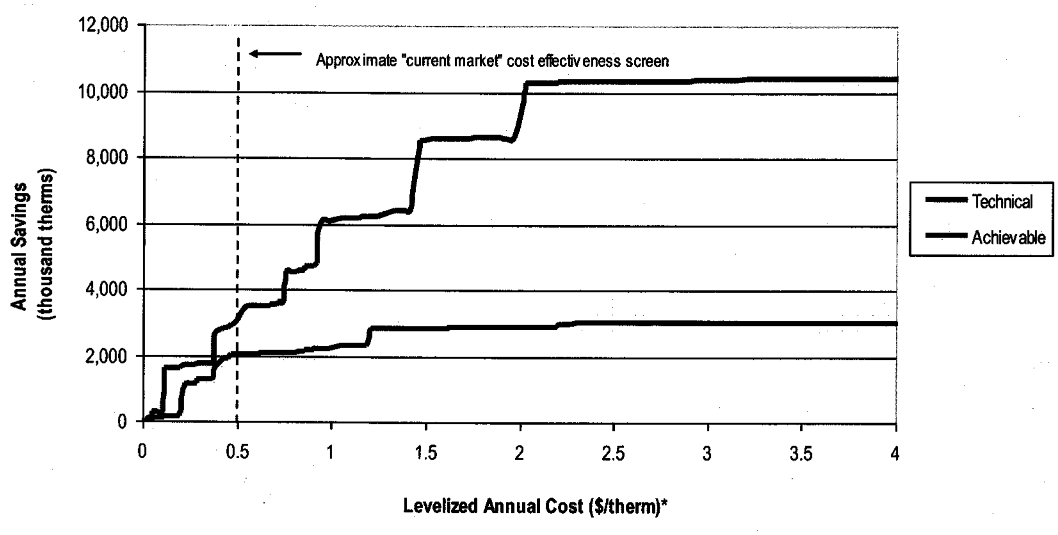
PHASE TWO: ASSESSING ACHIEVABLE POTENTIAL

Achievable potential represents a more realistic assessment of expected energy savings since it recognizes and accounts for economic and other constraints that preclude full installation of every identified conservation measure. Even the most robust information campaigns will not reach every eligible customer nor sufficiently motivate all affected customers to immediately install every conservation measure applicable to them.

Unlike other regional utilities that have selected an overall percentage to estimate achievable potential, Avista analyzes each measure's likely installation rate to establish measure by measure achievable potential. Engineers and program implementers begin their evaluation with the number of natural gas customers in that division broken down by the percentage that is single family, multifamily or manufactured homes. The applications are evaluated based on how many have that application in their home or facility and/or have access to have it in their home or facility and, finally, how many of those that would be replaced with a higher efficiency option over the standard option over the 20-year horizon. A summary list of technical and achievable potential is included in Appendix 4.2.

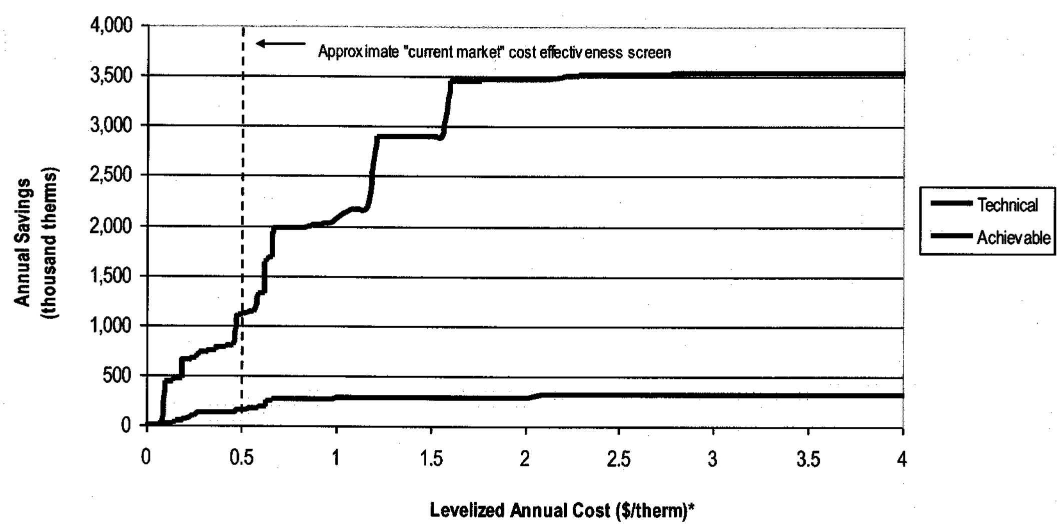
Figures 4.2 and 4.3 show the comparison of technical potential and achievable potential for our North and South Divisions, respectively. For perspective, we indicate a cost effectiveness screen of $0.50 per therm based on an approximate commodity cost of $5 per Dth. Around this level, Avista's achievable potential tracks much closer with the technical potential and is similar to other regional utilities. We further discuss the gap in technical versus achievable potential in Appendix 4.1 including our plans to obtain a new external study of technical potential prior to completion of the 2011 IRP.

Figure 4.2 Conservation Supply Curve - North
All Segments, 2010 DSM Potential



* Maximum cost is $11.89; chart scale truncated at $4

Figure 4.3 Conservation Supply Curve - South
All Segments, 2010 DSM Potential



* Maximum cost is $9.36; chart scale truncated at $4

These estimates are preliminary assessments of the best implementation approach for particular technologies and market segments and the expected growth or decline of those markets. These assessments may require revision based on further development of program plans during the implementation planning process.

PHASE THREE: SENDOUT® TESTING

In past IRPs, conservation measures were grouped into bundles to facilitate easier data input and faster system processing within SENDOUT®. However, this method required a complex process of manually calculating levelized total resource cost (TRC) outside the model based on estimated avoided costs that had to be checked and adjusted against SENDOUT® results in an iterative process.

For this IRP, we elected to invest the time to enter each individual conservation measure into SENDOUT® to enable more granular and accurate measure selection for DSM resource acquisition. This effort was no small task considering the exponential proliferation of inputs, as each assumption for every conservation measure had to be entered by customer class across the eight sub areas we model in SENDOUT®. This resulted in significantly more data entry that required managing around potential system processing constraints but eliminated prepackaging issues and potentially less accurate "group" measure selection.

Inputs included conservation measure cost, measure life, annual energy savings, non-energy benefits and discount rate. The model then calculated a levelized TRC for each measure to compare against the model's avoided cost calculation.

Mandated measures were entered into SENDOUT® as must takes which bypassed system cost effectiveness testing and were automatically selected as a preferred resource by the model. All other measures were evaluated by SENDOUT® against other supply-side resource options.

The demand-side resources selected by SENDOUT® are summarized in Table 4.1. Note that these results do not include site-specific measures. These measures are incorporated in the next phase of the IRP process.

Table 4.1 SENDOUT® DSM Results
(calendar year 2010)

	North	South
Residential measures	2,926,761	215,580
Non-residential measues	75,601	110,734
Total adopted measures (therms)	3,002,362	326,314

PHASE FOUR: CONSERVATION GOAL DEVELOPMENT

In this phase, we augment the results of the SENDOUT® testing with estimates of resource acquisition from commercial and industrial site-specific programs to develop a therm acquisition goal. These programs can include multiple conservation measures, are inherently individualized and have unique characteristics that preclude input into SENDOUT®.

Site-specific programs are designed to be all inclusive so any natural gas efficiency options with measureable therm savings qualify 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 based on differing regulation. Generally speaking, all projects have the potential for receiving technical assistance and many qualify for direct financial assistance. Site-specific therm acquisition is estimated by establishing a baseline of historical site-specific program results modified to reflect past and estimated future growth.

A final adjustment must be made to eliminate the duplication of resource opportunities between the all-inclusive site-specific programs and the measures accepted within the SENDOUT® modeling. Some of the measures incorporated into the SENDOUT® model 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 all of the South Division and 84 percent of the North Division future site-specific therm acquisition were included in the SENDOUT® analysis.

It is possible that there will be measures selected in this process that will subsequently be determined to be unsuitable for inclusion in Avista'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 that were rejected by this IRP as a result of this same process. Though the IRP is our best opportunity to comprehensively re-evaluate the DSM portfolio and its integration into the overall resource mix at one point in time, it is necessary to incorporate an ongoing implementation planning process to ensure that the best resource decisions are made.

PRELIMINARY CONSERVATION GOAL

The following therm goals reflect of the results of the integrated resource optimization as further described in Chapter 6 – Integrated Resource Portfolio. See that chapter for the complete results of the integrated resource optimization including the regional cumulative benefits over the 20-year planning horizon.

The SENDOUT® results[3] and modifications for site-specific programs for the first two years are summarized in Table 4.2.

Table 4.2 Results of Achievable Resource Potential
Current Year 2010 and 2011

	2010	2011
SENDOUT®-accepted residential programs	2,926,761	2,862,948
SENDOUT®-accepted non-residential programs	75,601	77,852
Estimated site-specific acquisition	811,920	844,397
Less: non-res prescriptive programs duplication	(685,440)	(712,858)
Total North Division	3,128,842	3,072,339
	2010	**2011**
SENDOUT®-accepted residential programs	215,580	206,333
SENDOUT®-accepted non-residential programs	110,734	118,650
Total South Division	326,314	324,983

[3] 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.

Based on the analytical process described in the above Methodology section, first-year energy savings goals resulting from the IRP process were approximately 3,128,842 therms in the North Division and 326,314 therms in the South Division. This commitment represents an increase of 98 percent from the 2007 IRP annual resource acquisition for 2010 in the North Division and an increase of 9 percent in the South Division.

Site-specific acquisition included in the above is estimated to be 126,480 therms for the North Division and is no longer applicable for the South Division as all measures were tested within SENDOUT®. These estimates incorporate consideration of the significantly different non-residential customer bases within our North and South Divisions. Specifically, non-residential customers within our South Division tend to be smaller-sized retail customers and generally non-industrial. However, in spite of their limited opportunity to acquire resources through their site-specific program, existing utility staff has been redeployed to establish and foster relationships with contract auditors and trade allies in effort to increase participation.

The North Division site-specific program has been a highly successful component of the overall portfolio. However, active and real-time management is necessary to continue to focus on and move toward new opportunities within this market. As more participation occurs in specific applications and technologies, program implementers and engineers use results to establish more prescriptive approaches in order to increase participation without having to add additional infrastructure. This has proved to be a successful approach to address developing markets and influencing customers toward them.

The North potential is in excess of the 2010 acquisition goal of 1,755,829 therms developed in the 2007 IRP. The potential increase in the target is the result of a steep carbon mitigation cost adder[4] in our natural gas price forecast that we model to take effect in 2015. This large increase in natural gas prices, correspondingly, significantly increases avoided costs over the planning horizon. A concern is how to influence customers to implement natural gas efficiency upgrades now based on a price increase modeled to take effect in 2015 which they may not see or are skeptical of it materializing that far into the future.

We are resolved to meet all cumulative potential identified in this IRP over the planning cycle, but will do so with a gradual ramping up of program activity. We determined it was possible to establish an approximate 6.5 percent constraint on the annual increase over the first 10 years while simultaneously achieving this objective in the long run by the end of the 20-year period. 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.

For the South Division, the potential is slightly below the 2010 acquisition goal of 304,548 therms from the 2007 IRP. This comes at a time when customers in this service territory are facing state unemployment rates exceeding 14 percent in some counties. We are resolved to meet all cumulative

[4] Adder reflects price impacts to comply with anticipated climate change legislation. Appendices 3.6 and 3.7 has detailed discussion on our modeling of climate change policy.

potential identified in this IRP over the long-term (20-year) planning cycle, but will do so with a gradual ramping up of program activity. We determined this to be possible by establishing an approximate 2.2 percent constraint on the annual increase over the first five years while simultaneously achieving this objective in the long run by the end of the 20-year planning horizon. This increase is greater than the projected customer growth but ensures that the infrastructure growth can be managed more carefully during this economic time.

Application of this 6.5 percent annual growth constraint for the North Division and 2.2 percent annual growth constraint for the South Division results in a summary of annual and cumulative acquisition and identified DSM potential as listed in Table 4.3

Table 4.3 Annual and Cumulative SENDOUT® Achievable Potential and Revised Goal

	North Divison				South Divison			
	Achievable Potential	Cumulative Potential	DSM Goal	Cumulative Goal	Achievable Potential	Cumulative Potential	DSM Goal	Cumulative Goal
CY2010	3,128,842	3,128,842	2,193,338	2,193,338	326,314	326,314	303,300	303,300
CY2011	3,072,339	6,201,181	2,336,541	4,529,879	324,983	651,297	309,973	613,273
CY2012	3,010,146	9,211,327	2,489,094	7,018,973	298,759	950,056	316,792	930,065
CY2013	3,000,080	12,211,407	2,651,607	9,670,579	280,458	1,230,514	299,879	1,229,944
CY2014	3,005,777	15,217,184	2,824,730	12,495,310	278,214	1,508,728	278,214	1,508,158
CY2015	2,943,985	18,161,169	3,009,157	15,504,466	275,973	1,784,701	275,973	1,784,130
CY2016	2,864,302	21,025,471	3,205,625	18,710,091	271,604	2,056,305	271,604	2,055,735
CY2017	2,849,376	23,874,847	3,414,920	22,125,011	266,358	2,322,663	266,358	2,322,093
CY2018	2,862,118	26,736,965	3,637,633	25,762,643	262,851	2,585,514	263,041	2,585,134
CY2019	2,900,317	29,637,283	3,874,639	29,637,283	266,715	2,852,229	267,095	2,852,229
CY2020	2,796,582	32,433,864	2,796,582	32,433,865	269,559	3,121,789	269,559	3,121,788
CY2021	2,675,821	35,109,685	2,675,821	35,109,686	257,134	3,378,923	257,134	3,378,922
CY2022	2,690,538	37,800,223	2,690,538	37,800,224	227,802	3,606,725	227,802	3,606,724
CY2023	2,707,941	40,508,164	2,707,941	40,508,165	188,897	3,795,622	188,897	3,795,621
CY2024	2,651,295	43,159,459	2,651,295	43,159,460	154,709	3,950,331	154,709	3,950,330
CY2025	2,621,258	45,780,716	2,621,258	45,780,718	136,043	4,086,374	136,043	4,086,373
CY2026	2,585,548	48,366,264	2,585,548	48,366,266	132,376	4,218,750	132,376	4,218,749
CY2027	2,278,881	50,645,145	2,278,881	50,645,147	135,054	4,353,804	135,054	4,353,803
CY2028	2,034,955	52,680,100	2,034,955	52,680,102	129,141	4,482,945	129,141	4,482,944
CY2029	2,029,521	54,709,621	2,029,521	54,709,623	120,643	4,603,588	120,643	4,603,587

The North Division potential and acquisition identified in Figures 4.4 and 4.5 indicates that we will fully acquire identified DSM potential over the 20-year planning cycle within the 6.5 and 2.2 percent annual ramp-up constraint for North and South, respectively.

Figure 4.4 Cumulative Identified Potential vs. Cumulative Acquired
North Division

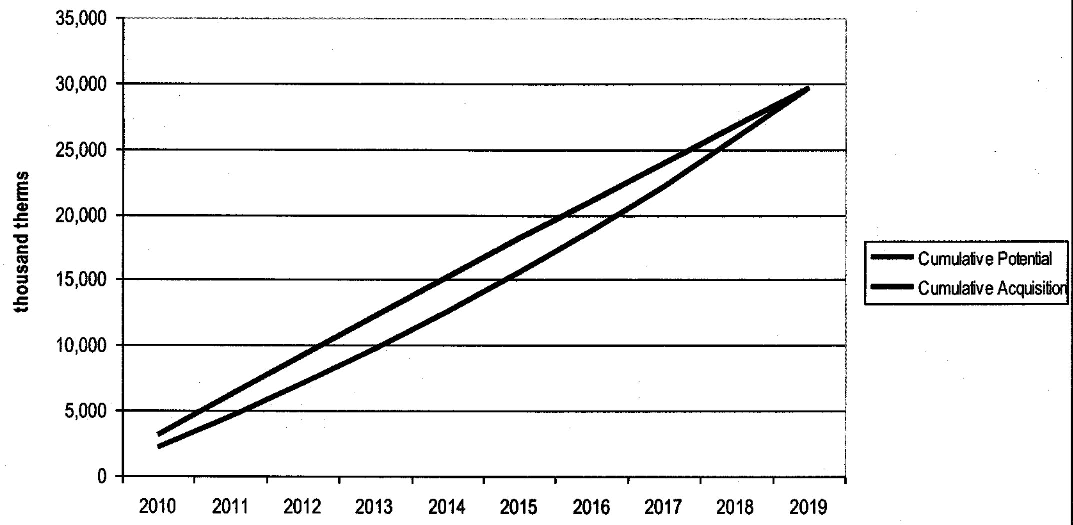
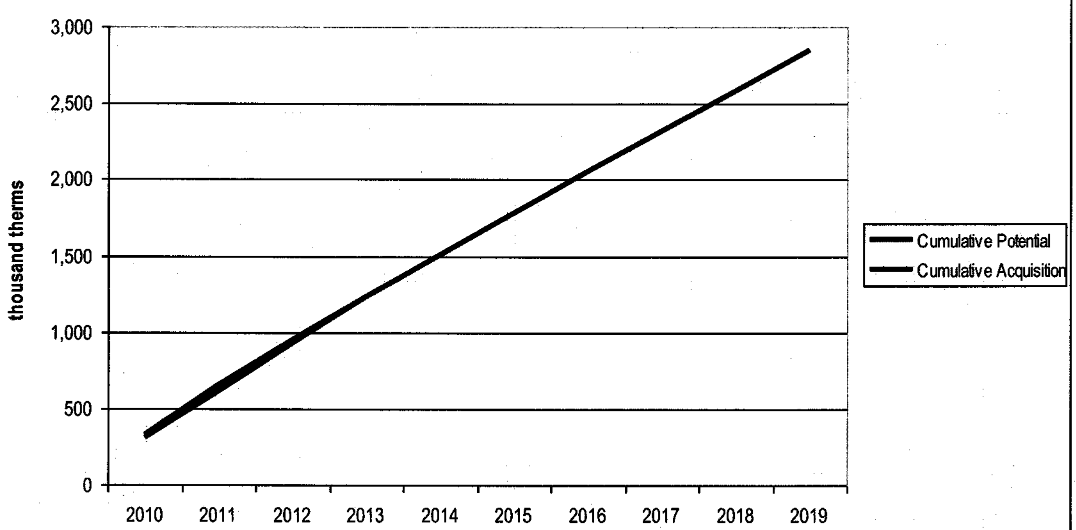


Figure 4.5 Cumulative Identified Potential vs. Cumulative Acquired
South Division



The IRP resource analysis is, as previously mentioned, the starting point for the implementation planning process. Appendix 4.1 discusses Avista's DSM programs and how the IRP results will be incorporated into DSM operations.

DSM SENSITIVITIES

Avista continues to acknowledge its obligation to acquire all cost effective natural gas-efficiency resources available through utility intervention. Given the rapid changes within the natural gas market, new efficiency opportunities may arise in the market within the 20-year horizon being analyzed within this process. As we continue to consider and evaluate any developing applications and/or technologies for inclusion in our portfolio between IRPs, considerable uncertainty remains regarding customers' response to these programs. Since this is a time of economic uncertainty when retail gas prices are declining, we face the challenge of how to get customers to respond now to prices they might not actually see for years to come. Historically, we have seen levels of less participation as retail prices decline. However, stimulus-related government incentives could accelerate participation.

To better understand how demand-side resources may be affected by uncertain economic conditions, we evaluated two DSM sensitivities based on the following:

- **DSM Accelerated** - Tax credits, particularly on the residential side, induce a combination of increasing participation in our programs to some degree, but the greatest impact is in inducing participating residential customers to stretch to higher levels of efficiency in order to qualify for tax credits as a complement to our existing rebates. Non-residential customers have far fewer such tax credits available to them, but to a much lesser degree the same impact occurs in that market. Stimulus funded residential audit programs result in the acquisition of low-cost/no-cost measures beyond what was assumed in the IRP base case.
- **DSM Delayed** - Budget constraints restrict customer incentives to less than current levels. Our program outreach is cut by 50% and staffing is curtailed. The economic recession continues and due to reduced disposable income, we see a reduction in non-lost-opportunity (deferrable) efficiency measures such as weatherization and a lesser reduction in the installation of lost-opportunity (furnace, hot water heater, etc.) measures. We also see a reduction in non-residential energy-efficiency measures due to the lack of discretionary capital budget within our customers businesses.

The resulting incremental (decremental) savings of these sensitivities are summarized in Table 4.4:

Table 4.4 DSM Sensitivities Summary

	DSM Accelerated		DSM Delayed	
	2010 Therms	Cumulative Therms over 20 Years	2010 Therms	Cumulative Therms over 20 Years
Annual Measures				
Medford	3,666	65,985	(444)	(7,986)
Roseburg	843	15,173	(102)	(1,837)
Klamath	1,539	27,697	(186)	(3,353)
LaGrande	642	11,560	(78)	(1,400)
WA/ID	56,311	1,013,598	(32,584)	(586,512)
Winter Measures				
Medford	16,330	293,944	-	-
Roseburg	3,755	67,586	-	-
Klamath	6,854	123,372	-	-
LaGrande	2,861	51,494	-	-
WA/ID	233,720	4,206,960	(125,057)	(2,251,026)

The impact of either sensitivity could be meaningful. We will continue to watch for signs of either sensitivity developing. However, this uncertainty does not preclude us from pursuing the planned aggressive ramp-up of natural gas-efficiency programs. Additionally, we have, and will continue to actively seek, opportunities for new or enhanced resource acquisition through the development of cooperative regional programs.

ENVIRONMENTAL EXTERNALITIES

The impact of utilizing energy on the environment continues to be a subject of societal concern and debate. If there are impacts that cannot be repaired naturally within a reasonable period of time, damage cost to the environment occurs for which society will have to pay in some future undetermined form. The question of who pays, how much and when payment should be made, are complicated issues. This debate is beginning to be addressed through a variety of public policy initiatives and legislation. Regulatory guidelines in Oregon advocate specific analysis in the IRP process to better understand these issues. Avista included an evaluation of the impacts of environmental externalities in the context of this evolving legislative environment. Appendix 4.4 discusses our analysis.

DEMAND RESPONSE

Demand response is a peak demand management concept where customers adjust the timing of their energy consumption away from consumption peaks in exchange for lower rates. Implementation strategies encompass a number of activities including real time pricing, time of use rates, critical peak pricing, demand buyback, interruptible rates and direct load controls. When effectively implemented, acquisition of costly supply resources can be deferred.

Demand response works best when it is a quick solution to an immediate problem. When demand peaks, system operators need the ability to either quickly notify customers to curtail consumption or do it themselves via control systems to physically manage/restrict gas flow to increase distribution system pressures.

This mechanism exists with respect to our interruptible transportation-only customers, which make up approximately one third of Avista's total annual throughput. However, because we do not purchase supply for these customers, they do not represent an incremental supply resource alternative. Only core customers with high winter consumption profiles would provide an incremental supply resource using demand response curtailment strategies. Unfortunately, we currently have very few core customers with a complying consumption profile. As a result, we believe that all customers who can manage their operations on interruptible service are currently served on an interruptible basis, leaving little opportunity to reduce peak loads through expanded interruptible service.

While little demand response opportunity exists on our natural gas system, we continue to monitor the progress of other natural gas utilities and their efforts of peak load shifting to offset hourly and/or daily flow constraints. Whereas electric demand response technologies have been in place for over two decades, major differences exist between electric and natural gas supply/delivery systems. The economics of the timing of natural gas usage are much more forgiving than electric due to underground storage and line packing. Furthermore, natural gas curtailment is not an option since a natural gas company cannot restart service without a technician on-site to ensure all pilots are properly lit for safety reasons.

At times natural gas providers may find implementing a demand response program helpful in offsetting or postponing a pipeline upgrade or in price balancing. However, mandatory participation in the affected areas would be vital to fund the necessary investment in enabling technologies.

One possible demand response program for the residential sector is remotely controllable thermostats. Avista is currently conducting a pilot project using this technology with Idaho electric customers. At present this pilot is limited to controlling the thermostat for space heating and cooling during times of electric peak demand. This pilot will conclude December 31, 2009 at which time a draft report will be compiled for results and what was learned from the program. Preliminary findings at this time show this technology is not cost effective for Avista for either summer or winter peak. Future technologies may offer cheaper, more reliable and flexible options for customers and their fuel providers. However, there are no near-term plans to pursue demand response programs.

CONCLUSION

By prompting customers to change their demand for natural gas, Avista can displace the need to purchase additional natural gas supplies, displace or delay contracting for incremental pipeline capacity and possibly displace or delay the need for reinforcements on our distribution system. This IRP process provides Avista with the necessary resource analysis to evaluate demand-side resource options alongside supply-side resources, periodically review and update DSM operations and finally, develop and implement improved natural gas efficiency programs.

The completion of IRP analysis is not the end point but rather the midpoint of a larger reassessment of the DSM resource portfolio. The IRP analysis presented has generally indicated a set of cost effective measures and achievable resource potential for a future DSM resource portfolio. Yet further evaluation is needed to facilitate the development of program plans and to incorporate them into an updated DSM implementation plan in the overall DSM operations.

CHAPTER 5 – SUPPLY-SIDE RESOURCES

OVERVIEW

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

We manage our natural gas procurement and related activities on a system-wide basis. We have a number of regional supply options available to serve our core customers. These include firm and non-firm supplies, firm and interruptible transportation on six interstate pipelines and two storage projects. Because Avista's core customers span three states, the diversity of delivery points and demand requirements adds to the options available to meet customers' needs. The utilization of these components varies depending on demand and operating conditions. In this chapter, we discuss the available regional commodity resources and our procurement plan strategies, the regional pipeline resource options available to deliver the commodity to our customers, and the storage resource options available which provide additional supply diversity, enhanced reliability, favorable price opportunities, and flexibility to meet a varied demand profile. Beyond these traditional supply-side resources, we discuss non-traditional resources which are also considered.

COMMODITY RESOURCES

SUPPLY BASINS

Avista is fortunate to be located in relatively close proximity to the two largest natural gas producing regions in North America—the Western Canadian Sedimentary Basin (WCSB), which is located primarily in the Canadian provinces of Alberta and British Columbia, and the Rocky Mountain gas basins, located primarily in Wyoming, Utah and Colorado. Avista sources virtually all of its natural gas supplies from these two basins.

The WCSB and Rockies gas basins used to have limited pipeline export potential, which has historically resulted in lower regional natural gas prices that were discounted to other parts of the country. Over the last decade, however, several large pipelines have been completed (or capacities of existing pipelines increased) connecting the WCSB and Rockies gas basins to the Southwest, Midwest and Northeast sections of the continent. This has, at times, diminished the discounted price advantage the region has enjoyed. Future projects that relieve bottlenecks and pipeline congestion out of the basins enabling gas to flow to higher priced markets could further erode this historically favorable price advantage. Future shale production in eastern markets could also reduce or eliminate this advantage.

REGIONAL MARKET HUBS

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

AECO – The AECO-C/Nova Inventory Transfer market center is a major connection region to long-distance transportation systems, which take gas to points throughout Canada and the United States. Alberta has historically produced 90% of Canada's natural gas and is the source of most Canadian natural gas exports to the United States representing volume that accounts for approximately 13% of U.S. natural gas requirements.

Rockies – This pricing "point" actually represents several locations on the southern end of the NWP system in the Rocky Mountain region. The system draws on Rocky Mountain gas-producing areas clustered in areas of Colorado, Utah, and Wyoming.

Sumas/Huntingdon – This pricing point at Sumas, Washington, is on the U.S.-Canadian border where the northern end of the NWP system connects with Spectra Energy's BC Pipeline, and is predominantly Canadian gas coming south from Northern British Columbia.

Malin – this pricing point is at Malin, Oregon on the California-Oregon border where the pipelines of TransCanada Gas Transmission Northwest (GTN) and Pacific Gas & Electric Co. connect.

Station 2 – Located at the center of the Spectra Energy - BC Pipeline system connecting to northern British Columbia production.

Stanfield – Located near the Washington/Oregon border at the intersection of the NWP and GTN pipelines

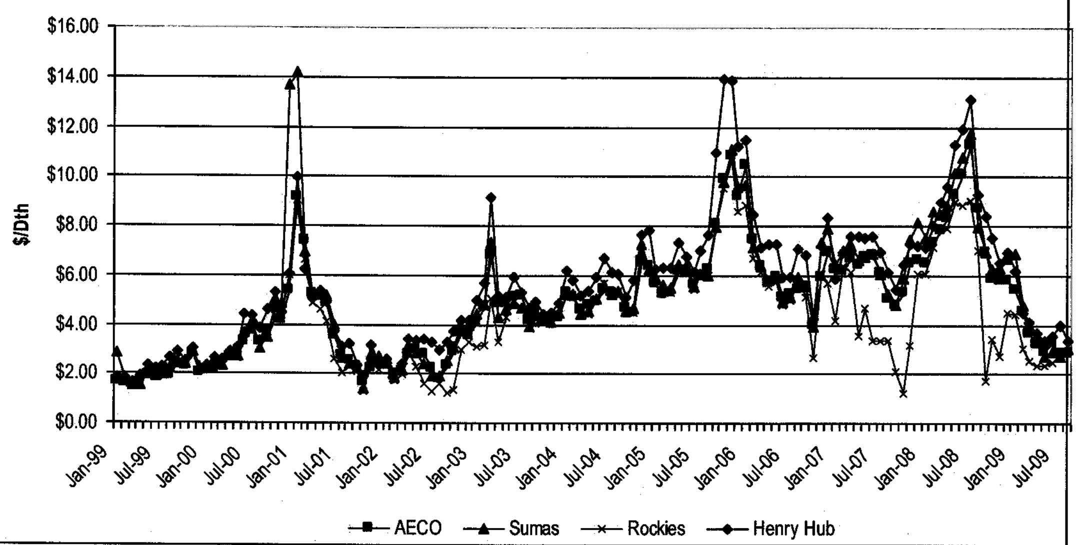
Kingsgate – Located at the US-Canadian (Idaho) border where the GTN pipeline connects with the TransCanada Foothills pipeline.

Given the ability to transport natural gas to other portions of North America, natural gas pricing is often compared to the Henry Hub price for natural gas. Henry Hub is a natural gas trading point located in Louisiana and is widely recognized as the primary natural gas pricing point in the United States. Henry Hub is also the trading point used in NYMEX futures contracts.

Figure 5.1 shows historic natural gas prices for first-of-month index physical purchases at AECO, Sumas, Rockies and Henry Hub. The figure illustrates there is usually a tight relationship among the various locations; however, there have been periods where one or more price points have disconnected. In winter 2000-2001, Sumas rallied on a combination of the western energy crisis and unusually cold local weather conditions. In fall of 2005, hurricanes Katrina and Rita disrupted significant Gulf of Mexico regional production causing the Henry Hub to spike disproportionately to Northwest hubs. Since 2007, increased production in the Rocky Mountain basin has exceeded the takeaway pipeline capacity forcing concessions on Rockies prices pending completion of major phases of the Rockies Express pipeline project. This significant project, completed in late summer

2009, enables substantial volumes to reach Midwestern and Northeast demand centers. Consequently, Rockies prices have resumed tighter tracking with Henry Hub prices.

Figure 5.1 Monthly Prices
AECO/Sumas/Rockies/Henry Hub



Natural gas prices among the Northwest regional supply points typically move together as well; however, the basis differential can change depending on market or operational factors. This includes differences in weather patterns, pipeline constraints at different locations and the ability to shift supplies to higher-priced delivery points in the United States or Canada. By monitoring these price shifts, we are often able to purchase at the lowest-priced trading hubs on a given day, subject to operational and contractual constraints.

As mentioned above, Rockies natural gas has tended to trade at a discount to Henry Hub when production out-paced local demand and takeaway pipeline capacity. Pipeline expansion activity moving incremental production southwest to California (Kern River pipeline) and east to the Midwest and Eastern seaboard markets (via the Rockies Express pipeline) has eased the basis differential between AECO and Sumas prices as well.

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

Procurement of natural gas is done via contracts. There are a number of contract specifics that vary from transaction-to-transaction, and many of those terms or conditions impact commodity pricing. Some of the agreed-upon terms and conditions include:

Firm vs. Non-Firm – Most term contracts specify that supplies are firm except for force majeure conditions. In the case of non-firm supplies, the standard provision is that they may be cut for reasons other than force majeure conditions.

Fixed vs. Floating Pricing – The agreed-upon price for the delivered gas may be fixed or based upon a daily or monthly index.

Physical vs. Financial – Certain counterparties, such as banking institutions, may not trade physical natural gas but are still active in the natural gas markets. Rather than managing physical supplies, those counterparties choose to transact financially rather than physically. Financial transactions provide another way for Avista to financially hedge price.

Load Factor/Variable Take – Some contracts have fixed reservation charges assessed during each of the winter months, while others have minimum daily or monthly take requirements. Depending on the specific provisions, the resulting commodity price will contain a discount or premium compared to standard terms.

Liquidated Damages – Most contracts contain provisions for symmetrical penalties for failure to take or supply natural gas.

For this IRP, the SENDOUT® model assumes the natural gas is purchased as a firm, physical, fixed-price contract regardless of when the contract is executed and what type of contract it is. However, in reality, we pursue a variety of contractual terms and conditions in order to capture the most value from each transaction.

AVISTA'S PROCUREMENT PLAN

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

Avista employs a time, location and counterparty diversified hedging strategy – It is appropriate to hedge over a period of time, and we establish hedge periods within which portions of future demand are financially hedged. The hedges may not be completed at the lowest possible price, but they will protect our customers from price volatility. Additionally, we pursue diversified purchases at multiple basin/market hubs and transact with a range of counterparties.

Avista establishes a disciplined but flexible hedging approach – In addition to establishing hedge periods within which hedges are to be completed, we also set upper and lower pricing points. In a rising market, this reduces Avista's exposure to extreme price spikes. In a declining market, this encourages capturing the benefit associated with lower prices.

Avista regularly reviews its procurement plan in light of changing market conditions and opportunities – Avista's plan is open to change in response to ongoing review of the assumptions that led to the procurement plan. Although we establish various targets in the initial plan design, policies provide flexibility to exercise judgment to revise/adjust targets in response to changing conditions.

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

TRANSPORTATION RESOURCES

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

The major pipelines servicing our region are as follows:

Williams - Northwest Pipeline (NWP) - A natural gas transmission pipeline serving the Pacific Northwest moving natural gas from the US/Canadian border in Washington and from the Rocky Mtn. region of the US.

TransCanada Gas Transmission Northwest (GTN) - A natural gas transmission pipeline originating at Kingsgate, ID (Canadian/US border) and terminating at the California/Oregon border close to Malin, OR.

TransCanada Alberta System - A natural gas gathering and transmission pipeline in Alberta Canada that delivers natural gas into the TransCanada Foothills pipeline at the Alberta/British Columbia border.

TransCanada BC System - A natural gas transmission pipeline that delivers natural gas between the Alberta, BC border and the Canadian/US border at Kingsgate, ID.

TransCanada Tuscarora Gas Transmission - A natural gas transmission pipeline originating at Malin, OR and terminating at Wadsworth, NV.

Spectra Energy - BC Pipeline - A natural gas transmission pipeline originating at Fort Nelson, BC and terminating at the Canadian/US border at Huntington, BC/Sumas, WA.

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

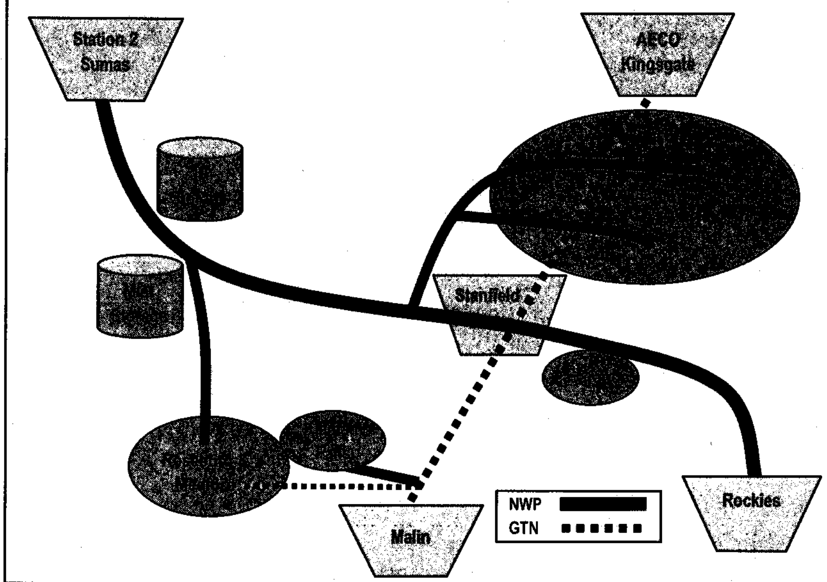
Table 5.1 - Existing Firm Transportation & Storage Resources
Dth/Day

	Avista North		Avista South	
Firm Transportation	**Winter**	**Summer**	**Winter**	**Summer**
NWP TF-1	119,526	119,526	22,562	22,562
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2	91,200		2,623	
Total	**311,331**	**195,308**	**67,445**	**43,202**
Firm Storage Resources - Deliverability				
Jackson Prairie	266,667		2,623	
MIST			15,000	
Total	**266,667**		**17,623**	

Avista defines two categories of interstate pipeline capacity. "Direct-connect" pipelines deliver supplies directly to our local distribution system from production areas, storage facilities or interconnections with other pipelines. "Upstream" pipelines deliver natural gas to the direct-connect pipelines from remote production areas, market centers and out of area storage facilities. Figure 5.2 illustrates the direct-connect pipeline network relative to our supply sources and service territories[1].

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

Figure 5.2 Direct-Connect Pipelines



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

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

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

Peak day planning aside, both pipelines provide an array of options to flexibly manage daily operations. Our two largest service territories are directly served by both pipelines providing diversification and risk management with respect to supply source, price and reliability. The NWP system (a bi-directional, fixed reservation fee-based pipeline) provides direct access to historically cheaper Rockies supply and facilitates excellent storage facility management. The Stanfield interconnect of the two lines is also geographically well situated to our service territories.

The rates we use in our planning model start with filed rates that are currently in effect (See Appendix 5.1). Forecasting future pipeline rates is challenging. Our assumptions for future rate changes are the result of market information on comparable pipeline projects, prior rate case experience and informal discussions. It is generally assumed that the pipelines will file to recover costs at rates equal to the GDP with adjustments made for specific project conditions. Refinement of theses assumptions will be done as better information becomes available.

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

Avista's transportation acquisition strategy is to contract for firm transportation to serve core customers should a peak day occur in the near-term planning horizon. Too much firm transportation could keep us from achieving our goal of being a low-cost energy provider. But too little firm transportation impairs our 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 annual and peak day demand, 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 can offset some or all of the cost of holding underutilized capacity.

STORAGE RESOURCES

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

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

Avista's existing storage resources consist of ownership and leasehold rights in two in-ground regional storage facilities.

JACKSON PRAIRIE STORAGE

Avista is one-third owner, with NWP and Puget Sound Energy (PSE), in the Jackson Prairie storage project for the benefit of its core customers in all three states. Jackson Prairie Storage is an underground reservoir facility located near Chehalis, Washington approximately 30 miles south of Olympia, Washington. The total working gas capacity of the facility is approximately 25 Bcf. Avista's current share of this capacity for core customers is approximately 5.2 Bcf and includes 266,667 Dth of daily deliverability rights.

In 1999, and again in 2002, Avista participated in capacity expansions of the project with NWP and PSE. 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 former 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. (Shell Energy). Concurrent with the sales transaction, Avista reacquired the rights to the 2002 expansion while the 1999 expansion rights were temporarily included in the sale. Shell Energy retains these rights through April 30, 2011. These rights represent approximately 3 Bcf of storage capacity and 100,000 Dth of daily deliverability.

After this date, we anticipate recalling these storage rights for availability in our utility operations, and have included it in our SENDOUT® model as an incremental available storage resource at that time.

We continue to evaluate our Jackson Prairie capacity and deliverability requirements to determine if we should opportunistically optimize storage capacity beyond what is able to be delivered to customers.

Outside of Avista's ownership rights, we have leased an additional 95,565 Dth of Jackson Prairie capacity with 2,623 Dth of deliverability from NWP to serve Oregon customers.

MIST STORAGE

The Mist storage project is an underground depleted reserve storage project owned by Northwest Natural Gas and is located near the small community of Mist, Oregon about 60 miles northwest of Portland, Oregon. The total working gas capacity of the facility is approximately 16 Bcf. For our Oregon customers, Avista has contracted for service in this storage project which includes rights to 500,000 Dth of capacity with 15,000 Dth of deliverability. This contract expires in April 2011.

INCREMENTAL SUPPLY-SIDE RESOURCE OPTIONS

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

SYSTEM ENHANCEMENTS

In certain instances, Avista can facilitate additional peak and base load-serving capabilities through a modification or upgrade of our distribution facilities. These opportunities are geographically specific and require case-by-case study. We have reviewed several enhancements and preliminary findings indicate that the following opportunities may be 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 costs associated with the purchase price, we would be able to terminate current NWP reservation and fuel charges at Klamath Falls and relocate the transportation contract deliverability on NWP to areas where additional deliverability is needed. This solution would facilitate additional deliveries into the Klamath Falls area off of GTN. If certain terms are met, this enhancement can likely be completed with less than one year's notice.

Medford System Enhancement – Avista is constructing a high-pressure distribution system reinforcement off of the GTN Medford lateral. This will facilitate delivery of incremental volumes off of the GTN system into Medford when needed. This solution also will allow existing NWP supply and capacity on the Grants Pass Lateral to be diverted from Medford back to the Roseburg area. Through this enhancement, potential resource shortages in the Medford and Roseburg areas can be addressed.

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 city-gate station such that the distribution system would be reinforced. This solution would allow additional deliveries off of the NWP system to La Grande.

CAPACITY RELEASE RECALL

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

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

GTN 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 relatively reliable basis. For example, Avista can purchase cost effective supplies at Malin, Oregon and transport those supplies via displacement 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 transporting those traditional supplies and paying the associated demand charges. The GTN system is a mileage-based system so we pay only 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.

Although we are confident in this resource option especially in the near to intermediate term, it is only available as long as sufficient forward-haul natural gas flow exists. Pipeline capacity at Malin is over two Bcf with several high volume subscribers currently flowing substantial daily volumes into

California. However, in the future this condition could change if declines in forward-haul volume occur or requests for backhauls increase, causing net forward-haul volume to be insufficient to honor all backhaul requests. Specifically, the proposed Ruby pipeline project (see new pipeline projects section below) which would interconnect with the GTN system at Malin could decrease forward-haul volumes if GTN subscribers source significant volumes from the new Ruby pipeline. We continue to monitor this possibility in conjunction with the Ruby project development.

NEW PIPELINE TRANSPORTATION

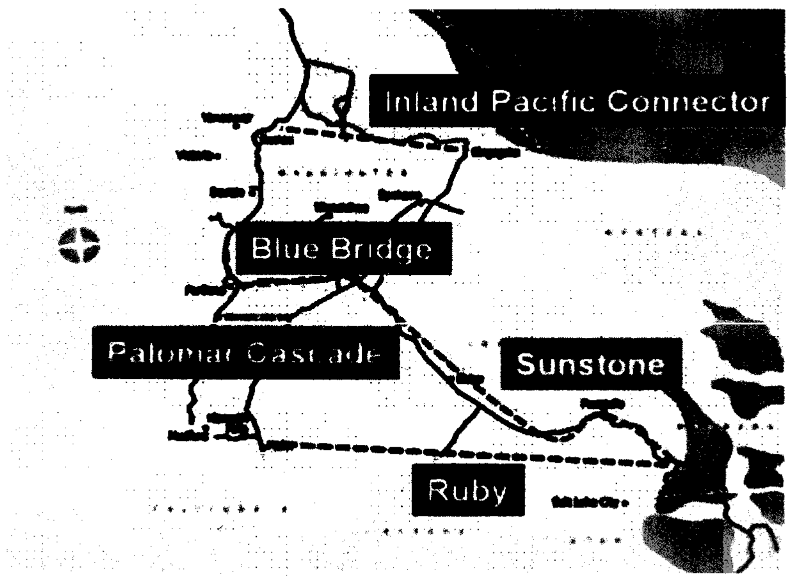
Additional firm pipeline transportation resources are viable and attractive resource options. However, determining the appropriate level, supply source and associated pipeline path, costs and timing and determining whether or not existing resources will be available at the appropriate time, make this resource difficult to analyze. Firm pipeline capacity provides several advantages; it provides the ability to receive firm supplies at the production basin, it provides for base-load demand and it can be a low-cost option given optimization and capacity release opportunities. Pipeline capacity also has several drawbacks, including typically long-dated contract requirements, limited need in the summer months (many pipelines require annual contracts) and limited availability and/or inconvenient sizing/timing relative to resource need.

Some 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 requirements. 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.

Pipeline expansions are typically more expensive than existing pipeline capacity and often require long-term annual contracts. Even though expansions may be more expensive than existing capacity, this approach may still provide the best option to us given that some of the other options discussed in this section require matching pipeline transportation anyway.

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

Figure 5.3 Proposed New Pipelines



Ruby – Project sponsor El Paso Corporation. The project is expected to include approximately 675 miles of 42-inch natural gas transmission pipeline beginning at the Opal Hub in Wyoming and terminating at interconnects near Malin, Oregon. The project will have an initial capacity of up to 1.5 billion cubic feet per day (Bcf/d) and would traverse portions of four states: Wyoming, Utah, Nevada, and Oregon.

Blue Bridge Pipeline – Northwest Pipeline GP and Puget Sound Energy are jointly proposing this project, which would include the installation of additional compression horsepower at existing Northwest Pipeline stations and the construction of up to 120 miles of pipe. The project is bi-directional and is designed to deliver between 250 and 500 MMcf/d from Stanfield, Oregon to the I-5 Corridor. The project would generally follow Northwest Pipeline's existing pipeline corridor for the majority of the route.

Inland Pacific Connector – Terasen Gas is proposing to build this 153-mile, 24-inch diameter pipeline as an extension of its Southern Crossing Pipeline from southern Alberta near Kingsgate, Idaho, to Huntingdon, BC, near Sumas, Washington. The initial design capacity is projected to be about 350 MMcf/d.

Palomar Cascade – Palomar Gas Transmission is a partnership between NW Natural and TransCanada. The proposed 110-mile, 36-inch-diameter pipeline would extend from TransCanada's GTN system near Madras, Oregon, to NW Natural's system near Molalla, Oregon. It would be a bi-directional pipeline with an initial capacity of up to 1,000 MMcf/d.

Sunstone – Project partners include Williams Gas Pipeline Company, LLC, TransCanada PipeLine USA Ltd. and Sempra Gas Pipelines and Storage Corp. The proposed 598-mile pipeline would transport gas from the Rockies to markets in the West and Pacific Northwest. The pipeline would generally follow existing pipeline and utility corridors from the Opal Hub in Wyoming through southern Idaho, connecting with TransCanada's GTN system and

Williams' Northwest Pipeline near Stanfield, Oregon. The developers have suspended activity on this project due to unfavorable current market conditions.

None of the above projects provide end delivery to any of our service territories. Therefore, to be a viable peak day incremental resource requires combining with additional pipeline resources. In our modeling, we utilized available cost and other information to develop more generic pipeline resource alternatives rather than specifically modeling the various segments.

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 pipeline estimates are costly and will be prudently acquired.

IN-GROUND STORAGE

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

Jackson Prairie

Jackson Prairie is a potential resource for expansion opportunities. The Shell Energy recall discussed earlier and any future storage expansion capacity does not include transportation and therefore cannot be considered an incremental peak day resource. However, we will continue to look for swap and transportation release opportunities that could fully utilize these additional resource options. Even without deliverability, we believe it can make financial sense to fully develop/recall Jackson Prairie capacity to optimize time spreads within the natural gas market and provide net revenue offsets to customer gas costs.

Other In-Ground Storage

Other regional storage facilities exist and may be cost effective. Additional capacity at Northwest Natural's Mist facility, capacity at one of the Alberta area storage facilities, Questar's Clay Basin facility in northeast Utah, and northern California storage are all possibilities. Again, transportation to and from these facilities to Avista's service territories continues to be the largest impediment to contracting for these options. Northern California storage opportunities may be able to overcome this hurdle by using backhaul transportation for deliveries to some of the Washington/Idaho and Oregon customers but firm, reliable delivery on peak days or cold weather events remains an issue. Another issue is whether sellers of storage capacity will offer multi-year contracts or contracts with beginning dates during the timeframes that we may need these incremental resources.

SATELLITE LNG

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

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

PLYMOUTH LNG

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

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

COMPANY OWNED LIQUEFACTION LNG

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

Construction would be dependent on regulatory and environmental approval as well as cost effectiveness requirements. Preliminary estimates of the construction, environmental, right of way, legal, operating and maintenance, required lead times, and inventory costs indicate company-owned LNG facilities have significant development risks. We include this resource in our modeling, recognizing this type of project is highly complex and there are many risk considerations that require evaluation and monitoring should this resource be selected.

IMPORTED LNG

Although burgeoning supply from unconventional gas production in the U.S. is now forecasted to ease the need for LNG imports to meet domestic demand, there continues to be interest and discussion nationally regarding LNG regasification terminals (import LNG). Several terminals have been proposed in the U.S., Mexico and Canada with several projects proposed for the Pacific Northwest[2]. Not all of these terminals will advance, and it may be possible that none of the Pacific Northwest projects will proceed. The siting of import 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 and public reception, secure LNG supply, long-term output/sales agreements and financing. We have participated in several forums on the various regional projects.

Although the Pacific Northwest may not provide project sponsors with these requirements, the announcement to construct a pipeline from the proposed Coos Bay LNG facility to Malin, Oregon remains of interest to Avista. This pipeline may provide gasified 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 continue to monitor the progress of this project having participated in their open season and contingently reserving capacity. We are also monitoring progress of other regional projects noting, however, that they currently do not provide supply directly to any of our service territories. In particular, we continue to monitor our regional prices relative to global prices, as these differentials directly affect the securing of dependable supply which we believe poses a significant challenge for LNG project sponsors.

Some 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 given the flexibility and responsiveness of incremental volumes to enter our domestic market. 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 import LNG a resource option available to the model. This is because LNG in the Pacific Northwest is highly speculative, the region is not considered to be a premium market when compared to 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 LNG imports to North America, so LNG commodity impacts are imbedded in those forecasts. If a terminal were to be built regionally, we believe the approximate supply price would be the nearest market hub price adjusted for delivery charges to our service territories. So to some extent, LNG resources are indirectly captured in our modeling.

[2] The Kitimat LNG project in Kitimat, British Columbia has changed its project scope to become a liquefaction terminal to export LNG to Asian and other markets.

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

BIOGAS

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

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

Biogas projects are inherently individualized, making reasonable and reliable cost estimates difficult to obtain. Project sponsorship has many complex issues and the more likely participation in such a project is as a long-term contracted purchaser. We did not consider biogas as a resource in this planning cycle but remain receptive to such projects as they are proposed.

SUPPLY SCENARIOS

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

Table 5.2 Alternate Supply Scenarios
Existing Resources
Existing + Expected Available
GTN Rate Escalation
GTN Fully Subscribed

Existing Resources – Represents all resources currently owned or contracted by Avista.

Existing + Expected Available – Existing resources plus supply resource options expected to be available when resource needs are identified. This includes: currently available GTN, capacity release recalls, NWP expansions, satellite LNG, backhauls combined with increased lateral compression, liquefaction LNG and Klamath Falls Lateral Purchase.

GTN Rate Escalation – Same resource options as Existing + Expected Available except GTN subscription rate is doubled.

GTN Fully Subscribed – Same resource options as Existing + Expected Available except GTN is fully subscribed so there is no incremental GTN capacity available.

SUPPLY ISSUES

The market for natural gas has undergone dramatic changes over the last several years. Previously, the commodity market was transitioning from a regionally-based market to a nationally-based, and perhaps, globally-based market. The economic recession and emerging abundant supply now looks to interrupt and potentially shift away from that paradigm. Issues likely to play a prominent role in defining the future for natural gas are as follows:

Unconventional Supply – Shale gas and other unconventional sources are changing the industry in ways not yet fully understood. Although there are several instances of mature and seasoned wells, most have limited long-term track records. The high natural gas prices pre-2008 spurred technological breakthroughs that have advanced and improved production methods. Yet as we enter a potentially long-term cycle of lower prices, innovation may be stifled. Some of the more promising plays are in areas with little or no infrastructure. Investment in required infrastructure may be stifled as well. Alternatively, lower natural gas prices may serve as an important catalyst for economic recovery and future investment.

Climate Change Policies – By design, climate change policy is intended to disrupt the consumption of fossil fuels. The role of natural gas in this arena is one of inherent contradiction. In the near term, consumption is predicted to increase significantly via gas-fired power generation replacing coal plants. It is unclear however, whether natural gas has a long-term role in power generation or will be marginalized by nuclear, renewables or other emerging technologies. Economic conditions add further uncertainty regarding legislative enactment and/or delayed implementation.

Supply from Canada – There is an abundance of evidence supporting the assumption that gas will continue to be imported from Canada into the United States. However, since much of our supply comes from the WCSB, the possibility that supply could become significantly constrained is monitored closely. Oil sands production and royalty structures are two key factors that will likely influence this issue. We will continue to monitor this situation looking for signals that indicate increased risk of disrupted supply from Canadian exports.

Pipeline rate increases – A sustained economic slow-down could result in excess or underutilized pipeline capacity in many parts of the country including our region. This excess capacity may cause capacity holders with expiring contracts to consider relinquishing their capacity back to the pipelines. Many capacity holders have shown a preference to 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.

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 role of LNG in the United States – Projections indicate that, over the long term, there will still be a growing gap between North American natural gas production and North American demand for natural gas. The consensus is that LNG will supply 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.

MARKET-RELATED RISKS AND RISK MANAGEMENT

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

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

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

- The Risk Management Committee consists of several corporate officers and senior-level management. The committee establishes the Risk Management Policy and monitors compliance. They receive regular reports on natural gas activity and meet regularly to discuss market conditions, hedging activity and other natural gas-related matters.
- The Strategic Oversight Group exists to coordinate natural gas matters among internal natural gas-related stakeholders and to serve as a reference/sounding board for strategic decisions, including hedges, made by the Natural Gas Supply department. Members include representatives from the Accounting, Regulatory, Credit, Power Resources and Risk Management departments. While the Natural Gas Supply department is responsible for implementing hedge transactions, the Group provides input and advice.

ACTION ITEMS

We will continue to monitor the supply issues identified in this chapter including shale production trends, climate change policies, slowing Canadian exports, pipeline constraints in our region, pipeline expansions moving volumes away from our region, pipeline cost escalations and import LNG activity.

We will also monitor new resource lead time requirements relative to when resources are needed to preserve resource option flexibility.

CONCLUSION

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

CHAPTER 6 – INTEGRATED RESOURCE PORTFOLIO

OVERVIEW

This chapter combines all previously discussed IRP components and the model used to determine resource deficiencies during the 20-year planning horizon. This chapter also provides an analysis of potential resource options 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 used for developing demand forecasts. Avista currently uses the "coldest day on record" as its weather planning standard for determining peak day demand. This is consistent with our past IRPs and is more fully described in Chapter 3 – Demand Forecasts. We utilize historic peak and average weather data for each demand region for this IRP. We plan to serve our expected peak day in each demand region with firm resources. Firm resources include natural gas supplies, pipeline transportation and storage resources. In addition to planning for peak requirements, we also plan for non-peak periods such as winter, shoulder and summer demand. Our modeling process includes running an optimization for every day of the 20-year planning period.

It is assumed that on a peak day all interruptible customers have left the system in order to provide service to firm customers. Avista does not make firm commitments to serve interruptible customers. Therefore, our IRP analysis of demand-serving capabilities only focuses on the residential, commercial and firm industrial classes.

Our supply forecasts are increased between 1.0 percent and 3.0 percent on both an annual and peak day basis to account for additional supplies that are purchased primarily for pipeline compressor station fuel. The percentage of additional supply that must be purchased is governed through FERC and National Energy Board approved tariffs.

SENDOUT® PLANNING MODEL

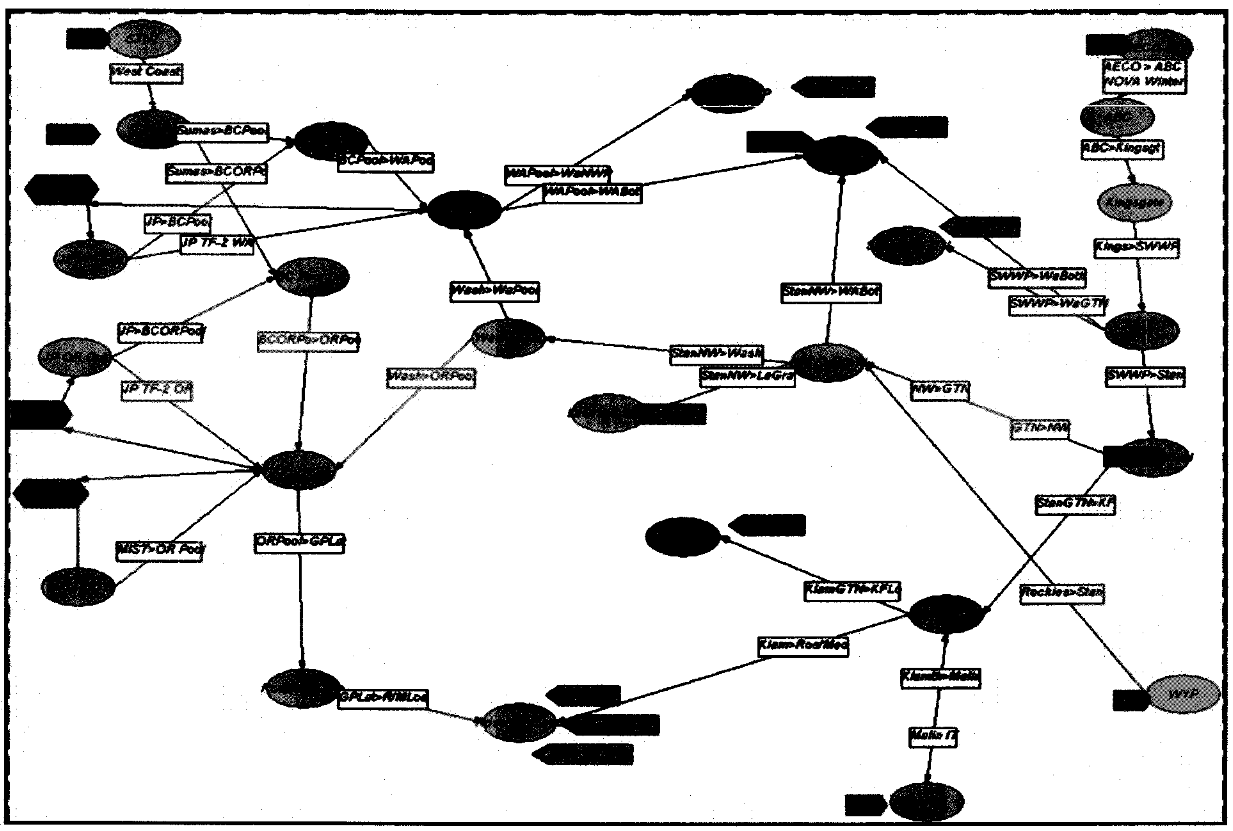
The SENDOUT® Gas Planning System from Ventyx is used to perform integrated resource optimization. The SENDOUT® model was purchased in April 1992 and has been used in preparing all IRPs since then. Avista has a long-term maintenance agreement with Ventyx that allows us to receive software updates and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

SENDOUT® is a linear programming model widely used to solve natural gas supply and transportation optimization questions. Linear programming is a proven technique used to solve minimization/maximization problems. SENDOUT® looks at the complete problem at one time within the study horizon, while taking into account physical limitations and contractual constraints. The software analyzes thousands of variables and valuates possible solutions to generate a least cost solution. The model uses the following variables:

- Demand data, such as customer count forecasts and demand coefficients by customer type (e.g. residential, commercial and industrial);
- 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/withdrawal rates, capacities and costs; and
- DSM programs.

Figure 6.1 is a SENDOUT® network diagram of our demand centers and resources (see also Appendix 6.5). This diagram illustrates Avista's current transportation and storage assets, flow paths and constraint points.

Figure 6.1 SENDOUT® Model Diagram



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

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

- Resource mix analysis for DSM programs;
- Weather pattern testing and analysis;
- Transportation cost analysis;
- Avoided cost calculations; and
- Short-term planning comparisons.

The latest SENDOUT® version includes Monte Carlo capabilities, which facilitates price and demand uncertainty modeling and detailed portfolio optimization techniques to produce probability distributions. Similar to SENDOUT®, there are numerous variables entered for Monte Carlo simulation. The variables required for the Monte Carlo analysis are:

- Expected monthly HDDs by month;
- Standard deviation of monthly HDDs;
- Monthly minimum and maximum HDDs;
- 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-temperature correlations;
- Price-to-price correlations; and
- Price-to-temperature correlations.

This additional software module enhances Avista's analytical capabilities. More information and analytical results are located in Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

RESOURCE INTEGRATION

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

DEMAND FORECASTING

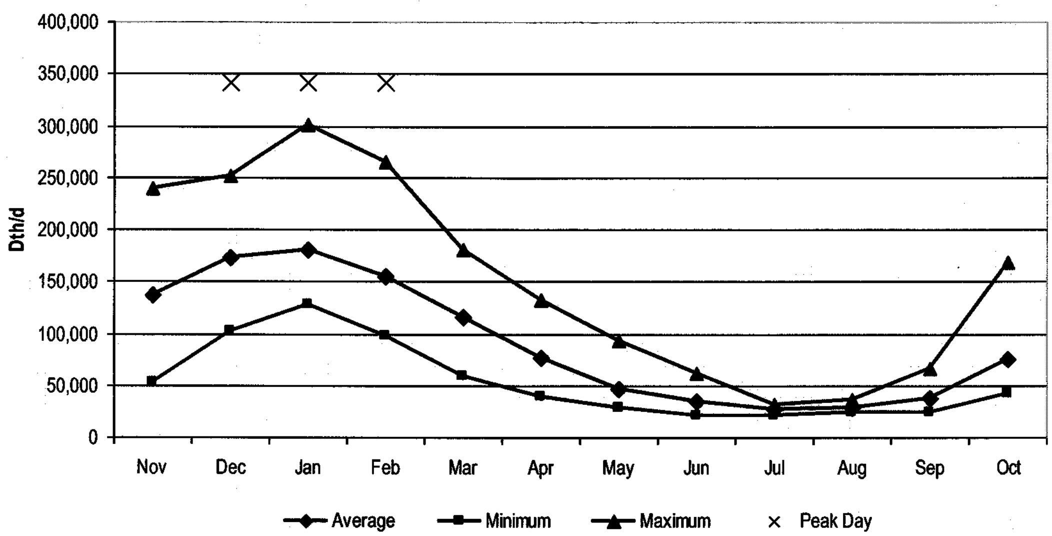
Avista's demand forecasting approach is described in detail in the Demand Forecasts chapter.

We forecast demand in the SENDOUT® model in eight service areas given the existence of distinct weather and demand patterns for each area and pipeline infrastructure dynamics. The SENDOUT® areas are Washington/Idaho (disaggregated into three sub-areas because of pipeline flow limitations), Medford (disaggregated into two sub-areas because of pipeline flow limitations) and

Roseburg, Klamath Falls and La Grande. In addition to area distinction, we also model demand by customer class within each area. The relevant customer classes in Avista's service territories are residential, commercial and firm industrial customers.

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

Figure 6.2 Total System Average Daily Demand
(Average, Minimum, Maximum, and Peak Day)



NATURAL GAS PRICE FORECASTS

Natural gas prices are a fundamental component of the IRP. The commodity price is a significant component of the total cost of a resource option. This in turn affects the avoided cost threshold for determining cost-effectiveness of conservation measures. We also recognize the price of natural gas influences consumption, so we include price elasticity analysis in our demand evaluation (see Chapter 3 – Demand Forecasts).

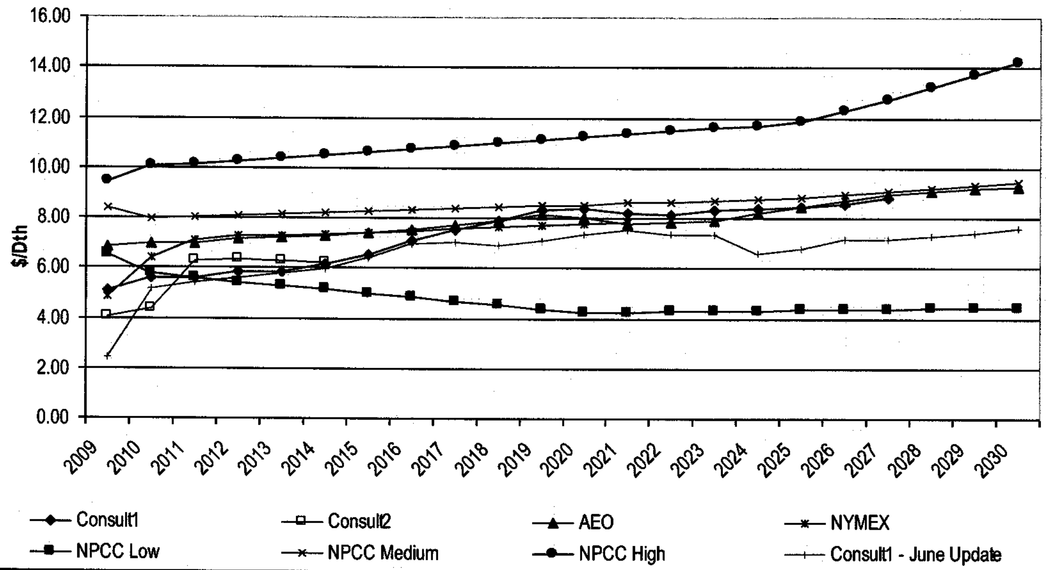
The natural gas price outlook has changed dramatically over the recent planning cycle in response to several influential events and trends affecting the industry. Most notably is the severe economic recession trigged by the global credit crisis, but two other significant influencers are the surge in shale gas production expectations and potential climate change legislation encouraging natural gas-fired power generation to replace coal burning power plants. The outlook for these factors has evolved rapidly in the midst of an environment of significant uncertainty precipitating wide swings and frequent updates to the price forecasts we monitor.

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

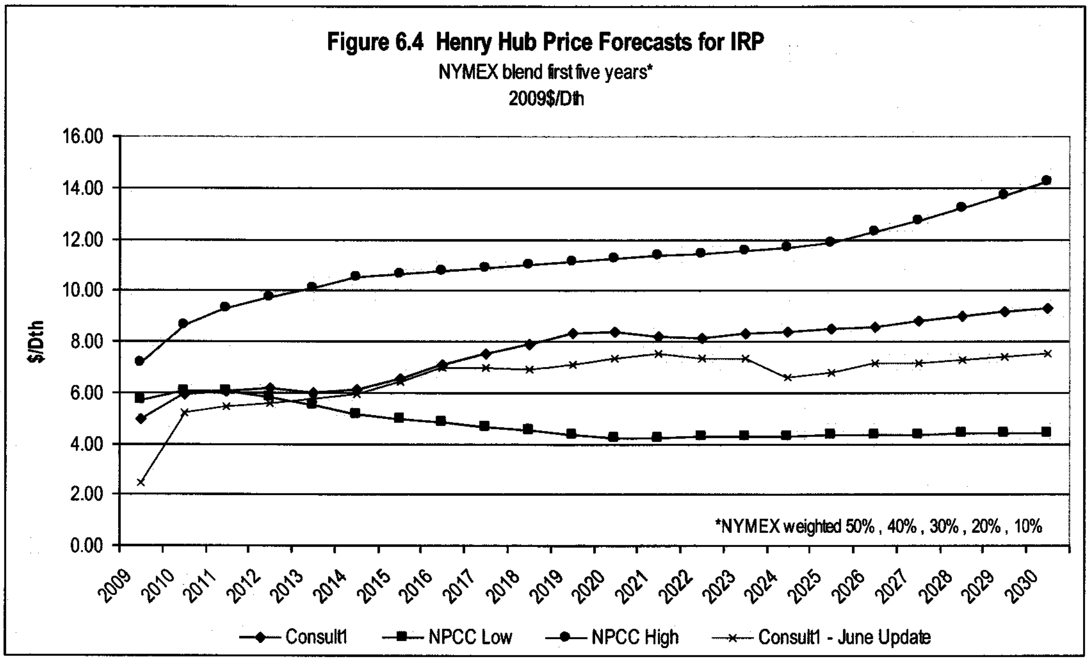
Even though we continually monitor these factors, we cannot accurately predict future prices for the 20-year horizon of this IRP. We have reviewed several price forecasts from credible sources. Figure 6.3 depicts the price forecasts we considered in our analyses.

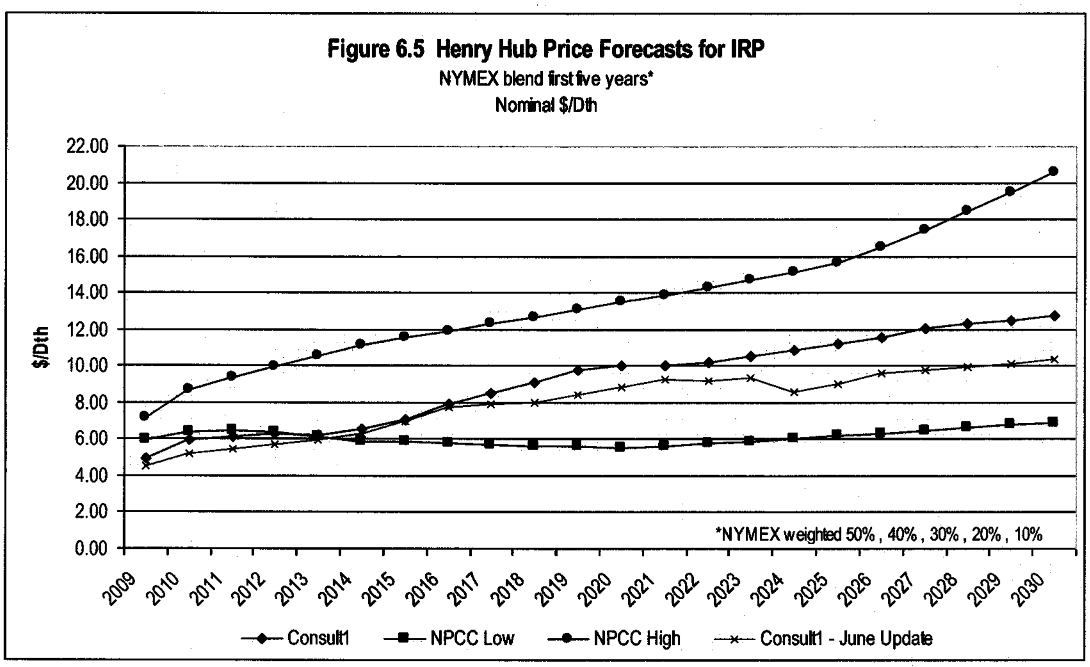
Figure 6.3 Henry Hub Price Forecasts

2009$/Dth



Some of these forecasts are more plausible than others, but most of them are possible. With assistance and concurrence of the TAC Committee, we selected high, medium and low price curves to consider possible outcomes and the impact that this volatile and high pricing environment might have on planning. The price curves we have selected have considerable variation, which is consistent with our theme of stretching modeling assumptions in an uncertain environment. These curves are shown in real dollars in Figure 6.4 and nominal dollars in Figure 6.5.





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

The primary physical supply points at Sumas, Washington, AECO Alberta, Canada, and Opal, Wyoming in the United States Rockies (and other secondary regional market hubs) ultimately determines Avista's costs. Prices at these points typically trade at a discount or negative basis differential to Henry Hub primarily because of their relative close proximity to the two largest natural gas basins in North America (the WCSB and the Rockies).

Table 6.1 shows the Pacific Northwest regional prices from our consultant as a percent of Henry Hub price along with historical comparisons.

Table 6.1 Regional Price as a percent of Henry Hub Price

	AECO	Rockies	Sumas	Malin	Stanfield
Consultant1 Forecast Average	**92.7%**	**85.6%**	**95.2%**	**94.1%**	**93.7%**
Forward Markets Five Yr Average	88.8%	84.5%	97.1%	N/A	N/A
Prior IRP	86.0%	80.5%	87.6%	N/A	N/A

This IRP used monthly prices for modeling purposes because of our heavily winter-weighted demand profile. Table 6.2 depicts the monthly price shape we used in this IRP and comparisons to the 2007 IRP.

Table 6.2 Monthly Price as a percent of Average Price

	Jan	Feb	Mar	Apr	May	Jun
Consult1	**107%**	**108%**	**103%**	**93%**	**93%**	**94%**
Prior IRP	113%	113%	110%	93%	92%	93%
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Consult1	**95%**	**96%**	**96%**	**97%**	**109%**	**110%**
Prior IRP	94%	94%	95%	96%	101%	106%

Appendix 6.1 contains detailed monthly price data behind the summary table information discussed above.

TRANSPORTATION AND STORAGE

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

Figure 6.6 Existing Firm Transportation Resources
North Division - WA/ID

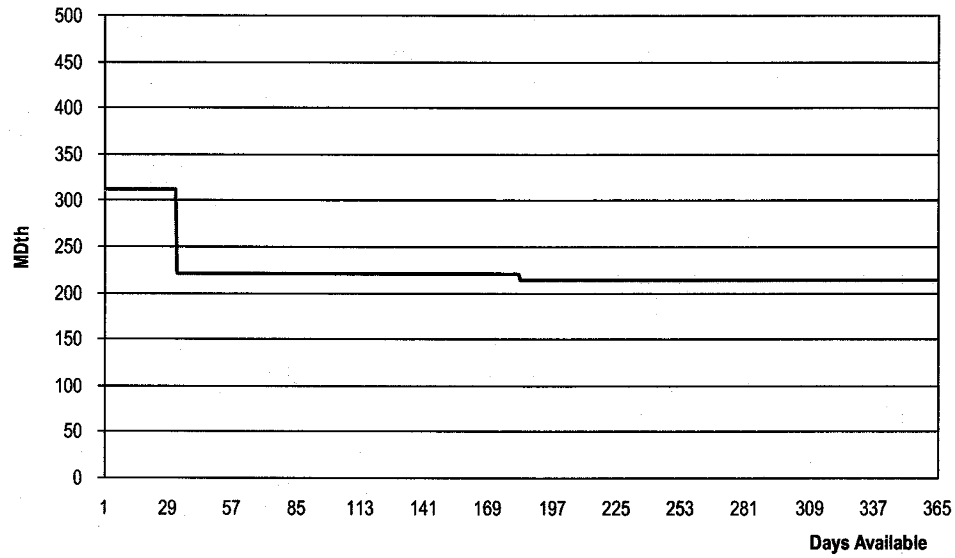
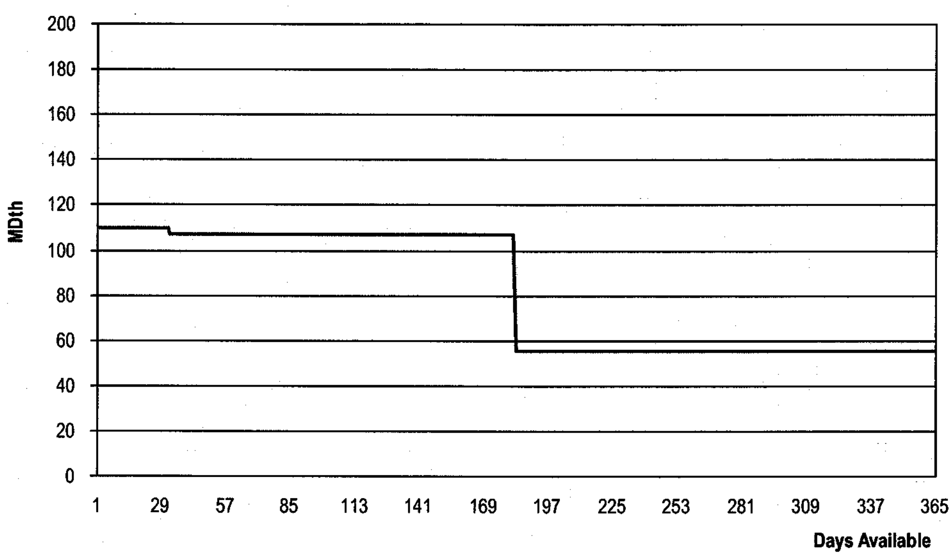


Figure 6.7 Existing Firm Transportation Resources
South Division - OR



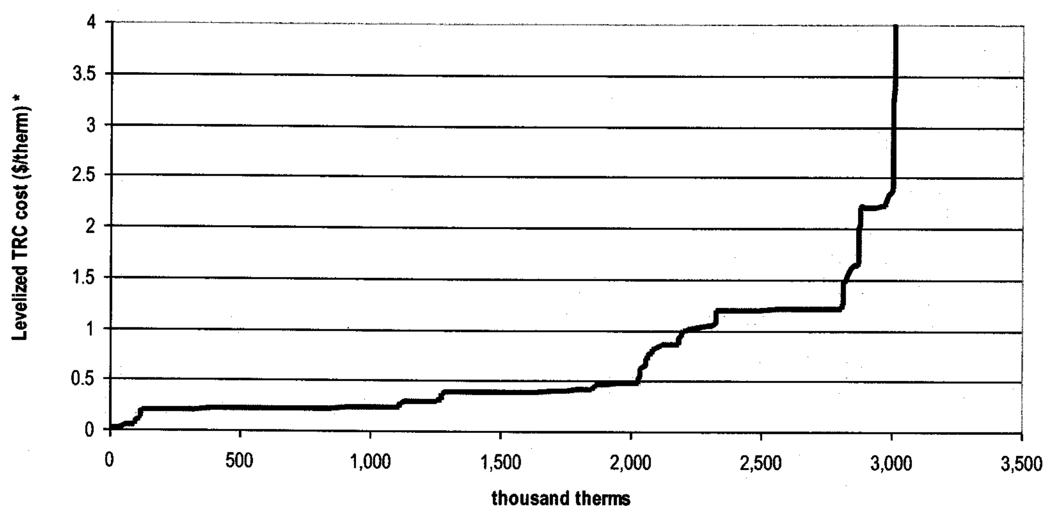
Current rates for capacity are in Appendix 5.1. Forecasting future pipeline rates can be a challenge, as we need to estimate the amount and timing of rate changes. Our estimates and timing of future rate increases are based on knowledge obtained from industry discussions and participation in various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

DEMAND-SIDE MANAGEMENT

Chapter 4 – Demand-side Resources describes the methodology used to identify all possible conservation measures (technical potential), ascertain what level of measures can be reasonably attained (achievable potential) and the interactive process deployed in SENDOUT® that computes avoided cost thresholds for determining cost effectiveness of conservation measures on an equivalent basis with supply-side resources.

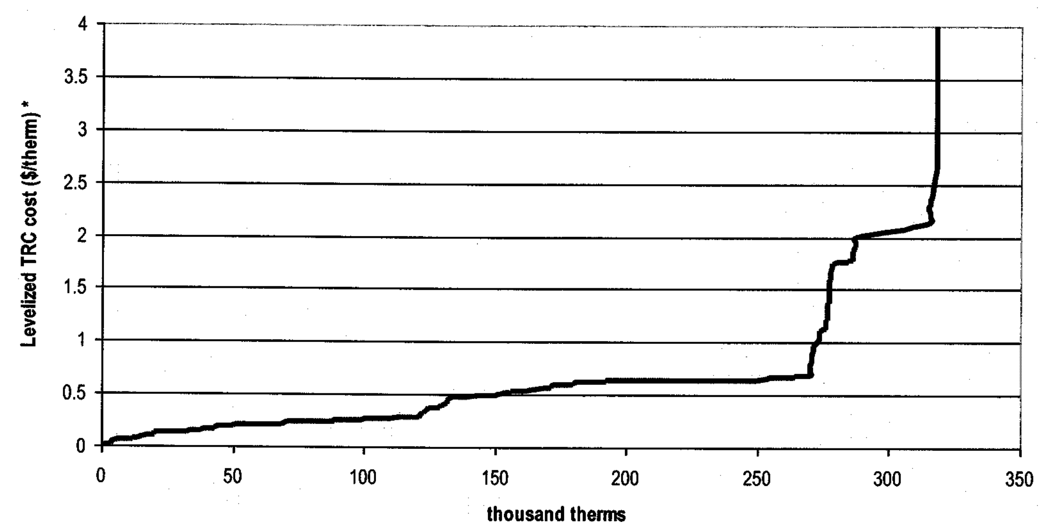
This process results in conservation measures data that facilitates construction of natural gas DSM supply curves. These curves represent the cumulative therms of the evaluated measures stacked in ascending order of levelized TRC. Supply curves for our Expected Case are presented for the two divisions (Figures 6.8 and 6.9).

Figure 6.8 North Division DSM Supply Curve, 1st Year (2010)
SENDOUT® selected mesures only



* Maximum cost is $11.89; chart scale truncated at $4

Figure 6.9 South Division DSM Supply Curve, 1st Year (2010)
SENDOUT® selected mesures only



* Maximum cost is $9.36; chart scale truncated at $4

PRELIMINARY RESULTS

After incorporating the above data into the SENDOUT® model, we then generate an assessment of demand compared to existing resources for several scenarios. The demand results from these cases are discussed in Chapter 3 – Demand Forecasts, with additional details supported in the Appendices 3.1 through 3.9.

Figures 6.10 through 6.13 graphically represent summaries of Expected Case peak day demand compared to existing resources, as well as demand comparisons to our prior IRP. This demand is net of DSM savings. This comparison shows by service territory the amount and timing of deficits over the planning horizon.

Figure 6.10 WA/ID Existing Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October

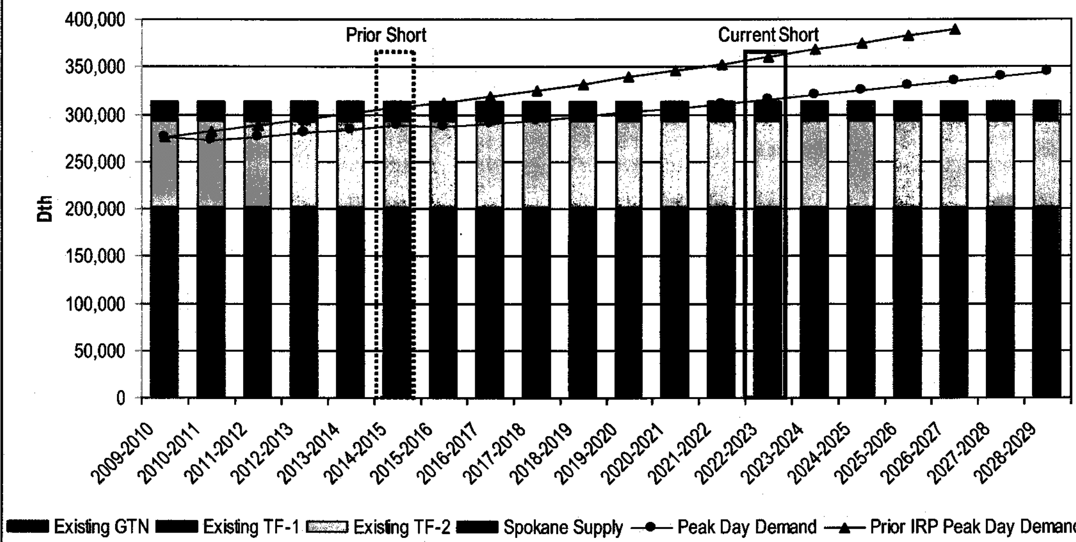


Figure 6.11 Medford/Roseburg Existing Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October

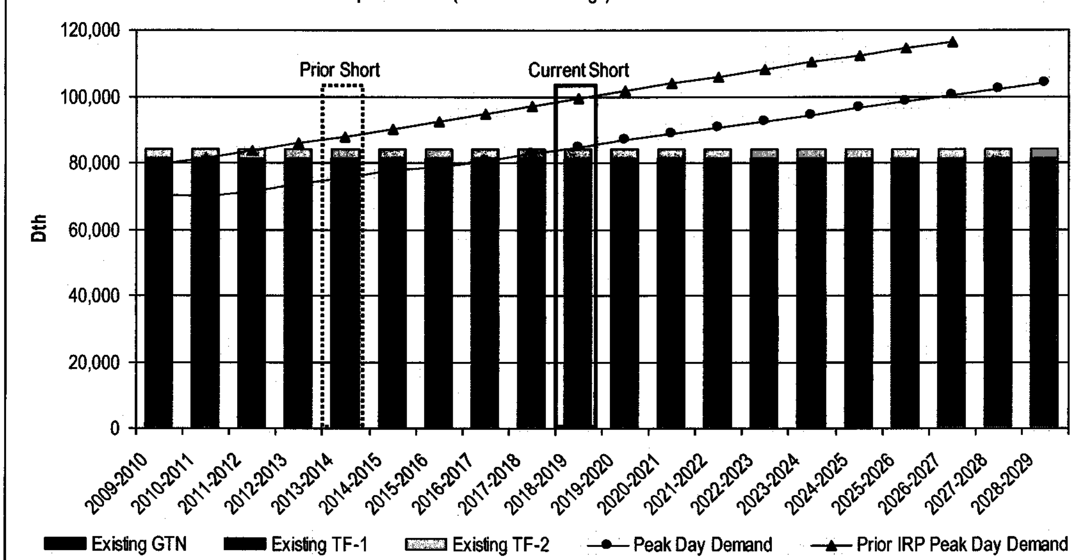


Figure 6.12 Klamath Falls Existing Resources vs. Peak Day Demand

Expected Case (net of DSM Savings) November to October

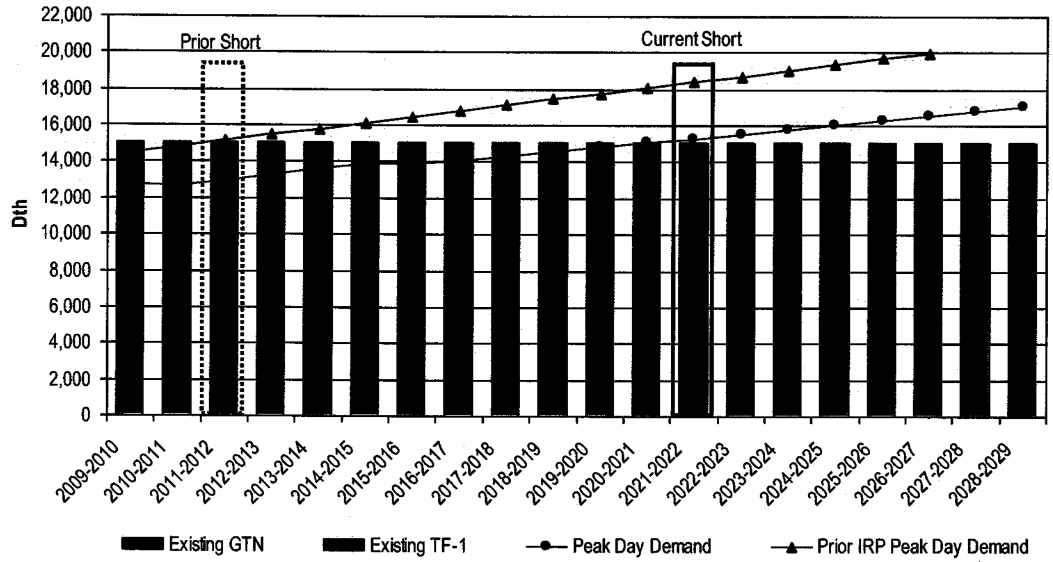
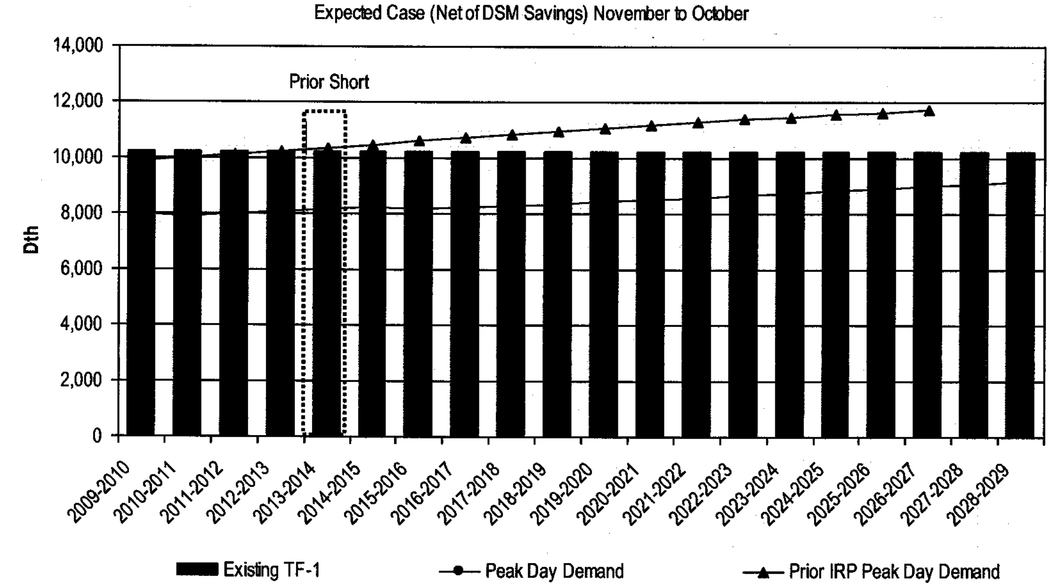


Figure 6.13 La Grande Existing Resources vs. Peak Day Demand

Expected Case (Net of DSM Savings) November to October



These charts show that resource shortages occur well into the future. In the Expected Case for Washington and Idaho, the system first becomes unserved in 2023. In Oregon, the first unserved year is in Medford/Roseburg in 2018 followed by Klamath Falls in 2021. The La Grande service territory does not go unserved at any time during the 20-year planning horizon. This surplus resource situation provides ample time to carefully monitor, plan and act on potential resource additions.

However, an important risk with respect to identified capacity shortages is the slope of forecasted demand growth which is almost flat. This outlook implies existing resources will be sufficient for quite some time to meet demand. However, if demand growth accelerates, increased demand could accelerate resource shortages by several years. This "flat demand risk" necessitates close monitoring of signs of accelerating demand and careful evaluation of lead times to acquire preferred incremental resources.

Table 6.3 quantifies the forecasted total demand (net of DSM savings) and unserved demand from the above charts, identifying the amount of deficiencies by region and growth in deficiencies over time. The next step is to determine the best risk/least cost resources to satisfy these deficiencies.

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

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	WA/ID Served	WA/ID Unserved	WA/ID Total
Expected	2009-2010	7.98	-	7.98	274.58	-	274.58
Expected	2010-2011	7.89	-	7.89	271.79	-	271.79
Expected	2011-2012	7.98	-	7.98	275.53	-	275.53
Expected	2012-2013	8.07	-	8.07	279.44	-	279.44
Expected	2013-2014	8.14	-	8.14	283.44	-	283.44
Expected	2014-2015	8.22	-	8.22	287.44	-	287.44
Expected	2015-2016	8.14	-	8.14	285.63	-	285.63
Expected	2016-2017	8.21	-	8.21	289.48	-	289.48
Expected	2017-2018	8.29	-	8.29	293.50	-	293.50
Expected	2018-2019	8.36	-	8.36	297.54	-	297.54
Expected	2019-2020	8.43	-	8.43	301.83	-	301.83
Expected	2020-2021	8.51	-	8.51	306.29	-	306.29
Expected	2021-2022	8.58	-	8.58	310.81	-	310.81
Expected	2022-2023	8.66	-	8.66	314.48	0.94	315.42
Expected	2023-2024	8.74	-	8.74	314.41	5.62	320.03
Expected	2024-2025	8.82	-	8.82	314.32	10.45	324.78
Expected	2025-2026	8.90	-	8.90	314.24	15.28	329.53
Expected	2026-2027	8.98	-	8.98	314.16	20.03	334.20
Expected	2027-2028	9.06	-	9.06	314.08	25.50	339.58
Expected	2028-2029	9.14		9.14	314.04	30.74	344.79

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total
Expected	2009-2010	12.71	-	12.71	70.44	-	70.44
Expected	2010-2011	12.67	-	12.67	70.01	-	70.01
Expected	2011-2012	12.94	-	12.94	71.18	-	71.18
Expected	2012-2013	13.27	-	13.27	73.37	-	73.37
Expected	2013-2014	13.62	-	13.62	75.47	-	75.47
Expected	2014-2015	13.86	-	13.86	77.65	-	77.65
Expected	2015-2016	13.84	-	13.84	78.47	-	78.47
Expected	2016-2017	14.08	-	14.08	80.67	-	80.67
Expected	2017-2018	14.31	-	14.31	82.78	-	82.78
Expected	2018-2019	14.56	-	14.56	84.08	0.69	84.78
Expected	2019-2020	14.79	-	14.79	84.09	2.60	86.68
Expected	2020-2021	15.03	-	15.03	84.08	4.54	88.62
Expected	2021-2022	15.03	0.23	15.26	84.09	6.46	90.55
Expected	2022-2023	15.03	0.47	15.50	84.09	8.40	92.48
Expected	2023-2024	15.03	0.72	15.75	84.08	10.36	94.45
Expected	2024-2025	15.03	0.97	16.00	84.09	12.35	96.44
Expected	2025-2026	15.03	1.22	16.25	84.08	14.24	98.32
Expected	2026-2027	15.03	1.47	16.50	84.08	16.05	100.13
Expected	2027-2028	15.03	1.72	16.75	84.09	17.85	101.94
Expected	2028-2029	15.03	1.97	17.00	84.08	19.66	103.75

NEW RESOURCE OPTIONS

The following considerations are important in determining the appropriateness of potential resources:

RESOURCE COST

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

LEAD TIME REQUIREMENTS

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

PEAK VERSUS BASE LOAD

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

RESOURCE USEFULNESS

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

"LUMPINESS" OF RESOURCE OPTIONS

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

RISKS AND UNCERTAINTIES

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

RESOURCE SELECTION

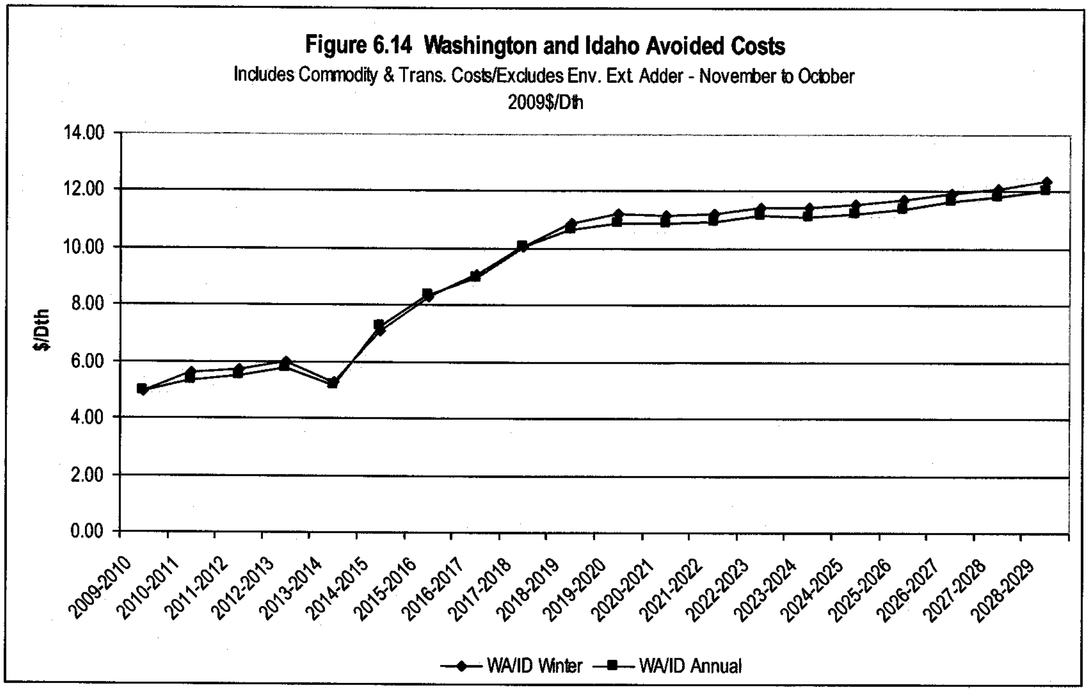
After identifying supply-side resource options and evaluating them based on the above considerations, we entered these supply-side scenarios (see Table 5.2) along with conservation measures (demand-side resources) into the SENDOUT® model for it to select the least cost approach to meeting resource deficiencies. This process is described in Chapter 4 – Demand-side Resources in the Methodology section. SENDOUT® compares demand-side and supply-side resources using PVRR analysis to determine which resource is the best risk adjusted/least cost resource. Appendix 4.3 lists the demand-side measures and Appendix 6.3 lists the supply-side resource options.

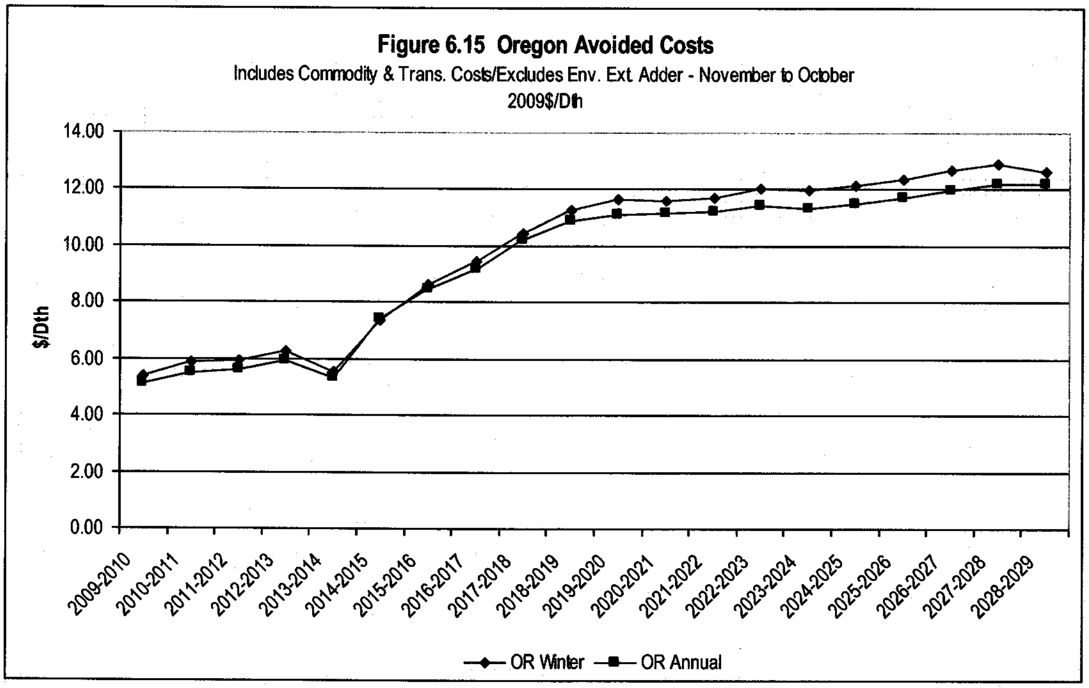
DEMAND-SIDE RESOURCES

Avoided Cost

The SENDOUT® model determined avoided cost figures represent the unit cost to serve the next unit of demand with a supply-side resource option during a given period. If a conservation measure's total resource cost is less than this avoided cost, it will cost effectively reduce customer demand and Avista can "avoid" possible commodity, storage, transportation and other supply resource costs. Measures that reduce heat-related demand are evaluated against a winter avoided cost while measures that reduce non-heat (base load) demand are evaluated against an annual avoided cost.

SENDOUT® calculates marginal cost data by day, month and year for each demand area. A summarized graphical depiction of avoided winter and annual costs for the Washington/Idaho and Oregon areas is in Figure 6.14 and 6.15. The detailed data is presented in Appendix 6.4. The avoided costs do not include environmental externality adders to monetarily recognize adverse environmental impacts. Appendix 4.4 discusses this concept more fully and includes specific requirements required in our Oregon service territory.





Following a small decline in 2013-2014, avoided costs increase rapidly over the next five years when carbon cost adders from anticipated cap-and-trade legislation is phased in.

Selected Measures

Using the above avoided cost thresholds, SENDOUT® selected all cost-effective measures and any mandatory measures. Table 6.4 details anticipated DSM savings in each region from the selected conservation measures for our Expected Case.

Table 6.4 Annual, Annual Average and Peak Day Demand Served by DSM

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/ Roseburg DSM (MDth)	Daily Medford/ Roseburg DSM (MDth/day)	Peak Day Medford/ Roseburg DSM (MDth/day)
Expected	2009-2010	6.540	0.018	0.052	3.154	0.009	0.027	22.184	0.061	0.171
Expected	2010-2011	13.084	0.036	0.104	6.231	0.017	0.055	45.948	0.126	0.348
Expected	2011-2012	19.618	0.054	0.156	9.261	0.025	0.082	67.996	0.186	0.522
Expected	2012-2013	25.330	0.069	0.200	11.929	0.033	0.106	87.756	0.240	0.674
Expected	2013-2014	30.960	0.085	0.245	14.564	0.040	0.130	107.443	0.294	0.826
Expected	2014-2015	36.687	0.101	0.290	17.104	0.047	0.154	126.867	0.348	0.978
Expected	2015-2016	42.421	0.116	0.334	19.659	0.054	0.178	146.081	0.399	1.130
Expected	2016-2017	48.049	0.132	0.379	22.100	0.061	0.202	164.829	0.452	1.282
Expected	2017-2018	53.695	0.147	0.424	24.475	0.067	0.226	183.263	0.502	1.434
Expected	2018-2019	59.324	0.163	0.468	26.806	0.073	0.250	201.418	0.552	1.586
Expected	2019-2020	65.018	0.178	0.513	29.314	0.080	0.274	220.444	0.602	1.736
Expected	2020-2021	70.603	0.193	0.557	31.783	0.087	0.298	239.075	0.655	1.887
Expected	2021-2022	75.958	0.208	0.601	34.162	0.094	0.321	256.083	0.702	2.034
Expected	2022-2023	80.360	0.220	0.642	36.077	0.099	0.343	270.585	0.741	2.175
Expected	2023-2024	83.972	0.229	0.675	37.583	0.103	0.361	282.427	0.772	2.292
Expected	2024-2025	87.083	0.239	0.708	38.873	0.107	0.379	292.007	0.800	2.406
Expected	2025-2026	90.025	0.247	0.739	40.067	0.110	0.396	301.099	0.825	2.518
Expected	2026-2027	93.001	0.256	0.771	41.291	0.113	0.414	310.146	0.850	2.631
Expected	2027-2028	95.958	0.262	0.803	42.573	0.116	0.431	319.671	0.873	2.743
Expected	2028-2029	98.806	0.271	0.835	43.640	0.120	0.448	327.820	0.898	2.855

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	2009-2010	31.879	0.087	0.250	301.191	0.825	3.336	333.070	0.913	3.585
Expected	2010-2011	65.263	0.179	0.507	600.472	1.645	6.672	665.735	1.824	7.179
Expected	2011-2012	96.875	0.265	0.760	889.351	2.430	10.008	986.226	2.695	10.768
Expected	2012-2013	125.015	0.343	0.981	1,175.141	3.220	13.344	1,300.156	3.562	14.325
Expected	2013-2014	152.967	0.419	1.202	1,460.913	4.003	16.680	1,613.879	4.422	17.882
Expected	2014-2015	180.657	0.495	1.422	1,746.704	4.785	20.016	1,927.362	5.280	21.438
Expected	2015-2016	208.161	0.569	1.643	2,018.933	5.516	23.351	2,227.094	6.085	24.994
Expected	2016-2017	234.978	0.644	1.863	2,287.557	6.267	26.687	2,522.535	6.911	28.550
Expected	2017-2018	261.433	0.716	2.084	2,555.521	7.001	30.022	2,816.954	7.718	32.106
Expected	2018-2019	287.549	0.788	2.304	2,825.361	7.741	33.357	3,112.910	8.529	35.662
Expected	2019-2020	314.776	0.860	2.523	3,099.580	8.469	36.691	3,414.356	9.329	39.213
Expected	2020-2021	341.460	0.936	2.741	3,347.233	9.171	39.967	3,688.694	10.106	42.708
Expected	2021-2022	366.203	1.003	2.957	3,595.802	9.852	43.243	3,962.005	10.855	46.199
Expected	2022-2023	387.021	1.060	3.160	3,844.841	10.534	46.519	4,231.862	11.594	49.679
Expected	2023-2024	403.982	1.104	3.329	4,095.271	11.189	49.795	4,499.253	12.293	53.124
Expected	2024-2025	417.963	1.145	3.493	4,331.296	11.867	53.046	4,749.258	13.012	56.539
Expected	2025-2026	431.191	1.181	3.654	4,573.965	12.531	56.295	5,005.156	13.713	59.950
Expected	2026-2027	444.438	1.218	3.816	4,801.026	13.153	59.544	5,245.464	14.371	63.360
Expected	2027-2028	458.202	1.252	3.977	4,980.468	13.608	62.068	5,438.669	14.860	66.045
Expected	2028-2029	470.266	1.288	4.139	5,156.772	14.128	64.592	5,627.038	15.417	68.731

The list of individual selected measures in the above savings is detailed in Appendix 4.2. Future implementation planning efforts will use these selected measures as a starting point for more detailed planning efforts but we will also investigate other measures that may not have been selected by the SENDOUT® model.

DSM Acquisition Goals

The avoided cost established in SENDOUT®, the demand-side resources selected and the resulting calculated therm savings is the basis for determining DSM acquisition goals and subsequent program implementation planning. The Preliminary Conservation Goal discussion in Chapter 4 – Demand-side Resources, has additional details on this process.

North Division DSM Goals

Changes in avoided costs, specifically adders taking effect in 2015, have driven the potential DSM goals identified in this IRP substantially beyond the 2010 goal of 1,755,829 therms developed in the 2007 IRP. SENDOUT® models escalating avoided costs into the future which are generally higher than the current prices actually experienced by our customers. This is partly due to regulatory lag as well as most customers typically do not explicitly consider higher future gas prices in their purchasing behavior. So customers are not as incented as the model indicates to choose DSM projects in the near term. We compensated for this situation by setting the 2010 DSM acquisition goal at 2,193,338 therms and increasing the DSM goal by 6.5 percent annually. The 6.5 percent annual growth rate results in the full acquisition of the identified potential over a 10-year planning cycle.

Achievement of a 6.5 percent annual increase in acquisition may result in 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.

South Division DSM Goals

Based on analyses for this IRP, a cost-effective annual acquisition of 303,300 first-year therms is achievable through utility intervention. The DSM goal originally identified by SENDOUT® significantly exceeds our past IRP goals. This coupled with unprecedented state unemployment and a recessive economy has caused us to constrain the annual ramp-up to 2.2 percent for the first five years. Overall, the acquisition over the entire 5-year planning cycle will accomplish full acquisition.

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.

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

SUPPLY-SIDE RESOURCES

SENDOUT® considered all options entered into the model, determined when and what resources were needed, and rejected options that were determined to not be cost effective. These selected resources represent the least cost solution, within given constraints, to serve anticipated customer requirements. Table 6.5 shows the SENDOUT® selected supply-side resources for the Expected Case.

Table 6.5 Supply Side Resource Selected in SENDOUT®

Case	Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Expected Case						
	GTN Capacity	WA/ID	25,000 Dth/d	GTN rate	2010	Currently available unsubscribed capacity
	GTN Capacity	OR	25,000 Dth/d	GTN rate	2010	Currently available unsubscribed capacity; requires expansion of Medford Lateral
	GTN Medford Lateral Expansion	OR	25,000 Dth/d	GTN rate	2011	Additional compression to allow more gas to flow from GTN mainline to the lateral
	Klamath Falls Lateral Purchase	OR	6,000 Dth/d	$2.5 million capital cost	November 2010	Agreement with NWPL to purchase the Klamath Falls lateral at net book value. If certain terms are met, can be done with less than one year's notice.
	Malin Backhaul	OR		GTN rate	2010	Backhaul capacity is provided by displacement and is available up to the amount of scheduled forward-haul capacity through a specific point. In order to facilitate additional deliveries to our OR properties an expansion of the Medford Lateral is necessary.

With additional research and investigation, we may later determine that alternative resources are more cost effective than those resources selected in this IRP. We will continue to review and refine knowledge of resource options and will act to secure these best cost/risk options when necessary or advantageous.

RESOURCE SELECTION RESULTS

Figures 6.16 through 6.18 summarize modeling results when comparing regional peak day demand against existing and incremental resources for the Expected Case over the 20-year planning period.

Figure 6.16 WA/ID Selected Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October

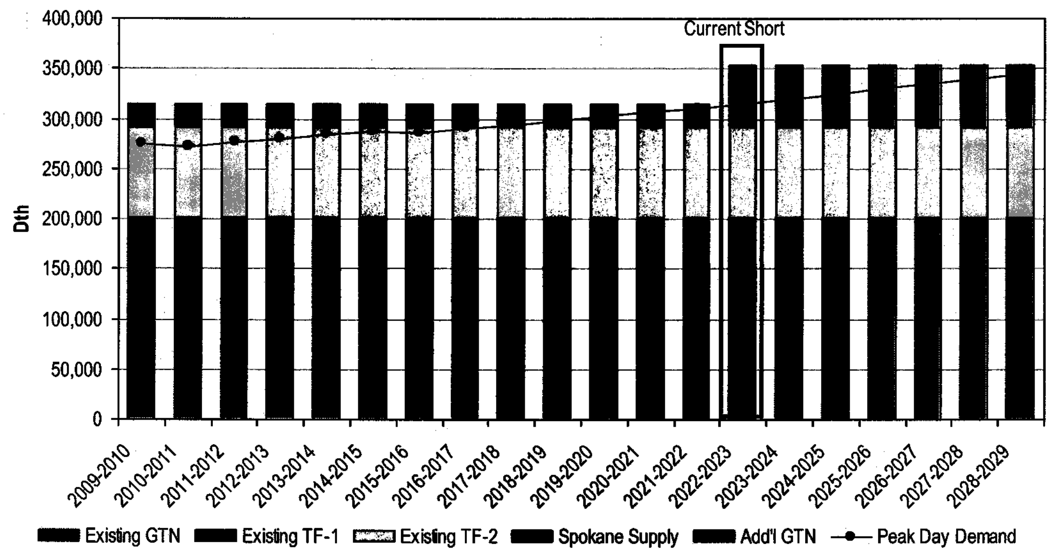


Figure 6.17 Medford/Roseburg Selected Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October

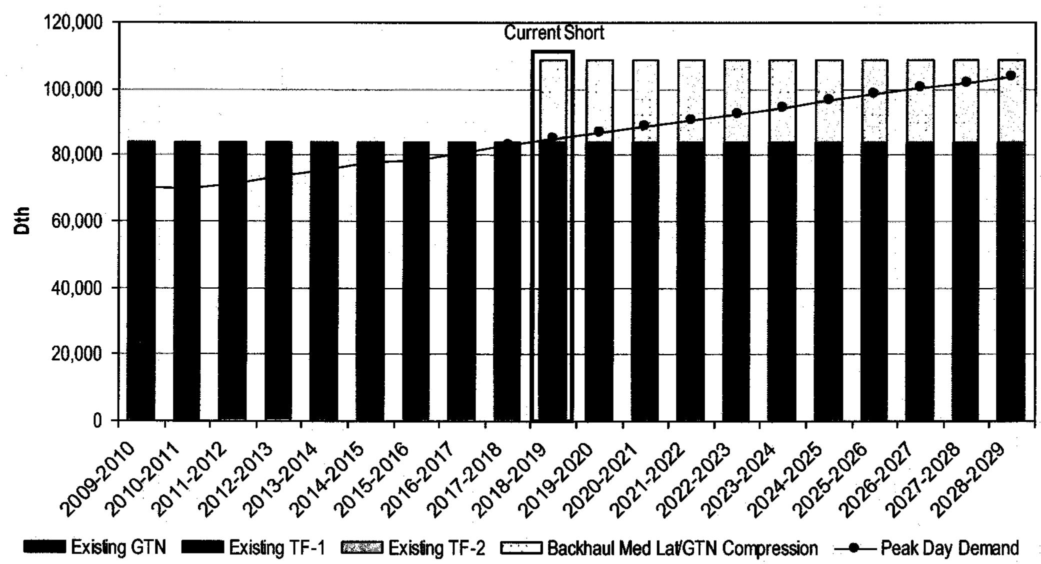
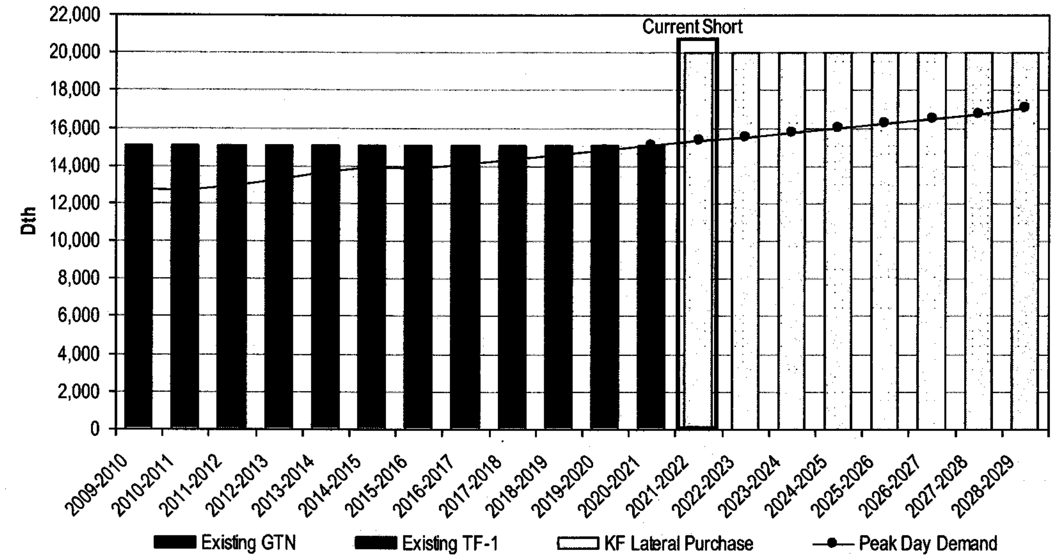


Figure 6.18 Klamath Falls Selected Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October



As indicated in the figures, after DSM savings, the model shows a general preference for incremental transportation resources from existing pipelines and supply basins to resolve capacity deficiencies.

Figures 6.19 and 6.20 show load duration curves and 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 peak day sufficiency and allows the opportunity to compare all demand days within that year. Although it appears there is excess capacity during non-winter periods, Avista utilizes this capacity for storage injections and transportation optimization opportunities.

Figure 6.19 Load Duration Curve & Resource Stack
Expected Case (net of DSM) - WA/ID

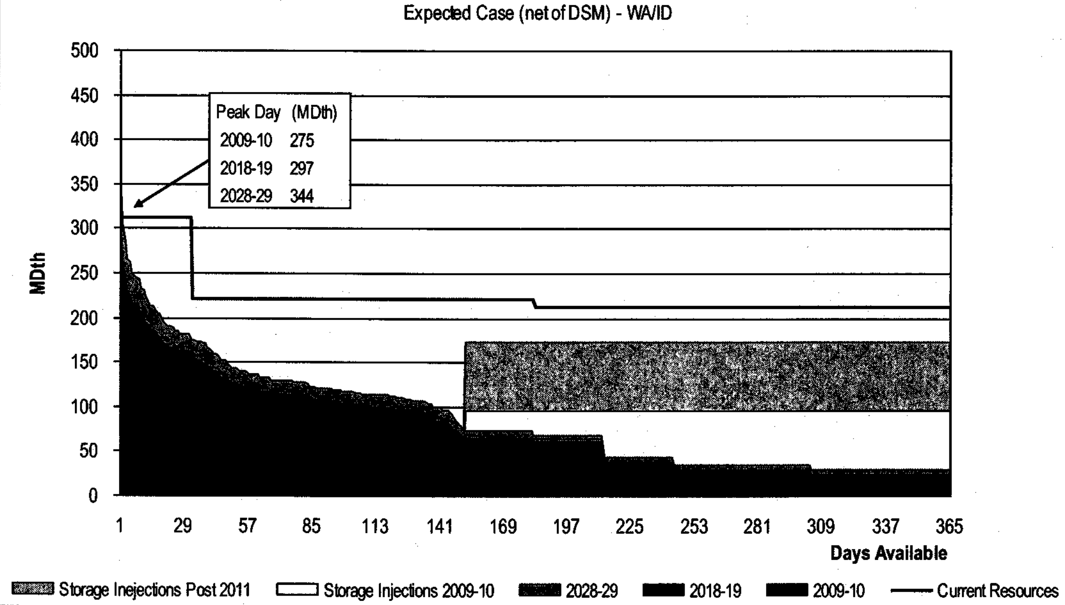
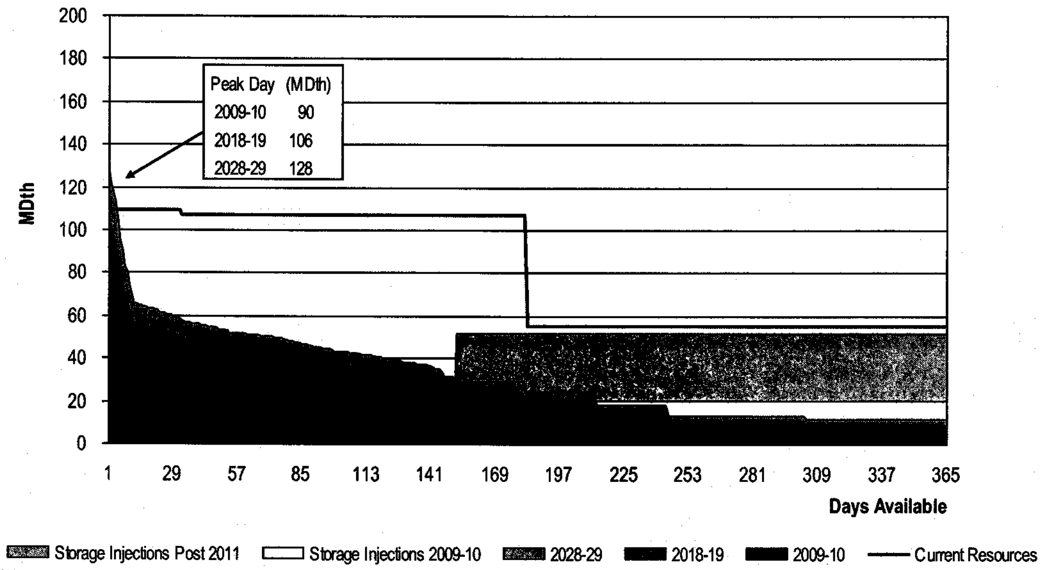


Figure 6.20 Load Duration Curve & Resource Stack
Expected Case (net of DSM) - OR



CONCLUSION

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

We fully recognize that there are numerous other potential outcomes. The process described in this chapter was applied to a host of alternate demand and supply resource scenarios and includes a price update to our initial Expected Case which is covered in the Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

CHAPTER 7 – ALTERNATE SCENARIOS, PORTFOLIOS AND STOCHASTIC ANALYSIS

OVERVIEW

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

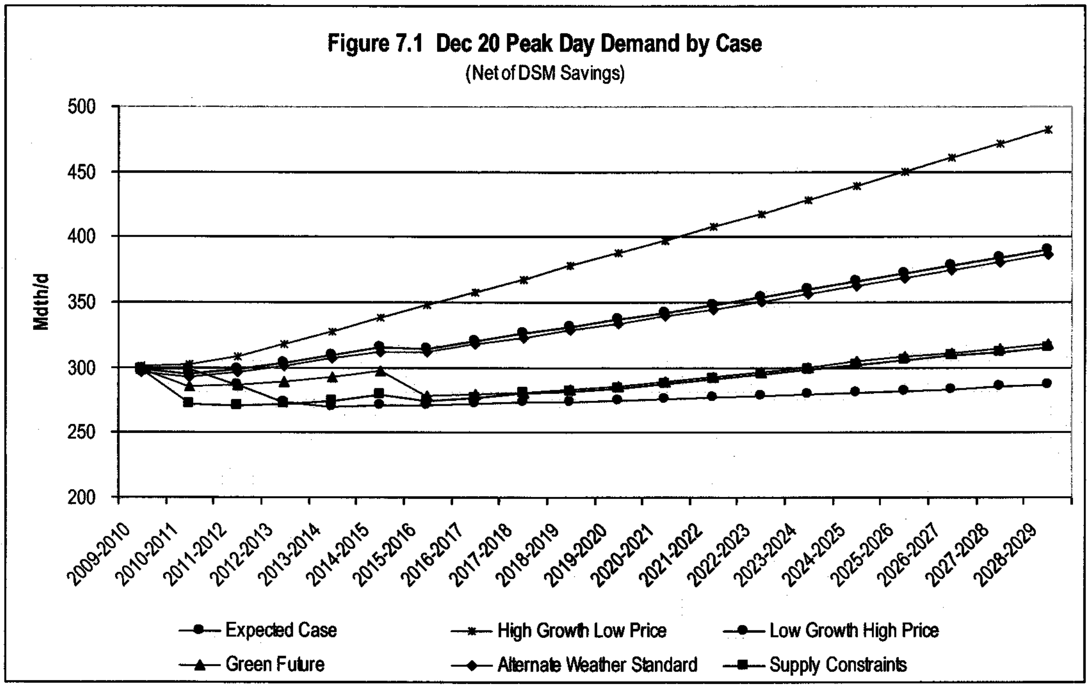
We also performed stochastic modeling for estimating probability distributions of potential outcomes by allowing for random variation in natural gas prices and weather based on fluctuations observed in historical data. This statistical analysis, in conjunction with our deterministic analysis, enabled us to statistically quantify the risk related to resource portfolios under varying price environments. We also developed weather probability distributions to complement our analysis of our weather planning standard.

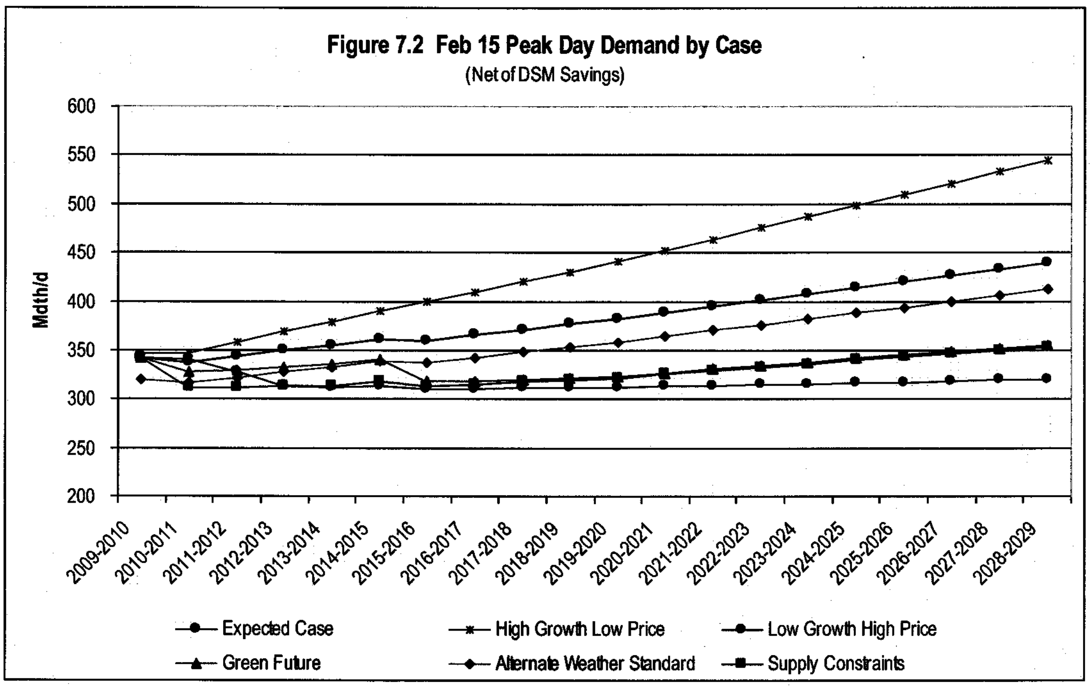
ALTERNATE DEMAND SCENARIOS

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

Table 7.1 Alternate Demand Scenarios
Expected Case
High Growth, Low Price
Low Growth, High Price
Green Future
Alternate Weather Standard
Supply Constraints

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

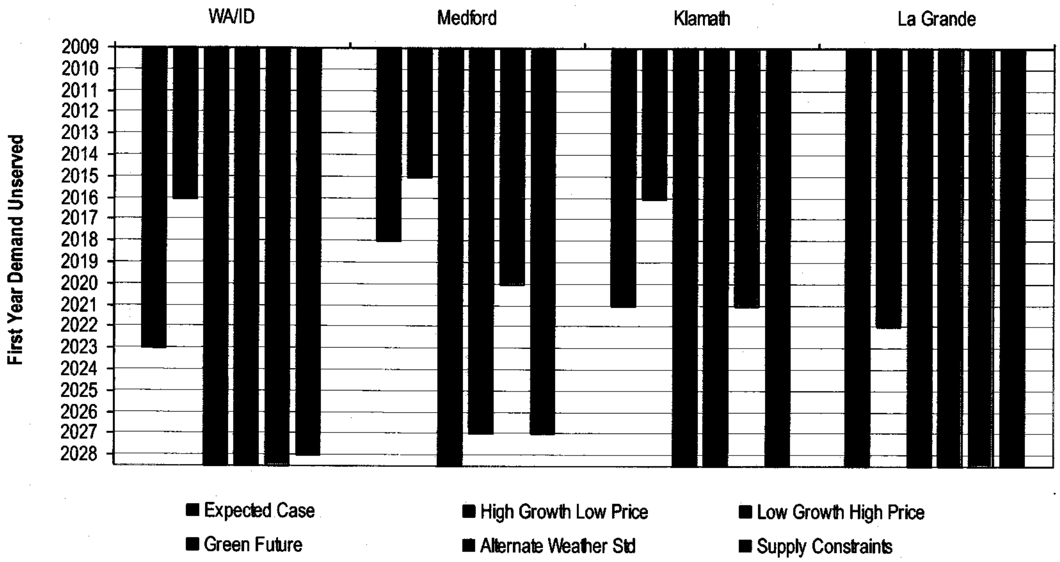




Noteworthy in these peak demand forecasts are two significant demand decline periods for most scenarios. The first occurs almost immediately followed by a second decline beginning in 2015. These declines are a direct result of customers reacting to steep increases in natural gas prices as modeled. The immediate period assumes that prices rise significantly from the current extremely low prices as the recession ebbs. We assume that customers respond to this price signal by consuming less. The price increase in 2015 is a result of significant carbon cost adders for climate change policy going into effect. Customers again react adversely to this sharp price movement, reducing their consumption in a second round.

As in the Expected Case, we modeled in SENDOUT® the same resource integration and optimization process described in this section for each of the other five demand scenarios (see Appendix 7.1 for a complete listing of all portfolios considered). This identified first year unserved dates for each scenario by service territory (Figure 7.3).

Figure 7.3 First Year Peak Demand Not Met with Existing Resources
Scenario Comparisons



As expected, our High Growth, Low Price scenario has the most rapid growth and the earliest first year unserved dates. Noteworthy is the significant acceleration of first year unserved dates that result from this higher growth scenario across all service territories:

- Washington/Idaho – seven years earlier (February 2016);
- Medford/Roseburg – three years earlier (December 2015);
- Klamath Falls – five years earlier (December 2016); and
- La Grande – at least six years earlier (February 2022).

This "steeper" demand exemplifies the "flat demand risk" discussed earlier. The potential for accelerated unserved dates warrants close monitoring of demand trends and resource lead times.

Several scenarios indicate no resource deficiencies over the planning horizon due to very slow or even negative demand growth. A key reason for this is the price elasticity assumptions combined with price forecasts with very steep price increases very early in the planning horizon. This "perfect storm" combination produces a significant curtailment in total demand early in the forecast. A key question for these scenarios is whether this early price shock materializes as forecasted and, if so, is demand really permanently curtailed as predicted in the price elastic response assumption. This condition also warrants close monitoring of actual results.

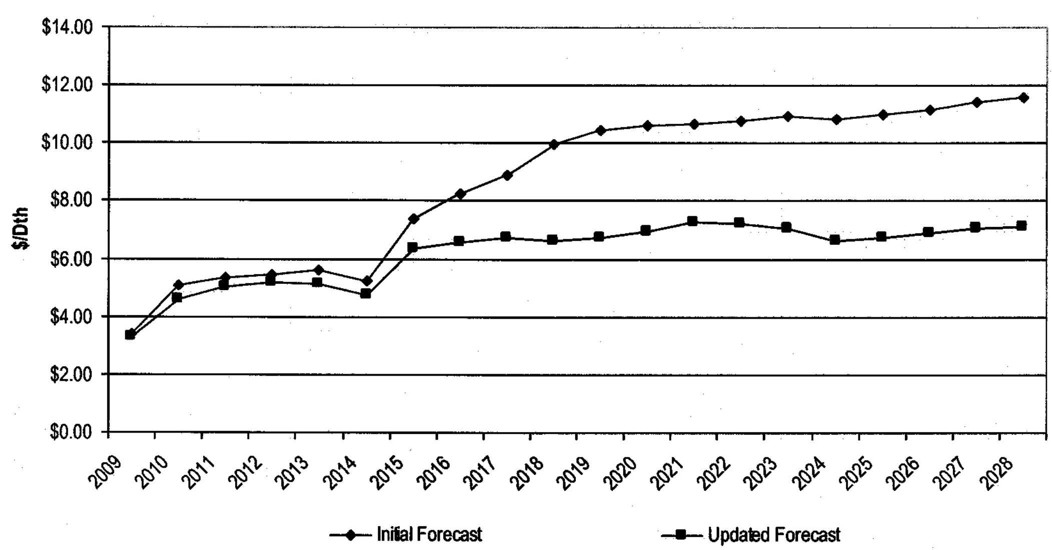
Analyses of alternative scenarios were extensive. Detailed information on certain selected scenarios is included in the following appendices:

- Demand and Selected Resources graphs by service territory (select cases only) – Appendix 7.2;
- Peak Day Demand, Served and Unserved table (all cases) – Appendix 7.3;
- Load Duration Curve graphs for High Growth and Low Growth cases – Appendix 7.4;
- Avoided cost curve detail and graphs for High Growth and Low Growth cases – Appendix 6.4.

UPDATED PRICE FORECASTS

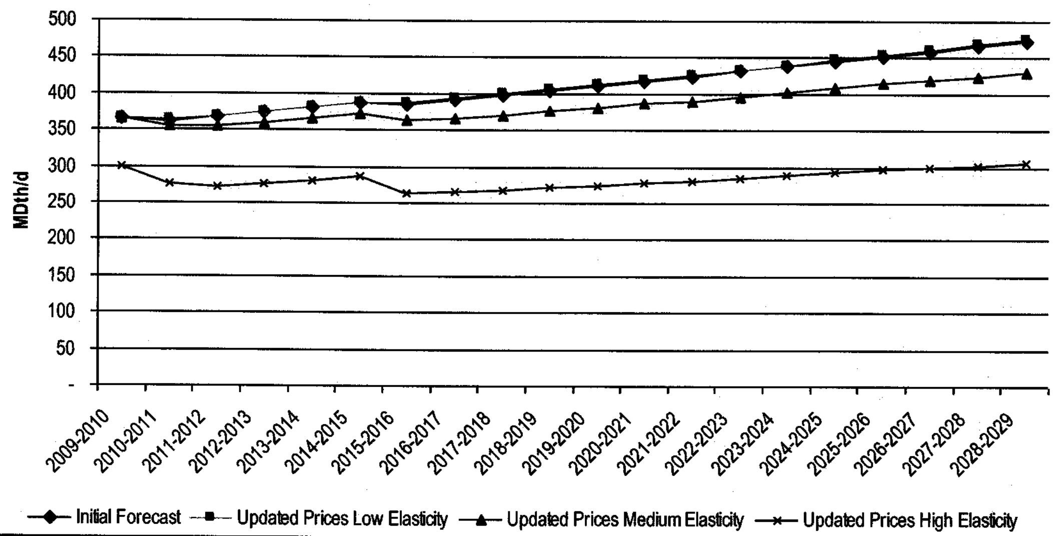
As discussed in Chapter 3 – Demand Forecasts, a dynamic forward market and several factors that influence fundamental price forecasts evolved quickly in the first half of 2009. We noted significant changes in forward prices and several updates to the forecasts we monitor, including the mid-range forecast we use in many of our scenarios. This prompted us to update our price forecasts in early August 2009. Timing restrictions to meet work plan and filing schedules precluded us from updating all of our prior analyses, limiting our price forecast updates to our Expected Case. A comparison of the initial price curve and the updated price curve is shown in Figure 7.4.

Figure 7.4 Price Curve Comparison
Initial vs. Updated Forecast (includes carbon adders) - Expected Case
2009$/Dth



After compiling updated prices, we ran three additional scenarios against our Expected Case assumptions reflecting low, medium and high price elasticity. The demand forecasts for these three new scenarios compared to the initial Expected Case scenario (with low price elasticity) is shown in Figure 7.5.

Figure 7.5 System Wide Peak Day Demand (Net of DSM Savings)
Initial vs. Updated Price Forecast Comparison - Expected Case



As anticipated, the Updated Prices, Low Elasticity scenario showed essentially unaffected demand from the changed price curve. Therefore, we determined there would be no change in the timing of unserved demand or resource selections made by SENDOUT®.

In the Updated Prices, High Elasticity scenario, the response to prices resulted in essentially flat demand over the planning horizon. SENDOUT® confirmed our expectation that no region goes resource deficient during the planning horizon.

In the Updated Prices, Medium Elasticity scenario, resource deficiencies did occur but several years later than under the initial Expected Case. The demand scenario was resource optimized in SENDOUT® for all jurisdictions which confirmed our expectation that the same resources would be selected but merely in the later year when the deficit occurred. In WA/ID the shortage was delayed beyond our planning horizon. Medford/Roseburg went resource deficient five years later than initially forecast to 2022. These results are shown in Figures 7.6 through 7.8.

Figure 7.6 WA/ID Existing Resources vs. Peak Day Demand
Expected Case with Medium Price Elasticity (Net of DSM Savings) November to October

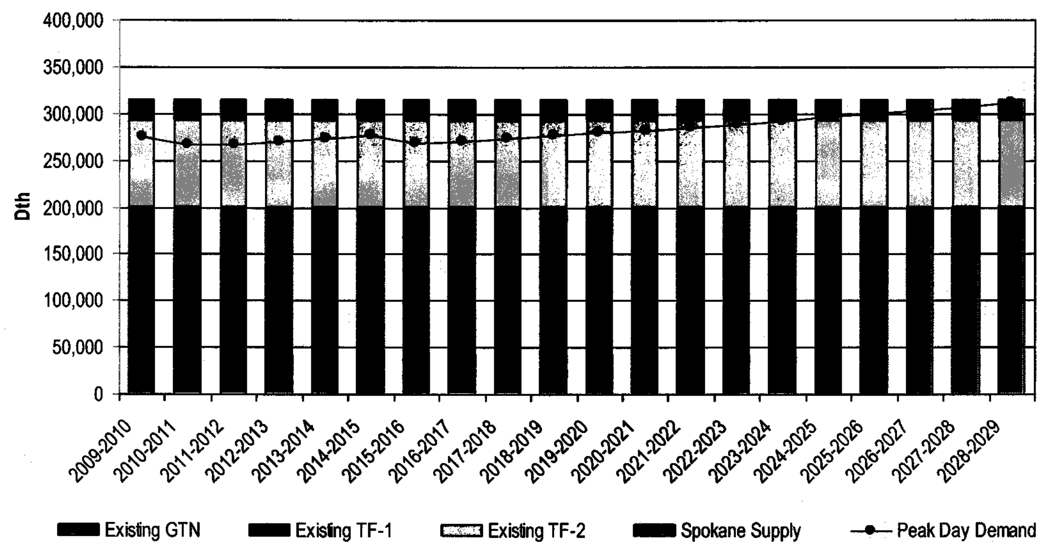
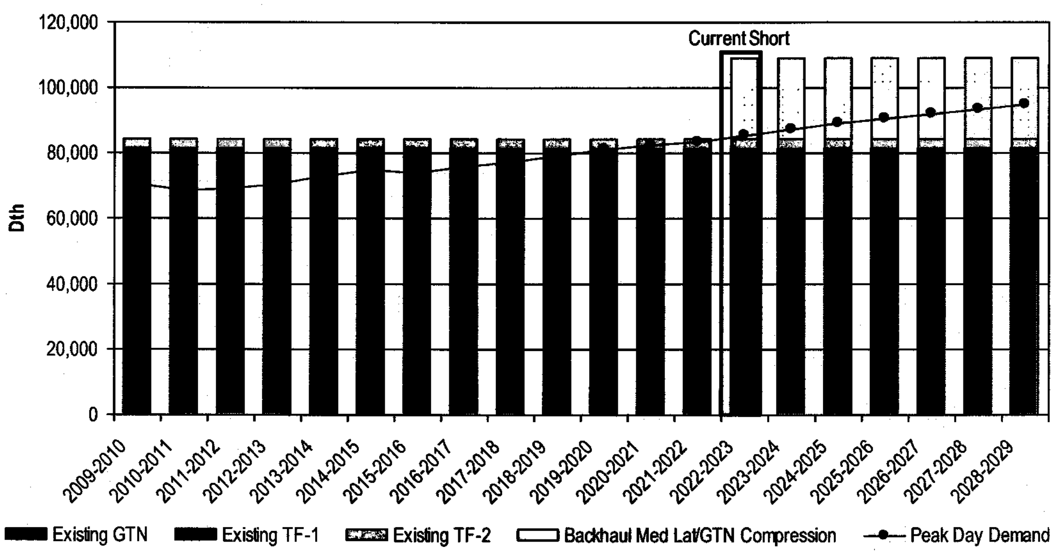
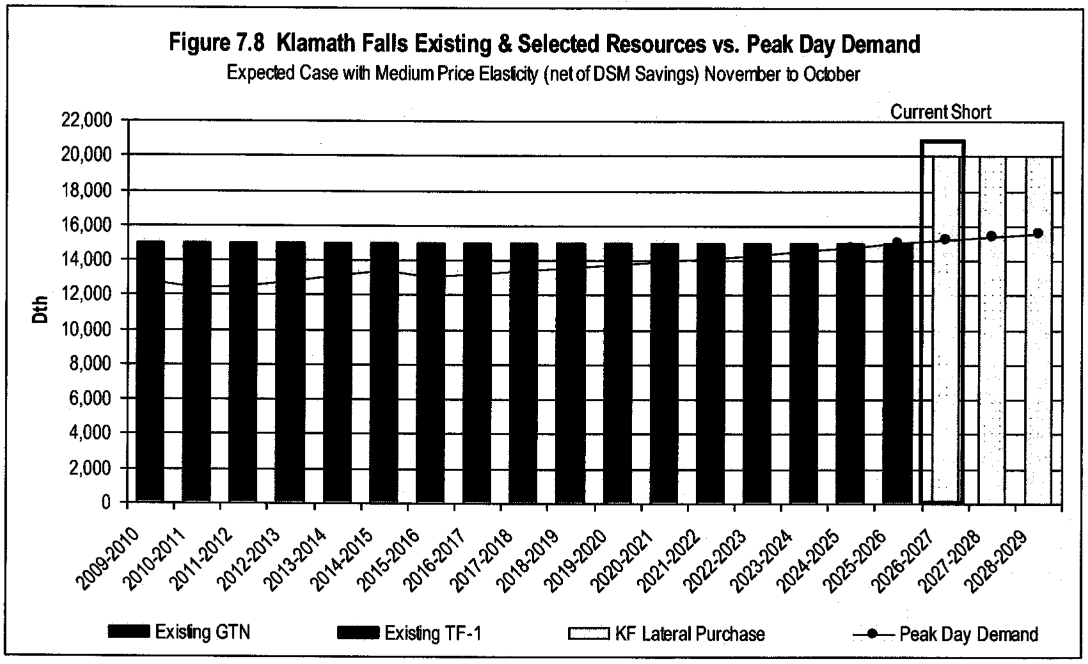


Figure 7.7 Medford/Roseburg Existing & Selected Resources vs. Peak Day Demand
Expected Case with Medium Price Elasticity (Net of DSM Savings) November to October





ALTERNATE SUPPLY SCENARIOS

The list of identified and available supply-side resource options at Appendix 6.3 is extensive and is meant to capture resource options we can reasonably count on if selected by SENDOUT® when running resource optimizations. The list includes other resources we considered but did not input into SENDOUT® because of various restrictions.

For example, contracted city gate deliveries in the form of a structured purchase transaction could be a viable and desirable option to meet super peak conditions. However, the market-based price and other terms are difficult to reliably determine until a formal agreement is negotiated. Exchange agreements also have market-based terms and are hard to reliably model especially when the resource is not needed in the near term.

Another example is Imported LNG. Model assumptions can be reasonably estimated for LNG import facilities but significant uncertainties outside of model assumptions preclude consideration of these resources as "firm" at this time. (See Appendix 5.2 for detailed information about supply-side scenarios.)

For our WA/ID and Medford/Roseburg service territories, unsubscribed firm capacity on GTN and/or backhaul plus lateral expansion is a preferred resource selection from our existing resources plus currently available supply scenario for most demand scenarios. However, assumptions on future availability could change over time. Therefore, we ran two additional alternate supply-side scenarios with changed assumptions on GTN capacity as per Table 7.2.

Table 7.2 Alternate Supply Scenarios
Existing Resources
Existing + Expected Available
GTN Rate Escalation
GTN Fully Subscribed

The first scenario we assumed significant decontracting occurs in the future which leads to much higher rates. The result of this scenario using our Expected Case demand profile is that, in Washington and Idaho, Satellite LNG is selected as the preferred resource portfolio. However, in Medford/Roseburg the model still favors the backhaul with and expansion of the Medford Lateral. (Figures detailing the resources selected based on this scenario are included in Appendix 7.2.)

The second scenario assumes GTN or the upstream pipelines are fully subscribed and therefore, capacity is not an available resource. This scenario resulted in satellite LNG for Washington and Idaho. However in Medford/Roseburg the model selected an expansion of the NWP mainline. Figures detailing the resources selected based on this scenario are included in Appendix 7.2)

PORTFOLIO SELECTION

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

In the Expected case, the Expected Demand with Existing Resources plus Expected Available portfolio has the lowest PVRR and was therefore selected as our preferred portfolio. In this portfolio, the supply-side resources selected to meet unserved demand include the acquisition of currently available pipeline capacity on GTN, additional compression on the GTN Medford Lateral and the purchase of the Klamath Falls lateral. These resources are the least cost/risk adjusted options available to meet peak day demand.

Table 7.3 summarizes the PVRR of all the portfolios considered. Each of these portfolios is based on unique assumptions and therefore a simple comparison of PVRR cannot be made. Detailed cost information on all portfolios can be found in Appendix 7.5.

Table 7.3 Net Present Value of Revenue Requirement (PVRR) by Portfolio

Portfolio		PVRR in (000's)
Expected Case		
Expected Demand with Existing Resources (before resource additions)	$	(6,514,895)
Expected Demand with Existing Resources plus Expected Available	$	(6,547,705)
Expected Demand with GTN Fully Subscribed	$	(6,593,845)
Expected Demand with GTN Rate Escalation	$	(7,440,510)
Additional Demand Scenarios		
Expected Demand with High Elasticity and Existing Resources	$	(5,856,847)
Expected Demand with Medium Elasticity and Existing Resources	$	(6,249,435)
Alternate Weather Standard Demand with Existing Resources	$	(7,997,147)
High Growth, Low Price Demand with Existing Resources	$	(7,691,204)
High Growth, Low Price Demand with Existing Resource plus Expected Available	$	(10,704,833)
Green Future with Exisiting Resources	$	(9,277,241)
Low Growth, High Price with Existing Resources	$	(10,814,967)
Supply Constraints with Existing Resources	$	(11,782,862)

STOCHASTIC ANALYSIS[1]

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

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

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

WEATHER

In order to evaluate weather and its effect on our portfolio, we derived 200 simulations (draws) through the use of SENDOUT®'s Monte Carlo capabilities. Unlike deterministic scenarios or sensitivities, the draws have more variability from month-to-month and year-to-year. In the model, random monthly total HDD draw values (subject to Monte Carlo parameters – see Table 7.4) are distributed on a daily basis for a month in history with similar HDD totals. The resulting draws provide a weather pattern with variability in the total HDD values, as well as variability in the shape of the weather pattern. This provides more robust basis for stress testing the deterministic analysis.

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

Table 7.4 Example of Monte Carlo Weather Inputs
Spokane

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

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

Figure 7.9 Frequency of Peak Day Occurrences
Spokane

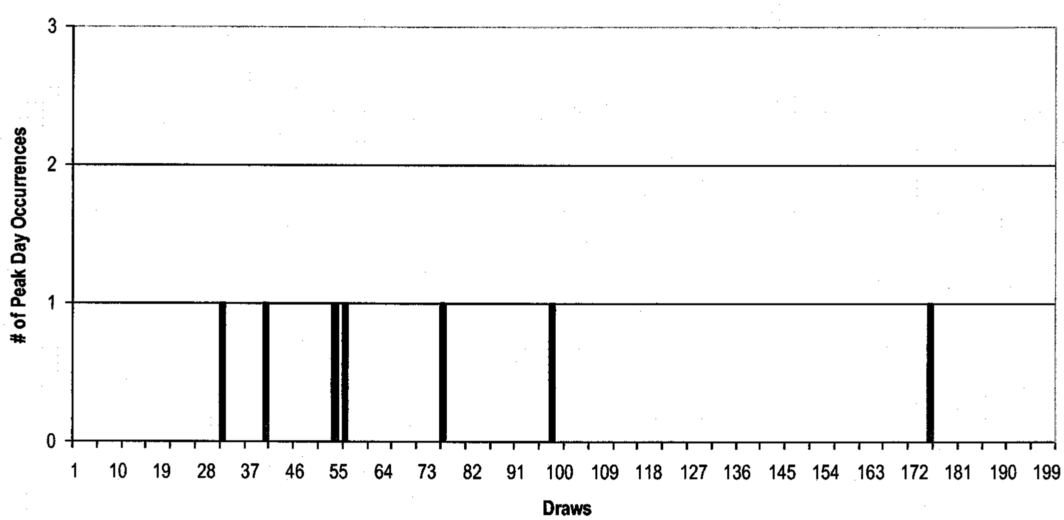


Figure 7.10 Frequency of Peak Day Occurrences
Medford

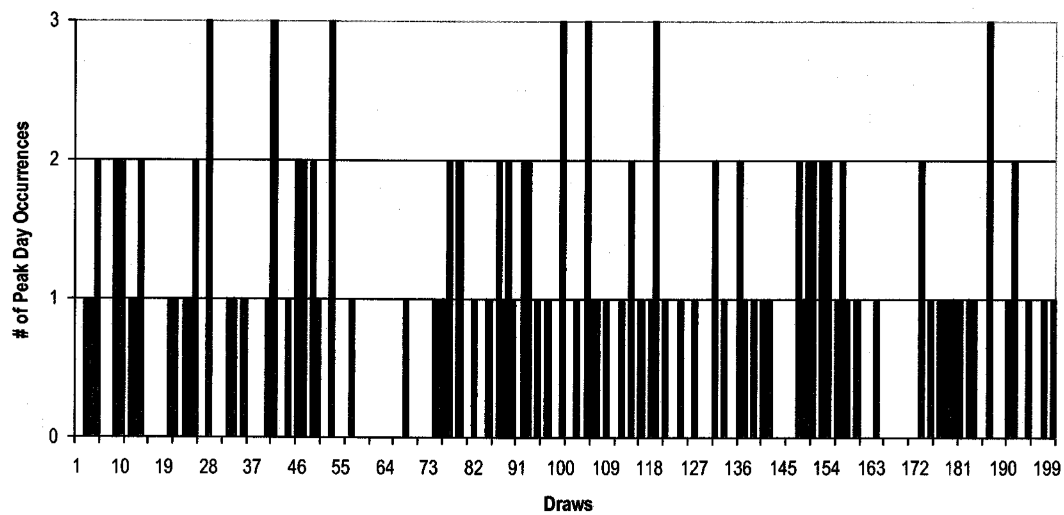


Figure 7.11 - Frequency of Peak Day Occurrences
Roseburg

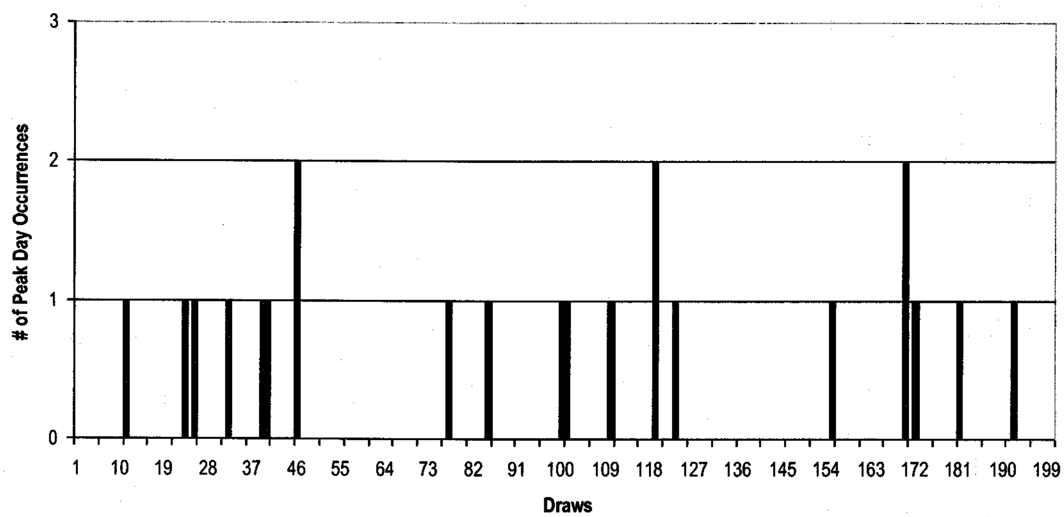


Figure 7.12 Frequency of Peak Day Occurrences
Klamath Falls

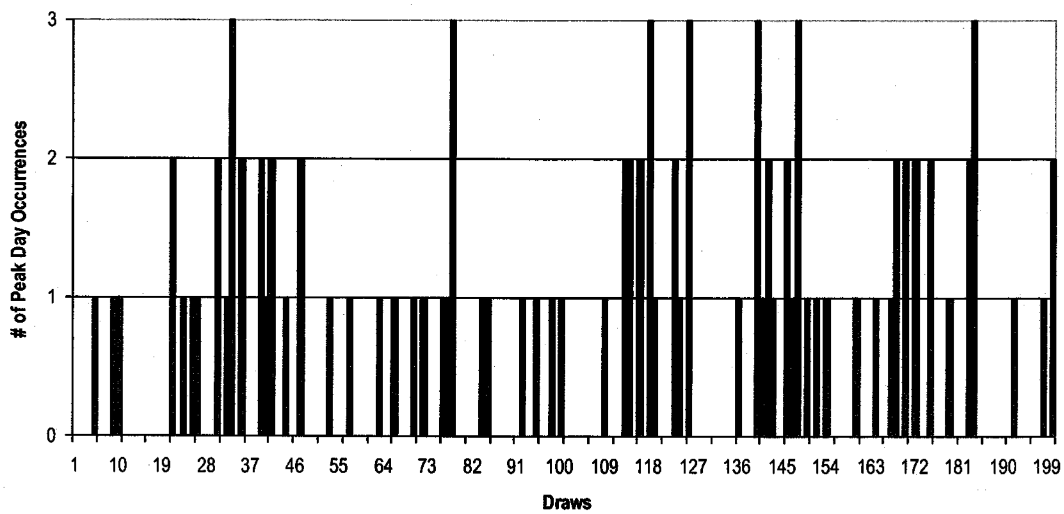
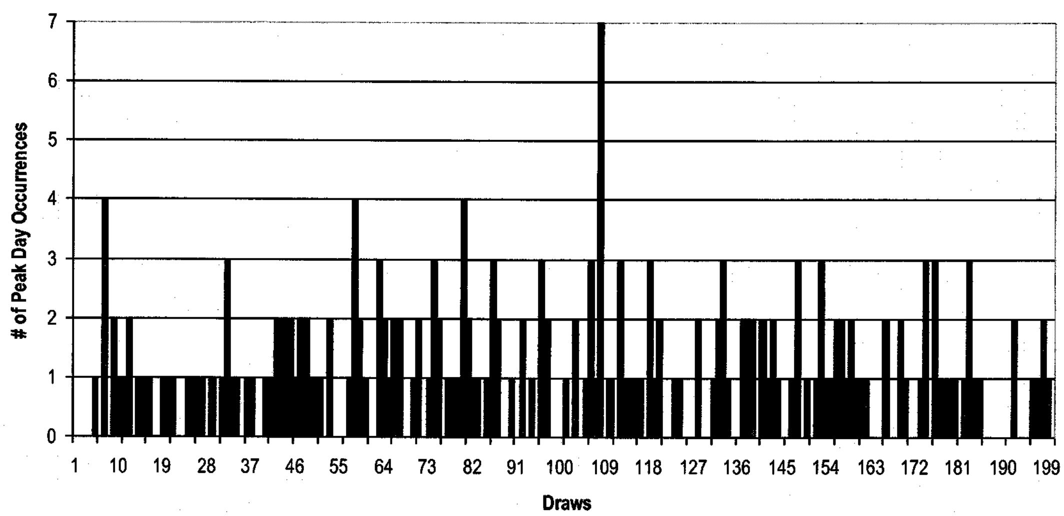


Figure 7.13 Frequency of Peak Day Occurrences
LaGrande

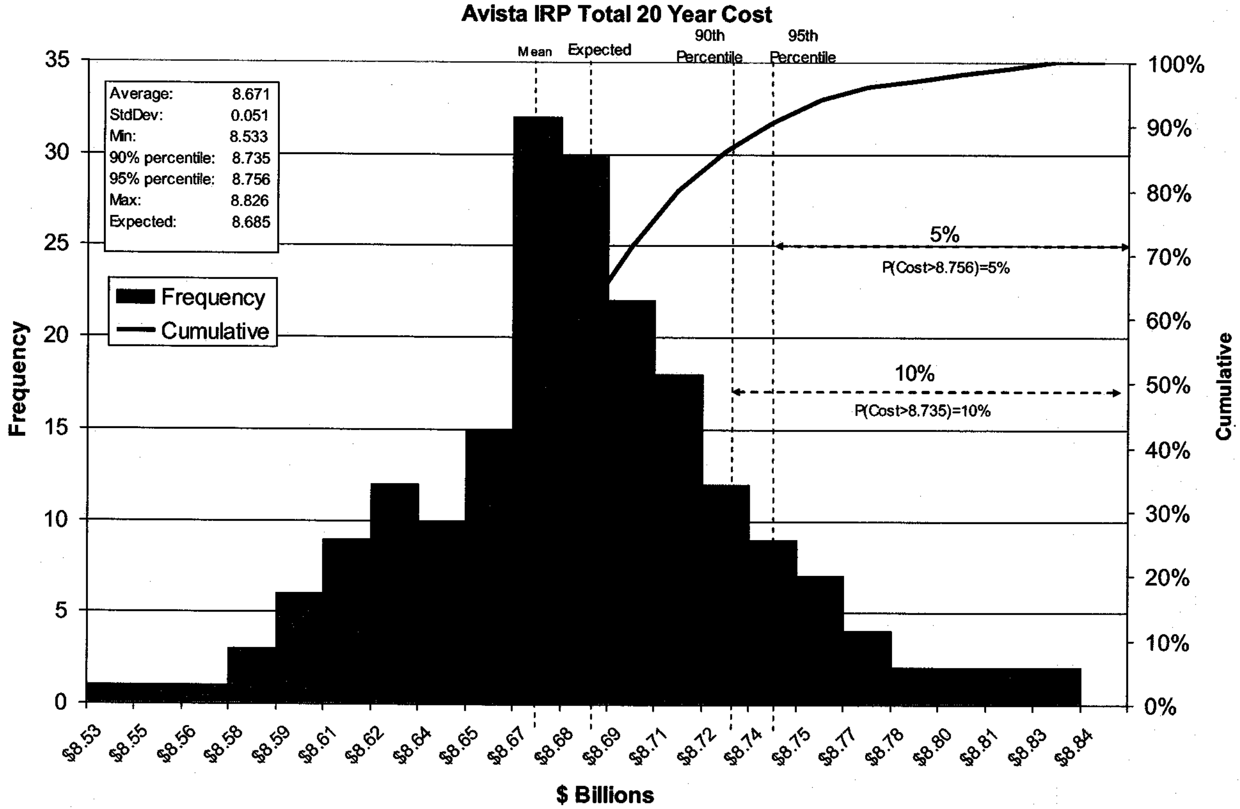


PRICE

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

Through Monte Carlo simulation, we are able to test our portfolio and quantify the risk to our customers when prices do not materialize as forecasted. We performed a simulation of 200 draws, varying prices, to investigate whether the Expected Case total portfolio costs from our deterministic analysis is within the range of occurrences in our stochastic analysis. Figure 7.14 shows a histogram of the total portfolio cost of all 200 draws, plus the Expected Case results. This histogram depicts the frequency and the total cost of the portfolio among all the draws, the mean of the draws, the standard deviation of the total costs, and the total costs from the Expected Case. The figure confirms that our Expected Case total portfolio cost is within an acceptable range of total portfolio costs based on 200 unique pricing scenarios. This provides us comfort that our Expected Case price curve and the resultant total portfolio cost is adequately statistically supported.

Figure 7.14
Avista IRP Total 20 Year Cost



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

REGULATORY REQUIREMENTS

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

- Examined a range of demand forecasts;

- Examined feasible means of meeting demand with both supply-side and demand-side resources;
- Treated supply-side and demand-side resources equally;
- Described our long-term plan for meeting expected demand growth;
- Described our plan for resource acquisitions between planning cycles;
- Taken planning uncertainties into consideration; and
- Involved the public in the planning process.

We have addressed the applicable requirements throughout this document. Appendix 2.1 lists the specific requirements and guidelines of each jurisdiction and describes our compliance in detail.

We are also required to consider risks and uncertainties throughout our planning and analysis. Our approach in addressing this requirement was to identify factors that could cause significant deviation from our Expected Case planning conclusions. We employed dynamic demand analytical methods and incorporated sensitivity analysis on various demand drivers that impacted demand forecast assumptions. From this, we created 15 demand sensitivities and modeled 6 demand scenario alternatives, which incorporated differing customer growth, use per customer, weather and price elasticity assumptions. We developed four supply scenarios to consider various risks of resource uncertainties. This resulted in 13 distinct portfolios analyzed within SENDOUT®.

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

We examined risk factors and uncertainties that could impact expectations and assumptions with respect to DSM programs and supply-side scenarios. From this, we developed four supply-side scenarios and included numerous DSM programs for evaluation.

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

CONCLUSION

Given the extreme increase and decrease in demand levels over the full planning horizon framed by the Low Growth and High Growth cases, we believe that we have modeled a sufficient range to capture all reasonably possible but less likely outcomes from our Expected Case.

Our portfolio and 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 the following:

- A total system supply portfolio should be maintained to provide the greatest flexibility for dispatching resources, while maintaining lower supply costs due to the diverse weather within our service territory.
- Long-term and short-term capacity releases and recalls should continue to be reviewed periodically.

We will continue to monitor demand levels and peak day requirements for signposts (e.g. greater than or less than expected customer growth or use per customer) that indicate demand levels are moving toward another case. 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.

CHAPTER 8 – DISTRIBUTION PLANNING

OVERVIEW

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

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

Avista's natural gas distribution system consists of approximately 3,400 miles of distribution main pipelines in Washington, 1,900 miles in Idaho and 2,300 miles in Oregon, as well as numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment. Currently, there are no storage facilities or compression systems within our distribution system. System pressure is maintained by pressure regulating stations that utilize pipeline pressures from the interstate transportation pipelines before natural gas enters our distribution networks.

DISTRIBUTION SYSTEM PLANNING

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

Ongoing evaluations of each distribution network in our four primary service territories are conducted to identify strategies for addressing local distribution requirements resulting from customer growth. Customer growth assessments are made based on many factors including our IRP demand forecasts[1], monitoring of gate station flows and other system metering, ongoing communication with construction staff and local area management regarding new service requests, field personnel discussion and inquiries from major developers.

[1] Distribution Planning forecasts customer growth rates by town code to generate local demand growth projections in its forecasting model consistent with the broader IRP customer forecasting methodology facilitating consistent integrated planning efforts. A town code is an unincorporated area within a county or a municipality within a county.

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

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

NETWORK DESIGN FUNDAMENTALS

Natural gas distribution networks rely on pressure differentials to flow gas from one place to another. When pressures are the same on both ends of a pipe, the gas does not move. When gas is removed from a point on the network, the pressure at that point drops lower than the pressure upstream in the network. Gas then moves from the higher pressure in the network to the point of removal, attempting to equalize the pressure throughout the network. If gas removed is not sufficiently replaced by new gas entering the network, the pressure differential will decrease and flow will stall and the network could run out of pressure. Therefore, it is important to design a distribution network so that the intake pressure (from gate stations and/or regulator stations) within the network is high enough to maintain an adequate pressure differential when gas leaves the network.

Not all gas flows equally throughout a network. Certain points within the network can constrain flow and thus restrict overall network capacity. Network constraints can occur over time as demand requirements on the network evolve. Anticipating these demand requirements, identifying potential constraints and forming cost effective solutions with sufficient lead times without overbuilding infrastructure are the key challenges in network design.

COMPUTER MODELING

Developing and maintaining effective network design is significantly aided by computer modeling to perform network demand studies. Demand studies have evolved with technology in the past decade to become a highly technical and powerful means for analyzing the 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 modeling solutions produced closely resemble actual system behavior.

Avista conducts network load studies using Advantica's SynerGEE® 4.3.0 software. This computer-based modeling tool runs on a Windows operating system and allows users to analyze and interpret solutions graphically. Appendix 8.1 describes in detail our computer modeling methodology while Appendix 8.2 provides an example load study presentation including graphical interface and output examples.

DETERMINING PEAK DEMAND

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

Core demand typically has a morning peaking period between 6 a.m. and 10 a.m. and an evening peaking period between 5 p.m. and 9 pm. The peak hour demand for these customers can be as much as 50% above the hourly average of the daily demand. Because of the importance of responding to hourly peaking in the distribution system, planning capacity requirements for our distribution systems are based on peak hour demand[2]. Included in Appendix 8.1 is the detailed methodology we use for determining peak demand.

DISTRIBUTION SYSTEM ENHANCEMENTS

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

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

PIPELINES

Pipeline solutions consist of looping, upsizing and uprating.

- Pipeline looping is the most common method of increasing capacity within an existing distribution system. It involves constructing new pipe parallel to an existing pipeline that has, or may become, a constraint point. Constraint points inhibit pressure capacities downstream of the constraint creating inadequate pressure during periods of high demand. When the parallel line is connected to the system, this second alternative path allows natural gas flow to bypass the original constraint point and bolster downstream pressure capacities. The feasibility of looping a pipeline is primarily dependant upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt, and steep or rocky terrain can greatly increase the cost to amounts that are unjustifiable so that other alternative solutions offer a more cost effective solution.

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

- Pipeline upsizing is simply replacing existing pipe with a larger size pipe. The increased pipe capacity relative to surface area of the pipe results in less friction and therefore a lower pressure drop. This option is usually pursued when there is damaged pipe or pipe integrity issues exist. If the existing pipe is otherwise in satisfactory condition, looping is usually pursued, allowing the existing pipe to remain in use.
- Pipeline uprating involves increasing the maximum allowable operating pressure of an existing pipeline. This enhancement can be a quick and relatively inexpensive method of increasing capacity in the existing distribution system before constructing more costly additional system facilities. However, safety considerations and pipe regulations may prohibit feasibility or lengthen the time before completion of this option. Also, increasing line pressure may produce leaks and other pipeline damage creating unanticipated costly repairs.

REGULATORS

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

COMPRESSION

Compressor stations present a capacity enhancing option for pipelines with significant gas flow and the ability to operate at higher pressures. For pipelines experiencing a relatively high and constant flow of gas, a single, large volume compressor can be installed in the optimal position along the pipeline to boost downstream pressure. However, this type of compressor configuration will not function effectively if the flow in the pipeline has high variability.

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

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

CONSERVATION RESOURCES

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

PLANNING RESULTS

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

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

3203 - East Medford Reinforcement – This project will install a high-pressure (HP) steel line from North Phoenix Road, ending in White City. The total length of the line will be about nine miles. The 2010 project will install approximately 3000 feet of HP main into an open right-of-way in conjunction with road reconstruction by third parties. The remainder of the project, approximately 14,000 feet will be completed in the future.

Observed local growth and our IRP indicate increased gas deliveries will likely be needed from the TransCanada Pipeline source at Phoenix Road Gate Station in southeast Medford. To facilitate distribution receipt of the increased gas volumes, a new HP gas line encircling Medford to the east and tying into an existing high-pressure feeder in White City will improve delivery capacity and provide a much needed reinforcement in the East Medford area which is forecasting higher growth.

3204 - Roseburg Reinforcement – This is a three-part project to bring HP gas into the central and east Roseburg areas. The first phase, completed in 2008, extended HP steel from an existing main located in south Roseburg to the downtown area. The second phase will extend HP pipe to the east side of Roseburg and install a regulator station. The final phase of the project will complete the main extension from south Roseburg to Winston where it will be connected to a new HP source.

The Roseburg distribution system is fed entirely from the west side of town where Northwest Pipeline is located. There is currently no HP source located on the east side of town. Current and projected growth is heavy on the east side of Roseburg, causing pressure problems in the winter months. This project will ease this problem and position the system for future growth.

The scope of this project was modified in 2008. Due to excessive construction costs to complete the previously proposed second phase of the project, an alternate temporary solution was implemented. The sequence for completing the final two phases of the project was changed to fully utilize the 2008 temporary system enhancement while completing the necessary reinforcement for the east side of Roseburg.

3237 – U.S. 2 North Spokane Reinforcement – This project will reinforce the area north of Spokane along U.S. Highway 2. This mixed-use area with residential, commercial and industrial demand experiences low pressure at unpredictable times given varied demand profiles of the diverse customer base. Completion of this reinforcement will improve pressures in the U.S. 2 north Kaiser area. Approximately 8,000 feet of HP steel will be installed in a newly established easement along U.S. Highway 2.

3240 – Grants Pass Reinforcement – This project will extend approximately two miles of HP main from near the existing Jones Creek Gate Station to the downtown Grants Pass area. This project will provide two benefits to our customers. First, it will provide for necessary additional delivery volumes into Grants Pass. Grants Pass high-pressure gas delivery is constrained by the size of the existing distribution main. Secondly, the project will replace a section of HP main that has a number of identified high-consequence areas (HCAs) that must be mitigated under the PHMSA Integrity Management Regulation.

Contingencies include extension of other HP sources into Grants Pass. The identified solution is currently the low cost alternative based on length of pipe installed. Installation of new main as identified allows for a pressure reduction in the existing portion of the HP transmission main into Grants Pass. Installation of the new main avoids integrity management mitigation costs and reduces the consequences and risks associated with a pipeline incident.

3269 – Clarkston Reinforcement – This project will reinforce the southwest area of Clarkston. The existing HP feeder serving the Clarkston Heights area is capacity constrained on a peak day. Reinforcement is required to reliably serve the area. The project will include the installation of 14,400 feet of HP steel main from the existing source in Clarkston to Critchfield Road.

Table 8.1 Distribution Planning Capital Projects

Ref #	TITLE	Sate	Project Type	2010	2011	2012	2013	Beyond 2013	Total
				Estimated Budget and Timing					
3112	Re-Route Kettle Falls Feed & Gate Station	WA	compliance			1,800,000	2,760,000		4,560,000
3245	Cheney HP Feeder Project	WA	reinforcement				3,600,000		3,600,000
* 3269	Clarkston Reinforcement	WA	reinforcement	2,000,000					2,000,000
* 3237	US2 N Spokane Reinforcement	WA	reinforcement	1,200,000					1,200,000
3102	N-S Freeway/Gas	WA	road requiremnt	50,000	100,000	100,000	100,000	100,000	450,000
3107	Bridging the Valley	WA	road requiremnt	50,000	100,000	100,000	100,000	100,000	450,000
3268	Reinforcement - Appleway Bridge Crossing	WA	reinforcement	275,000					275,000
3273	Relocation, Stevenson Bridge Bore	WA	enhancement				250,000		250,000
3260	Reinforcement, Install casing and pipe on Bridge Spokane	WA	reinforcement	100,000					100,000
3274	Reinforcement, Loop existing HP from Tolo to White City	OR	reinforcement					6,615,000	6,615,000
* 3204	Roseburg Reinforcement	OR	reinforcement		1,934,000	3,347,000			5,281,000
* 3203	East Medford Reinforcement	OR	reinforcement	600,000				4,100,000	4,700,000
3242	Reinforce Talent OR Gate Station & Piping	OR	reinforcement					3,600,000	3,600,000
* 3240	Grants Pass Reinforcement	OR	reinforcement	2,000,000					2,000,000
3277	IMP Pipe Replacements Medford	OR	compliance		1,500,000				1,500,000
3209	Elgin Line Reinforcement	OR	reinforcement					1,500,000	1,500,000
3267	Rebuild - Jackie St/Winston Gate Station, Roseburg	OR	reinforcement	1,000,000					1,000,000
TBD	Relocation - N Ross Ln. (2010 Road Project), Medford	OR	road requiremnt	200,000					200,000
3257	Oakland Bridge Bore and Relocation, Oakland	OR	compliance	180,000					180,000
3227	Tri-City Hwy 99 Road Project, Roseburg	OR	road requiremnt	150,000					150,000
3261	Brown Bridge Relocation, Roseburg	OR	road requiremnt	136,000					136,000
3258	Relocation, Davis Creek, Roseburg	OR	compliance	125,000					125,000
3213	Altamont & Crosby Road Project, K Falls	OR	road requiremnt	100,000					100,000
3278	Relocation - Reg Station, Medford	OR	compliance			100,000			100,000
3276	Reinforcement, Wolf Lodge Tap, Coeur d'Alene	ID	reinforcement					2,700,000	2,700,000
3246	Chase Rd Gate Station, Post Falls	ID	reinforcement		2,100,000				2,100,000
3270	Reinforcement - Southeast Coeur d'Alene	ID	reinforcement	255,000	285,000	245,000	450,000		1,235,000
TBD	Reinforcement - Spirit lake Main, Athol	ID	reinforcement			1,000,000			1,000,000
3275	Upgrade - Coeur d'Alene East Tap, Coeur d'Alene	ID	reinforcement				700,000		700,000
3279	Reinforcement - Main Extension south from CDA East Gate	ID	reinforcement			450,000			450,000
TBD	Reinforcement - Pack Saddle Area, CDA ID	ID	reinforcement	170,000					170,000
3271	Rebuild - Reg Station, Sandpoint ID	ID	reliability	150,000					150,000
	* Details of project described in IRP			8,741,000	6,019,000	7,142,000	7,960,000	18,715,000	48,577,000

CONCLUSION

Avista'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 cost effective gas delivery is also enhanced through the recent integration of customer growth forecasting at the town code level and localized distribution planning enabling coordinated targeting of distribution projects that are responsive to detailed customer growth patterns.

CHAPTER 9 – ACTION PLAN

2008-2009 ACTION PLAN REVIEW

The 2008-2009 Action Plan focused on the following areas:

- Integrated Resource Portfolio
- Demand Forecasting
- Demand-Side Management
- Supply-Side Resources

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

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 is 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 steps,
- Assess the impacts of project timing from possible changes in our weather planning standard.

Results:

The economic downturn and resultant weak demand delayed the projected unserved demand in all of our service territory regions.

Klamath Falls – In 2008, we performed an internal assessment of our standing option to purchase the Klamath Falls lateral from NWP. This agreement requires relocation of maximum daily quantities from Klamath Falls to another point (or points) on NWP's system to maintain our total contract demand. We explored numerous possible areas that might benefit from increased capacity. None are currently constrained and our current assessment does not indicate a resource need in the near term. We also explored the potential for new large demand customers with our marketing team which indicated limited near-term prospects, especially in light of the current economic environment. Although purchasing the lateral benefits our Oregon customers, the lack of actual, anticipated or prospective need for additional capacity that could fulfill the maximum daily quantities relocation requirement (either within the Klamath Falls service territory or elsewhere on the NWP system) restricts the purchase of the lateral at this time.

Medford – Demand trends for Medford have tracked to the low end of our IRP forecasts for some time. We, therefore, have deferred incurring the cost of a formal pipeline expansion study given sufficient time exists to monitor actual demand trends which we have updated in our 2009 IRP.

Action Item:

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

Results:

In re-evaluating our weather standard we performed the following analyses:

- Sensitivities around one and two HDD weather adjustments
- Monte Carlo simulations to analyze probabilities of encountering peak weather
- Applied confidence levels to review upper-limit exposure in conjunction with the regressions performed during our gate station demand and resources work, as well as use per customer coefficient development
- Examined important qualitative factors around safety and reliability

While other planning assumptions allow for continuous monitoring for reasonableness and corrective adjustments over time, peak day weather can occur with no warning which severely limits any response adjustments. Significant safety risk, property damage and inconvenience can occur if actual weather exceeds our peak day weather planning standard. Because there have been limited recent extreme cold weather events, more uncertainty and potential error exists in predicting cold weather usage. The recent actual data we do have on very cold weather events indicate instances when demand has been higher than the projected usage from our regression analysis. Because of these factors, we are maintaining our current "coldest day on record" planning standard for our Expected Case.

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.

Results:

We have met with Commission Staff several times since our last acknowledged IRP to provide information on market activities, risk management programs, the IRP and procurement practices. Schedules permitting, we attempt to meet on a quarterly basis.

DEMAND FORECASTING

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.

Results:

VectorGas™ (now incorporated into SENDOUT®) has provided statistically-based analysis in support of our peak day weather standard evaluation. We developed statistical modeling and analysis of potential price outcomes and the impacts on total portfolio cost and alternate resource selections. Looking forward for the next IRP, we are also exploring potential applications for simulating probabilistic weather outcomes in a possible global warming scenario. We continue to review other applications to employ the VectorGas™ analytical tool in our 2011 IRP.

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.

Results:

Town code forecasting continues to be an effective method for developing and monitoring expectations for customer growth rates providing benefits beyond the IRP, including corporate budgeting and distribution planning. The use per customer coefficient is the other key driver in determining forecasted demand in SENDOUT®. We have explored several potential methods for developing sub-regional use per customer coefficients that enhance predicting reasonable expectations of forecasted demand while reconciling tightly back to actual results with backcasting.

We use linear regression on daily observable temperature/demand data to produce coefficients. Allocations of monthly customer demand by class are applied to our gate station data as necessary, given few customers have daily metering. Our attempts to build daily town code level coefficients by customer class from allocations of monthly town code level data have not produced satisfactory results. It appears that billing period and cutoff issues are magnified when constructing coefficients with smaller customer groupings. Consequently, unacceptable distortions arise in backcasting to actual demand.

We have been more successful in refining our coefficient development into monthly factors from broader regional data. Using more data points, this method provides improved capturing of the seasonal consumption profile. The regressions on the coldest data points from this method were also used in our reassessment and analysis of our peak day weather standard. Because of the superior backcasting that regional coefficients provide, we will forego sub-regional/town code level use per customer coefficient development at this time.

DEMAND-SIDE MANAGEMENT

Action Item:

The IRP analysis has indicated a set of cost effective measures and achievable resource potential for a future DSM portfolio. We established targets for first-year energy savings goals for 2008 of 1,425,000 therms in Washington/Idaho and 350,000 therms in Oregon. In 2009 the goals for first-year energy savings are 1,581,000 therms in Washington/Idaho 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.

Results:

Washington/Idaho DSM energy savings achieved in 2008 totaled 1,888,061 therms, reflecting an increase over our initial 2007 IRP goal. Oregon DSM energy savings achieved in 2008 totaled 287,476 therms, a shortfall from our 2008 goal of 350,000 therms. Additional detail around actual-to-goal results is discussed in Appendix 4.1.

Action Item:

We will file our cost effectiveness limits 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.

Results:

Cost effectiveness limits were filed on June 9, 2008 with an effective date of July 1, 2008.

We reviewed the value components of our electric avoided costs to determine if conceptually there was applicability to our natural gas customers. We have initiated analysis to assess the potential value that our customers place on the value of reduced volatility. This work continues. Regarding quantifying the value customers ascribe to reduced distribution capacity and greenhouse gas emissions, we concluded quantifications were not reliably determinable.

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
- Large scale LNG activity

Results:

Through our various information sources (retainer services, industry publications, seminars, and conversations with industry participants) we monitor ongoing developments on the above items. The following are brief summaries of our current assessments:

Tight production/productive capacity – The economic downturn has dramatically reversed this previously very tight situation, producing significant excess capacity. Massive rig count reduction in response to demand destruction has significant potential to overshoot when demand stabilizes, triggering a return to very tight conditions, prompting spikes in prices and volatility.

Pipeline constraints in our region – Several regional pipeline projects were proposed in early 2008. We monitor their progress and assess how they may fit into our resource strategy. We currently have non-binding participation agreements on some of these projects.

Pipeline expansions that move volumes away from our region – Rockies Express eastward expansion has experienced some delays but will ultimately facilitate more Rockies production to reach East Coast markets.

Pipeline cost escalations – Much lower steel commodity prices and delayed/cancelled projects appear to have reversed the cost-escalation trend in the near term.

Large scale LNG activity – Regional proposed projects continue to be challenged by regional market prices that trade at a discount to other potential markets for LNG as well as complex environmental issues.

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.

Results:

Given likely deferred resource needs, we have deferred any expenditure for formal cost and project feasibility studies. We have collected information from publicly available sources and informal inquiries. We also have gained insights on expansion rates/costs/timelines from our non-binding participation in various proposed interstate pipeline projects. This information provides useful proxies for project costs for use in resource modeling.

Although the easing of regional demand correspondingly eases the urgency for needle peaking solutions in the near term, we continue to evaluate the region's participants and their resources for possible transactions. We have engaged in discussions with a neighboring utility regarding a potential mutual assistance agreement around transport assets with dialogue continuing. We also receive and solicit information on various structured product transactions.

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.

Results:

We periodically see solicitations for storage leasing. We evaluate the project economics and consider our resource needs. In some cases, we have placed bids; however, our bids have not been selected. We have entered into a month-to-month storage agreement at Clay Basin for interruptible service which facilitates daily/short-term demand balancing for scheduling. Finally, we continue to engage in intra-seasonal optimization tractions as market pricing conditions warrant to capture value for our customers.

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.

Results:

Our annual procurement plan development process undertaken each fall provides a comprehensive assessment of existing and potential new procurement practices and strategies. The result is a targeted but flexible procurement plan that serves as a base to evaluate changing conditions throughout the year and modify strategy and actions as necessary.

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.

Results:

We utilize multiple information sources to monitor and track developments on declining Canadian exports including our retainer services, industry news subscriptions, seminars and market pricing behavior. Historical information from the Energy Information Administration indicates a rebound in export volumes in recent months following a decade low volume in June 2008. Lower oil sands production in the face of sharp oil price declines is likely a significant factor in this near-term trend reversal. Longer term, we see the oil/gas price relationship as a primary driver of Canadian domestic natural gas demand and correspondingly, export volumes. Significant unconventional gas discoveries in British Columbia have both the potential to reverse export declines with prolific potential production or accelerate export declines if these volumes are diverted to oil sands extraction in a high oil price environment.

In our 2009 IRP, we included sensitivity analysis on estimated price implications resulting from a more severe decline in Canadian exports than included in our base price forecasts. We then included a price adder in alternate demand scenarios. Additional detail is contained in Chapter 3 and Appendices 3.6 and 3.7.

2010-2011 ACTION PLAN

Key components for our 2010-2011 Action Plan include:

Action Item:

Monitor actual demand closely for indications of faster growth exceeding our forecasted growth to respond aggressively to address potential accelerated resource deficiencies arising from our exposure to "flat demand" risk. This includes researching and refining 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.

Action Item:

Analyze actual use per customer data and DSM program results for indications of price elasticity response trends that may have been influenced by evolving economic conditions. Investigate contemporary analytical sources for information on natural gas price elasticity. Explore persuading the AGA to update their analytical work and/or consider hiring a third party price elasticity study including assessing interest of other utilities in pursuing a regional project.

Action Item:

Continue our pursuit of cost effective demand-side solutions to reduce demand. In Washington and Idaho, conservation measures are targeted to reduce demand by approximately 2,193,000 therms in the first year. In Oregon conservation measures are targeted to reduce demand by approximately 303,000 therms in the first year. These goals represent increases of 54 percent in Washington and Idaho and 1 percent in Oregon from our prior 2007 IRP.

Action Item:

Research and engage a conservation consultant to perform an updated assessment of conservation technical and achievable potential in our service territories prior to the next IRP.

Action Item:

As much of our supply comes from Canadian natural gas exports, the notion that this supply could diminish significantly remains a 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.

Action Item:

We believe our forecasting methodology is sound, cost effective and adequate but will explore and evaluate alternative and additional forecasting methodologies for potential inclusion in our next IRP. Methodologies to be evaluated include statistical, non-statistical, quantitative, qualitative and terrain overview approaches.

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.

CHAPTER 10 – GLOSSARY OF TERMS AND ACRONYMS

Achievable Potential
Represents a realistic assessment of expected energy savings recognizing and accounting for economic and other constraints that preclude full installation of every identified conservation measure.

Annual Measures
Conservation measures that achieve generally uniform year round energy savings independent of weather temperature changes. Annual measures are also often called base load measures.

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

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

Base Load
As applied to natural gas, a given demand for natural gas that remains fairly constant over a period of time, usually not temperature sensitive.

Base Load Measures
Conservation measures that achieve generally uniform year round energy savings independent of weather temperature changes. Base load measures are also often called annual measures.

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

British Thermal Unit (BTU)
The amount of heat required to raise the temperature of one pound of pure water one degree Fahrenheit under stated conditions of pressure and temperature; a therm (see below) of natural gas has an energy value of 100,000 BTUs and is approximately equivalent to 100 cubic feet of natural gas.

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

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

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

Contract Demand (CD)

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

Core Load

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

Cost Effectiveness

The determination of whether the present value of the therm savings for any given conservation measure is greater than the cost to achieve the savings.

CPI

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

Cubic Foot (cf)

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

Curtailment

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

Dekatherm

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

Demand-Side Management (DSM)

The activity pursued by an energy utility to influence its customers to reduce their energy consumption or change their patterns of energy use away from peak consumption periods.

Demand-Side Resources

Energy resources obtained through assisting customers to reduce their "demand" or use of natural gas. Also represents the aggregate energy savings attained from installation of conservation measures.

Dth

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

External Energy Efficiency Board

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

Externalities

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

Federal Energy Regulatory Commission (FERC)
The government agency charged with the regulation and oversight of interstate natural gas pipelines, wholesale electric rates and hydroelectric licensing; the FERC regulates the interstate pipelines with which Avista does business and determines rates charged in interstate transactions.

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

Force Majeure
An unexpected event or occurrence not within the control of the parties to a contract, which alters the application of the terms of a contract; sometimes referred to as "an act of God;" examples include severe weather, war, strikes, pipeline failure and other similar events.

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

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

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

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

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

Interruptible Service
A service of lower priority than firm service offered to customers under schedules or contracts that anticipate and permit interruptions on short notice; the interruption happens when the demand of all firm customers exceeds the capability of the system to continue deliveries to all of those customers.

IPUC
Idaho Public Utilities Commission

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

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

Liquefaction
Any process in which natural gas is converted from the gaseous to the liquid state; for natural gas, this process is accomplished through lowering the temperature of the natural gas (see LNG).

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

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

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

Load Factor
The average load of a customer, a group of customers, or an entire system, divided by the maximum load; can be calculated over any time period.

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

Looping
The construction of a second pipeline parallel to an existing pipeline over the whole or any part of its length, thus increasing the capacity of that section of the system.

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

MDQ
Maximum Daily Quantity.

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

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

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

Natural Gas
A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geologic formations beneath the earth's surface, often in association with petroleum; the principal constituent is methane, and it is lighter than air.

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

Nominal
Discounting method that includes inflation.

Nomination
The scheduling of daily natural gas requirements.

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

Non-Firm Open Market Supplies
Natural gas purchased via short-term purchase arrangements; may be used to supplement firm contracts during times of high demand or to displace other volumes when it is cost-effective to do so; also referred to as spot market supplies.

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

NOVA Gas Transmission (NOVA)
See TransCanada Alberta System

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

OPUC
Public Utility Commission of Oregon

Peak Day
The greatest total natural gas demand forecasted in a 24-hour period used as a basis for planning peak capacity requirements.

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

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

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

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

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

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

Real
Discounting method that excludes inflation.

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

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

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

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

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

Spot Market Gas
Natural gas purchased under short-term agreements as available on the open market; prices are set by market pressure of supply and demand.

Storage
The utilization of facilities for storing natural gas which has been transferred from its original location for the purposes of serving peak loads, load balancing and the optimization of basis differentials; the facilities are usually natural geological reservoirs such as depleted oil or natural gas fields or water-bearing sands sealed on the top by an impermeable cap rock; the facilities may be man-made or natural caverns. LNG storage facilities generally utilize above ground insulated tanks.

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

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

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

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

Technical Potential
An estimate of all energy savings that could theoretically be accomplished if every customer that could potentially install a conservation measure did so without consideration of market barriers such as cost and customer awareness.

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

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

TransCanada Alberta System
Previously known as NOVA Gas Transmission; a natural gas gathering and transmission corporation in Alberta that delivers natural gas into the TransCanada BC System pipeline at the Alberta/British Columbia border; one of six natural gas pipelines Avista transacts with directly.

TransCanada BC System
Previously known as Alberta Natural Gas; a natural gas transmission corporation of British Columbia that delivers natural gas between the TransCanada-Alberta System and GTN pipelines that runs from the Alberta/British Columbia border to the United States border; one of six natural gas pipelines Avista transacts with directly.

Transportation Gas
Natural gas purchased either directly from the producer or through a broker and is used for either system supply or for specific end-use customers, depending on the transportation arrangements; NWP and GTN transportation may be firm or interruptible.

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

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

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

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

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

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

Withdrawal
The process of removing natural gas from a storage facility, making it available for delivery into the connected pipelines; vaporization is necessary to make withdrawals from an LNG plant.

WUTC
Washington Utilities and Transportation Commission.