AVISTA®
Corp.

2003 NATURAL GAS INTEGRATED RESOURCE PLAN

AVISTA® Corp.

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EXECUTIVE SUMMARY

THE COMPANY

Avista Utilities is a division of Avista Corp., a diversified energy company with utility and subsidiary operations located throughout North America. Avista Corp. also operates Avista Capital, which owns all the company's non-regulated energy and non-energy businesses. Avista Capital companies include Avista Energy, Avista Energy Canada, Ltd., and Avista Advantage. Avista Corp.'s portfolio of businesses focuses on creating and delivering energy and information to homes and businesses throughout the United States and Canada.

Avista Utilities has two geographic operating divisions: Avista Utilities North serves natural gas and electricity in eastern Washington and northern Idaho, and Avista Utilities South serves natural gas in Oregon and California. Avista Corp.'s stock is traded under the ticker symbol "AVA". For more information about Avista Corp. and its affiliate businesses, visit the corporate website at www.avistacorp.com.

Avista Utilities and the Region It Serves

North Operating Division

The North operating division of Avista Utilities covers about 26,000 square miles, primarily in eastern Washington and northern Idaho, with its headquarters in Spokane, Washington. This division supplies approximately 320,000 customers with electric service and more than 188,000 customers with natural gas. The estimated population in the Washington/Idaho service area is more than 700,000. The service territory includes urban areas and highly productive farm and timberlands, as well as the Coeur d'Alene mining district. Over the last 20 years, this area has transformed from a natural resource-based manufacturing economy to a relatively diverse light manufacturing and service-based economy. Spokane is the largest metropolitan area, with a regional population of approximately 350,000, followed by the Lewiston, Idaho and Clarkston, Washington area and Coeur d'Alene, Idaho. The North operating division consists of about 3,000 miles of gas distribution mains.

The North operating division is advantageously located on two interstate natural gas pipelines. Williams Pipeline – West, still referred to as Northwest Pipeline Corporation (NWP), provides firm and interruptible transportation service to access British Columbia and domestic Rocky Mountain gas. National Energy & Gas Transmission – Gas Transmission Northwest (GTN) provides firm and interruptible transportation service to access Alberta natural gas supplies.

South Operating Division

The South operating division of Avista Utilities was purchased in 1991 from CP National, a natural gas local distribution company in Oregon and California. The estimated population in the five counties served in Oregon is slightly greater than 400,000. The Company's Oregon service territory includes urban areas and highly productive farm and timberlands. The Medford, Ashland and Grants Pass area, located in Jackson and Josephine Counties, is the largest district with a regional population of around 100,000. The South operating division consists of about 32 miles of gas transmission mains and approximately 2,000 miles of gas distribution mains.

Two interstate natural gas pipelines serve the South operating division. Williams Pipeline – West, still referred to as Northwest Pipeline Corporation (NWP), provides firm and interruptible transportation service to access British Columbia and domestic Rocky Mountain gas. National Energy & Gas Transmission – Gas Transmission Northwest (GTN) provides firm and interruptible transportation service to access Alberta gas.

Integrated Resource Planning

The 2003 Natural Gas Integrated Resource Plan (IRP) is filed in the states of Washington, Idaho, and Oregon under the regulation of the Washington Utilities and Transportation Commission (WUTC), the Idaho Public Utilities Commission (IPUC), and the Oregon Public Utility Commission (OPUC) respectfully.

Integrated resource planning is a comprehensive, long-range planning tool that fully integrates forecasted energy requirements with potential energy resources. The process determines the most cost-effective means for the Company to meet projected firm load requirements.

Planning itself is not new to the Company. Forecasting customer demand on both a short-term and long-term basis is a regular part of operations, as is determining how to meet load requirements. The formal exercise of bringing forecasts of customer demand together with comprehensive analyses of resource options is valuable to the Company, its customers and its regulatory commissions in their long-range planning activities.

The development of an effective planning process involves input not only from within the Company but also from interested stack holders. This input is necessary to:

- develop a reasonable demand forecast
- examine a wide array of demand and supply resource options
- integrate resources into a cost-effective portfolio
- provide for strategies based on portfolio results
- select a realistic set of action plan items

Throughout the planning process, contributions are solicited from outside parties. Technical Advisory Committee (TAC) meetings are held to allow interested parties to provide formal input, review and comment on drafts, and discuss comments and suggestions in detail. Members of the Company's gas integrated resource plan TAC include representatives of many organizations providing perspectives from regulatory agencies, social services, customers, pipelines, other utilities, and the Company itself.

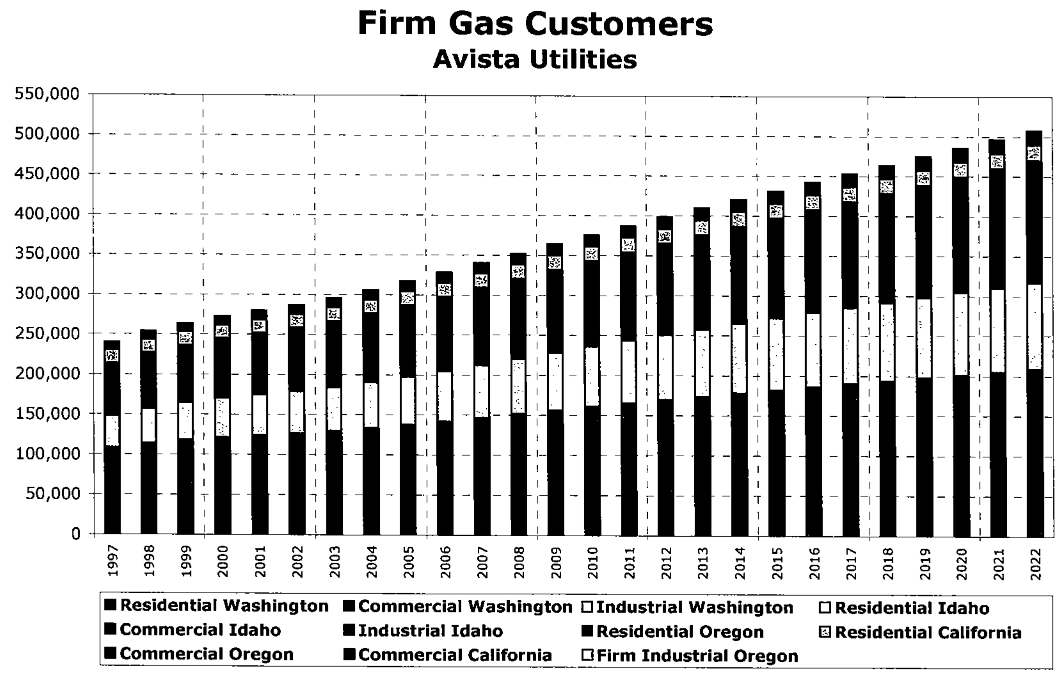
Natural Gas Sales Forecast

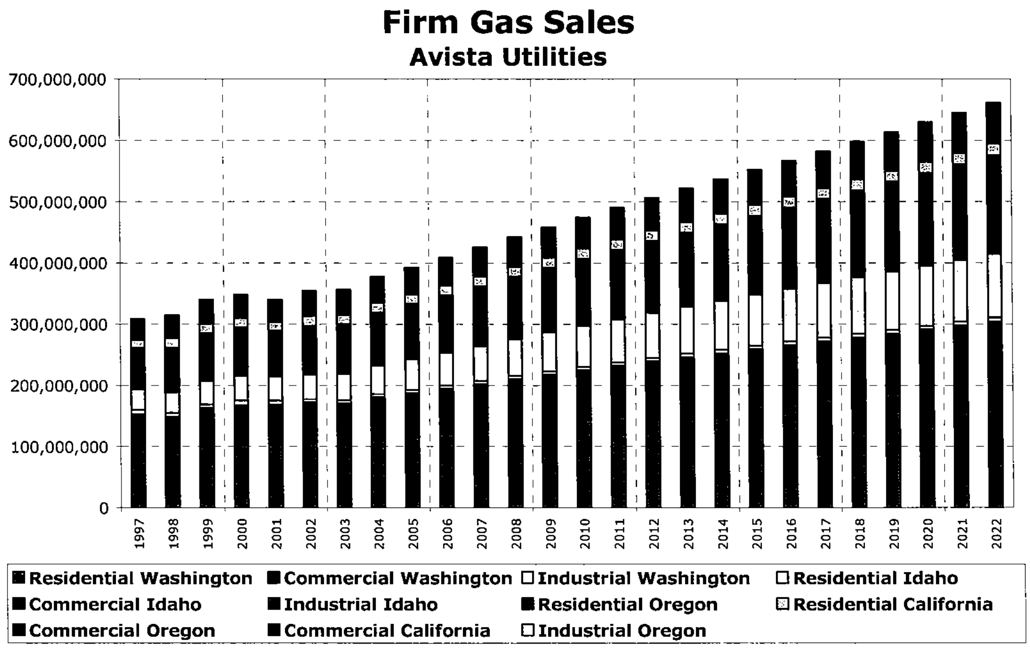
The 2003 natural gas sales forecast was prepared during the summer of 2002. It is the first step in the IRP process, namely the assessment of natural gas demand so that studies of optimal supplies and transportation can be performed.

Avista's utility operations planning period is ten years for capital budgeting and pipeline contracting. Avista Utilities prepares its natural gas forecasts concurrently with its electric operations forecast where electricity and natural gas are both provided to customers, thus utilizing common assumptions for both energy products. The results of the forecast are the planning forecast information used for internal purposes, as well as the official information supplied to external entities.

Avista Utilities purchases employment and population forecasts from global Insight, Inc. (formerly Data Resources, Inc.), an internationally recognized economic forecasting consulting firm.

Results of the natural gas forecasting are shown below.





Demand-Side Management

Natural gas efficiency within Avista is independently implemented by each of the two Avista Utilities divisions. The South operating division provides the implementation for Oregon gas service territories and the North operating division serves the Washington and Idaho service territories.

North Division

Avista Utilities North division gas and electric energy efficiency activities have been funded under a Tariff Rider mechanism since 1995. This allows for the funding of energy efficiency activities without creating a regulatory asset. The gas Tariff Rider is currently set at 0.5%. This funding mechanism yields approximately $1 million in annual revenues.

The four-year (2002 to 2005 inclusive) business plan calls for combined gas and electric DSM expenditures to be limited to approximately 62% of tariff rider revenues. While this strategy is projected to return the combined gas and electric DSM balance to zero by the close of 2005, detailed projections also indicate that the gas tariff rider will be negative at this time and will be offset by a positive balance in the electric tariff rider. Intervention may be required to rectify this imbalance if the demand for gas-efficiency projects remains at the current high levels. This intervention may come in the form of substituting new residential electric programs for existing residential gas programs or reductions in the gas-efficiency incentive levels specified in Schedule 190. These actions will be reevaluated in early 2004 based upon the gas DSM balance and the projections of customer demand and revenue through the close of 2005.

South Division

Within Avista Utilities South operating division natural gas efficiency programs are more traditionally funded. Natural gas efficiency expenses are capitalized and recovered over a period of time roughly commensurate with their benefits.

Residential energy audits and weatherization incentives, mandated by the State of Oregon, continue to be offered. The Company also offers incentives for high-efficiency furnaces and water heaters to qualifying residential customers. This was originally introduced in 1994 as a short-term market transformation program, but has been extended in recognition of the programs' customer value.

SUPPLY SIDE RESOURCES

The supply options of Avista's integrated resource portfolio consist of various components. These include firm and non-firm supplies contracted for on a long and short-term basis, firm and interruptible transportation on seven interstate pipelines, and three storage services. Avista acquires supplies to meet the demand of core customers in four states; California, Idaho, Oregon and Washington. This diversity of delivery points and load requirements adds to the options available to meet customers' needs. The utilization of these components varies depending on demand and operating conditions.

INCENTIVE MECHANISMS

In 1999, the Company entered into an agreement with Avista Energy to have Avista Energy manage all the supply and transportation needs of Avista Utilities gas customers except for the California. Avista Energy is not only managing the current supply and transportation contracts that are held by Avista Utilities, but has the responsibility to acquire additional supplies as needed to meet the demand of the core utility customers and manage Avista Utilities underutilized pipeline capacity. Avista Utilities, in concert with Avista Energy, determine the level and timing of fixed price commodity purchases using hedges in order to meet approximately one-half of expected core customer demand. This is done through periodic meetings of the Strategic Oversight Committee (SOC). This committee is made up of individuals from the natural gas area of Avista Energy and Avista Utilities. Also included in the Committee are representatives from the Rates Department and Risk Management area of the Utilities.

The incentive mechanisms were first established in Washington, Idaho, and Oregon on a 2-year, 9-month trial in 1999. In each of these jurisdictions the mechanism is similar, however, the pricing and sharing structures vary between the states. At the end of the trial period, Avista Utilities filed with the State Commissions to extend, with modifications, the mechanism for an additional 3 years. The current mechanism is approved in Oregon and Idaho until March 31, 2005 and until January 29, 2004 in Washington. At the time of the printing of this document, Avista was awaiting the WUTC Order to determine the future status of the "benchmarking" mechanism.

In 2000, the industry experienced the highest prices ever seen. In response, Avista Utilities, through Avista Energy, has established a schedule to lock in hedges and volumes for price stability. The hedging schedule provides for both structure and flexibility for both timing and volumes. Avista has established a base line that approximately 50% of our annual monthly loads will be hedged prior to entering into the heating season.

FUTURE RESOURCES

The Company in its resource management activities also considers other potential resources. These potential resources include those requiring physical assets and those dependent upon contractual or financial arrangements. Some of these are detailed below.

JACKSON PRAIRIE STORAGE PROJECT

Avista Corporation has participated in several expansions of the Jackson Prairie Storage Project with Williams Pipeline and Puget Sound Energy since its inception. Some of the expansions have been needed for core utility customers and others have not been needed and have been released to others with provisions that Avista retains the rights to the storage in the future. The Company will continue to evaluate its Jackson Prairie capacity and deliverability for requirements to determine if it should continue present releases, calling back some or all capacity, perhaps negotiating additional releases, or participate in future expansions of the project.

PIPELINE CAPACITY

Pipeline capacity expansion projects create potential difficulties for a local distribution company. Chief among these is that the timing of the pipeline expansion project may not necessarily match the needs of the LDC. When the LDC's long-term projections show a need for, or benefit to be derived from, participating in a proposed expansion, it may be appropriate to do so. The previous IRP showed that additional pipeline capacity was needed for the South operating division in the 2003/04 time-frame. This needed capacity was acquired from GTN in order to meet core load demand. As demonstrated in this document, the South operating division now has sufficient transportation for the current 5 – 7 year planning horizon, the North operating division though will need to acquire additional transportation by the 2007/08 heating season based on the current forecast.

TRANSPORTATION AND STORAGE RESOURCES

TRANSPORTATION

The Company has many contracts with NWP and GTN for firm and interruptible transportation to serve the core customers. These contracts are of different vintages, thus different expiration dates, but all have the right to be renewed by Avista Utilities. This gives the Company, and the customer, the knowledge that Avista Utilities will have available capacity to meet current and future core load demand.

The Company's strategy is to contract for a reasonable amount of firm transportation to serve firm customers should a design peak day occur in a seven to ten year period. Too much firm transportation could keep the Company from achieving its goal of being a low-cost energy provider. The ability to release capacity however, acts to offset the cost of holding underutilized capacity. Too little firm transportation impairs the Company's goal of being a reliable energy provider.

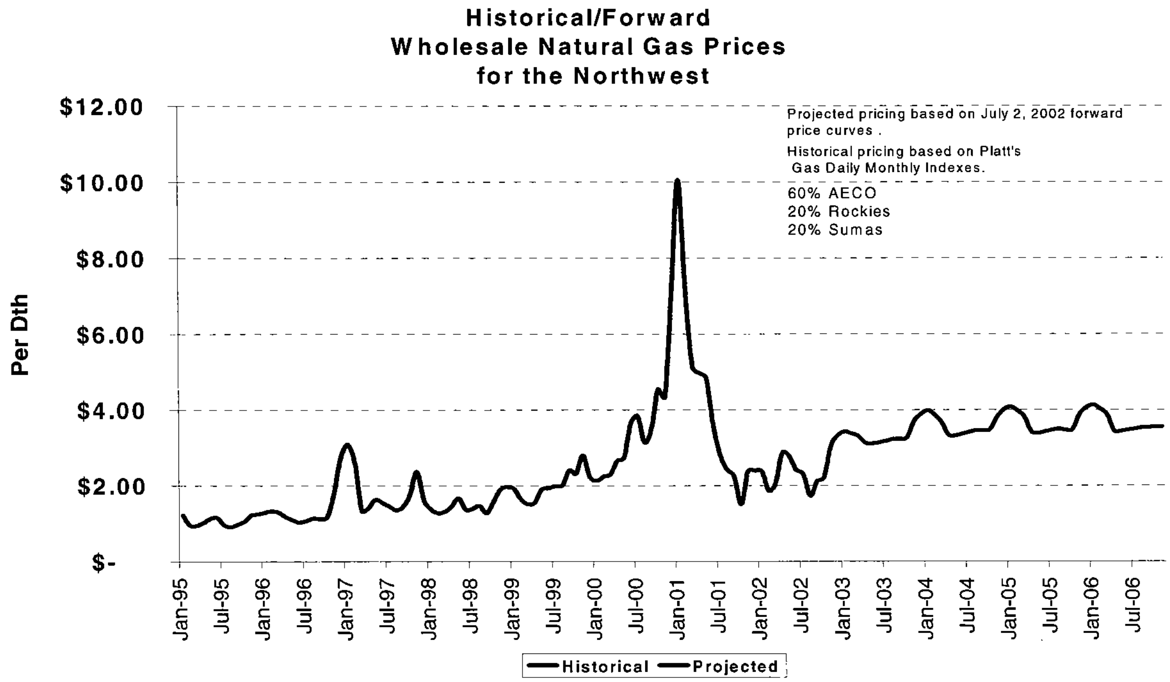
STORAGE

The Company is part owner, along with Williams Pipeline - West and Puget Sound Energy (PSE), in the Jackson Prairie Storage Project. Avista has contracted for service in this underground gas storage project along with LNG storage at Plymouth to serve core customers. Jackson Prairie Storage is an underground reservoir project located near NWP's mainline near Chehalis, Washington. Plymouth LNG is a liquefied natural gas storage facility located near NWP's mainline near Plymouth, Washington. Storage becomes a strategic resource due to the Company's low load factor.

SUPPLY RESOURCE

The Company holds several long-term supply contracts for supplies from three separate supply basins. These supplies are for annual and seasonal core customer needs. Through the arrangement with Avista Energy, Avista Energy supplies the natural gas for Avista Utilities core customers, except California, based on forecasts from the Utility. Figure 1 shows historic gas prices and 4-year forward looking based on July 2002 prices. These prices are a composite of 60% Alberta, 20% Domestic, and 20% British Columbia supply basins.

Figure 1



In evaluating possible capacity releases, Avista considers, among other things, peak day demand as it corresponds to peak day capacity. During off-peak periods, Avista releases under-utilized pipeline capacity to other parties through pre-arranged transactions and through the use of NWP and GTN electronic bulletin boards (EBB). Avista's goal is to maximize the revenue generated from capacity releases in order to minimize the cost to consumers of holding pipeline capacity contracts. The capacity release function is managed by Avista Energy.

DISTRIBUTION PLANNING

The primary goal of distribution system planning is to identify the potential problems and weak areas of the distribution system. By knowing when and where pressure problems may occur, the necessary reinforcements can be incorporated in normal maintenance. Thus, more costly "reactive" and emergency solutions can be avoided.

When designing new main extensions, computer modeling can help determine the most optimum size pipeline for present and future needs. Undersized facilities are extremely expensive to replace, and oversized facilities will cause unnecessary expenses to the company.

Designs for present needs can be compared with those for future needs. This allows us to satisfy current requirements while taking a step towards meeting future needs.

In Avista's distribution system analysis, the Company uses the STONER SynerGEE 3.1 gas distribution modeling system.

INTEGRATED RESOURCE PORTFOLIO

Avista's analysis and selection of resource options in the context of the IRP for its natural gas operations as well as the resulting strategies employed to develop on integrated resource plan are composed of:

- Resource Options Summary
- Gas Resource Model
- Analysis Framework
- Weather Data
- Avoided Cost
- Environmental Externalities
- Portfolio Integration

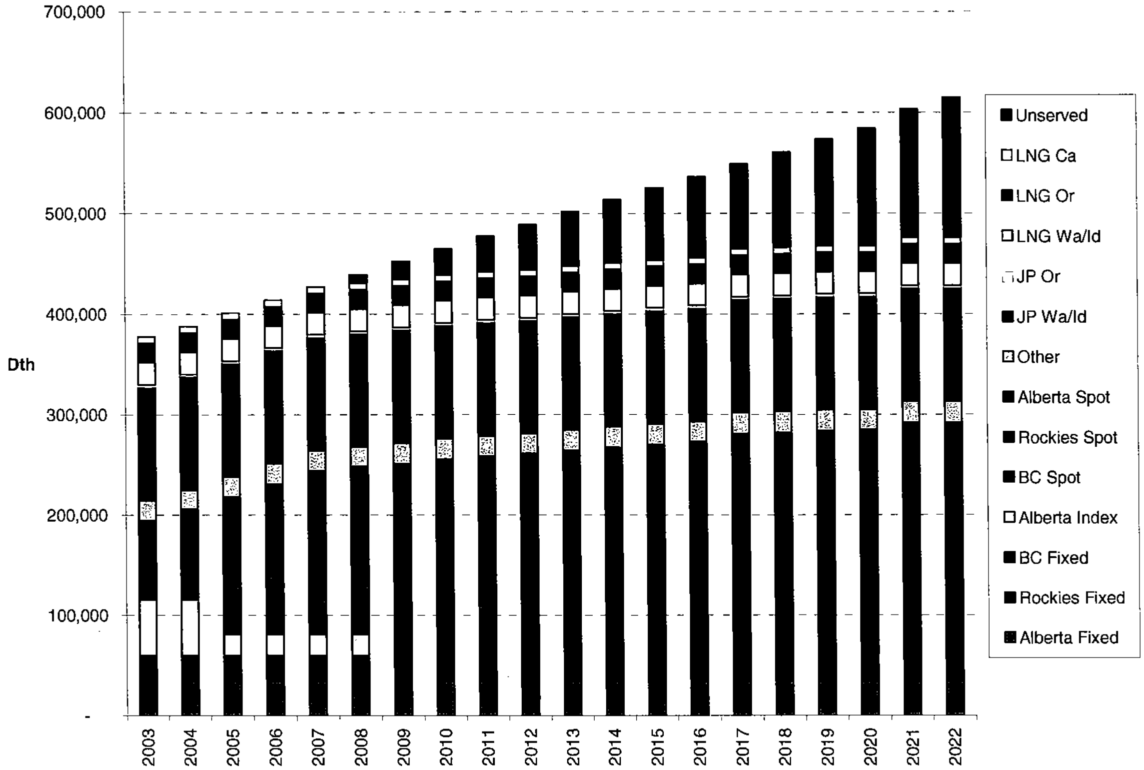
The foundation for the selection of resources for an integrated resource portfolio is the annual and peak day load forecast requirements.

The Company plans for its firm pipeline capacity and supplies based on firm peak day load requirements. It is assumed that on a peak day all interruptible customers have left the system in order to provide service to firm customers.

PORTFOLIO INTEGRATION

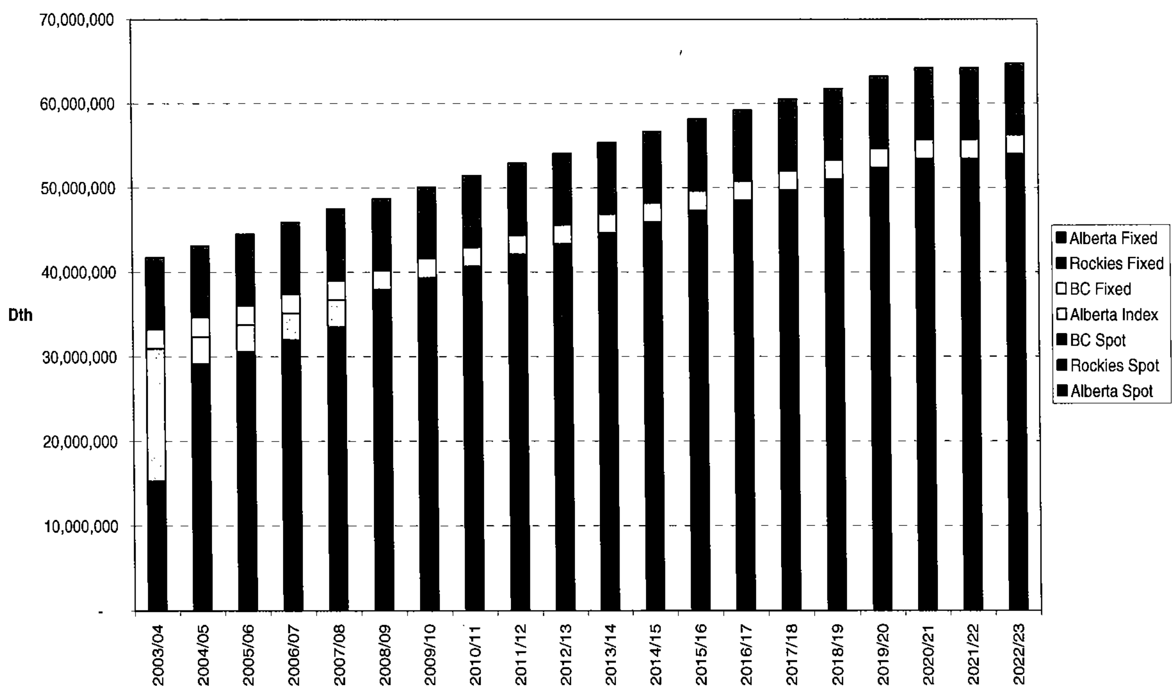
The combined Oregon, Washington and Idaho integrated resource portfolio, which results from the linear optimization model run, is shown in below. These figures represent total system requirements for a non-coincidental peak day, defined to be on February 15. This date was chosen as an indicator of the end of severe weather period because historical weather data suggest that severe cold has not happened after mid-February. The critical part to planning for a peak day is to reserve enough storage, supplies, and transportation to meet the peak day demand. On a peak day, only firm demand is planned for. This would encompass firm sales and transportation to residential, commercial, and industrial customers, firm transportation to our firm commercial and industrial customers, and any capacity releases of firm transportation that do not have a recall clause.

**Figure 5 - Peak Day Supply
Firm Demand
(Noncoincidential Peak)**



Shown below is the total system annual requirements for a 10-year planning horizon.

Figure 6 - Annual Requirements



PUBLIC INVOLVEMENT

Part of the Integrated Resource Plan is to involve the public in the least cost planning process. To accomplish this, the Company held two public Technical Advisory Committee (TAC) Meetings to review different phases of the plan during 2002. The first meeting was a joint session with the Avista Corp. electric TAC members and the natural gas TAC members covering Washington, Idaho, and Oregon. The second meeting was held with just the natural gas TAC members and covered Washington, Idaho, and Oregon.

In addition to state commission staff, the meetings included representatives from other state government agencies, several industrial customers, county government, and pipeline companies.

ACTION PLAN

The following action items will be discussed with the Technical Advisory Committee:

- continue to track the price elasticity customer use responses
- continue to use the SENDOUT® Gas Planning Model and the Nostradamus® Forecasting Model
- continue to monitor Avista Energy as part of the "bench marking" agreement
- continue to supply the State Commission staffs with quarterly reports as stipulated in the "bench marking" agreement
- continue to analyze the need for additional interstate pipeline capacity and to evaluate the renewal of transportation contracts as they expire
- the Company's Washington and Idaho service territory we will work toward achieving available cost-effective gas-efficiency opportunities while simultaneously bringing the tariff rider balance back to zero in a timely manner
- continue to target low-cost / no-cost and lost opportunity measures in the commercial / industrial segments
- evaluate the rotation of programs contained within the residential portfolio to create a sense of urgency on the part of customers and dealer infrastructure
- leverage regional and local electric-efficiency programs to realize gas-efficiency opportunities
- evaluate the impact of the space and water heating gas-efficiency programs, to include an evaluation of the market transformation effects
- continuously reevaluate our approach to meeting our mandated residential weatherization, commercial audit and commercial incentive program responsibilities
- continue to use the Stoner Workstation in activities of distribution planning and continue to integrate the GIS system into the planning functions

- continue to participate in the energy planning efforts of other organizations in the Northwest as well as any national studies that may occur

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Corporate Summary

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At year-end 2002, Avista Corp. had about 17,200 shareholders of common stock located in all 50 states as well as many countries. A total of 55% of company shareholders lives in the Pacific Northwest.

The map included on page 7 shows the Company's present service territory in eastern Washington, northern Idaho, Oregon and California as well as its underground gas storage facility near Chehalis in western Washington. The routes of the interstate natural gas pipelines and the supply basins that serve the area are also shown.

Avista Utilities

North Operating Division

The North operating division of Avista Utilities covers about 26,000 square miles, primarily in eastern Washington and northern Idaho, with its headquarters in Spokane, Washington. This division supplies approximately 320,000 customers with electric service and more than 188,000 customers with natural gas. The estimated population in the Washington/Idaho service area is more than 700,000. The service territory includes urban areas and highly productive farm and timberlands, as well as the Coeur d'Alene mining district. Spokane is the largest metropolitan area, with a regional population of approximately 350,000, followed by the Lewiston, Idaho and Clarkston, Washington area and Coeur d'Alene, Idaho.

Because of the region's diversified economy, it is somewhat insulated from the economic swings that affect the country as a whole. Stated in the 2000 IRP "The region is, however, vulnerable to swings in the metals market because of the mining influence and heavy industry in the region, which includes two aluminum plants and a magnesium alloy production facility." This vulnerability has been shown in the past several years with the closure on one of the two aluminum plants, and the closer of the magnesium alloy production facility.

The North operating division is advantageously located on two interstate natural gas pipelines. Williams Pipeline – West, still referred to as Northwest Pipeline Corporation (NWP), provides firm and interruptible transportation service to access British Columbia and domestic Rocky Mountain natural gas supplies. National Energy & Gas Transmission – Gas Transmission Northwest (GTN) provides firm and interruptible transportation service to access Alberta natural gas supplies.

Avista Corp. is part owner in the Jackson Prairie Storage Project, an underground natural gas storage facility located near Chehalis, Washington. Utilizing a naturally occurring underground dome structure and aquifer, the facility allows participating companies to store natural gas during times of low demand and withdraw gas during periods of high demand. Its primary benefit is the flexibility it allows participants in managing the region's gas supplies, and thus controlling costs to consumers.

The North operating division consists of about 3,000 miles of gas distribution mains, through which it delivers annual volumes of slightly less than 350 million therms. This gas is received at more than 40 points along the interstate pipelines and distributed to more than 188,000 residential, commercial and industrial customers.

South Operating Division

The South operating division of Avista Utilities serves counties in Oregon and South Lake Tahoe in California. The estimated population in the five counties served in Oregon is slightly greater than 400,000. The Company's Oregon service territory includes urban areas and highly productive farm and timberlands. The Medford, Ashland and Grants Pass area, located in Jackson and Josephine Counties, is the largest district with a regional population of around 100,000.

The Oregon service area is currently experiencing residential, commercial and industrial load growth. Because of excellent health care facilities and moderate year around climate, the region is a popular destination for retirees, thus continued inward migration of residents. Timber, agriculture, health care and tourism are all large contributors to the regional economy.

Two interstate natural gas pipelines serve the South operating division. Williams Pipeline – West, still referred to as Northwest Pipeline Corporation (NWP), provides firm and interruptible transportation service to access British Columbia and domestic Rocky Mountain natural gas supplies. National Energy & Gas Transmission – Gas Transmission Northwest (GTN) provides firm and interruptible transportation service to access Alberta natural gas supplies.

The South operating division contracts for service from the Jackson Prairie Storage Project, an underground natural gas storage facility located near Chehalis, Washington. Utilizing a naturally occurring underground dome structure and aquifer, the facility allows participating companies to store natural gas during times of low demand and withdraw gas during periods of high demand. Its primary benefit is the flexibility it allows participants in managing the regions gas supplies, and thus controlling cost to consumers.

The South operating division consists of about 32 miles of gas transmission mains and 2,000 miles of gas distribution mains, through which it delivers annual volumes of slightly more than 125 million therms. This gas is received at more than 20 points along the interstate pipelines and distributed to more than 84,700 residential, commercial and industrial customers in Oregon and approximately 18,500 customers in South Lake Tahoe, California.

INTRODUCTION TO IRP

INTEGRATED RESOURCE PLANNING – THE PRODUCT

This Integrated Resource Plan is the formalized documentation of the principles used in the company's long-term and short-term planning and analysis of business and resource decisions. This IRP is the culmination of work by many individuals within the Company. Participation from Marketing, Demand Side Management, Forecast, Gas Supply, Gas Engineering, Operations, and Rates sections all contributed to this plan.

The Washington Utilities and Transportation Commission (WUTC), the Idaho Public Utilities Commission (IPUC), the Oregon Public Utility Commission (OPUC), and the California Public Utilities Commission (CPUC) regulate the Washington, Idaho, Oregon, and California natural gas operations respectively. This IRP is being filed with the WUTC, IPUC, and the OPUC under their formal requirements.

Comments about this document should be directed to:

Richard T. Winters
Sr. Gas Planning Analyst
Avista Corporation
1411 E. Mission (MSC-7)
Spokane, WA 99220
(509) 495-4175.

INTEGRATED RESOURCE PLANNING – THE PROCESS

Integrated resource planning is a comprehensive, long-range planning tool that fully integrates forecasted energy requirements with potential energy resources. The process determines the most cost-effective means for the Company to meet those projected requirements.

Planning itself is not new to the Company. Forecasting customer demand on both a short-term and long-term basis is a regular part of operations, as is determining how to meet load requirements. The formal exercise of bringing forecasts of customer demand together with comprehensive analyses of resource options, which include both supply-side and demand-side measures, is valuable to the Company, its customers and its regulatory commissions in their long-range planning activities.

Data from the 2000 IRP and the data compiled for this plan have been used to assist in making many business decisions. Some examples of this are:

- amount of peaking supplies required
- amount of capacity available for release and for what length of time
- assistance to Gas Scheduling as to projected usage based on degree days
- least cost path to move supplies into service areas
- utilization of storage
- acquisition of additional pipeline capacity

The development of an effective planning process involves input not only from within the Company but also from people outside it. This input is necessary to:

- develop a reasonable demand forecast
- examine a wide array of demand and supply resource options
- integrate resources into a cost-effective portfolio
- provide for strategies based on portfolio results
- select a realistic set of action plan items

Because the planning process is ongoing, the level of information is constantly evolving. As such, this document represents only a snapshot of the Company's gas operations.

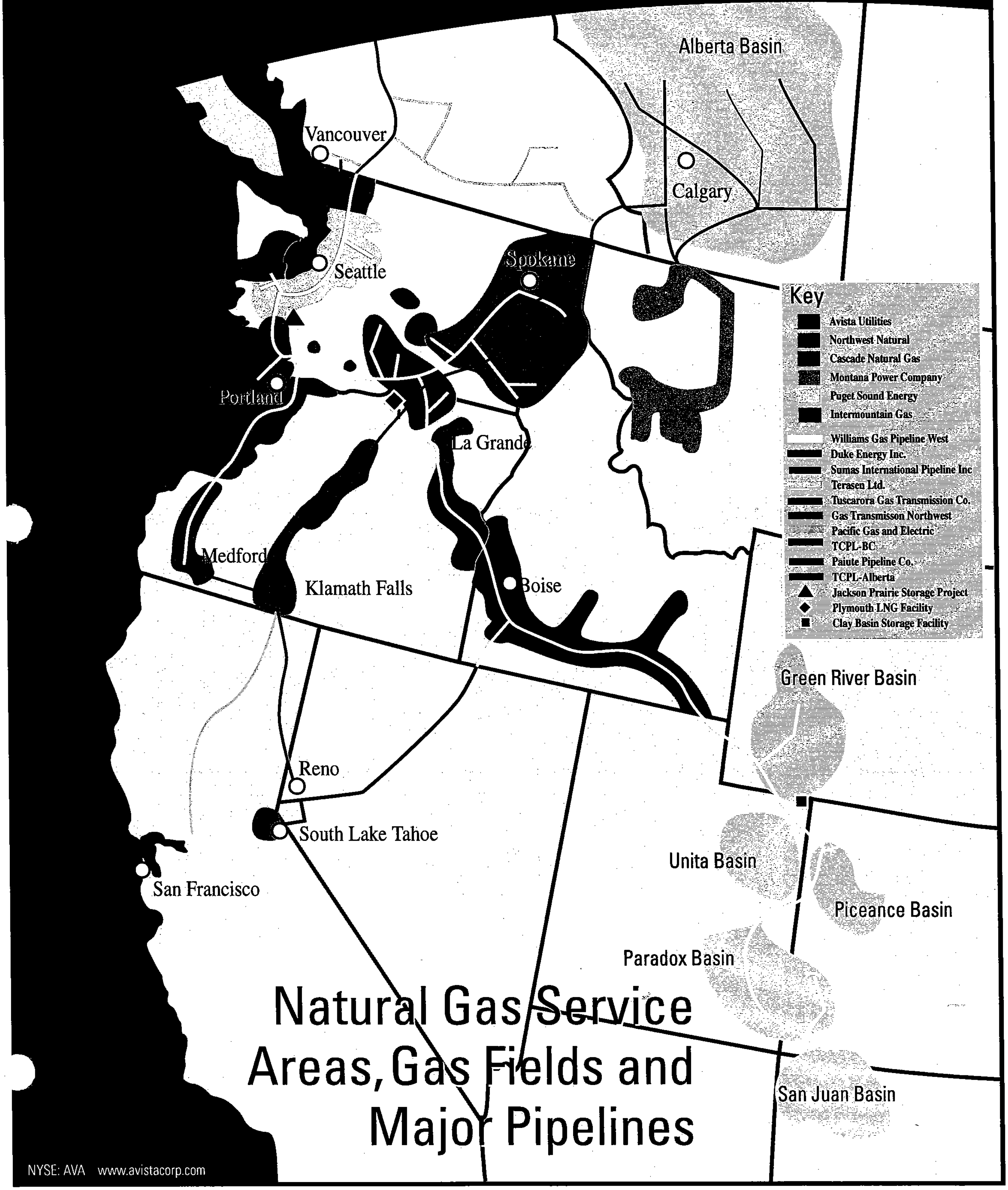
The integrated resource planning process must be viewed as an optimization process that takes into account contingency planning. It necessitates an examination of a broad spectrum of resource options. This examination is based as much on flexibility and reliability of resources as on price.

With so much uncertainty in the natural gas industry today, it is impossible to discern a single "least cost" path into the future. With the use of tools such as a flexible planning process, which this plan describes, along with cooperation between utilities, the commissions and others, these uncertainties can become more manageable.

Throughout the planning process, contributions are solicited from outside parties. Formal public input is provided by a Technical Advisory Committee (TAC), which reviews and comments on drafts of the integrated resource plan. TAC meetings are held to allow members to discuss comments and suggestions in detail. Members of the Company's gas Integrated Resource Plan TAC include representatives of many organizations providing perspectives from regulatory agencies, social services, customers, pipelines, other utilities, and the Company itself. A list of those attending the TAC meetings or those that commented on this plan can be made available by request.

AVISTA Corp.

Natural Gas Service Areas, Gas Fields and Major Pipelines



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NATURAL GAS CONVERSION INFORMATION

Btu	=	British thermal unit
cf	=	cubic feet
Th	=	Therm
GJ	=	Gigajoule
10^3m^3	=	1,000 cubic meters
cf	=	1,000 Btu*
Therm	=	100,000 Btu
	=	100 cf*
Dth	=	1,000 cf*
	=	1,000,000Btu
	=	10 Therm
	=	1 MMBtu
	=	1.055GJ
	=	1 Mcf*
	=	.028 10^3m^3
One Therm of Gas	=	100,000 Btu
Decatherm (Dth)	=	10 Therm
1 Gallon Liquid Natural Gas	=	88,000 Btu
1 Gallon Gasoline	=	130,000 Btu
1 Gallon #2 Oil	=	140,000 Btu
1 Gallon #6 Oil	=	150,000 Btu
1 Gallon Propane	=	92,000 Btu
1 Kilowatt Hour (kWh)	=	3,412 Btu
1 Therm at 100% Efficiency	=	29.308 kWh (100% Efficiency)
1 Therm at 90% Efficiency	=	26.377 kWh (100% Efficiency)
1 Therm at 80% Efficiency	=	23.447 kWh (100% Efficiency)

* Based on a calorific heating value of 1,000 Btu per cubic foot.

GLOSSARY OF TERMS

AVISTA Corporation
Avista Corp. is an energy, information, and technology company with utility and subsidiary operations located in the Pacific Northwest, headquarters located in Spokane, Washington.
The parent company for Avista Utilities.

AVISTA Energy
The non-regulated energy marketing and trading affiliate of Avista Corporation.

AVISTA Utilities
The regulated entity of Avista Corporation, divided into two operating divisions, north (Washington and Idaho) and south (Oregon and California).

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

Best Efforts
A contractual requirement related to a buyer's or seller's obligation to perform. There is usually no penalty for failure to take or deliver gas covered by the agreement.

British Thermal Unit
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.
Acronym: Btu

Broker
A person acting as an agent for a buyer or seller of gas in a transaction. The broker does not assume title to the gas.

Capacity, Peaking
The capability of facilities or equipment normally used to supply incremental gas under extreme demand conditions; generally available for a limited number of days at maximum rate.

CAPP
Canadian Association of Petroleum Producers.

Cascade Natural Gas Corporation
A natural gas local distribution company headquartered in Seattle, Washington, serving customers in Washington and Oregon.
Acronym: Cascade

Combustion Turbine
A natural gas fired resource.

Commercial Energy Demand Modeling System
End-use forecast model for commercial class customers.
Acronym: CEDMS

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

Compressed Natural Gas
The compression of natural gas in storage vessels to pressures of 2,400 to 3,600 pounds per square inch, generally for use as a vehicle fuel.
Acronym: CNG

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

Contract Demand
The maximum daily, monthly, seasonal or annual quantities 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.
Acronym: CD

CPI
Consumer Price Index

Cubic Foot
The most common unit of measurement applied to gas volume. It is the amount of gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor.
Acronym: cf

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

Cushion Gas
The gas required in a reservoir used for storage of natural gas so that the reservoir pressure is such that the storage gas may be recovered.

Delivery Pressure
The pressure at which gas is delivered to the customer. Typical pressures are:

Combustion Turbine	350 – 650 psi
Gas-fired Boiler	5 psi
Small Commercial	2 psi
Residential	7 inch water column (¼ psi)

Demand-Side Resources
Energy resources obtained through assisting customers in modifying (reducing) their "demand" or use of natural gas.

Demand-Side Management
The activity of implementing demand-side measures in customers' facilities.
Acronym: DSM

Design Day
A 24-hour period of demand which is used as a basis for planning peak gas capacity requirements.

Econometric Model
A set of equations developed through regression analysis and other quantitative techniques, as well as intuitive judgement, that mathematically represents and forecasts relationships.

Electronic Bulletin Boards
Online informational gathering systems.
Acronym: EBB

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

Externalities
Cost and benefits, which are not reflected in the price, paid for goods or services.

Federal Energy Regulatory Commission
A government agency charged with the regulation and over-site of interstate pipelines, wholesale electric rates and hydroelectric licensing. The FERC regulates the interstate pipelines with which Avista Corp. does business and determines rates charged in interstate transactions.
Acronym: FERC

FERC's Order 636
An Order imposed by the Federal Energy Regulatory Commission in 1992, and fully implemented at Avista in 1993. This Order brought the natural gas industry to its current state of deregulation.

Firm Open Market Supplies
Natural Gas purchased via long-term purchase arrangements. The Company has negotiated agreements anywhere from three months to five years with several natural gas suppliers for firm winter supplies to be transported on NWP or GTN.

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 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.

Gas Day
A period of 24 consecutive hours commencing at 9:00 a.m. Central Clock Time (7:00 a.m. Pacific Clock Time). This is an industry standard throughout North America.

Gas Industry Standards Board
A board established by the FERC to set rules by which interstate natural gas pipelines must operate. Has been replaced by NAESB.
Acronym: GISB

Gas, Natural
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.

GasSolutions
A relational database system developed by Avista Corp. to nominate, track and report flows of gas.

Global Insight, Inc.
A national economic forecasting company.

Heating Degree Day
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.
Acronym: HDD

Intermountain Gas Company
A natural gas local distribution company headquartered in Boise, Idaho whose parent is Intermountain Industries Company. Distributes natural gas in Idaho.
Acronym: IGC

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

Interruptible Service
Low priority service offered to customers under schedules or contracts that anticipate and permit interruption on short notice. The interruption happens when the demands of all customers exceed the capability of the system to continue deliveries to all of those customers.

IPUC
Idaho Public Utilities Commission

IRP
Integrated Resource Plan

Jackson Prairie Storage Project
An underground storage project jointly owned by Avista Corp., Puget Sound Energy, and Northwest Pipeline. 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.
Acronym: JPSP

LCP
Least Cost Plan.

Linepack
The quantity of gas in a pipeline or in a gas distribution system at any point in time.

Liquefaction
Any process in which gas is converted from the gaseous to the liquid state. For natural gas, this process is accomplished through lowering the temperature of the gas.

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

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

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

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

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

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.

LS-1
Northwest Pipeline rate schedule covering its Liquefied Natural Gas (LNG) service. Also used to refer to the gas (as in "LS-1" gas).

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

MDDO
Maximum Daily Deliverability Obligation

MDQ
Maximum Daily Quantity

MMBtu
A unit of heat equal to one million British thermal units (Btu).

National Energy & Gas Transmission – Gas Transmission Northwest
One of the seven natural gas pipelines the Company deals with directly or indirectly. GTN is headquartered in Portland, Oregon and was a subsidiary of Pacific Gas and Electric. This is a natural gas pipeline that runs from Canada to the Oregon/California border.
Acronym: GTN

National Energy Board
The Canadian equivalent to the Federal Energy Regulatory Commission.
Acronym: NEB

National Oceanic Atmospheric Administration
Publishes the latest weather data. The 30-year weather study is based on this information.
Acronym: NOAA

New Energy Associates
The developers of the SENDOUT® Gas Planning System, a Siemens Company.

Nomination
The scheduling of daily gas requirements.

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

NORTH AMERICA ENERGY STANDARDS BOARD
A board established by the FERC to set rules by which interstate natural gas pipelines and distributors must operate. Replaces GISB.
Acronym: NAESB

Northwest Passage
Daily gas nomination and capacity release electronic bulletin board system for NWP.

Northwest Pipeline Corporation
The principal interstate pipeline serving the Pacific Northwest and one of seven natural gas pipelines the Company deals with directly or indirectly. NWP is the Company's primary transporter of natural gas. Headquarters are in Salt Lake City, Utah. NWP is a subsidiary of The Williams Companies.
Acronym: NWP

NOVA Gas Transmission
Currently known as TransCanada Alberta System. A natural gas gathering and transmission corporation of Alberta that delivers gas into the TransCanada BC System pipeline at the Alberta/British Columbia, Canada, border. One of seven natural gas pipelines the Company deals with directly or indirectly.
Acronym: NOVA

NPPC
Northwest Power Planning Council

Open Access
The non-discriminatory access to interstate pipeline transportation services. This enables end-use customers the option of securing their own gas supplies rather than relying upon local distribution companies.

OPUC
Oregon Public Utility Commission

Pacific Gas and Electric Company
The previous parent company of GTN, based in San Francisco, California.

Pacific Trail
Daily gas nomination and capacity release electronic bulletin board system for GTN.

Paiute Pipeline Company
A subsidiary of Southwest Gas Company. This natural gas pipeline is used to service the customers of Avista Utilites located in California. One of the seven natural gas pipelines the Company deals with directly or indirectly.

Peak Day
The 24-hour day period of greatest total gas sendout. May be used to represent historical actual or projected (budget) requirement.

Peak Day Curtailment
Curtailment imposed on a day-to-day basis during periods of extremely cold weather when demands for gas exceed the maximum daily delivery capability of a pipeline system. Peak day curtailment is applied independent of seasonal curtailment and does not affect overall authorized volumes to customers under seasonal curtailment.

Propane Air
Propane mixed with air and natural gas to allow burning in a natural gas system to supplement natural gas supplies for customers on peak days.

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 public service.

Residential Energy Demand Modeling System
End-use forecast model for residential class customers.
Acronym: REDMS

Resource Stack
Sources of gas supply available to Avista's system.

Seasonal Contracts
Gas supply contracts designed to provide gas to utility sales customers only in the peak winter months (November through March).

Sendout
The amount of gas burned on any given day.

SENDOUT®
Gas planning system from New Energy Associates. It is a linear programming optimization model used to solve minimization problems.

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

SGS-1
Northwest Pipeline rate schedule covering storage gas from Jackson Prairie. Also used to refer to storage gas supply.

Shoulder Months
Generally defined as the months of March, April, May, September, and October when the temperatures are moderate and customer demand is unpredictable.

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

Storage, Underground
The utilization of subsurface facilities for storing gas which has been transferred from its original location for the primary purposes of load balancing. The facilities are usually natural geological reservoirs such as depleted oil or gas fields or water-bearing sands sealed on the top by an impermeable cap rock. The facilities may be man-made or natural caverns.

Take and Pay
The clause in a gas supply contract which provides that a premium be paid for the availability of the gas supply in addition to the commodity price.

Take or Pay
The clause in a gas supply contract which provides that, during a given period, a specified minimum quantity of gas must be paid for whether or not delivery is accepted by the purchaser. Some contracts contain a time period in which the buyer may take later delivery of the gas without penalty.

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

TF-I
Northwest Pipeline's rate schedule under which Avista Corp. moves gas supplies on a firm basis.

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

TI-I
Northwest Pipeline's rate schedule under which Avista Corp. moves third party gas supplies on an interruptible basis.

Therm
A unit of heating value equivalent to 100,000 British thermal units (Btu).

TransCanada Alberta System
Previously known as NOVA Gas Transmission. A natural gas gathering and transmission corporation of Alberta that delivers gas into the TransCanada BC System pipeline at the Alberta/British Columbia border. One of seven natural gas pipelines the Company deals with directly or indirectly.
Acronym: TCPL-AB

TransCanada BC System
Previously known as Alberta Natural Gas. A natural gas transmission corporation of British Columbia that delivers gas between the TransCanada-Alberta System and GTN pipelines that runs from the Alberta/British Columbia border to the US border. One of seven natural gas pipelines the Company deals with directly or indirectly.
Acronym: TCPL-BC

Transportation Gas
Gas that is 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 transpor-tation arrangements. NWP and GTN transportation may be firm or interruptible.

Tuscarora Gas Transmission Company
One of the seven natural gas pipelines the Company deals with directly or indirectly. Tuscarora is a subsidiary of Sierra Pacific Resources and TransCanada. This natural gas pipeline runs from the Oregon/California border to Reno, Nevada.

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

WACOG
Weighted Average Cost of Gas, the price paid for a volume of gas and associated transportation based on the prices of individual volumes of gas that make up the total quantity supplied.

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.

Withdrawal
The process of removing 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.

AVISTA® Corp.

APPENDIX 'A'

NATURAL GAS SALES FORECAST

AVISTA Corp.

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NATURAL GAS SALES FORECAST

INTRODUCTION

On September 24, 2002, Avista hosted an Integrated Resource Plan Technical Advisory Committee meeting in Spokane, Washington. The results of the Company's natural gas forecast were presented at this meeting.

What follows is summary documentation of the economic outlook underlying the forecast, the results reported as customer forecasts, and sales forecasts for firm customers and other types of customers for which Avista acquires delivery resources.

ECONOMIC CONDITIONS IN THE SERVICE AREA

Avista Utilities serves natural gas in portions of four states: Washington, Idaho, Oregon, and California. The shorthand terminology used by the Company to describe the two operational areas of Avista's natural gas business is North and South. The North includes properties in Washington and Idaho, and the South includes properties in Oregon and California.

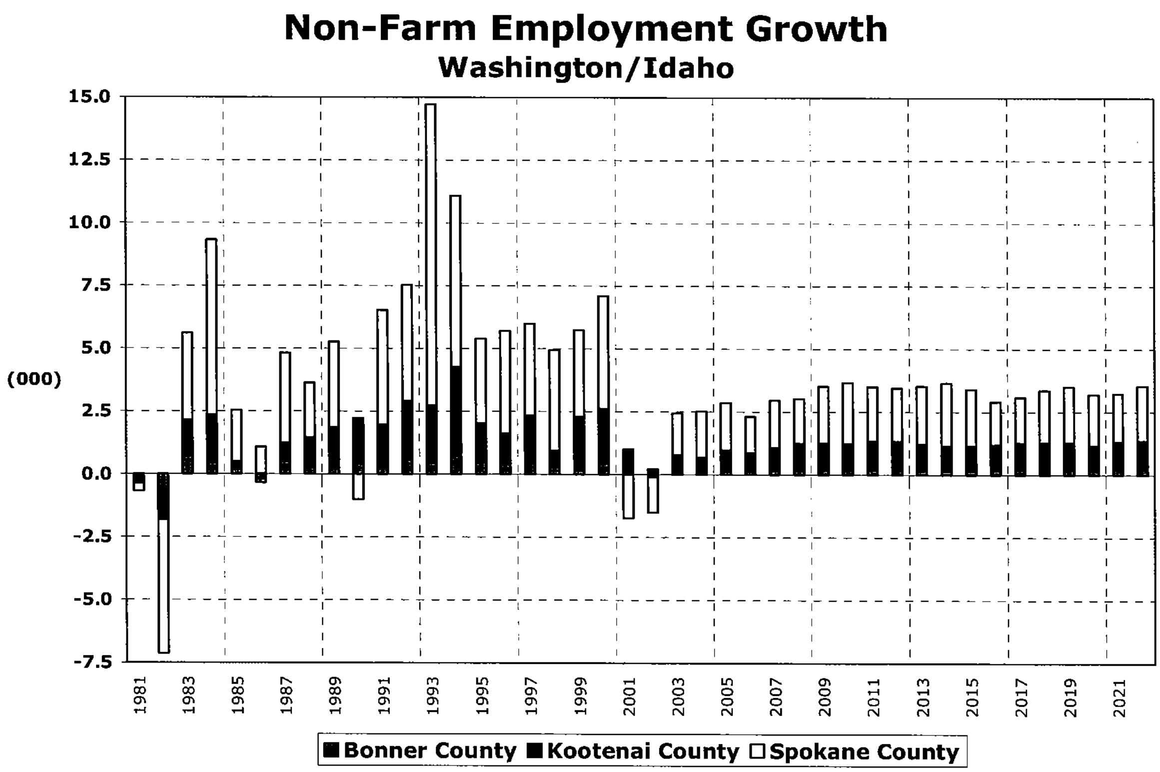
The Avista Utilities North natural gas service territory covers a wide swathe of Eastern Washington and Northern Idaho. The geography is as diverse as the economy. Rugged mountains, fertile river valleys, and glacially created plains provide natural resources, farmlands, and cityscapes for over 800,000 residents of the Inland Northwest. Avista Utilities serves most of the urbanized and suburban areas in nearly two dozen counties. As a combination electric and natural gas utility in the North area, Avista Utilities is the sole provider of natural gas through most of these communities, and is the electricity provider as well.

The Avista Utilities South natural gas service territory is focused in five Oregon Counties and a small portion of one California County. The California property has a stable economy, limited by growth management laws.

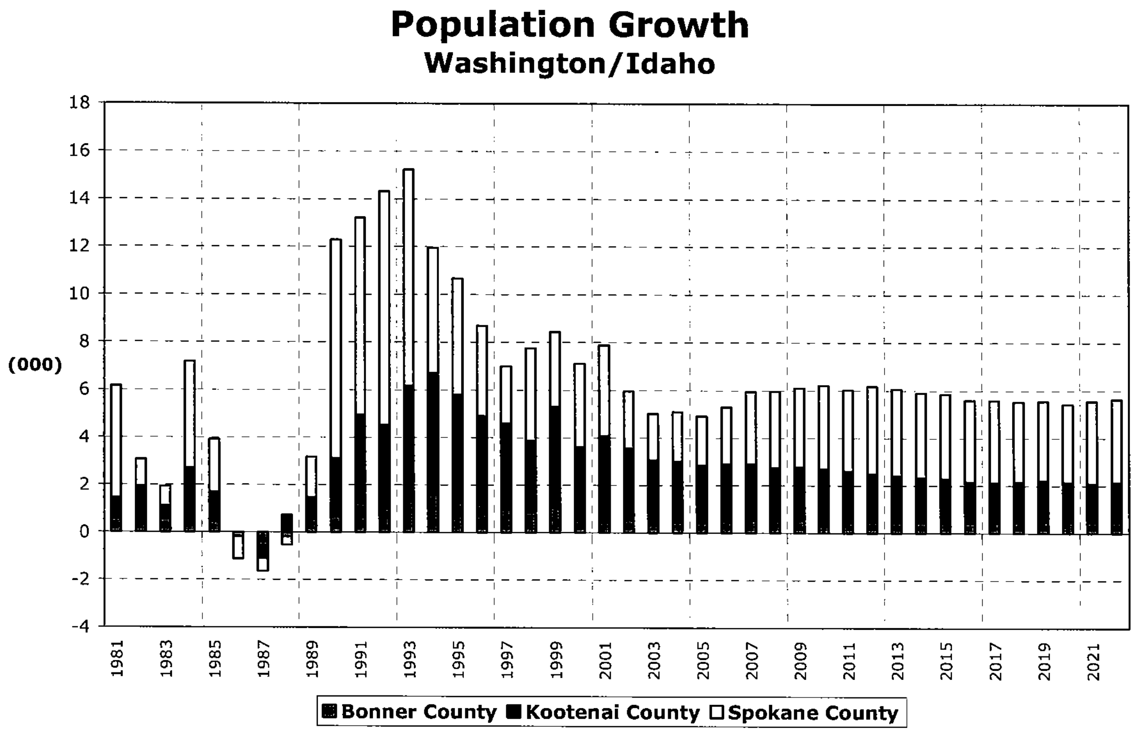
NORTH OPERATING DIVISION ECONOMY

Over the last 20 years of recent economic history, the economy of the Inland Northwest has transformed from a natural resource-based manufacturing economy to a relatively diverse light manufacturing and service-based economy. Manufacturing employment has declined as mining reserves, particularly in Shoshone County, Idaho, and Stevens and Pend Oreille Counties, Washington have been depleted. Similarly, much of the mountainous area of the region is owned by the Federal government, and managed by the USDA Forest Service. Timber harvests on public lands have been severely curtailed, which has led to the closure of the majority of sawmills scattered through the region. Two pulp and paper plants served by Avista Utilities have large private holdings of forested lands, but they have not been completely insulated from Forest Service impacts, and they continue to face stiff domestic and international competition for their products.

During the 1980's, two national recessions were felt strongly in the Inland Northwest. Typically, these economic slowdowns are reflected in employment data, with employment expanding during expansionary times, and contracting during recessions. The 1980's typified that pattern. The U.S. recession in the early 1990's bypassed much of the area economy. The most recent recession in early 2000's has provided a harsh reminder that it remains difficult to insulate one's regional economy from national events. The historical patterns of employment for the three principal counties in the Avista Utilities service area are shown below.

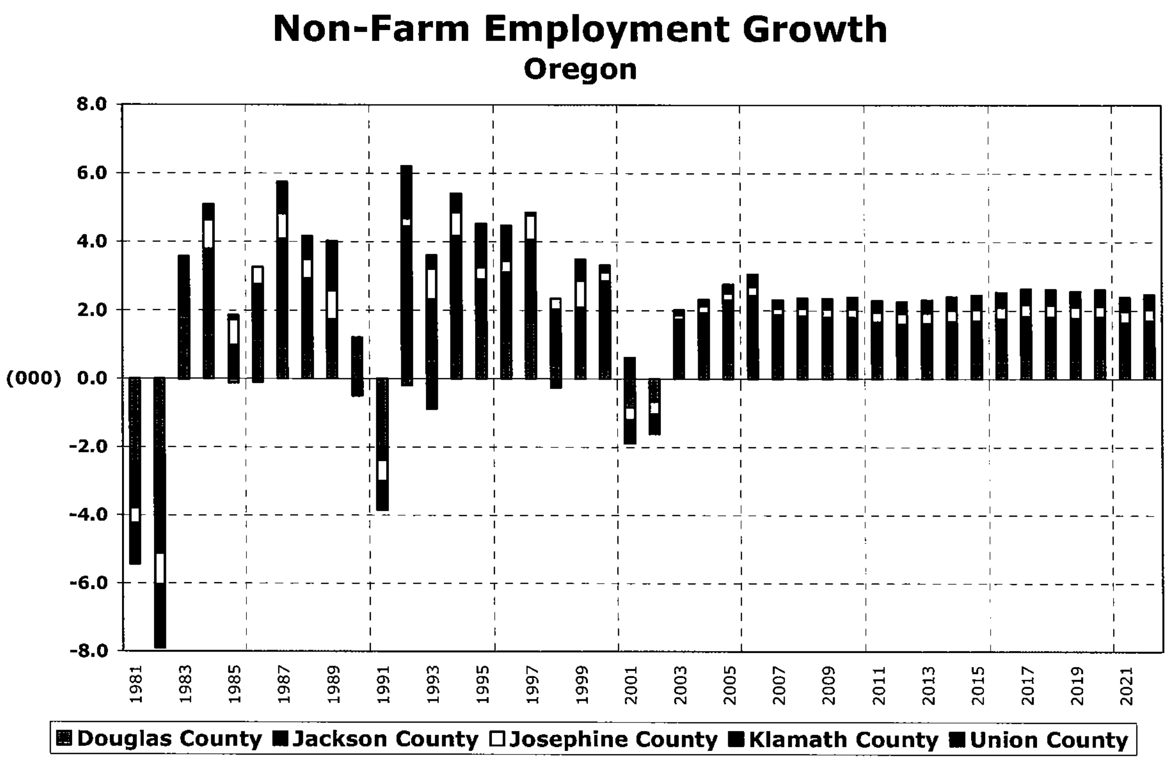


Population levels are much more stable than employment during good and bad times. However, during severe economic downturns, as we observed in the early 1980's, total area population can contract.

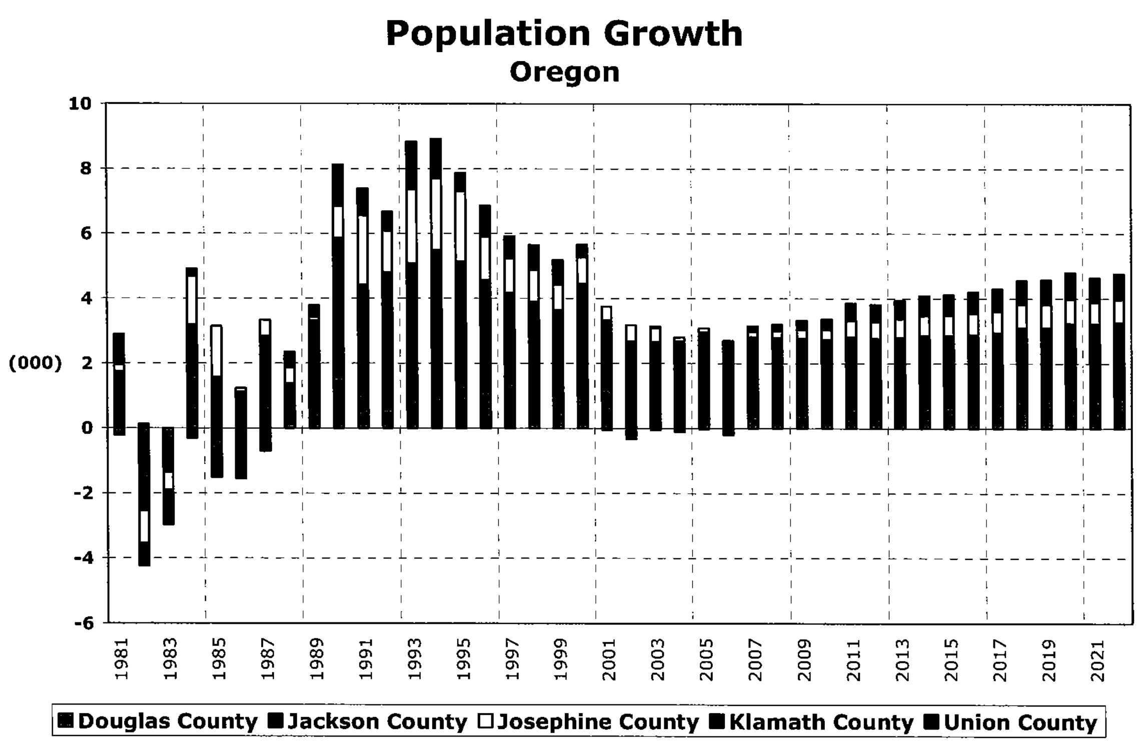


SOUTH OPERATING DIVISION ECONOMY

The five Oregon counties in Avista's natural gas service area have one thing in common: their economies have been dominated by the forest products industry. There is one word that describes this dominant industry: collapse. The more diversified economy of Jackson County, with Medford as its centerpiece, has faired as the best of the bunch, with wage and salary employment in manufacturing up over 10% in the last 20 years. But because the lumber and wood products industry includes non-salaried workers in logging, hauling, and other forest-related work, the true extent of the impact is understated. Manufacturing employment has decreased by over 30% in Douglas County, 25% in Josephine County, and over 20% in Klamath County. Only Union County has had stable manufacturing employment over the last 20 years, but they, too, have lost many forest product workers. In Union County the population has been stable over the same 20 year time period. In the four other counties, population has increased. Douglas County, with Roseburg as the principal city, increased by 10,000 over 20 years, or by 11%. Klamath County, with Klamath Falls as the principal city, increased by 5,000, or by 9%. Josephine County, with Grants Pass as its largest city, increased by 17,000 persons, or by 29%, largely transforming itself into a bedroom community of workers for Jackson County. And Jackson County, with Medford as the central place for most of southwestern Oregon, increased by 48,000 persons, or by 36%.



Other than Union County with stable population, the four other counties Avista serves in Oregon have seen considerable population growth during the last twenty years.



THE ECONOMIC FORECASTS

Avista Utilities purchases employment and population forecasts from Global Insight, Inc. (formerly Data Resources, Inc.), an internationally recognized economic forecasting consulting firm. Avista purchases data for the eight principal counties comprising over 80% of the service area economy, namely, Spokane County, Washington, Kootenai and Bonner Counties in Idaho, and Jackson, Josephine, Douglas, Klamath, and Union Counties in Oregon. The national forecast, upon which these regional forecasts are based, was prepared in March 2002, the county-level estimates were completed in May 2002.

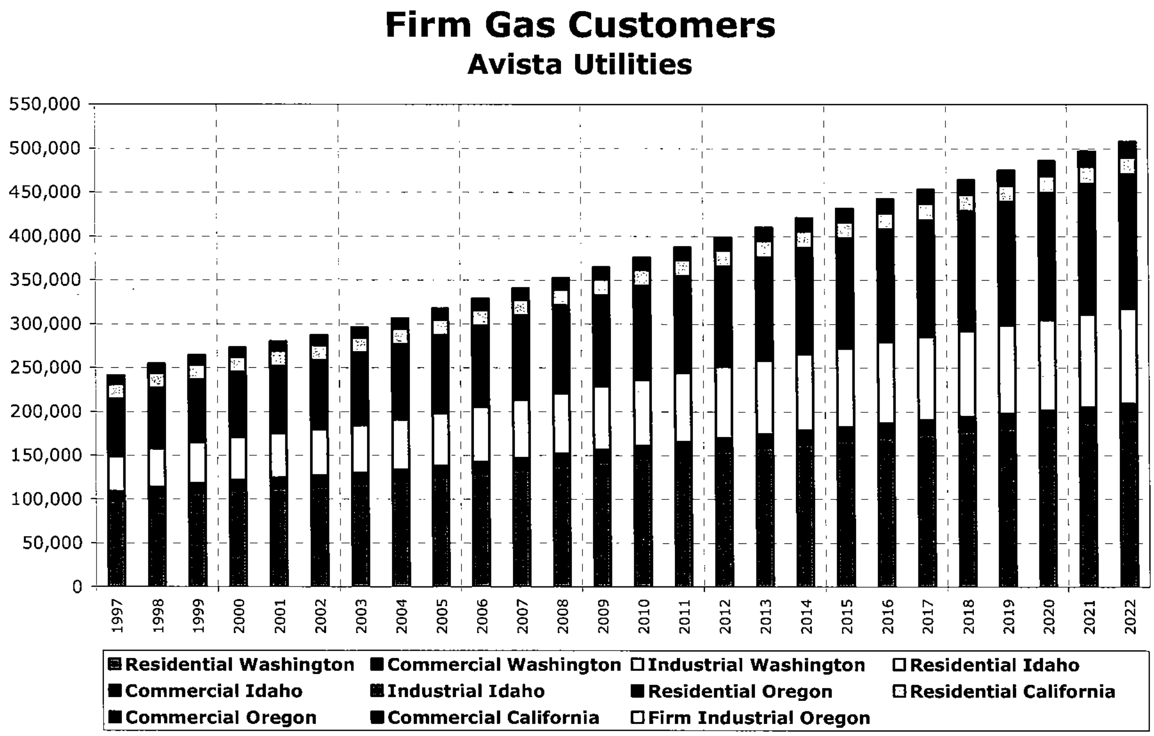
These forecasts provide the basis for the natural gas customer forecasts into the future. To characterize the forecasts for employment and population in the North area by county, Spokane County, with the City of Spokane as the central place, is expected to exhibit moderate, steady growth for the next 20 years. Kootenai County, and the well known city of Coeur d'Alene, was one of the fastest growing counties in the U.S. during the 1990's and is anticipated to continue stellar growth going forward. Bonner County is expected to have steady, modest growth, although its size is dwarfed by its southern neighbors, namely Kootenai County. As for the South, growth in Jackson County for both employment and population into the future will account for two-thirds of growth in the Oregon properties, with the remainder of Oregon split among the other counties, with the I-5 corridor seeing more action than the remote, inland areas. The South Lake Tahoe area is expected to remain stable.

The charts above illustrate the historical and forecast changes in employment and population expected throughout the Avista Utilities service area.

Natural Gas Customer Forecasts

The key driver of natural gas customer forecasts is population growth. Although there is not a one-to-one matching, population provides the fundamental demand for housing. Other factors that influence housing demand include interest rates, apartment vacancy rates, and student housing construction on college campuses. Over the last several years, the region's housing market has seen considerable absorption of a surplus that was generated after the population boom of the early 1990's. Favorable low interest rates all during 2002 sparked a 26.5% increase in residential permits in Spokane and Kootenai County alone, compared to 2001, and many of those houses became Avista Utilities retail customers. The unsold inventory of housing is also at a cyclical low. The upswing in the economy in 2003 and 2004 is expected to provide a strong housing market. In the South service area of Oregon, Roseburg and Klamath Falls are expected to attract more spillover retirement and second home seekers from California, extending the reach of the Rogue River Valley housing boom underway for the last five years.

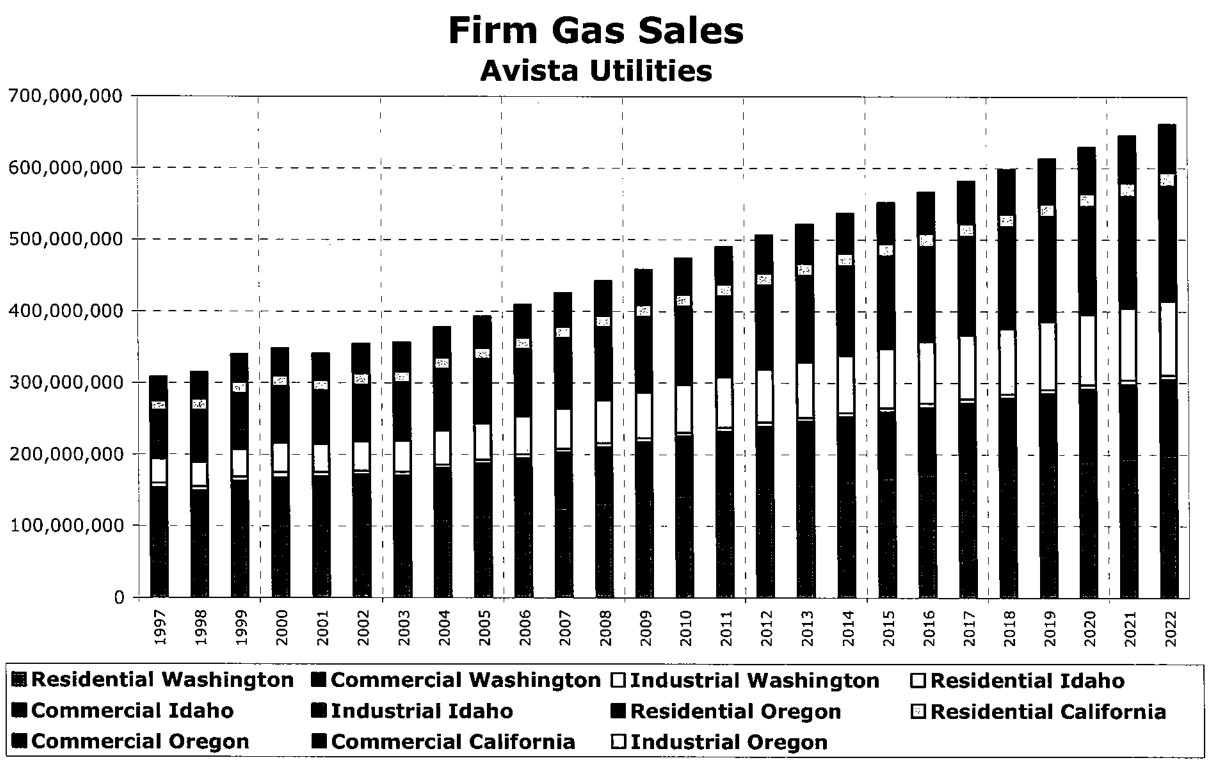
Housing is the fundamental driver of commercial customer expansion, as more retail stores, schools, and other "population-serving" business are attracted to these new markets. Over the longer-term twenty-year horizon, customer growth is estimated to average 2.9% per year in the North, somewhat slower than the 3.8% over the past five years. In the South area of Oregon, customer growth averages 4.0% for twenty years, slightly faster than the 3.8% during the past five years. California only grows 0.6% per year, consistent with past trends.



Natural Gas Retail Sales (Firm)

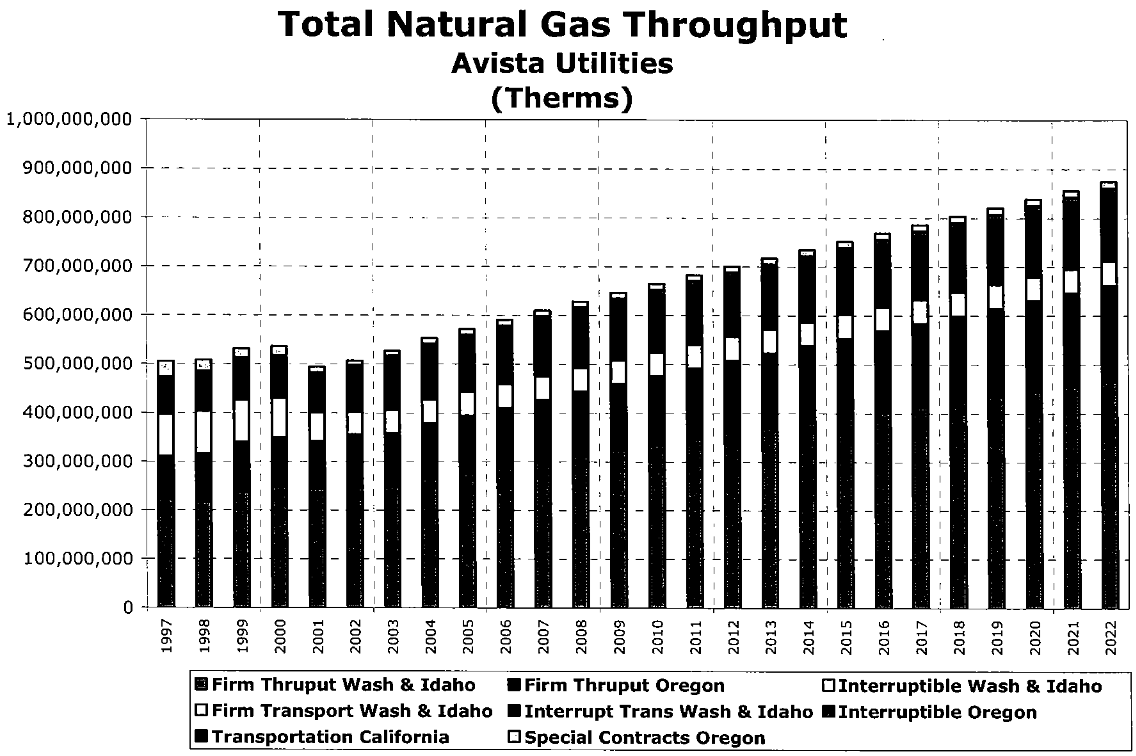
Without going into a complete dissection of retail natural gas sales between 1997 and 2002, suffice it to say the path has been rocked by some major changes, not the least of which was a marked increase in natural gas prices. The energy crisis of 2000/01 included the implementation of widespread, permanent voluntary conservation efforts by our customers that spilled over from the electricity situation in California and the West. In 2002, natural gas prices were sending price elasticity signals to customers, reinforcing conservation efforts. Due to the economic recession during 2001 and 2002, several large industrial facilities served by Avista Utilities were permanently closed, and a major employer in the aluminum industry has also closed. The forecast has a conservative assumption regarding these closed companies, namely that the closures are permanent. When these facilities are purchased by new operators or restarted by existing owners, it would be our intention to adjust the annual forecast.

Despite the combined impacts of conservation, natural gas price increases, and manufacturing plant closures, there was an increase in firm retail gas consumption between 1997 and 2002 in the North, averaging 1.8% on a compounded basis. The North forecast for firm sales is 3.3%. The South firm sales averaged only 0.4% during the last five years, while the forecast is expected to return to normal growth of 3.1%, reflecting rough constancy in usage per customer as natural gas prices remain stable in inflation terms over the timeframe.



Natural Gas Interruptible, Transportation, and Total Volumes

As has been the practice of Avista Utilities for a number of years, the retail firm sales forecast is combined with the interruptible and transportation volume forecasts to create a total throughput forecast, this being the total volume of natural gas that is delivered through Avista's distribution system. The following chart shows these volumes.



Enhancements to the Forecasting Models and Forecasting Process

Consistent with our two-year action plan, the models were updated with the latest energy consumption profiles. The model coefficients were checked for price elasticity impacts, and the new values were incorporated into the forecast. The new volumes, driven largely by the recent run up in gas prices, were a reduction in price elasticity for our firm residential and commercial customers. We remain cautious with our elasticity estimates for our industrial customers, because dramatic changes in commodity prices can hamper or severely curtail their international competitiveness. The wild excursions in commodity prices over the last two years appears to be subsiding, even though volatile, and the forecast going forward anticipates rationality in these supply markets.

Avista Corp.

APPENDIX 'B'

DEMAND-SIDE MANAGEMENT

Avista Corp.

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Demand-Side Management

BACKGROUND

Natural gas demand-side management (DSM) programs are separately implemented in the Company's north division (Washington and Idaho) service territory and the Company's Oregon service territory. The current status and future plans for these two divisions will be presented separately below.

WASHINGTON/IDAHO GAS DSM

FUNDAMENTAL OVERVIEW

Avista's Washington/Idaho gas DSM operations are currently funded through a 0.5% tariff rider levied upon retail gas sales in Washington and Idaho. This funding mechanism yields approximately $1 million in annual revenues. Idaho and Washington jurisdiction revenues and expenditures (and the consequential balance) are independently tracked.

There is no regulatory mechanism for lost margin recovery for any north division gas-efficiency acquisition.

Gas DSM operations are governed by two tariffs. Schedule 191 establishes the rates levied upon non-transport gas rates to fund gas DSM. Schedule 190 governs the implementation of DSM itself.

Schedule 190 specifies an incentive formula that can be applied to any gas-efficiency measure. The incentive levels are tiered based upon the simple-payback of the project. The more cost-effective the measure is to the customer the less the incentive. There are two separate tier structures available, one for standard gas-efficiency projects and a second structure for designated "new technology" measures.

Standard Gas-Efficiency Measures

Customer Simple Payback	Customer Direct Incentive
0 to 17 months	$0.00 per first year therm
18 to 47 months	$2.00 per first year therm
48 to 71 months	$2.50 per first year therm
72 months or more	$3.00 per first year therm

Subject to a maximum payment of 50% of the incremental cost

New Technology Gas-Efficiency Measures

Customer Simple Payback	Customer Direct Incentive
0 to 47 months	$2.50 per first year therm
48 to 71 months	$3.00 per first year therm
72 months or more	$3.50 per first year therm

Subject to a maximum payment of 75% of the incremental cost

North division DSM is overseen by a non-binding oversight organization, the External Energy Efficiency Board (also known as the "Triple-E" Board). Periodic reports on cost-effectiveness, resource acquisition and other measures of effectiveness are presented to the Triple-E Board. The Triple-E Board is convened twice per year to review and assess Avista DSM programs.

PROGRAM AVAILABILITY

North division electric and gas DSM programs are subdivided into three portfolios: non-residential, residential and limited income. Each of the different portfolios fulfills the requirements of Schedule 190 with slightly different approaches.

Within the non-residential portfolio there is a heavy reliance upon site-specific calculations of energy savings and an individualized application of the Schedule 190 incentive formula for each project. Any gas-efficiency measure qualifies for assistance (financial and/or non-financial) within this portfolio.

Residential segment gas DSM is composed of a portfolio of prescriptive programs. Incentive levels are established based upon the Schedule 190 incentive formula applied to a typical installation. Prescriptive residential gas-efficiency programs for programmable thermostats, high-efficiency gas furnaces, high-efficiency gas water heating and weatherization (duct, floor, wall, ceiling and attic) are currently available. Incentive levels of these programs are periodically modified as necessary based upon changes in retail rates and typical installation characteristics. It is anticipated that measures will be periodically rotated to keep the overall residential portfolio 'fresh' and maintain the interest of the customers and the dealer infrastructure.

Qualified limited income customers are eligible for incentives implemented through five separate community action program (CAP) agencies within the Avista service territory. These programs fund the previously identified residential measures plus infiltration up to 75% of the total cost of installation. Additionally the CAP agency qualifies for up to a 15% reimbursement for administrative expenses. The total funding available to the CAP agencies is governed by an annual contract with each individual agency.

RECENT HISTORY

In February 2001 the Company filed revisions to the Washington and Idaho Schedule 191 tariffs that raised the tariff rider levels from 0.0% to 0.5%. Shortly after that revision two PGA filings resulting in significant retail rate increases were implemented. During this same period of time the summer of 2001 energy emergency brought energy issues literally to the front page on an almost daily basis. Though much of the crisis revolved around electric wholesale rates and availability the general public did not always distinguish between the two forms of energy.

As a result of this situation the Company achieved 476,065 first-year therms of natural gas savings in 2001 at a cost of $1,383,268. The gas tariff rider balance at the close of the year was a negative (expenditures exceeding revenues) $596,296. This contributed to a $12.4 million negative combined electric and gas tariff rider balance.

At the close of 2001 the Company created a four-year business plan to bring the DSM tariff rider balances back to zero without an increase in tariff rider surcharges or significant reductions in program availability. That plan involved a variety of cost-control measures, scheduling of non-residential incentive payments and the targeting of low-cost/no-cost and lost opportunity measures. The Company is committed to delivering energy savings that are at least proportionate to the percentage of tariff rider funds that were expended during this time.

The four-year (2002 to 2005 inclusive) business plan calls for combined gas and electric DSM expenditures to be limited to approximately 62% of tariff rider revenues. While this strategy is projected to return the combined gas and electric DSM balance to zero by the close of 2005, detailed projections also indicate that the gas tariff rider will be negative at this time and will be offset by a positive balance in the electric tariff rider. Intervention may be required to rectify this imbalance if the demand for gas-efficiency projects remains at the current high levels. This intervention may come in the form of substituting new residential electric programs for existing residential gas programs or reductions in the gas-efficiency incentive levels specified in Schedule 190. These actions will be reevaluated in early 2004 based upon the gas DSM balance and the projections of customer demand and revenue through the close of 2005.

ENERGY SAVINGS

In 2001 the gas DSM portfolio delivered 198% of the energy savings goal established in Schedule 190 using only 183% of the incoming revenues. Preliminary projections for 2002 indicate approximately 269% of the savings goal has been achieved with 146% of the revenues being expended.

It remains to be seen if these disproportionate level of savings can be sustained. Retail rate increases and the summer of 2001 energy emergency created a unique energy-efficiency opportunity. Lower retail rates and saturation of gas-efficiency measures during this period may lead to reduced achievements in future years.

FUTURE PROSPECTS

To date the Company has been able to continue to offer the same programs to our customers in spite of the need for overall reductions in utility expenditures to bring the tariff rider balance back to zero. Customer demand and the individual measures implemented will determine if there will be a future need for changes in program availability and/or the incentive formula specified in the tariff rider. At this point such changes would be premature.

Regardless of any future changes to DSM operations the Company intends to continue to deliver on the commitment to acquire gas savings that are at least proportionate to the percentage of tariff rider revenues being expended. The specifics of how this will be achieved will be based upon the opportunities for cost-effective gas-efficiency.

OREGON GAS DSM

FUNDAMENTAL OVERVIEW

Avista's gas DSM programs in Oregon are capitalized investments that ultimately become ratebased assets. Unlike Washington and Idaho there is a lost margin recovery mechanism for demonstrable gas-efficiency savings resulting from utility DSM programs. Avista serves only natural gas in Oregon and has done so since it acquired this service territory in 1991.

DSM OPERATIONAL ACHIEVEMENTS

Commercial audits are offered on an annual basis to all Schedule 420 and 424 commercial gas customers. Direct incentives are available to these customers for qualifying gas-efficiency projects. The standardized incentive structure provides customer direct incentives for the present value of the avoided cost savings in excess of a two year participant simple payback, subject to a maximum payment of 50% of the incremental cost associated with the gas-efficiency measure. Under this commercial program the south division has achieved 99,020 first-year therm savings from April 1994 to the close of calendar year 2002.

Residential energy audits and weatherization incentives, mandated by the State of Oregon, continue to be offered. The Company's implementation of these programs is augmented by local community action agencies serving the limited income customer segment. These agencies receive a reimbursement of administrative costs for their program implementation assistance. The weatherization programs have resulted in 850,190 first-year therm savings from the 4^{th} quarter of 1991 through the close of 2002.

The Company has also offered incentives for high-efficiency furnaces and water heaters to qualifying residential customers since 1994. That program was originally designed as a short-term market transformation program to address the stocking patterns and pricing of high-efficiency gas appliances in the Oregon service territory west of the Cascades and has been extended in recognition of the programs' customer value.

The program has been successful in reducing the wholesale cost of these appliances and increasing their availability. High-efficiency appliances are now a viable option for those customers with unexpected "no heat" failures. In the past these customers would be forced to wait (without heat) while a high-efficiency appliance was ordered from wholesalers in Portland.

The cost premium for high-efficiency appliances at the wholesale level of distribution has fallen as a direct consequence of the program. This premium reduction has not yet been fully realized at the retail level, but market forces should ultimately cause these savings to be passed on to the end-use customer.

Due to the success of the program west of the Cascades and the increased cost-effectiveness resulting from increased wholesale natural gas prices, the program was not only continued beyond the originally planned 2001 ramp-down date, but extended throughout the Oregon service territory. The Company will perform a cost-effectiveness analysis on continued program activity prior to the next Integrated Resource Plan in order to determine the long-term future of these rebates.

From the 1994 adoption of the high-efficiency space and water heat appliance program to the close of 2002 the Company has achieved 507,569 first-year therm savings.

Overall the south division has acquired 110,675 first-year therms of gas-efficiency resources in 2000, 122,259 in 2001 and 134,469 in 2002.

Business Energy Tax Credits (BETC) will continue to be aggressively leveraged to increase the penetration of gas-efficiency measures and broaden the participation in the Company's gas-efficiency programs. The availability of these tax benefits has been and will continue to be a significant benefit to the marketing of these programs.

FUTURE PROSPECTS

The Company will continue the high-efficiency space and water heating appliance program pending completion of a full analysis of the cost-effectiveness of the market transformation program. Should the program be determined to be cost-effective beyond the originally specified market transformation period it will be adapted into a long-term program offering.

Mandated residential weatherization programs will continue as well, with their implementation coordinated with community action agencies to maximize the participation of limited income customers.

Schedule 420 and 424 customers will continue to receive audit assistance and qualifying projects will be eligible for direct cash incentives.

APPENDIX 'C'

SUPPLY SIDE RESOURCES

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SUPPLY SIDE RESOURCES

The supply options of Avista's integrated resource portfolio consist of various components. These include firm and non-firm supplies contracted for on a long-term and short-term basis, firm and interruptible transportation on seven interstate pipelines, and three storage services. Avista acquires supplies to meet the demand of core customers in four states; California, Idaho, Oregon and Washington. This diversity of delivery points and load requirements adds to the options available to meet customers' needs. The utilization of these components varies depending on demand and operating conditions.

In order to achieve a balanced resource portfolio, Avista attempts to balance the benefits and risks involved in purchasing spot market gas. At the same time, it is important to minimize the premium associated with firm supply contracts, while ensuring sufficient gas to meet peak day and winter requirements. The Company is committed to providing reliable, reasonably priced natural gas service to its customers both today and in the future through the use of a diversified supply procurement strategy and numerous pipeline transportation contracts.

In 1999, the Company entered into an agreement with Avista Energy to have Avista Energy manage all the supply and transportation needs of Avista Utilities except for the California properties. Avista Energy is not only managing the current supply and transportation contracts that are held by Avista Utilities, but has the responsibility to acquire additional supplies as needed to meet the demand of the core utility customers and manage Avista Utilities underutilized pipeline capacity. Avista Utilities, in concert with Avista Energy, determine the level and timing of fixed price commodity purchases using hedges in order to meet approximately one-half of expected core customer demand. This is done through periodic meetings of the Strategic Oversight Committee (SOC). This committee is made up of individuals from the natural gas area of Avista Energy and Avista Utilities. Also included in the Committee are representatives from the Rates Department and Risk Management area of the Utilities.

EMERGING ISSUES

The Company continues to be impacted by the Federal Energy Regulatory Commission (FERC) Order 636 which brought the natural gas industry to its current state of deregulation. This Order was imposed in 1992, and fully implemented at Avista in 1993. The Company's rates, for example, were impacted by the FERC's imposition of a rate design that captured all interstate pipeline's fixed costs in the demand charge paid by the pipeline's firm customers.

A continuing issue at FERC is how pipeline expansion costs will be placed into rates. FERC's current plans call for all new pipeline expansions to be priced at incremental rates unless it can be proven that it is beneficial to all customers with no increase in tariff rates. This is a departure from the previous methodology that allowed rates to be rolled-in unless the impact was greater than a 5% increase to existing customers.

INCENTIVE MECHANISMS

As stated earlier, Avista Utilities entered into an agreement with Avista Energy to manage the utilities supply and transportation needs for the customers of Washington, Idaho, and Oregon. Avista Utilities still manages the supply and transportation for the California customers and for any natural gas purchases for electric generation for Avista Utilities. This arrangement seeks to provide the company with incentives to reduce overall gas costs to core customers and to allow both customers and shareholders to share the benefits (or costs) of lower (or higher) gas costs as compared with certain benchmark levels.

The incentive mechanisms were first established in Washington, Idaho, and Oregon on a 2-year, 9-month trial in 1999. In each of these jurisdictions the mechanism is similar, however, the pricing and sharing structures vary between the states. At the end of the trial period, Avista Utilities filed with the State Commissions to extend, with modifications, the mechanism for an additional 3 years. The current mechanism is approved in Oregon and Idaho until March 31, 2005 and until January 29, 2004 in Washington. At the time of the printing of this document, Avista was awaiting the WUTC Order to determine the future status of the "benchmarking" mechanism.

RISK MANAGEMENT

In 2000, the industry experienced the highest prices ever seen. In response, Avista Utilities, through Avista Energy, has established a schedule to lock in hedges and volumes for price stability. The hedging schedule provides for both structure and flexibility for both timing and volumes. Avista has established a base line that approximately 50% of our annual monthly loads will be hedged prior to entering into the heating season, that being November 15th, with fixed price natural gas. This volume was selected because except in a very rare weather situation, core loads will not be lower than this on any given day within the month. Volumes above the 50% have a different pricing profile, but the majority is based on a composite of monthly index gas from AECO, Sumas, and Rockies. The current composite of monthly index gas is 50/25/25, (AECO, Sumas, Rockies) for Idaho and Oregon, and 57/18/25, (AECO, Sumas, Rockies) for Washington.

NATURAL GAS COMMODITY RESOURCES

Historically, Avista Corp. has purchased supplies in several different ways. *Firm open market supplies* have been purchased from suppliers of natural gas. The Company has negotiated agreements anywhere from three months to five years with several natural gas suppliers for firm winter supplies to be transported on NWP or GTN. The agreements generally run from November through February or March of each year, which enables the Company to ensure firm winter supplies without incurring obligations for high levels of takes during periods of low demand in the summer months. Firm gas is also contracted for on an annual basis. Avista's ability to contract for high load factor supplies is limited because of the relatively low summer demand on the system. Currently, several Alberta supply contracts provide for supply on an annual basis.

Although contract specifics vary, most specify that supplies are firm except for *force majeure* conditions. In addition, some contracts specify fixed prices, while others are indexed to floating prices. Some contracts have fixed reservation charges assessed during each of the winter months, while others have minimum daily or monthly take requirements. Most contain provisions for symmetrical penalties for failure to take or supply gas according to contract terms. Contract details will also vary from year to year, depending on company and supplier needs and the general trends in the market.

Non-firm open market supplies (spot market supplies) are short-term purchase arrangements. They have a lower reliability, balanced by reduced performance obligations by both parties. Prices are market driven and at any given time may be either lower or higher than longer-term contracts. Non-firm supplies may also be used to supplement firm contracts during times of high demand or to displace other volumes when it is cost-effective to do so. These non-firm supplies may be transported under either firm or interruptible transportation, depending on transportation availability. Non-firm or spot market purchases can be made for an entire month, for a few days, or for a single day. Spot market supplies are also used to meet fluctuating loads especially in the shoulder months.

As part of the incentive mechanism with Avista Energy, a detailed schedule of when gas purchases, for a portion of gas supply needs, will occur for the following heating season has been established. The schedule was put into place to help mitigate risks in the market place due to price fluctuations from season to season and year to year.

FUTURE RESOURCES

The Company in its resource management activities also considers other potential resources. These potential resources include those requiring physical assets and those dependent upon contractual or financial arrangements. Some of these are detailed below. The Integrated Resource Portfolio section of this document will show the future needs for each of the potential resources to meet future demand.

JACKSON PRAIRIE STORAGE PROJECT

In the early 1980's, Avista determined it did not then need its entire Jackson Prairie storage capacity to meet firm system requirements. In 1982, Avista released half of its capacity and deliverability at Jackson Prairie to B. C. Hydro. The primary term of the original contract was set to expire in 1996, with a provision for year-to-year continuation thereafter. The new contract with BC Gas, successor to BC Hydro for gas operations, has been in place since 1996 with recall provisions after 2000. This retains the storage capacity for Avista's future use, while providing a return on Avista's investment in the form of rental payments until such time as the additional capacity is needed. The year to year renewal of this contract is analyzed each year to determine the appropriateness of continuing this agreement with BC Gas.

In late 1990, Avista made a similar, but smaller, release to Cascade Natural Gas Company (Cascade). As with the BC Gas release, this release to Cascade retains the storage capacity for Avista's future need and is analyzed each year to determine the appropriateness of continuing.

In 1999 and again in 2001, Avista Corporation participated in expansions of the Jackson Prairie Storage Project with Williams Pipeline and Puget Sound Energy. It was determined that the additional capacity was not needed at the current time for core utility customers and is being managed by Avista Energy.

The Company continues to evaluate its Jackson Prairie capacity and deliverability for requirements to determine if it should continue present releases, calling back some or all capacity, perhaps negotiating additional releases, or participate in future expansions of the project.

PIPELINE CAPACITY

Pipeline capacity expansion projects create potential difficulties for a local distribution company. Chief among these is that the timing of the pipeline expansion project may not necessarily match the needs of the LDC. When the LDC's long-term projections show a need for, or benefit to be derived from, participating in a proposed expansion, it may be appropriate to do so. While this may result in temporarily under-utilized firm capacity, it may be appropriate when long-term benefits are considered when supported by detailed analysis. Pipeline expansions in the past were very infrequent, but since 1991, expansion projects have been proposed about every two to three years. Pipelines offer an open season for pipeline expansions when they are:

- requested to by a shipper or potential shipper
- the pipeline has been continuously running near maximum capacity
- other circumstances

Other considerations that must be evaluated is if the need for a shipper is for additional mainline only transportation, lateral only, or both.

Since the last IRP, Avista Utilities has acquired additional pipeline capacity from GTN in the amount of 20,000 Dth/day. This was for capacity on the lateral between GTN's mainline near Klamath Falls, Oregon and Medford, Oregon. This was pipeline capacity that had not been contracted for from the construction of the lateral in 1995 and satisfied the growing core load demand in southern Oregon. This need was demonstrated in the 2000 IRP.

CAPACITY RELEASE

FERC's Order 636 allows greater flexibility than in the past for a LDC. Should a utility have temporarily under-utilized transportation capacity, especially in the early years following an expansion, it can release capacity to third parties for limited periods. This allows a utility to recall capacity to meet the needs of its core customers. On the other hand, if a utility faced unexpected load growth or the next pipeline expansion was delayed, the utility itself can go out and if the capacity is available from some other shipper, contract for capacity for the limited period until a permanent alternative becomes available.

The FERC established a test period where by capacity releases with less than one year of duration could be released for more than 100% of the firm transportation costs. This allowed for true market pricing for transportation in the one year or less market. This test period ended in 2002, at which time the FERC reverted to its long-standing policy that capacity could only be marketed at 100% of tariff or less.

ADDITIONAL STORAGE FACILITIES

Located in Avista's service area are several other potential supply resources.

(1) Company owned liquefied natural gas storage. LNG facilities could be constructed within the Company's service area. By locating within the Avista service area and not on the interstate pipelines, Avista could avoid annual pipeline charges. Such construction would be dependent on regulatory and environmental approval as well as cost effectiveness requirements.

Preliminary engineering estimates of the construction, environmental, right of way, legal, operating and maintenance, and inventory costs for a needle-peaking resource indicate that Company owned LNG facilities do not appear to be cost effective. This resource is continually looked at and studied.

(2) Company owned satellite liquefied natural gas storage is another option. Satellite LNG facilities could be constructed within the Company's service area. Unlike LNG facilities described in (1), satellite LNG uses natural gas trucked to the facilities in liquid form rather than liquefying on site. By locating within the Avista service area and not on the interstate pipelines, Avista could avoid annual pipeline charges.

Estimates for this type of needle-peaking resource look interesting, but as with stand-alone LNG, this option is not cost beneficial to our customers at this time. The Company will continue to monitor and evaluate the cost and benefit of satellite LNG systems as new supply increments need to be added to Avista's portfolio.

(3) Propane-air facilities are yet another option. Propane air and natural gas interchangeability concerns may limit the cost-effective application of a propane-air system to individual industrial customer facilities or to metropolitan areas the size of Spokane. Interchangeability concerns about the blending of too great a concentration of propane-air with natural gas can pose service, maintenance and safety problems. Avista has had experience with propane-air systems in the Medford, Oregon service area for peaking in the past, but at this time does not operate a propane-air plant.

(4) The Company has been working with GTN as to the feasibility of a new underground storage facility in southeastern Washington. Geological studies were performed and one test well drilled. This project is currently on hold.

The Company will continue to evaluate the cost and benefit of new underground storage facilities as new supply increments need to be added to Avista's portfolio.

(5) The Company currently has a few alternate fuel contracts with an industrial customer. Under such arrangements customers agree to sell back certain levels of firm capacity on a peak-shaving basis, thus providing a potential peak resource. The cost considerations for these types of contracts include the cost of alternate fuel systems paid for and installed at the customer's site by Avista. As more industrial customers sign greater long-term transportation agreements with Avista, this option will continue to be evaluated. This kind of arrangement would be dependent on industrial customers having a significant amount of firm load.

TRANSPORTATION AND STORAGE RESOURCES

TRANSPORTATION

The Company has many contracts with NWP and GTN for firm and interruptible transportation to serve the core customers. In addition to this capacity, Avista also contracts for capacity on upstream pipelines to flow gas to NWP and GTN. Table 1 recaps the firm transportation/resource services contracted for by Avista Utilities today. These contracts are of different vintages, thus different expiration dates, but all have the right to be renewed by Avista Utilities. This gives the Company, and the customer, the knowledge that Avista Utilities will have available capacity to meet current and future core load demand.

NWP and GTN provide interruptible transportation service to the Company. The level of service of interruptible transportation is subject to curtailment when pipeline capacity constraints limit the amount of gas that may be moved. Although the commodity cost per therm transported is higher than under firm transportation, there are no demand or reservation charges connected with this transportation contract. Since the market place for capacity release of transportation capacity has become so prevalent, the use of interruptible transportation services has diminished. Avista Utilities does not rely on interruptible capacity to meet core load requirements.

The Company's strategy is to contract for a reasonable amount of firm transportation to serve firm customers should a design peak day occur in a seven to ten year period. Too much firm transportation could keep the Company from achieving its goal of being a low-cost energy provider. The ability to release capacity however, acts to offset the cost of holding underutilized capacity. Too little firm transportation impairs the Company's goal of being a reliable energy provider.

Determining the appropriate level of firm transportation is a complex evaluation of many factors, including the projected number of firm customers and their expected demand on an annual and peak day basis, opportunities for future pipeline or storage expansions, and relative costs between pipelines and their upstream supplies.

Table 1
Maximum Available Firm Transportation/Resources
Dth

	Avista Utilities North		Avista Utilities South	
Firm Transportation	**Winter**	**Summer**	**Winter**	**Summer**
NWP TF-1	143,370	143,370	45,731	45,731
GTN T-1	110,605	85,782	62,260	20,640
NWP TF-2 (JPSP)	76,200	76,200	2,623	2,623
NWP TF-2 (LNG)	22,000	22,000	19,200	19,200
Total	**352,175**	**327,352**	**129,814**	**88,194**
Firm Storage Resources				
JPSP (SGS-1)	112,667		2,623	
NWP LNG (LS-1)	22,000		19,200	
Total	**134,667**		**21,823**	

STORAGE

The Company is one-third owner, along with Williams Pipeline - West and Puget Sound Energy (PSE), in the Jackson Prairie Storage Project. Avista has contracted for service in this underground gas storage project along with LNG storage at Plymouth to serve core customers. Jackson Prairie Storage is an underground reservoir project located near NWP's mainline near Chehalis, Washington. Plymouth LNG is a liquefied natural gas storage facility located near NWP's mainline near Plymouth, Washington. Storage becomes a strategic resource due to the Company's low load factor. It accomplishes four goals:

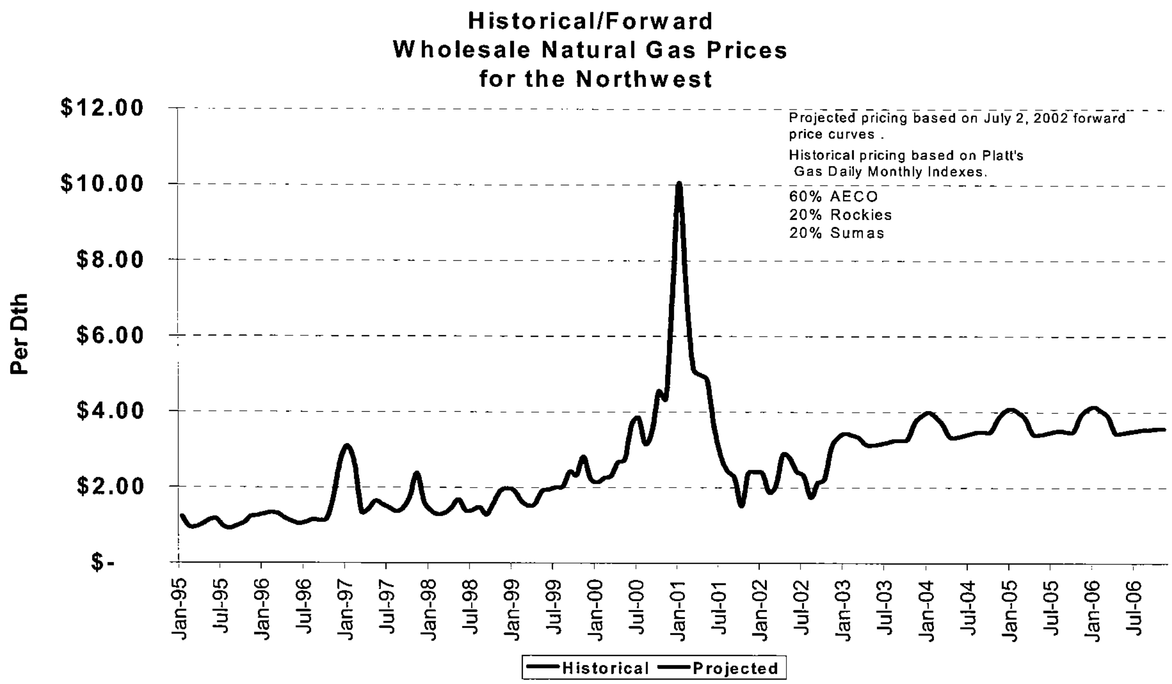
- minimizes need for future high cost annual firm transportation
- increases load factor of existing firm transportation
- access to normally lower cost summer supplies
- provides flexible peaking capability

Table 1 also recaps the current storage resources by area.

SUPPLY RESOURCE

The Company holds several long-term supply contracts for supplies from three separate supply basins. These supplies are for annual and seasonal core customer needs. Through the arrangement with Avista Energy, Avista Energy supplies the natural gas for Avista Utilities core customers, except California, based on forecasts from the Utility. Figure 1 shows historic gas prices and 4-year forward looking based on July 2002 prices. These prices are a composite of 60% Alberta, 20% Domestic, and 20% British Columbia supply basins.

Figure 1



SUPPLY SIDE OPTIMIZATION

The gas-planning model SENDOUT® analyzes the Company's supply and transportation constraints. The SENDOUT® model is more fully described in Appendix D, Integrated Resource Portfolio. The model takes into account the forecast demand characteristics, or load shape. Figures 2 and 3 show the forecasted Load Duration Curve for 2003/2004 for Avista Utilities north and south divisions. This is the forecasted firm requirement based on average weather with design peak days.

Figure 2

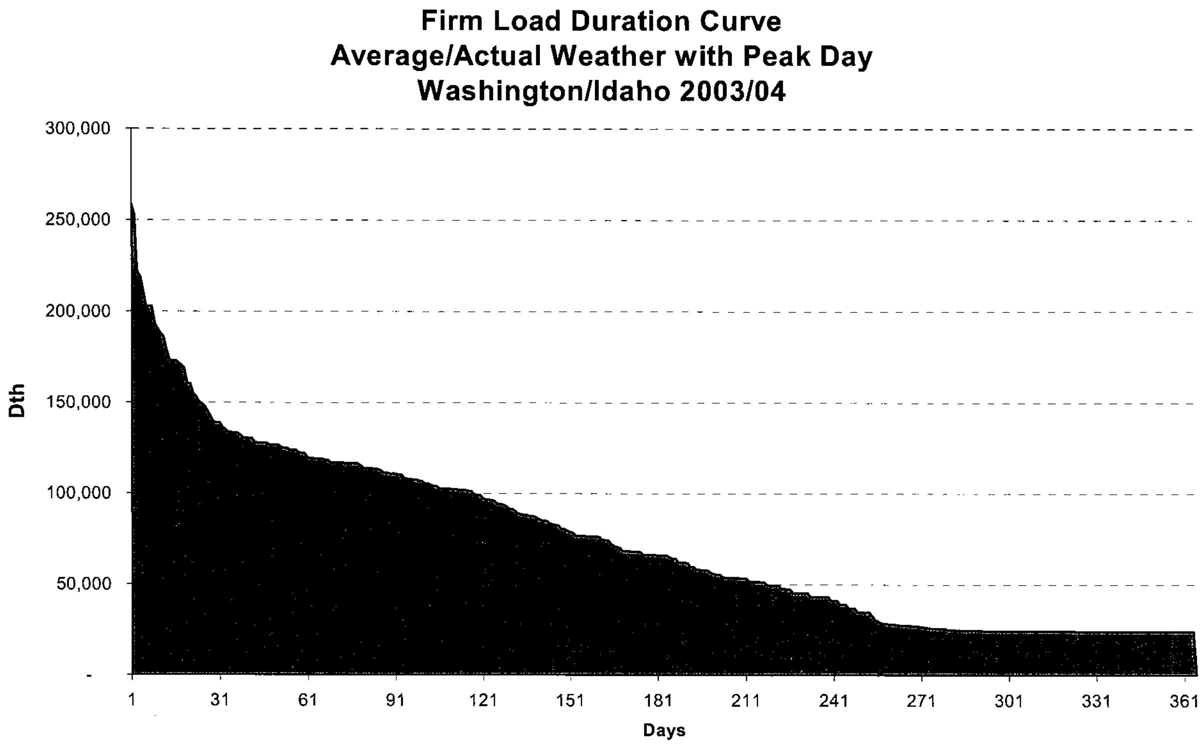
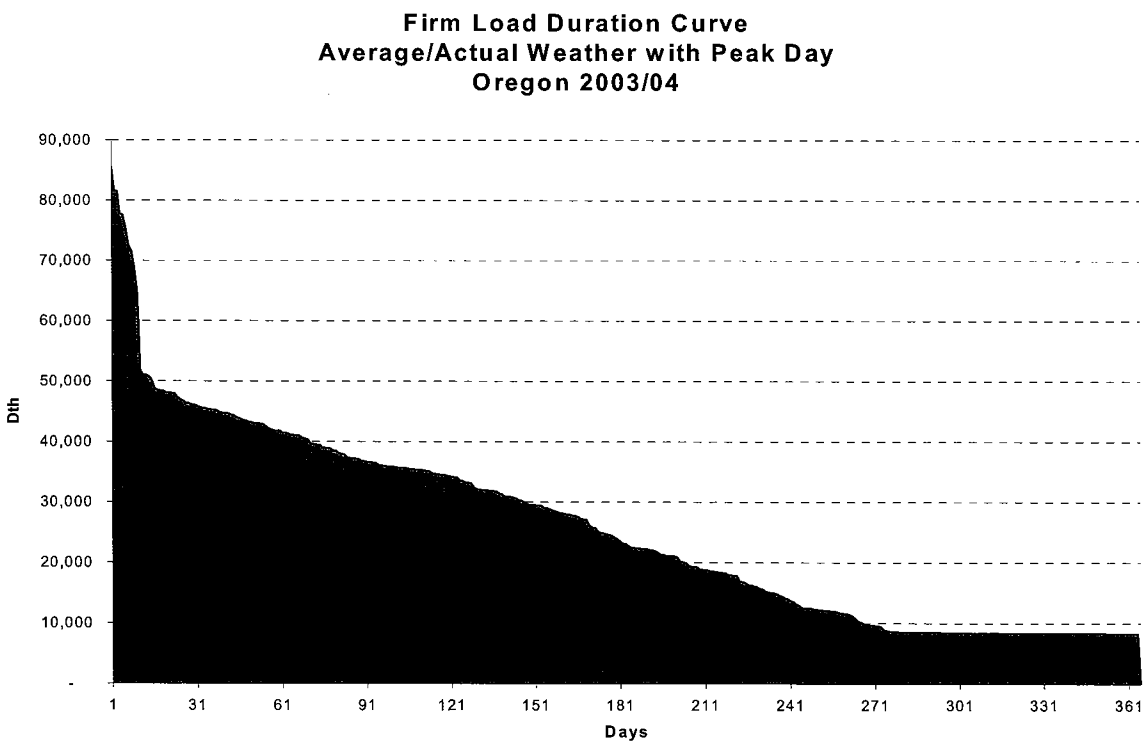


Figure 3

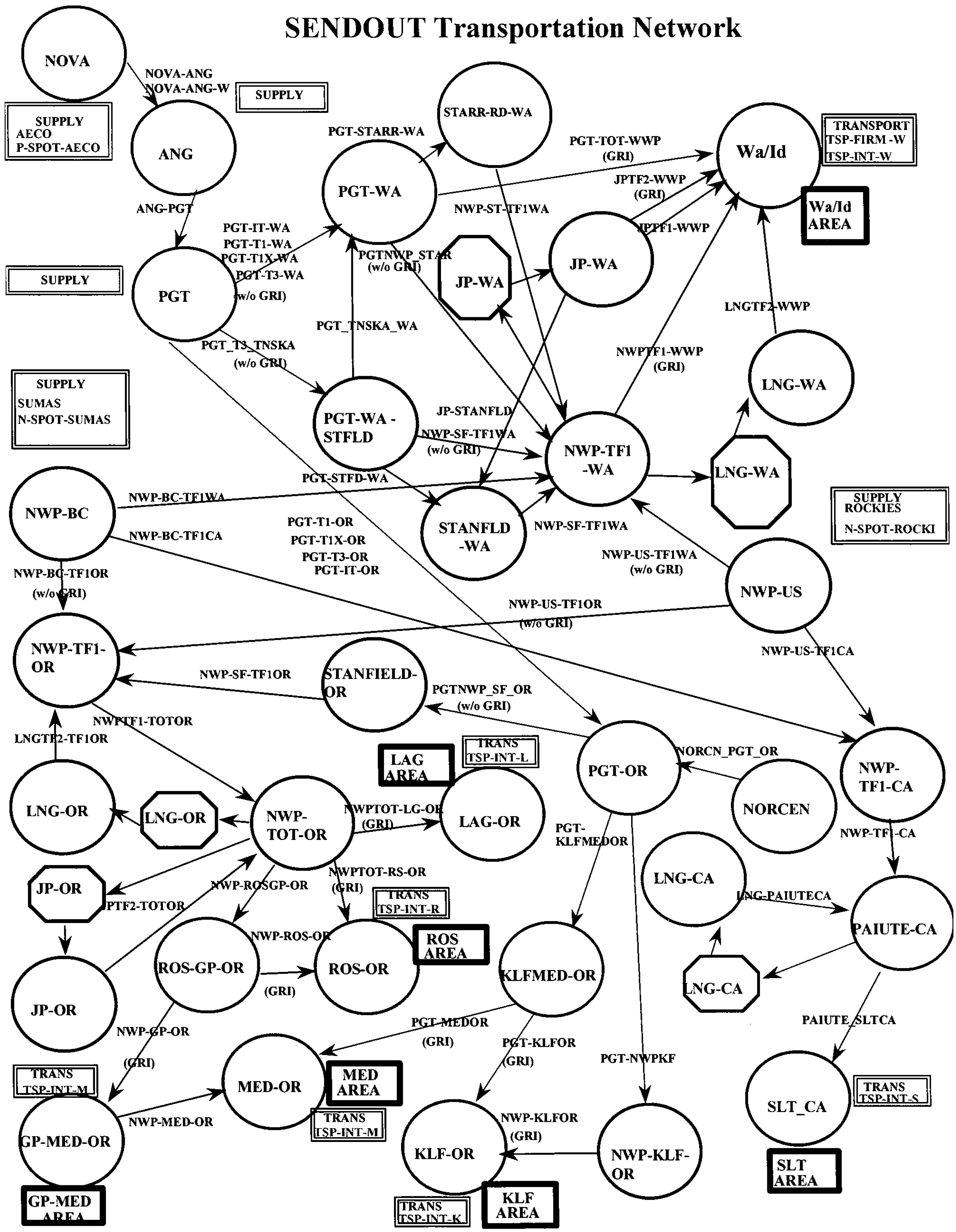


In evaluating possible capacity releases, Avista considers, among other things, peak day demand as it corresponds to peak day capacity. During off-peak periods, Avista releases under-utilized pipeline capacity to other parties through pre-arranged transactions and through the use of NWP and GTN electronic bulletin boards (EBB). Avista's goal is to maximize the revenue generated from capacity releases in order to minimize the cost to consumers of holding pipeline capacity contracts. Avista Energy, through the bench marking mechanism manages this for Avista Utilities.

The physical network for supplies, transportation and storage is represented in Figure 4. This is a graphical presentation how the supply, demand, and transportation are modeled within SENDOUT®.

Figure 4

SENDOUT Transportation Network



Avista Corp.

APPENDIX 'D'

Distribution Planning

AVISTA® Corp.

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DISTRIBUTION PLANNING

COMPUTER MODELING

The primary goal of distribution system planning is to identify the potential problems and weak areas of the distribution system. Knowing when and where pressure problems may occur, the necessary reinforcements can be incorporated into normal maintenance. Thus, more costly "reactive" and emergency solutions can be avoided.

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

Designs for present needs can be compared with those for future needs. This allows the Company to satisfy current requirements while taking a step towards meeting future needs.

THEORY AND APPLICATION OF STUDY

Gas network load studies have evolved in recent years to a highly technical and useful means of analyzing the operation of a distribution system. Using a pipeline fluid flow formula, a specified parameter of each pipe element can be simultaneously solved. A variety of pipeline equations exist, each tailored to a specific flow behavior. Through years of research, these equations have been refined allowing solutions obtained to closely represent actual system behavior.

Network load studies are conducted using Advantica Stoner's SynerGEE 3.33 software. This is a computer based modeling tool that runs on a Windows operating system, allowing users to analyze and interpret solutions graphically.

CREATING A MODEL

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

Nodes (points where gas enters or leaves the system) are placed at all pipe intersections, beginnings and ends of mains, changes in pipe diameter/material, and for all large commercial customers.

Nodes can be named with alphanumeric characters; for example, nodes representing large commercial customers can be named or abbreviated to reflect the customer's name.

A model element connects two nodes together. Therefore, a "to node" and a "from node" will represent an element, between those two nodes. An element can be a pipe, regulator, valve, and reservoir. Almost all of the elements in a model will be pipes.

Regulators are treated like adjustable valves, where the downstream pressure is set to a known value. Although specific regulator types can be entered for realistic behavior, the “expected” flow passing through the actual regulator is determined and the modeled regulator is forced to accommodate such flows. Valves are not included in models, but can be inserted later if required. The necessary input for regulators is fixed downstream pressure and valve constant (C or Cg).

FLUID MECHANICS OF MODEL

Pipe flow equations are used to determine the relationships between flow, pressure drop, diameter, and pipe length. There are several flow equations available within SynerGEE, each tailored for specific flow regimes. For all models, the Fundamental Flow equation (FM) is used due to its demonstrated reliability.

Efficiency factors are used to account for the equivalent resistance of valves, fittings, and angle changes within the distribution. Starting with a 95% factor, the efficiency can be changed to fine tune the model in order to match field results. If efficiency factors deviate from +/- 10%, the model must be re-checked for validity.

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

STEADY STATE COMPUTER SIMULATION

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

Customer loads are obtained from the Customer Billing System and transferred to an algebraic format so loads can be generated for various conditions.

In the event of a peak day or an extremely cold weather condition, it will be assumed that all curtailable loads are interrupted. Therefore, models will be conducted with only firm or non-curtailable loads unless otherwise stated.

DETERMINING GAS CUSTOMERS' MAXIMUM HOURLY USAGE

DETERMINING A BASE LOAD

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

By determining the amount of days in the billing period and the average hours of use in a day, the "peak hourly base load" of each customer can be estimated as shown in Table 1.

Table 1 - Determining A Base Load

$$\frac{\text{Customer Usage}}{\text{Billing Period}} \times \frac{\text{Billing Period}}{\text{days in billing period}} \times 0.0625^{*} = \textbf{Peak Hourly Base Load}$$

---

*note: The average residential customer's peak usage was found to be 6.25% of total daily load. This factor was estimated by studying the ratio of the peak hourly flow and the total daily flow at the pipeline gate stations (result =6.25% of total daily load.) This is also known as the "peaking factor".

DETERMINING A HEAT LOAD

A heat load will be proportional to degree days (DD's): at 0 DD, the load will be zero. A heat load can be reasonably calculated from Customer Billing information. The billing period with the greatest consumption is usually the January month. This month reflects maximum space heating loads as well as non-space heating loads.

Customer's usage for January (winter) billing, minus usage for August (summer) billing, leaves a reasonable estimate for heat load. This load can be divided by the amount of DD's that occurred in January, leaving usage per DD. Customer needs can be calculated by applying the peaking factor, resulting in a "peak hourly heat load" per DD. This is shown in Table 2.

Table 2 - Determining a Heat Load

$$\frac{\text{Customer Usage}}{\text{Winter Billing Period}} - \frac{\text{Customer Usage}}{\text{Summer Billing Period}} = \frac{\text{Heat Load}}{\text{Winter Billing Period}}$$

$$\frac{\text{Heat Load}}{\text{Winter Billing Period}} \times \frac{\text{Winter Billing Period}}{\text{Degree Days}} \times \frac{\text{Design Degree Days}}{\text{Day}} \times 0.0625$$

$$= \textbf{Peak Hourly Heat Load}$$

DETERMINING A DESIGN PEAK HOURLY LOAD

Adding the hourly base load and hourly heat load for a design temperature results in the design peak hourly load for a customer. This estimate reflects all types of loads under worst-case conditions, as shown in Table 3.

Table 3 - Determining a Design Peak Hourly Load

Peak Hourly Base Load + Peak Hourly Heat Load

= Design Peak Hourly Load

APPLYING LOADS

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

GENERATING LOADS

Temperature-based and non-temperature-based loads are established for each node, thus loads can be varied based on any temperature (DD). Such a tool is necessary to evaluate the difference in flow and pressure due to different weather conditions.

If a load study is based on former system data and certain growth in an area is known, loads can be adjusted using a "prorate" or "reduce" tool. Such prevents commercial loads from being increased by the same factor as residential loads.

WHAT IS GIS?

Although Avista is converting its gas facility maps to GIS, (geographic information system) few have a clear understanding of how GIS differs from maps. While GIS can provide a variety of map products, its power lies in its analytical capability. GIS consists of three components: spatial operations, data linkage, and map production.

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

- Identify electric customers adjacent to gas mains that are not currently receiving gas
- Display ratio of customers to length of pipe in EOP zones
- Define high pressure pipeline proximity criteria

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

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

BUILDING SynerGEE MODELS FROM GIS

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

Customers are geographically located based on a street centerline referencing. Through spatial operations customers can be attached to segments of pipe with a particular address range. From this, PD (connectivity) and XY (coordinates) files are created that can be read by SynerGEE. Summarizing the load for each segment of pipe creates the LOA (loads) file. Finally, loads can be applied and analysis of the system can begin.

MAINTENANCE USING GIS

GIS helps maintain the existing distribution facility by allowing a design to be initiated on GIS. Currently, design jobs for the Avista gas system are managed through the Work Management System (WMS). This system is being integrated with GIS, allowing jobs to be designed directly on GIS. Once completed, the as-built information is submitted to GIS and the facility is immediately updated. This eliminates the need to convert physical maps to GIS at a later date. Because the facility is updated on GIS, load studies can remain current by refreshing the analysis.

DEVELOPING A PRESENT CASE LOAD STUDY

In order for any model to have accuracy, a "present case" model has to be developed, specifically, a model that reflects what the system was doing when downstream pressures and flows were known. To establish the “present case”, pressure charts located throughout the distribution were used.

Pressure charts plot pressure (newer units include temperature) versus time over several days. Various locations recording simultaneously were used to validate the model. The loads on SynerGEE were generated to correspond with temperature, which was recorded on the pressure charts. An accurate model’s downstream pressures will match the corresponding location’s “field” pressure chart. To further refine the model's pressures, efficiency factors were fine-tuned.

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

DEVELOPING A PEAK CASE LOAD STUDY

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

ANALYZING RESULTS

After a model has been balanced, several features within the SynerGEE model are used to translate results. Color plots are generated to depict flow direction, pressure, pipe diameter, and gradient with specific break points. Thus "tie-ins," or pipe diameters, could be adjusted, and after re-balancing, pressure changes could be visually displayed.

Any model resulting in node pressures below 15 psig indicates a likelihood of distribution failure and reinforcements will be necessary.

DETERMINING MAXIMUM CAPACITY FOR A SYSTEM

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

Since the approximate gas usage for the average customer is known, it can be determined what the theoretical maximum number of new customers that can be added to the system before necessitating system reinforcements.

Additional model scenarios can be run with new construction proposals or pipe reinforcements to determine the resulting increase in capacity.

FIVE YEAR FORECASTING

The intent of load study forecasting is to predict the system's behavior and what reinforcements are necessary within the next five years. To facilitate, Marketing and field personnel provide information to determine where and why certain areas may experience growth. Forecasting will continue to improve with the joining of SynerGEE and GIS.

CONCLUSION

Computer modeling increases the reliability of the distribution system by pointing out specific areas within the system that may require changes. It is the goal of Avista to maintain its distribution systems in order to deliver gas reliably to every customer with the minimum investment. This goal can be better achieved with computer modeling.

SynerGEE models are constantly used to look at different areas within Avista Utilities' gas service area. From these analyses, near-term and five-year construction budgeting and prioritization are determined. Model results can be made available for review upon request.

Corp.

APPENDIX 'E'

INTEGRATED RESOURCE PORTFOLIO

AVISTA Corp.

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INTEGRATED RESOURCE PORTFOLIO

This appendix describes an analysis and selection of resource options in the context of the Integrated Resource Plan for the north and south operating divisions of Avista Utilities. It also presents the resulting strategies employed to develop an optimal integrated resource portfolio. It is divided into the following sections:

- Resource Options Summary
- Gas Resource Model
- Analysis Framework
- Weather Data
- Avoided Cost
- Environmental Externalities
- Portfolio Integration

The foundation for the selection of resources for an integrated resource portfolio is the annual and peak day load forecast requirements. Prior sections of this report have described in detail the development of the forecast.

The Company plans for its firm pipeline capacity and supplies based on firm peak day load requirements. It is assumed that on a peak day all interruptible customers have left the system in order to provide service to firm customers. The Company does not make long-term firm commitments to serve interruptible customers. However, the projected annual load forecast includes interruptible customer usage because the Company provides gas supply for that load. Interruptible load benefits all customers by absorbing some otherwise fixed costs when contracted levels of firm resources are under-utilized. Therefore, the interruptible customers' requirements are included in the integrated resource portfolio for projected annual load but are excluded in considering peak day load requirements.

Avista Utilities load forecasts are increased between 0.9% and 2.1% on both an annual and peak day basis to account for additional supplies that are purchased for non-sales purposes. This gas is used primarily as fuel for pipeline compressor stations. The percentage of additional supply that must be purchased is governed through the FERC and NEB tariff filings of the pipelines.

The following pages summarize the resource options and describe the avoided cost calculation, analytical process and anticipated results reflected in the Integrated Resource Plan.

RESOURCE OPTIONS SUMMARY

The section on Supply Side Resources contains a description of various supply options available to the Company, which attempts to properly balance the need for both low cost and high reliability in its natural gas operations. These options include:

- Firm supplies via firm NWP or GTN transportation
- Interruptible supply via firm NWP or GTN transportation
- Interruptible supply via interruptible NWP or GTN transportation
- Jackson Prairie or Plymouth LNG storage

GAS RESOURCE MODEL

The gas resource optimization model used by the Company is the SENDOUT® Gas Planning System from the New Energy Associates, a subsidiary of the Siemens Westinghouse Power Corp. This software was originally purchased from Energy Management Associates, who was purchased by Electronic Data Systems, who later sold it to the current software suppliers. The SENDOUT® model was purchased in April of 1992 and has been used in the preparation of all Least Cost Plans since then. The Company has a long-term maintenance agreement with New Energy Associates (NEA) that allows Avista to receive changes to the software as changes become available. These changes not only encompass software fixes, but also change to the software brought on by industry changes.

The users of the SENDOUT® model have established a "user group" that meets once a year. The main purpose of this meeting is to assist NEA as to what direction to go as far as enhancements to the existing system. A side benefit, which is probably more valuable, is the ability to get to know others in the natural gas industry that also use the SENDOUT® model. These meetings not only discuss what enhancements to make, but there are also presentations from different users as to how they are using the model. Avista has been a participant in these meetings at one level or another since the model was first purchased.

SENDOUT® is a PC-based linear programming model used in gas supply and transportation optimization to reach the best-cost solution working within given constraints. Linear programming is a proven technique used to solve minimization/maximization problems. SENDOUT® looks at the complete problem at one time within the study horizon, taking into account physical limitations and contractual constraints. The software looks at thousands of variables and evaluates thousands of possible solutions in order to generate the least cost solution. Among the variables required by the model are:

- Demand forecast for a given area by customer type e.g. residential, commercial, industrial
- Weather pattern information
- Transportation data which describes to the model the distribution network for the physical movement of the gas and pipeline costs

- Supply options consisting of gas contract prices, minimum and maximum take requirements
- Gas storage options with associated injection/withdrawal rates, capacities
- Capacity release data affecting transportation decisions

Some of the major features and functions of the SENDOUT® model include:

- Extensive reporting capabilities including a custom report writer
- Scenario analysis
- Supply contract analysis
- Interfaces to spreadsheets
- Variable length planning horizons and flexible sub-period determination
- Ease of changing time-dependent data
- Capability to define transportation paths
- Ease and flexibility to input and arrange menu data
- An online help text

The SENDOUT® model gives the Company a flexible tool with which to analyze a multitude of potential scenarios such as:

- Optimum levels of pipeline expansion participation
- Affects of different weather patterns upon demand
- Affects of gas price increases upon total gas costs
- Storage optimization studies
- Analysis of pipeline capacity needs
- Resource mix analysis for Demand Side Management programs
- Analysis of transportation costs
- Short-term planning comparison guide

The SENDOUT® model has provided the Company with valuable information used as the framework for developing numerous studies relating to capacity release, storage optimization, peaking supply needs, DSM resource mix, avoided cost calculations, and weather pattern testing and analysis.

ANALYSIS FRAMEWORK

The framework used to analyze Avista Utilities long-range gas supply planning options focuses on the sensitivity of the model solution to changes in:

- Forecast assumptions
- Contractual constraints
- Supply availability and pricing
- Weather assumptions
- Avoided cost

The first three items have been previously discussed. The last two items are presented below.

WEATHER ASSUMPTIONS

Because Avista Utilities loads reflect a weather dependent customer base, the study of weather becomes very important in least cost planning. The analysis in this IRP is based on the weather data as published by, the National Oceanic Atmospheric Administration, NOAA. This is a 30-year weather study spanning 1961-1990. Figures 1 and 2 show the NOAA 30-year average weather data in comparison to the coldest and warmest planning year in the past 30 years for the Spokane and Medford areas. In graphic form, it is very evident that average weather does not give a realistic pattern of actual weather conditions. Actual weather has many days above and below average.

Figure 3 and 4 compare the NOAA 30-year average weather with a composite of weather months that form a weather year based on average heating degree-days, but with the variability of actual weather. These composite weather patterns are used in most of the analysis done within the planning department.

On December 30, 1968, the north operating division area experienced the coldest day on record, an 82 heating degree-day for Spokane. This is equal to an average daily temperature of -17 degrees Fahrenheit. For the purpose of forecasting, this is used as the design day for cold conditions in the Washington/Idaho service area. Only one 82 heating degree day has been experienced in the last thirty+ years for this area, but within that same time period an 80 and 79 heating degree day has occurred on December 29, 1968 and December 31,1978 respectively.

On December 9, 1972, Medford experienced the coldest day on record for the south operating division, a 61 heating degree-day. This is equal to an average daily temperature of 4 degrees Fahrenheit. For the purpose of forecast, this is used as the design-day for cold conditions in Medford. Medford has experienced only one 61 heating degree day in the last thirty years, but has also experienced a 59 and 58 heating degree day in the same 30-year time period, December 8, 1972 and December 17, 1987 respectively. The other three areas in Oregon have similar weather data. For Klamath Falls, a 72 heating degree-day happened on December 21, 1990, a 74 heating degree-day happened on December 23, 1983, in LaGrande, and a 55 heating degree-day happened on December 22, 1990, in Roseburg. For South Lake Tahoe, a 73 heating degree-day happened several times in the past, the most recent occurrence on February 7, 1989.

Figure 1 - Average vs. Coldest vs. Warmest (84/85 plus 82 HDD, 91/92, NOAA) Spokane Weather

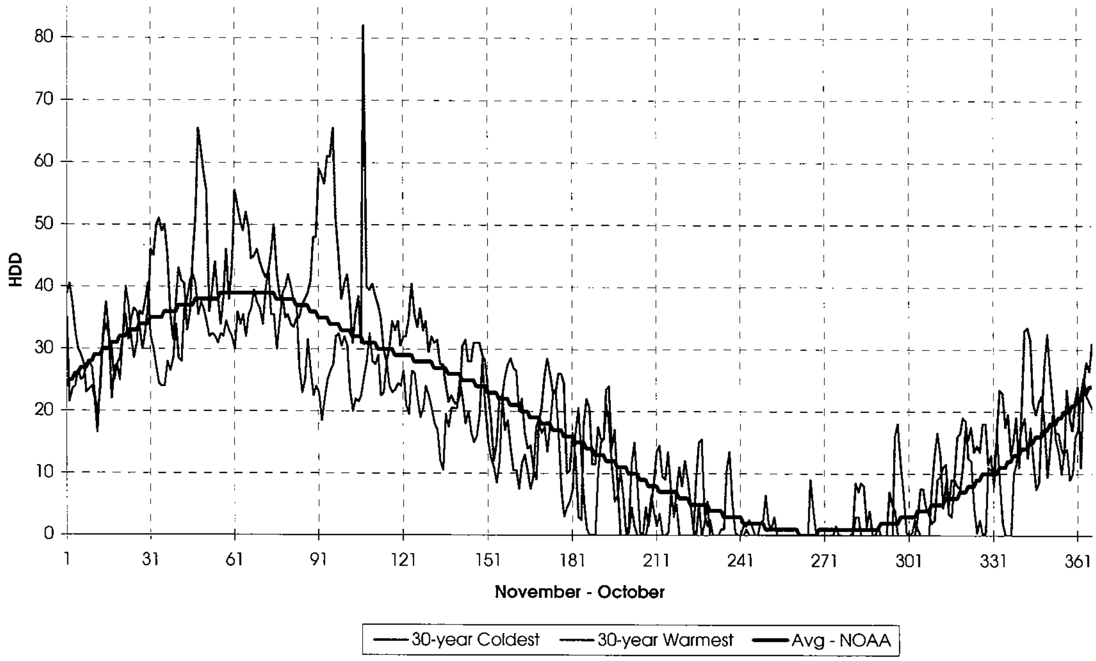


Figure 2 - Average vs. Coldest vs. Warmest (63/64 plus 61 HDD, 91/92, NOAA) Medford Weather

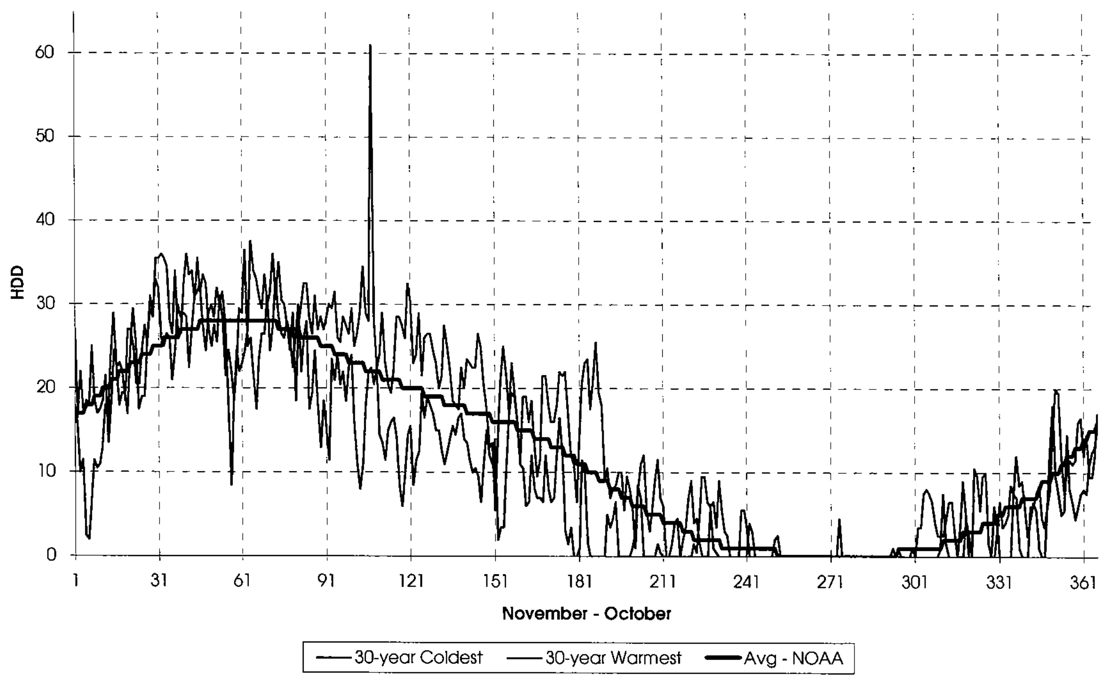


Figure 3 - NOAA 30-year Average vs. Planning Weather
(added 82 HDD on Feb. 15)
Spokane Weather

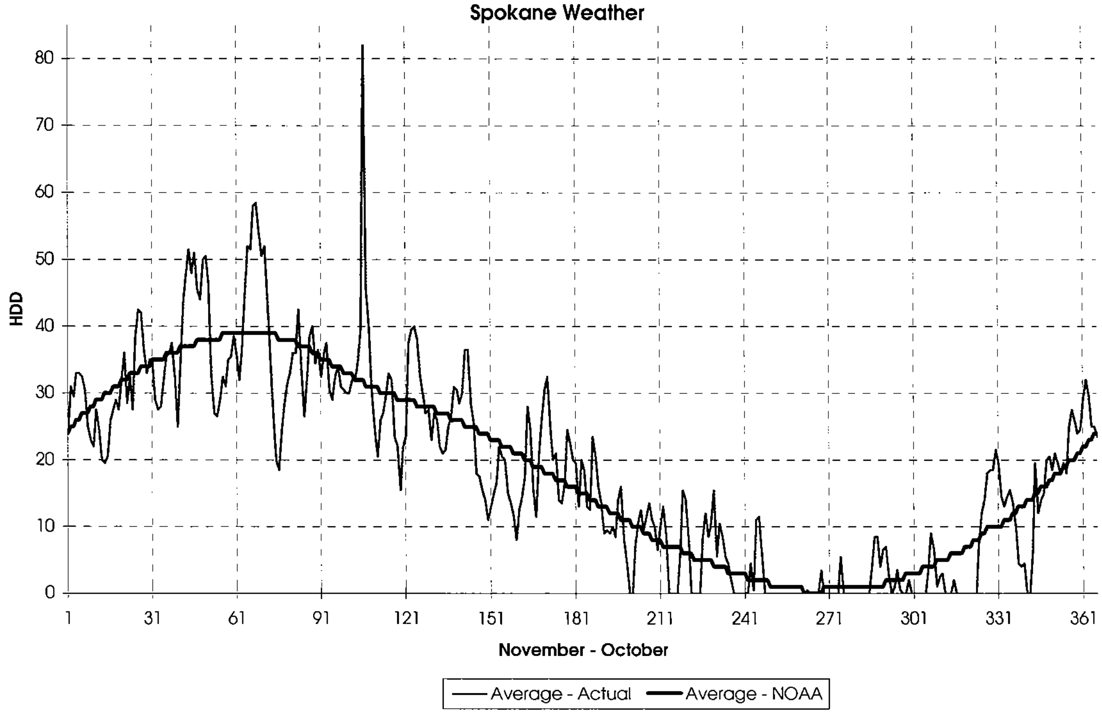
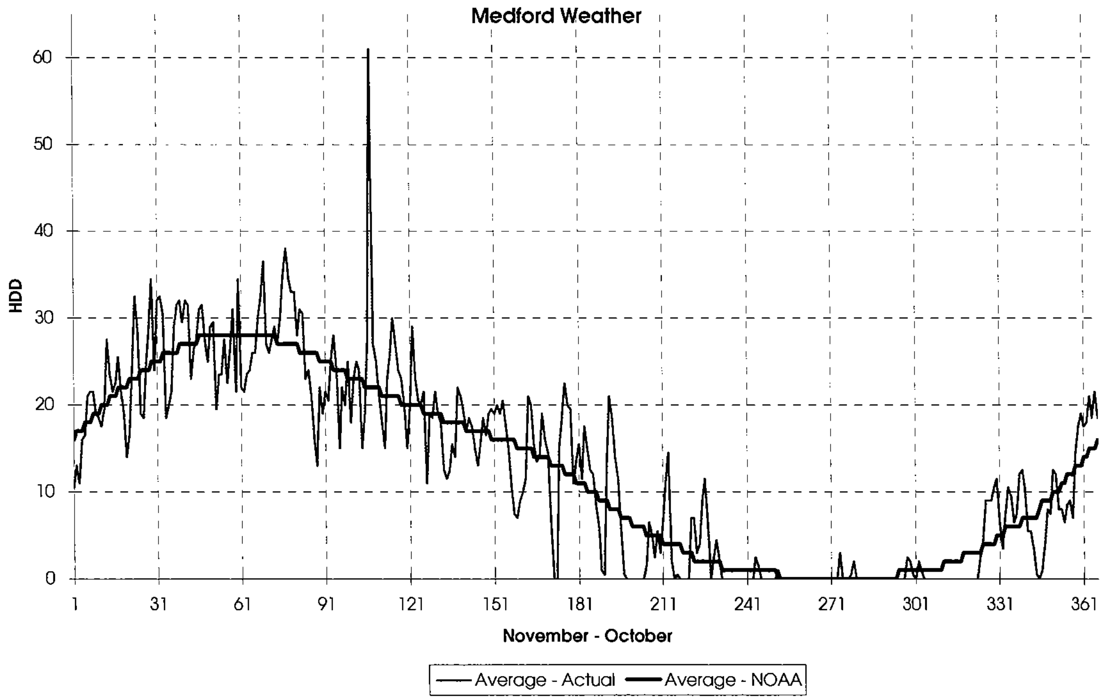


Figure 4 - NOAA 30-year Average vs. Planning Weather
(added 61 HDD on Feb. 15)
Medford Weather



AVOIDED COST

Avoided Cost, as defined in the September 1994 Gas IRP Review published by Gas Research Institute, "is the economic value of fixed (capacity) costs and variable (dispatch) costs not incurred because of the use of supply side and demand-side management measures".

Avoided cost estimates are used to measure costs of DSM programs against the benefits of those programs. These estimates allow supply-side and demand-side options to be evaluated on a comparable basis. The avoided costs help to determine whether it is less expensive to obtain DSM savings via the DSM programs or to increase supply by purchasing more gas.

Industry wide, there are currently four principal methods for calculating avoided costs that are predominate:

- targeted marginal cost
- planning model
- load curve segmentation
- combination

Targeted Marginal Cost

In targeted marginal cost you must first identify the main demand types; this would be non-heat load (baseload) and heat sensitive load. Each supply resource is then categorized according to the type of demand it is used to meet. Targeted marginal cost assumes that the most expensive supply resource will be reduced by the given DSM program, i.e. high efficiency water heaters would avoid baseload supplies while high efficiency furnaces would avoid heat sensitive supplies.

Planning Model

Using the planning model method, a gas-dispatch model is used to optimize supply purchases with and without DSM measures for base and heat load. Avoided costs are calculated as the difference between the optimization runs with and without DSM.

Load Curve Segmentation

A load duration curve is used to determine the number of days a utility supplies a given quantity of gas from different sources. The load duration curve is then divided into segments, (peak, winter, shoulder, and summer) and uses a weighted average of the segments to estimate avoided capacity costs.

Combination

This method combines any of the three methods above or any other methods.

In the 1991 Least Cost Plan (LCP), Avista Corp. used a simple weighted average cost of gas (WACOG) methodology to determine the supply costs avoided by DSM measures. In the 1993 Plan, the Company used a targeted marginal avoided cost analysis. This method targeted the highest cost supply and transportation resource combination for three types of supplies avoided by a particular DSM program or group of DSM programs. The three avoided costs being annual, winter, and peak. This method was further modified in the 1995 Plan. The modification being that only two avoided costs were created, those being annual and winter.

The Company continues to believe that a targeted marginal avoided cost analysis is still the most appropriate method to evaluate various DSM programs. As in the 2000 Plan, the Company has used the SENDOUT Planning model to assist in establishing the supply cost differences and is again proposing two avoided costs; the annual avoided cost and the winter avoided cost. These two avoided costs seem to cover the range of DSM programs. The Company believes the method used for calculating its avoided cost is consistent with the OPUC's UM-551 order. This order addresses the calculation and use of cost effectiveness levels for conservation.

In calculating the 2003 avoided costs, the SENDOUT® model was again used to generate the supply costs for the first 10 year period, then escalating at the 3.6% rate of the remaining 20 years. Along with this was added the current fixed transportation cost escalated over the 30-year period. Additionally for Oregon, a conservation adder of 10% was factored into the avoided cost calculation. The assumptions of the avoided cost are summarized in Table 1. The actual avoided cost calculations are detailed in Exhibit A.

Table 1 – Avoided Cost Calculations
Summary of Assumptions

General:	
Discount Rate:	
Real	5.47%
Nominal	8.22%
Inflation Rate (25 year)	
Domestic Demand Deflator	2.60%
Gas Supply	5.10%
Transportation	2.60%
Annual Supply Avoided:	
Load Factor	100%
Supply Cost per therm	\$0.327
Trans. Component (NWP)	\$0.032
Winter Supply Avoided:	
Load Factor	56%
Supply Cost per therm	\$0.336
Trans. Component (NWP)	\$0.058
Avoided Cost Results:	
(30) years levelized per therm	
Nominal (key for Wa/Id)	
Annual	\$0.473
Winter	\$0.537
Real (key for Oregon)	
Annual	\$0.404
Winter	\$0.459

ENVIRONMENTAL EXTERNALITIES (Oregon only)

There are two forms of environmental externalities used in the Company's 2003 IRP. Both are incorporated into the calculation of avoided cost by adding the costs to the supply and transportation costs. The first is for conservation costs (the state-mandated conservation cost adder of ten percent). This was added to the unit supply and transportation costs, and thus contains the inherent inflation escalators used for those costs. This conservation cost adder was included in the calculation of avoided cost used to actually determine cost effective demand side management resources. The Company's DSM filing is consistent with selection of demand side resources where cost effectiveness was determined with this avoided cost methodology.

The second externally cost component is the environmental externalities adder discussed in OPUC Docket UM-424. The primary externality relevant to natural gas consumption is carbon dioxide, with minor amounts of nitrous oxide, carbon monoxide and methane emissions. Avista Utilities is using the same externality cost estimates for Oregon that were used in the 2000 Plan and acknowledged as still representative in the draft. They are presented in Table 2.

Table 2 – Cost of Externalities Applied to Natural Gas

Emission	Weight per therm	Cost per ton	Cost per therm
CO_2	11.800 lbs	\$ 10 - \$ 40	06.000¢ - 24.000¢
NO_x	.090 lbs	\$2,000 - \$5,000	00.080¢ - 00.160¢
CO	.004 lbs	\$ 500 - \$1,000	00.001¢ - 00.002¢
CH_4	.028 lbs	\$ 100 - \$ 400	00.001¢ - 00.004¢
Total per therm Adder:			6.082¢ - 24.166¢

Table 2 summarizes the emission weight and cost of externalities applied to natural gas provided by the Oregon State Department of Energy.

The Company urges care in the use of any avoided cost that includes environmental externalities. The Company's avoided cost (including externalities) should only be compared with other fuels or other natural gas providers on an "apples to apples" basis in which similar environmental externalities are included. The Company also believes that ultimately if any environmental costs are used then all such costs should be included. The commission currently addresses only air emissions, which capture almost the entire category of externalities for natural gas, while other fuels may have significant environmental impacts on ground and water.

In addition, the inclusion of both a ten percent conservation cost and the externality costs is probably overstating the environmental impact of natural gas use. Because air emissions represent the majority of natural gas externalities, the

Company would prefer that all costs be considered and that either the greater of the environmental costs or ten percent be included.

PORTFOLIO INTEGRATION

The combined Oregon, Washington and Idaho integrated resource portfolio, which results from the linear optimization model run, is shown in Figure 5 and Table 3 peak day requirements. For these model runs, the actual supply contracts have been divided into individual supply basins, thus maintaining the confidentiality of

Figure 5 - Peak Day Supply
Firm Demand
(Noncoincidential Peak)

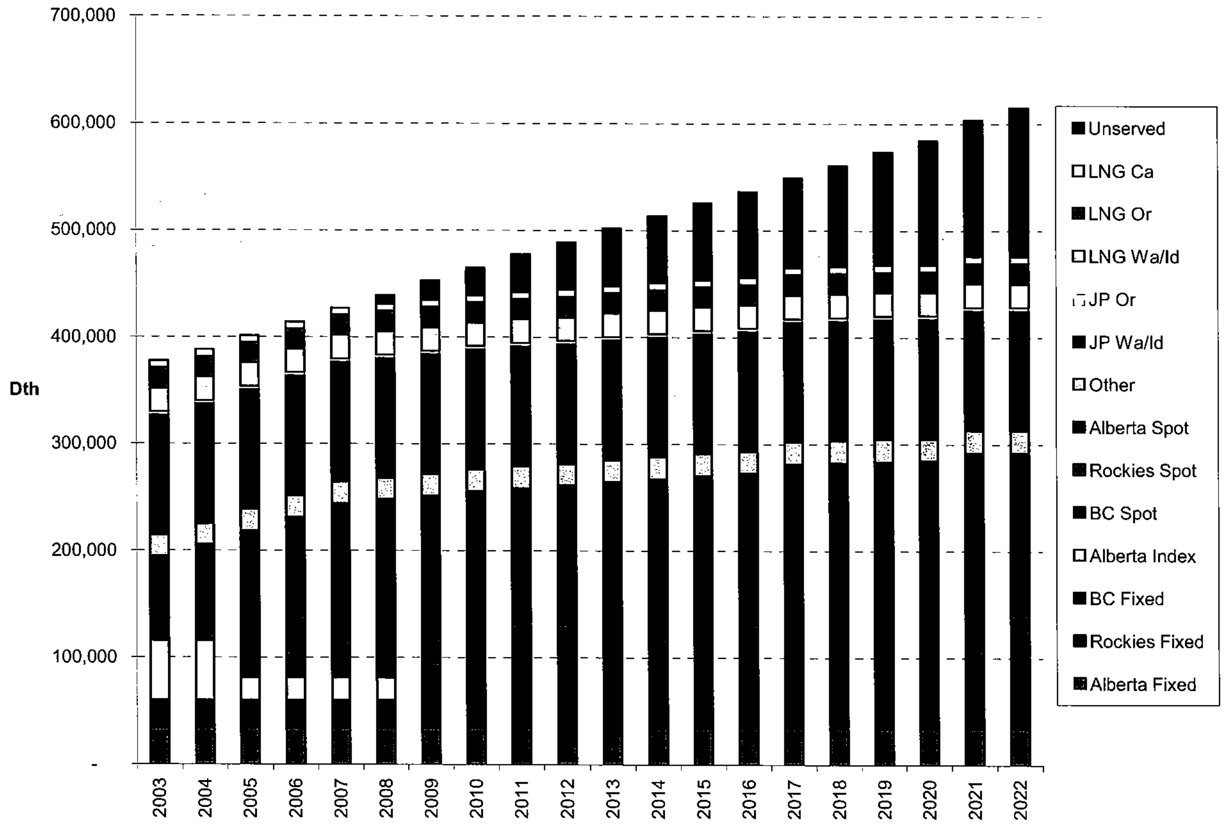


Table 3 - Peak Day Supply
2003 - 2022

Noncoincidential Peak

	2003	2004	2005	2006	2007	2008	2009
Alberta Fixed	34,000	34,000	34,000	34,000	34,000	34,000	34,000
Rockies Fixed	13,000	13,000	13,000	13,000	13,000	13,000	13,000
BC Fixed	13,000	13,000	13,000	13,000	13,000	13,000	13,000
Alberta Index	55,740	55,740	21,140	21,140	21,140	21,140	-
BC Spot	-	1,880	10,250	20,590	30,470	31,650	31,750
Rockies Spot	37,200	35,920	37,200	37,200	37,200	37,200	37,200
Alberta Spot	41,650	52,200	89,640	92,170	95,270	98,310	122,320
Other	19,960	19,340	20,100	20,170	20,240	19,610	20,380
JP Wa/Id	112,670	112,670	112,670	112,670	112,670	112,670	112,670
JP Or	2,620	2,620	2,620	2,620	2,620	2,620	2,620
LNG Wa/Id	22,000	22,000	22,000	22,000	22,000	22,000	22,000
LNG Or	19,200	19,200	19,200	19,200	19,200	19,200	19,200
LNG Ca	6,340	6,340	6,340	6,340	6,340	6,340	6,340
Unserved		-	-	-	-	8,430	18,210
	377,380	387,910	401,160	414,100	427,150	439,170	452,690

	2010	2011	2012	2013	2014	2015	2016
Alberta Fixed	34,000	34,000	34,000	34,000	34,000	34,000	34,000
Rockies Fixed	13,000	13,000	13,000	13,000	13,000	13,000	13,000
BC Fixed	13,000	13,000	13,000	13,000	13,000	13,000	13,000
Alberta Index	-	-	-	-	-	-	-
BC Spot	33,590	33,680	33,780	33,870	33,960	34,060	34,150
Rockies Spot	37,200	37,200	37,200	37,200	37,200	37,200	37,200
Alberta Spot	124,960	127,700	130,470	133,180	135,990	138,820	141,610
Other	20,460	20,530	19,890	20,680	20,760	20,830	20,190
JP Wa/Id	112,670	112,670	112,670	112,670	112,670	112,670	112,670
JP Or	2,620	2,620	2,620	2,620	2,620	2,620	2,620
LNG Wa/Id	22,000	22,000	22,000	22,000	22,000	22,000	22,000
LNG Or	19,200	19,200	19,200	19,200	19,200	19,200	19,200
LNG Ca	6,340	6,340	6,340	6,340	6,340	6,340	6,340
Unserved	26,150	35,580	44,720	54,010	63,020	71,860	80,490
	465,190	477,520	488,890	501,770	513,760	525,600	536,470

	2017	2018	2019	2020	2021	2022
Alberta Fixed	34,000	34,000	34,000	34,000	34,000	34,000
Rockies Fixed	13,000	13,000	13,000	13,000	13,000	13,000
BC Fixed	13,000	13,000	13,000	13,000	13,000	13,000
Alberta Index	-	-	-	-	-	-
BC Spot	42,300	42,390	43,680	43,680	43,680	43,680
Rockies Spot	37,200	37,200	37,200	37,200	37,200	37,200
Alberta Spot	141,610	142,640	142,640	143,780	150,930	150,930
Other	20,980	21,060	21,140	20,480	21,290	21,290
JP Wa/Id	112,670	112,670	112,670	112,670	112,670	112,670
JP Or	2,620	2,620	2,620	2,620	2,620	2,620
LNG Wa/Id	22,000	22,000	22,000	22,000	22,000	22,000
LNG Or	19,200	19,200	19,200	19,200	19,200	19,200
LNG Ca	6,340	6,340	6,340	6,340	6,340	6,340
Unserved	84,180	94,620	106,010	116,330	127,740	139,120
	549,100	560,740	573,500	584,300	603,670	615,050

the suppliers. Supplies have not been defined between states as Avista operates the north and south divisions as one. These figures represent total system requirements for a non-coincidental peak day, defined to be on February 15. This date was chosen as an indicator of the end of severe weather period because historical weather data suggest that severe cold has not happened after mid-February. The critical part to planning for a peak day is to reserve enough storage, supplies, and transportation to meet the peak day demand. On a peak day, only firm demand is planned for. This would encompass firm sales and transportation to residential, commercial, and industrial customers, firm transportation to our firm commercial and industrial customers, and any capacity releases of firm transportation that do not have a recall clause.

Figure 6 and Table 4 show the total system annual requirements for a 20-year planning horizon. Figure 7 and 8 show the firm forecasted demand using the average/actual weather pattern for the Spokane and Medford areas respectively. Exhibits B through I are the detailed reports for the twenty-year planning horizon for annual usage and peak day needs from the SENDOUT® model.

Figure 6 - Annual Requirements

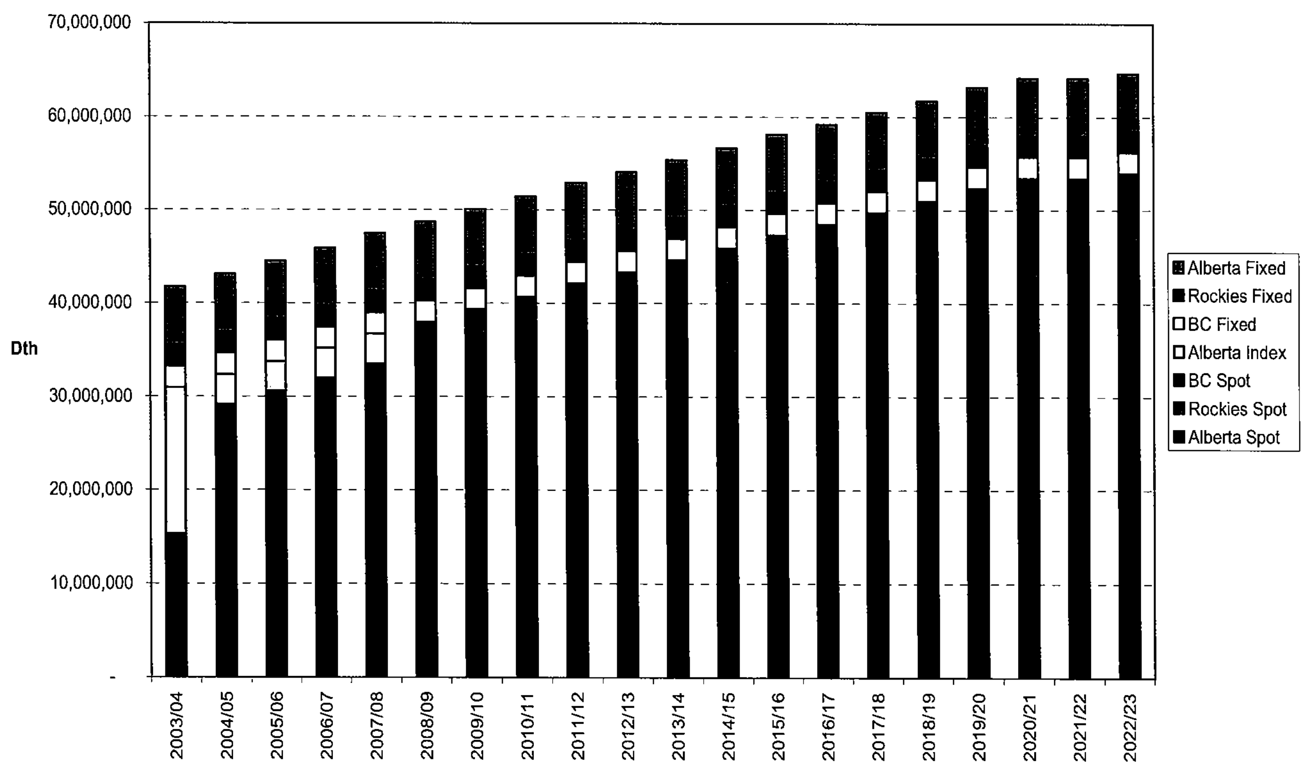


Table 4 - Annual Requirments
2003 - 2022
Dth

	2003/04	2004/05	2005/06	2006/07	2007/08
Alberta Fixed	6,228,000	6,194,000	6,194,000	6,194,000	6,228,000
Rockies Fixed	2,291,000	2,278,000	2,278,000	2,278,000	2,291,000
BC Fixed	2,291,000	2,278,000	2,278,000	2,278,000	2,291,000
Alberta Index	15,647,030	3,191,390	3,191,390	3,191,390	3,212,520
BC Spot	188,120	56,250	397,280	784,240	1,200,770
Rockies Spot	9,579,440	4,926,050	5,708,660	6,048,140	6,340,170
Alberta Spot	5,522,180	24,190,460	24,464,950	25,137,840	25,940,960
	41,746,770	43,114,150	44,512,280	45,911,610	47,504,420

	2008/09	2009/10	2010/11	2011/12	2012/13
Alberta Fixed	6,194,000	6,194,000	6,194,000	6,228,000	6,194,000
Rockies Fixed	2,278,000	2,278,000	2,278,000	2,291,000	2,278,000
BC Fixed	2,278,000	2,278,000	2,278,000	2,291,000	2,278,000
Alberta Index	-	-	-	-	-
BC Spot	1,613,350	2,145,290	2,437,180	2,685,950	2,915,650
Rockies Spot	6,376,890	6,646,770	6,840,060	7,179,000	7,342,920
Alberta Spot	29,960,120	30,534,730	31,393,870	32,252,480	33,055,310
	48,700,360	50,076,790	51,421,110	52,927,430	54,063,880

	2013/14	2014/15	2015/16	2016/17	2017/18
Alberta Fixed	6,194,000	6,194,000	6,228,000	6,194,000	6,194,000
Rockies Fixed	2,278,000	2,278,000	2,291,000	2,278,000	2,278,000
BC Fixed	2,278,000	2,278,000	2,291,000	2,278,000	2,278,000
Alberta Index	-	-	-	-	-
BC Spot	3,129,790	3,389,950	3,595,480	4,463,000	4,748,180
Rockies Spot	7,544,460	7,789,490	8,082,750	8,207,230	8,381,640
Alberta Spot	33,943,680	34,724,410	35,637,990	35,789,360	36,596,950
	55,367,930	56,653,850	58,126,220	59,209,590	60,476,770

	2018/19	2019/20	2020/21	2021/22	2022/23
Alberta Fixed	6,194,000	6,228,000	6,194,000	6,194,000	6,194,000
Rockies Fixed	2,278,000	2,291,000	2,278,000	2,278,000	2,278,000
BC Fixed	2,278,000	2,291,000	2,278,000	2,278,000	2,278,000
Alberta Index	-	-	-	-	-
BC Spot	5,024,590	5,315,320	5,526,320	5,526,320	5,714,550
Rockies Spot	8,554,720	8,806,370	8,572,630	8,572,630	8,163,730
Alberta Spot	37,394,820	38,254,740	39,334,270	39,334,270	40,083,630
	61,724,130	63,186,430	64,183,220	64,183,220	64,711,910

Figure 7 - Total Firm Forecast Demand (Avg/Actual Weather with Peak Day) Washington/Idaho 2003/04

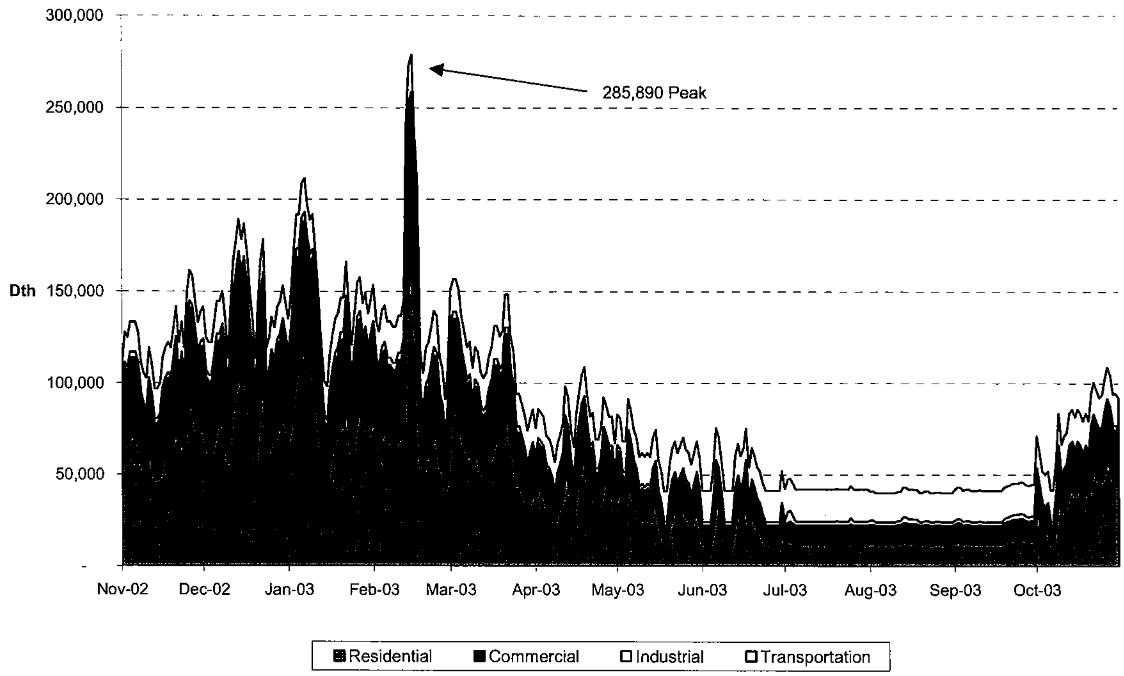
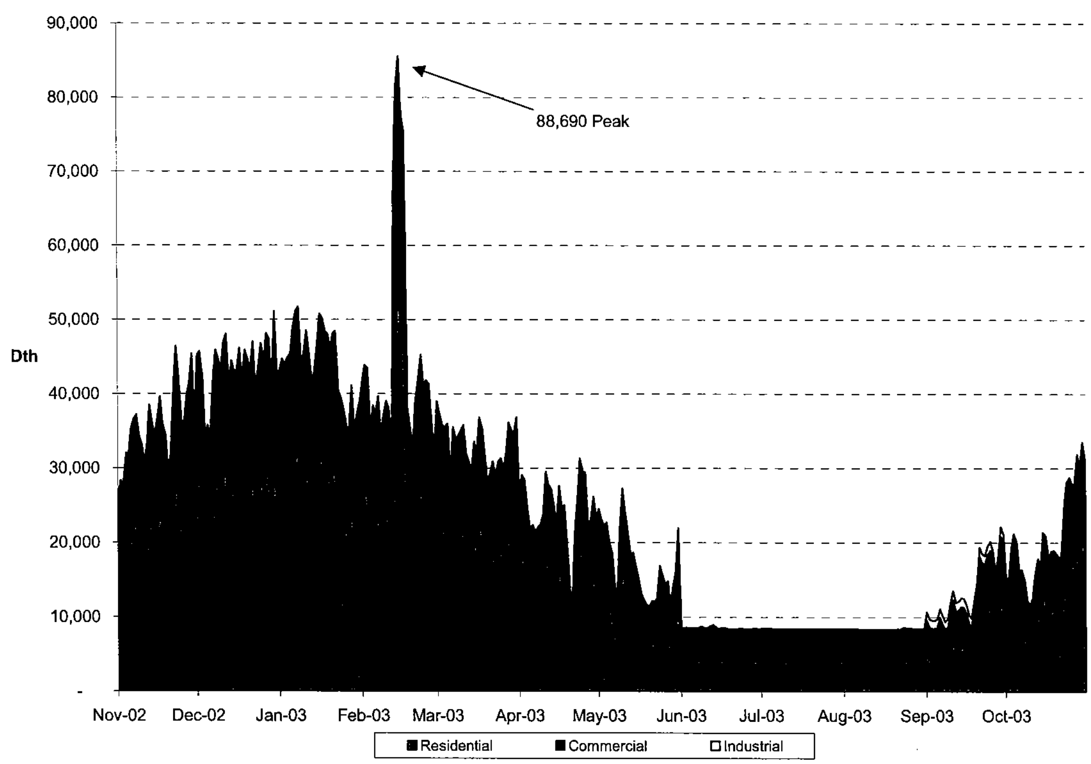


Figure 8 - Total Firm Forecast Demand (Avg/Actual Weather with Peak Day) Oregon 2003/04



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

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

Avista Utilities' resource stack for a design peak day can be seen in Exhibit D, report 9D. The selected resources represent the Company's best-cost solution, within given constraints, to serve anticipated customer requirements. As discussed earlier, Avista Energy is managing all supply and transportation needs for the core customers. This resource stack is based on contracts in place for the 2003/2004 heating season. Table 5 represents the transportation costs associated to deliver supplies to Avista Utilities system.

Table 5
Transportation Costs

Transportation	# of Days Available	Variable Cost $/Dth	Fixed Cost $/Dth
Northwest Pipeline TF-1	365	$0.0361	$0.2792
Northwest Pipeline TF-2 - JP	32	$0.0300	$0.2776
Northwest Pipeline TF-2 - LNG	8	$0.0300	$0.2776
GTN T-1 Vintage (to Spokane)	365	$0.0075	$0.0706
GTN T-3 (to Spokane)	150	$0.0075	$0.0731
GTN T-1 Vintage (to Klamath Falls)	365	$0.0139	$0.2516
GTN T-3 (to Klamath Falls)	150	$0.0139	$0.2577
GTN E-2 Medford Lateral	365	$0.0000	$0.5569
TransCanada - Alberta	365	$0.0000	$0.1037
TransCanada - BC System	365	$0.0028	$0.0469

As noted in the 2000 IRP, the Oregon service area would not be able to completely serve the design day demand of the firm customers after the 2002/03 heating season. With this in mind, the Company, as part of its strategic planning process, contracted for additional pipeline capacity on GTN to serve this area. Other options looked at before making this decision were:

- Additional pipeline contract demand with NWP
- Propane air peaking facility
- Sighting of a satellite LNG plant within distribution area

The results of the SENDOUT® model runs for this IRP indicate that with the projected load growth, assuming existing transportation contracts are renewed, Avista Utilities is not in need of additional transportation at this time. The north division will first potentially experience unserved core load on a design day in the winter of 2007/08. For the south division, the first potential for unserved core load on a design day is the winter of 2010/11. Both the north and south divisions are within the acceptable timeframe for transportation expansions.

Exhibit B is the Cost and Flow Summary report for total system by planning year. It summarizes the supply, storage, and transportation costs by planning year and also has each of these components in finer detail. (Years 1, 5, 10, 15 and 20 only are shown.)

Exhibit C is a Daily Served Demand by planning year broken down by several classes. (Only the 2003/2004 planning year is shown.)

Exhibit D is the Total System Peak Day System Activity detail. (Years 1, 5, 10, 15, and 20 only are shown.)

Exhibit E is the Month-by-Month System Flow for total system. (Years 1, 5, 10, 15 and 20 only are shown.)

Exhibit F is the Cost and Flow Summary reports for total system by planning year based on the low case forecast. (Years 1, 5, 10, 15 and 20 only are shown.)

Exhibit G is the Cost and Flow Summary reports for total system by planning year based on the high case forecast. (Years 1, 5, 10, 15 and 20 only are shown.)

Exhibit H is the Peak Day System Activity detail for total system based on the low case forecast. (Years 1, 5, 10,15 and 20 only are shown.)

Exhibit I is the Peak Day System Activity detail for total system based on the high case forecast. (Years 1, 5, 10,15 and 20 only are shown.)

Exhibit J is a special model run requested by the OPUC using the Base Case Forecast but with a commodity price based off the July 1st Nymex spread. (Years 1, 5, 10, 15 and 20 only are shown.)