2009

Electric
Integrated Resource Plan

- Public Draft -
Technical Advisory Committee

July 6, 2009

Safe Harbor Statement

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

For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

List of Acronyms and Key Terms

AARG	Annual Average Growth Rate
AVA	Avista
aMW	Average Megawatts
BPA	Bonneville Power Administration
CCCT	Combined-Cycle Combustion Turbine
CFL	Compact Fluorescent Lamp
CO_2	Carbon Dioxide
CSA	Climate Stewardship Act (also known as the McCain-Lieberman Bill)
CVR	Controlled Voltage Reduction
Dth	Unit of Measurement: Natural Gas, 10 Therms = 1 mmbtu
EF	Efficiency
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GWh	Gigawatt-hour
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning (HVAC)
IDP	Idaho Power Company
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
IS	Information Systems
kV	kilo-volt
kVA	kilovolt-ampere
kW	kilowatt
kWh	kilowatt-hour
LIRAP	Low Income Rate Assistance Program
LP	Linear Programming
Mmbtu	Million British Thermal Units, 1 mmbtu = 1 dth of Natural Gas
MW	Megawatt
MWh	Megawatt-hour
NCEP	National Commission for Energy Policy
NEB	Non-Energy Benefits
Nominal	Discounting Method that includes Inflation
NPCC	Northwest Power and Conservation Council (formerly Northwest Power Planning Commission)
NPV	Net Present Value
NWPP	Northwest Power Pool
O&M	Operations and Maintenance
OASIS	Open Access Same-Time Information System
OSU	Oregon State University
PC	Personal Computer
PGE	Portland General Electric
PRS Strategy	Preferred Resource
PRiSM	Preferred Resource Strategy Model
psig	Pounds Per Square Inch Gauge
PTC	Production Tax Credit
PUD	Public Utility District
PURPA	Public Utility Regulatory Policies Act of 1978
Real	Discounting Method that Excludes Inflation
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
SCCT	Simple-Cycle Combustion Turbine
TAC	Technical Advisory Committee
TIG	Transmission Improvements Group
TRC	Total Resource Cost
Triple E	External Energy Efficiency Board
VFD	Variable Frequency Drive
WECC	Western Electricity Coordinating Council
WNP-3	Washington Public Power Supply System (WPPSS, now Energy Northwest) – Washington Nuclear Plant No. 3

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Executive Summary

Avista's 2009 Integrated Resource Plan (IRP) guides the utility's resource acquisition strategy over the next two years and indicates the overall direction of resource procurements for the remainder of the 20-year planning horizon. The IRP provides a snapshot of the Company's resources and loads, and the IRP provides guidance regarding resource needs and acquisitions. A Preferred Resource Strategy (PRS) is a mix of renewable resources, conservation, efficiency upgrades at existing facilities, and new gas-fired generation.

The PRS balances low cost, reliable service, reasonable future rate volatility, and renewable resource requirements. Avista's management and stakeholders from the Technical Advisory Committee (TAC) play a key role in guiding the development of the PRS and the IRP as a whole. TAC members include customers, commission staff, consumer advocates, academics, utility peers, government agencies, and interested internal parties. The TAC provides significant input on modeling, planning assumptions, and the general direction of the planning process.

Resource Needs

Plant upgrades and conservation measures are an integral part of Avista's resource strategy, but they are ultimately inadequate to meet all future load growth. Annual energy deficits begin in 2018, with loads plus a planning margin exceeding resource capability by 27 aMW. Energy deficits rise to 126 aMW in 2022 and 527 aMW in 2029. The Company will be short 45 MW of capacity in 2015. In 2022 and 2029, capacity deficits rise to 139 MW and 667 MW, respectively. Table 1 presents Avista's net load position for the first 10 years of the study.

Table 1: Net Position Forecast

Net Position	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy (aMW)	309	185	123	110	93	59	38	31	-27	-35
Capacity (MW)	293	124	53	31	0	-45	-74	45	11	-46

Increasing deficits are a result of forecasted 1.7% energy and capacity load growth through 2029. Expirations of certain long-term contracts also increase deficiencies. Figures 1 and 2 provide graphical representations of the Company's load and resource balance. The forecasted load in each year includes the one-in-two peak forecast plus planning and operating reserve obligations. The forecast would be higher without conservation acquisitions.

Figure 1: Load Resource Balance—Winter Capacity

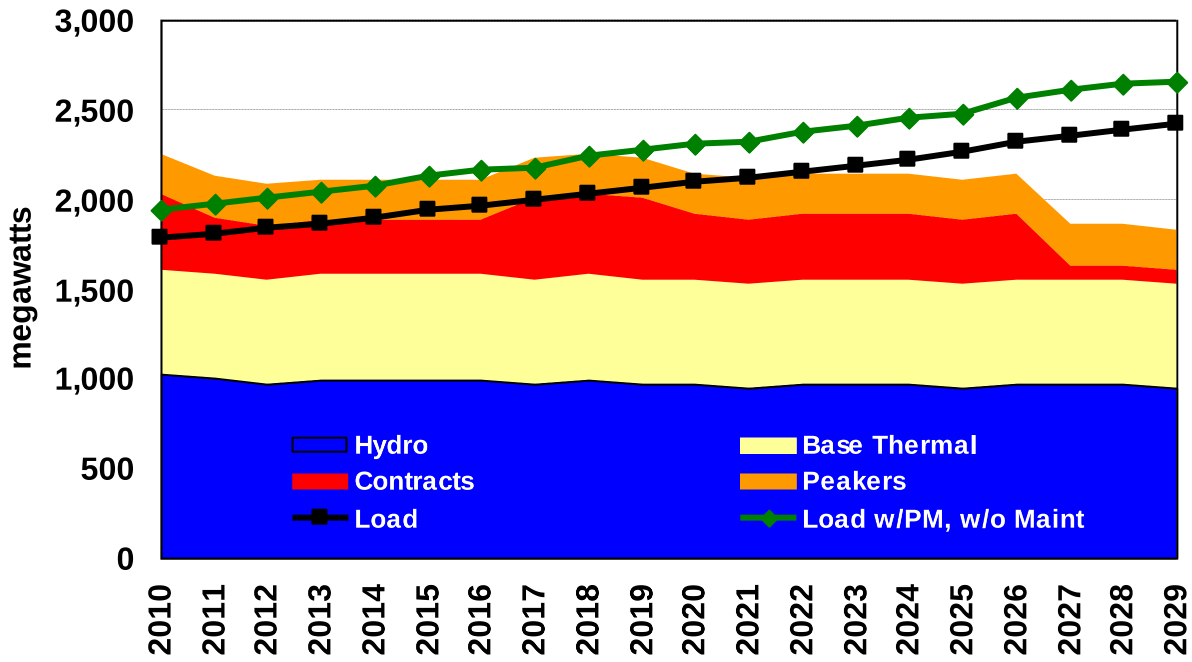
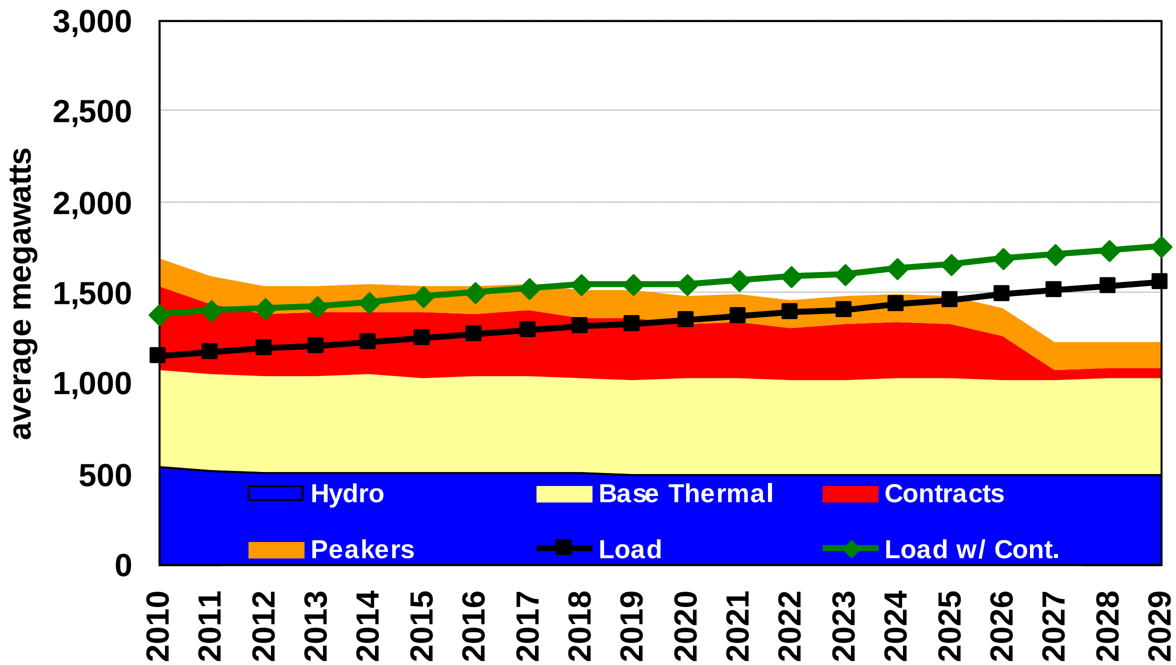


Figure 2: Load Resource Balance—Energy



Modeling and Results

Avista used a multi-step approach to develop its Preferred Resource Strategy. The process began with the identification and quantification of potential new resources to serve future demand across the West. A Western Interconnect-wide study was performed to understand the impact of regional markets on the Northwest electricity marketplace. Avista's existing resource stack was combined with the present transmission grid to simulate hourly operations for the Western Interconnect from 2010 to 2029.

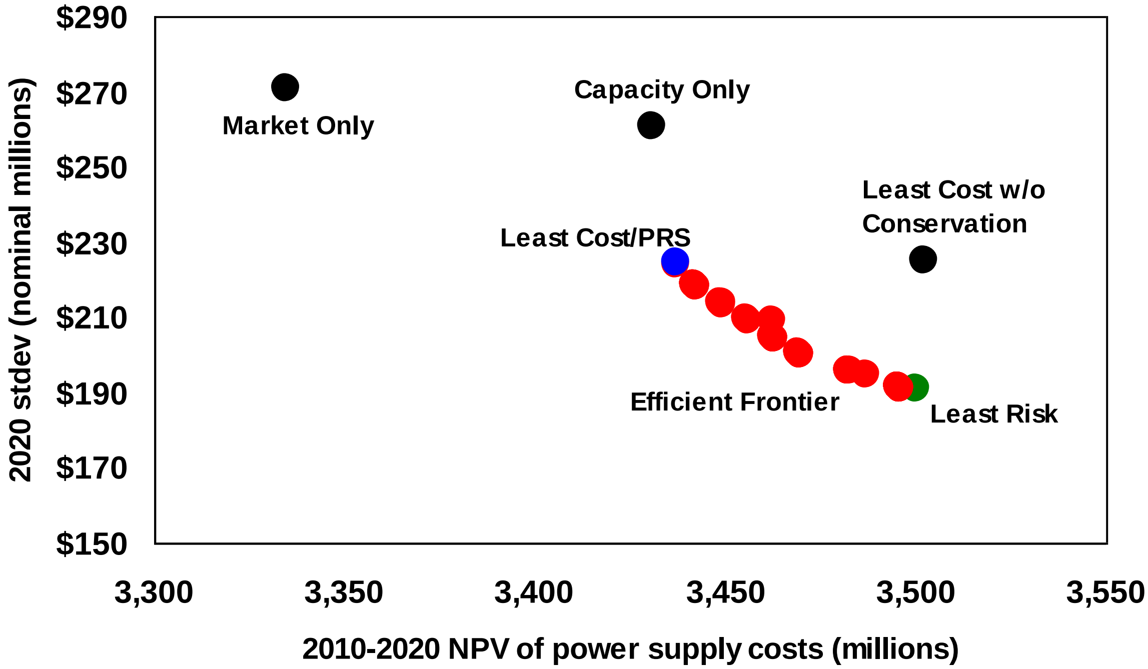
Cost-effective new resources and transmission were added as necessary to meet growing loads. Monte Carlo-style analysis varied hydro, wind, load, forced outages, greenhouse gas emissions, and gas price data over 300 iterations of potential future conditions. The simulation results were used to estimate the Mid-Columbia electric market, and the iterations collectively formed the Base Case for this IRP.

Estimated market prices were used to analyze potential conservation initiatives and available supply-side resources to meet forecasted resource requirements. Each new resource option was valued against the Mid-Columbia market to identify the future value of each asset to the Company, as well as its inherent risk measured in year-to-year power supply cost volatility. Future market values and risk were compared with the capital and fixed operation and maintenance (O&M) costs that would be incurred. Avista's Preferred Resource Strategy Linear Programming Model (PRiSM) assisted in selecting the Preferred Resource Strategy (PRS) for serving future load. The PRS selection was based on forecasted energy and capacity needs, resource values, state mandated renewable portfolio standards, and limiting power supply expense variability.

Portfolio scenarios were used to identify the tipping points that would change the PRS under alternative conditions beyond the expected Base Case. The scenarios identified changes to underlying assumptions that could alter the PRS, such as changes to load growth, capital costs, hydro upgrades, the emergence of other small renewable projects, and nuclear revival.

The preferred resource portfolio must address two key challenges that include the mitigation of future costs and risk given a set of environmental constraints. An efficient frontier helps determine trade offs between risk and cost. This approach is similar to finding the optimal mix of risk and return when developing a personal investment portfolio. As expected returns increase, so do risks; whereas reducing risk reduces overall returns. Finding the PRS is very similar to the investor's dilemma, but the trade-off is future costs against power supply cost variation. Figure 3 presents the change in cost and risk from the Preferred Portfolio Strategy on the Efficient Frontier.

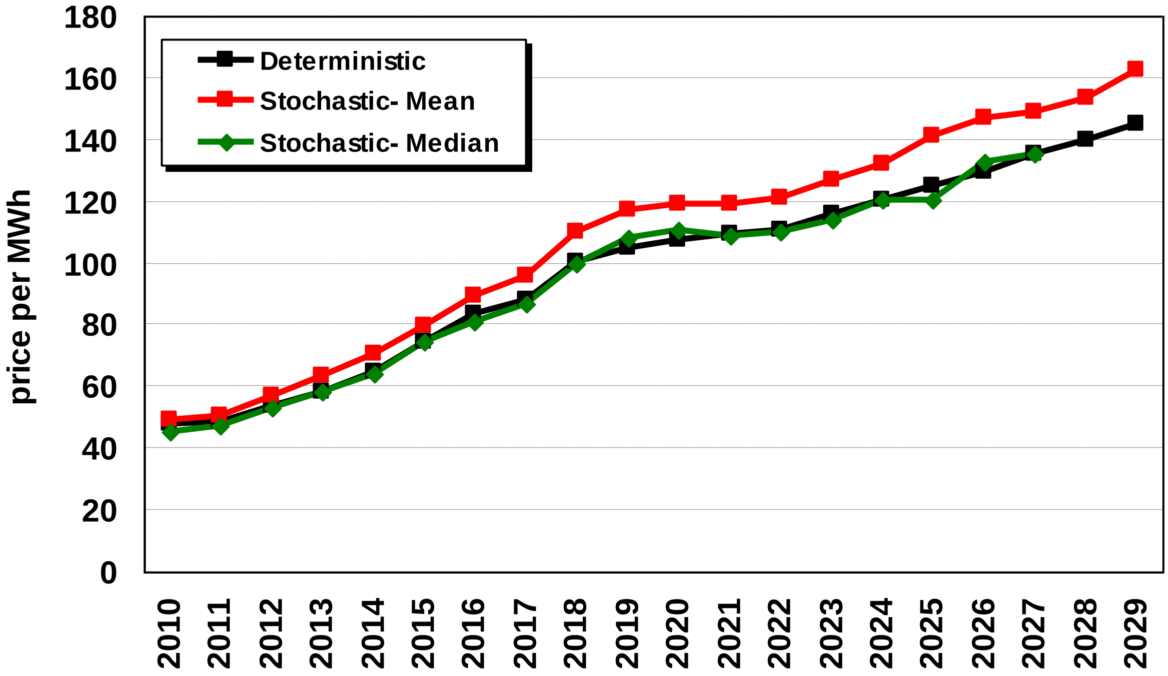
Figure 3: Efficient Frontier



Electricity and Natural Gas Market Forecasts

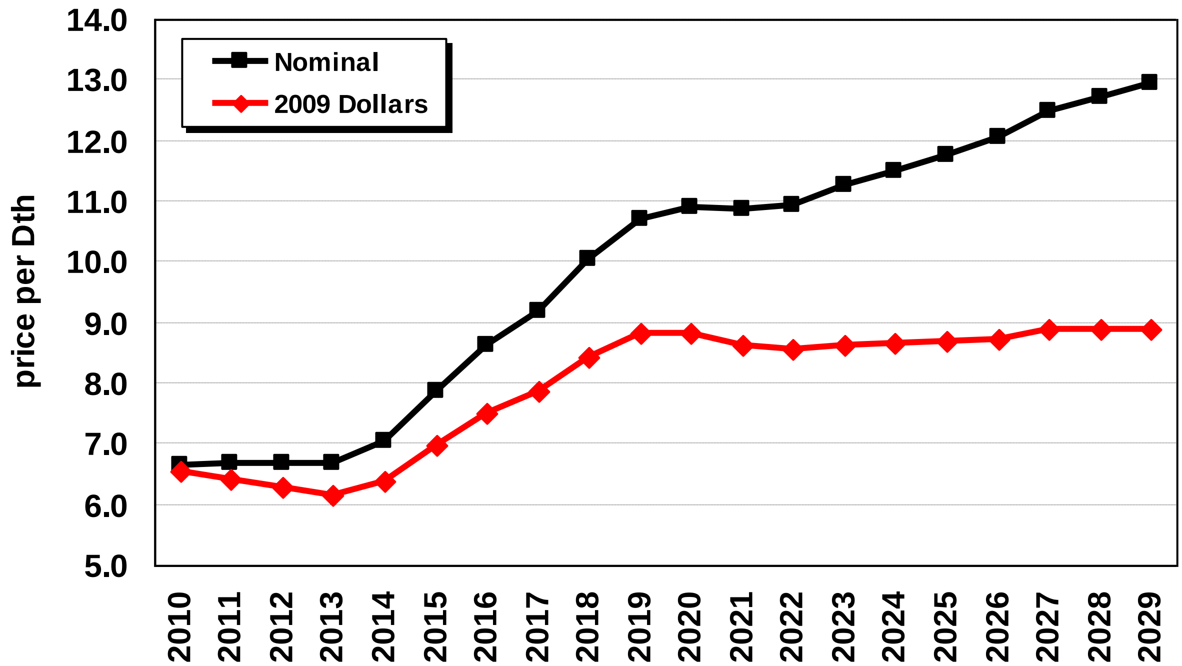
Figure 4 shows the Company's electricity price forecast that was developed for the 2009 IRP. The Mid-Columbia market price is expected to average $79.56 per MWh in 2009 dollars over the next 20 years; the average nominal price is $93.74 per MWh. Spreads between on- and off-peak prices are $14.34 per MWh in 2010, and $32.71 per MWh in 2029. Stochastic prices are higher then deterministic prices, as the stochastic model accounts for carbon, hydro, natural gas, forced outage and wind energy risks.

Figure 4: Annual Flat Mid-Columbia Prices



Electricity prices are highly correlated with natural gas prices because natural-gas fired generation is the marginal resource in the Western Interconnect. Base Case natural gas prices at Henry Hub are shown in Figure 5. Henry Hub; the levelized nominal price is expected to be $9.05 per Dth over the next 20 years and, the real 2009 dollar levelized cost is $7.67. The natural gas forecast is derived from a combination of sources in the near term including NYMEX, EIA, Wood Mackenzie and other consultants. Longer term prices rely on the forecast from Wood Mackenzie. The forecast includes an price adder of $0.50 in 2013 and $1.00 after 2018 (2009 dollars) to account for the increase in demand of natural gas due to a shift from coal generation to natural gas generation

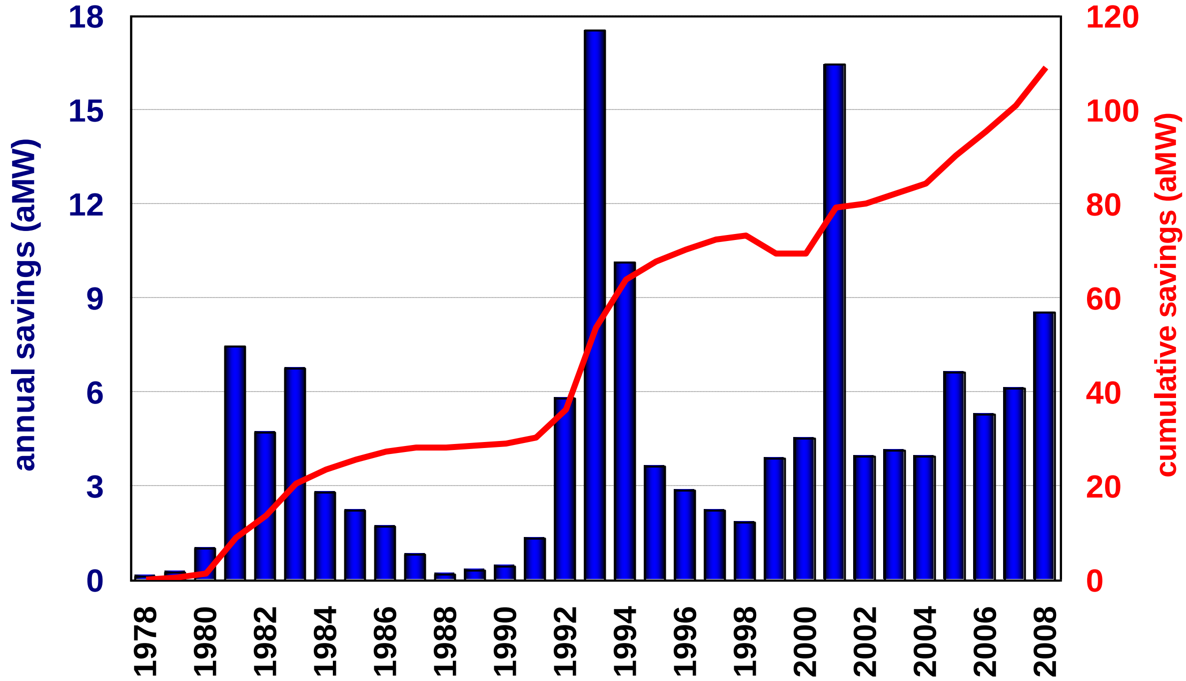
Figure 5: Annual Average Henry Hub Natural Gas Price



Conservation Acquisition

Figure 6 shows how conservation has decreased the Company's energy requirements by 138.5 aMW since programs began in the late 1970s with 109 aMW of efficiency projects acquired over the past 18 years still online.

Figure 6: Cumulative Conservation Acquisitions



Preferred Resource Strategy

The PRS is developed after careful consideration of the information gathered over the IRP process. The PRS is reviewed and critiqued by management and the Technical Advisory Committee. The 2009 plan relies on a combination of conservation, distribution system upgrades, wind, hydro upgrades, and gas-fired combined-cycle combustion turbines (CCCTs), and identifies transmission projects to improve system reliability and to access generation resources necessary to comply with Washington's renewable portfolio standard (Initiative Measure 937). Figure 7 illustrates the Company's PRS.

Table 2: The 2007 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Non-Wind Renewable	2011	20.0	18.0
Non-Wind Renewable	2012	10.0	9.0
NW Wind	2013	100.0	33.0
Non Wind Renewable	2013	5.0	4.5
Share of CCCT	2014	75.0	67.5
NW Wind	2015	100.0	33.0
NW Wind	2016	100.0	33.0
Non Wind Renewable	2019	10.0	9.0
Non Wind Renewable	2020	10.0	9.0
Non Wind Renewable	2021	5.0	4.5
Share of CCCT[1]	2019	297.0	267.3
Share of CCCT	2027	305.0	274.5
Total		**1,037.0**	**762.3**

The specific resources contained within the PRS, shown in nameplate capability, are shown in tabular format in Table 2 for the 2007 PRS and Table 3 for the 2009 PRS. Conservation acquisitions are not included in either of these tables.

Table 3: 2009 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
NW Wind	2012	150.0	48.0
Distribution Efficiencies	2010-2015	5.0	2.7
Little Falls Unit Upgrades	2013-2016	3.0	0.9
NW Wind	2019	150.0	50.0
CCCT	2019	250.0	225.0
Upper Falls	2020	2.0	1.0
NW Wind	2022	50.0	17.0
CCCT	2024	250.0	225.0
CCCT	2027	250.0	225.0
Total		**1,110.0**	**794.6**

The 2009 IRP requires just over $1.0 billion in net present value of new capital investments over the next 20 years. This level of investment will enable Avista to have ownership of all new resource investments.

[1] The 2007 IRP modeled CCCT resource acquisitions after the first 10 years, as the remaining capacity requirements would be served by a CCCT resource rather than resource sizes in specified years.

Carbon Emissions

Carbon emissions have been included in the Base Case since the 2007 IRP. Carbon costs estimates from a national market study by Wood Mackenzie. Figure 7 shows projected CO_2 emissions prices. Figure 8 shows the projected carbon emissions for existing and new generation assets. These estimates do not include emissions from market/contract purchases, nor reduce emission for wholesale sales. Further the white area of the chart indicates estimated emission levels with no national/regional legislative action.

Figure 7: Price of CO_2 Credits

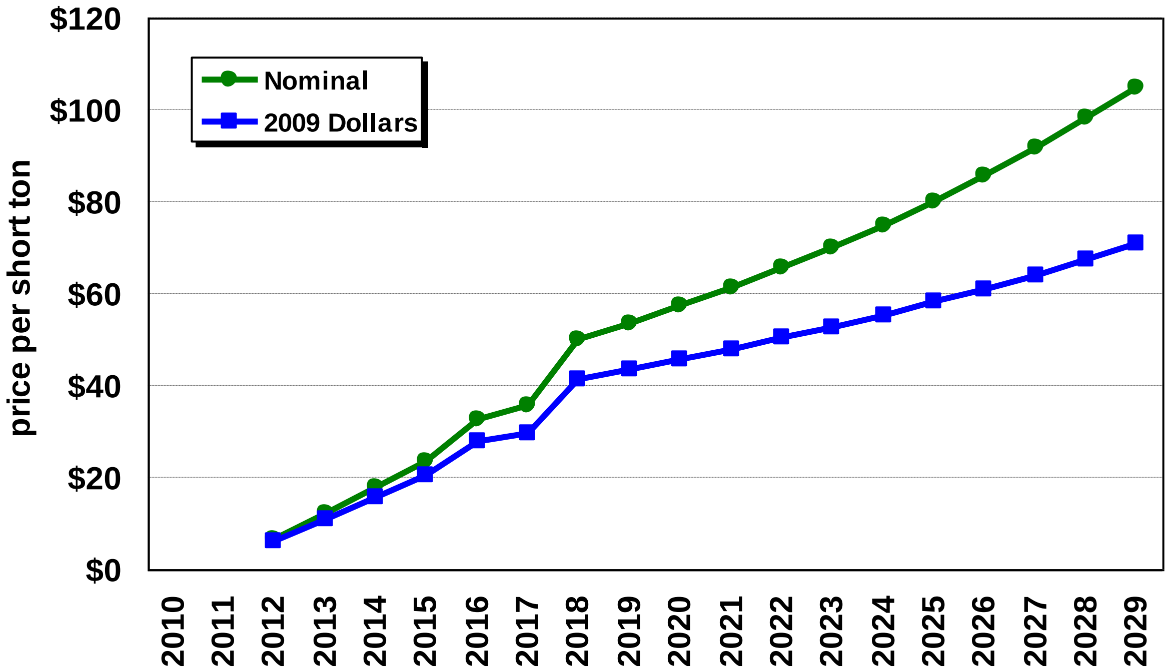
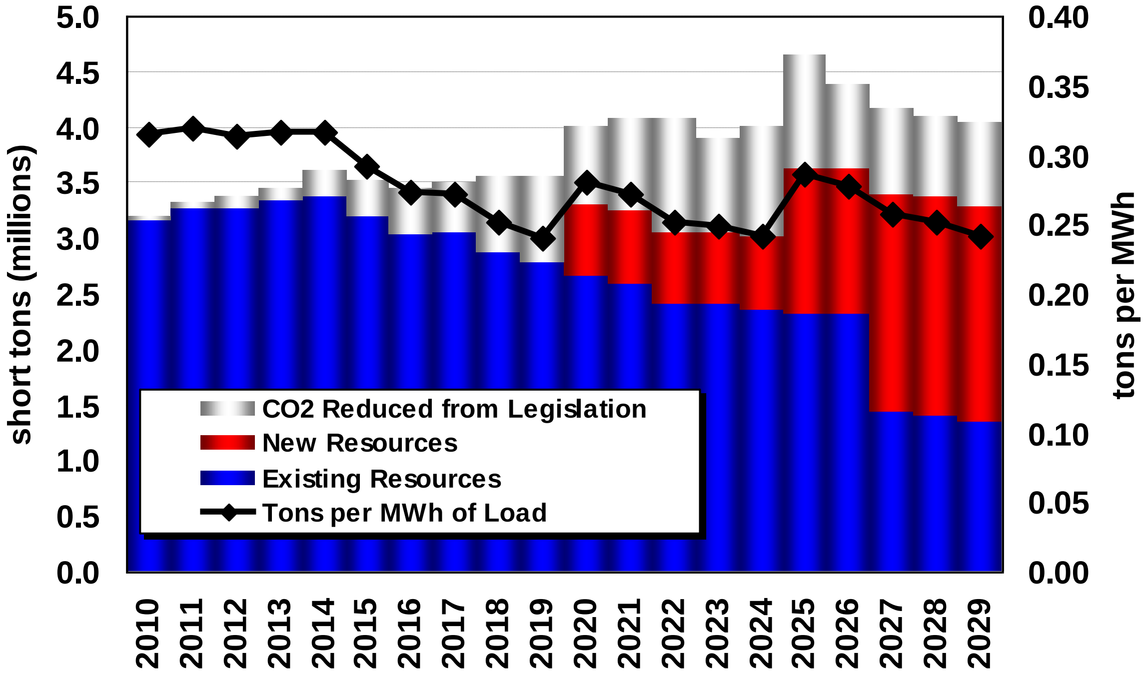


Figure 8: Avista Owned and Controlled Resource's Greenhouse Gas Emissions



Action Items

The Company's 2009 Action Plan outlines the activities and studies to be developed and presented in the 2011 Integrated Resource Plan. The Action Plan was developed using input from Commission Staff, the Company's management team, and the Technical Advisory Committee. Action Item categories include resource additions and analysis, demand side management, environmental policy, modeling and forecasting enhancements, and transmission planning.

1. Introduction and Stakeholder Involvement

Avista Utilities submits a biennial Integrated Resource Plan (IRP) to the Idaho and Washington public utility commissions.[1] The 2009 IRP is Avista's eleventh plan identifying and describing its Preferred Resource Strategy for meeting customer's future requirements while balancing cost and risk measures.

The Company is statutorily obligated to provide reliable electric service to customers at rates, terms, and conditions that are just, reasonable, and sufficient. We assess resource acquisition strategies and business plans to acquire resources to meet resource adequacy requirements and optimize the value of our current resource portfolio. Avista uses the IRP as a resource evaluation tool, rather than a plan for acquiring a particular asset. The 2009 IRP focuses on refining our process for the evaluation of resource decisions, requests for proposal, and other acquisition efforts.

IRP Process

Avista actively sought input from a variety of constituents through the Technical Advisory Committee (TAC). The TAC included Commission Staff, customers, academics, government agencies, consultants, utilities, and other parties who had accepted the Company's invitation to join or had asked to be involved in the planning the process. The Company sponsored six TAC meetings for the 2009 IRP. The TAC process began on May 14, 2008 and ended with a final meeting to present the results of the 2009 IRP on June 24, 2009. Over 70 people were invited to each meeting. Each TAC meeting covered different aspects of the 2009 IRP planning activities and solicited contributions and assessments regarding modeling assumptions, modeling processes, and results. Agendas and presentations may be found in Appendix X and on Avista's web site located at http://www.avistautilities.com/inside/resources/irp/electric.

Stakeholder Participation

The IRP process provides substantial opportunities for stakeholders to participate in Avista's resource planning activities. The Company utilizes three main groups of stakeholders for the public involvement component of the IRP. The main component involves stakeholders with expertise in various aspects of utility planning to provide input concerning the studies that are completed, resource data, modeling efforts, and critical review of the modeling results. This group includes Commission Staff, planners from other utilities, academics, and consultants. The second group includes parties involved with a specific aspect of the IRP. Examples in this group include environmental groups such as the Northwest Energy Coalition and government agencies. The third area of public involvement includes delegates from and participation in regional planning efforts, such as the Northwest Power and Conservation Council and the Western Electric Coordinating Council.

[1] Washington IRP requirements are contained in WAC 480-100-251 Least Cost Planning. Idaho IRP requirements are outlined in Case No. U-1500-165 Order No. 22299, Case No. GNR-E-93-1, Order No. 24729, and Case No. GNR-E-93-3, Order No. 25260.

Public Process

The 2009 IRP is developed and written with the aid of a public process. All of the 2009 TAC presentations are available for review at www.avistautilities.com. The entire 2009 IRP and its appendices can be downloaded from this location. All previous Company IRPs are also available at our web site.

Technical Advisory Committee

Avista's Integrated Resource Plan is developed with significant amounts of public input and involvement. The Company had six TAC meetings supplemented with phone and email contact to develop this plan. Some of the topics included in the 2009 TAC series were: resource options, conservation, modeling, fuel price forecasts, load forecasts, market drivers, and environmental issues.

The TAC mailing list includes over 70 individuals from 46 different organizations. The Company greatly appreciates all of the time and effort expended by the participants in the TAC process and looks forward to their continued involvement in the 2011 IRP. Avista wishes to acknowledge the contributions of a number of TAC participants. Refer to Table 1.1.

Table 1.1: TAC Participants

Participant	Organization
Andy Ford	WSU
Robin Toth	Greater Spokane Inc.
Dave Van Hersett	Resource Development Associates
Mike Connelly	Idaho Forest Group
John Daquisto	Gonzaga University
Lea Daeschel	Attorney General's Office
Deborah Reynolds	WUTC
Steve Johnson	WUTC
David Nightingale	WUTC
Vanda Novak	WUTC
Carrie Dolwick	Northwest Energy Coalition
Kirsten Wilson	WA State Gen Admin
Rick Sterling	IPUC
Chuck Murray	CTED
Tom Noll	Idaho Power
Maury Galbraith	NPCC
Villamour Gamponia	Puget Sound Energy
Mike Kersh	Inland Empire Paper

Table 1.2 provides a list of each TAC meeting date and the agenda items covered in each meeting.

Table 1.2: TAC Meeting Dates and Agenda Items

Meeting Date	Agenda Items
TAC 1 – May 14, 2008	• Load & Resource Balance Update • Climate Change Update • Renewable Acquisitions • Loss of Load Probability Analysis • 2009 IRP Topic Discussions – Work Plan and Analytical Process Changes
TAC 2 – August 27, 2008	• Risk Assumptions/PRiSM • Resource Assumptions • Scenarios and Futures • Demand Side Management
TAC 3 – October 22, 2008	• Load Forecast • Natural Gas Price Forecast • Electric Price Forecast • Legislative Update
TAC 4 – January 28, 2009	• 2008 Peak Load Event • Natural Gas and Electric Price Update • Resource Assumptions • Transmission • Draft Preferred Resource Strategy
TAC 5 – March 25, 2009	• Conservation • Preferred Resource Strategy • Scenarios and Futures • 2009 IRP Topics
TAC 6 – June 24, 3009	• Presentation of the 2009 PRS • 2009 IRP Action Items

Issue Specific Public Involvement Activities

Besides the TAC meetings, Avista also sponsors and participates in several other collaborative processes involving a range of public interests.

External Energy Efficiency ("Triple E") Board

The Triple E Board is a biannual meeting that began in 1995 for stakeholders and public groups to gather and discus conservation efforts. The Triple E Group grew out of the DSM Issues group, which was influential in developing the country's first distribution surcharge for conservation acquisition for Avista.

FERC Hydro Relicensing – Clark Fork River Projects

Over 50 stakeholder groups participated in the Clark Fork hydro-relicensing process beginning in 1993. This led to the first all-party settlement filed with a FERC relicensing application, and eventual issuance of a 45-year FERC operating license in February 2003. The nationally recognized Living License concept was a result of this process. This collaborative process continues in the implementation phase of the Living License with stakeholders participating in various protection, mitigation, and enhancement measures.

FERC Hydro Relicensing – Spokane River Projects

The Company has utilized a hydro relicensing process for the Spokane River Projects similar to the process used for relicensing the Clark Fork Projects. Avista was issued a 50-year license for the Spokane River Projects by FERC in June 2009. Approximately 100 stakeholder groups participated in this collaborative effort.

Low Income Rate Assistance Program (LIRAP)

LIRAP progress is shared with the four community action agencies in the Company's Washington service territory through regular meetings. The program began in 2001 and has quarterly meetings to review administrative issues and needs.

Regional Planning

The Pacific Northwest's generation and transmission system is operated in a coordinated fashion. Avista participates in the efforts of many organization's planning processes. Information from this participation is used to supplement the Company's integrated resource planning process. Some of the organizations that Avista participates in are:

- Western Electricity Coordinating Council
- Northwest Power and Conservation Council
- Northwest Power Pool
- Pacific Northwest Utilities Conference Committee
- ColumbiaGrid
- Northwest Transmission Assessment Committee
- Seems Steering Group – Western Interconnection
- North American Electric Reliability Council

Future Public Involvement

Avista actively solicits input from interested parties to enhance the integrated resource planning process. Advice will be requested from members of the Technical Advisory Committee on wide variety of resource planning issues. We will continue to work on expanding the diversity of the members on the TAC, and will strive to maintain the TAC meetings as an open public process.

2009 IRP Outline

The 2009 IRP consists of eight chapters plus an executive summary and this introduction. A series of technical appendices supplement this report.

Executive Summary

This chapter summarizes the overall results and highlights of the key results of the 2009 IRP.

Chapter 1: Introduction and Stakeholder Involvement

This chapter introduces the IRP and provides details concerning public participation and involvement in the integrated resource planning process.

Chapter 2: Loads and Resources

The first half of this chapter covers Avista's load forecast and relevant local economic forecasts. The last half describes the Company's owned generating resources, major contractual rights and obligations, capacity and energy tabulations, and reserve issues.

Chapter 3: Energy Efficiency

This chapter discusses Avista's energy efficiency programs. It provides an overview of the programs, descriptions of conservation measures, analysis of conservation measures for the IRP, and the conservation results for the 2009 IRP.

Chapter 4: Environmental Policy

This chapter covers the emissions issues modeled in the 2009 IRP. The chapter focuses on modeling efforts and issues surrounding greenhouse gas emissions and state and federal environmental regulations.

Chapter 5: Transmission and Distribution Planning

This chapter discusses Avista's distribution and transmission systems, as well as regional transmission planning issues. Transmission cost studies used in IRP modeling efforts are also covered here.

Chapter 6: Generation Resource Options

This chapter covers the costs and operating characteristics of the varying generation resource types modeled for the 2009 IRP.

Chapter 7: Market Analysis

This chapter covers the analysis of wholesale markets for the 2009 IRP.

Chapter 8: Preferred Resource Strategy

This chapter provides details about Avista's 2009 Preferred Resource Strategy. It compares the PRS to a variety of theoretical portfolios under stochastic and scenario based analyses.

Chapter 9: Action Items

This chapter provides an overview of the progress made on Action Items from the 2007 IRP and presents details about Action Items for the 2009 IRP.

Regulatory Requirements

The IRP process for Washington has several requirements that must be met and documented under Washington Administrative Code (WAC). Table 1.3 provides the applicable WACs and indicates the chapter where each rule or requirement is met.

Table 1.3 Washington IRP Rules and Requirements

Rule and Requirement	Plan Citation
WAC 480-100-238(4) – Work plan filed no later than 12 months before next IRP due date. Work plan outlines content of IRP. Work plan outlines method for assessing potential resources.	Work plan submitted to the WUTC on August 29, 2008, See Appendix X
WAC 480-100-238(5) – Work plan outlines timing and extent of public participation.	Appendix X
WAC 480-100-238(2)(a) – Plan describes mix of energy supply resources.	Chapter 6- Generation Resource Options
WAC 480-100-238(2)(a) – Plan describes conservation supply.	Chapter 3- Energy Efficiency
WAC 480-100-238(2)(a) – Plan addresses supply in terms of current and future needs of utility ratepayers.	Chapter 2- Loads & Resources
WAC 480-100-238(2)(b) – Plan uses lowest reasonable cost (LRC) analysis to select mix of resources.	Chapter 8- Preferred Resource Strategy
WAC 480-100-238(2)(b) – LRC analysis considers resource costs.	Chapter 8- Preferred Resource Strategy
WAC 480-100-238(2)(b) – LRC analysis considers market-volatility risks.	Chapter 4- Environmental Policy Chapter 7- Market Analysis Chapter 8- Preferred Resource Strategy
WAC 480-100-238 (2)(b) – LRC analysis considers demand side uncertainties.	Chapter 3- Energy Efficiency
WAC 480-100-238(2)(b) – LRC analysis considers resource dispatchability.	Chapter 6- Generation Resource Options Chapter 7- Market Analysis
WAC 480-100-238(2)(b) – LRC analysis considers resource effect on system operation.	Chapter 7- Market Analysis Chapter 8- Preferred Resource Strategy

WAC 480-100-238(2)(b) – LRC analysis considers risks imposed on ratepayers.	Chapter 4- Environmental Policy Chapter 6- Generation Resource Options Chapter 7- Market Analysis Chapter 8- Preferred Resource Strategy
WAC 480-100-238(2)(b) – LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	Chapter 2- Loads & Resources Chapter 4- Environmental Policy Chapter 8- Preferred Resource Strategy
WAC 480-100-238(2)(b) – LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	Chapter 4- Environmental Policy Chapter 8- Preferred Resource Strategy
WAC 480-100-238(2)(c) – Plan defines conservation as any reduction in electric power consumption that results from increases in the efficiency of energy use, production, or distribution.	Chapter 3- Energy Efficiency Chapter 8- Preferred Resource Strategy
WAC 480-100-238(3)(a) – Plan includes a range of forecasts of future demand.	Chapter 2- Loads and Resources Chapter 8- Preferred Resource Strategy
WAC 480-100-238(3)(a) – Plan develops forecasts using methods that examine the effect of economic forces on the consumption of electricity.	Chapter 2- Loads and Resources Chapter 5- Transmission & Distribution Chapter 8- Preferred Resource Strategy
WAC 480-100-238-(3)(a) – Plan develops forecasts using methods that address changes in the number, type and efficiency of end-uses.	Chapter 2- Loads and Resources Chapter 3- Energy Efficiency Chapter 5- Transmission & Distribution
WAC 480-100-238(3)(b) – Plan includes an assessment of commercially available conservation, including load management.	Chapter 3- Energy Efficiency Chapter 5- Transmission & Distribution
WAC 480-100-238(3)(b) – Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	Chapter 3- Energy Efficiency Chapter 5- Transmission & Distribution

WAC 480-100-238(3)(c) – Plan includes an assessment of a wide range of conventional and commercially available nonconventional generating technologies.	Chapter 6- Generator Resource Options Chapter 8- Preferred Resource Strategy
WAC 480-100-238(3)(d) – Plan includes an assessment of transmission system capability and reliability (as allowed by current law).	Chapter 5- Transmission & Distribution
WAC 480-100-238(3)(e) – Plan includes a comparative evaluation of energy supply resources (including transmission sand distribution) and improvements in conservation using LRC.	Chapter 3- Energy Efficiency Chapter 5- Transmission & Distribution
WAC-480-100-238(3)(f) – Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	Chapter 3- Energy Efficiency Chapter 5- Transmission & Distribution Chapter 6- Generator Resource Options Chapter 8- Preferred Resource Strategy
WAC 480-100-238(3)(g) – Plan includes a two-year action plan that implements the long range plan.	Chapter 9- Action Items
WAC 480-100-238(3)(h) – Plan includes a progress report on the implementation of the previously filed plan.	Chapter 9- Action Items
WAC 480-100-238(5) – Plan includes description of consultation with commission staff. (Description not required)	Chapter 1- Introduction and Stakeholder Involvement
WAC 480-100-238(5) – Plan includes description of work plan. (Description not required)	Appendix X

2. Loads & Resources

Introduction & Highlights

Loads and resources represent two of the key components of the Integrated Resource Plan (IRP). The first half of this chapter summarizes customer and load forecasts for our service territory. This includes forecast ranges, load scenarios and an overview of recent enhancements to our forecasting models and processes. The second half of the chapter covers resource requirements, including descriptions of Company-owned and operated resources, as well as long-term contracts.

Section Highlights

- Weak economic growth is expected through 2011 in Avista's service territory.
- Historic conservation acquisitions are included in the load forecast; higher acquisition levels anticipated in this IRP reduce the load forecast further.
- Annual electricity sales growth from 2010-2020 averages 1.7 percent over the next decade (199 aMW) and 1.7 percent over the entire 20-year forecast.
- Peak loads are expected to grow at a 1.7 percent annual rate over the next 10 years (312 MW) and 1.7 percent over the 20-year forecast.
- Avista's energy deficits begin 2018, without conservation deficits would begin in 2016.
- RPS deficiencies now are the predominate driver of near-term resource need.

Addendum

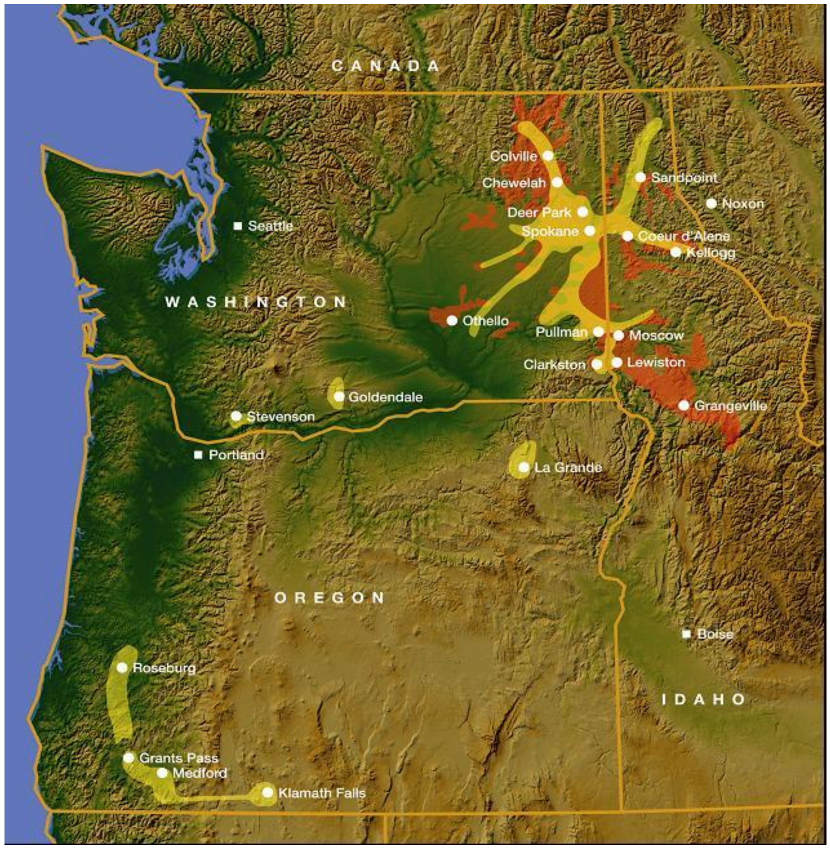
Avista updated its load forecast in April 2009 for known and measurable changes, including a more severe recession than incorporated in the July 2008 estimate along with small changes in retail price forecasts. The resulting changes were not material in terms of magnitude: 3 aMW lower in 2011, 6 aMW lower in 2020, and 5 aMW lower in 2030 when compared to the July 2008 forecast. This 0.3 to 0.5 percent reduction did not change the 10 and 20-year growth rates. However, loads in 2010 are now expected to be 10 aMW below the June forecast, a reduction of 0.9 percent, changing the Company's short-term operating plan.

Economic Conditions in the Electric Service Territory

Avista serves a wide area of eastern Washington and northern Idaho. This area is geographically and economically diverse. Avista serves most of the urbanized and suburban areas in 24 counties. Figure 2.1 is a map of the Company's electric and natural gas service territories.

The economy of the Inland Northwest has transformed over the past 20 years, from a natural resource-based manufacturing to diversified light manufacturing and services. Much of the mountainous area of the region is owned by the Federal government and managed by the United States Forest Service. Timber harvest reductions on public lands have closed many local sawmills. Two pulp and paper plants served by Avista have access to large forest land holdings; but they continue to face stiff domestic and international competition for their products.

Figure 2.1: Avista's Service Territory



Employment grows during periods of economic expansion and contracts during recessions. Our service territory experienced large scale periods of unemployment during two national recessions in the 1980s. Avista's service territory was mostly bypassed by the 1991/92 national recession, but was not as fortunate during the 2001 recession. The current recession is expected to end by 2011. Effects of recessions and economic growth are best illustrated by employment for the three principal counties in Avista's electric service territory: Bonner, Kootenai and Spokane. Regional employment data is provided later in this chapter.

Population often is more stable than employment during times of economic change; however, population will contract during severe economic downturns as people leave in search of employment opportunities. Over the past 25 years, 1987 was the only year the region experienced a net loss in population. Figure 2.2 details annual population changes in Bonner, Kootenai, and Spokane counties from 1990 forward. Figure 2.3 shows total population in these three counties for the same period.

Figure 2.2: Population Change for Spokane, Kootenai and Bonner Counties

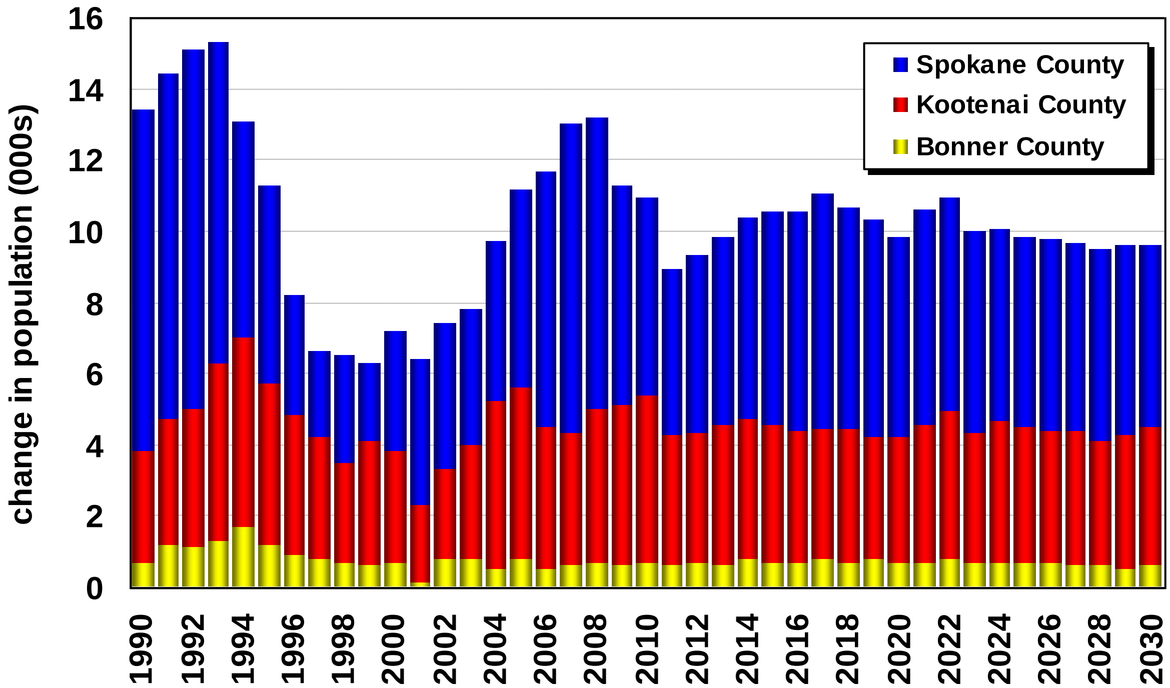
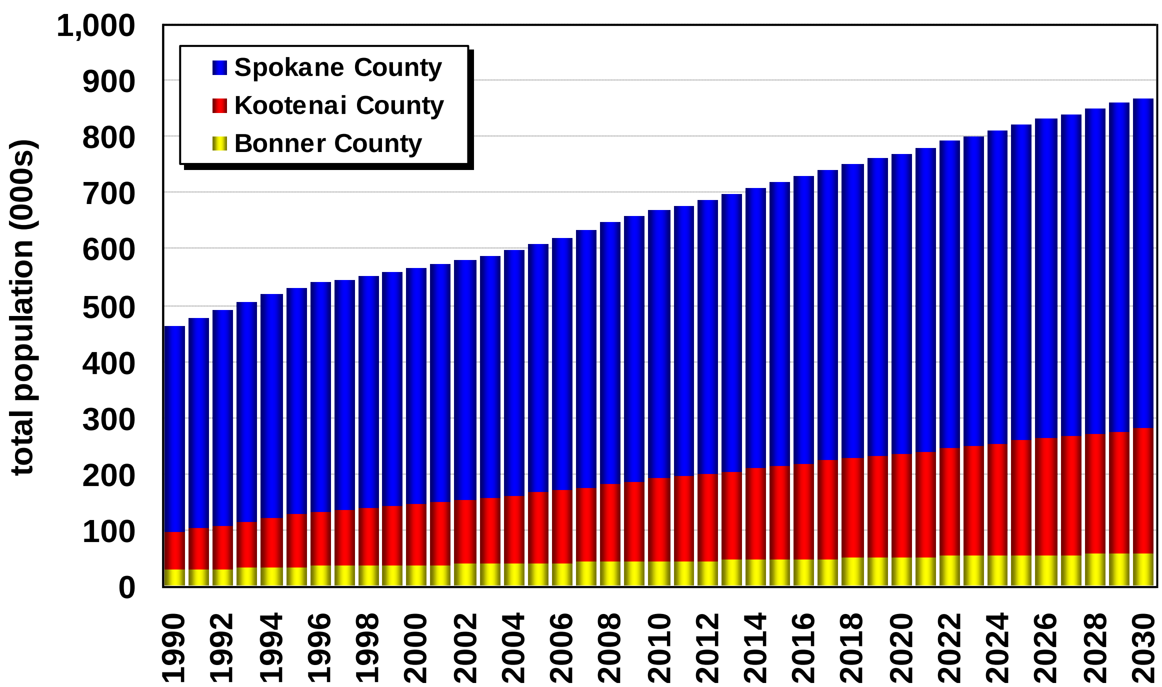


Figure 2.3: Total Population for Spokane, Kootenai and Bonner Counties



People, Jobs, and Customers

Avista purchases national and county-level employment and population forecasts from Global Insight, Inc. Global Insight is an internationally recognized economic forecasting consulting firm used by various agencies in Washington and Idaho. The data encompasses the three principal counties which comprise over 80 percent of our service area economy, namely, Spokane County in Washington; and Kootenai and Bonner counties in Idaho. The national forecast was prepared in March 2008; county-level estimates were completed in June 2008 and the load forecast was completed in July 2008.

The forecast and underlying assumptions used in this IRP were presented at the Third Technical Advisory Committee meeting for Avista's 2009 Integrated Resource Plan on October 22, 2009. Key forecasts assumptions are shown in Table 2.1.

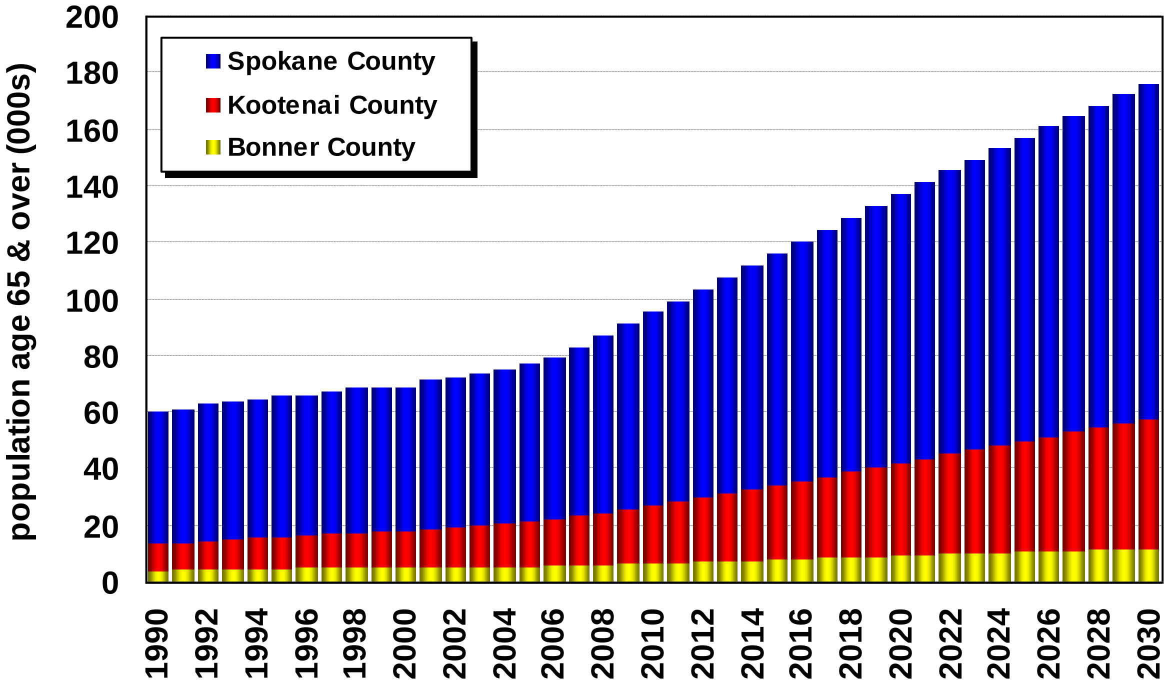
Table 2.1: Global Insight National Long Range Forecast Assumptions

Assumption	Range	Assumption	Range
Gross Domestic Product	1.9-3.2%	Housing Starts (mil.)	1.5-1.8/year
Consumer Price Index	3.5%-1.7%	Job Growth	0.9%/year
West Texas Crude 2000$	$30-$50	Worker Productivity	2%
Fed Funds Rate	4%-8%	Consumer Sentiment	90
Unemployment Rate	4.3%-4.9%		

Looking forward, the national economy slows after recovering from the present recession, setting the stage for regional economic performance in Avista's electric service area. As shown in the charts above, population growth rebounds after slow growth from 1997 to 2002. Population growth is expected to resume its recent trend after 2010.

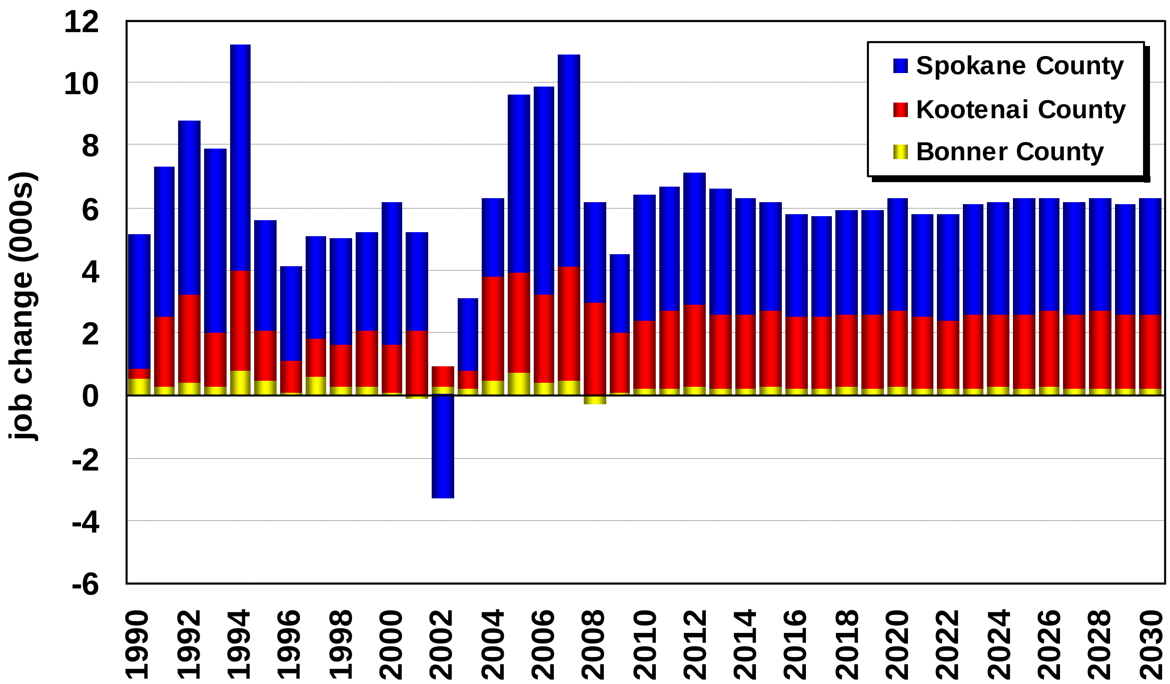
Regional population growth is supported by retiree immigration, representing between 10 and 20 percent of overall population growth. Figure 2.4 presents the population history and forecast for individuals 65 years and over in the three-county area. Between 1990 and 2010 this segment averages a compound growth rate of 2.6 percent in Bonner County, 4.1 percent in Kootenai County, and 1.0 percent in Spokane County. The age group represents 14.2 percent of the overall population in 2010. The forecast predicts growth of 3.1 percent, 4.0 percent, and 2.8 percent, respectively, pushing the overall contribution of this age group to 20.2 percent in 2030.

Figure 2.4: Three-County Population Age 65 and Over



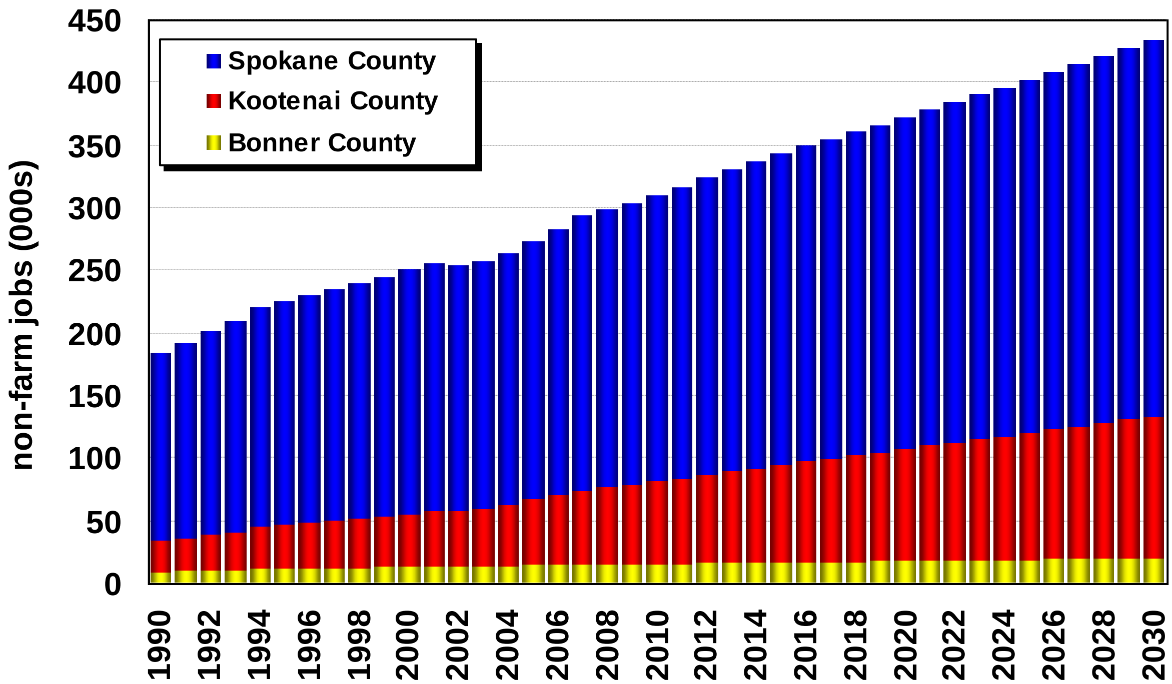
Employment growth often drives population growth. Figure 2.5 shows historical employment trends from 1990 and anticipated growth through 2030.

Figure 2.5: Three-County Job Change



Overall non-farm wage and salary employment over the past 20 years averaged 2.8 percent for Bonner County, 5.1 percent for Kootenai County, and 2.1 percent for Spokane County. Figure 2.6 provides additional non-farm employment data. Over the forecast horizon growth rates are predicted at 1.4 percent, 2.8 percent, and 1.4 percent, respectively. As indicated in the following chart, employment growth is expected to equal approximately 6,200 new jobs annually.

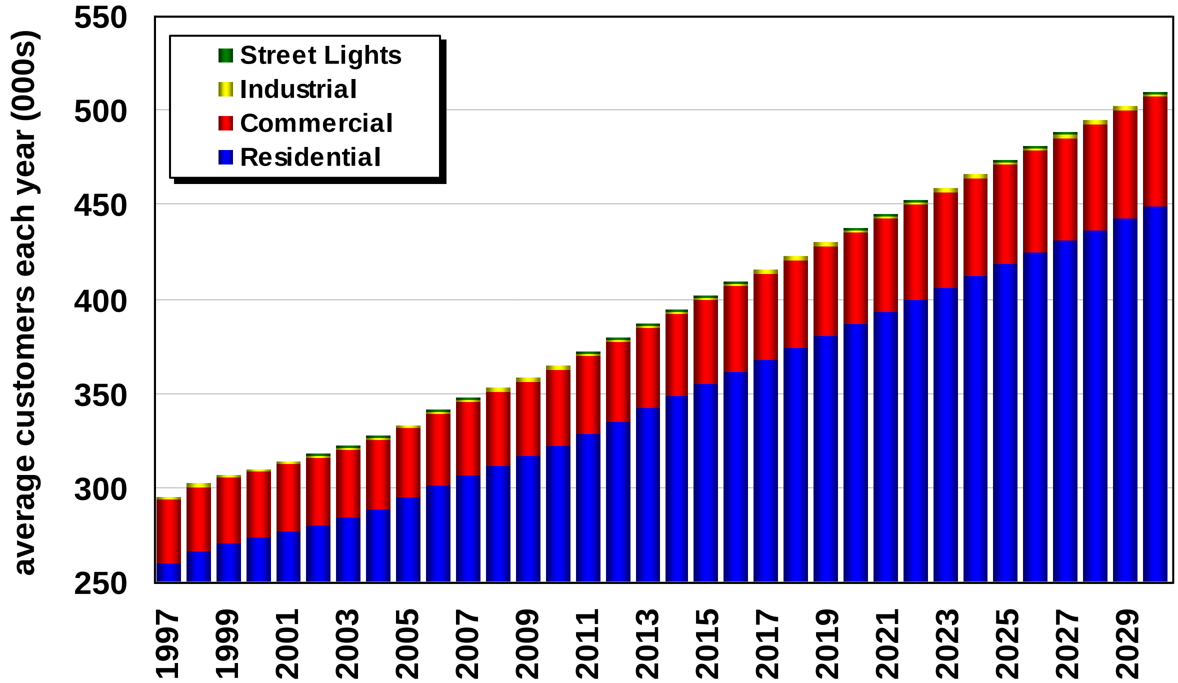
Figure 2.6: Three-County Non-Farm Jobs



Customer growth projections follow from baseline economic forecasts. The Company tracks four key customer classes—residential, commercial, industrial and street lighting. Residential customer forecasts are driven by population. Commercial forecasts rely heavily on employment and lagged residential growth trends. Industrial customer growth is correlated with employment growth. Employment statistics have the greatest probability of near term changes as we emerge from the present recession. Street lighting trends with population growth.

Avista forecasts sales by rate schedule. The overall customer forecast is a compilation of the various rate schedules of our served states. For example, the residential class forecast is comprised of separate forecasts prepared for rate schedules 1, 12, 22, and 32 for Washington and Idaho. See Figure 2.7

Figure 2.7: Avista Annual Average Customer Forecast



Avista served 311,807 residential customers, 39,154 commercial customers, 1,393 industrial customers, and 433 street lighting customers for a total of 352,786 retail customers in 2008. This is an increase from 340,652 retail customers in 2006. The 2029 forecast predicts 443,278 residential, 56,849 commercial, 1,654 industrial and 644 street lighting customers for a grand total of 502,425 retail customers. The 20-year compound growth rate averages 1.7 percent.

Weather Forecasts

The baseline electricity sales forecast is based on 30-year normal temperatures recorded at the Spokane International Airport weather station, as tabulated by the National Weather Service from 1971 through 2000. Daily values go back as far as 1890. There are several other weather stations with historical records in the Company's electric service area; however data is available over a much shorter duration. Sales forecasts are prepared using monthly data, as more granular load information is not available. The Company finds high correlations between the Spokane International Airport and other weather stations in its service territory. It uses heating degree days to measure cold weather and cooling degree days to measure hot weather in its retail sales forecast.

In response to questions from the Technical Advisory Committee, the Company has implemented estimates of the impacts of climate change on its retail load forecast. Ample evidence of cooling and warming trends exists in the 115-year record. The recent trend has been a warming climate compared to the 30-year normal. Trends in heating and cooling degree days for Spokane are roughly equal to the scientific community's predictions for this geographic area, implying a one degree warming every twenty-five years. Incorporating the trend finds that in 20 years summer load would be approximately 26 aMW higher than the 30 year average weather case. In the winter, loads would be approximately 40 aMW lower in 2029, for a net impact of a 14 aMW load decrease. The Company will continue to study these data trends in its two year Action Plan, and report any additional findings in the 2011 Integrated Resource Plan.

Price Elasticity

Price elasticity is a central economic concept of projecting electricity demand. Price elasticity of demand is the ratio of the percentage change in the quantity demanded of a good or service to a percentage change in its price. Elasticity measures the responsiveness of buyers to changes in electricity prices. A consumer who is sensitive to price changes has a relatively elastic demand profile. A customer who is unresponsive to price changes has a relatively inelastic demand profile. During the 2000-01 energy crisis customers showed increased sensitivity, or price elasticity of demand, by reducing their overall electricity usage in response to price increases.

Cross elasticity of demand, or cross-price elasticity, is the ratio of the percentage change in the quantity demanded of one good to a one percent change in the price of another good. A positive coefficient indicates that the two products are substitutes; a negative coefficient indicates they are complementary goods. Substitute goods are replacements for one another. As the price of the first good increases relative to the price of the second good, consumers shift their consumption to the second good. Complementary goods are used together; increases in the price of one good result in a decrease in demand for the second good along with the first. The principal cross elasticity impact on electricity demand is the substitutability of natural gas in some applications, including water and space heating.

Income elasticity of demand is the ratio of the percentage change in the quantity demanded of one good to a one percent change in consumer income. Income elasticity measures the responsiveness of consumer purchases to income changes. Two impacts affect electricity demand. The first is affordability. As incomes rise, a consumer’s ability to pay for goods and services increases. The second income-related impact is the amount and number of customers using equipment within their homes and businesses. Simply stated, as incomes rise consumers are more likely to purchase more electricity-consuming equipment, live in larger dwellings, and use their electrical equipment more often.

The correlation between retail electricity prices and the commodity cost of natural gas has increased in recent years. We estimate customer class price elasticity in our computation of electricity and natural gas demand. Residential customer price elasticity is estimated at negative 0.15. Commercial customer price elasticity is estimated at negative 0.10. The cross-price elasticity of natural gas and electricity is estimated to be positive 0.05. Income elasticity is estimated at positive 0.75, meaning electricity is more affordable as incomes rise.

Retail Price Forecast

The retail sales forecast is based on retail prices increasing an average of 10 percent annually from 2010 to 2018, followed by increases at the rate of inflation thereafter. Approximately one third of the rate rise is assumed to be driven by carbon-related legislation, assuming that future federal carbon legislation does not provide for any rate mitigation.

Conservation

It is difficult to separate the interrelated impacts of rising electricity and natural gas prices, rising incomes, and conservation programs. Avista collects data on total demand, and must derive the impacts associated with consumption changes. The Company has offered conservation programs to its customers since 1978. The impact of conservation on electricity usage is fully embedded in the historical data; therefore, we concluded that existing conservation levels (7.5 aMW) are embedded in the forecast. Where conservation acquisition decreases from this level, retail load obligations would increase. As this IRP forecasts growing conservation acquisition, this growth reduces retail load obligations from the forecast.

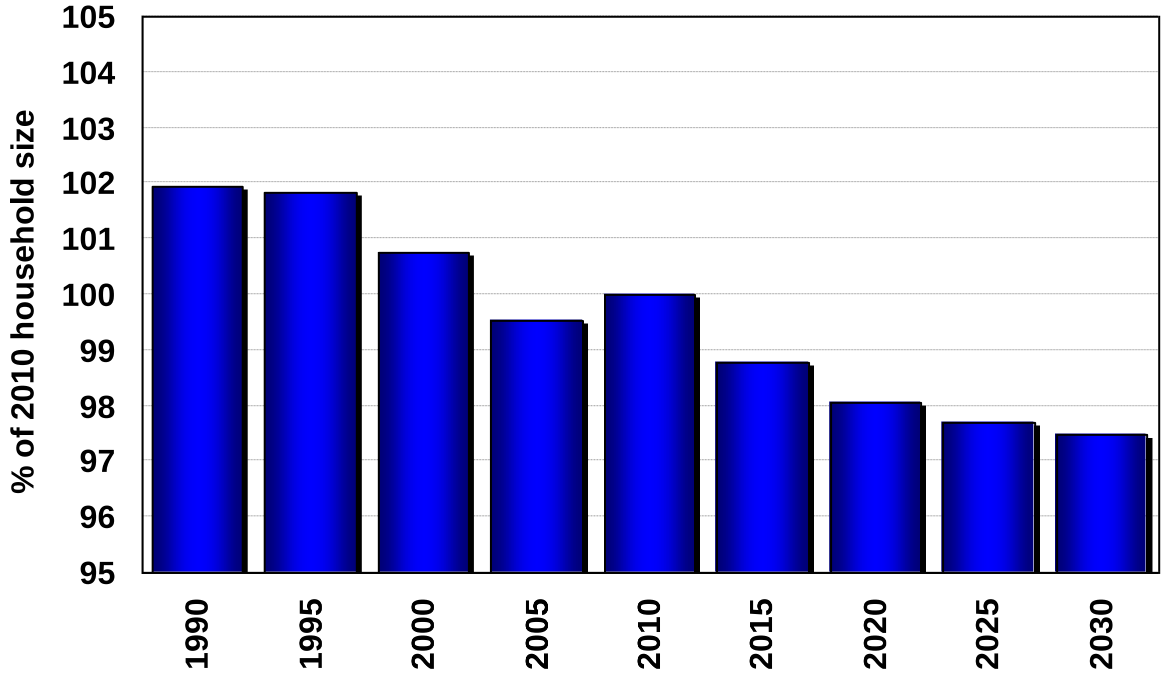
Use per Customer Projections

The database used to project usage per customer uses monthly electricity sales and number of customers by rate schedule, customer class, and state from 1997 to 2008. Historical data is weather-normalized to remove the impact of heating and cooling degree day deviations from expected normal values, as discussed above. Retail electric price increase assumptions are applied to price elasticity estimates to estimate price-induced reductions in electrical use per customer.

The Company included a forecast of personal residential electric vehicles in the base case. These vehicles are a combination of plug-in hybrids and electric-only, and they represent a proportional share from the Northwest Power and Conservation Council's estimates available in mid-2008.

The residential use per customer trend over the long term is flat, consistent with embedded conservation, warming temperatures and price elasticity offset by electric vehicles. The number of occupants per household is also decreasing over time. Figure 2.8 shows the slightly declining number of persons per household over the next 20 years.

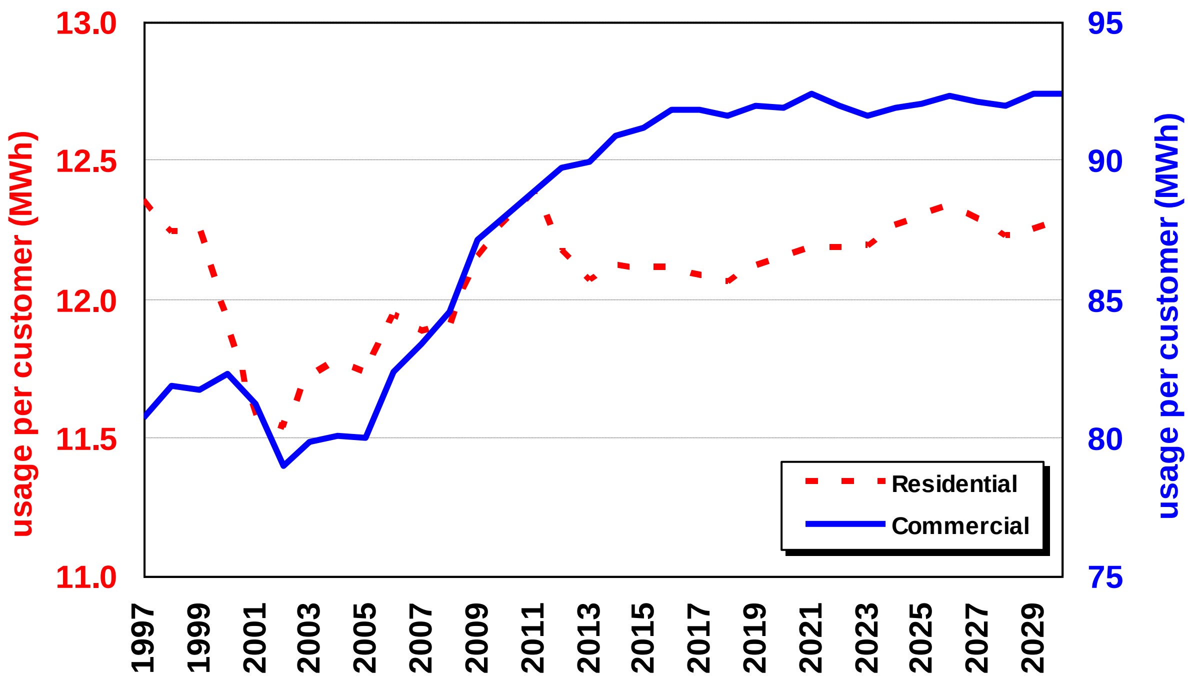
Figure 2.8: Household Size Index



Residential customers tend to be homogeneous relative to size of their dwellings. Commercial customers, on the other hand, are heterogeneous, ranging from small customers with varying electricity intensity per square foot of floor space to big box retailers with generally high intensities. The addition of new large commercial customers, specifically the largest universities and hospitals, can greatly skew average use per average customer statistics. Customer usage is illustrated in Figure 2.9.

Estimates for residential usage per customer across all schedules are relatively smooth. Commercial usage per customer is forecast to increase for several years due to additional buildings either built or anticipated to be built by existing very large customers, such as Washington State University and Sacred Heart Hospital. Expected additions for very large customers are included in the forecast through 2015, and no additions are included in the forecast after 2015. We will include publicly-announced long lead time buildings in the load forecast in future IRPs.

Figure 2.9: Use per Customer



Retail Electricity Sales Forecast

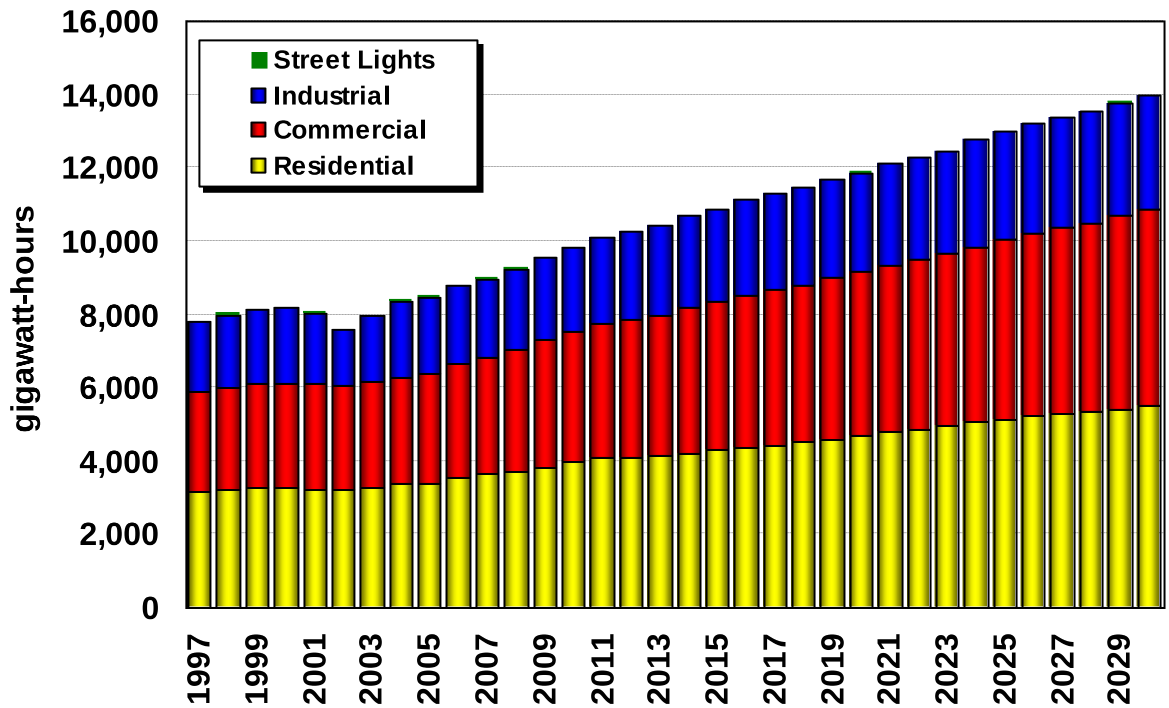
Between 1997 and 2008 the region was affected by major economic changes, not the least of which was a marked increase in wholesale and retail electricity prices. The energy crisis of 2000-01 included the implementation of widespread, permanent conservation efforts by our customers. In 2004, rising retail electricity rates further reinforced conservation efforts. Several large industrial facilities served by the Company closed permanently during the 2001-02 economic recession. Recently the economy has entered a significant recession.

Retail electricity consumption rose from 8.2 billion kWh in 1999 to over 8.9 billion kWh in 2008. This increase was in spite of the combined impacts of higher prices and decreased electricity demand during the energy crisis. The forecasted average annual increase in retail sales over the 2009 to 2029 period is 1.8 percent.

The sales forecast takes a “bottom up” approach, summing forecasts of number of customers and usage per customer to produce a retail sales forecast. Individual forecasts for our largest industrial customers (Schedule 25) include planned or announced production increases or decreases. Lumber and wood products industries have slowed down from very high production levels, which is consistent with the decline in housing starts at the national level and the recession. The load forecasts for these sectors were reduced to account for decreased production levels. Anticipated sales to aerospace and aeronautical equipment suppliers have increased and local plants have announced plans to hire more workers and increase their output.

Actual, not weather corrected, retail electricity sales to Avista customers in 2008 were 8.93 billion kWh. Heating degree days in 2008 were 103 percent of normal, almost completely offset in terms of energy use by 121 percent of normal cooling degree days. The forecast for 2030 is 12.85 billion kWh, representing a 1.6 percent compounded increase in retail sales. See Figure 2.10. Degree days in 2030 are forecast to be 87 percent of the 1971-2000 thirty year normal for heating and 149 percent for cooling.

Figure 2.10: Avista's Retail Sales Forecast

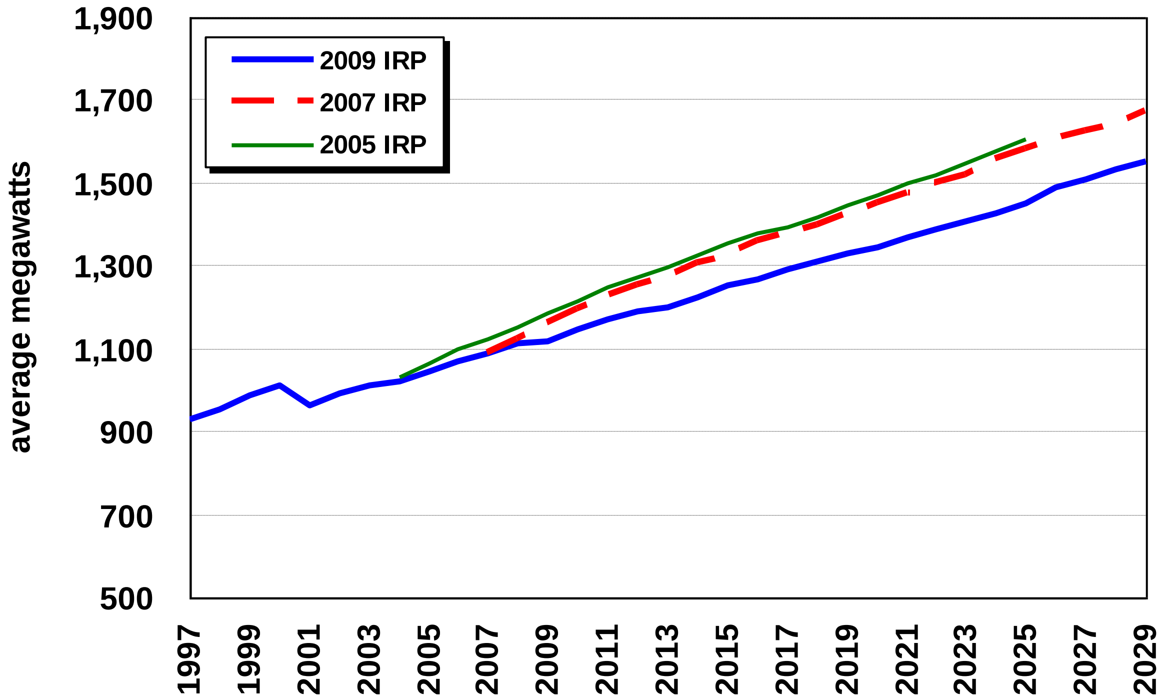


Load Forecast

Load forecasts are derived from retail sales. Retail sales in kilowatt hours are converted into average megawatt hours using a regression model to ensure monthly load shapes conform to history. The Company's load forecast is termed its Native Load. Native Load is net of line losses across the Avista transmission system.

Native Load growth is shown in Figure 2.11. Note the significant drop in 2001 during the energy crisis. Loads from 1997 to 2008 are not weather normalized. Annual growth is expected to be 1.7 percent over the next twenty years. The 2007 IRP load forecast is presented for comparison purposes. Loads are moderately lower in the 2009 IRP compared with the 2007 IRP due to the cumulative impact of additional conservation measures from the 2007 IRP being incorporated in this forecast.

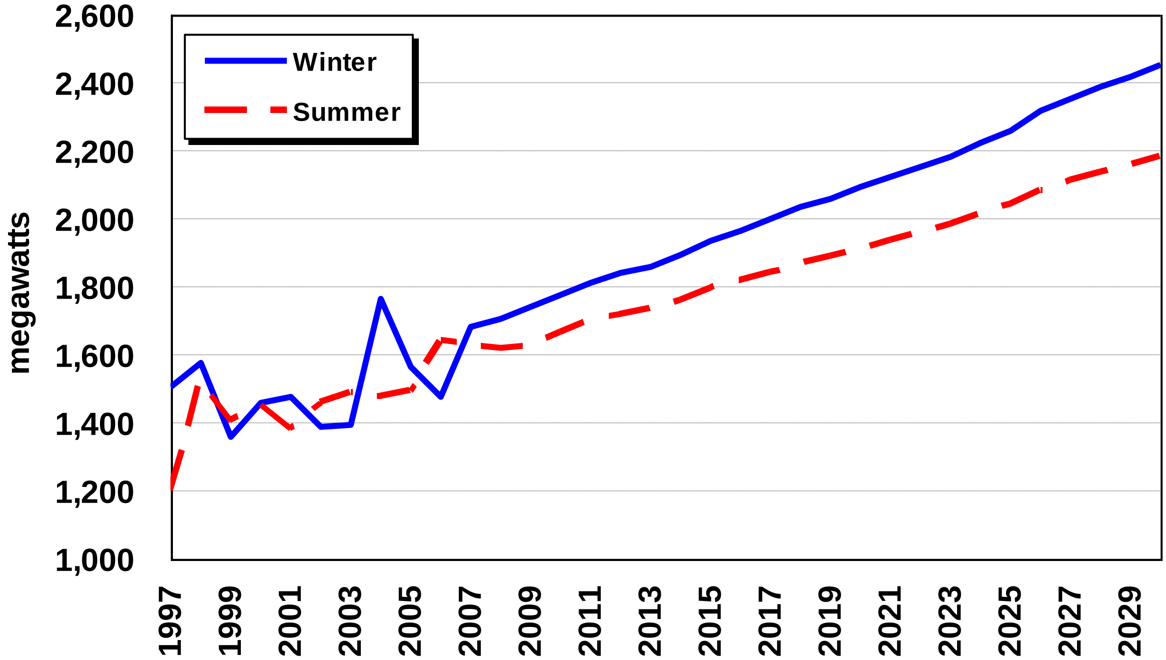
Figure 2.11: Annual Net Native Load



Peak Demand Forecast

The peak demand forecast in each year represents the most likely value for that year. It does not represent the extreme peak demand. The most likely peak demand has a 50 percent chance of being exceeded in any year. The peak forecast is produced by running a regression between actual peak demand and net native load. The peak demand forecast is in Figure 2.12. Peak loads are expected to grow at 1.7 percent between 2009 and 2019 (223 MW) and 1.7 percent over the entire 20-year forecast.

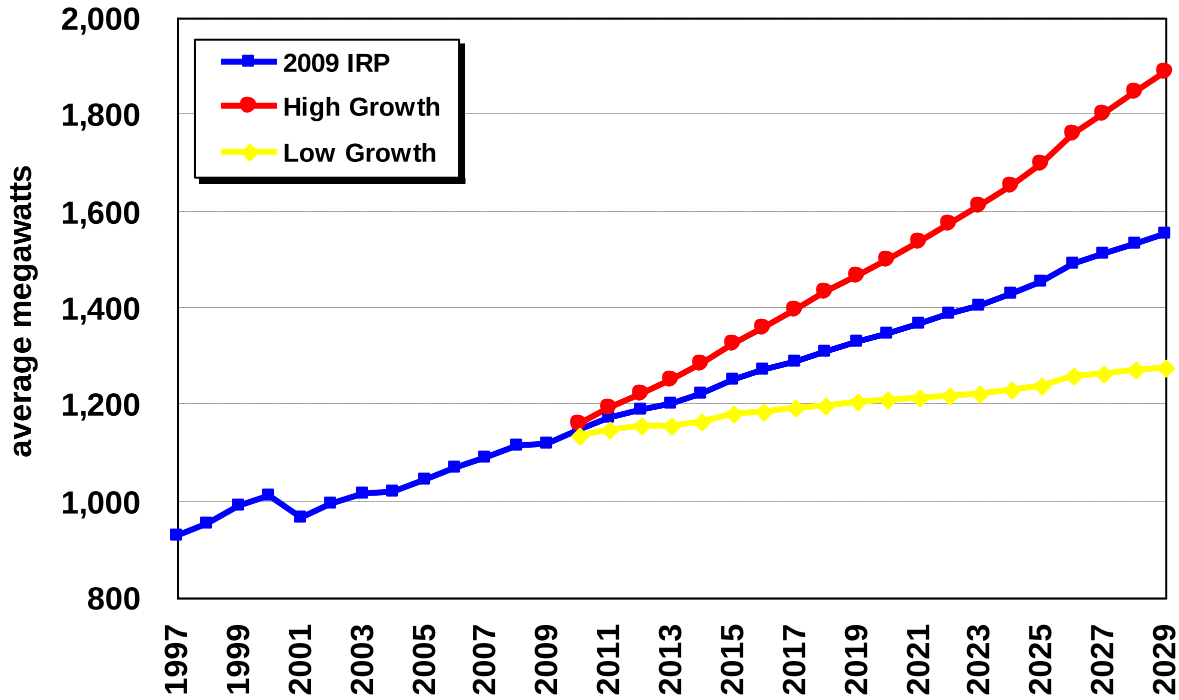
Figure 2.12: Calendar Year Peak Demand



Historical data are influenced by extreme weather events. The comparatively low 1999 peak demand figure was the result of a warmer-than-average winter peak day; the peak in 2006 was the result of a below-average winter peak day. The 1999 and 2006 peak demand values illustrate why relying on compound growth rates for the peak demand forecast is an oversimplification and why the Company plans to own or control enough generation assets and contracts to meet peak demand during weather events.

Avista has witnessed significant summer load growth as air conditioning penetration has risen in its service territory. That said, Avista expects to remain a winter-peaking utility in the foreseeable future. It is possible that very mild winter weather and extremely hot summertime temperatures could result in our summer peak load exceeding our wintertime demand level. This will be an anomaly. The 2007 IRP provided an illustration of this trend into the future.

Figure 2.13: Electric Load Forecast Scenarios



Avista Resources & Contracts

The Company relies on a diversified portfolio of generating assets to meet customer loads. Avista owns and operates eight hydroelectric projects located on the Spokane and Clark Fork Rivers. Its thermal assets include partial ownership of two coal-fired units in Montana, four natural gas-fired projects within its service territory, another natural gas-fired project in Oregon and a biomass plant near Kettle Falls, Washington.

Spokane River Hydroelectric Projects

Avista owns and operates six hydroelectric projects on the Spokane River. These projects received a new 50-year FERC operating license in June 2009. The following section includes a short description of the Spokane River projects with the maximum capacity and nameplate ratings for each plant. The maximum capacity of a generating unit is the total amount of electricity a plant can safely generate. This is often higher than the nameplate rating. The nameplate, or installed capacity is the plant's capacity as rated by the manufacturer.

Post Falls

The upper most hydro facility on the Spokane River is Post Falls, located at its Idaho namesake near the Washington/Idaho border. The project began operation in 1906 and maintains lake elevation during the summer for Lake Coeur d'Alene. The project has six units, with the last added in 1980. The project is capable of producing 18.0 MW and has a 14.75 MW nameplate rating. Avista is studying the potential to replace the powerhouse with two larger units to increase energy production at the plant, and another option to increase generation by upgrading Unit 6.

Upper Falls
The Upper Falls project began generating in 1922 in downtown Spokane, and now is within the city's Riverfront Park. This project is comprised of a single 10.0 MW unit with a 10.26 MW maximum capacity rating. Rewinding the generator and replacing the runner is evaluated in this IRP; the upgrade would increase generation by approximately 2.0 MW

Monroe Street
The Monroe Street facility was the Company's first generating unit. It started service in 1890 near what is now Riverfront Park. Rebuilt in 1992, the single generating unit now has a 15.0 MW maximum capacity and a 14.8 MW nameplate rating. In year's past a second powerhouse at Monroe Street was evaluated. As part of the Company's efforts to increase renewable generation, this option will be studied further.

Nine Mile
The Nine Mile project was built by a private developer in 1908 near Nine Mile Falls, Washington, nine miles northwest of Spokane. The Company purchased it in 1925 from the Spokane & Eastern Railway. Its four units have a 17.6 MW maximum capacity[1] and a 26.4 MW nameplate rating. Currently Unit 1 provides no generation and Unit 2 is limited to half load. These units will be replaced and is expected to be online by 2012 and 2013. A rubber dam will be added to the facility replacing flashboards to take advantage of high flows. The total incremental capacity is 8.8 MW and an additional 4.4 aMW of renewable energy from its former operational capability.

Long Lake
The Long Lake project is located northwest of Spokane and maintains Lake Spokane, also known as Long Lake. The facility was the highest spillway dam with the largest turbines in the world when it was completed in 1915. The plant was upgraded with new runners in the 1990s, adding 2.2 aMW of renewable energy. The project's four units provide 88.0 MW of combined capacity and have am 81.6 MW nameplate rating. This IRP evaluates two additional upgrades at the project, either an additional 24 MW unit in the existing powerhouse or a second powerhouse with a 60 MW generator.

Little Falls
The Little Falls project was completed in 1910 near Ford, Washington, and is the furthest downstream hydro facility on the Spokane River. The facility was recently upgraded to generate an additional 0.6 aMW of renewable energy with a runner replacement on Unit 4. The facility's four units generate 35.2 MW of maximum capacity and have a 32.0 MW nameplate rating. Generator rewinds at each of these units were included at as resource options in this IRP for a total potential of 4.0 MW of additional capacity and 1.3 aMW of energy.

[1] This is the de-rated capacity considering the outage of unit 1 and de-rate of unit 2

Clark Fork River Hydroelectric Project

The Clark Fork River Project includes hydroelectric projects near Clark Fork, Idaho, and Noxon, Montana, 70 miles south of the Canadian border. The plants are operated under a FERC license through 2046.

Cabinet Gorge

The Cabinet Gorge plant started generating power in 1952 with two units. The plant was expanded with two additional generators in the following year. The current maximum capacity of the plant is 270.5 MW; it has a nameplate rating of 265.2 MW. Upgrades at this project began with the replacement of turbine Unit 1 in 1994. Unit 3 was upgraded in 2001. Unit 2 was upgraded in 2004. The final unit, Unit 4, received a $6 million turbine upgrade in 2007, increasing its generating capacity from 55 MW to 64 MW, and adding 2.1 aMW of renewable energy. The Company is evaluating the addition of a fifth unit at the project. This addition would add 50 to 60 MW of capacity and up to 10.2 aMW of renewable energy.

Noxon Rapids

The Noxon Rapids project includes four generators installed between 1959 and 1960, and a fifth unit added in 1977. The current plant configuration has a maximum capacity of 541.0 MW and a generator nameplate rating of 480.6 MW. The project's units are currently being upgraded. The Unit 1 upgrade was completed in April 2009 and the remaining units will be replaced over the next three years. The upgrades are expected to add 30 MW of capacity and 6 aMW of qualified renewable energy to the Company's resource portfolio.

Total Hydroelectric Generation

In total, our hydroelectric plants are capable of generating as much as 986 MW. Table 2.2 summarizes the Company's hydro projects. This table also includes the average annual energy output of each facility based on the 70-year hydrologic record.

Table 2.2: Company-Owned Hydro Resources

Project Name	River System	Location	Start Date	Nameplate Capacity (MW)	Maximum Capability (MW)	Expected Energy (aMW)
Monroe Street	Spokane	Spokane, WA	1890	14.8	15.0	11.6
Post Falls	Spokane	Post Falls, ID	1906	14.7	18.0	9.8
Nine Mile	Spokane	Nine Mile Falls, WA	1925	26.4	17.6	13.3
Little Falls	Spokane	Ford, WA	1910	32.0	35.2	23.7
Long Lake	Spokane	Ford, WA	1915	81.6	88.0	58.4
Upper Falls	Spokane	Spokane, WA	1922	10.3	10.0	8.6
Cabinet Gorge	Clark Fork	Clark Fork, ID	1952	265.2	270.5	123.8
Noxon Rapids	Clark Fork	Noxon, MT	1959	541.0	480.6	197.1
Total				**986.0**	**934.9**	**446.3**

Thermal Resources

Avista owns seven thermal assets located across the Northwest. Each thermal plant is expected to continue to be available through the 20-year duration of the 2009 IRP. The Company's thermal resources provide dependable low-cost energy to serve base loads and provide peak load serving capabilities. A summary of Avista resources is shown in Table 2.3.

Colstrip

The Colstrip plant, located in Eastern Montana, consists of four coal-fired steam plants owned by a group of utilities. PPL Global operates the facilities. Avista owns 15 percent of Units 3 and 4. Unit 3 was completed in 1984 and Unit 4 was finished in 1986. The Company's share of each Colstrip unit has a maximum net capacity of 111.0 MW and a nameplate rating of 123.5 MW. Capital improvements to both units were completed in 2006 and 2007 to improve efficiency, reliability and generation capacity. The upgrades included new high-pressure steam turbine rotors and a conversion from analog to digital control systems. These capital improvements increased the Company's share of generation by 4.2 MW at each unit without any additional fuel consumption.

Rathdrum

Rathdrum is a two-unit simple-cycle combustion turbine. The gas-fired plant is located near Rathdrum, Idaho. It entered service in 1995 and has a maximum capacity of 180.0 MW in the winter and 126.0 MW in the summer. The nameplate rating is 166.5 MW.

Northeast

The Northeast plant, located in northeast Spokane, is a two-unit aero-derivative simple-cycle plant completed in 1978. The plant is capable of burning natural gas or fuel oil, but current air permits prevent the use of fuel oil. The combined maximum capacity of the units is 68.0 MW in the winter and 42.0 MW in the summer, with a nameplate rating of 61.2 MW. Northeast is primarily used for reserve capacity to protect against reliability concerns and market aberrations.

Boulder Park

The Boulder Park project was completed in Spokane Valley in 2002. The site uses six natural gas-fired internal combustion engines to produce a combined maximum capacity and nameplate rating of 24.6 MW.

Coyote Springs 2

Coyote Springs 2 is a natural gas-fired combined cycle combustion turbine located near Boardman, Oregon. The plant began service in 2003. The maximum capacity is 280.6 MW in the winter and 226.5 MW in the summer and the duct burner provides the unit with an additional capability of up to 20.4 MW. The nameplate rating is 287.3 MW.

Kettle Falls and Kettle Falls CT

The Kettle Falls biomass facility was completed in 1983 near Kettle Falls, Washington and is one of the largest biomass plants in North America. The open-loop biomass steam plant is fueled by waste wood products from area mills and forest slash, but can also run on natural gas. A gas-fired CT was added to the facility in 2002. The CT burns natural gas and sends exhaust heat to the wood facilities boiler to increase wood fuel efficiency.

The wood portion of the plant has a maximum capacity of 50.0 MW and a nameplate rating is 50.7 MW; typically the plant operates between 45 and 47 MW due to fuel quality issues. The plant's capacity increases to 56.0 MW when operated in combined-cycle mode with the CT. The CT produces 5.2 MW of peaking capability in the summer and 7.8 MW in the winter. The CT resource has limited operations in winter when the gas pipeline is constrained. Avista is evaluating upgrading the capacity of the pipe line, This IRP also evaluates the addition of a wood gasifier to the project so that the CT can use less natural gas and generate more renewable energy.

Table 2.3: Company-Owned Thermal Resources

Project Name	Location	Fuel Type	Start Date	Winter Maximum Capacity (MW)	Summer Maximum Capacity (MW)	Nameplate Capacity (MW)
Colstrip 3 (15%)	Colstrip, MT	Coal	1984	111.0	111.0	123.5
Colstrip 4 (15%)	Colstrip, MT	Coal	1986	111.0	111.0	123.5
Rathdrum	Rathdrum, ID	Gas	1995	180.0	126.0	166.5
Northeast	Spokane, WA	Gas	1978	68.0	42.0	61.2
Boulder Park	Spokane, WA	Gas	2002	24.6	24.6	24.6
Coyote Springs 2	Boardman, OR	Gas	2003	301.0	246.9	287.3
Kettle Falls[2]	Kettle Falls, WA	Wood/Gas	1983	50.0	50.0	50.7
Kettle Falls CT	Kettle Falls, WA	Gas	2002	7.8	5.2	7.2
Total				**853.4**	**716.7**	**844.5**

Power Purchase and Sale Contracts

The Company utilizes several power supply purchase and sale arrangements of varying lengths to meet some load requirements. This chapter describes the contracts in effect during the scope of the 2009 IRP. Contracts can provide a many benefits including environmentally low-impact and low-cost hydro and wind power. A 2010 annual summary of Avista large contracts is in Table 2.4.

Bonneville Power Administration – WNP-3 Settlement

Avista (then Washington Water Power) signed settlement agreements with BPA and Energy Northwest (formerly the Washington Public Power Supply System or WPPSS) on September 17, 1985, ending construction delay claims against both parties. The settlement provides an energy exchange through June 30, 2019, with an agreement to reimburse the Company for certain WPPSS – Washington Nuclear Plant No. 3 (WNP-3) preservation costs and an irrevocable offer of WNP-3 capability for acquisition under the Regional Power Act.

[2] Assumes combined cycle mode- when not in this mode the operational capacity is between 45-47 MW depending upon fuel quality

The energy exchange portion of the settlement contains two basic provisions. The first provision provides approximately 42 aMW of energy to the Company from BPA through 2019, subject to a contract minimum of 5.8 million megawatt-hours. Avista is obligated to pay BPA operating and maintenance costs associated with the energy exchange as determined by a formula that ranges from $16 to $29 per megawatt-hour in 1987 year constant dollars.

The second provision provides BPA approximately 32 aMW of return energy at a cost equal to the actual operating cost of the Company's highest-cost resource. A further discussion of this obligation, and how Avista plans to account for it, is covered under the Planning Margin heading of this chapter.

Mid-Columbia Hydroelectric Contracts

During the 1950s and 1960s, various public utility districts (PUDs) in central Washington developed hydroelectric projects on the Columbia River. Each plant was oversized compared to the loads then served by the PUDs. Long-term contracts were signed with public, municipal, and investor-owned utilities throughout the Northwest to assist with project financing, and to ensure a market for the surplus power.

The Company entered into long-term contracts for the output of four of these projects "at cost." The contracts provide energy, capacity, and reserve capabilities; in 2010 contracts will provide approximately 164 MW of capacity and 85 aMW of energy. Over the next 20 years, the Wells (2018) and Rocky Reach (2011) contracts will expire. Avista may be able to extend these contracts; however, it has no assurance today that extensions will be offered. Due to this uncertainty, the IRP does not include these contracts beyond their expiration dates.

Avista renewed its contract with Grant PUD in 2005 for power from the Priest Rapids project. The contract term will equal the term in the forthcoming Priest Rapids and Wanapum dam FERC licenses in 2052.

Lancaster

Avista acquired the output rights to the Lancaster combined-cycle generating station as part of the sale of Avista Energy to Shell in 2007. Lancaster is also known as the Rathdrum Generating Station, but the plant is referred to as Lancaster in this IRP to remove confusion with the Rathdrum CT. The project is under a tolling PPA with Goldman Sachs (20 percent) and Energy Investors Funds (80 percent) through October 2026. Avista has the right to dispatch the plant and is responsible for providing fuel and energy and capacity payments. The 2007 IRP showed that the Lancaster project was a lower cost acquisition than a greenfield site, and was also lower in cost than recent CCCT transactions in the Northwest.

Table 2.4: Large Contractual Rights and Obligations

Contract	Type	End Date	Winter Capacity (MW)	Summer Capacity (MW)	2010 Annual Energy (aMW)
Wanapum/Priest Rapids	Purchase	Mar- 2052	67.6	66.6	34.8
Rocky Reach	Purchase	Oct- 2011	34.5	34.0	20.3
Wells	Purchase	Aug- 2018	26.1	25.9	14.7
PGE Capacity	Exchange	Dec- 2016	150.0	150.0	0.0
Upriver (net load)	Purchase	Dec- 2011	8.2	-1.3	6.1
WNP-3	Purchase/Sale	Jun- 2019	89.3	0.0	42.3
Stateline	Purchase	Dec- 2011	0.0	0.0	8.3
Nichols Pumping	Sale	n/a	6.8	6.8	6.8
Lancaster	Purchase	Oct- 2026	281.0	264.0	237.8
Canadian Entitlement	Sale	n/a	6.3	6.3	3.6
Grant Displacement	Purchase	Sep- 2011	17.4	19.6	22.0
Forward Market	Purchase	Dec- 2010	100.0	100.0	100.0
Potlatch	PURPA	Dec- 2011	75.0	75.0	47.6
Stimson Lumber	Purchase	Sep- 2011	4.2	4.4	4.2
Douglas Settlement	Purchase	Sep- 2018	2.5	3.9	3.7

Reserve Margins

Planning reserves accommodate situations when loads exceed and/or resources are below expectations due to adverse weather, forced outages, poor water conditions, or other contingencies. There are disagreements within the industry on adequate reserve margin levels. Many stem from system differences, such as resource mix, system size, and transmission interconnections. For example, a hydro-based utility generally has a higher capacity to energy ratio than a thermal-based utility.

Reserve margins, on average, increase customer rates when compared to resource portfolios without reserves, due to carrying additional cost of generation. Reserve resources have the physical capability to generate electricity, but high operating costs limit economic dispatch and the potential to create revenues to offset capital investments.

Avista Planning Margin

Avista retains two types of planning margins—capacity and energy. Capacity planning is a traditional planning metric for many utilities to ensure they can meet peak loads at times of system strain. Energy planning is used for utilities with resources that have an unpredictable fuel source, such as wind and hydro, but also to cover load variance. For capacity planning, Avista reserves are not directly based on unit size or resource type. Planning reserves are set at a level equal to 15 percent planning reserve margin during the Company's peak load hour.

For energy planning, resources must be adequate to meet customer requirements. Extreme weather conditions can change monthly energy obligations by up to 30 percent. If generation capability does not meet high load variations, customers and the utility are exposed to increased short term market volatility. In addition to load variance, Avista also uses a planning margin for its hydro generation. Unlike weather, hydro is not normally distributed due to river regulation by the hydroelectric projects.

There is a difference of regional opinion concerning the proper method for establishing a resource planning margin. Many utilities in the Northwest base their capacity planning on critical water using the 1936/37 hydro year as the critical time period. The critical water year of 1936/37 is poor on an annual basis, but it is not necessarily critical month-to-month. The utility could build resources to reach the 99 percent confidence level, and could significantly decrease the frequency of market purchases, but this strategy requires approximately 200 MW of additional generation capability. Additional capital expenditures to support this level of reliability would put upward pressure on retail rates. Analysis of historical data indicates that an optimal criterion is the use of a 90 percent confidence interval based on the monthly variability of load and the 10th percentile of monthly historical hydro energy. This results in a 10 percent chance of load exceeding the planning criteria for each month. In other words, there is a 10 percent chance that the Company would need to purchase energy from the market in any given month.

Additional variability is inherent in Avista's WNP-3 contract with BPA. The contract includes a return energy provision that can equal 32 aMW annually. The contract would be exercised under adverse conditions, such as low hydroelectric generation or high loads. The contract was last exercised in 2001. Energy planning margin is increased by 32 aMW to account for the WNP-3 obligation through its expiration in 2019. The total capacity planning margin and energy margin adds 267 MW of required capacity and 227 aMW of energy in 2010.

Other Planning Methods

Parallel to planning margins is a gray area between energy and capacity planning. Sustained peaking and Loss of Load Probability (LOLP) metrics can be used to further evaluate system constraints. Avista has actively participated in the Northwest Power and Conservation Council's Resource Adequacy committees over the past few years. This effort has used LOLP and sustained capacity analyses to evaluate the Northwest's resource position over extended timeframes. Preliminary work indicates that the Northwest should carry approximately a 25 percent planning margin in the wintertime and a 17 percent planning margin in the summertime. These levels are much higher than the 12 to 15 percent levels recommended in other markets, primarily due to the Northwest's heavier reliance on hydroelectric generation. Given the uncertainties surrounding higher planning margins, Avista will not adopt the NPCC metrics in this planning cycle. The Company will continue to participate in the regional process and will use the results for future resource planning.

Sustained peaking capacity is a tabulation of loads and resources over a period exceeding the traditional one-hour definition. It is also a measure of reliability and recognizes that peak loads do not stress the system for just one hour. The difference from traditional one hour peak analysis is a look at multiple days versus one hour. The analysis also considers how the hydro system will be impacted by freezing temperatures and hydro reservoir depletion.

Loss of Load probability has only recently gained attention in the Northwest. The industry standard is a 5 percent acceptable loss of load. Avista has created a tool to evaluate LOLP, but there is still significant uncertainty surrounding how much energy from the wholesale market would be available to Avista at a time of regional peak loads. At the first TAC meeting, an early analysis was shown for 2009 and included many scenarios. The results of this study indicated for the 2009 planning year the LOLP is 2.1 percent in the winter and 3.8 percent in the summer, but this includes a market availability of 300 MW. If only 200 MW of on-peak market is available, the LOLP increases to 7.4 percent in the winter and 12.1 percent in the summer. Additional studies are required for this analysis. The goal for the LOLP tool is to ensure the Preferred Resource Strategy adds resources adequate to meet reliability criteria, but the critical assumption is the amount of energy available from the market. The Northwest Power and Conservation Council are studying this problem, and Avista will use the results from that process.

Washington State Renewable Portfolio Standard

In the November 2006 general election, Washington State voters approved Citizens Initiative 937. The initiative requires utilities with more than 25,000 customers to source 3 percent of their energy from non-hydro renewables by 2012, 9 percent by 2016, and 15 percent by 2020. Utilities also must acquire all cost effective conservation and energy efficiency measures. Even though Avista does not require new resources to meet forecasted loads through 2017, this new law requires Avista to acquire generation or REC resources it otherwise would not need to meet the initiative's renewable goals.

Avista will meet or exceed its renewable requirement goals between 2012 and 2015 with a recent REC purchase and qualified hydroelectric upgrades. The Company plans to acquire resources to ensure that it is not forced to make REC purchases in a strained market in nine of 10 years due to lower-than-expected wind and hydro generation levels. See Table 2.5.

Resource Requirements

The differences between loads and resources illustrate potential needs the Company must address through future resource acquisitions. Avista regularly develops a 20-year forecast of peak capacity loads and resources. Peak load is the maximum one-hour obligation, including operating reserves, on the expected average coldest day in January and the average hottest day in August. Peak resource capability is the maximum one hour generation capability of Company resources, including net contract contribution, at the time of the one-hour system peak, and excludes resource that are on maintenance during peak load periods.

Avista is surplus capacity through 2014. It then carries a modest deficit until the Portland General Exchange contract expires in 2016. Avista is then capacity surplus in 2019. Deficits grow after 2018 as peaking requirements increase with load growth, and as the Company's resource base declines with the expiration of market purchases and Mid-Columbia hydroelectric project contracts. Winter and summer capacity positions are shown in Figures 2.15 and 2.16, respectively. Tabular views of this data are in Table 2.6 and Table 2.7.

In addition to balancing capacity, Avista procures enough resources to meet its energy obligations. The energy L&R includes resources at their full capability during normal weather conditions in each month. It includes generation maintenance schedules and loads based on expected normal temperatures. The first deficit year for energy (including the planning margin) is 2018. Quarterly deficits begin in the fourth quarter of 2014. A graphical representation of Avista's positions is shown in Figure 2.17; a tabular version of the data is shown Table 2.8. Each of these charts includes conservation levels per the 2007 IRP. In Chapter 8, conservation levels are updated to reflect 2009 IRP levels.

Figure 2.15: Winter Capacity Position

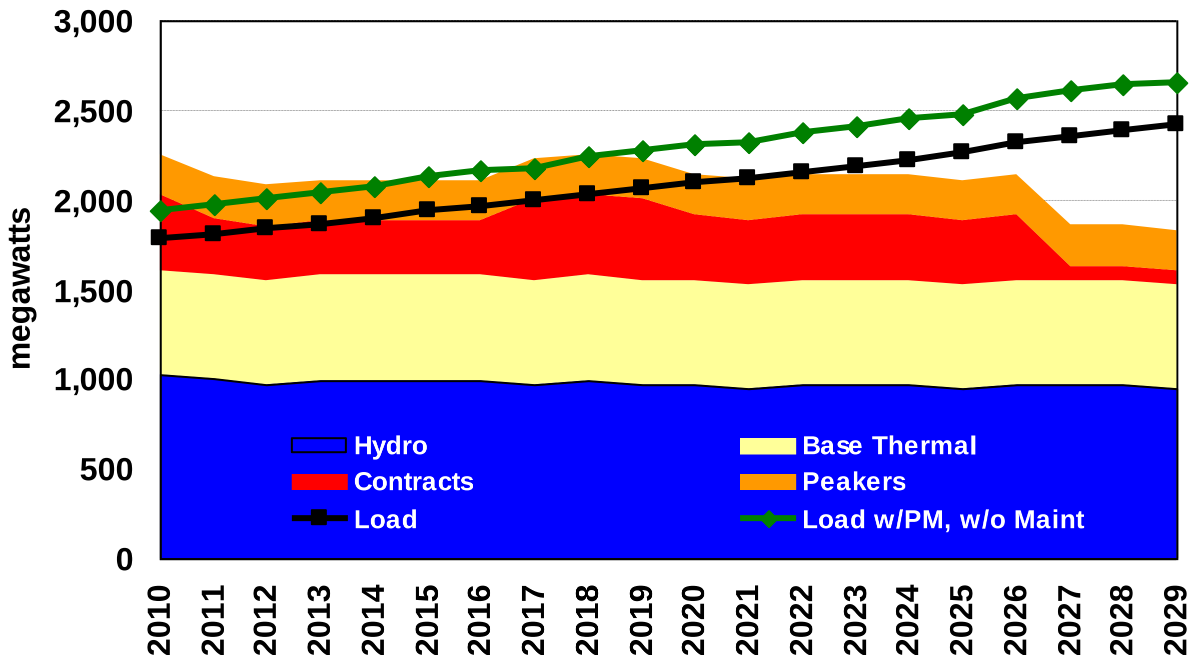


Figure 2.16: Summer Capacity Position

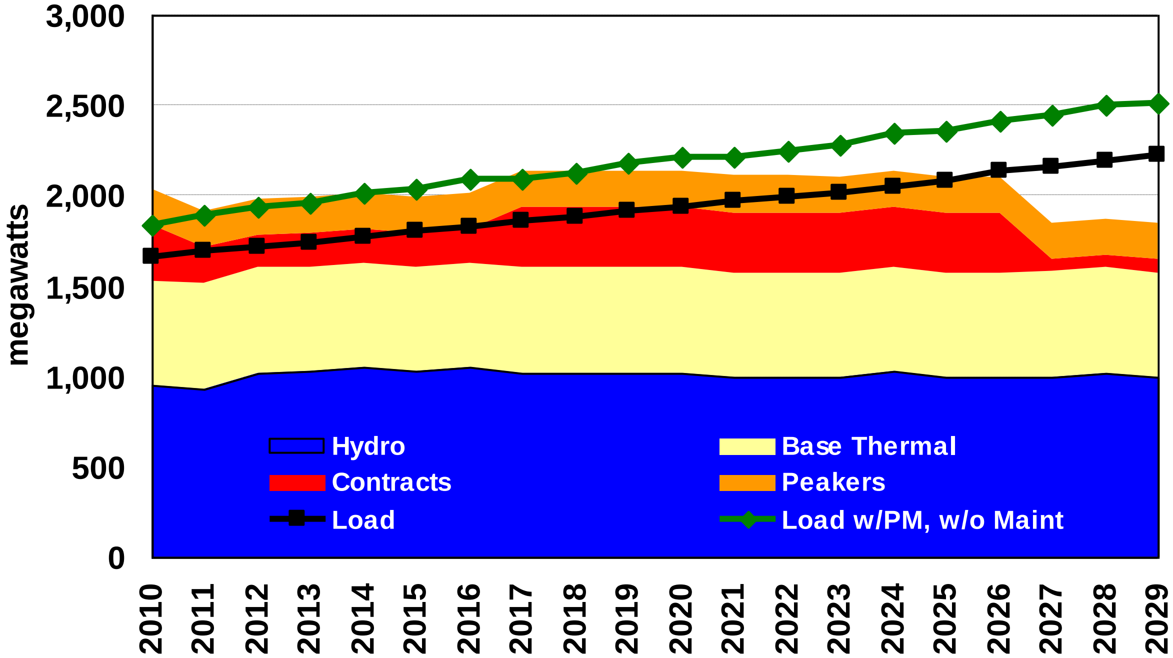


Figure 2.17: Annual Average Position

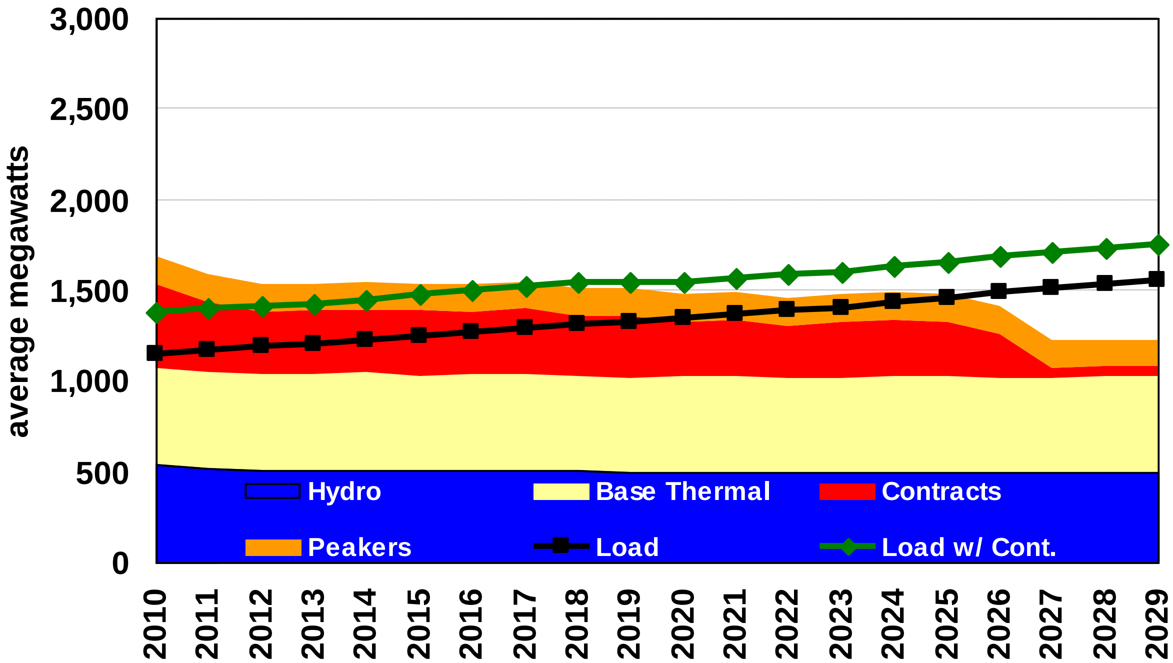


Table 2.5: Washington State RPS Detail (aMW)

	On-line Year	Upgrade Energy	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
WA State Retail Sales Forecast			653	668	678	686	695	703	716	729	744	756	768	782	795	808	823	837	851
Load 10% Change of Exceedance			29	29	30	30	31	31	32	32	33	33	34	34	35	35	36	37	37
Planning RPS Load			681	697	708	716	725	734	748	762	776	789	802	817	830	843	859	874	888
RPS %			0%	0%	3%	3%	3%	3%	9%	9%	9%	9%	15%	15%	15%	15%	15%	15%	15%
Required Renewable Energy			**0.0**	**0.0**	**20.7**	**21.1**	**21.4**	**21.6**	**65.7**	**66.7**	**67.9**	**69.2**	**117.4**	**119.3**	**121.4**	**123.5**	**125.5**	**127.6**	**129.9**
Renewable Resources																			
Purchased RECs			0.0	0.0	5.7	5.7	5.7	5.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kettle Falls	1983		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stateline	1999		7.5	7.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Long Lake 3	1999		2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Little Falls 4	2001		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Cabinet 2	2004		2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Cabinet 3	2001		4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Cabinet 4	2007		2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Apprentice Credits			0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Hydro 10% Chance of Exceedance			(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)
Total Qualifying Resources			***16.6***	***16.6***	***14.8***	***14.8***	***14.8***	***14.8***	***9.1***	***9.1***	***9.1***	***9.1***	***9.1***	***9.1***	***9.1***	***9.1***	***9.1***	***9.1***	***9.1***
Net REC Position (Completed)			**16.6**	**16.6**	**(5.9)**	**(6.3)**	**(6.6)**	**(6.8)**	**(56.6)**	**(57.6)**	**(58.8)**	**(60.1)**	**(108.3)**	**(110.2)**	**(112.3)**	**(114.4)**	**(116.4)**	**(118.5)**	**(120.8)**
Budgeted Hydro Upgrades																			
Noxon 1	2009	2.30	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Noxon 2	2010	1.00	0.6	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Noxon 3	2011	1.30	0.0	0.8	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Noxon 4	2012	1.20	0.0	0.0	0.7	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Nine Mile	2012	3.80	0.0	0.0	2.3	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Hydro 10% Chance of Exceedance			(1.0)	(1.4)	(2.3)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)
Total Budgeted Hydro Upgrades			***2.4***	***3.3***	***6.2***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***
Net REC Postion (Budgeted Upgrades)			**19.0**	**19.9**	**0.3**	**2.2**	**2.0**	**1.7**	**(48.1)**	**(49.1)**	**(50.3)**	**(51.6)**	**(99.8)**	**(101.7)**	**(103.8)**	**(105.9)**	**(107.9)**	**(110.0)**	**(112.3)**

Table 2.6: Winter Capacity Position (MW) - Plan for Position Excluding Maintenance

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
REQUIREMENTS																				
Native Load	-1,779	-1,812	-1,839	-1,862	-1,893	-1,937	-1,967	-1,998	-2,033	-2,062	-2,091	-2,124	-2,154	-2,185	-2,222	-2,261	-2,320	-2,352	-2,387	-2,419
Contracts Obligations	-240	-239	-239	-239	-239	-164	-164	-14	-14	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12
Total Requirements	**-2,019**	**-2,051**	**-2,078**	**-2,101**	**-2,132**	**-2,101**	**-2,131**	**-2,012**	**-2,046**	**-2,074**	**-2,103**	**-2,136**	**-2,166**	**-2,197**	**-2,234**	**-2,273**	**-2,331**	**-2,364**	**-2,398**	**-2,431**
RESOURCES																				
Contracts Rights	657	557	539	539	539	464	464	464	464	462	372	372	372	371	371	371	371	90	90	90
Hydro Resources	1,030	1,000	972	997	997	997	997	970	997	971	971	944	971	971	971	944	971	971	971	944
Base Load Thermals	580	584	584	584	584	584	584	584	584	584	584	584	584	584	584	584	584	584	584	584
Peaking Units	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226
Total Resources	**2,493**	**2,366**	**2,321**	**2,346**	**2,346**	**2,271**	**2,271**	**2,244**	**2,271**	**2,242**	**2,153**	**2,126**	**2,153**	**2,152**	**2,152**	**2,125**	**2,152**	**1,871**	**1,871**	**1,844**
PEAK POSITION	**474**	**315**	**242**	**246**	**214**	**170**	**141**	**232**	**225**	**169**	**50**	**-10**	**-14**	**-45**	**-82**	**-148**	**-180**	**-493**	**-528**	**-587**
RESERVE PLANNING																				
Planning Reserve Margin	-267	-272	-276	-279	-284	-291	-295	-300	-305	-309	-314	-319	-323	-328	-333	-339	-348	-353	-358	-363
Peak Position With Maint.	207	43	-33	-34	-70	-120	-154	-67	-80	-140	-264	-328	-337	-373	-416	-487	-528	-846	-886	-950
POSITION EXCLUDING MAINT.	**313**	**148**	**71**	**66**	**30**	**-20**	**-54**	**60**	**20**	**-40**	**-164**	**-201**	**-237**	**-273**	**-316**	**-360**	**-428**	**-746**	**-786**	**-823**

Table 2.7: Summer Capacity Position (MW) - Plan for Position Excluding Maintenance

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
REQUIREMENTS																				
Native Load	-1,659	-1,695	-1,720	-1,739	-1,766	-1,805	-1,830	-1,858	-1,887	-1,912	-1,938	-1,966	-1,993	-2,019	-2,051	-2,085	-2,136	-2,164	-2,194	-2,222
Contracts Obligations	-241	-240	-240	-240	-240	-165	-165	-15	-15	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13
Total Requirements	**-1,900**	**-1,936**	**-1,960**	**-1,979**	**-2,006**	**-1,970**	**-1,995**	**-1,872**	**-1,902**	**-1,925**	**-1,951**	**-1,979**	**-2,006**	**-2,032**	**-2,064**	**-2,098**	**-2,149**	**-2,177**	**-2,207**	**-2,235**
RESOURCES																				
Contracts Rights	545	445	425	425	425	350	350	350	350	346	346	346	346	346	346	346	346	82	82	82
Hydro Resources	953	932	1,020	1,028	1,051	1,028	1,049	1,022	1,022	1,021	1,023	996	996	993	1,028	996	996	1,002	1,023	996
Base Load Thermals	577	581	581	581	581	581	581	581	581	581	581	581	581	581	581	581	581	581	581	581
Peaking Units	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Total Resources	**2,274**	**2,158**	**2,225**	**2,234**	**2,257**	**2,159**	**2,180**	**2,152**	**2,152**	**2,147**	**2,150**	**2,122**	**2,122**	**2,119**	**2,155**	**2,122**	**2,122**	**1,864**	**1,885**	**1,858**
PEAK POSITION	**374**	**222**	**266**	**255**	**251**	**189**	**184**	**280**	**250**	**222**	**198**	**143**	**116**	**87**	**90**	**24**	**-27**	**-313**	**-322**	**-377**
RESERVE PLANNING																				
Planning Reserve Margin	-249	-254	-258	-261	-265	-271	-275	-279	-283	-287	-291	-295	-299	-303	-308	-313	-320	-325	-329	-333
Peak Position with Maint.	125	-33	8	-6	-14	-82	-90	1	-33	-65	-92	-152	-182	-216	-217	-289	-348	-637	-651	-711
POSITION EXCLUDING MAINT.	**293**	**124**	**53**	**31**	**0**	**-45**	**-74**	**45**	**11**	**-46**	**-76**	**-108**	**-139**	**-169**	**-206**	**-245**	**-304**	**-600**	**-634**	**-667**

Table 2.8: Annual Energy Position (aMW) - Plan for Contingency Net Position

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
REQUIREMENTS																				
Native Load	-1,148	-1,171	-1,189	-1,202	-1,222	-1,252	-1,270	-1,289	-1,311	-1,329	-1,348	-1,367	-1,386	-1,405	-1,429	-1,452	-1,491	-1,511	-1,533	-1,553
Contract Obligations	-139	-139	-139	-139	-139	-64	-64	-12	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11
Total Requirements	**-1,287**	**-1,310**	**-1,328**	**-1,341**	**-1,361**	**-1,315**	**-1,334**	**-1,301**	**-1,322**	**-1,339**	**-1,358**	**-1,378**	**-1,397**	**-1,416**	**-1,439**	**-1,463**	**-1,502**	**-1,522**	**-1,544**	**-1,564**
RESOURCES																				
Contract Rights	604	521	487	495	473	420	410	368	346	347	311	322	299	321	321	310	254	61	61	61
Hydro	538	520	509	511	511	511	511	511	507	496	496	496	496	496	496	496	496	496	496	496
Thermal Resources	528	528	527	526	542	517	526	528	519	520	530	530	519	520	529	531	519	523	529	530
Total Resources	**1,670**	**1,569**	**1,522**	**1,532**	**1,526**	**1,448**	**1,446**	**1,407**	**1,371**	**1,363**	**1,337**	**1,348**	**1,314**	**1,337**	**1,346**	**1,336**	**1,270**	**1,080**	**1,086**	**1,087**
POSITION	**382**	**259**	**194**	**191**	**165**	**133**	**112**	**106**	**49**	**24**	**-21**	**-30**	**-83**	**-79**	**-94**	**-127**	**-232**	**-442**	**-458**	**-477**
CONTINGENCY PLANNING																				
Contingency Total	-227	-228	-224	-225	-226	-227	-227	-228	-229	-212	-195	-196	-197	-198	-199	-200	-201	-202	-202	-203
Peaking Resources	153	153	153	144	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
CONTINGENCY NET POSITION	**309**	**185**	**123**	**110**	**93**	**59**	**38**	**31**	**-27**	**-35**	**-63**	**-73**	**-126**	**-124**	**-139**	**-173**	**-280**	**-490**	**-507**	**-527**

3. Energy Efficiency

Introduction

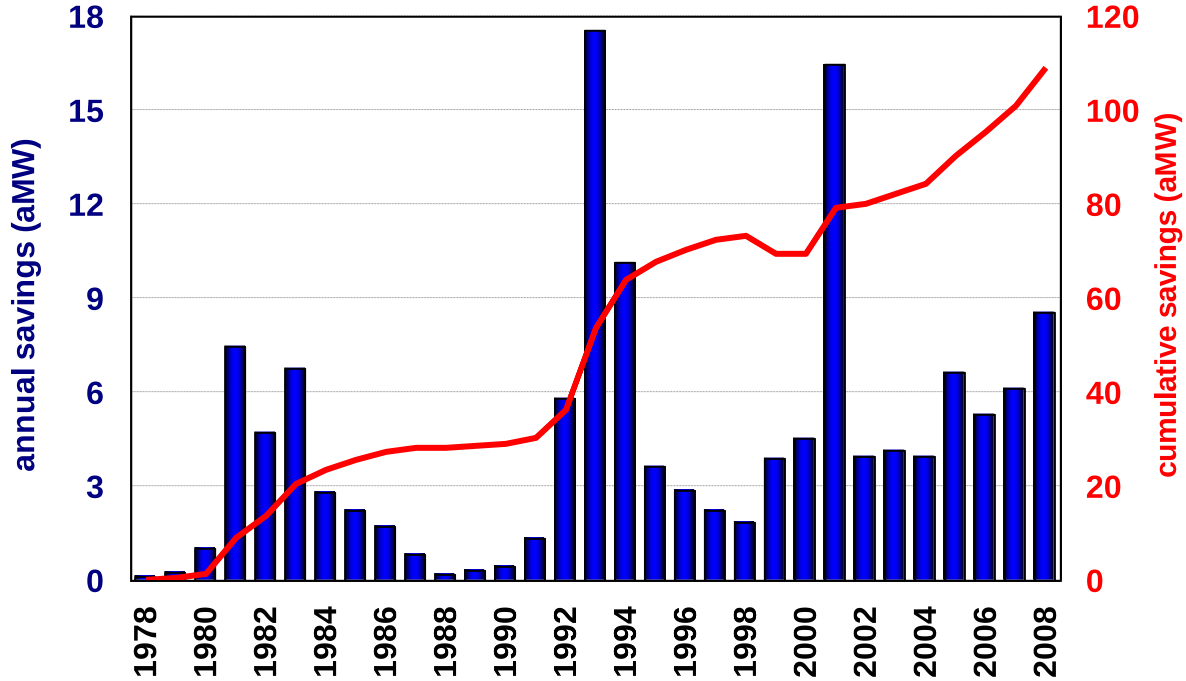
Avista's energy efficiency programs provide a wide range of conservation programs and education for residential, commercial, industrial and low income customers. Programs fall into prescriptive and site-specific classifications. Prescriptive programs offer cash incentives for standardized products, such as compact fluorescent light bulbs and high efficiency appliances. These programs are primarily directed towards residential and small commercial customers. Site-specific programs provide cash incentives for any cost-effective energy savings measure with a payback greater than one year. These site-specific programs require customized services for commercial and industrial customers because many applications need to be tailored to the unique characteristics of customer's premises and processes.

Avista has continuously offered electric efficiency programs since 1978. Some of Avista's most notable efficiency achievements include the Energy Exchanger programs, which converted over 20,000 homes from electric to natural gas space or water heating from 1992-1994; pioneering the country's first system benefit charge for energy efficiency in 1995; and the immediate conservation response during the 2001 Western energy crisis which tripled annual energy savings at only twice the cost in half the time and reduced energy usage during a period of high wholesale market prices. The Company's conservation programs provide savings that regularly meet or exceed its regional share of energy efficiency savings as outlined by the Northwest Power Planning and Conservation Council. Figure 3.1 illustrates Avista's historical electricity conservation acquisitions.

Section Highlights

- Conservation additions provide 26 percent of new supplies through 2020.
- 2009 IRP includes 0.3 aMW (3.3 percent) more conservation than 2007 IRP.
- Avista has offered conservation programs for over 30 years.
- The Company has acquired 138.5 aMW of electric-efficiency in the past three decades; an estimated 109 aMW continue to reduce customer loads.
- The Company is prepared to quickly respond to another energy crisis with efficiency measures.
- Approximately 3,000 efficiency measures were evaluated for the 2009 IRP.
- 7.5 aMW of local and 2.9 aMW of regional conservation are expected in 2010.

Figure 3.1: Historical Conservation Acquisition



Avista has acquired 138.5 aMW of cumulative electricity efficiency resources over the last 30-year; of the 138.5 aMW total, 109 aMW acquired during the last 18 years is assumed to still be online and providing resource value today. Northwest Energy Efficiency Alliance's (NEEA's) cumulative conservation estimates are based on an 18-year average weighted measure life.

In this IRP all conservation measures and programs have been examined based on surrogate generation costs. New savings targets have been established and the Company is planning a significant ramp-up of energy efficiency activity in the coming years.

Avista is also expanding the breadth of its energy efficiency activities to include demand response initiatives and is analyzing the potential for transmission and distribution efficiency measures. More details about the transmission and distribution efficiency projects can be found in the Transmission and Distribution chapter of this IRP. Our demand response pilot is still in process, so there is not enough data to currently determine if Avista will continue demand response initiatives, so they were not included in this IRP. The results demand response pilot will be addressed in detail in the 2011 IRP.

Cooperative Regional Market Transformation Programs

Avista is a funding and fully participating member of NEEA. NEEA's web site is www.nwalliance.org. NEEA is funded by investor-owned and public utilities throughout the Northwest to acquire electric efficiency measures that are best achieved through market transformation efforts. These efforts reach beyond individual service territories and consequently require regional cooperation to succeed.

In the past, NEEA funding has been $20 million shared throughout the region. Avista's four percent portion of NEEA funding has been $800,000 annually. Recently, the Northwest funding utilities have been discussing increasing this amount by 50 percent or more and reapportioning member shares to reflect current retail load among the participants. Consequently, Avista's share would be increased from four percent to 5.41 percent. This is increase in our share of regional funding which would also increase our savings acquisition significantly. Assuming the same percent increase, our historical 1.5 aMW per year would increase to over two aMW. NEEA has proven to be a cost-effective component of regional resource acquisition. Avista has and continues to leverage NEEA ventures when cost-effective enhancements to these programs can be achieved for our customers.

Regional attribution of conservation savings to individual utilities is difficult. In order to ensure that resources are not double-counted at regional and local levels, NEEA has excluded all energy for which local utility rebates have been granted. This allows the summation of the local and regional acquisitions to determine the total impact in a market. Avista has typically applied our funding share of slightly less than four percent to NEEA's annual claim of energy savings. It was assumed that historic acquisitions would remain flat at the most recent level because there are no reliable 20-year estimates of regional program acquisitions. This assumption is speculative and dependent on the opportunities for regional market transformation during this period, but is consistent with the recent history of NEEA funding.

Program Funding

Avista changed its approach to conservation cost-recovery in 1995 from the traditional capitalization of the investments to cost-recovery through a non-bypassable public benefits surcharge (the tariff rider). Avista currently manages four separate tariff riders for Washington electric, Idaho electric, Washington natural gas and Idaho natural gas investments. Based upon the demand for funds and incoming tariff rider revenues, this balance can be positive or negative at any particular point in time.

The aggregate tariff rider balances were returned to a zero balance in 2005 from a $12.4 million deficit in the aftermath of the 2001 Western energy crisis. Recent demand for conservation services has exceeded tariff rider revenues. The most recent projection forecasts a $3.6 million negative balance in the Washington electric DSM tariff rider by the end of 2009. The Idaho electric tariff balance is projected to be just below $4.0 million at that time. Avista anticipates proposing an increase to Idaho schedule 91 rates in the second quarter of 2009.

Renewable Portfolio Standards

Washington's Renewable Portfolio Standard (RPS), established under Initiative 937 (I-937) and codified under RCW 19.285 requires utilities with over 25,000 customers to obtain a fixed percentage of their electricity from qualifying renewable resources. The RPS mandates are three percent by 2012, nine percent by 2016 and 15 percent by 2020. As experience has shown in other jurisdictions, these requirements could be increased by the state legislature in the future. In addition to its renewable portfolio standard, I-937 requires qualifying utilities to acquire all cost-effective and achievable energy conservation and equals 20 percent of the first ten-year target identified in the

Northwest Power and Conservation Council's Sixth Power Plan. As of the writing of this IRP, regional discussions are under way regarding the definition of "pro-rata." Avista would propose a ramping of the 10 year targets as identified in the Sixth Power Plan as opposed to acquiring 20 percent of the first ten-year target identified in the Sixth Power Plan because to do otherwise would creates a ramping issue since utilities will have to acquire twenty of the entire 20 year potential. In an attempt to resolve this ramping issue, it is the Company's intent for purposes of Washington RPS to comply with our portion of the Sixth Power Plan's year by year targets. Penalties of $50 per MW exist for utilities not achieving Washington RPS targets.

The first performance period where the Company will be held to the Washington RPS target will be 2010-2011. Pursuant to Washington regulation, the Company must file its biennial conservation target on or before January 31, 2010. Avista's report, as required by WAC 480-109 (3)(c) will "describe the technologies, data collection, processes, procedures and assumptions the utility used to develop these figures. This report must describe and support any changes in assumptions or methodologies used in the Utility's most recent IRP or the Conservation Council's Power Plan." WAC 480-109 requires approval, approval with modifications or rejection by the WUTC of the Company's targets. Avista's filing will follow, and this IRP will be consistent with, the Council's Sixth Power Plan. The Company's report will include traditional conservation efforts (possibly exclusive of electric to natural gas conversions), non-programmatic adoption of energy efficiency measures consistent with the Sixth Power Plan and distribution efficiency measures which would include savings on the utility and customer sides of the meter. Since distribution efficiencies count toward our goal, meeting plan requirements with the least net cost to ratepayers will involve interdepartmental coordination of efforts and development of new processes.

Avista is considering various means of accounting for the Washington RPS, possibly outside of the traditional tariff rider funding, for conservation acquired above our avoided costs.

American Recovery and Reinvestment Act of 2009

Portions of the American Recovery and Reinvestment Act of 2009 (ARRA) provide economic stimulus funding for energy conservation, such as residential audits, weatherization and smart grid development. Avista is working with local governments to field residential audits funded by a combination of our energy efficiency tariff rider, local government Energy Efficiency Conservation Block Grant (EECBG) funds, State Energy Program (SEP) funds and the customer. The most recent iteration of these analyses calls for a "mid-level" audit that includes the installation of low-cost measures such as CFL's, door sweeps, water tank blankets, low-flow showerheads, furnace filter replacements, refrigerator and coil cleaning, as well as several infiltration reduction measures.

The audit was designed to be a $325 direct investment which includes about $160 in low-cost direct-install measures and the remainder being the auditor labor cost. The Company anticipates some program administrative labor needs on the back-end and estimates this to be the equivalent of about 2.9 full-time employees.

The Company currently estimates that customers will pay $150 and the remainder of the $325 incremental audit cost will be split between the tariff rider and the local governments EECBG funds. The full cost of the additional back office labor will also be funded by the tariff rider. If the local government chooses to not provide EECBG funds, customers will be responsible for paying the total cost of the audit. This enables Avista to offer this service throughout our Washington and Idaho jurisdictions, regardless of how different local governments choose to use their EECBG funds.

The ARRA economic stimulus funding low income weatherization will be allocated directly to regional community action agencies since they already have infrastructure to distribute these funds to low income customers. Therefore, Avista will not be involved in administering programs funded under this portion of the Act. There may be material increases in the low income population served by the economic stimulus funding, however these savings will not be counted towards our goal since the Company is not contributing to the acquisition process.

Another stimulus-funded project that Avista may be participating in is a regional smart grid demonstration project. The scope of the project would include items such as Distribution Automation, Distributed Generation, Energy Storage, Advanced Metering Infrastructure (AMI), software and support and demand response. The application deadline to the Department of Energy for this project is August 26, 2009.

Electric-Efficiency in the 2009 IRP

With the possibility of building new fossil fuel generation in the near future based on the results of the 2005 IRP and power supply technology still developing, Avista wanted an updated review at all efficiency options to ensure that we were evaluating all alternatives in an effort to delay building additional infrastructure. The Heritage Project began during the 2007 IRP evaluation and "roadmaps" for several key areas were developed and followed. The roadmaps included: Energy Efficiency, Demand Response, Transmission and Distribution and Analytics.

Energy Efficiency

The Company completed a comprehensive assessment of best practices in energy efficiency and enhanced program offerings. As a result of this process, the Company launched rebate programs for Residential Fireplace Dampers, Non-Residential Prescriptive Side-stream Filtration, Prescriptive Energy/Heat Recovery Ventilation, Prescriptive Demand Control Ventilation, Prescriptive Steam Trap Maintenance, Retro-Commissioning, as well as offering CFL coupons and community outreach and education on low cost and no cost ways to save energy. In addition, the Company has an on-going Facilities Model program where increased focus is given to energy efficiency while maintaining and upgrading our facilities. Several projects at Avista such as HVAC control upgrades, variable frequency drives (VFDs) on fan motors, and upgrades to the economizer cooling were estimated to save the Company 270,000 kWh and nearly 20,000 therms per year. The Company continues to assess the implementation of cost-effective energy efficiency upgrades where appropriate.

Load Management

While Avista faces higher peak prices, our costs are very different from other parts of the country. Technology costs continue to decline while technological improvements continue to develop making integration with our system a possibility. Since the Load Management Roadmap was developed, a program manager was added to evaluate load management. As part of this effort, a two year pilot of end-use control technology as well as customer acceptance was launched. This pilot will be completed on December 31, 2009. The Company will report on the pilot results in the 2011 IRP.

Analytics

Identification of cost-effective energy efficiency through traditional conservation or distribution efficiencies, as well as demand response, is dependent upon a technically sound and transparent analytical approach. Representatives from several departments developed concepts for resource evaluation of six resource value categories. Four of these values are part of a total avoided cost of energy usage while the remaining two values represent reductions in system coincident peak. Components included in the avoided cost of energy are commodity cost of energy, avoidance of carbon emissions, reducing retail rate volatility, and transmission and distribution system loss reduction. The value of system coincident peak capacity includes deferring future investments in generation capacity and transmission and distribution.

Transmission and Distribution

Avista completed a comprehensive assessment of the available cost-effective electric efficiency opportunities. This is always a factor in the completion of all IRP efforts given, but it is significantly increased. Further evaluation of these efficiency opportunities continue past the IRP processes. Avista evaluates energy-efficiency potential for the IRP in a manner that can augment the conservation business planning process and ultimately lead to appropriate revisions in DSM acquisition operations.

Consistency between the IRP Evaluation and Conservation Operations

Avista evaluates energy-efficiency potential for the IRP in a manner that can augment the conservation business planning process and ultimately lead to appropriate revisions in conservation acquisition operations.

Avista utilizes the IRP process to comprehensively reevaluate the conservation market. This assessment evaluates individual technologies (generally prescriptive programs) where possible as well as program potential when a technology approach is infeasible. The evaluation assesses resource characteristics and constructs a conservation supply curve using the levelized total resource cost (TRC) and acquirable resource potential for each technology. Cost-effective technologies, compared to the defined avoided cost, are incorporated into the IRP acquisition target.

Further detailed program evaluation is applied when technologies in the program cannot be defined to permit their individual evaluation. This is the case in the Company’s comprehensive limited income program, a portion of the non-residential site specific programs and the cooperative regional programs. The target acquisition for these programs is based on the modification of the historical baseline for known or likely changes in the market. This includes but is not necessarily limited to modifying the baseline for price elasticity and load growth.

Evaluation of Efficiency Technology Opportunities

The Regional Technical Forum (RTF) periodically surveys Pacific Northwest utilities and evaluates the amount of remaining conservation potential in the region. The Company used the results of these efforts as the starting point for evaluating different types of conservation technologies. Approximately 3,000 efficiency concepts were evaluated by Avista's staff using a six-stage review process. The process began with concepts using easily obtained data and moved toward more technically rigorous analyses. Measures that ranked poorly on the initial review did not receive further consideration. The individual phases of the analytical process are as follows.

Defining: Refinement and redefinition of the concept list to eliminate duplicative concepts and develop common definitions.

Qualitative ranking: The refined concepts were ranked based on a qualitative feasibility assessment. Concepts determined not be acquirable through utility intervention were eliminated from further consideration.

Defining cost characteristics: Concepts with a reasonable potential for incorporation in the conservation portfolio were evaluated based on preliminary assessments of cost-effectiveness. This step required estimates of incremental customer cost, non-energy benefits, energy savings and measure life to develop a TRC levelized cost. Concepts were sorted based upon these cost characteristics.

Defining resource potential: Acquirable potentials for concepts specific to Avista's customers were estimated for the remaining concepts. These acquirable potentials came from an evaluation of technical and economic potential adjusted for utility intervention limitations to address barriers to customer adoption regardless of the economics.

Identifying load profiles: The value of capacity contribution (transmission, distribution and generation) is also included for evaluation of the total avoided cost. The Company based the avoided cost of energy on a 20-year, 8,760-hour avoided cost matrix. A 70-year avoided cost projection was developed to account for the longevity of some measures. This avoided cost structure made it necessary to develop an 8,760-hour load profile for each evaluated measure. Avista uses thirty-three residential and non-residential load profiles in this part of the exercise. Appendix X contains a list of the load profiles used in this analysis.

Calculating TRC cost-effectiveness: A full TRC cost-effectiveness evaluation was performed on the remaining 706 residential and 2,484 non-residential concepts. The following section provides a more detailed explanation of the review of these concepts. A summary list of concepts reaching the evaluation stage is included in Appendix X.

Evaluation of TRC Cost-Effectiveness for Finalist Concepts

The construction of the TRC cost for each measure was based on the incremental customer cost. Non-energy benefits were considered, but none of the evaluated measures had a large enough non-energy benefit to materially change the final cost-effectiveness evaluation.

Estimating the TRC values is an intrinsically quantitative process. This required a present value calculation of the avoided energy and capacity cost over the measure life for each concept. The avoided cost of energy was based upon an application of the measure's 8,760-hour load profile to the 8,760-hour avoided cost structure.

For purposes of measure evaluation, it was appropriate to focus upon deferring a summer space-cooling-driven load. The 3,190 evaluated concepts had significant differences in their impact upon system coincident load, and these differences were not always apparent based upon the general pattern of the measure load shape. To determine the expected impact upon the deemed space cooling-driven system peak load, the 3,190 concepts and 33 load shapes (including a flat load option) were categorized into three groups.

Zero impact: Measures that would not have any impact on a summer space-cooling-driven peak received a zero valuation regardless of their load profile. This includes measures such as residential space-heating efficiencies.

Non-Drivers: Measures that were not related to space cooling but would potentially contribute to system load during a space cooling-driven peak received a capacity valuation based upon the average demand of their specific load profile during eight hour summer peak load period. The eight peak hours were 1 pm to 8 pm, weekdays only, between June 15 and September 15. These measures include commercial lighting and residential appliances.

Drivers: Measures that would drive a space cooling peak received a capacity valuation based on the maximum hourly demand identified in their 8,760-hour load profile. This includes measures such as residential and non-residential air conditioning efficiency.

A TRC ratio was developed after the TRC cost and benefit calculations were completed. Even though this analysis limits the identification of future DSM acquisition to measures that fully pass the TRC cost-effectiveness test, the Company plans on evaluating all measures with a benefit-to-cost ratio of 0.75 or higher in order to provide a fair evaluation of the marginally failing measures.

Having identified TRC cost-effective measures, the next step determined the annual acquisition of the identified potential. This completed the evaluation of those concepts that were suitable for review by groups of technology types within the IRP. These results are revisited following the explanation of the programmatically reviewed elements of the DSM portfolio.

Evaluation of Comprehensive Program Elements

The all-inclusive nature of Avista's non-residential site specific and limited income portfolios make it infeasible to generically evaluate the entire spectrum of possible efficiency measures. Nevertheless, it is necessary to develop estimates for the potential of these markets in order to establish a meaningful business planning process. Unique efficiency measures could not be generically evaluated as individual technologies. In place of this approach, the Company established a historical baseline level of acquisition and modified it to incorporate the impact of known or likely changes in the market.

The Company's limited income portfolio is all-inclusive for qualifying efficiency measures. The portfolio is implemented in cooperation with community action agencies, which are given wide latitude in their approach to distributing program funds. Given that no changes were expected in the ability of the agency infrastructure to deliver these programs, nor were there any known market or technology changes that would cause a significant change in the ability to obtain efficiency resources from this segment, it was determined that a historical baseline would be the most appropriate starting point for estimating future throughput. The economic stimulus funding from the American Recovery and Reinvestment Act of 2009 for low income weatherization was unknown at the time this analysis was completed. There may be material increases in the low income population served by the economic stimulus funding. Analysis of the impacts of this funding will be treated as an Action Item for reporting in the 2011 IRP. This historical baseline was modified for load growth and retail price elasticity based upon assumptions consistent with the forecasts available at the time. This resulted in a forecast of limited income acquisition for incorporation into the final conservation forecast.

Although some of the measures incorporated into the site-specific program were specifically evaluated, a large portion of non-residential acquisition comes from measures which could not be generically evaluated. As with the limited income program, the historical baseline was modified for anticipated load growth and retail price elasticity to develop a forecast. Unlike the limited income program, it was necessary to separate the specifically evaluated measures from the historical baseline, and then combine the two again as part of the final expected conservation acquisition.
This process is illustrated in a flowchart in Appendix X.

Technical Potential

Every five years, the Northwest Power and Conservation Council (NWPCC) develops a regional Power Plan that evaluates the technically available conservation potential. This amount is reduced to reflect the fraction of measures that can never be practically achieved, even if the measures were free and cost-effective. The Council believes this practically achievable conservation potential can reach penetration levels of 85 percent over the next twenty years.

The Council estimated the regional achievable potential at 3,900 aMW for the twenty year period for the Fifth Power Plan. The Company's portion of this regional number was 3.94 percent, or 154 aMW. The Sixth Power Plan is currently being drafted and will not be completed until after submission of the 2009 IRP, however, the Council's draft plan estimates Avista's portion of the regional target to be 329 aMW for the twenty year period. This is an early estimate but should be within 10 to 15 percent of this estimate per the Council.

The Company's last external study on our energy savings potential was done in 2005. As an action item, Avista is committing to updating our estimates through another third-party savings potential study. We anticipate this study will cover all states and fuels intended to be used in the preparation of the 2011 IRP.

The Council only provides targets at a higher, utility level. Our measures along with their acquirable potential are illustrated in Appendix X.

Compilation of the Final DSM Resource Estimates

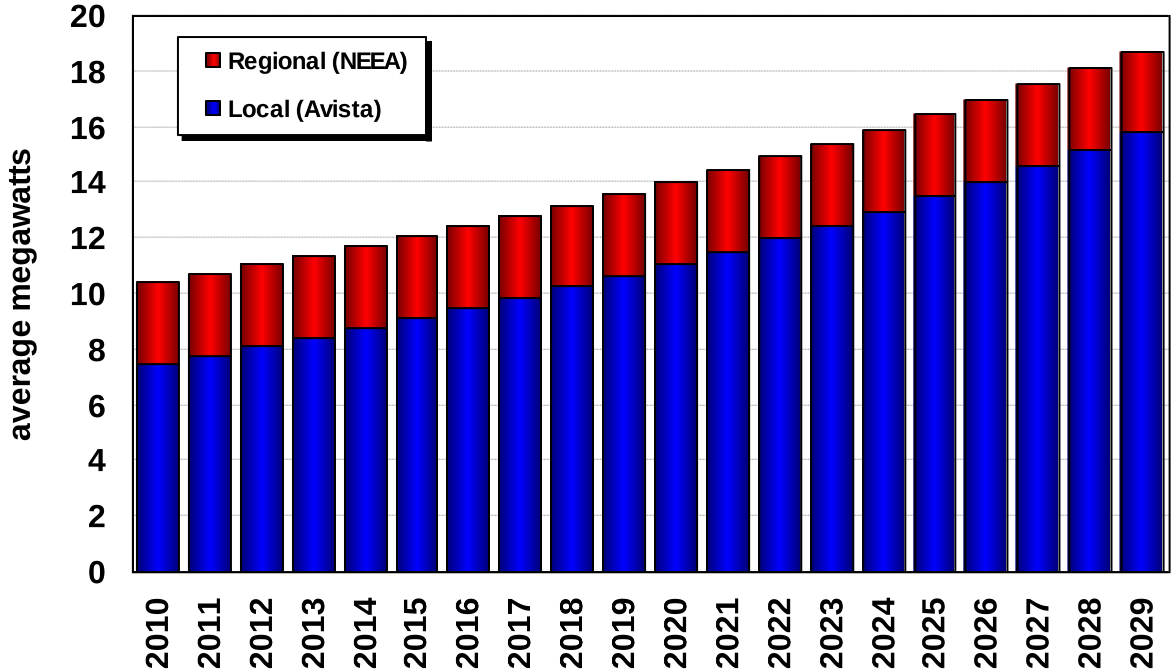
The following conservation targets were developed by summing individually evaluated concepts and the evaluated programs over a 20-year period. The first two years of the targets are detailed in Table 3.3.

Table 3.1: Current Avista Energy Efficiency Programs

Portfolio	2010 Target	2011 Target
Limited Income Residential	1,977,099	2,056,183
Residential	20,518,584	21,339,327
Prescriptive Non-Residential	18,211,396	18,939,852
Site-Specific Non-Residential	24,936,765	25,934,236
Total Local Acquisition (kWh)	**65,643,844**	**68,269,598**
Local	7.5	7.8
Regional	2.9	2.9
Total Acquisition (aMW)	**10.4**	**10.7**
Draft NPCC 6th Plan Goal (aMW)	**11.2**	**12.4**

A graphical representation of the annual conservation targets for the full 20-year horizon is illustrated in Figure 3.3. A flat annual 2.94 aMW estimate of Avista’s share of regional resource acquisition (Avista’s pro-rated share of NEEA’s annual savings) is included in the estimate. In the absence of reliable 20-year estimates of regional program acquisition, it was assumed that the historic acquisition levels would remain flat during that time at their most recent anticipated level. This assumption is speculative and dependent on the opportunities for regional market transformation during this period, but is consistent with the recent history of flat NEAA funding.

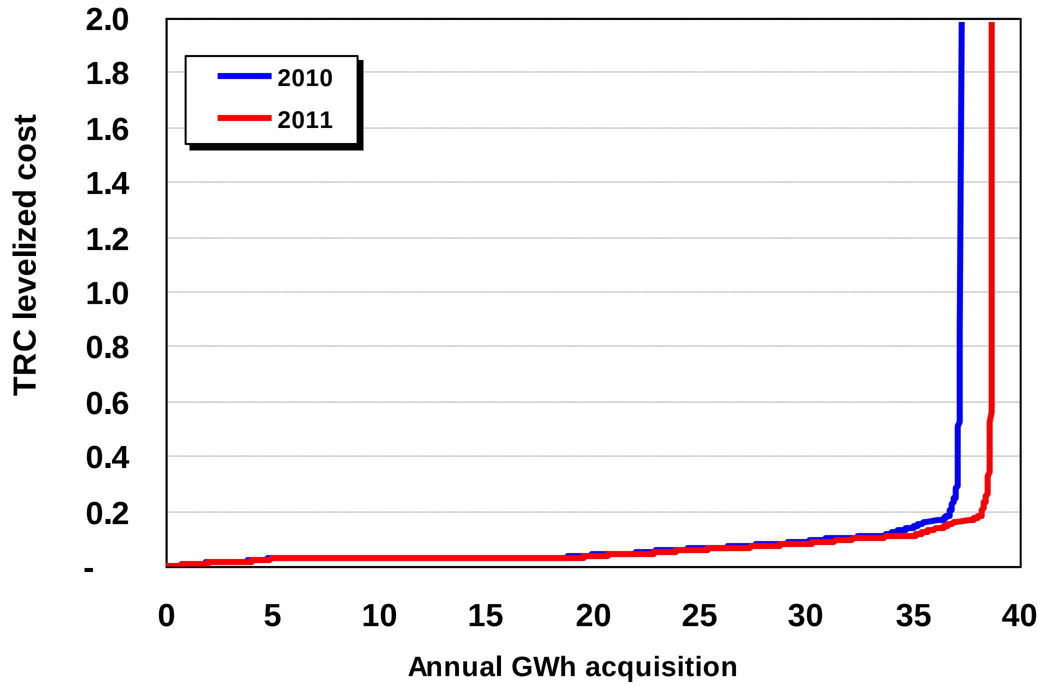
Figure 3.2: Forecast of Conservation Acquisition



A measure-by-measure stacking of the 845 evaluated concepts, in ascending order of levelized total resource cost, leads to a traditional upward-sloping supply curve for this component of the conservation target, as illustrated in Figure 3.3. Supply curves for both 2010 and 2011 have been shown to represent the two years which will elapse before the next IRP. The rightward shift of the supply curve over time is a consequence of the assumption that lower cost measures will be less available in subsequent years due to early adoption thereby causing movement up the supply curve.

The rapid sloping of the supply curve is a result of including some measures. These programs, though small, significantly extended the vertical axis of the supply curve developed for the conservation measures.

Figure 3.3: Supply of Evaluated Conservation Measures (Levelized TRC Cost)



Integrating IRP Results into the Business Planning Process

The IRP evaluation process provides a high-level estimate of cost-effective conservation acquisition. Avista uses the results of the IRP evaluation to establish a budget for conservation measures, determine the size and skill sets necessary for future conservation operations, and identify general target markets for programs. However, the results are not detailed enough to become an operational conservation business plan. The results of the IRP analysis establish baseline goals for continued development and enhancement of Avista's conservation programs. The near-term conservation business planning is summarized by portfolio in the following sections.

Residential Portfolio

A review of residential program concepts and their sensitivity to key assumptions indicate that more detailed assumptions based upon actual program plans and target markets may improve the cost-effectiveness of many of the residential concepts that marginally failed in this analysis. To account for this marginal failure rate, all concepts with TRC benefit-to-cost ratios of 0.75 or better are evaluated as part of the business planning process. Over 62 percent (443 out of 706) of the evaluated residential concepts met the criteria. Measures unavailable at the time of the IRP evaluation will be inserted into a reevaluation process for possible inclusion in the Business Plan.

Limited Income Residential Portfolio

Avista is committed to maintaining stable funding and maintaining program flexibility for limited income conservation programs. There are six local community action partner (CAP) agencies the Company funds to deliver limited income weatherization and energy efficiency programs. Cap agency funding is currently set at $1,972,000 million per year

($490,000 to Idaho and $1,482,000 to Washington). Limited income programs include infiltration, insulation, Energy Star approved windows, doors and refrigerators, space and water heating upgrades, and electric to natural gas space and water heating conversions. CAP agencies can offer other cost-effective programs with Avista's approval. These programs require periodic updates because of changes in fuel focus and target measures. The Company is quantifying potential impacts of the three-year Northwest Sustainable Energy for Economic Development project.

Non-Residential Portfolio

There is sufficient uncertainty and potential for improvement in evaluated non-residential program concepts warrant regular reevaluations to ensure they retain a minimum TRC cost-to-benefit ratio of 0.75 based on refined program planning assumptions. Ninety four percent (2,337) of the 2,484 non-residential concepts evaluated for the IRP meet the TRC criteria. The programs will be reviewed for target marketing, the creation of a prescriptive program, or for targeting under a site-specific program.

All electric-efficiency measures with a simple payback exceeding one year automatically qualify for the non-residential portfolio. The IRP provides account executives, program managers and end-use engineers with valuable information regarding potentially cost-effective target markets. However, the unique and specific characteristics of a customer's facility override any high-level program prioritization.

Demand Response

The Idaho Public Utilities Commission approved a residential demand response pilot that was launched in July 2007. Smart thermostats and direct control unit (DCU) switches for water heaters, as well as compressors for heat pumps or air conditioners were selected for this pilot. Seventy-two customers participated in the Sandpoint and Moscow area projects. Two demand response events were called during 2008 and three demand response events were called during the winter of 2008-2009. This pilot is scheduled to continue through December 31, 2009. The Company anticipates calling two to three additional summer events and two to three more winter events before the end of this pilot. Test results were not available in time for the 2009 IRP.

Summary

The IRP evaluation process assists the Company in developing a conservation business plan and meeting regulatory requirements. Avista uses this opportunity for comprehensive evaluation as an integral part of the ongoing management of Avista's conservation portfolio. The acquisition targets provide valuable information for future budgetary, staffing and resource planning needs. However, numerical targets do not displace the Company's fundamental obligation to pursue a resource strategy that best meets customer needs under a continually changing environment. The efficiency targets established in this IRP planning process may be modified as necessary to meet these evolving obligations.

4. Environmental Policy

Environmental policy can mean different things to different stakeholders. The 2007 IRP included a chapter on emissions that focused on state and federal legislation and regulations concerning sulfur dioxide (SO_2), nitrogen oxide (NO_x), mercury (Hg), and carbon dioxide (CO_2); including modeling assumptions used for each of these emission types. The current regulatory environment diminishes the need for a specific discussion on SO_2, NO_x and Hg emissions in this chapter. Current Washington laws, specifically an emissions performance standard, effectively forbid the addition of new coal plants in the Preferred Resource Strategy and additional mercury controls have been added to the Company's coal projects located in Colstrip, Montana. This chapter is dedicated to a discussion of the two most important areas of environmentally related legislation: renewable portfolio standards and the regulation of greenhouse gases.

Environmental Concerns

Greenhouse gas emissions present a unique resource planning challenge because of continuously evolving legislative developments resulting in ever-changing projections of the scope and costs of a carbon allocation market. If environmental concerns were the only issue faced by utilities, resource planning would be reduced to choosing the required amount and type of renewable generating technology to use. However, utility planning is compounded by the need to maintain system reliability, acquire least cost resources, mitigate price volatility, meet renewable generation requirements and satisfy greenhouse gas emissions constraints. Each generating resource also has distinctive operating characteristics, cost structures and environmental challenges. Traditional generation technologies are understood. Coal-fired units have high capital costs, long lead times, and relatively low and stable fuel costs. They are difficult to site because of state laws and local opposition, and environmental issues ranging from mercury to greenhouse gas emissions. There are also problems with the remote locations of coal mines or the high cost of transporting coal. Natural gas-fired plants have relatively low capital costs, can be located closer to load centers than coal plants, can be constructed in a relatively short time frame, and have much lower emission levels than traditional coal-fired technologies, but they are affected by high fuel price volatility.

Chapter Highlights

- Avista supports national greenhouse gas legislation that is workable, cost effective, fair, protects the economy, supports technological innovation, and addresses emissions from developing nations.
- The Company is a member of the Clean Energy Group.
- The Company is gaining experience in trading carbon credits through its membership in the Chicago Climate Exchange.
- Avista's Climate Change Committee monitors greenhouse gas legislation and issues.
- Avista participates in the annual Carbon Disclosure Project.

Renewable energy technologies such as wind, biomass, and solar generation have different challenges. Renewable resources are attractive because of their low or no fuel costs and low or no emissions, but they can have limited capacity value, present integration challenges and high upfront capital costs. Similar to coal plants, renewable resource projects are usually located where their fuel source is most abundant. Remote locations may require a significant investment in transmission interconnection and capacity expansion, as well as resolution of possible wildlife and aesthetic concerns. Unlike coal or natural gas-fired plants, the fuel for non-biomass renewable resources cannot be transported from one location to another to better utilize existing transmission facilities or to minimize opposition to project development. Biomass facilities can be particularly challenged because of their dependence on the health of the forest products industry and access to biomass materials located in publicly-owned forests.

Furthermore, the long-term economic viability of renewable resources is uncertain for at least two important reasons. First, federal investment and production tax credits are scheduled to expire within the planning horizon of this IRP and their continuation cannot be relied upon in light of the impact such subsidies have on the finances of the federal government and the relative maturity of wind technology development,. Second, the cost of renewable technologies is affected by many relatively unpredictable factors, such as renewable portfolio standard mandates, material prices and currency exchange rates, the effect of which cannot be predicted. Future political developments should help with forecasting the cost of renewable resources in subsequent IRPs.

There still is a great deal of uncertainty regarding greenhouse gas emissions regulation. There continues to be strong regional and national support for addressing climate change. Since the publication of the 2007 IRP, many changes in the approach and potential for actual greenhouse gas emissions regulation have occurred, including:

- Different and changing federal legislative proposals: Lieberman-Warner, Dingell-Boucher, and now Waxman-Markey;
- Leadership changes at the federal level leading to a determination to address climate change. The election of President Obama and the commitment of Congressional leaders to enact climate change legislation in the near-term.
- Passage of H.R. 2454, the American Clean Energy and Security Act;
- Joining RPS and greenhouse gas issues under the Waxman-Markey legislation; and
- Developments in climate change legislation in jurisdictions such as Washington and Oregon.

Climate Change Policy Efforts

Avista’s Climate Change Committee (CCC) was chartered as a clearinghouse for all matters related to climate change. In regards to climate change, the CCC:

- Anticipates and evaluates strategic needs and opportunities relating to climate change;
- Analyzes the implications of various trends and proposals;

- Develops recommendations on positions and action plans; and
- Facilitates internal and external communications regarding climate change issues.

The core team of the CCC includes members from Environmental Affairs, Government Relations, Corporate Communications, Engineering, Energy Solutions, and Resource Planning. Other areas of the Company are invited as needed. The monthly meetings for this group include work divided into immediate and long term concerns. The immediate concerns include reviewing and analyzing state and federal legislation, reviewing corporate climate change policy, and responding to internal and external data requests. Longer term issues involve emissions tracking and certification, providing recommendations for greenhouse gas reduction goals and activities, evaluating the merits of different reduction programs, actively participating in the development of legislation, and benchmarking climate change policies and activities against other organizations.

Avista has maintained its membership in the Clean Energy Group which includes Calpine, Entergy, Exelon, Florida Power and Light, Pacific Gas & Electric and Public Service Energy Group. This group collectively evaluates and supports different greenhouse gas legislation such as H.R. 2454, the American Clean Energy and Security Act of 2009 submitted by Congressmen Henry A. Waxman and Edward J. Markey and narrowly passed in June 2009. This legislation aims to combine RPS, greenhouse gas and energy efficiency issues under a single bill. Avista also participates in hydro and biomass issues through its membership in national hydroelectric and biomass associations.

Avista's Position on Climate Change Legislation

Avista expects comprehensive federal greenhouse gas legislation to be enacted within the next two to three years. This is slightly longer than projected in the 2007 IRP, primarily because of issues involving the current recession taking up legislative time. The current lack of definitive legislation makes for an uncertain planning environment as Avista plans to meet future customer loads. Avista does not have a preferred form of greenhouse gas legislation at this time, but supports federal legislation that is:

- Workable and cost effective;
- Fair;
- Protective of the economy and consumers;
- Supportive of technological innovation; and
- Includes emissions from developing nations.

Workable and cost effective legislation would be carefully crafted to produce actual greenhouse gas reductions through a single system, as opposed to competing, if not conflicting, state, regional and federal systems. The legislation also needs to be fair in that its impacts must be equitably distributed across all sectors of the economy based on relative contribution to greenhouse gas emissions. Protecting the economy and consumers is of utmost importance. The legislation cannot be so onerous that it stalls the economy or fails to have any sort of adjustment mechanism in case the market solution fails causing allowance or offset prices to escalate at unmanageable rates. Supporting a wide variety of technological innovations should be a key component of any greenhouse gas reduction legislation because innovation can help contain costs, as well as provide a potential boost to the economy through an increased manufacturing base. Climate change legislation must involve developing nations (China has already overtaken the U.S. as the leading source of greenhouse gas emissions); legislation should include strategies for working with other nations directly or through international bodies to control world-wide emissions.

Greenhouse Gas Concerns for Resource Planning

Resource planning in the context of greenhouse gas emissions regulation raises concerns about the balance between the Company's obligations for environmental stewardship and the cost implications for our customers. Consideration must be given to the cost effectiveness of resource decisions as well as the need to mitigate the financial impact of emissions risks.

- Complying with greenhouse gas emission regulations, particularly in the form of a cap and trade mechanism, involves two actions: ensuring the Company maintains sufficient allowances and/or offsets to correspond with its emissions during a compliance period, and undertaking measures to reduce the Company's future emissions. Effectuating emission reductions on a utility-wide basis can entail any and all of the following:
- Increasing efficiency of existing fossil-fueled generation resources;
- Reducing emissions from existing fossil-fueled generation through fuel displacement including co-firing with biomass or biofuels;
- Permanently decreasing the output from existing fossil-fueled resources and substituting them with lower emitting resources;
- Decommissioning or divesting fossil-fueled generation and substituting lower emitting resources;
- Reducing exposure to market purchases of fossil-fueled generation, particularly during periods of diminished hydropower production, by establishing larger reserves based on lower emitting technologies; and
- Increasing investments in energy efficiency measures.

With the exception of increasing Avista's commitment to energy efficiency, the cost and risks of the other specific actions listed above cannot be adequately, let alone fully, evaluated until the uncertainty about the nature of greenhouse gas emission regulations is resolved; that is, after a regulatory regime has been implemented and the economic effects of its interacting components can be modeled. A specific reduction strategy as part of an IRP may be forthcoming when greater regulatory clarity and more precise modeling parameters exist. In the meantime, the model for this IRP internalizes a carbon price proxy based on the Wood MacKenzie forecast based on the November 2008 discussion draft legislation sponsored by Representatives John Dingell and Rick Boucher. The 2009 IRP focuses on the costs and mitigation of carbon dioxide since it is the most prevalent and primary greenhouse gas emitted from fossil-fueled generation sources.

Emissions Legislation

Several themes have emerged from various climate change legislative proposals that have been considered since publication of the 2007 IRP. These include:

- Settling of scientific questions about human contributions to climate change; it is viewed as a largely anthropogenic or human-developed phenomenon.
- A consensus view that regulation should be applied on an economy-wide basis, rather than one or two sectors at a time.
- Technology will be a key component to reducing overall greenhouse gas emissions, particularly in the electric sector. Significant investment in carbon capture and sequestration technology will be needed since coal will continue to be an important part of the U.S. generation fleet into the foreseeable future.
- Developing countries must be involved in reducing global emissions as greenhouse gas emissions generally increase with economic growth.
- The longer federal legislation takes to enact, the higher the probability of that inconsistent state and regional regulatory schemes may be implemented. A patchwork of regulation may obstruct the operation of businesses serving multiple jurisdictions by causing market disruptions and increasing the uncertainty of how federal and disparate state and regional regulatory systems might interact.

These themes all point towards a need to develop national greenhouse gas legislation in a timely manner to ensure the best environmental and economic outcomes. The current version of the Waxman-Markey bill importantly acknowledges these multi-jurisdiction problems by superseding state and regional cap and trade regulation over emissions covered under federal law between 2012 and 2017.

Federal Emissions and Renewables Legislation

The U.S. House of Representatives passed H.R. 2454, the American Clean Energy and Security Act by Waxman and Markey on June 26, 2009. Among its many components, this bill establishes greenhouse gas reduction goals, creates a national cap-and-trade program, and outlines a national renewable portfolio standard. Some of the bill’s details include:

- RPS goals start at six percent in 2012 and increase to 20 percent by 2020.
- Recognizes hydroelectric efficiency upgrades and additions effectuated since January 1, 1992 as qualifying against the renewable energy standard.
- Removes existing hydroelectric power generation, excluding upgrades made after January 1, 1992, from the load base against which the renewable energy standard is applied.
- Allows electric utilities to make $25 per MWh alternative compliance payments, adjusted for inflation starting in 2010, in lieu of acquiring new renewable resources or renewable energy credits (REC).

- Permits REC trading, and banking of RECs for three years.
- Greenhouse gas reduction goals of 3 percent below 2005 levels by 2012, 17 percent by 2020, 42 percent by 2030, and 83 percent by 2005.
- Proposes to administratively allocate allowances to electric utilities beginning in 2011 through 2028, with 50 percent of them being allocated on the basis of a utility's share of emissions associated with retail sales and 50 percent being allocated based on a utility's annual average electricity deliveries.
- Calculates a utility's average annual emissions based upon data from 2006 through 2008, or any three consecutive calendar years between 1999 and 2008, as may be selected by the utility.
- Allows banking and borrowing of allowances.
- Allows for some forms of carbon offsets.
- Establishes mechanisms for containing costs and for regulating allowance and derivative markets.

Jeff Bingaman is also developing a federal RPS bill that is working its way through the Senate. The Bingaman bill sets a 15 percent renewable energy goal by 2021 and allows electric utilities to meet up to four percent of their RPS goals with energy efficiency. The bill also creates an off ramp provision exempting a utility from the RPS if their retail rates would increase by four or more percent in any given year for complying with the law.

Avista's main concerns with the potential federal climate change legislation concerns the compliance costs, which centers primarily, though not exclusively, on the method of allocating allowances and the amount of allowances the Company may be required to purchase through auction. Avista favors the adoption of a compromise advocated by the Edison Electric Institute, which allows for half of the allowances allocated to electric utilities to be load based and half of the allowances to be emissions based. This is a more equitable compromise than allocation based solely on historic emissions, which could provide a windfall for non-utility generators for their past greenhouse gas emissions and effectively penalizes past use of renewable energy. Administrative or direct allocation, at least in the beginning of the program, is also favored because it will mitigate compliance cost impacts on customers while the allowance markets and emissions reductions technologies are developed.

State Level Emissions Legislation

The failure of the federal government to enact greenhouse gas emission regulations during the current decade has encouraged many states to develop their own climate change laws and regulations. Climate change legislation can take many forms, including comprehensive regulation in the form of a cap and trade system, and complementary policies, such as renewable portfolio standards, energy efficiency standards, and emission performance standards. All of these standards are included for Washington, but not necessarily in other jurisdictions where Avista operates. Individual state actions can produce a patchwork of competing rules and regulations for utilities to follow, which may be particularly problematic for multi-jurisdictional utilities such as Avista. There are currently 23 states plus the District of Columbia with active renewable portfolio standards.

One of the more notable state level greenhouse gas initiatives outside of the Pacific Northwest include the Regional Greenhouse Gas Initiative (RGGI) agreement between ten northeastern and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) to implement a cap and trade program for carbon dioxide emissions from power plants. The District of Columbia, Pennsylvania, and some Canadian Provinces are also participating as RGGI observers. RGGI's cap and trade regulations have been effective since January, 2009.

The Western Regional Climate Action Initiative, otherwise known as the Western Climate Initiative (WCI), began with a February 26, 2007 agreement to reduce greenhouse gas emissions through a regional reduction goal and market-based trading system. This group includes Arizona, British Columbia, California, Manitoba, Montana, New Mexico, Oregon, Utah, Quebec and Washington. In September 2008, the WCI released a set of Final Design recommendations for a regional cap and trade regulatory system to cover 90 percent of the societal greenhouse gas emissions within the region by 2015. The WCI is presently proceeding to finish its Work Plan, which completes details necessary to implement its proposed cap and trade system. The WCI has also recently initiated a process to identify and evaluate complementary policies that can be adopted region-wide to further ensure that greenhouse gas reduction goals are met. In addition, the WCI has formally submitted comments to Congress regarding the content of the Waxman-Markey bill.

There have also a number of regional municipalities participating in the U.S. Mayors Climate Protection Agreement to reduce GHG emissions to seven percent below 1990 levels by 2012.

It is important to acknowledge that a federal cap and trade program, such as that envisioned by the Waxman-Markey legislation, will not operate in isolation. Members of the Western Climate Initiative, such as Washington, Oregon, and Montana, are likely to – as some of them have already – pursue complementary policies to regulate emission sources that are covered under cap and trade regulation, as well as those that will not be regulated under a cap and trade program. The Waxman-Markey bill in its current form illustrates this potentiality. Even though the federal legislation would preclude states from implementing their own cap and trade regulations between 2012 and 2017, it would not prevent states from imposing any different form of regulations on the covered sources before, during or after that time frame, or from administering and augmenting federal cap and trade regulations after 2017.

The adoption of greenhouse gas emission reduction goals and any associated regulations by Washington could directly impact the Company's generation assets in the state, which are largely comprised of the Kettle Falls Generating Station and the Northeast Combustion turbines and Boulder Park peaking facilities. Oregon's greenhouse gas reduction goals and potential future regulations can be applied to the Coyote Springs 2 project.

Idaho Emissions Legislation

Idaho is not a member of the Western Climate Initiative and currently does not regulate greenhouse gases or have an RPS.

Montana Emissions Legislation

The Montana Global Warming Solutions Act (HB753) was submitted in late 2006 to establish greenhouse gas reductions goals to be achieved by 2020. This legislation did not leave committee. Montana now has a non-statutory goal of reducing greenhouse gas emissions to 1990 levels by 2020. In 2007, the Legislature passed House Bill 25, requiring new coal-fired facilities built in the state to sequester 50 percent of their emissions. Montana's renewable portfolio standard law, which was enacted through Senate Bill 415 in 2005, does not apply to Avista. While involved in the Western Climate Initiative, Montana did not consider any legislation during the 2009 Legislative Session to authorize its participation in and implementation of the regional cap and trade system designed by the WCI.

Oregon Emissions Legislation

The State of Oregon has been actively developing legislation concerning greenhouse gases and renewable portfolio standards. Oregon's climate change legislation began in December 2004 when the Oregon Strategy for Greenhouse Gas Reduction with calls for the development of a detailed GHG report by the end of 2007. That year, the Legislature enacted House Bill 3543 calling for reductions of greenhouse gas emissions to 10 percent below 1990 levels by 2020, and 75 percent below 1990 levels by 2050. These reduction goals are in addition to 1997 regulation requiring fossil-fueled generation developers to offset the project's CO_2 emissions exceeding 83 percent of the emissions of a state-of-the-art gas-fired CCCT by paying into the Climate Trust of Oregon. Senate Bill 838 requires large electric utilities to generate 25 percent of annual electricity sales with renewable resources by 2025. Shorter term goals include five percent by 2011, 15 percent by 2015, and 20 percent by 2020. Governor Ted Kulongoski introduced Senate Bill 80 during the 2009 Legislative Session to authorize the state's implementation of cap and trade regulations either in isolation or as part of a regional program. This legislation failed. Oregon continues to be an active member in the Western Climate Initiative.

Washington Emissions Legislation

The State of Washington has enacted several measures concerning emissions from fossil-fueled generation and the diversification of generation resources. A law was enacted in 2004 that requires new fossil-fueled thermal electric generating facilities of more that 25 MW generation capacity to mitigate CO_2 emissions through a plan including: third party mitigation, purchased carbon credits, or cogeneration. Washington's Energy Independence Act (I-937), passed in the November 2006 election, and established a requirement for utilities with over 25,000 customers to use qualified renewable energy or renewable energy credits to serve three percent of retail load by 2012, nine percent by 2016 and 15 percent by 2020. Failure to meet the RPS requirements results in a $50 per MWh fine. The initiative also requires utilities to acquire all cost effective conservation and energy efficiency measures.

Senate Bill 5840 was brought forward in 2009 to correct shortcomings of the initiative, qualify existing biomass generation (e.g., Kettle Falls) as an eligible renewable resource, and adjust the renewable energy standards, but it failed to obtain the needed votes after emerging from Conference Committee in the closing days of the Legislative Session. The renewable requirement begins in 2012. Avista is projected to meet or exceed its renewable requirements between 2012 and 2015 through a combination of hydro upgrades and a strategic REC purchase. The Company has the ability to bank RECs acquired from the Stateline Wind contract in 2011 for 2012, but these RECs are being used for the Buck-a-Block program. The 2009 IRP has been developed so that the I-937 RPS goals will be achieved by the Company.

In 2007, the Legislature passed Senate Bill 6001, which prohibits electric utilities from entering into long-term financial commitments beyond five years duration for fossil-fueled generation with emissions that exceed 1,100 pounds per MWh. In 2013, the emissions performance standard will begin to be lowered every five years to reflect the emissions profile of the latest commercially available CCCT. The emissions performance standard effectively prevents utilities from developing new coal-fired generation and expanding the generation capacity of existing coal-fired generation, unless they can sequester emissions from the facility. The Legislature amended Senate Bill 6001 in 2009 to prohibit contractual long-term financial commitments for generation that contain more than 12 percent of the total power from unspecified sources.

Governor Christine Gregoire signed Executive Order 07-02 in February 2007 which established the following GHG emissions goals:

- 1990 levels by 2020;
- 25 percent below 1990 levels by 2035;
- 50 percent below 1990 levels by 2050 or 75 percent below expected emissions in 2050;
- Increase clean energy jobs to 25,000 by 2020; and
- Reduce statewide fuel imports by 20 percent.

The goals of this Executive Order were later codified into law when the Legislature enacted Senate Bill 6001 in 2007. Taking the next step to achieve the State's greenhouse gas reduction goals, the governor introduced legislation (Senate Bill 5735 and House Bill 1819) during the 2009 Legislative Session to authorize the Department of Ecology to adopt rules, consistent from recommendations from the Western Climate Initiative, enabling the state to administer and enforce a regional cap and trade program. When that legislation failed, Governor Gregoire signed Executive Order 09-05 directs the Department of Ecology to develop emission reduction "strategies and actions", including complementary policies, to meet Washington's 2020 emission reduction target by October 1, 2010. This directive will require the agency to provide "each facility that the Department of Ecology believes is responsible for the emission of 25,000 metric tons or more of carbon dioxide equivalent each year in Washington with an estimate of each facility's baseline emissions and to designate each facility's proportionate share of greenhouse gas emission reductions necessary to achieve the state's 2020 emission reduction goal. The department is also asked, by December 1, 2009, to develop emission benchmarks, by industry sector, for facilities the Department of Ecology believes will be covered by a federal or regional cap and trade program; the state may advocate the use of these emission benchmarks in any federal or regional cap and trade program as an appropriate basis for the distribution of emission allowances. The department must submit recommendations regarding its industry benchmarks and their appropriate use to the Governor by July 1, 2011.

Washington Renewable Portfolio Standard (I-937)

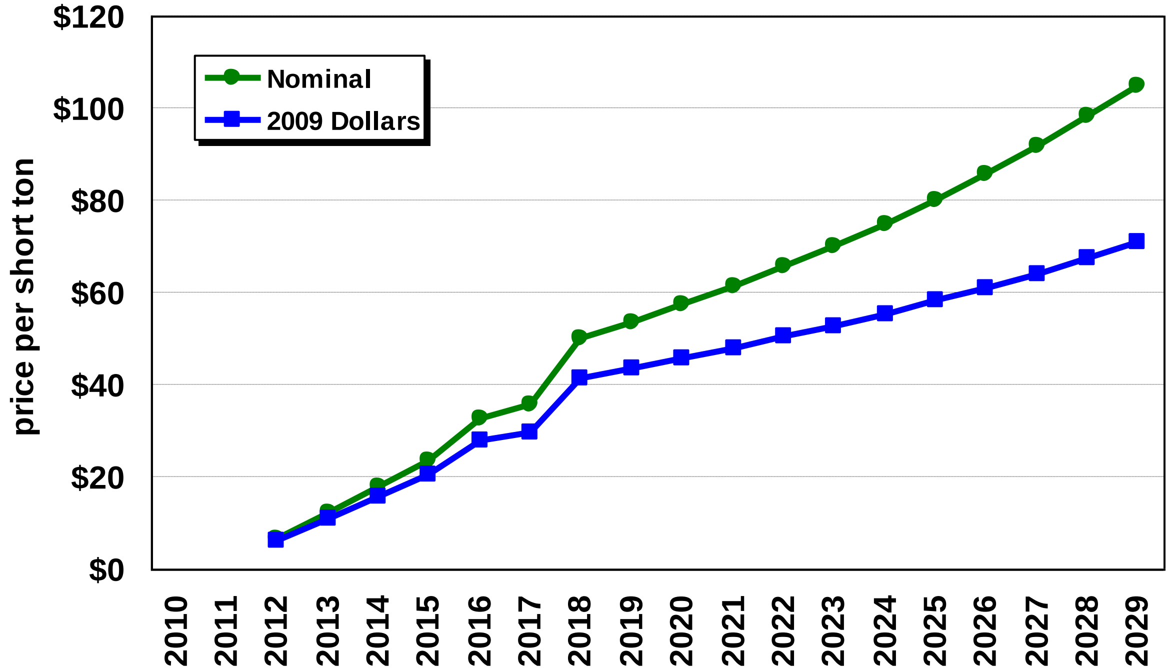
National RPS legislation is being developed through Waxman and Markey's American Clean Energy Security Act of 2009 (HR 2454) and Senator Bingaman's draft RPS bill. The proposed federal RPS level ranges between 10 and 25 percent with several target years. Federal legislation is expected to include a hydro netting provision, which excludes loads served by hydropower energy from the RPS requirement. Federal legislation conceptually – and significantly -- differs from I-937, in particular with respect to hydro-netting. The absence of hydro-netting makes the Washington RPS more stringent than proposed federal requirements. Avista will need to meet the federal RPS for its Idaho service territory. National legislation may count existing biomass resources, including Kettle Falls, against the renewable energy standard, as well as power from upgrades to hydropower facilities that were effectuated before 1999 (the date established in I-937 to determine resource eligibility). Treatment of renewable resources in federal legislation would not allow the Company to use RECs from federally-eligible resources to comply with I-937, but Avista would be able to make REC sales from certain facilities into a national market and perhaps individual states governed by their own RPS requirements.

Emissions Measurement and Modeling

Greenhouse gas tracking is an important part of the IRP modeling process because emissions legislation is one the greatest fundamental risks facing the electric marketplace today. Reducing carbon dioxide emissions from power plants will fundamentally alter the resource mix as society moves towards a carbon constrained future. Though there are no federal laws regulating carbon emissions presently, carbon costs still need to be projected for planning purposes because expectations for carbon regulation can change resource decisions.

This IRP uses the Wood Mackenzie carbon price forecast. Wood Mackenzie based its carbon price forecast on November 2008 legislation sponsored by Representatives Dingell and Boucher. Even though the Dingell-Boucher bill is no longer being considered for federal greenhouse gas legislation, it does provide a reasonable proxy for the current Waxman-Markey bill. Wood Mackenzie balanced its macro-economic models by identifying a carbon price forecast to meet national greenhouse gas reduction goals. Figure 4.1 shows the carbon price forecast for this IRP. The 2009 IRP assumes carbon will have a cost starting in 2012. The levelized cost of carbon is $46.14 (nominal) and $33.37 (2009 dollars). Natural gas prices greatly affect carbon offset values. Therefore, when natural gas prices rise or fall, the IRP assumes carbon costs will change to balance the relative competitiveness of gas and coal.

Figure 4.1: Price of Carbon Dioxide Credits



5. Transmission and Distribution

Introduction

This section of the Integrated Resource Plan provides an overview of Avista's transmission system, recent completed and planned upgrades, transmission planning issues, and estimated costs and issues involved with integrating a variety of potential resources into the transmission system.

Comprehensive coordination of transmission system operations and planning activities among regional transmission providers is necessary to maintain reliable and economic transmission service for Avista's end-use customers. Transmission providers and interested stakeholders continue to implement changes in the region's approach to planning, constructing and operating the transmission system under new rules promulgated by the Federal Energy Regulatory Commission (FERC), and under state and local siting agencies. This section was developed in full compliance with Avista's FERC Standards of Conduct governing communications between Avista merchant and transmission functions.

Chapter Highlights

- Avista has completed a $130 million transmission improvement project.
- Avista has over 2,200 miles of high voltage transmission.
- Avista remains actively involved in regional transmission planning efforts.
- The costs of transmission upgrades are included in the 2009 Preferred Resource Strategy.

Avista's Transmission System

Transmission map will go here.

Avista owns and operates a system over 2,200 miles of electric transmission facilities. This system is comprised of approximately 685 miles of 230 kilovolt (kV) line and 1,527 miles of 115 kV line. Avista also owns an 11 percent interest in 495 miles of a 500 kV line between Colstrip and Townsend, Montana. The transmission system includes switching stations and high-voltage substations with transformers, monitoring and metering devices, and other system operation-related equipment. The system transfers power from Avista's generation resources to its retail load centers. Avista also has network interconnections with the following utilities:

- Bonneville Power Administration (BPA)
- Chelan County PUD (Chelan)
- Grant County PUD (Grant)
- Idaho Power Company (IPC)
- NorthWestern Energy (NWE)

- PacifiCorp (PAC)
- Pend Oreille County PUD (POPUD)

In addition to providing enhanced transmission system reliability, these network interconnections serve as points of receipt for power from generating facilities outside Avista's service area, including the Colstrip generating station, Coyote Springs 2, and contracts from Mid-Columbia hydroelectric facilities. These interconnections also provide for the interchange of power with entities within and outside of the Pacific Northwest, including the integration of long and short-term contract resources. Additionally, Avista has interconnections with several government-owned and cooperative utilities at transmission and distribution voltage levels, representing non-network, radial points of delivery for service to wholesale loads.

Transmission Changes since the 2007 IRP

Avista has completed a multi-year $130 million transmission upgrade project, however much of this construction was completed prior to 2007 and was documented in the 2007 IRP. The largest projects completed since the 2007 IRP are described below.

Avista completed 60 miles of new 230 kV transmission between its Benewah and Shawnee substations to increase capacity between the north and south portions of its system. The project provides a second 230 kV transmission line between Avista's northern and southern load service areas, significantly improving reliability. Energized in December, 2007, Avista installed a new 200 megavolt- ampere-reactive (MVAR) 230 kV capacitor bank at the Benewah station in October of 2008, and installed a new 125 MVA 230/115 kV transformer in November of 2008. This work, known as the West of Hatwai reinforcement, was part of a joint transmission project between Avista and BPA.

Future Upgrades and Interconnections

Station Upgrades

Several station upgrades are planned for the next 10 years. The final scope of the station upgrades has not yet been determined, but four of the Company's 230 kV station upgrades (Noxon, Moscow, Westside, and Pine Creek) are slotted for completion within the next five to 10 years. A number of 115 kV capacitor banks will also be installed at various substations throughout the Avista transmission system.

South Spokane 230 kV Reinforcement

Recent transmission studies indicate the need for an additional 230 kV line to the south and west of Spokane. Avista currently has no 230 kV source southwest of the Spokane area, and relies on its 115 kV system for load service as well as bulk power flow through the area. The project scope is currently being defined; however, preliminary studies indicate the need for the following projects:

- New 230/115 kV station near Garden Springs;
- Tap the Benewah-Boulder 230 kV line southwest of the Liberty Lake area and construct a new 230 kV switching station (for later development of a 230/115 kV substation);
- Connection of the Liberty Lake 230 kV station with the Garden Springs 230 kV station;
- New 230 kV line from Garden Springs to Westside; and
- Origination and termination of the 115 kV lines from the Spokane 230/115 kV.

Placeholder for transmission map.

The final scope for the South Spokane 230 kV Reinforcement project is scheduled for completion by the end of 2009. Its energization date is expected to be 2018, with staged in-service dates beginning in 2014.

Canada/Northwest/California Transmission Project & Devils Gap Interconnection

One of the primary projects under review at the Transmission Coordination Work Group (TCWG, see below) is a new transmission line involving four major projects.

- 500 kV HVAC facilities from Selkirk in southeast British Columbia to the proposed Northeast Oregon (NEO) Station, with an intermediate interconnection with Avista at a new Devils Gap Substation near Spokane;
- 500 kV HVDC facilities from NEO Station to Collinsville Substation in the San Francisco Bay Area, with a possible third terminal at Cottonwood Area Substation in northern California (DC Segment);
- Voltage support at the interconnecting substations; and
- Remedial actions for project outages.

The proposed north-to-south rating for the two project segments is 3,000 MW. It will improve system reliability in the Western Interconnection, as well as provide access to significant renewable resources. Its target operating date is December 2015. Avista joins the primary project sponsor, Pacific Gas and Electric, along with PacifiCorp, and the British Columbia Transmission Corporation in this project.

The Avista Devils Gap Interconnection project is comprised of a 500 MW bi-directional 500/230 kV interconnection and 230 kV transmission into the Spokane area 230 kV grid. It (plus additional transmission in the area around the proposed NEO substation) would provide additional transmission Avista could use to integrate Coyote Springs 2 generation. The Project will allow Avista to enhance its access to incremental renewable resources in the Pacific Northwest, Canada, and, at times, the southwestern United States. Immediate and future environmental and resource needs of Avista and other Western Interconnected utilities will be aided by this Project.

Avista's goal also is to provide market participants with beneficial opportunities to use its facilities. Through its participation in TCWG meetings Avista makes all project information available to group members, including resource developers, load serving entities, energy marketers, and independent transmission owners.

Regional Transmission System

BPA operates over 15,000 miles of transmission facilities throughout the Pacific Northwest. BPA's system represents a large portion of the region's high voltage (230 kV or higher) transmission grid. Avista uses the BPA transmission system to transfer output from its remote generation sources to Avista's transmission system, including its Colstrip units, Coyote Springs 2 and its Washington Public Power Supply System Washington Nuclear Plant No. 3 settlement contract. Avista also contracts with BPA for Network Integration Transmission Service to transfer power to 10 delivery points on the BPA system to serve portions of the Company's retail load.

Avista participates in regional and BPA-specific forums to coordinate system reliability issues and manage BPA transmission costs. We participate in BPA transmission and power rate case processes, and in BPA's Business Practices Technical Forum, to ensure charges remain reasonable and support system reliability and access. Avista also works with BPA and other regional utilities to coordinate major transmission facility outages.

Future generation resource development will require the construction of new transmission assets. BPA recently received $3.5 billion in additional borrowing authority through the American Recovery and Reinvestment Act of 2009. Increased borrowing capability enhances BPA's ability to construct new transmission projects. One recent example is the 79-mile long 500 kV McNary-John Day upgrade. This $200 million project had been on hold since 2002 because of BPA's inability to finance the project.

FERC Planning Requirements and Processes

The Federal Energy Regulatory Commission (FERC) provides guidance to both regional and local area transmission planning. The following section describes several requirements and processes that are important to Avista's transmission planning function.

Attachment K

On December 7, 2007, Avista submitted a revised Attachment K to its Open Access Transmission Tariff (OATT). The revisions to the prior Attachment K met nine transmission planning principles proposed in FERC Order 890. The principles made the planning process more open to interested stakeholders and formalized coordination between interconnected utilities. In its Attachment K process, Avista established three levels of planning on the local, sub-regional and regional levels.

At the local level Avista develops a two-year Local Planning Process culminating with the production of a Local Planning Report (in coordination with Avista's five- and ten-year Transmission Plans). Avista encourages participation of interconnected neighbors, transmission customers, and other stakeholders in the local planning process. The Company uses ColumbiaGrid to coordinate planning with sub-regional groups. Regionally, Avista participates in several WECC processes and groups, including various Regional Review processes, Transmission Expansion Planning Policy Committee (TEPPC), Planning Coordination Committee (PCC), and the newly formed Transmission Coordination Work Group (TCWG). Participation in these efforts supports regional coordination of Avista's transmission projects.

Avista submitted a modified Attachment K to FERC on October 15, 2008 to correct deficiencies in its 2007 filing. The Attachment K revisions included clarifications that did not change the substance of the original filing.

Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) coordinates and promotes electric system reliability in the Western Interconnection. WECC also supports efficient and competitive power markets, assures open and non-discriminatory transmission access among its members, provides a forum for resolving transmission access or capacity ownership disputes, and provides an environment for coordinating the operating and planning activities of its members as set forth in WECC Bylaws.

Avista participates in WECC’s Planning, Operations, and Market Interface Committees, as well as various sub groups and other processes such as the TCWG.

Northwest Power Pool

The Pacific Northwest has a long history of coordinated transmission planning through various Northwest Power Pool (NWPP) workgroups. The NWPP was formed in 1942 when the federal government directed utilities to coordinate operations in support of wartime production. NWPP activities are determined by committees including the Operating Committee, the PNCA Coordinating Group, and the Transmission Planning Committee (TPC). The TPC, formed in 1990, provides a forum for addressing northwest electric planning issues and concerns, including a structured interface with outside stakeholders.

The NWPP serves as a Northwest electricity industry reliability forum. It helps coordinate both present and future industry restructuring. NWPP promotes member cooperation to achieve reliable system operation, coordinate power system planning, and assist transmission planning in the Northwest Interconnected area. NWPP membership is voluntary, and includes major generating utilities serving the Northwestern U.S., British Columbia and Alberta. Smaller, principally non-generating utilities, participate indirectly through their member systems.

ColumbiaGrid

ColumbiaGrid was formed on March 31, 2006 to develop sub-regional transmission plans, assess transmission alternatives (including non-wires alternatives), provide a decision-making forum, and a cost-allocation methodology for new transmission projects. This group was formed in response to a number of FERC initiatives. Avista joined ColumbiaGrid in early 2007. Other members include BPA, Chelan County PUD, Grant County PUD, Puget Sound Energy, Seattle City Light, and Tacoma Power. Though not a member, Snohomish PUD participates in a number of functional agreements. These agreements are used to help different organizations and groups determine areas of transmission work and establish agreements to carry out the plans.

Transmission Coordination Work Group

The TCWG is the joint effort of Avista, BPA, Idaho Power, Pacific Gas and Electric, PacifiCorp, Portland General Electric, Sea Breeze Pacific-RTS, and TransCanada to coordinate transmission project developments expected to interconnect at or near the proposed NEO station near Boardman, Oregon. These projects are following the WECC Regional Planning and Project Rating Guidelines. Detailed information on NEO and the projects that could potentially be integrated at NEO may be found at www.nwpp.org/tcwg .

Avista Transmission Reliability and Operations

Avista plans and operates its transmission system pursuant to applicable criteria established by the North American Electric Reliability Corporation (NERC), WECC and the NWPP. Through involvement in WECC and NWPP standing committees and sub-committees, Avista participates in the development of new and revised criteria, and coordinates planning and operation of its transmission system with neighboring systems. Mandatory reliability standards promulgated through FERC and NERC, subject Avista to periodic performance audits through these regional organizations. Portions of Avista's transmission system are fully subscribed for transferring power output of Company generation resources to its retail load centers. Transmission capacity that is not reserved and scheduled to move power to satisfy long-term (greater than one year) obligations is marketed on a short-term basis and may be used by Avista for short-term resource optimization or third parties seeking short-term transmission service pursuant to FERC requirements under Orders 888, 889 and 890.

Transmission Construction Costs

An essential part of the IRP is estimating transmission costs to integrate new generation that benefits retail electricity customers. Construction-quality estimates were only made for three projects proposed in the IRP. The other options identified in this IRP are based on engineering judgment. There is an inverse relationship between transmission project size and the certainty of the estimates. A 50 MW resource can be integrated in many places on the Company's system for a moderate cost compared to its overall installation cost. There are fewer options available for locating a 500 MW plant on Avista's system. 750 and 1,000 MW plants have even fewer location options. Each would require participation in the FERC's Generation Interconnection Process as well as coordination through the regional processes described above. These processes would be completed to determine more precisely those impacts on Avista and other systems' transmission grid before a final plant placement decision.

Estimating Transmission and Integration Costs

The following sections provide an overview of Avista's estimated resource integration costs for the 2009 IRP. Integration points were roughly divided into locations where interconnection study work has been completed and additional points where new resources might be interconnected. Rigorous analyses have not been completed for off-system alternatives because of the breadth of study needed for those estimates. Limited study work has been completed except for projects with existing generation interconnection requests to Avista's transmission group. Completing transmission studies without detailed project parameters is nearly impossible. Approximate worst-case estimates have been assigned based on engineering judgment for neighboring system impacts. Generation interconnection costs are listed for locations within the Avista transmission system. Internal cost estimates are in 2009 dollars and are based on engineering judgment with a 50 percent margin for error. Construction timelines are defined from the beginning of the permitting process to line energization.

Integration of Resources External to the Avista System

Avista's load serving entity function (Avista-LSE) is required to submit generation interconnection and transmission service requests on third party transmission systems. The third party determines transmission system integration and wheeling service costs for delivering new resource power to Avista's system. Construction cost estimates are based on $2 million per mile of new 500 kV lines, $700,000 per mile of 230 kV lines and $350,000 per mile of 115 kV lines.

Eastern Montana Resources

A regional study sponsored by the NWPP and Northwest Transmission Assessment Committee (NTAC) found that enhancement of existing 500 kV and 230 kV facilities would be required to integrate additional generation from Montana. Power transfer from eastern Montana to the Northwest is affected by several constraints. A more detailed study effort focusing on relieving constraints from central and eastern Montana is underway as a joint effort by Avista, BPA, NorthWestern Energy, PacifiCorp, and Puget Sound Energy. The study is scheduled for completion in 2010 to identify transmission constraints and engineering-level construction cost estimates to fix the constraints.

Integration of Resources on the Avista Transmission System

Avista-LSE has requested three generator interconnection studies: one near Reardan, Washington, a second near Grangeville, Idaho, and a third in Garfield County, Washington. Each is discussed below.

Reardan, Washington

Avista-LSE submitted a generator interconnection request to Avista Transmission for a 65 MW wind project located south of Reardan, Washington, and has requested a study of interconnection to Avista's 115 kV Devil's Gap – Lind line. The point of interconnection is located approximately six miles south of the Reardan Substation on the Gaffney – Reardan segment of the line. Initial studies indicate that construction of a new 115 kV transmission line into the Spokane area will be required to accommodate the full output of the project. Preliminary cost estimates of interconnecting a wind project at Reardan are under $15 million; however, not all costs associated with the upgrade will be directly assigned to the project because of upgrades that are needed whether or nor the project is completed.

Avista-LSE will submit a transmission service request to determine any required system reinforcements necessary to enable the proposed project to be a designated network resource serving native load under FERC Open Access Transmission Tariff (OATT) requirements.

Grangeville, Idaho

Avista-LSE submitted a generator interconnection request to Avista Transmission in 2008 for a proposed 120 MW wind project located near Grangeville, Idaho. The transmission line from the project to the point of interconnection is approximately 10 miles. Studies indicate the project is feasible based on the preliminary analysis; however the work also identified thermal violations under certain contingency conditions. The total estimated cost of interconnecting this project at the Grangeville Substation without mitigating the reactive power consumption of the transmission system is estimated to be $12.9 million including reconductoring the local transmission lines. The cost estimate does not include constructing a radial 115 kV interconnection transmission line from the project to the point of interconnection at the Grangeville substation.

Garfield County, Washington

Avista-LSE submitted a generator interconnection request for a 200 MW wind project located approximately three miles east of the Columbia/Garfield (Washington) county line in Garfield County. The project, located near Pomeroy, Washington, would interconnect to the existing Dry Creek-Talbot 230 kV line via a double-bus, double-breaker (six breaker station) configured station. The approximate interconnection cost is $4 million.

Lancaster Integration

Avista is evaluating various alternatives for a new transmission interconnection with BPA in the Spokane Valley. One interconnection is at BPA's Lancaster Substation. This interconnection might allow Avista to eliminate or offset some BPA wheeling charges for moving the Lancaster combustion turbine project to Avista's system. Avista is working with BPA to determine what form the interconnection should take. Preliminary studies indicate that Avista could expand existing BPA facilities, construct an interconnection to BPA facilities, and build a loop-in to the Avista Boulder-Rathdrum 230 kV line.

This project could benefit Avista and BPA by increasing system reliability, decreasing losses, and delay the need for additional transformation at the BPA Bell Substation. The proposed plan of service may represent the best option for service from Avista's sole perspective. Additional studies indicate that looping the Boulder-Rathdrum 230 kV line into the Lancaster Substation may allow more transfer capability across the combined transmission infrastructure of Avista and BPA. The preliminary study results are expected by the end of the third quarter of 2009. Construction could be completed by the end of 2010.

Other Potential Resources

2009 IRP resources could be located on Avista's or another organizations transmission grid. The following section provides details concerning generic potential resources. Generator interconnection and transmission service requests would be required to integrate a new generation resource.

CCCT with Duct Burner

A 150 to 250 MW CCCT could be integrated into Avista's 230 kV grid at several locations. The best locations, from a transmission siting perspective, are near the existing Rathdrum and Lancaster units near Rathdrum, Idaho, or near the Benewah 230/115 kV station near Benewah, Idaho

Small Co-Gen (<5 MW)

Small cogeneration plants are likely to be near or congruent to large industrial loads. Because of the unique nature of these installations, detailed studies must be run to determine integration costs. These costs cannot be estimated until a request for generator interconnection of these facilities is made.

Hybrid SCCT (LMS 100)

As with the CCCT, a 100 MW SCCT could be integrated into the Avista 230 kV grid in several locations. The best locations from a transmission siting perspective are near the existing Rathdrum and Lancaster units near Rathdrum, Idaho, or near the Benewah 230/115 kV station near Benewah, Idaho.

Coal

It is unlikely that a coal-fired facility (traditional or gasification) would be built in Avista's service territory, especially with Washington's emissions performance standards. If a coal plant is developed, it would probably be integrated on a third party transmission system.

Geothermal

There are no known geothermal resources in Avista's service territory, so this resource type would require an interconnection request on another system. The most likely areas for this type of generation for Avista are located in Nevada or Oregon. Significant transmission constraints exist between these states and Avista's system, increasing the cost of integrating a geothermal resource.

Nuclear

Direct integration of nuclear power into Avista's transmission system is unlikely because of the significant cost, siting, and waste issues associated with this resource. If this type of resource were constructed, regional studies as well as generator interconnection and transmission service requests on the transmission provider would be required.

Hydro Upgrades

Spokane River Upgrades

The transmission system serving the Spokane River projects plant is robust so small upgrades could be integrated with minimal system impacts. Larger upgrade options, such as a second powerhouse at Monroe Street or a Post Falls rebuild, could require significant upgrades. Generator interconnection and transmission service requests would be necessary prior to work being initiated.

Clark Fork Hydro Upgrades

The Clark Fork area transmission system consists of Avista and BPA 230 kV lines integrating Western Montana hydro projects. These include the federally-operated Libby and Hungry Horse projects and Avista's Clark Fork Projects (Cabinet Gorge and Noxon Rapids). The Clark Fork project will have a peak generation capacity of 826 MW after planned upgrades are completed. Avista coordinates operation of the Clark Fork projects with BPA to maintain system reliability in the Western Montana area. Additional transmission upgrades are not anticipated to integrate the planned Clark Fork upgrades. However, the addition of new units to the Clark Fork project may require transmission upgrades.

Distribution Efficiencies

Avista delivers electrical energy from generators to the customer's meter through a network of conductors (links) and stations (nodes). The network system is operated at various voltages to reduce current losses across the system dependent upon the distance the energy must travel. A common rule to determine efficient energy delivery is one kV per mile. For example, 115 kV power system commonly transfers energy over a distance of 115 miles while 13 kV power systems generally limited the delivery of energy to 13 miles.

Avista's energy delivery systems are categorized into the following two classes; transmission and distribution. Avista's transmission system operates at nominal voltages of 230 kV and 115 kV. Avista's distribution is operated at a range of voltages between 4.16 kV and 34.5 kV. Avista's distribution system is typically operated at a nominal voltage of 13.2 kV in its urban service centers. In addition to voltages, the transmission system is designed and operated distinctly from distribution system. For example, the transmission system is a network linking multiple sources with multiple loads while the distribution system is configured in radial feeders which link a single source to multiple loads.

System Efficiencies Team

Approximately two years ago an Avista system efficiencies team of operational, engineering and planning staff developed a plan to evaluate potential energy savings from Transmission and Distribution (T&D) system upgrades. The first phase summarized potential energy savings from distribution feeder upgrades. The second phase, beginning in the summer of 2009, combines transmission system topologies with "right sizing" distribution feeders to reduce system losses, improve system reliability, and meet future load growth.

Distribution Feeders

The system efficiencies team evaluated energy losses across Avista's distribution system. Avista's distribution system consists of approximately 330 feeders covering 30,000 square miles. The distribution feeders range in length from 3 to 73 miles. For the rural distribution, the feeder lengths varied widely to meet the electrical loads resulting from the startup and shutdown business swings of the timber, mining and agriculture industries.

The system efficiencies team evaluated a variety of efficiency programs across the urban and rural distribution feeders. The programs consisted of the following system enhancements:

- Conductor losses,
- Distribution Transformers,
- Secondary Districts, and
- VAR compensation.

The energy loss, capital investment and reduction in O&M costs resulting from the individual efficiency programs were combined on a per feeder basis. This approach provided a means to rank and compare energy savings and net resource cost for each feeder.

Economic Analysis

The economic analysis determined the net resource costs to upgrade each feeder for the four program areas listed above. The net resource cost determines the avoided cost of a new energy resource levelized over the asset's life-cycle expressed in dollars per megawatt (MW). This economic value is calculated by estimating the capital investment, energy savings, and avoidance of O&M and interim capital investments resulting from feeder upgrades. The economic analysis methodology and assumptions are more fully described in the Avista Distribution System Efficiencies Program document in Appendix X.

The O&M avoided costs for upgrades were determined by modeling existing feeders in the Availability Workbench program. This program is an expected value model combining a weighted average time and material cost of equipment failure with the probability of failure. The distribution feeder's conductor, transformers and ancillary equipment were used to determine the failure model for each feeder. Customer, material and labor costs incurred by outages equipment failure are the economic parameters used to measure the economic risk of a failure. The results were calibrated the expected value model by to industry indexes and Avista's actual outage history.

A sensitivity analysis was conducted to determine the variability of net resource values to different projected O&M time horizons since O&M avoided costs are based on expected outcomes. Figure 5.1 illustrates the levelized cost of feeder upgrades.

Distribution feeders with the highest potential for efficiency gains were included in the IRP analysis. The five selected feeders are estimated to reduce system losses by 2.7 aMW. Figure 5.2 shows the projected feeder upgrade supply curve of potential for loss reduction. This chart represents a conservative estimate of energy savings for two levels of levelized costs. If all feeders under $100 per MWh using the 40 year levelized cost method nearly 13 aMW could be saved and between 20 and 25 MW of peak savings could be realized.

The distribution feeder Ninth and Central 12F4 energy savings was assumed for all feeders used for the IRP. The feeder analysis estimated to reduce system losses by 2.7

aMW over five years. Figure 5.2 shows the projected feeder upgrade supply curve of potential for loss reduction. This chart represents a conservative estimate of energy savings for two levels of levelized costs. If all feeders under $100 per MWh using the 40 year levelized cost method nearly 13 aMW could be saved and between 20 and 25 MW of peak savings could be realized.

Figure 5.1: Levelized Cost of Feeder Upgrades

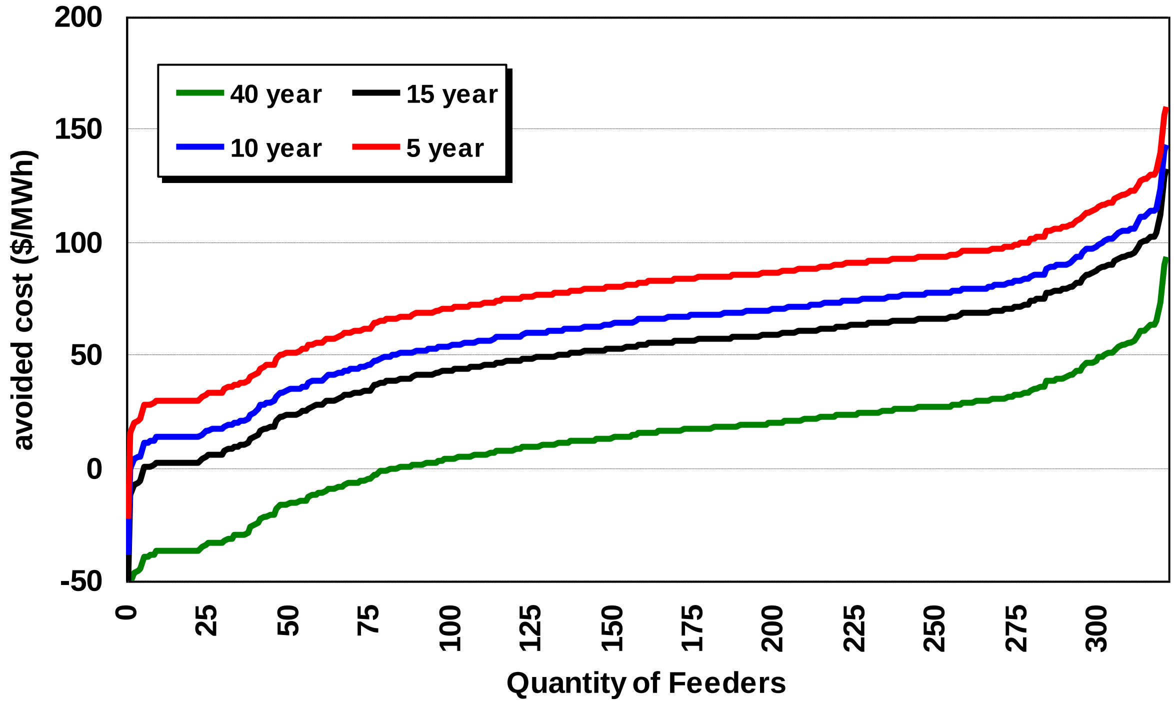
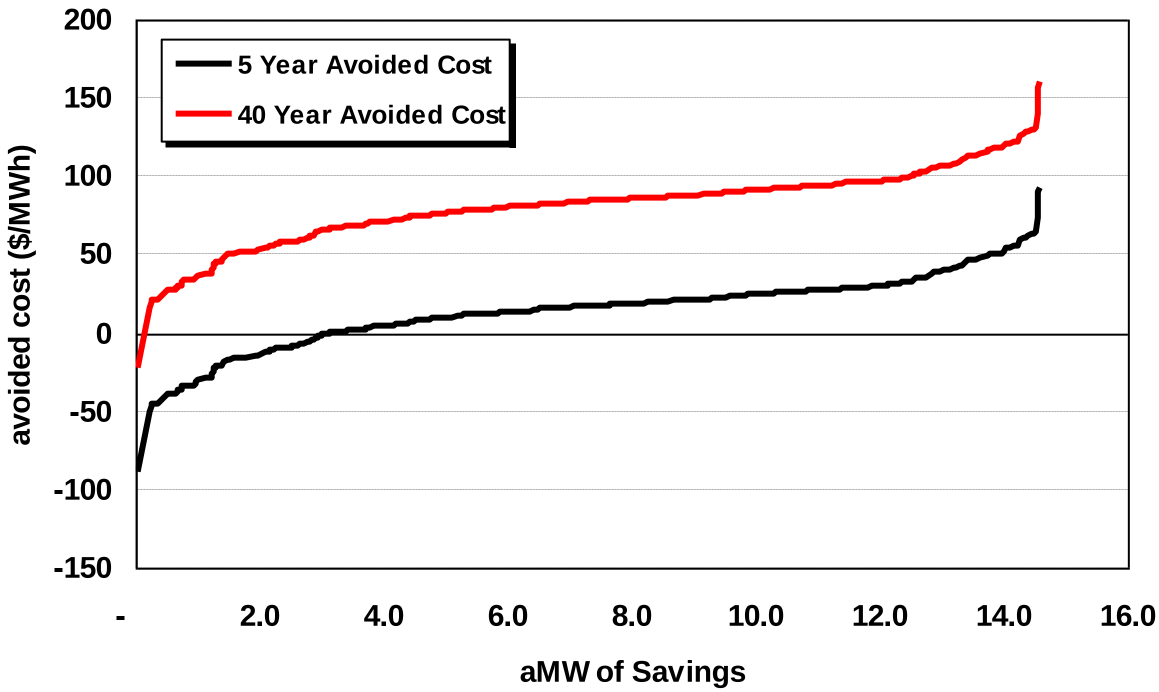


Figure 5.2: Estimated Feeder Supply Curve



Operational Considerations

By implementing the feeder efficiency programs, the voltage drop across the feeder will be lowered and will provide an opportunity to deploy a Conservation Voltage Reduction (CVR) program. Although CVR was not evaluated in the system efficiencies program, previous studies conducted on Avista feeders suggest additional energy savings can be achieved by lowering the voltage. Also, with the implementation of "smart grid" technology, the voltage can be regulated to follow the time varying load profile along the feeder more accurately. The energy savings associated with CVR can be challenging to forecast since its dependent upon system configuration and varying load characteristics. However, a study conducted by the Northwest Energy Efficiency Alliance in January 2008 determined a general guideline of 0.7 percent reduction in energy consumption with a 1 percent change in voltage.

Transmission Topologies and Distribution Feeder Sizing

As mentioned previously, with the completion of the distribution analysis, a second phase analysis will incorporate transmissions topology, station locations and load growth into the analysis. Historically, Avista's power grid was designed and built to adhere to reliability and capacity guidelines for the least first cost. This approach was reasonable considering the low cost of electrical energy at the time the system was constructed. With the increasing cost of energy, a life cycle economic analysis is warranted to evaluate power system losses corresponding to various power grid configurations.

The comprehensive analysis will review a variety of transmission topologies to determine the most efficient configuration to move bulk power through and by Avista's balancing area. The transmission topologies will consider the efficiency between star network, hub and loop, southern loop and southern source. Avista's load service will be incorporated in this analysis by determining ideal substation placement and feeder sizes as well as forecasted load growth. The comprehensive analysis will evaluate many of the items listed below.

- Develop a performance criteria to determine system measures
- Develop a base case to measure existing system performance
- Develop a methodology to determine a full build out load case
- Identify reasonable transmission topologies to be evaluated
- Identify reasonable guidelines for placing substations
- Identify reasonable guidelines for distribution feeder sizes
- Bound the analysis to ensure the system remains reliable, compliant and operationally flexible**.**

Summary

Avista's transmission system consists of over 2,200 miles of high voltage transmission lines. Transmission system planning utilizes various local, sub-region, and regional processes providing opportunities for stakeholder input into system expansions and upgrades. The system can integrate small amounts of generation in many areas for moderate integration costs; these costs tend to escalate rapidly as generation project size increases. Planning and initial cost estimates have been developed for three wind projects on the Avista system. Integration costs for the interconnection of customer-owned generation will be developed after a complete generation interconnection request has been submitted and accepted by Avista's Transmission Department.

6. Generation Resource Options

Introduction

There are many generating resource options to meet future resource deficits. Avista can upgrade existing resources, build new facilities, or contract with other energy companies for future delivery. This section describes the resources considered to meet future resource needs. The new resources described in this chapter are mostly generic. Actual resources may differ in size, cost, and operating characteristics due to siting or engineering requirements. This chapter also includes some resource options specific to Avista, including the Reardan Wind Project and hydro upgrades to our Spokane and Clark Fork River Projects. The costs and characteristics of these resources are based on preliminary studies.

Section Highlights

- Only resources with well-defined costs and characteristics were considered in the PRS analysis; other resources were studied in sensitivities.
- Renewable resource economics include federal tax incentives.
- Small hydro upgrades and wood fired upgrades were considered in this IRP.
- Solar is included as resource option for Avista.

Assumptions

For the Preferred Resource Strategy (PRS) analysis, Avista only considers commercially-available resources with well known cost, availability and generation profiles. These resources include gas-fired combined cycle combustion turbines (CCCT) and simple cycle combustion turbines (SCCT), large scale wind, and small hydro upgrades to the Spokane River Projects. Several other resource options described later in the chapter were not included the PRS analysis, but were modeled as sensitivities to understand their potential impacts to the PRS.

Levelized costs referred to throughout this section are assumed to be at the generation busbar. The nominal discount rate used in the analyses is 7.08 percent; the real discount rate is 5.09 percent. Nominal levelized costs were computed by discounting nominal cash flows at the nominal interest rate. Real levelized costs were computed by discounting real 2009 dollar cash flows at the real discount rate.

Renewable resources eligible for either the federal investment tax credit[1] (ITC) or production tax credit (PTC) are assumed to use the highest-value credit. The levelized costs shown later in this chapter are based on maximum available energy for each year instead of expected generation. For example, wind generation assumes 33 percent availability, CCCT generation assumes 90 percent availability, and SCCT generation

[1] Avista would likely not be able to take advantage of the full 30 percent tax credit in a single year. The utility may need to find a tax investor or spread the tax investment over multiple years. The Company may be eligible for treasury credits for projects with construction dates beginning before January 1, 2011.

assumes 92 percent availability. The following are definitions levelized cost items used in this chapter:

- *Capital Recovery and Taxes*: includes depreciation, return on capital, income taxes, property taxes, insurance, and miscellaneous charges such as uncollectible accounts and state taxes for each of these items pertaining to generation asset investment.
- *Interconnection Capital Recovery*: includes depreciation, return on capital, income taxes, property taxes, insurance, and miscellaneous charges such as uncollectible accounts and state taxes for each of these items pertaining to transmission asset investments needed to interconnect the generator.
- *Allowance for Funds Used During Construction (AFUDC):* The cost of money for construction payments before the utility is allowed to recover prudently invested costs.
- *Variable Operations and Maintenance (O&M):* Costs per MWh related to incremental generation.
- *Fixed O&M:* Costs related to operating the plant such as labor, parts, and other maintenance services (pipeline capacity costs are included for CCCT resources) that are not based on generation levels.
- *CO_2 Emissions Adder:* Cost of carbon dioxide (greenhouse gas) emissions based on Wood Mackenzie forecast.
- *NOx and SO_2:* Cost of nitrous oxide and sulfur dioxide emissions based on the Wood Mackenzie forecast.
- *Fuel Costs*: The cost of fuels such as natural gas, coal, or wood per the efficiency of the generator. Further details on fuel prices are included in the Market Modeling section.
- *Excise Taxes and Other Overheads:* Includes miscellaneous charges for non-capital expenses.

At the end of this chapter various tables (Table 6.28 and Table 6.29) show incremental capacity, heat rates, generation and transmission capital cost estimates before AFUDC, fixed O&M, variable costs, peak credit[2], and levelized costs. All costs shown in this section are in 2009 dollars unless otherwise noted.

Gas-Fired Combined Cycle Combustion Turbine (CCCT)

The gas-fired CCCT plants were the Northwest resource of choice in the early part of this decade. The technology provides a reliable source of both capacity and energy for a relatively inexpensive upfront investment. The main disadvantage is generation cost volatility due to its reliance on natural gas. The Company's 2007 IRP discussed the potential for buying long-term fixed price contracts or supplies to reduce the price volatility and risk associated with this technology.

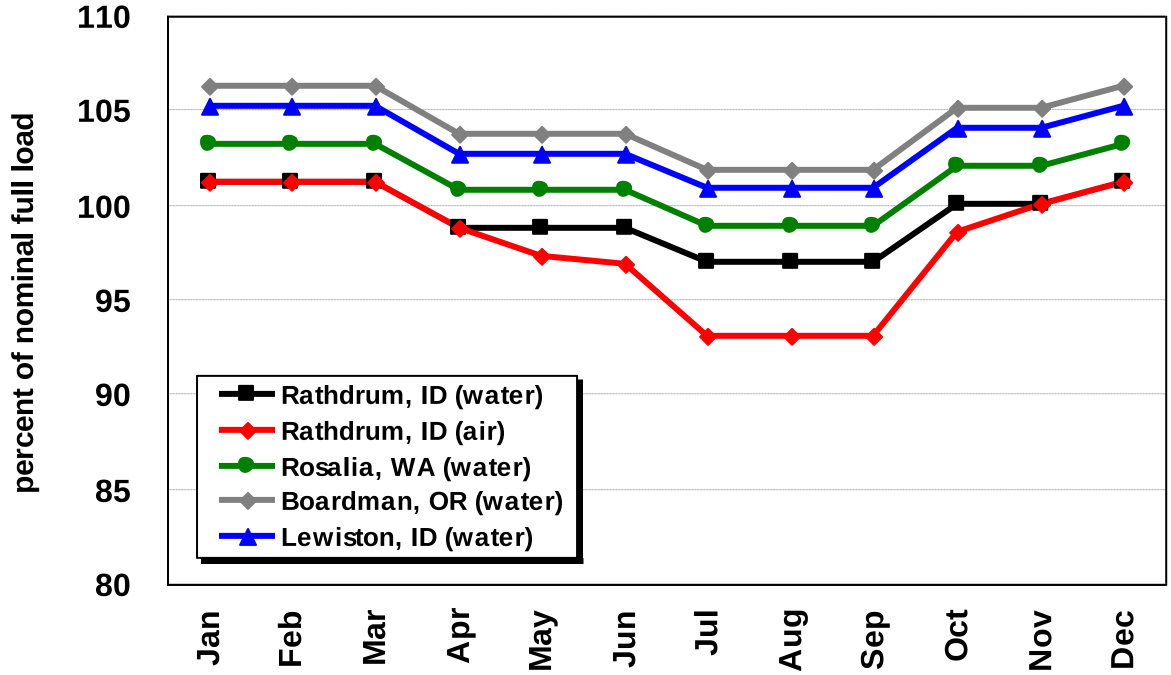
[2] Peak credit is the amount of capacity a resource contributes at system peak.

CCCTs were modeled using one-on-one (1x1) configurations with both water- and air-cooling technologies. This configuration consists of a single gas turbine, a single heat recovery steam generator (HRSG), and a duct burner to gain more generation from the HRSG. These plants are 250 MW to 300 MW each. Plants can be constructed with two gas turbines and one HRSG (2x1 configuration) up to 600 MW. For modeling purposes, 250 MW and 400 MW plant sizes were included as resource options to Avista. Capital cost estimates were based on a General Electric (GE) 7FA machine technology. Operation and maintenance costs were based on engineering estimates from the Company's experience with Coyote Spring 2.

The heat rate modeled for water-cooled CCCT resource is 6,750 Btu/kWh in 2009. The CCCT heat rate falls by 0.5 percent annually to reflect anticipated technological improvements. The plants include seven percent of rated capacity as duct firing at a heat rate of 8,500 Btu/kWh. Forced outage rates are estimated at 5 percent per year; 18 days of maintenance are assumed. Cold startup costs are $35/MWh plus 6.6 decatherms per megawatt per start.

CCCT plants are modeled to back down to 55 percent of their nameplate capacity, and ramp from zero to full load in five hours. Carbon emissions are 117 pounds per decatherm of fuel. The maximum capability of each plant is highly dependent on ambient temperature and plant elevation. Figure 6.1 illustrates the average capacity by month for a water-cooled CCCT located in Rathdrum, Idaho, compared to the same technology at other locations. The air-cooled technology is shown for illustrative purposes and would be an alternative configuration if an adequate water supply is unavailable. Air-cooled technologies provide less capacity during warmer periods of the year. The figure illustrates how combined cycle capacity is greatly affected by site elevation.

Figure 6.1: CCCT Output Per 100 MW of Nameplate Capacity



The capital cost for a CCCT with AFUDC is estimated to be $1,553 per kW. Fixed O&M costs are expected to be $11 per kW-year. Table 6.1 is the levelized cost for a CCCT resource in both nominal and 2009 dollars.

Table 6.1: CCCT (Water Cooled) Levelized Costs

Item	Nominal $	Real 2009$
Capital recovery and taxes	20.91	15.49
Interconnection capital recovery	0.76	0.64
AFUDC	2.60	2.21
Variable O&M	3.88	3.29
Fixed O&M	4.00	3.39
CO_2 emissions adder	15.25	12.94
NOx and SO_2 emission adder	0.15	0.13
Fuel costs	59.29	50.28
Excise taxes and other overheads	3.57	3.04
Total Cost	**110.41**	**91.40**

It is possible to sequester 90 percent of the carbon emissions from a gas-fired resource. A cost adder of $1,374 per kW was added for sequestration, for a total cost of $2,907 per kW including AFUDC. The fixed O&M is expected to increase to $18.70 per kW-year. The levelized cost for this resource option is shown in Table 6.2.

Table 6.2: CCCT w/ Carbon Sequestration Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	43.70	32.38
Interconnection capital recovery	0.57	0.48
AFUDC	7.51	6.37
Variable O&M	5.69	4.83
Fixed O&M	5.86	4.97
CO_2 emissions adder	1.98	1.68
NOx & SO_2 emission adder	0.00	0.00
Fuel costs	75.51	64.20
Excise taxes and other overheads	3.86	3.30
Total Cost	**144.68**	**118.18**

Gas-Fired Simple Cycle Combustion Turbine (SCCT)

Gas-fired combustion turbines (CTs) provide low-cost capacity and are capable of providing energy as needed. Technology advances allow some CTs the ability to start and ramp quickly, enabling them to provide regulation services and reserves for varying loads and resources such as wind.

Two SCCT options were modeled in the IRP: Frame (GE 7EA) and hybrid aero-derivative (GE LMS 100). The LMS 100 ramps up quickly and has a lower heat rate and start-up costs than the 7EA model, but its capital costs are significantly higher. Operation and maintenance costs are based on engineering and NPCC estimates. The frame machine is modeled in 60 MW increments and the LMS 100 in 100 MW increments.

Heat rates for SCCT plants are 8,400 Btu/kWh (LMS) and 10,200 Btu/kWh (frame) in 2009, decreasing by 0.5 percent per year (real) to reflect anticipated technological improvements. Forced outage rates are estimated at five percent per year, with no maintenance outages (approximately 10 days per year) because it is assumed to occur in months when these plants do not typically operate. Cold startup costs are $15 per MW per start for the frame machine and one decatherm per MW for the LMS 100. The maximum capabilities of these plants are highly dependent on ambient temperature, and use the same monthly shape as CCCT plants.

The capital cost for a 2009 SCCT with AFUDC is estimated to be $676 per kW for the frame and $1,342 per kW for the LMS 100. Fixed O&M costs are modeled at $4 per kW-year for each resource. Tables 6.3 and 6.4 show the levelized cost per MWh for each resource. The LMS 100 can provide regulation for load and wind; reserves were valued at $84 per kW-year in the PRS analysis.

Table 6.3: Frame SCCT Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	9.27	6.87
Interconnection capital recovery	0.74	0.63
AFUDC	0.43	0.36
Variable O&M	5.90	5.00
Fixed O&M	0.58	0.49
CO_2 emissions adder	23.04	19.55
NOx & SO_2 emission adder	0.23	0.19
Fuel costs	90.09	76.40
Excise taxes and other overheads	5.19	4.40
Total Cost	**135.47**	**113.90**

Table 6.4: LMS 100 Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	19.31	14.13
Interconnection capital recovery	0.74	0.63
AFUDC	0.89	0.75
Variable O&M	6.49	5.50
Fixed O&M	0.58	0.49
CO_2 emissions adder	18.97	16.10
NOx & SO_2 emission adder	0.19	0.16
Fuel costs	74.19	62.92
Excise taxes and other overheads	4.35	3.69
Total Cost	**125.71**	**104.55**

Wind

Concerns over the environmental impact of carbon-based generation technologies have increased demand for wind generation. Governments are promoting wind generation through tax credits, renewable portfolio standards, and climate change legislation. The 2009 American Recovery and Reinvestment Act extended the PTC for wind through January 1, 2013, and provided an option for owners to select a 30 percent investment tax credit (ITC) instead.

Several wind resource locations were studied for this IRP:

- Reardan (up to 50 MW);
- Columbia Basin (50 MW increments);
- Montana (25 MW increments);
- Small scale (less than 1 MW); and
- Offshore (75 MW increments).

Reardan and Columbia Basin locations were the only wind resources considered for the Preferred Resource Strategy analysis. Other resource locations will be considered if projects are submitted in response to competitive solicitations.

Transmission is a road block for many wind projects. Projects often are not close to transmission, or when they are the existing lines are fully subscribed. New transmission must be constructed. For IRP analyses, transmission costs are assumed to be:

- ***Reardan***: Avista transmission system requiring $15 million in transmission improvements.
- ***Columbia Basin (Tier 1 and Tier 2)***: BPA wheel[3] and $100 per kW for local interconnection.
- ***Montana***: Northwestern wheel[4] and $50 per kW for local interconnection.
- ***Small Scale***: Avista distribution system and $100 per kW for distribution interconnection and a 10 percent adder for saved transmission and distribution losses.
- ***Offshore***: BPA wheel and $36 per kW for local interconnection (assumes economies of scale).

Wind resources benefit from having no emissions profile and no fuel costs, but are disadvantaged by not being dispatchable, and its being capital and labor intensive. The costs for capital, fixed O&M, and capacity factors are shown in Table 6.5. Capacity factors are expected (P50) values for each wind location. A statistical method, based on regional wind studies, was used to derive a range of capacity factors depending on the wind regime in each year (see stochastic modeling assumptions for more details). Using these expected capacity factors and the capital and operating costs, levelized costs are illustrated in Tables 6.6, 6.7, and 6.8. The cost of integrating wind generation is not shown, but is expected to change over time depending upon the amount of wind resources on the Avista system. The PRS analysis used a cost of $3.50 per MWh for integration services.

Table 6.5: Wind Capital and Fixed O&M Costs

Location	Capital 2009$ (includes AFUDC)	Fixed O&M ($ per kW-year)	Capacity Factor
Reardan[5]	2,183	45	30.0%
Columbia Basin (Tier 1)	2,262	50	33.0%
Columbia Basin (Tier 2)	2,262	50	26.4%
Montana	2,262	50	37.0%
Small Scale	3,343	50	20.0%
Off Shore	5,573	95	45.0%

[3] $18 per kW-year and losses are 1.9 percent. Tier 2 wind has a 20 percent lower capacity factor than Tier 1 wind.
[4] $40.80 per kW-year and losses are 4.0 percent
[5] Costs for the Reardan Wind Project are generic based on prices at the time of modeling. Actual costs will vary depending on turbine and balance of plant costs at time of construction. Reardan is assumed to be slightly less expensive than Columbia Basin projects, due to lack of significant transmission upgrade costs, no third party development fees, and the proximity of the project to Avista's operations center.

Table 6.6: Columbia Basin Wind Project Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	56.63	48.01
Interconnection capital recovery	4.4	3.73
AFUDC	4.6	3.90
Variable O&M	3.54	3.00
Fixed O&M	20.79	17.63
CO_2 emissions adder	0.00	0.00
NO_x & SO_2 emissions adder	0.00	0.00
Fuel costs	0.00	0.00
Integration	4.05	3.50
Excise taxes and other overheads	1.05	0.89
Total Cost	**95.06**	**80.66**

Table 6.7: Small Scale Project Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	125.01	105.97
Interconnection capital recovery	0.00	0.00
AFUDC	10.14	8.60
Variable O&M	3.54	3.00
Fixed O&M	30.60	25.94
CO_2 emissions adder	0.00	0.00
NOx and SO_2 emission adder	0.00	0.00
Fuel costs	0.00	0.00
Integration	4.05	3.50
Excise taxes and other overheads	1.48	1.25
Total Cost	**174.82**	**148.27**

Table 6.8: Offshore Wind Project Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	103.83	88.02
Interconnection capital recovery	1.16	0.99
AFUDC	11.16	9.46
Variable O&M	5.90	5.00
Fixed O&M	28.97	24.57
CO_2 emissions adder	0.00	0.00
NO_x and SO_2 emissions adder	0.00	0.00
Fuel costs	0.00	0.00
Integration	4.05	3.50
Excise taxes and other overheads	1.51	1.28
Total Cost	**156.58**	**132.81**

Coal

Pulverized and integrated gasification combined cycle (IGCC) coal plants were included as resource options for the IRP. Pulverized coal options included sub-critical, super-critical, ultra-critical and circulating fluidized bed (CFB) technologies. These different technologies have different boiler temperatures and pressures, resulting in different capital cost and operating efficiencies. The ultra-critical plant was modeled for sensitivity analysis.

IGCC plants gasify coal, thereby creating a more efficient use of the fuel lowering carbon emissions and removing other toxic substances before combustion. This technology has the potential to sequester 90 percent of carbon emissions, effectively reducing CO_2 emissions from 205 pounds per MMBtu to 20.5 pounds per MMBtu.

The Washington State legislature passed Senate Bill 6001 in 2007, effectively prohibiting electric utilities in that state from developing coal fired facilities that do not sequester emissions. A coal facility could legally be constructed to serve Idaho loads, where not emissions performance standard exists, but Avista is not considering a pulverized coal facility for the 2009 IRP. IGCC facilities were modeled in 200 MW increments in the PRS analysis with availability beginning in 2022 for IGCC plants without sequestration, and 2025 for an IGCC plants with sequestration.

Capital and fixed O&M costs, and heat rates, are shown in Table 6.9. Levelized costs per MWh are shown in Tables 6.10, 6.11, and 6.12. IGCC resources currently may qualify for the federal PTC; but the levelized costs in the tables below do not reflect the incentive as it is expected to expire before an IGCC resource could be built in 2022. IGCC coal plants are assumed to be located in Montana, with transmission provided by upgrades to Northwestern's system.

Table 6.9: Coal Capital Costs (2009$)

Technology	Capital Cost ($/kW includes AFUDC)	Fixed O&M ($/kW/Yr)	Heat Rate (btu/kWh)
Ultra Critical Pulverized Coal	$3,594	$38	8,825
IGCC	$4,305	$41	8,130
IGCC with Sequestration	$6,013	$50	9,595

Table 6.10: Ultra Critical Pulverized Coal Project Levelized Cost per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	49.96	37.02
Interconnection capital recovery	0.60	0.57
AFUDC	9.29	7.87
Variable O&M	1.53	1.30
Fixed O&M	5.98	5.07
CO_2 emissions adder	34.92	29.63
NOx and SO_2 emission adder	1.30	1.26
Fuel costs	11.37	9.64
Excise taxes and other overheads	2.39	2.03
Total Cost	**117.34**	**94.32**

Table 6.11: IGCC Coal Project Levelized Cost per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	59.95	44.42
Interconnection capital recovery	0.60	0.51
AFUDC	11.14	9.45
Variable O&M	4.72	4.00
Fixed O&M	6.45	5.47
CO_2 emissions adder	32.17	27.30
NOx and SO_2 emission adder	0.59	0.54
Fuel costs	10.47	8.88
Excise taxes and other overheads	2.36	2.00
Total Cost	**128.45**	**102.56**

Table 6.12: IGCC with Carbon Sequestration Coal Project Levelized Cost ($/MWh)

Item	Nominal $	Real 2009$
Capital recovery and taxes	84.71	62.77
Interconnection capital recovery	0.61	0.51
AFUDC	15.75	13.35
Variable O&M	5.19	4.40
Fixed O&M	7.94	6.73
CO_2 emissions adder	3.80	3.22
NOx and SO_2 emission adder	0.18	0.15
Fuel costs	12.36	10.48
Excise taxes and other overheads	1.28	1.08
Total Cost	**131.82**	**102.70**

Hydroelectric Project Upgrades

Avista has a long history of owning, maintaining and operating hydroelectric projects. We continue to programmatically upgrade many of our hydroelectric facilities. Our latest hydro upgrades add 7 MW at Noxon Rapids Unit 1 and 17 MW at Cabinet Gorge Unit 4. The Company is planning to upgrade units 2, 3 and 4 at Noxon Rapids (2010, 2011 and 2012 respectively), and units 1 and 2 at Nine Mile in 2012.

Avista designed and studied other larger potential upgrades at Long Lake and Cabinet Gorge. These upgrades were too costly in previous studies, but increasing market prices, growing capacity needs, renewable energy incentives, and carbon emission costs, these resources may be financially more attractive now. Upgrade options include a second powerhouse at Long Lake, a fifth unit at Long Lake, and Cabinet Gorge Unit 5. These upgrades are not included as PRS options, but they were evaluated for sensitivity analysis. See Table 6.13 for more information on these hydro upgrades.

Avista engineers also developed preliminary plans to replace the powerhouse at Post Falls, doubling its capacity. These large hydro upgrade options have attracted attention during this IRP cycle and will be further studied between now and the 2011 IRP. The estimated levelized costs of hydro upgrades are included in Table 6.14 and Table 6.15.

Table 6.13: Hydro Upgrade Project Characteristics

Project	Capital Cost (2009$) (includes AFUDC)	Year Available	Capacity (MW)	Capacity Factor
Little Falls Unit 1	2,787	2014	1.0	32%
Little Falls Unit 2	1,929	2015	1.0	32%
Little Falls Unit 3	3,430	2016	1.0	32%
Little Falls Unit 4	1,393	2017	1.0	32%
Post Falls Unit 6	5,359	2018	0.2	32%
Upper Falls	3,870	2019	2.0	49%
Long Lake Unit 5	2,882	2020	24.0	34%
Long Lake 2nd Powerhouse	2,454	2020	60.0	30%
Cabinet Gorge Unit 5	1,660	2015	60.0	17%

Table 6.14: Hydro Upgrade Nominal Levelized Costs per MWh

Project	Generation Capital Recovery & Taxes	Transmission Capital Recovery & Taxes	AFUDC	Fixed O&M	Total Cost
Little Falls Unit 1	81.07	0.00	5.82	0.00	**86.89**
Little Falls Unit 2	56.13	0.00	4.03	0.00	**60.16**
Little Falls Unit 3	99.78	0.00	7.16	0.00	**106.94**
Little Falls Unit 4	40.54	0.00	2.91	0.00	**43.45**
Post Falls Unit 6	155.91	0.00	11.19	0.00	**167.10**
Upper Falls	71.27	0.00	7.54	0.00	**78.81**
Long Lake Unit 5	63.58	14.38	10.93	0.40	**89.31**
Long Lake 2nd PH	66.52	6.51	10.56	0.90	**84.52**
Cabinet Gorge Unit 5	83.15	0.00	14.29	1.58	**99.09**

Table 6.15: Hydro Upgrade 2009$ Levelized Costs per MWh

Project	Generation Capital Recovery & Taxes	Transmission Capital Recovery & Taxes	AFUDC	Fixed O&M	Total Cost
Little Falls Unit 1	68.72	0.00	4.93	0.00	**73.66**
Little Falls Unit 2	47.58	0.00	3.42	0.00	**50.99**
Little Falls Unit 3	84.58	0.00	6.07	0.00	**90.66**
Little Falls Unit 4	34.36	0.00	2.47	0.00	**36.83**
Post Falls Unit 6	132.16	0.00	9.49	0.00	**141.65**
Upper Falls	60.42	0.00	6.39	0.00	**66.80**
Long Lake Unit 5	53.90	12.19	9.26	0.34	**75.71**
Long Lake 2nd PH	56.39	5.52	8.95	0.76	**71.65**
Cabinet Gorge Unit 5	70.49	0.00	12.12	1.34	**84.00**

Other Resource Options

A thorough IRP considers resources that may not be commercially or economically ready for utility-scale development. This is particularly true for some emerging technologies that are attractive from an environmental perspective. These resources are analyzed to ensure that the Company does not overlook resource options with changing economic characteristics. Avista analyzed solar, tidal (wave), biomass, geothermal, co-generation, nuclear, pumped storage, hydrokinetics, and large scale hydro.

Solar

Solar technology has advanced in the last several years with help from renewable portfolio standards, the federal ITC, and state incentives. Solar still struggles economically against other resources because of its low capacity factor and high capital cost. To its credit, solar provides predictable on-peak generation that complements the loads of summer-peaking utilities.

The Northwest is not a prime location for solar. A well placed utility scale photovoltaic system located in the Pacific Northwest would achieve a capacity factor of less than 20 percent. Three solar technologies were studied for this IRP: utility scale photovoltaic, solar-thermal, and roof-top photovoltaic. Each option has certain advantages. Utility scale photovoltaic can be optimally located for the best solar radiation, solar thermal has the ability to produce a higher capacity factor (up to 30 percent) and store energy for several hours, and roof-top solar is located at the source of the load which reduces system losses. Capital costs, including AFUDC, for these technologies are expected to be:

- Utility Scale Photovoltaic: $7,900 per kW;
- Solar or Concentrating Thermal: $4,541 per kW; and
- Roof Top Solar: $8,283 per kW.

The levelized costs of these resources, including federal incentives,[6] are shown in Tables 6.16 and 6.17.

Table 6.16: Solar Nominal Levelized Cost ($/MWh)

Item	Utility Scale Photovoltaic	Solar Thermal	Roof-Top Solar
Capital recovery and taxes	312.51	130.82	444.46
Interconnection capital recovery	0.00	4.86	0.00
AFUDC	11.06	12.84	15.73
Variable O&M	0.00	0.00	0.00
Fixed O&M	19.58	29.73	24.48
CO_2 emissions adder	0.00	0.00	0.00
NO_x and SO_2 emissions adder	0.00	0.00	0.00
Fuel costs	0.00	0.00	0.00
Excise taxes and other overheads	0.85	1.29	1.06
Total Cost	**344.00**	**179.54**	**485.73**

[6] Washington has small renewable energy incentives for up to $2,000 per year depending upon location of manufacturing through June of 2014. These incentives are not included in this analysis.

Table 6.17: Solar 2009$ Levelized Cost ($/MWh)

Item	Utility Scale Photovoltaic	Solar Thermal	Roof-Top Solar
Capital recovery and taxes	264.93	110.90	376.79
Interconnection capital recovery	0.00	0.51	0.00
AFUDC	9.38	10.88	13.34
Variable O&M	0.00	0.00	0.00
Fixed O&M	16.60	25.21	20.76
CO_2 emissions adder	0.00	0.00	0.00
NO_x and SO_2 emissions adder	0.00	0.00	0.00
Fuel costs	0.00	0.00	0.00
Excise taxes and other overheads	0.72	1.09	0.90
Total Cost	**291.63**	**152.20**	**411.78**

Biomass and Wood Generation

Avista is an industry leader in biomass generation. In 1983, the Company built one of the largest biomass generation facilities in North America, the 50 MW Kettle Falls Generating Station. Eastern Washington and Northern Idaho have the potential for new biomass facilities. As part of the 2007 IRP Action Plan to study biomass potential, the Company targeted its biomass focus on wood generation. Several unique options were evaluated for this IRP.

The first option is to use the utility's existing steam turbine capacity at Coyote Spring 2 by augmenting with wood; this option is labeled as the CCCT Wood Boiler and would require new facilities at Coyote Springs for wood handling. It would also require fuel deliveries from locations remote from the plant, increasing its fuel costs. This option could add 10 MW of capacity when the gas-fired portion of the plant is online.

A second option is to add a wood gasifier to the Kettle Falls Combustion Turbine. It would utilize existing facilities and infrastructure, and increase winter peak generating capacity[7] by 7.8 MW. The IRP analysis also includes generic biomass resources, including a new large biomass generation facility using wood gasification technology, and generic biomass resources fueled with manure, landfill gas, wood, and other bio-waste fuels, including open- and closed-loop technologies. Assumed capital and operating costs are shown in Table 6.18. The levelized costs are shown in Table 6.19 and Table 6.20. The costs include production tax credits that were extended through January 1, 2014; closed loop technologies receive double the federal credits. No fuel costs were included for non-wood biomass resources because the fuel cost will depend on the type of fuel source. For example, a digester resource located at a dairy will have free fuel.

[7] The Kettle Falls CT is currently unavailable for winter peak generation due to limited fuel transportation. Increasing fuel capacity to the northern service area is currently being examined by Avista.

Table 6.18: Biomass Capital Costs

Project	Capital Cost (2009$) (includes AFUDC)	Fixed O&M ($/kW/Yr)
CCCT Wood Boiler	2,745	121
KFCT Wood Gasifier	4,645	85
Wood Gasifer Combined Cycle	3,476	85
Biomass Open-Loop	5,406	85
Biomass Closed-Loop	8,649	150

Table 6.19: Biomass Nominal Levelized Costs per MWh

Item	CCCT Wood Boiler	KFCT Wood Gasifier	Wood Gasifier CC	Biomass Open-Loop	Biomass Closed-Loop
Capital recovery and taxes	24.67	43.03	32.49	48.16	77.07
Interconnection capital recovery	0.00	0.00	0.28	0.28	0.28
AFUDC	2.42	2.30	1.73	3.91	6.25
Variable O&M	7.08	9.08	9.08	3.54	11.79
Fixed O&M	18.09	12.68	12.68	12.40	21.89
CO_2 emissions adder	0.00	0.00	0.00	0.00	0.00
NOx and SO_2 emission adder	2.12	0.00	0.00	0.00	0.00
Fuel costs	82.50	40.46	40.46	0.00	0.00
Excise taxes and other overheads	4.75	2.69	2.69	0.69	1.46
Total Cost	**141.63**	**110.24**	**99.41**	**68.98**	**118.74**

Table 6.20: Biomass 2009 Dollar Levelized Cost per MWh

Item	CCCT Wood Boiler	KFCT Wood Gasifier	Wood Gasifier CC	Biomass Open-Loop	Biomass Closed-Loop
Capital recovery and taxes	20.91	36.48	27.55	40.83	65.33
Interconnection capital recovery	0.00	0.00	0.24	0.24	0.24
AFUDC	2.05	1.95	1.47	3.31	5.30
Variable O&M	6.00	7.70	7.70	3.00	10.00
Fixed O&M	15.34	10.75	10.75	10.52	18.56
CO_2 emissions adder	0.00	0.00	0.00	0.00	0.00
NOx and SO_2 emission adder	1.83	0.00	0.00	0.00	0.00
Fuel costs	69.95	34.31	34.31	0.00	0.00
Excise taxes and other overheads	4.03	2.28	2.28	0.59	1.24
Total Cost	**120.12**	**93.47**	**84.30**	**58.48**	**100.66**

Geothermal

Northwest utilities have developed an increased interest in geothermal energy over the past two years. Geothermal energy provides a stable renewable source that can provide capacity and energy with minimal carbon dioxide emissions (zero to 200 pounds per MWh). The federal government has also extended production tax credits to this technology through January 1, 2014. Geothermal energy is disadvantaged by a risky development process involving drilling several thousand feet below the earth's crust; each hole can cost in excess of $3 million. Capital costs are assumed to be $5,698, including AFUDC, with fixed operating costs of $75 per kW-year. Table 6.21 presents the levelized cost for geothermal. Geothermal costs appear attractive once a viable location has been found, but the risk capital required to find a viable site in the first place is significant and cannot be underestimated. The values below do not account for dry-hole costs.

Table 6.21: Geothermal Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	49.05	41.58
Interconnection capital recovery	0.28	0.24
AFUDC	6.85	5.81
Variable O&M	5.90	5.00
Fixed O&M	11.14	9.45
CO_2 emissions adder	1.93	1.64
NOx and SO_2 emission adder	0.00	0.00
Fuel costs	0.00	0.00
Excise taxes and other overheads	0.82	0.70
Total Cost	**75.97**	**64.41**

Tidal and Wave

Tidal and wave power is a technology in the early stages of development. Like other renewable resources it has varying generation, but is more predictable than wind. Questions remain surrounding corrosion, bio-fouling by barnacles and other marine organisms, environmental issues, and siting concerns. Depending upon its application, tidal power can generate in two time periods daily, but the generation pattern follows the lunar cycle. A 30 percent capacity factor was assumed for the IRP analysis.

Given its early development stage, tidal power was not considered for the PRS. The costs of tidal power are uncertain at this time and were estimated using a variety of sources and engineering estimates. Capital costs including AFUDC are expected to be $10,389 per kW. Costs presented in Table 6.22 are estimated costs for an experimental project.

Table 6.22: Tidal/Wave Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	305.57	259.04
Interconnection capital recovery	0.00	0.00
AFUDC	11.90	10.09
Variable O&M	0.00	0.00
Fixed O&M	448.74	379.52
CO_2 emissions adder	0.00	0.00
NO_x & SO_2 emission adder	0.00	0.00
Fuel costs	0.00	0.00
Excise taxes and other overheads	19.42	16.47
Total	**785.63**	**665.12**

Small Co-Generation

Avista has few industrial customers capable of developing a co-generation project. If an interested customer was inclined to proceed, it could provide benefits including reduced transmission and distribution losses, shared fuel/capital/emissions costs, and credit towards Washington's I-937 targets. This resource was excluded from the PRS, because Avista is not aware of any cogeneration plans by its customers. If a customer wanted to pursue this resource, Avista would consider it along with other generation options. The expected levelized costs for cogeneration are shown in Table 6.23.

Table 6.23: Small Co-generation Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	28.09	20.81
Interconnection capital recovery	0.00	0.00
AFUDC	1.29	1.10
Variable O&M	5.90	5.00
Fixed O&M	2.43	2.06
CO_2 emissions adder	12.87	10.92
NO_x and SO_2 emission adder	0.13	0.11
Fuel costs	49.18	41.70
Excise taxes and other overheads	3.05	2.59
Total	**102.94**	**84.29**

Nuclear

Nuclear plants are not currently considered a viable resource option for Avista given the uncertainty of their economics, the apparent lack of political support for the technology in the region, and the negative experience the Company had during the 1980s with its participation in WNP #3. Like coal plants, nuclear resources need to be studied because other utilities in the Western Interconnect may be able to incorporate nuclear power into their resource mix. The viability of nuclear power could change as national policy priorities focus attention on de-carbonizing the nation's energy supply. Nuclear capital costs are difficult to forecast, as no new nuclear facility has been built in the United States since the 1980s, so they were obtained from industry studies and plant license proposals. Capital cost sensitivity analyses were performed to compensate for the difficulties obtaining reliable capital costs for nuclear plants. The starting point for capital costs was $7,168 per kW, including AFUDC. Levelized costs are shown in Table 6.24.

Table 6.24: Nuclear Levelized costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	91.79	77.81
Interconnection capital recovery	0.60	0.51
AFUDC	27.23	23.09
Variable O&M	0.65	0.55
Fixed O&M	15.29	12.96
CO_2 emissions adder	0.00	0.00
NOx and SO_2 emission adder	0.00	0.00
Fuel costs	12.06	10.22
Excise taxes and other overheads	0.55	0.47
Total	**148.17**	**125.61**

Hydrokinetics

Hydrokinetics projects consist of small turbines placed in rivers that generate based on the amount of water flow in the system. Avista has identified potential locations for this technology and has developed preliminary cost estimates shown in Table 6.25. Capital costs for this low-impact hydro resource is expected to be $4,212 per kW including AFUDC and fixed O&M is $3 per kW-year.

Table 6.25: Hydrokinetics Levelized costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	138.89	117.75
Interconnection capital recovery	0.00	0.00
AFUDC	7.38	6.25
Variable O&M	0.00	0.00
Fixed O&M	1.53	1.30
CO_2 emissions adder	0.00	0.00
NOx and SO_2 emission adder	0.00	0.00
Fuel costs	0.00	0.00
Excise taxes and other overheads	0.07	0.06
Total Cost	**147.87**	**125.35**

Pumped Storage

Increasing wind generation levels in the Northwest has renewed interest in pumped storage. Few studies have been conducted for the Northwest market. The most likely storage options are water or battery technologies. Either option faces significant re-charging penalties illustrated by the high variable O&M charge. The expected capital cost is $4,151 per kW, including AFUDC, with $5 per kW-year for fixed O&M. Levelized costs estimates are shown in Table 6.26. The reserve value, estimated to be $84 per kW-year is not shown in the table.

Table 6.26: Pumped Storage Levelized costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	90.71	88.61
Interconnection capital recovery	2.59	2.20
AFUDC	16.86	14.29
Variable O&M	92.86	78.76
Fixed O&M	1.22	1.04
CO_2 emissions adder	0.00	0.00
NO_x and SO_2 emissions adder	0.00	0.00
Fuel costs	0.00	0.00
Excise taxes and other overheads	4.07	3.45
Total	**208.31**	**188.35**

Large Scale Hydro

New large hydro projects are not likely to be built in the Pacific Northwest because of environmental and cost hurdles. British Columbia has projects in the design phases. Avista may be able to contract with a Canadian firm for delivery of this energy. However, the resource was not considered for the PRS analyses because of the uncertainty surrounding large hydro, and the lack of transmission from British Columbia to Avista's service territory. The expected capital costs, including AFUDC, are estimated at $5,273 per kW; fixed O&M is estimated at $2 per kW-year. The levelized cost analysis shown in Table 6.27 includes BPA and British Columbia Transmission Corporation transmission wheels.

Table 6.27: Large Scale Hydro Levelized costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	232.41	197.01
Interconnection capital recovery	1.86	1.58
AFUDC	39.95	39.09
Variable O&M	0.00	0.00
Fixed O&M	0.98	0.83
CO_2 emissions adder	0.00	0.00
NO_x and SO_2 emission adder	0.00	0.00
Fuel costs	0.00	0.00
Excise taxes and other overheads	0.04	0.04
Total	**275.24**	**238.54**

Summary

Avista has several resource alternatives to select from for this IRP. Each provides differing benefits, costs, and risks. The role of this IRP is to identify the relevant characteristics and choose a set of resources that are actionable, meet customer's energy and capacity needs, balance state renewable requirements, and keep customer costs minimized. Table 6.28 is a summary of resource costs and plant characteristics used in the PRS analyses. All other resources are shown in Table 6.29. The PRS chapter discusses resource choices and provides "tipping-point" analyses to explain how resource cost would need to change to be included in the PRS.

Table 6.28: Resource Analysis Summary for Preferred Resource Strategy Analysis

Resource	Resource Size (MW)	Heat Rate (btu/ kWh)	Gen. Capital Cost ($2009/k W)	Trans. Capital Cost ($2009/k W)	Fixed O&M ($2009/ kW/yr)	Variable O&M ($2009/ MWh)	Peak Credit (Winter/ Summer) (%)	Nominal Levelized Costs ($MWh)	Real Levelized Costs (2009$/ MWh)
Little Falls 4	1	n/a	1,300	0	0	0	100/90	43.45	36.83
Little Falls 2	1	n/a	1,800	0	0	0	100/90	60.16	50.99
Upper Falls	2	n/a	3,500	0	0	0	100/90	78.81	66.80
Little Falls 1	1	n/a	2,600	0	0	0	100/90	86.89	73.66
Wind (Generic)	50	n/a	2,000	100	50	3	0/0	95.06	80.66
Little Falls 3	1	n/a	3,200	0	0	0	100/90	106.94	90.66
CCCT (1x1) Water Cooled	250/400	6,750	1,321	48	11	3.29	105/95	110.41	91.40
IGCC	200	8,130	3,600	36	41	4	105/95	128.45	102.56
IGCC with Sequestration	200	9,595	5,040	36	50	4.4	100/100	131.82	102.70
SCCT LMS 100	100	8,400	1,247	48	4	5.5	105/95	125.71	104.55
SCCT Frame	60	10,200	600	48	4	5	105/95	135.47	113.90
CCCT (2x1) w/ Seq	125	8,775	2,240	48	18.7	4.83	105/95	144.68	118.18

Table 6.29: Resource Analysis Summary for Other Resources Options

Resource	Increment Resource Size (MW)	Heat Rate (btu /kWh)	Capital Cost ($2009/ kW)	Trans. Capital Cost ($2009/kW)	Fixed O&M ($2009/kW/yr)	Variable O&M ($2009/ MWh)	Peak Credit (Winter/ Summer)	Nominal Levelized Costs ($MWh)	Real Levelized Costs (2009$/ MWh)
Biomass Open-Loop	5	10,500	5,000	18	85	3	100/100	68.91	58.48
Geothermal	5	n/a	5,000	18	75	5	110/90	75.97	64.41
Long Lake 2nd Powerhouse	60	n/a	2,000	0	2	0	100/90	84.49	71.65
Long Lake Unit 5	24	n/a	2,167	0	1	0	100/90	89.29	75.71
Cabinet Gorge Unit 5	60	n/a	1,417	0	2	0	100/100	99.02	84.00
Small Co-Gen	2.5	5,700	2,000	0	5	5	105/95	102.94	84.29
Wood Gasifer Combined Cycle	5	10,300	3,300	18	85	7.7	110/90	99.41	84.30
KFCT Wood Gasifier	7	10,300	4,370	0	85	7.7	100/0	110.24	93.47
Ultra Critical Pulverized Coal	200	8,825	3,000	36	38	1.3	100/100	117.34	94.32
Biomass Closed-Loop	5	10,500	8,000	18	150	10	100/100	118.74	100.66
CCCT Wood Boiler	10	10,500	2,500	0	121	6	100/100	141.62	120.12
Hydrokinetics	0.1	n/a	4,000	0	3	0	100/100	147.87	125.35
Nuclear	250	10,400	5,500	36	97	0.55	100/100	148.17	125.61
Wind: Off Shore	75	n/a	5,000	36	95	5	0/0	156.58	132.81
Post Falls Unit 6	0.2	n/a	5,000	0	0	0	100/90	167.10	141.65
Wind: Small Scale	0.1	n/a	3,000	100	50	3	0/0	174.82	148.27
Solar Thermal	2	n/a	4,200	100	3	0	5/100	179.54	152.20
Pumped Storage	5	n/a	3,500	100	5	0	100/100	208.31	188.35
Large Scale Hydro	100	n/a	4,500	36	2	0	100/100	275.24	238.54
Utility Scale Photovoltaic	0.5	n/a	7,500	0	1	0	May-60	344.00	291.63
Roof-Top Solar	0.5	n/a	8,000	0	0.5	0	May-60	485.73	411.78
Tidal (wave)	0.1	n/a	10,000	0	1000	0	0/0	785.63	666.12

7. Market Analysis

Introduction

This section discusses the expected market environment that Avista is facing. The analytical foundation for the 2009 IRP is a fundamentals-based electricity model of the entire Western Interconnect. The market analysis compares potential resource options on their value in the wholesale marketplace, rather than on their overall costs. Resource net market values are used in the Preferred Resource Strategy (PRS) analyses. Understanding market conditions in the different geographic areas of the Western Interconnect is important, because regional markets are highly correlated because of large transmission linkages between load centers. This IRP builds on prior analytical work by maintaining the relationships between the various sub-markets within the Western Interconnect and the changing value of company-owned and contracted-for resources. The backbone of the analysis is AURORAxmp, an electric market model that dispatches resources to loads across the Western Interconnect with given fuel prices, hydro conditions, and transmission and resource constraints. The model's primary outputs are electricity prices at key market hubs (e.g., Mid-Columbia), resource dispatch costs and values and greenhouse gas emissions.

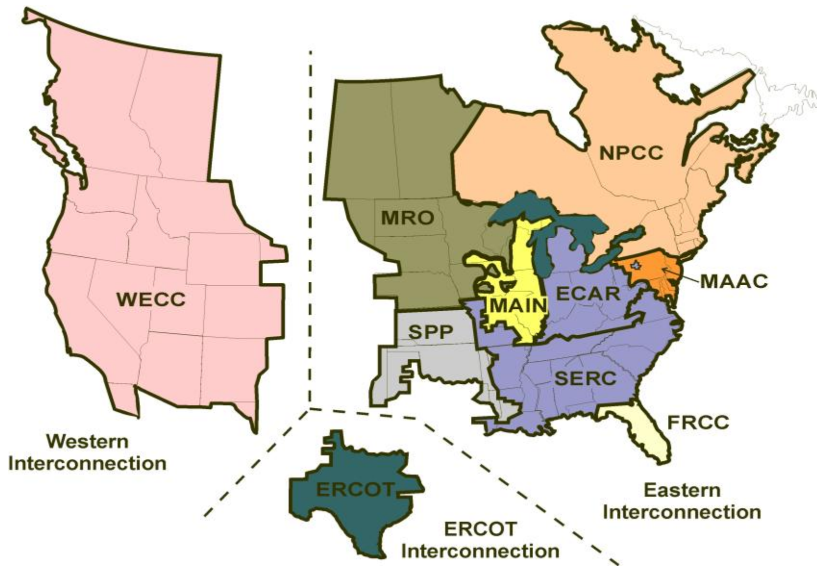
Section Highlights

- Mid-Columbia electric and Malin natural gas prices are 27 and 20 percent higher than the 2007 IRP, primarily due to carbon legislation impacts
- Mid-Columbia electric prices are expected to average $79.56 per megawatt-hour (levelized) over the next 20 years
- Average Malin natural gas prices are expected to be $7.36 per decatherm (levelized) over the next 20 years
- Gas-fired resources continue to serve most new loads and take the place of coal generation to reduce greenhouse gas emissions
- Future carbon credit prices will depend on reduction goals and the difference between natural gas and coal prices
- New environment-driven investment, combined with higher market prices will lead to higher retail rates
- Carbon legislation is expected to increase overall cost of fuel for electricity generation by $42.5 billion (16.3 percent); overall cost increase including capital and O&M is $25.7 billion.

Marketplace

AURORAxmp is a modeling tool used to simulate the Western Interconnect. The Western Interconnect includes the states west of the Rocky Mountains, the Canadian provinces of British Columbia and Alberta and the Baja region of Mexico as shown in Figure 7.1. The modeled area has an installed resource base of approximately 200,000 MW, and an average load of approximately half that level.

Figure 7.1: NERC Interconnection Map



The Western Interconnect is separated from the Eastern Interconnect and ERCOT systems except by eight inverter stations. The Western Interconnect follows operation and reliability guidelines administered by the Western Electricity Coordinating Council (WECC).

The Western Interconnect electric system is divided into 16 AURORAxmp modeling zones based on load concentrations and transmission constraints. After extensive study, Avista found that the Northwest is best modeled in the software as a single zone. The single zone more accurately dispatches resources relative to splitting the Northwest into multiple areas. The regional topology in this IRP therefore differs from the previous plan by reverting to a single zone.

Fundamentals-based electricity models range in their abilities to emulate power system operations. Some account for every bus and transmission line while others utilize regions or zones. An IRP requires regional price and plant dispatch information. The specific zones modeled are described in Table 7.1.

Table 7.1: AURORA^{XMP} Zones

Northwest- OR/WA/ID/MT	Southern Idaho
Eastern Montana	Wyoming
Northern California	Southern California
Central California	Arizona
Colorado	New Mexico
British Columbia	Alberta
North Nevada	South Nevada
Utah	Baja, Mexico

Western Interconnect Loads

A load forecast was developed for each area of the Western Interconnect. Avista relied on external sources to quantify load growth across the west. These sources included the integrated resource plans for Northwest utilities, and Wood Mackenzie for the remaining areas. Carbon legislation and associated price increases are expected to reduce loads over time from their present trajectory. Wood Mackenzie forecasts loads to be one percent lower in 2020 and 4.6 percent lower in 2026 compared to projected loads without carbon legislation.

Specific regional load growth levels are presented in Table 7.2. Overall Western Interconnect loads are forecast to rise by an average level of 1.6% over the next 20 years, from 106,727 aMW in 2010 to 146,579 aMW in 2029. A planning margin was added to the load forecast to account for unplanned events. Regional planning margins are assumed to be 25 percent in the winter in the Northwest, 17 percent for California, and 15 percent for all other zones. Higher Northwest planning margins are needed to account for hydroelectric variability. Additional details about planning margins may be found in the Loads and Resources chapter.

Table 7.2: 20 Year Annual Average Peak & Energy Load Growth Rates

Northwest Areas	Growth Rate	Other Areas	Growth Rate
Eastern Oregon	0.01%	California	1.51%
Eastern WA/North Idaho	1.39%	Baja, Mexico	1.51%
Northwest Washington	1.69%	Arizona	1.97%
Seattle Metro Area	1.69%	South Nevada	1.97%
Portland Metro Area	1.74%	North Nevada	2.18%
SW Washington	1.69%	New Mexico	1.83%
Western Oregon	0.01%	Colorado	1.48%
Central Washington	2.53%	Wyoming	3.59%
South Idaho	1.31%	Utah	1.91%
Western Montana	0.61%	Alberta	2.00%
British Columbia	1.26%	Eastern Montana	0.61%

Transmission

Several regional transmission projects have been announced in the last two years. Many of these projects will move renewable resources to load centers for Renewable Portfolio Standards (RPS) obligations. The AURORAxmp model was updated to reflect the transmission upgrades shown in Table 7.3. The transmission expansion represents the most likely upgrades from Avista's point of view at the time the price forecast was developed (Dec 2008). Transmission upgrades within AURORAxmp zones were not included in the model, as they do not impact power transactions between zones.

Table 7.3: Western Interconnect Transmission Upgrades Included in Analysis

Project	From	To	Year Available	Capacity MW
Canada – PNW Project	British Columbia	Northwest	2018	3,000
PNW –California Project	Northwest	California	2018	3,500
Eastern Nevada Intertie	North Nevada	South Nevada	2015	1,600
Colstrip Transmission	Montana	Northwest	2012	500
Gateway South	Utah	Nevada	2014	600
Gateway South	Wyoming	Utah	2015	3,000
Gateway Central	Idaho	Utah	2016	1,500
Sunzia/Navajo Transmission	Arizona	New Mexico	2013	3,000
Wyoming- Colorado Intertie	Wyoming	Colorado	2013	900
Gateway South	Wyoming	Utah	2015	3,000
Gateway West	Wyoming	Idaho	2016	3,000
Hemingway to Boardman	Idaho	Northwest	2015	1,500
Hemingway to Captain Jack	Idaho	Southern Oregon	2015	1,500
Total				**26,600**

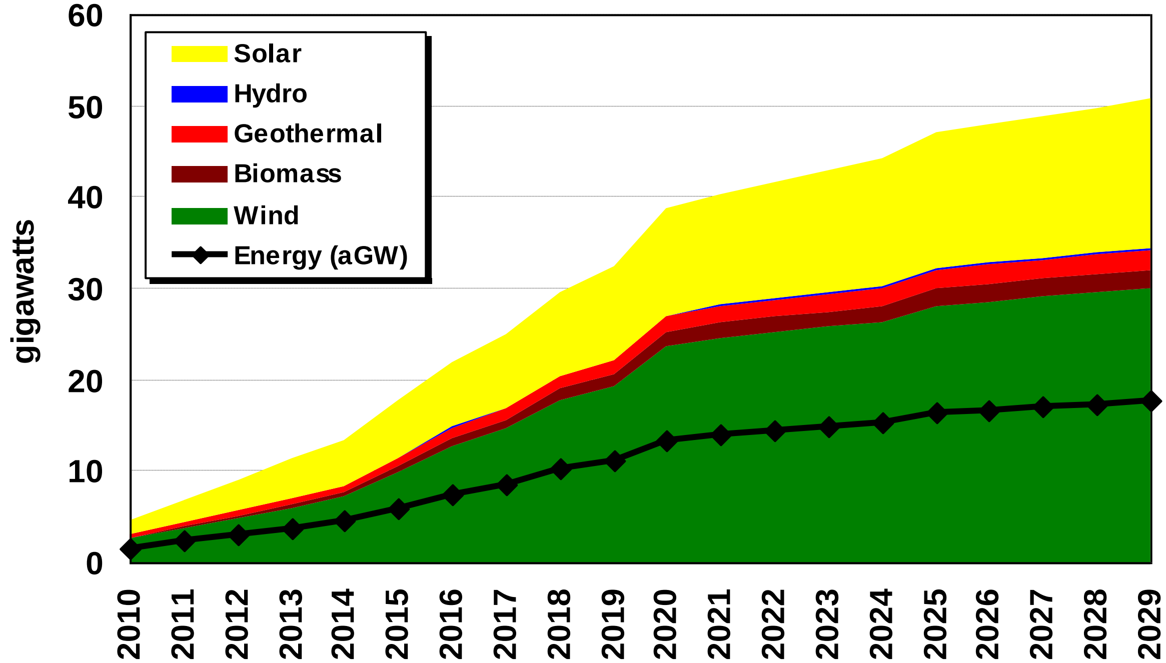
Regional Renewable Portfolio Standards

In an effort to curb greenhouse gas emissions, and to diversify energy sources, many states have created RPS requirements. RPS legislation requires utilities to meet a portion of their load with renewable resources. Each state defines their RPS obligations differently. AURORAxmp model does not have the ability to target RPS levels. RPS requirements therefore were input into the model to ensure that the renewable resource levels satisfy state laws.

Wind, the predominant renewable resource, does not add capacity to the electric system; and are not likely recover all of their life-cycle costs from the wholesale marketplace. Renewable resource portfolios to meet Western Interconnect RPS obligations were developed by the Northwest Power and Conservation Council (NPCC); these percentages were applied to the estimated RPS shortfalls in each state. California has the most aggressive RPS goal (33 percent by 2020). The 2009 IRP adopts the NPCC resource mix assumptions. Figure 7.2 illustrates projected renewable resource additions to the Western Interconnect. Renewable resources were manually added only to meet RPS requirements, not exceed it. AURORAxmp could have added additional renewable resources as part of its optimization routine, but it did not.

Figure 7.2 illustrates the difference between nameplate capacity and the delivered energy of the RPS additions. Most renewable energy requirements are met by wind followed by solar. Geothermal, biomass, and hydro resources fill the remaining RPS needs. The renewable resource choices are modeled to differ by state. The Southwest will meet requirements with solar and wind; the Northwest will use wind and hydro; and the Rocky Mountain states will predominately use wind to meet RPS needs.

Figure 7.2: Renewable Resource Additions to Meet RPS

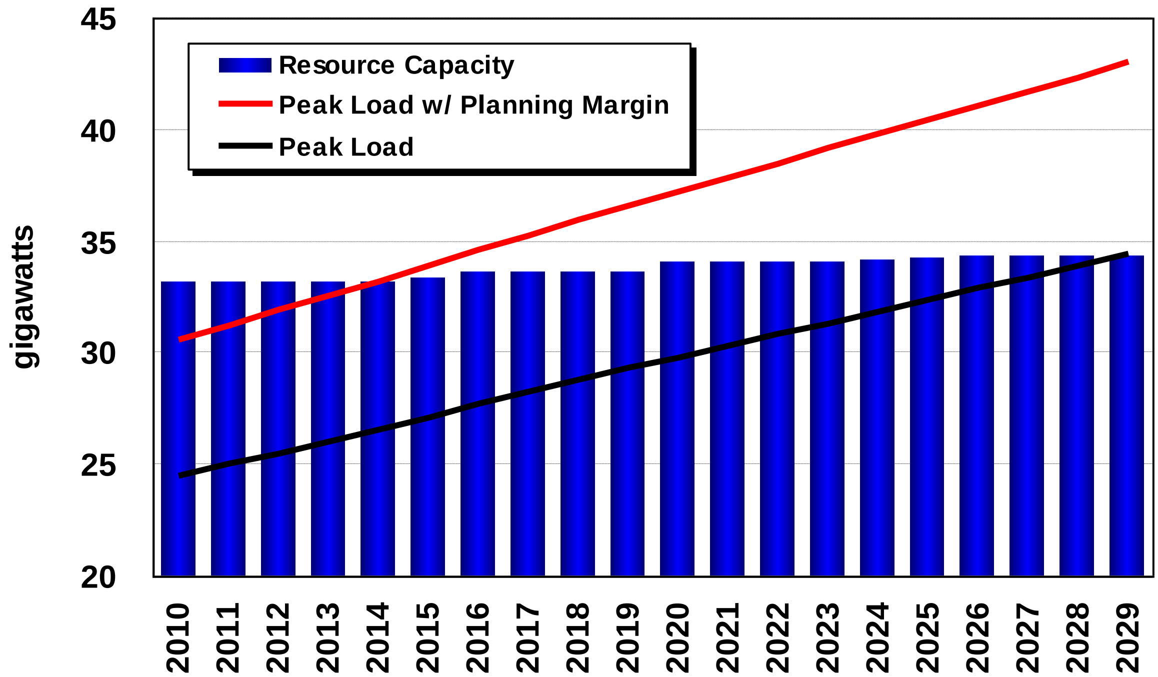


Resource Deficits

Assumptions are made on when, where, and how many of each new resource type will be added to the electric system to meet peak demand in order to forecast electric market prices. New renewable resources meet energy needs, but add a much smaller level of capacity to the system so that each megawatt of additional wind requires an additional resource to provide dependable capacity. In line with the NPCC assumptions, wind is assumed to provide five percent of its nameplate capacity to meet regional system capacity in the IRP price forecast analysis.

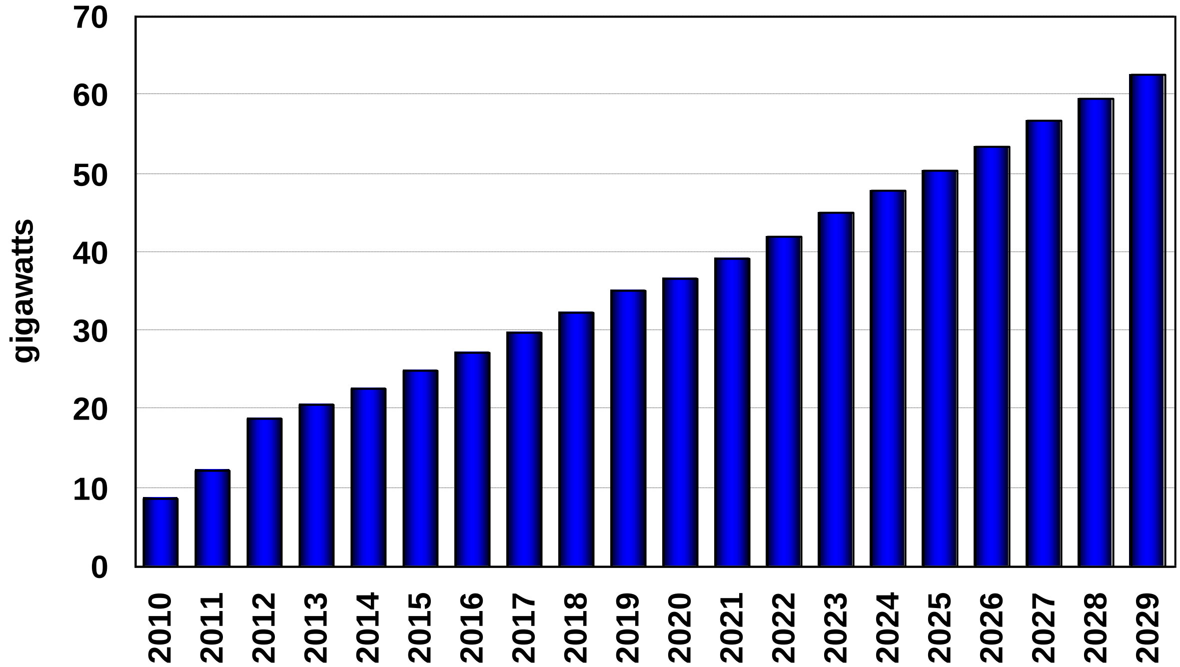
The Northwest historically has depended on hydro system flexibility to meet peak demand, but new wind regulation obligations, combined with increased fisheries obligations, have constrained the system. The hydro system can flex for a few hours during a cold day, but may not have the energy to meet a sustained cold or hot weather event lasting several days. AURORAxmp adds resources to meet one hour system peaks. To simulate a sustained peaking event, the amount of hydro available to meet system peaks was decreased to 68 percent. Figure 7.3 illustrates the Northwest resource shortfall. Blue bars represent the capacity contributions of hydro, thermal, and other resources. The black line represents the forecasted winter peak load, plus net firm transfers from outside the region (net load). The red line is the net load with a 25 percent planning margin. Based on these assumptions, the Northwest region is deficit beginning in 2015; individual utility needs may be prior to or after 2015. Avista's resource position was described in Chapter Two.

Figure 7.3: Northwest Peak Load/Resource Balance



Outside the Northwest, the resources and loads are more closely aligned, with deficits in some areas beginning in 2010. Figure 7.4 sums capacity deficits for the entire Western Interconnect; nearly 10 gigawatts of capacity are needed in 2010, 38 GW in 2020, and 62 GW in 2029.

Figure 7.4: Total Western Interconnect Capacity Deficits



New Resource Options

The resource deficits shown in Figure 7.4 must be met by resources with dependable capacity, including gas-fired CCCT or SCCT, coal IGCC, coal with carbon sequestration, solar, nuclear, and traditional pulverized coal plants. Table 7.4 shows resource options available to fill deficits in different regions.

Table 7.4: New Resources Available to Meet Resource Deficits

Region	CCCT/ SCCT	Wind	Solar	Nuclear	Pulv. Coal	IGCC Coal	IGCC Coal w/ CO_2 Seq.
Northwest	Unlimited	Tier 2	Unlimited	2022	n/a	n/a	2025
California	Unlimited	Tier 2	Unlimited	n/a	n/a	n/a	2025
Desert SW	Unlimited	Tier 2	Unlimited	2022	n/a	n/a	2025
Rocky Mountains	Unlimited	Tier 1	Unlimited	2022	n/a	2015	2025
Canada	Unlimited	Tier 1	Unlimited	2022	2015	2015	2025

Fuel Prices and Conditions

Some of the most important drivers of resource costs and values are fuel cost and availability. Some resources, including geothermal and biomass, have limited fuel options or sources, while coal and natural gas have more fuel sources. Hydro and wind use free fuel sources, but highly dependent on weather.

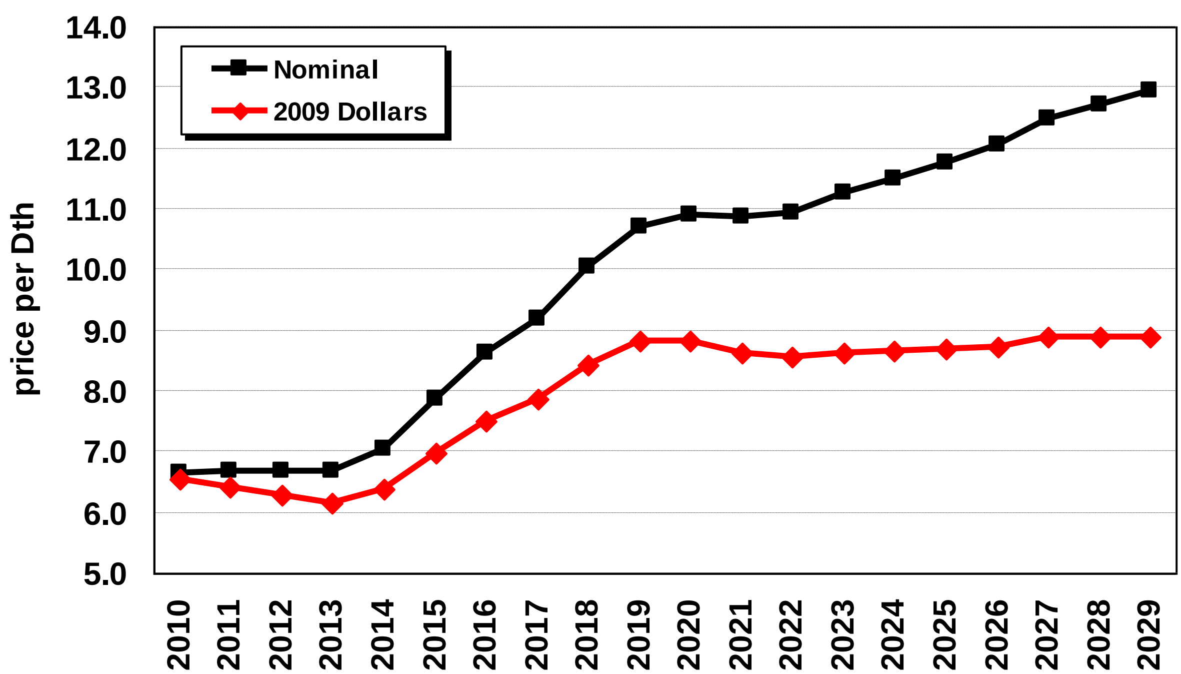
Natural Gas

The fuel of choice for new base load and peaking resources continues to be natural gas. The largest drawback to natural gas is its high price volatility. Avista used forward market prices and a combination of sources such as the Energy Information Administration (EIA), the New York Mercantile Exchange and Wood Mackenzie through 2011. Wood Mackenzie prices were used from 2013 through 2029. 2012 was the average of 2011 and 2013.

The natural gas prices forecast was completed in December 2008. It was adjusted for the expected impacts of carbon legislation. Such legislation will cause the demand for natural gas to increase as generation shifts from coal. For example, the increase is $0.50 in 2013 and $1.00 per year after 2018 (2009 dollars).

Economic recovery is expected to absorb excess productive capacity for natural gas and increase overall demand growth by 2014. Carbon legislation also will spur incremental demand for a multi-year cycle of gas-fired generation construction. This increased demand, combined with low investments in drilling in years prior, should push prices higher. The Frontier Gas Pipeline (1 bcfd) from Alberta to Chicago should also be operational by the end of the next decade. Figure 7.5 shows the price forecast for Henry Hub; the levelized nominal price is $9.05 per Dth, the real levelized cost is $7.67 per Dth.

Figure 7.5: Henry Hub Natural Gas Price Forecast



Prices differences across North America depend on demand at the various trading hubs and the pipeline constraints between them. Many pipeline projects have been announced in the Northwest and the west to access cheaper gas supplies located in the Rocky Mountains. Table 7.5 presents western gas basin differentials from Henry Hub, and the levelized price of gas at each basin. Prices converge over the course of the study as new pipelines are built and new sources of gas come online. To illustrate the seasonality of natural gas prices, the monthly Malin price shape is provided in Table 7.6 for various years of the forecast.

Table 7.5: Natural Gas Price Basin Differentials from Henry Hub (Nominal Dollars)

Basin	2010	2015	2020	2025	Nominal Levelized Cost	2009$ Levelized Costs
Henry Hub					$9.05	$7.67
Opal	-2.46	-0.61	-0.68	-0.58	$8.11	$6.88
San Juan	-0.26	-0.10	-0.08	0.39	$9.08	$7.70
Southern CA	-0.32	-0.15	-0.19	1.42	$9.11	$7.73
Malin	-0.51	-0.24	-0.32	-0.49	$8.64	$7.33
Sumas	-0.51	-0.20	-0.26	-0.36	$8.70	$7.38
AECO	-0.61	-0.31	-0.42	-0.67	$8.54	$7.24

Table 7.6: Monthly Price Differentials for Malin

Month	2010	2015	2020	2025
Jan	103.7%	99.8%	105.0%	106.9%
Feb	104.7%	104.9%	109.4%	107.6%
Mar	100.7%	103.7%	104.6%	101.8%
Apr	92.3%	90.6%	94.7%	93.4%
May	92.5%	94.2%	95.4%	94.1%
Jun	94.1%	93.6%	96.0%	94.8%
Jul	95.0%	96.4%	97.8%	95.9%
Aug	95.9%	97.1%	97.8%	96.4%
Sep	97.5%	97.7%	95.2%	97.4%
Oct	98.1%	98.8%	95.3%	97.6%
Nov	112.6%	111.0%	104.1%	106.7%
Dec	113.0%	112.0%	104.7%	107.4%

Coal

Coal transportation prices for existing facilities are based on estimates in the AURORAxmp database. For new projects coal mine costs are based on data provided by the EIA for Wyoming mine-mouth coal. Transportation costs were added based on an assumed transportation rates and each existing or proposed plant’s distance from the coal supply source. The IRP includes three representative coal plant delivery locations for all new plants: mine mouth, short haul (250 miles) and long haul (1,000 miles). Coal details are located in Table 7.7.

Table 7.7: Western Interconnect Coal Prices (2009$)

Coal type	$/MMBtu	$/short ton
Mine mouth	$0.73	$12.41
Short haul	$1.26	$21.34
Long haul	$2.83	$48.11

Wood/Hog Fuel

Avista has operated the Kettle Falls wood-fired generator for 25 years. When Kettle Falls was constructed, hog fuel was a waste product from area sawmills at near-zero cost. The future price and availability of hog fuel are critical to understanding the viability of new wood-fired facilities. The hog fuel costs for new plants are forecasted for two locations. The first is fuel in Avista's service territory, forecast at $30 per ton or $3.30 per MMBtu in real 2009 dollars. The second fuel forecast is for the Boardman, Oregon area for the Coyote Spring 2 wood addition, where the price is estimated to be $60 per ton or $6.60 per MMBtu (2009$). Hog fuel availability is highly dependent on overall lumber demand. The Kettle Falls plant had surplus fuel in the mid-2000s, but the plant has struggled to find enough fuel over the past two years.

Hydro

The Northwest and British Columbia have substantial hydroelectric generation capacity. A favorable characteristic of hydro power is its ability to provide short periods of near-instantaneous generation. This characteristic is particularly valuable for meeting peak load demands, following general intra-day load trends, shaping energy for sale during higher-valued peak hours, and integrating wind generation. The key drawback to hydroelectricity is its lack of predictable energy on a year-to-year or seasonal basis. Hydroelectricity is constrained by weather patterns and subsequent stream flows. The amount of energy available at a particular plant depends on river system characteristics.

The IRP uses the Northwest Power Pool's (NWPP) 2007-08 Headwater Benefit Study to model regional hydro availability. The NWPP study provides energy levels for each hydroelectric plant by month from 1928 to 1999. British Columbia plants are modeled using data from the Canadian government.

Many of the analyses in this IRP use an average of the 70-year hydroelectric record; whereas stochastic studies randomly draw from the 70-year record (see Risk Analysis later in this section). Hydroelectric plants are divided into geographic regions and represented as a single plant in each zone. The Company models its own projects individually to provide greater detail about its resources. Table 7.8 shows average assumed hydro capacity factors for the Northwest hydroelectric plants.

Table 7.8: Northwest Hydro Capacity Factors

Area	Annual Avg Capacity Factor
Eastern Oregon	42%
Eastern WA/North Idaho	43%
Northwest Washington	40%
Portland Metro Area	41%
SW Washington	38%
Western Oregon	31%
Central Washington	46%
South Idaho	44%
Western Montana	42%
British Columbia	64%

AURORAxmp represents hydroelectric plants using annual and monthly capacity factors, minimum and maximum generation levels, and sustained peaking generation capabilities. The model's objective, subject to constraints, is to move hydroelectric generation into peak hours to follow daily load changes; this maximizes the value of the system consistent with actual operations.

Wind and Solar

As additional wind and solar capacity is added to the electric system to satisfy renewable portfolio standards, there will be significant competition for higher quality wind and solar sites. The capacity factors in Table 7.9 present average generation for the entire area, not specific projects. The Rocky Mountain area is the best location for wind generation; the desert Southwest is best for solar generation.

Table 7.9: Western Interconnect Wind Capacity Factors

Area	Wind CF (%)	Solar CF (%)	Area	Wind CF (%)	Solar CF (%)
Montana	37.36	19.63	Colorado	34.32	25.23
Canada	36.29	16.82	New Mexico	33.09	25.23
Wyoming	36.13	19.63	South Nevada	33.05	28.04
South Idaho	34.91	22.43	Northwest	32.77	19.63
Utah	34.85	22.43	South California	31.20	25.23
Arizona	32.39	25.23	North California	28.97	19.63
North Nevada	34.56	22.43	Baja, Mexico	31.20	28.04

Greenhouse (CO_2) Emissions

Greenhouse gas legislation is one the greatest fundamental risks facing the electricity marketplace today. Reducing carbon dioxide emissions from power plants will change the current resource mix over time as society moves away from traditional resources and shifts to an increased reliance on renewable resources. There is currently no federal regulation of carbon emissions, but legislation is expected to pass in the next few years. In the interim, several western states and provinces are promoting the Western Climate Initiative to develop a multi-jurisdictional greenhouse gas reduction program. Whether or not a federal system will ultimately supersede these efforts is not known.

The Wood Mackenzie carbon price forecast was used in the IRP. Wood Mackenzie considered this forecast as it developed its other commodity price forecasts. Carbon prices ultimately will depend on the greenhouse gas reduction goals, the supply and cost of allowances and offsets, and the price of natural gas. The only way to greatly reduce carbon emissions is to price carbon at a level high enough to greatly reduce the dispatch of coal-fired plants.

Wood Mackenzie based its carbon price forecast on November 2008 legislation sponsored by Representatives Dingell and Boucher. Their macro-economic models were balanced by identifying a carbon price forecast adequate to meet federal emission goals. The analysis included new nuclear and carbon sequestration resources to meet future load growth in the 2020’s. Figure 7.6 shows the carbon price forecast. The IRP assumes carbon will have a cost starting in 2012. The price trajectory increases greatly starting in 2018 when the next major step in carbon reduction goals begins. The levelized cost of carbon is $46.14 (nominal) and $33.37 (2009 dollars). When natural gas prices rise or fall, the cost of carbon is expected to change to balance the relative competitiveness of gas and coal.

The only way to reduce carbon emissions from existing levels under a cap-and-trade model is to increase carbon prices to a level making the marginal cost of a coal plant higher than a natural gas-fired resource. For example, a natural gas plant facing a $7.50 per Dth natural gas price will require a the carbon price of approximately $60 per short ton to make its dispatch attractive relative to that of a coal plant with $1.00 per MMBtu fuel. Figure 7.7 illustrates carbon price levels that would be necessary at various natural gas and coal prices to allow natural gas generation to displace coal. The crossover point between the “dashed” coal marginal costs and the “solid” natural gas marginal cost represent the price of carbon for each resource to be equal for dispatch designs.

Figure 7.6: Price of Carbon Dioxide Credits

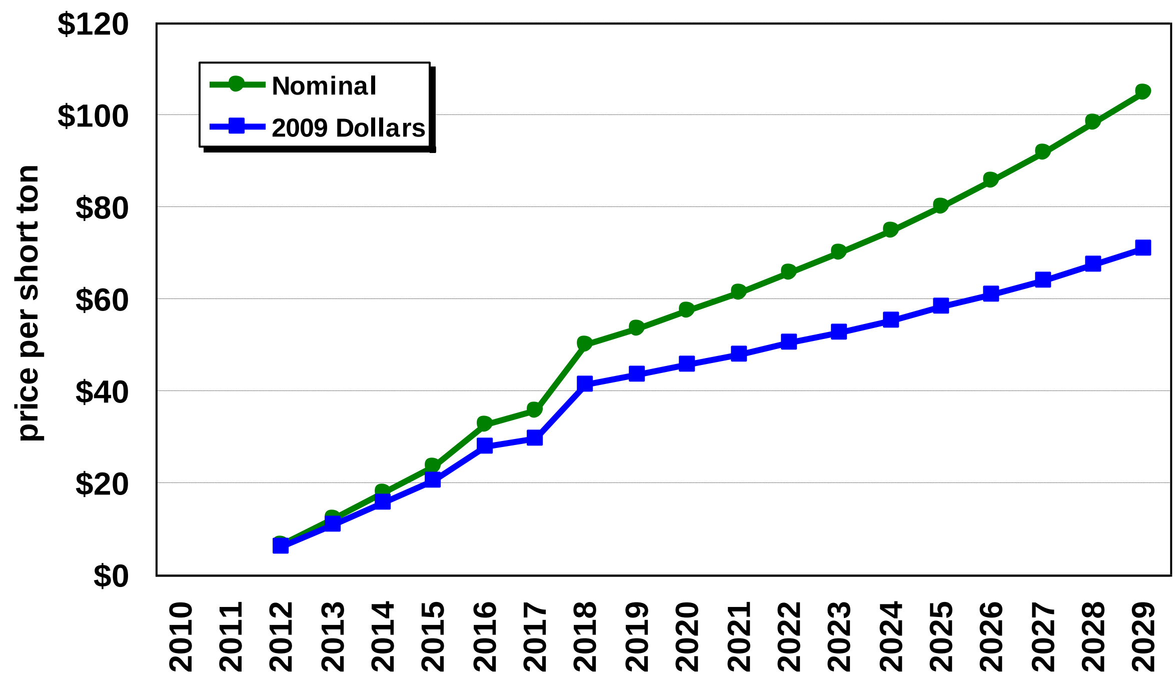
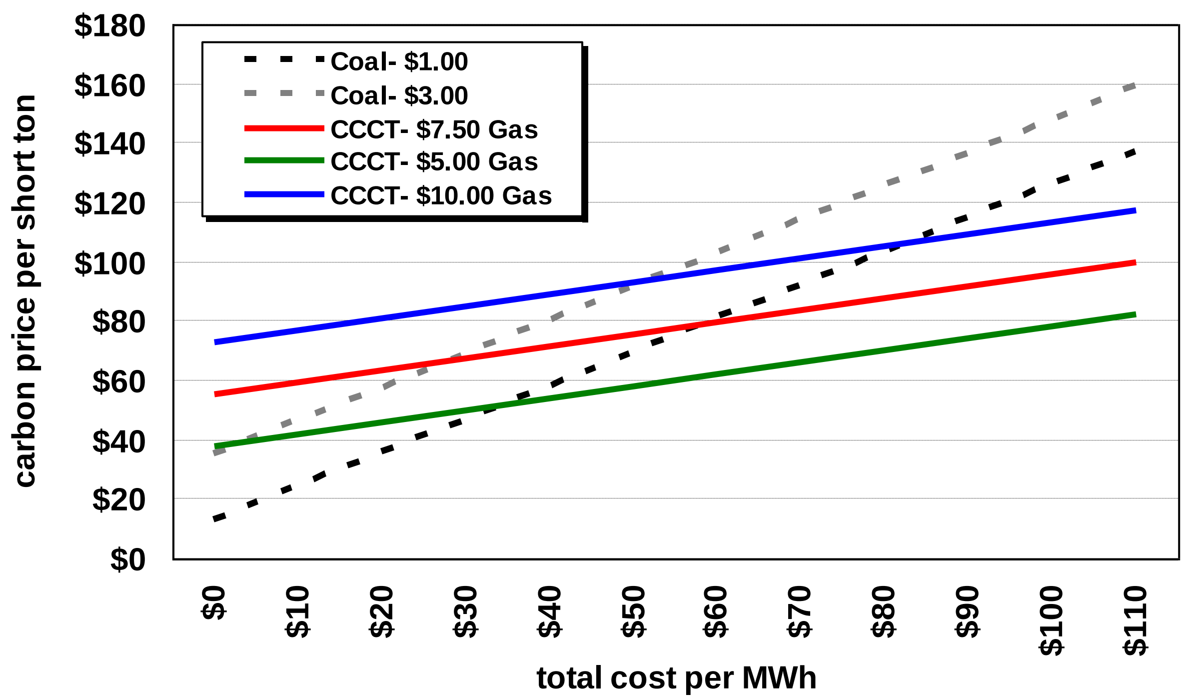


Figure 7.7: Cost of Carbon Dioxide Credits



Risk Analysis

Base assumptions in this chapter were modeled stochastically to account for the fact that we do not know what future conditions actually will be. All base case assumptions discussed earlier in this chapter represent the expected values, not their expected ranges over time. Some market drivers are correlated. For example, higher natural gas prices will likely require higher carbon prices to ensure that carbon reduction goals are met. The increased costs will cause a subsequent load decrease and affect other fuel prices (e.g., hog fuel price might increase as generators chose to burn more of this fuel to avoid higher carbon prices). Table 7.10 illustrates the correlations between variables in the IRP. The relationships between variables were developed to show expected levels of cause and effect, not on the results of statistical analysis. In other words, market data does not exist for many of these relationships; therefore, Avista made the assumptions shown in Table 7.10.

Table 7.10: Stochastic Study Correlation Matrix

	Natural Gas Prices	GHG Prices	New Coal Prices	Hog Fuel Prices	Load Growth
Gas Prices	1				
GHG Prices	0.50	1			
New Coal Prices		-0.25	1		
Hog Fuel Prices	0.50	0.50		1	
Load Growth	-0.25	-0.25		-0.5	1

Wind, hydro and forced outages are not necessarily correlated to other market drivers. The stochastic study portion of the IRP includes 250 combinations of these variables; 500 combinations were studied, but no difference in the mean and standard deviation of the results was found.

Greenhouse (GHG) Prices

Without established federal legislation and no formal rules for western carbon markets, the expected price of GHG is difficult to determine without macroeconomic models capably of determining financial impacts outside of the electric industry. Even with rules in place, carbon prices will be determined based on the tradeoff and interaction between natural gas and coal prices. The lack of certainty means that a range of potential prices needs to be modeled. This IRP utilized ten EPA scenarios as possible legislative outcomes. The EPA scenarios were developed for the Lieberman-Warner bill, the leading federal greenhouse gas legislation at the time the modeling for this IRP was developed. Each scenario was given a weight out of 100 percent (see Table 7.11) by members of Avista's Climate Change Committee. For the scholastic price forecast, the assigned weight will be the probability of a certain base price level.

Table 7.11: EPA Carbon Study (Nominal Price per Short/Ton)

Study	Weight	2012	2020	2025
ADAGE	10%	28.60	50.89	72.40
IGEM	3%	40.50	70.15	98.04
ADAGE - Low Intl Action	15%	26.20	48.14	66.36
IGEM Unlimited Offsets	10%	8.70	20.63	28.66
IGEM with No Offsets	2%	80.80	134.79	190.04
ADAGE Scenario 6	3%	39.70	67.39	95.02
ADAGE Scenario 7	2%	57.20	94.90	132.73
Alt. Ref. ADAGE	35%	21.00	38.51	54.30
Alt. Ref. IGEM	5%	35.00	61.89	85.97
1766 ADAGE	15%	10.20	20.63	28.66
Weighted Average	**100%**	**23.46**	**42.76**	**59.91**

The EPA and Wood Mackenzie studies differ in many aspects, but the major difference between the two is their assumed natural gas price forecasts. To adjust for these differences, 10 price scenarios were developed for the stochastic portion of the IRP. See Table 7.12 for the 10 base carbon scenarios modeled for this IRP.

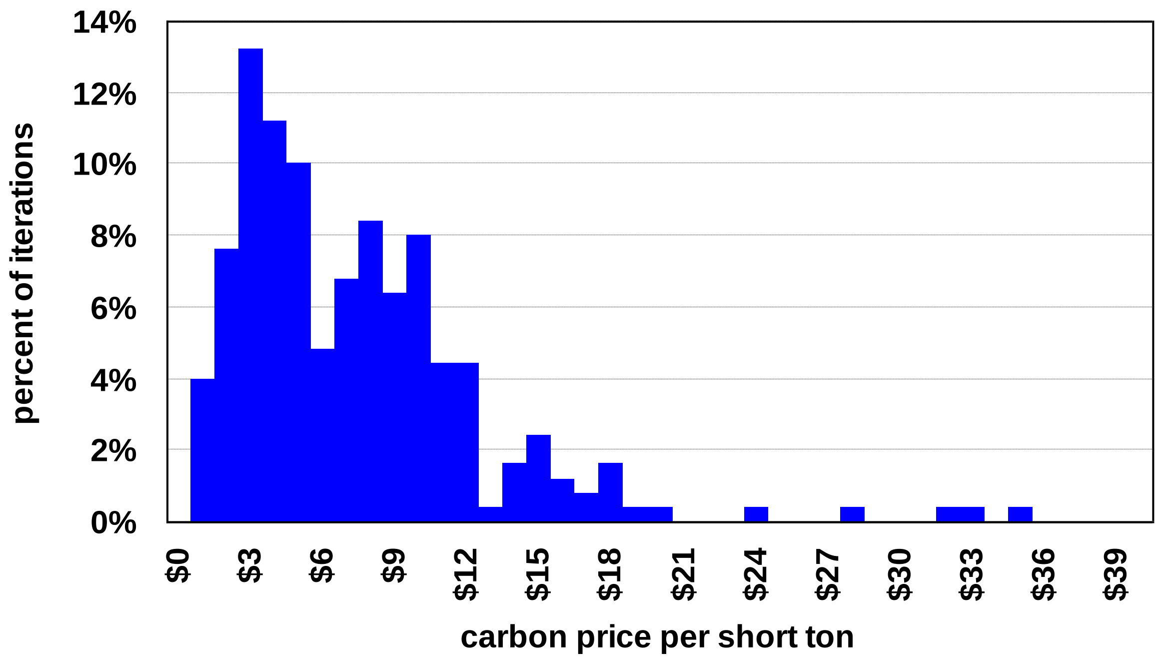
Table 7.12: Ten Cost Scenarios Based on Wood Mackenzie and EPA Studies (Nominal Price per Short Ton)

Scenario	Weight	2012	2020	2025
1	10%	8.01	68.28	96.89
2	3%	11.31	94.12	131.21
3	15%	7.32	64.59	88.82
4	10%	2.42	27.68	38.35
5	2%	22.56	180.86	254.34
6	3%	11.09	90.43	127.17
7	2%	15.97	127.34	177.63
8	35%	5.86	51.67	72.67
9	5%	9.77	83.05	115.06
10	15%	2.85	27.68	38.35
Weighted Average	100%	6.55	57.37	80.18

The carbon price is determined in a two-step process. The first step draws the carbon price regime; the second adjusts natural gas prices and other variables. The adjustment keeps prices correlated, so the market effect is consistent. See Figure 7.8 for the carbon price distribution for the 250 iterations in 2012. Carbon prices range from $1 to $35 per short ton, with an average of $6.55 per short ton. The standard deviation of carbon price in 2012 to 50 percent, 25 percent in 2014, and 10 percent in 2016 through the end of the IRP study to reflect a market that stabilizes over time.

The correlation between carbon and natural gas is likely to be high because gas-fired resources set the marginal price of electricity in most markets. A 50-percent correlation between carbon and natural gas is used for this IRP. A 90-percent correlation scenario found no material impact on the results. The method for obtaining carbon prices and its correlation to other market drivers will be an ongoing IRP process task.

Figure 7.8: Distribution of Annual Average Carbon Prices for 2012



Natural Gas

Natural gas prices are highly volatile. Daily prices at AECO were as high as $12.92 and as low as $0.78 per Dth between 2002 and 2009. To represent future natural gas price uncertainty, volatility is modeled to increase over the study horizon. The standard deviation is set to 35 percent in 2012, 40 percent in 2015, 45 percent in 2020, and 50 percent in 2025 in a lognormal distribution. Prices ultimately will be determined by the development and timing of new gas supplies and changes in demand. The IRP risk analysis is an attempt to capture the range of potential outcomes in this uncertain future. The 2012 distribution for average prices is in Figure 7.9. Mean prices in 2012 are expected to be $6.76 per Dth and the median level is $6.24 per Dth. The lognormal distribution skews prices upward. The 95 percent confidence level is $11.56 per Dth and the TailVar90, or average of the highest 10 percent of the iterations, is $12.37 per Dth.

Figure 7.10 illustrates the range of gas prices. The gas prices discussed earlier in this section are shown as white diamonds. The red lines represent the median values from the stochastic draws; the bars represent the 80 percent confident interval band. The triangles are the 95 percent confidence level prices. The range of prices increases as time goes on, consistent with the standard deviation assumptions discussed above.

Figure 7.9: Distribution of Annual Average Natural Gas Prices for 2012

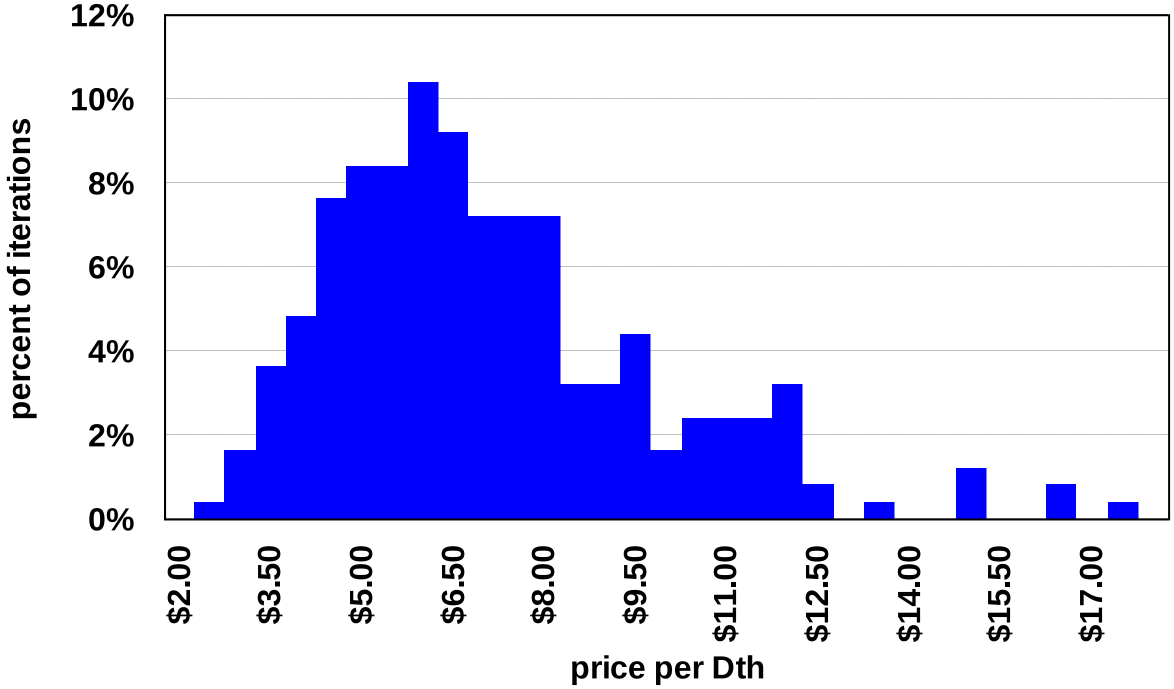
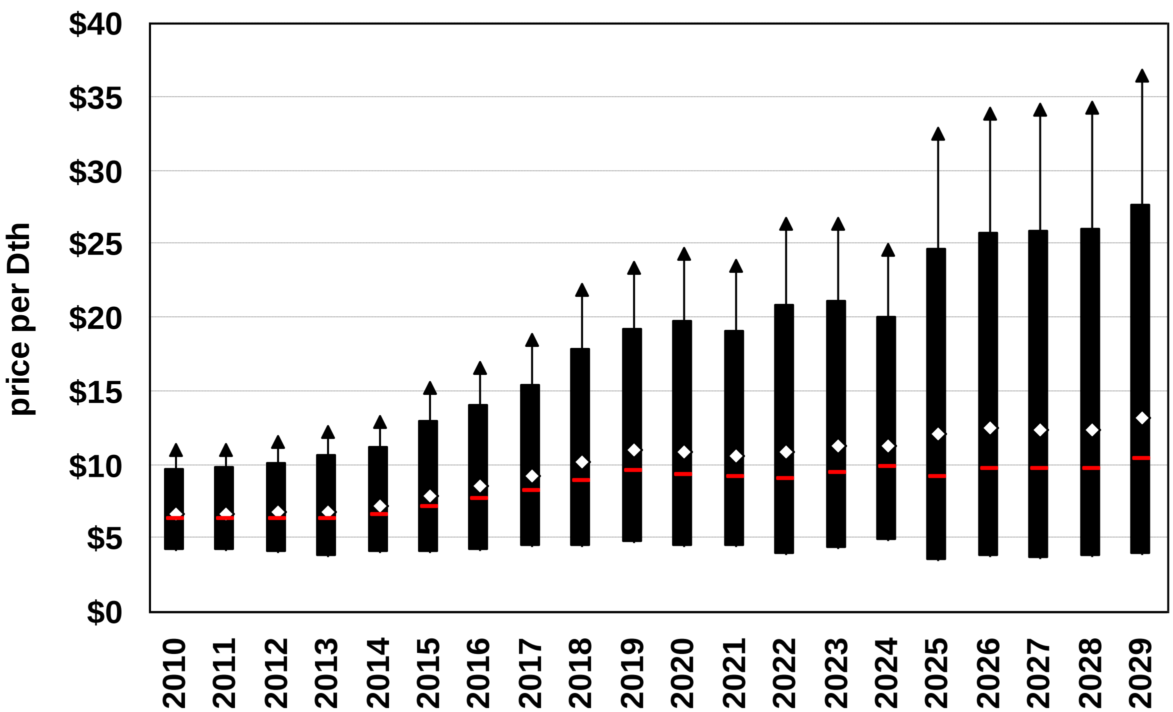
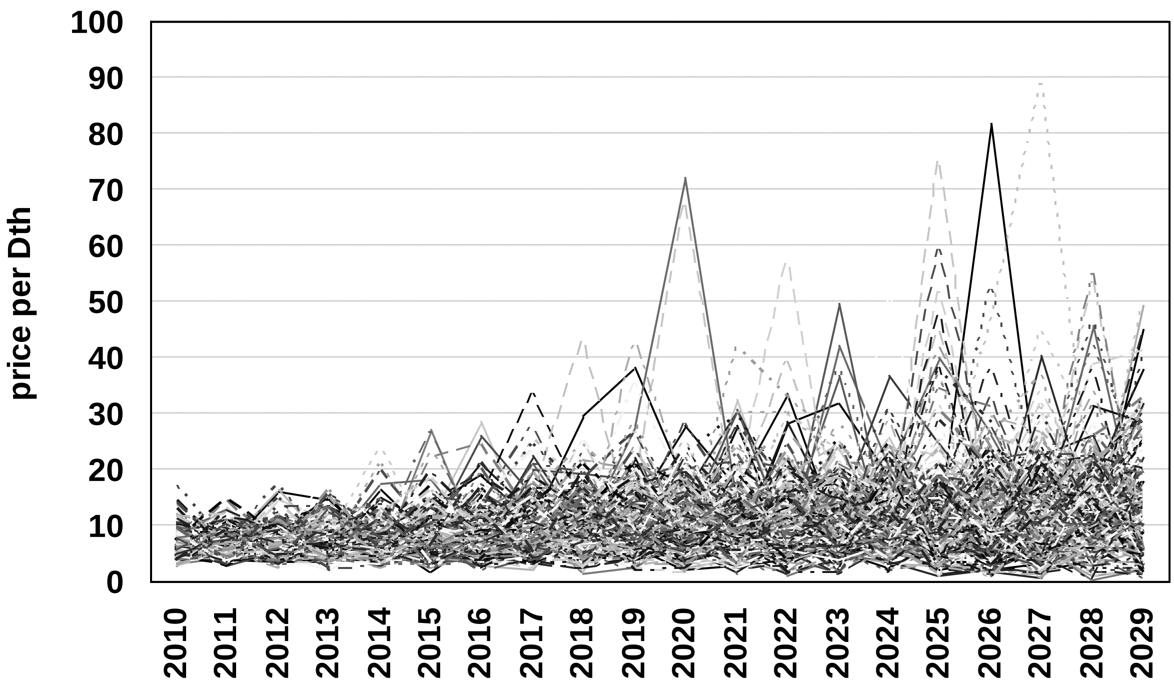


Figure 7.10: Henry Hub Natural Gas Distributions



High carbon prices generally lead to higher natural gas prices due to the 50 percent assumed correlation between the two. In the 2025 to 2029 time period, extremely high carbon and natural gas prices are possible due to the vast uncertainty of future price levels. In past IRPs the year-to-year prices of a draw were correlated, but Avista no longer believes there is enough statistical evidence to support this assumption. As shown in Figure 7.11 shows the randomness of annual prices from one year to the next.

Figure 7.11: Random Draws from the Henry Hub Price Distribution



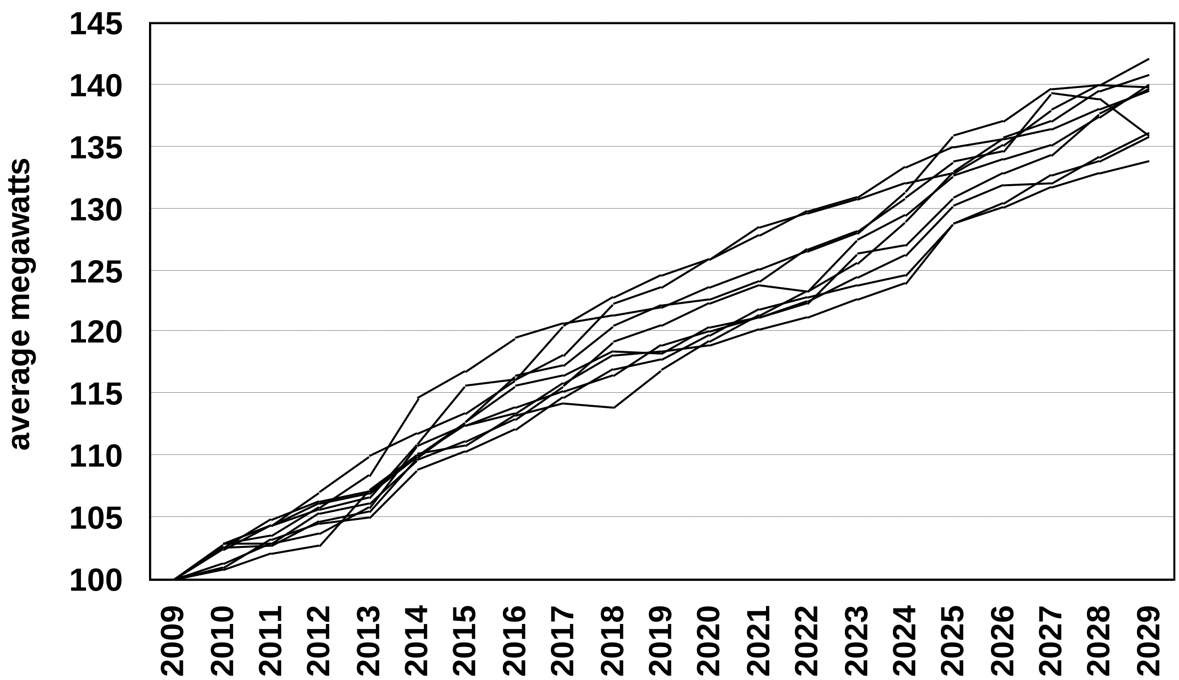
Load

Load has several drivers causing its uncertainty. The common driver is weather because extreme variations can move loads up or down compared to overall expected levels. The recent economic downturn has decreased electric demand relative to the long-term average, while earlier economic expansions increased loads relative to the average. Loads are modeled to increase at the levels discussed earlier in the chapter, but this risk analysis includes varying economic and weather conditions. The economic adjustment is inversely correlated to natural gas and carbon prices using a lag function, meaning if carbon prices were high last year, then the probability of lower loads is likely this year (25 percent probability) due to price elasticity responses.

The standard deviation for load growth is estimated at 50 percent. If a load area was forecast to have a 2 percent average annual load growth rate, the load in any given year would be between one and three percent at one standard deviation; two-thirds of all random draws should fall within this range. Figure 7.12 illustrates the annual load growth trajectory for the Western Interconnect in 10 selected iterations.

The Western Interconnect has many diverse areas and economies. The long-term load-growth correlation between each area is assumed to be 20 percent. The low correlation means each area within the Western Interconnect acts in a relatively independent manner. As with many of the risk assumptions, the Company will continue to assess the proper correlations and variation for major drivers of the electricity market. A study of historical weather adjusted load growth will be examined for Western Interconnect areas for the next IRP.

Figure 7.12: Random Draws Load Forecast with Year 2009 at 100



The method Avista adopted for its 2003 IRP is used to reflect weather patterns across the Western Interconnect. FERC Form 714 data was collected for the years 2002-07. Correlations between Northwest and other Western Interconnect load areas were calculated and represented as stochastic weather adjustments to the load model. Correlating area loads avoids oversimplifying the Western Interconnect load picture. Absent correlations, stochastic models would offset load changes in one zone with load changes in another, thereby virtually eliminating the possibility of modeling the West-wide load excursions we witness in today's marketplace. Given the high degree of interdependency across the Western Interconnect (e.g., the Northwest and California), this additional accuracy is crucial for understanding variation in wholesale electricity market prices and the value of resources used to meet such variation (i.e., peaking generation). For example, without regional correlation the volatility would be measured, but would not take into account the affect to loads of heat waves or cold snaps.

Tables 7.13 and 7.14 illustrate the correlations used in the IRP. The correlation statistics are relative to the Northwest load area (Oregon, Washington, and North Idaho).

"NotSig" indicates no statistically valid correlation was found in the evaluated data. "Mix" indicates the relationship was not consistent across time and was not used in this analysis. Tables 7.15 and 7.16 provide the coefficient of determination (standard deviation divided by the average) values for each zone. The weather adjustments are fairly consistent for each area, except for shoulder months where loads diverge from one another.

Table 7.13: January through June Area Correlations

	Jan	Feb	Mar	Apr	May	Jun
Alberta	0.674	0.631	0.494	0.679	0.593	0.771
Avista	0.934	0.886	0.848	0.706	0.819	0.691
Arizona	0.236	0.162	0.077	Mix	Not Sig	0.312
Baja	0.530	0.584	Mix	0.076	Mix	0.692
British Columbia	0.753	0.765	0.763	0.693	0.552	0.552
Colorado	0.653	0.425	Not Sig	0.402	0.493	0.503
Idaho South	0.847	0.743	0.797	0.075	0.237	0.585
Montana	0.831	0.836	0.655	0.338	0.533	0.726
New Mexico	0.570	0.413	0.349	0.469	0.737	0.622
Nevada North	0.690	0.725	0.658	0.683	0.685	0.830
Nevada South	0.785	0.779	0.075	Mix	0.242	0.726
California South	0.499	0.334	Mix	Mix	Not Sig	0.164
Utah	0.482	Not Sig	0.259	Mix	0.077	0.425
Wyoming	0.486	Not Sig	0.167	Mix	Not Sig	0.386
California North	0.750	0.728	0.603	Mix	0.327	0.543

Table 7.14: July through December Area Correlations

	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	0.767	0.777	0.821	0.733	0.673	0.786
Avista	0.909	0.776	0.594	0.873	0.909	0.878
Arizona	0.368	Not Sig	Mix	Mix	Not Sig	Not Sig
Baja	0.689	0.757	Mix	Mix	0.072	0.456
British Columbia	0.677	Mix	0.247	0.666	0.743	0.732
Colorado	0.505	0.686	0.663	0.672	0.694	0.774
Idaho South	0.747	0.760	Mix	0.426	0.873	0.870
Montana	0.782	0.673	0.635	0.775	0.882	0.833
New Mexico	0.596	Mix	0.664	0.525	0.420	0.689
Nevada North	0.780	0.818	0.626	0.447	0.756	0.793
Nevada South	0.689	0.608	0.418	Mix	0.543	0.821
California South	0.487	0.249	Mix	Mix	Not Sig	Mix
Utah	0.400	Mix	0.243	0.161	0.076	Not Sig
Wyoming	0.240	Mix	Mix	Mix	0.072	Not Sig
California North	0.707	0.503	Mix	Mix	0.560	0.764

Table 7.15: Area Load Coefficient of Determination (Std Dev/Mean)

	Jan	Feb	Mar	Apr	May	Jun
Alberta	2.8%	2.4%	3.0%	2.9%	2.7%	3.6%
Arizona	5.8%	4.7%	4.3%	6.4%	11.0%	7.6%
Avista	6.7%	5.8%	6.3%	5.4%	5.5%	6.9%
Baja	9.5%	7.9%	8.5%	9.2%	10.5%	7.6%
British Columbia	5.4%	3.8%	5.0%	4.9%	4.3%	4.1%
California North	5.3%	5.5%	5.4%	6.0%	8.6%	9.4%
Colorado	5.2%	5.4%	5.5%	5.2%	6.6%	7.6%
Idaho South	5.2%	5.9%	6.8%	6.0%	10.3%	10.9%
Montana	5.0%	4.7%	4.7%	4.5%	4.7%	5.8%
Nevada North	2.8%	2.8%	3.2%	3.3%	4.9%	5.0%
Nevada South	4.2%	3.7%	3.8%	6.6%	13.8%	9.2%
New Mexico	4.6%	4.4%	4.3%	4.6%	6.8%	5.9%
Oregon Washington Idaho	7.0%	5.6%	6.3%	5.4%	5.0%	5.1%
Southern California	6.7%	6.4%	6.6%	7.4%	9.0%	8.1%
Utah	4.9%	5.3%	5.3%	5.0%	6.7%	8.1%
Wyoming	5.0%	5.4%	5.3%	5.0%	6.5%	8.2%

Table 7.16: Area Load Coefficient of Determination (Std Dev/Mean)

	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	3.5%	3.2%	2.7%	2.9%	2.5%	3.0%
Arizona	7.3%	7.1%	10.5%	10.4%	4.9%	6.1%
Avista	7.8%	6.8%	5.7%	5.9%	6.7%	5.7%
Baja	6.4%	6.3%	11.6%	9.9%	7.6%	10.2%
British Columbia	4.8%	4.4%	4.4%	5.2%	5.9%	4.6%
California North	9.5%	8.0%	9.0%	6.0%	5.9%	5.8%
Colorado	7.2%	7.3%	7.3%	5.2%	5.5%	5.6%
Idaho South	6.2%	6.9%	9.8%	4.5%	6.6%	6.1%
Montana	5.9%	5.4%	4.2%	4.5%	5.4%	4.4%
Nevada North	5.0%	4.4%	5.0%	2.9%	3.4%	3.5%
Nevada South	7.1%	7.2%	12.7%	8.5%	4.0%	4.3%
New Mexico	5.9%	5.4%	5.8%	5.3%	5.0%	5.2%
Oregon Washington Idaho	6.3%	5.1%	4.8%	5.7%	7.0%	5.8%
Southern California	8.8%	8.0%	10.4%	7.6%	7.4%	6.8%
Utah	5.7%	5.6%	7.2%	4.5%	5.4%	5.4%
Wyoming	5.8%	5.6%	7.0%	4.5%	5.4%	5.5%

Coal Prices

Coal prices are not modeled stochastically for existing plants. Coal prices are typically contractually based for long time periods. As coal project contracts expire and the plants begin to rely on new fuel sources, prices change with coal supply and demand and transportation. Coal prices were modeled stochastically using a 10 percent standard deviation for new coal projects options considered in Avista's PRS Analysis. Prices are inversely correlated to carbon, as higher carbon prices are expected to decrease coal demand. It is possible that increased international demand for U.S. domestic coal will cause prices to increase. Lower coal demand could reduce the number of suppliers, causing prices to increase. Transportation costs increases arising from factors besides carbon reduction also could increase the cost of coal.

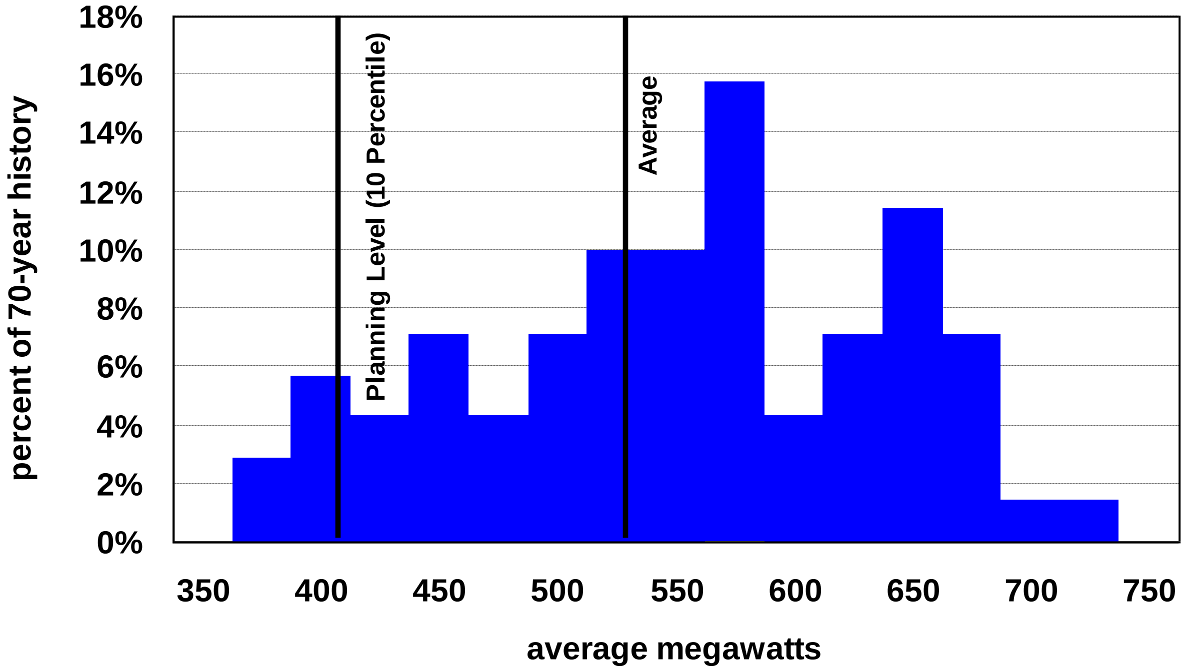
Wood/Hog Fuel

The price of wood, or hog fuel, is modeled stochastically for new resource options available to the PRS. Avista's experience with woody biomass generation indicates consistent price increases for a fuel that used to be free. The price and availability of hog fuel varies with the economy. The IRP stochastic analysis assumes a standard deviation of 10 percent. Further demand for wood residues will increase with aggressive greenhouse gas and renewable portfolio standard legislation. Environmental concerns will encourage more woody-biomass generation or co-firing with wood pellets. The correlation between wood and carbon prices is therefore assumed to be 50 percent. Hog fuel is also correlated 50 percent to natural gas prices because most commercial wood residue is displacing natural gas.

Hydro

The hydro risk analysis uses the 70-year record (1928 to 1999) from the 2008-09 Headwater Benefits Study completed by Northwest Power Pool. Each water year is drawn randomly for each iteration of the stochastic analysis. Hydro is not correlated to any other variable in this study. Some preliminary studies indicated that there might be modest correlation between hydroelectric and wind generation over a calendar year or certain seasons. However, Avista is not aware of any comprehensive study of correlation between the two resources. This relationship will be studied as more wind data becomes available. Figure 7.13 shows the distribution of annual hydro capacity factors for Avista's hydro fleet over the 70-year record. Expected hydro output is 538 aMW and median output is 543 aMW.

Figure 7.13: Distribution of Avista's Hydro Generation



Wind

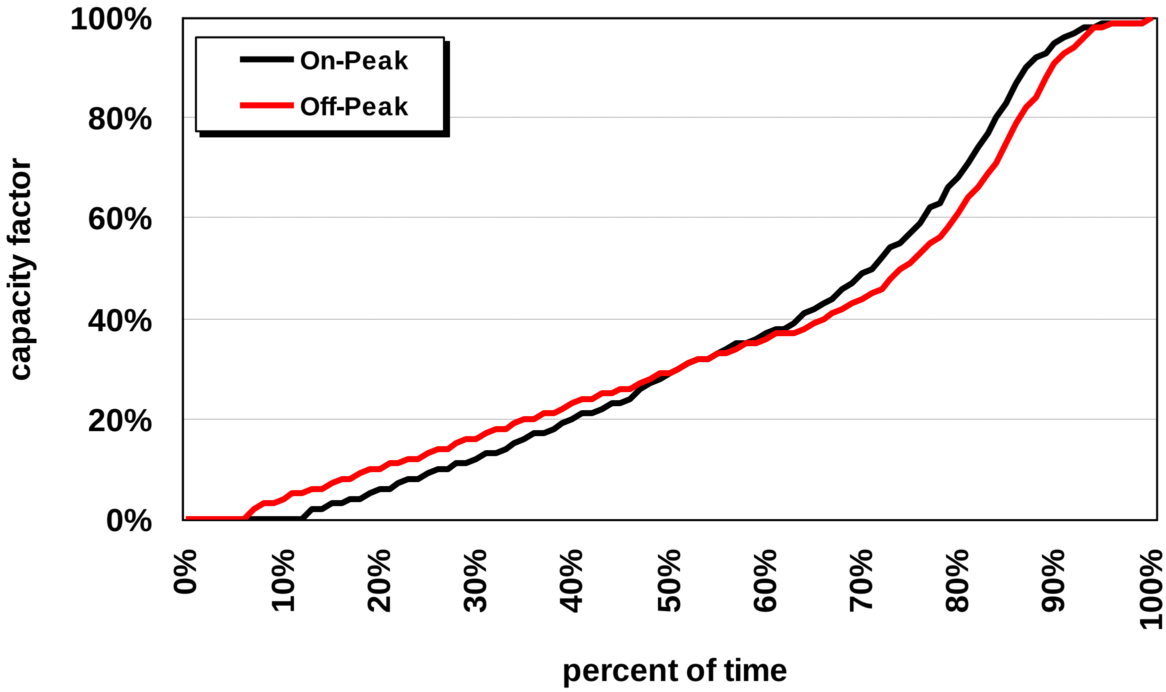
Wind is one of the most volatile generating resources available to utilities. Storage, apart from some integration with hydro, is not a financially viable option based on currently available technologies. This makes it necessary to capture wind volatility in the power supply model to determine its impacts on the overall market, as well as the value of any wind project acquisition. Accurately modeling wind resources requires hourly generation shapes. Variability is modeled in a manner similar to how AURORAxmp models hydroelectric resources for regional analyses. A single wind generation shape is developed for each area. This generation shape is smoother than individual plant characteristics, but closely represents how a large number of wind farms across a geographical area would operate together.

This simplified wind methodology works well for forecasting electricity prices across a large market, but it does not represent well the volatility of specific wind resources the Company might select. A different wind shape was used for each Avista resource option in each of the 250 iterations. This analysis used historical wind speed data for potential wind sites at Reardan, Washington the Columbia Basin and Montana.

The first step in developing the wind randomization model was to create a distribution of hourly output. Figure 7.14 shows the distribution for a Northwest wind site. In this example, generation is zero for 13 percent of the on-peak hours and is zero for 6 percent of the off-peak hours. The resource is near full output only 5 percent of the time. The second step links next-hour generation to present generation levels. The next hour has a 95 percent probability of being within two percent of the last hour's generation level. The model also correlates wind locations: Reardan is 75 percent correlated to

Northwest resources and Montana is 25 percent correlated to Northwest wind resources.

Figure 7.14: Wind Output Distribution



Forced Outages

Forced outages at CCCT, coal and nuclear plants were included in the risk analysis. The forced outage logic in the AURORAxmp algorithm is based on a mean time to repair and a forced outage rate. The model randomly forces a unit out of service, and then brings it back online at different intervals throughout the year based on its mean time to repair. Operating performance varies from iteration to iteration.

Market Forecast

An optimal resource portfolio must account for the extrinsic value inherent in the resource choices. The 2009 IRP simulation was conducted by comparing each resource's expected hourly output at a forecasted Mid-Columbia hourly price. This exercise was repeated for 250 iterations of Monte Carlo-style analysis. Resources generating during on-peak hours generally contribute higher margins to Avista's resource portfolio than resources with intermediate and unpredictable output.

Assumptions used to develop the electric price forecast were discussed earlier in this chapter. In general, the hourly electricity price is set by either the operating cost of the marginal unit in the Northwest or the economic cost to move power into or out of the Northwest. To create an electricity market price projection, a forecast of available future resources must be determined. The IRP uses regional planning margins to set minimum capacity requirements, instead of using the summation of capacity needs of each utility in the region. Western regions can have resource surpluses even where some individual utilities may be in deficit. This imbalance can be due to the ownership of regional generation by independent power producers, and possible differences in planning methodologies used by those utilities.

AURORAxmp assigns market values to each resource alternative available to the Preferred Resource Strategy (PRS), but it does not select PRS resources. Several market price forecasts are used to determine the value and volatility of a resource portfolio. As Avista does not know what will happen in the future with any degree of certainty, it relies on risk analysis to help determine an optimal resource strategy. Risk analysis uses several market price forecasts with different assumptions than the base case or changes the underlying statistics of a study. These alternate cases are split into stochastic and deterministic studies.

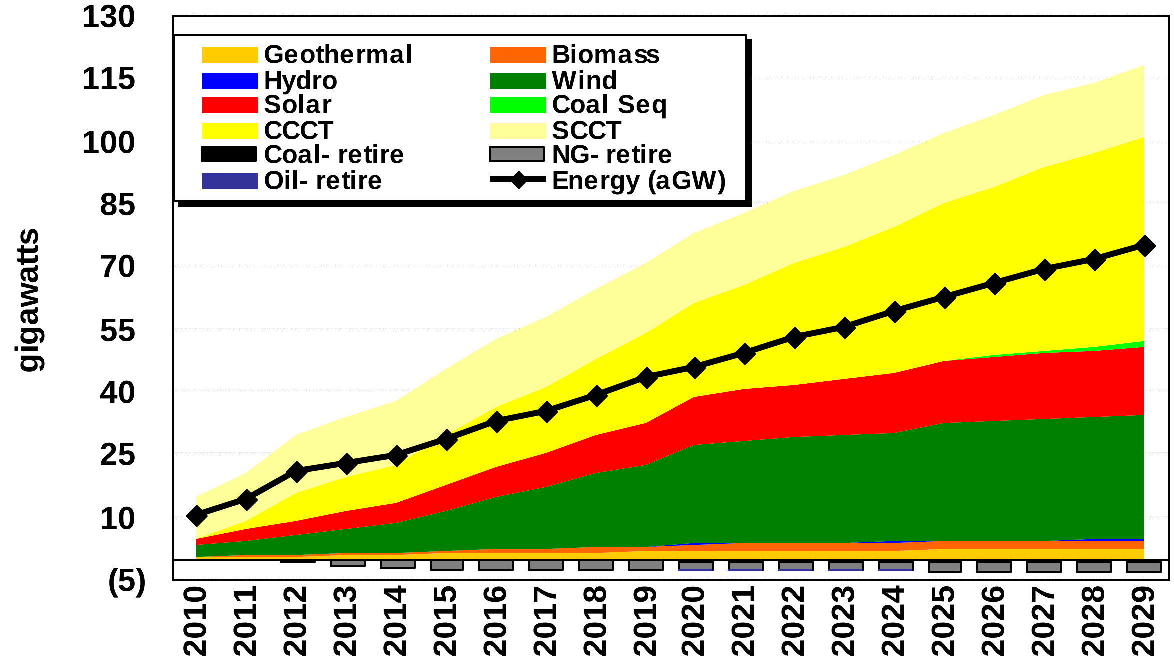
A stochastic study uses Monte Carlo analysis to quantify the variability in future market prices. These analyses include 250 iterations of varying gas prices, loads, hydro, thermal outages, wind shapes and emissions prices. Two stochastic studies were developed for this IRP, one with and one without carbon legislation. The remaining studies were deterministic scenario analyses.

Resource Selection

New resource options were discussed earlier in this chapter, along with the amount of capacity necessary to meet capacity targets. New resources for the Western Interconnect will primarily be natural gas-fired. Renewable resources added to meet renewable portfolio standards help fill system energy needs, but fail to provide equivalent capacity for system reliability. Figure 7.15 shows the new resources selected to meet capacity needs and RPS requirements for the Western Interconnect. The model retires a number of coal and high heat rate natural gas plants for economic reasons. Using the same scale, the amount of potential energy is shown in the black line with diamonds. In 2020, 78 GW of nameplate capacity is added, but only 48 GW of energy is available from these resources. Society's mandates to acquire new renewable resources help reduce carbon emissions, but forces utilities to invest in twice as much infrastructure.

The Northwest is expected to need new capacity in 2015, as described earlier in this chapter. The predominant resource selected after renewables to meet Northwest loads are combined cycle combustion turbines (CCCT). 8,100 MW of CCCT will be added to the Northwest between 2015 and 2029.

Figure 7.15: Base Case New Resource Selection



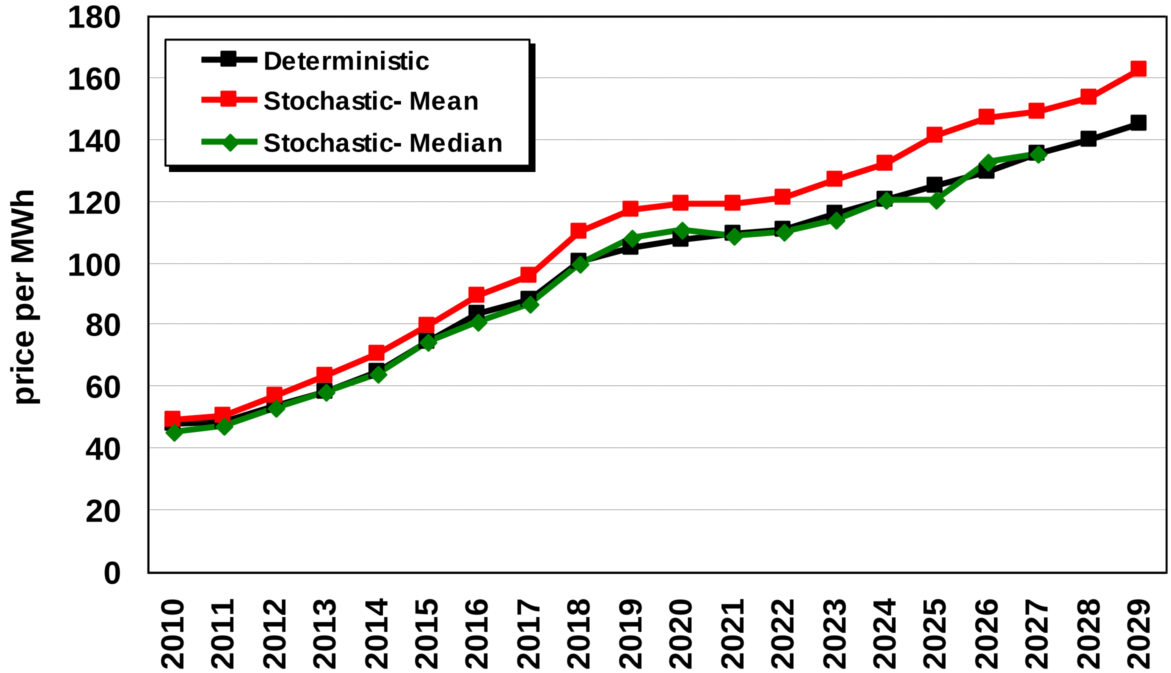
Mid-Columbia Price Forecast

The Mid-Columbia electricity trading hub is Avista's primary trading hub. The Western Interconnect also has trading hubs on the California/Oregon Border (COB), Four Corners, Palo Verde, SP15 (southern California), NP15 (northern California) and Mead. The Mid-Columbia market is usually least cost market because of low cost hydro generation, though other markets can be less expensive when Rocky Mountain area gas prices are low. Fundamentals-based market analysis is critical to understanding the environment Avista competes in.

Two studies were conducted for the Base Case. The first is a deterministic market view using expected levels for key assumptions discussed in the first part of this chapter. The second is a risk or stochastic study with 250 unique scenarios based on different underlining assumptions for gas prices, load, carbon prices, wind, hydro, forced outages, and others. Each of these studies simulates the entire Western Interconnect between 2010 and 2029 for each hour. The analysis used 25 CPUs linked to a SQL server to simulate the studies, creating over 26.5 GB of data requiring 1,500 hours of computing time.

Average prices from the stochastic study do not match deterministic or median prices. Lognormal natural gas prices with carbon penalties affect prices in a lognormal way, with more up-side than down-side. Figure 7.16 compares the stochastic market price results compared to the deterministic base case scenario. The price distributions are shown in Figure 7.17 for selected years: the horizontal axis is the percent of time, indicating 10 percent of the iteration's annual flat prices were above $75 per MWh in 2010 and 50 percent of the time prices were over $48 per MWh.

Figure 7.16: Annual Flat Mid-Columbia Electric Prices



Annual on- and off-peak prices are presented in Table 7.17, along with the levelized costs for both the deterministic and stochastic analyses. The Mid-Columbia market price is expected to average $79.56 per MWh in 2009 dollars over the next 20 years; the average nominal price is $93.74 per MWh. Spreads between on- and off-peak prices are $14.34 per MWh in 2010, and $32.71 per MWh in 2029.

Figure 7.17: Selected Mid-Columbia Annual Flat Price Duration Curves

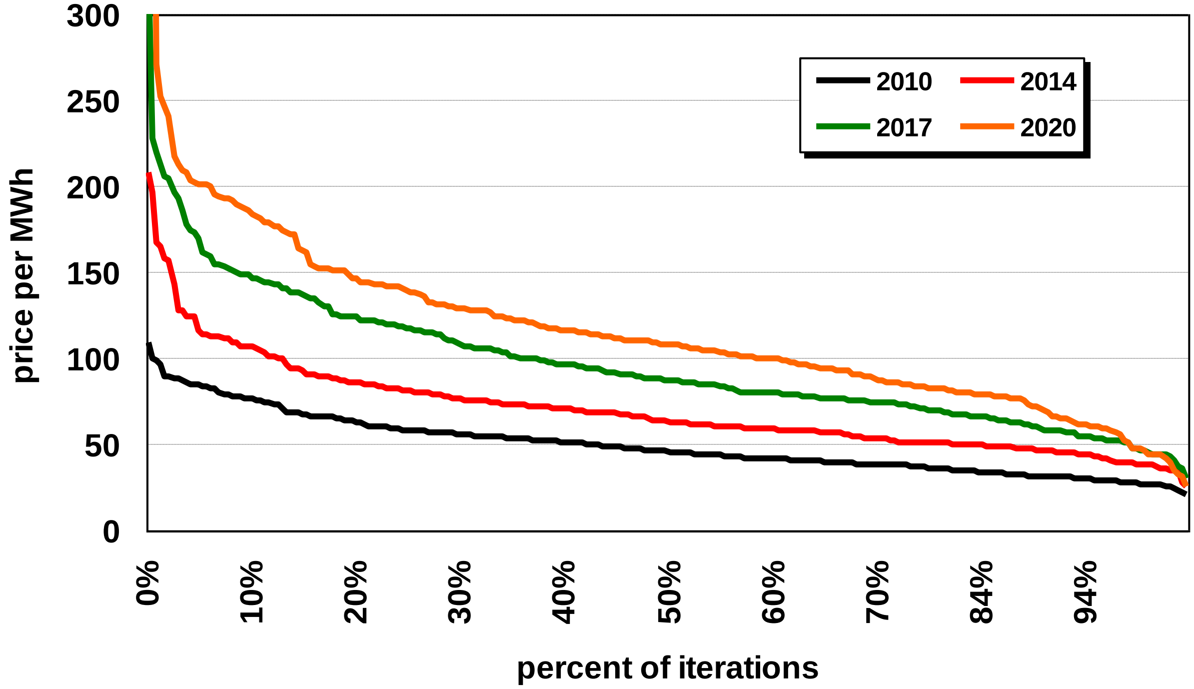


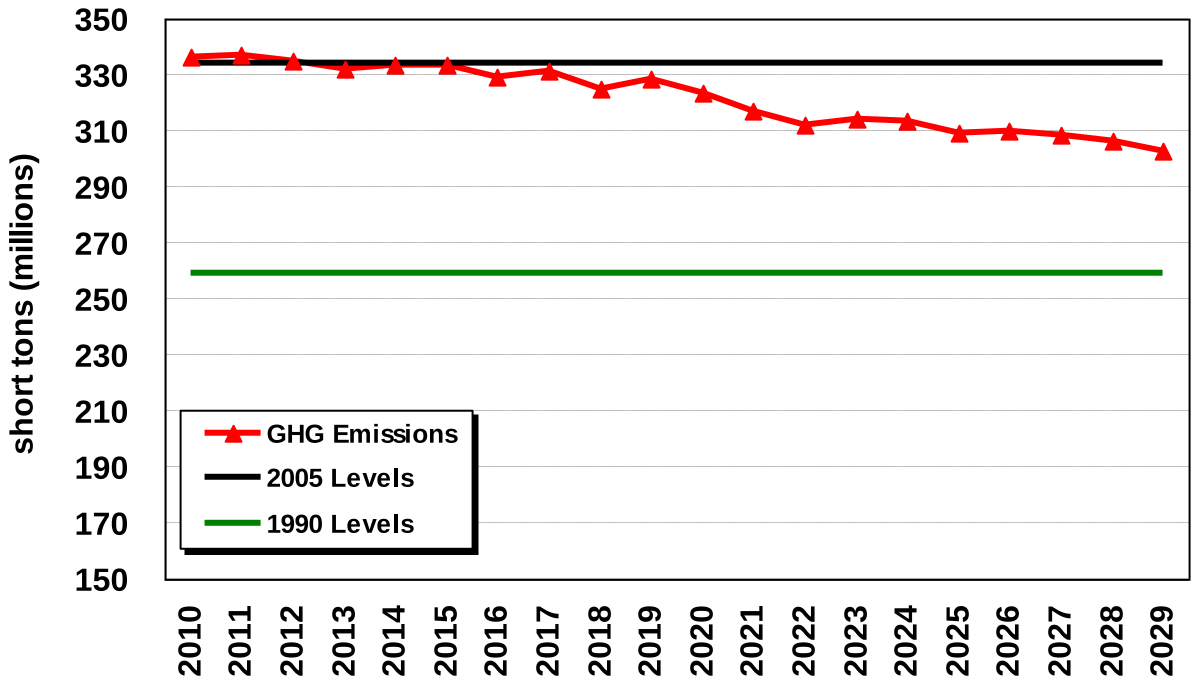
Table 7.17: Annual Mid-Columbia Electric Prices ($/MWh)

Year	Deterministic On Peak	Deterministic Off Peak	Deterministic Flat	Stochastic Mean On Peak	Stochastic Mean Off Peak	Stochastic Mean Flat
2010	53.86	40.08	47.96	55.44	41.10	49.29
2011	54.40	40.35	48.38	56.70	42.10	50.44
2012	59.09	45.83	53.39	62.56	48.49	56.51
2013	63.62	50.37	57.95	68.92	54.34	62.68
2014	71.19	56.95	65.09	76.76	60.98	70.00
2015	80.72	65.87	74.36	86.94	70.07	79.71
2016	90.50	74.69	83.73	97.00	78.71	89.17
2017	95.46	78.86	88.32	103.78	84.00	95.27
2018	107.32	91.28	100.45	119.24	97.01	109.72
2019	112.00	95.68	105.01	126.03	102.86	116.10
2020	114.88	98.22	107.75	128.40	104.45	118.15
2021	116.16	99.70	109.11	129.17	105.09	118.86
2022	117.84	101.50	110.84	131.07	106.60	120.59
2023	123.03	106.01	115.71	138.34	112.73	127.33
2024	128.07	110.46	120.53	142.84	116.61	131.61
2025	132.85	114.43	124.97	152.13	123.83	140.01
2026	137.71	119.03	129.71	158.82	129.10	146.09
2027	143.78	124.25	135.42	161.94	131.58	148.94
2028	148.88	128.60	140.16	166.20	135.23	152.89
2029	153.78	133.09	144.92	175.56	142.85	161.55
Nominal Levelized	**93.10**	**77.39**	**86.36**	**102.41**	**82.17**	**93.74**
2009$ Levelized	**79.01**	**65.68**	**73.30**	**86.92**	**69.75**	**79.56**

Greenhouse Gas Emissions Levels

Greenhouse gas levels are expected to increase over the study period without an emission penalty. The carbon costs discussed earlier in this chapter provide price signals to encourage reduction in greenhouse gas emissions following proposed legislation at the end of 2008. The prices were based on a Wood Mackenzie study including the entire U.S. electrical system. Figure 7.18 shows emissions by states within the Western Interconnect. Emissions are expected to fall to 2005 levels, and then approach 1990 levels by the end of the study. The Wood Mackenzie study assumed carbon offsets would help meet carbon reduction goals. Carbon prices would need to be significantly higher to meet 1990 emissions levels without the offset assumptions. The study found the Eastern Interconnect will lower emissions at twice the level as the West, but the West would reduce it emissions by a higher percentage. Ultimately the western states would not reduce their emission levels to 1990 levels by 2029. Carbon reductions would come from other more greenhouse gas intensive parts of the country first.

Figure 7.18: Western States Greenhouse Gas Emissions

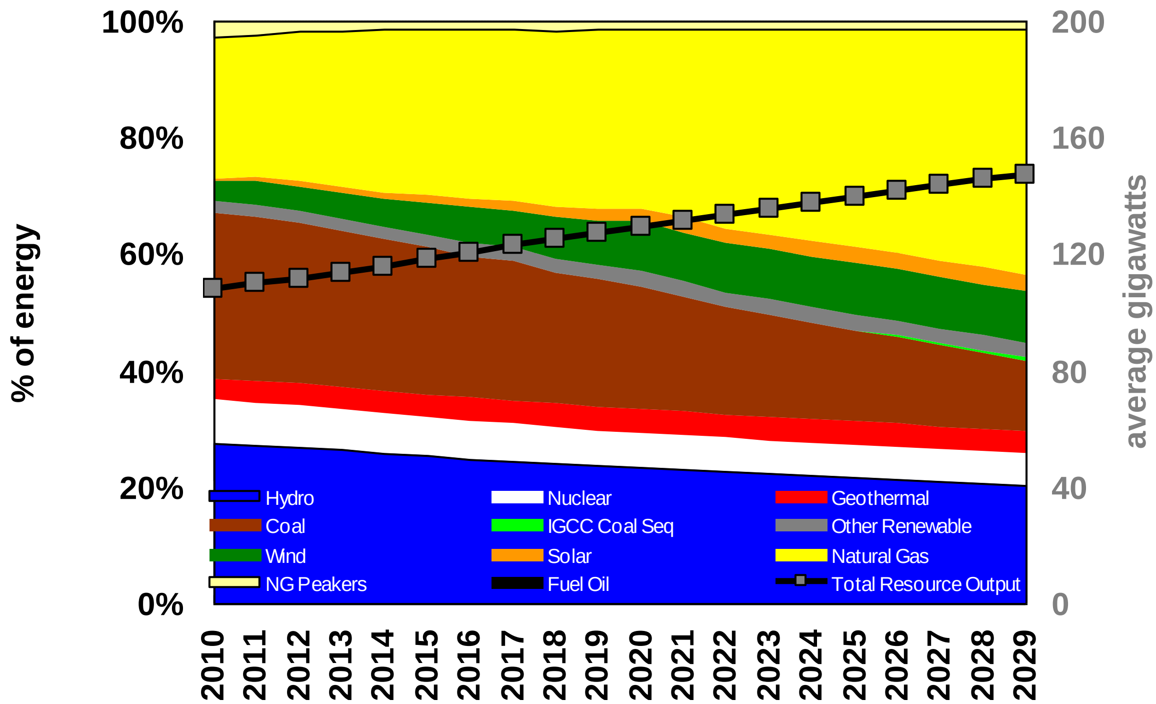


Resource Dispatch

State-level RPS and carbon legislation will change resource dispatch decisions and affect future power supply expenses. Figure 7.19 illustrates that natural gas is expected to be 27 percent of power generation in 2010, 32 percent in 2020 and 44 percent in 2029. Coal decreases from 29 percent of Western Interconnect generation in 2010 to 16 percent in 2029. Non-hydro based renewables increase from 10 percent in 2010 to 25 percent in 2029. The reduction in coal generation is offset by new renewable generation, but load growth will primarily be met by natural gas-fired resources.

Public policy changes to encourage renewable energy development and reduce greenhouse gas emissions will change the electric marketplace. Policy changes are likely to move the electric generation fleet toward its most volatile –contributor—natural gas. These policies will displace low-cost and dependable coal-fired generation with higher cost renewables and gas-fired generation having lower capacity factors (wind) and higher marginal costs (natural gas). Regulated utilities are expected to recover stranded coal costs, requiring customers to pay for duplicative resources as new renewable and natural gas resources are built to satisfy RPS and emissions performance standards. Wholesale prices will increase with the effects of the changing resource dispatch driven by carbon emission limitations. New environment-driven investment, combined with higher market prices, will lead to higher retail rates.

Figure 7.19: Base Case Western Interconnect Resource Energy



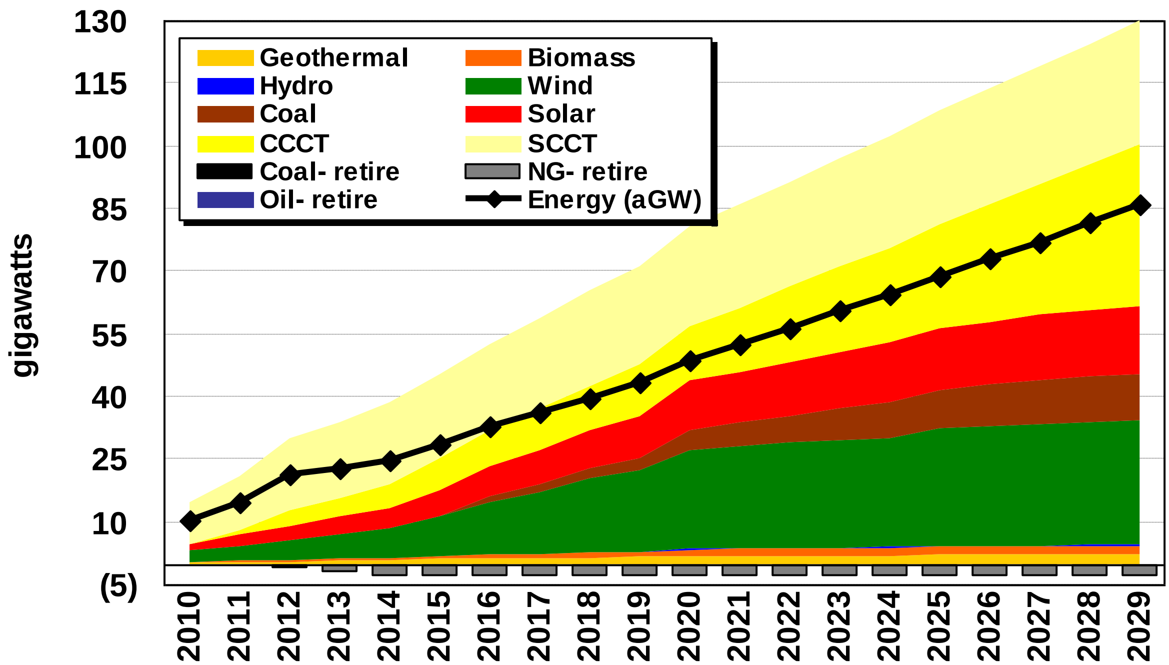
Scenario Analysis

This section evaluates the market, with specific changes in individual assumptions. The unconstrained carbon emissions scenario is modeled both stochastically and deterministically. It is modeled stochastically because it is used in the PRS analysis to determine the total cost of carbon legislation. The high gas price, low gas price and solar saturation scenarios are provided to show the impact of significant market changes on electricity and carbon prices. Market scenarios were used in prior IRPs to stress test the PRS against different market scenarios. Since the PRS accounts for a range of possible outcomes in its risk analysis, the market scenario analysis section has been limited in this IRP.

Unconstrained Carbon Emissions

The unconstrained carbon emissions scenario quantifies the projected cost of greenhouse gas legislation. The scenario is first studied deterministically, then stochastically, with 250 iterations of varying natural gas prices, loads, wind, forced outages, and hydro conditions. The assumptions are similar to the Base Case with a few notable exceptions. First, the natural gas price forecast is lower because of less demand for natural gas caused by the continued use of coal-fired generation. Without carbon legislation, gas prices are expected to be $0.80 per Dth lower, an 8.6 percent decrease. The resources selected for this scenario are shown in Figure 7.20. The primary difference between this scenario's resource selection and the Base Case is the reduction in additional natural gas resources and the increase in new coal resources. New coal resources totaled 11,000 MW over the 20-year study; an equivalent amount of CCCTs were removed from the portfolio. A few additional peaking resources were developed in this scenario.

Figure 7.20: Unconstrained Carbon Emissions Resource Selection



Mid-Columbia market prices would be lower absent carbon legislation. The deterministic analysis found prices would be $22.43 per MWh lower on a nominal levelized basis over the forecast horizon; the stochastic analysis found prices would be $25.52 per MWh lower. Prices are lower without carbon penalties because fuel and hence dispatch costs for natural gas plants are lower. A comparison of the two forecasts is shown in Figure 7.21.

Figure 7.21: Mid-Columbia Prices Comparison with and without Carbon Legislation

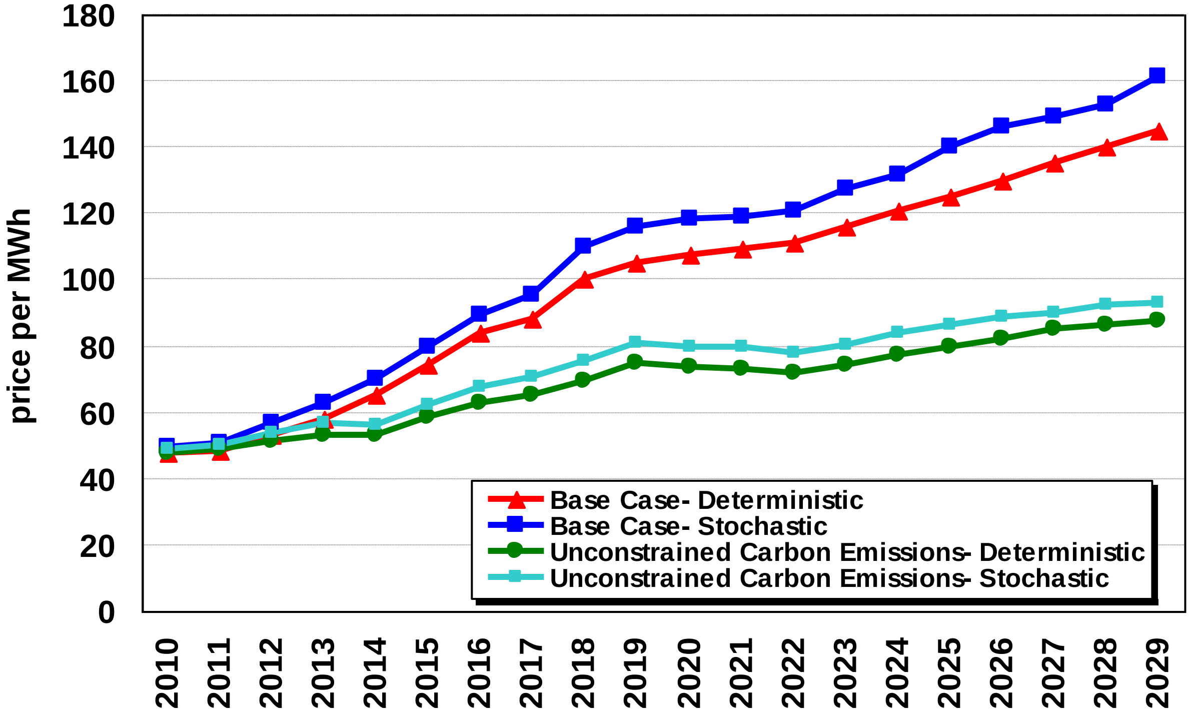


Figure 7.22 illustrates the difference between carbon emissions with and without the carbon adder included in the Base Case. Carbon emissions would be 11 percent higher in 2020, and 40 percent higher in 2029 without the Base Case carbon adder. The increased emissions are caused by higher dispatch levels for coal-fired resources (Figure 7.23) relative to the Base Case. Carbon emission impacts on coal plants could increase overall fuel costs across the Western Interconnect by 16.3 percent or $42.5 billion in present value terms (2009 dollars). Annual cost increases are shown in Figure 7.24. Carbon legislation further adds $328 million in present value term (2009 dollars) over the study period for operations, but reduces capital and other non-O&M costs by $17.1 billion. In total carbon legislation on a 20 year net present value calculation will increase costs by $25.7 billion.

Figure 7.22: Western U.S. Carbon Emissions Comparison

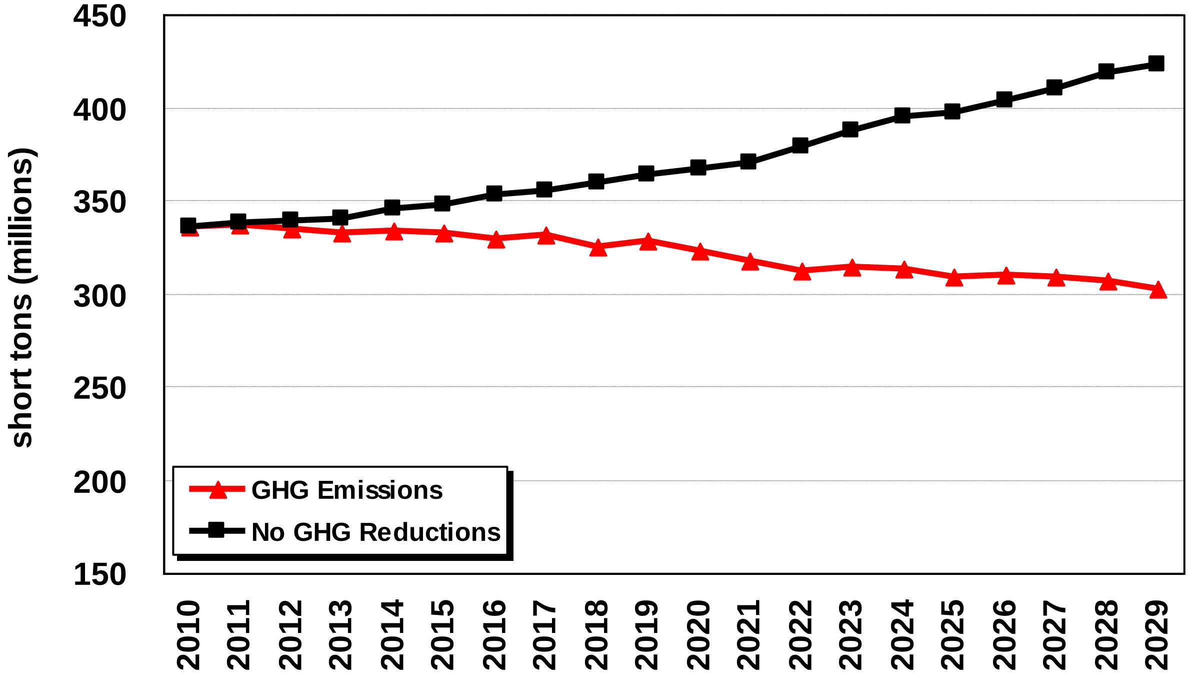


Figure 7.23: Unconstrained Carbon Scenrio Resource Dispatch

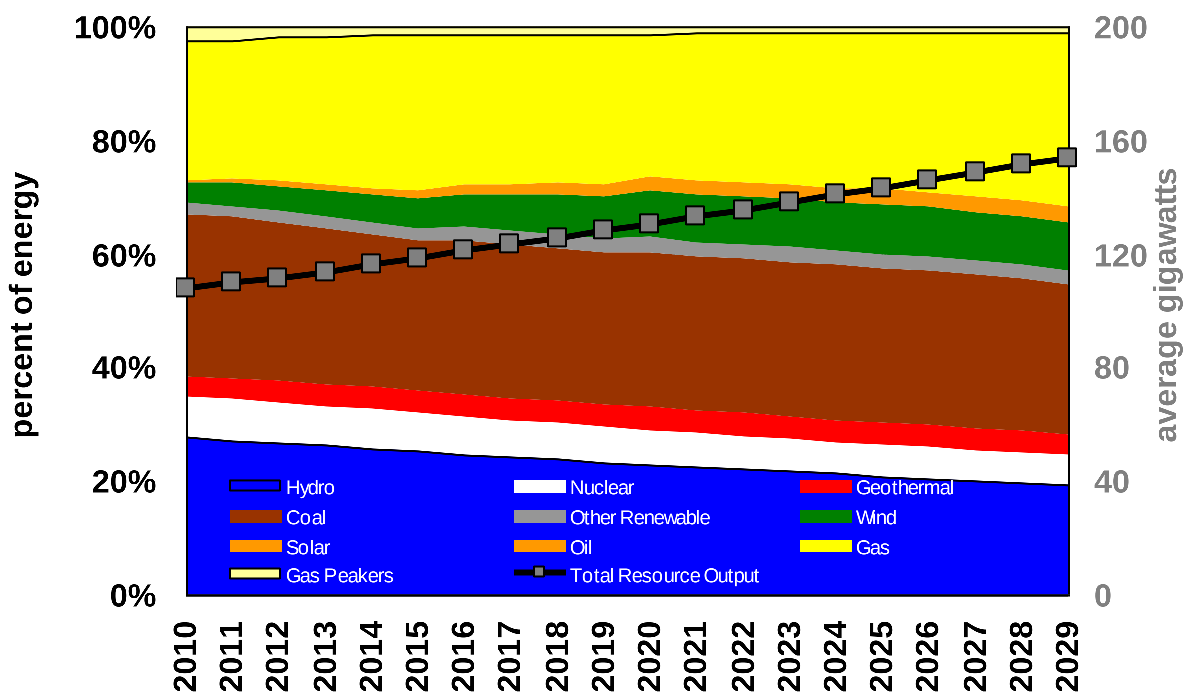
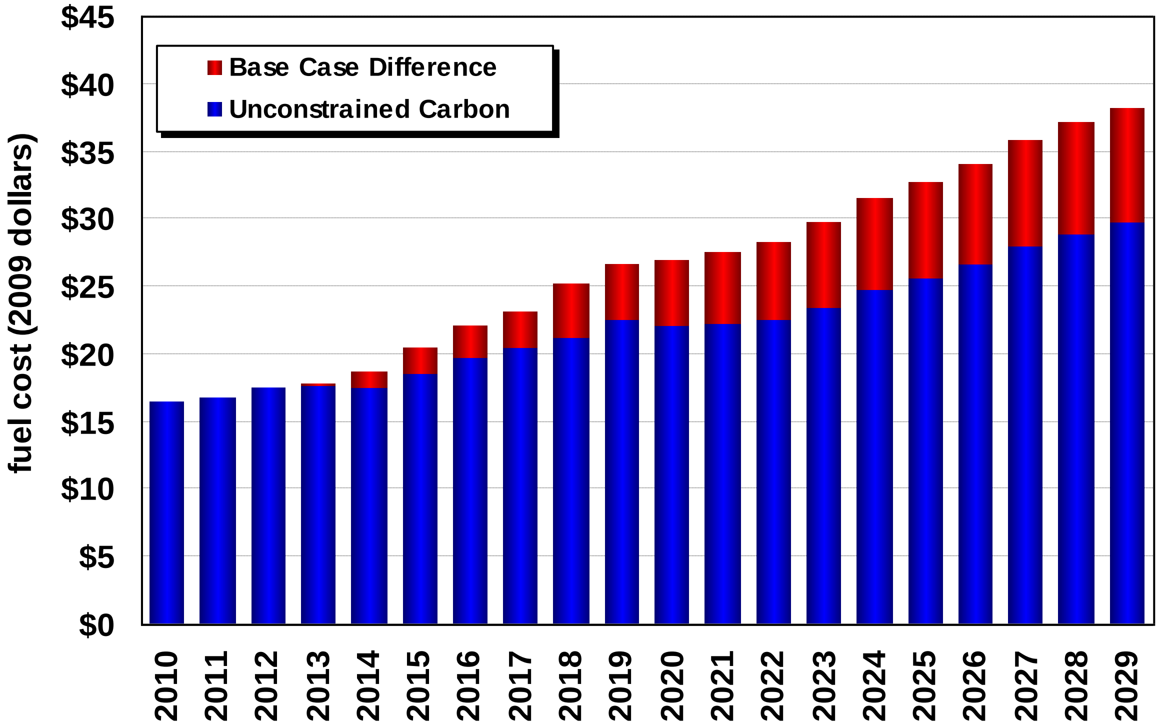


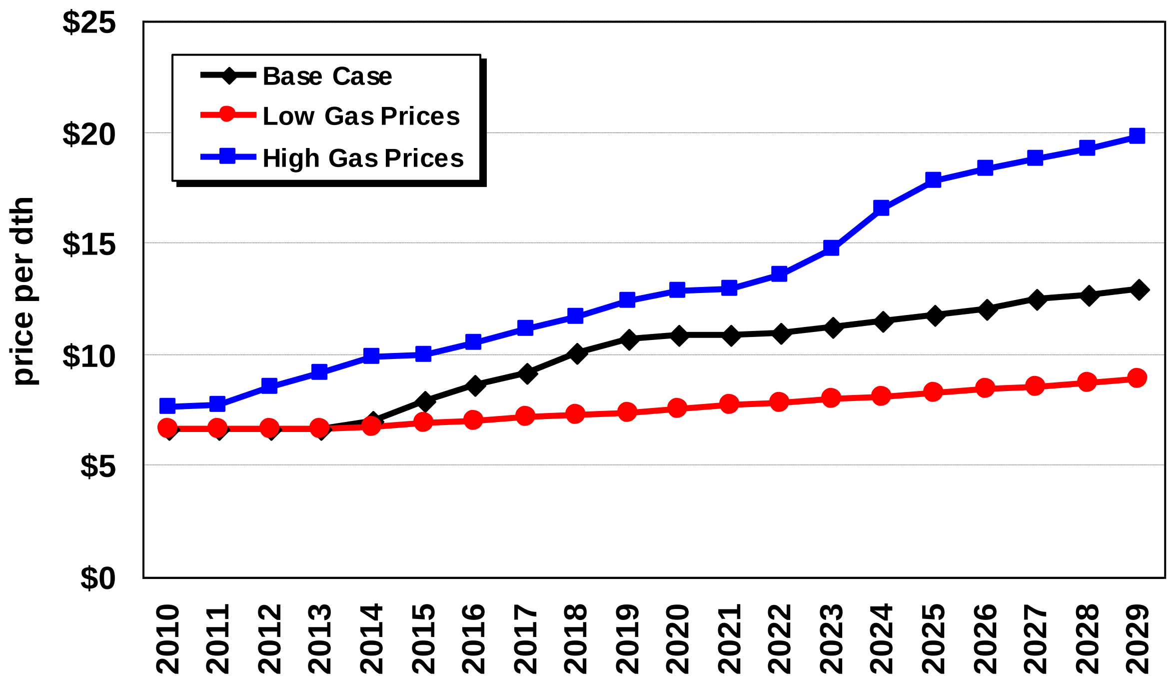
Figure 7.24: Western Interconnect Fuel Cost Comparison



High & Low Natural Gas Prices

The High and Low Natural Gas Price scenarios illustrate the range in Mid-Columbia electric prices for different ranges of natural gas prices. These scenarios also keep carbon emissions at the same level as the Base Case; therefore, a carbon price can be derived if gas prices change from the Base Case assumptions. Figure 7.25 shows the natural gas prices used for these analyses at the Henry Hub. The monthly and basin differential prices remain the same as the Base Case. The objective of the Low Natural Gas Price scenario is to maintain the real price level at the 2010 level throughout the study and only allow the nominal prices to increase with inflation. The levelized price is $7.50 per Dth (nominal) and $6.36 per Dth (2009 dollars) in this scenario. The High Natural Gas Price scenario uses a Wood Mackenzie price forecast from the summer of 2008. Prices in this scenario did not include the current recession and subsequent market effects as well as including lower levels of unconventional gas supplies. The levelized price is $12.17 per Dth (nominal) and $10.33 per Dth (2009 dollars) for the High Natural Gas Price scenario.

Figure 7.25: Henry Hub Prices for High and Low Natural Gas Price Scenarios



As discussed throughout this chapter, carbon prices are dependent on natural gas prices. The objective of the high and low gas scenarios is to keep carbon emissions at the same level as in the Base Case. To achieve these levels, the carbon emission prices shown in Figure 7.26 were used. The nominal levelized greenhouse gas price was $47.12 per short ton for the high gas price scenario. It was $24.12 for the low gas price scenario, compared to the Base Case of $38.61 per short ton. The real carbon prices in 2009 dollars are $40.06, $20.49 and $32.83 per short ton respectively.

The new resources selected by AURORAxmp in the high and low natural gas price scenarios do not differ greatly from the Base Case. This is mostly due to RPS assumptions remaining the same between all cases and because traditional coal is not an option for U.S. utilities; therefore, the model uses a mix of gas, nuclear, sequestered coal, and low capacity factor wind or solar resources. The high gas price scenario is displayed in Figure 7.27. The model in this case selected more carbon sequestration than in the Base Case, and added nuclear generation to the resource mix. The model also retired three gigawatts of natural gas and one gigawatt of coal-fired generation.

New resources for the low gas price scenario are shown in Figure 7.28. In the low gas price environment, the model selected only new gas-fired resources in addition to the RPS resources. The model retired four gigawatts of natural gas and two gigawatts of coal-fired plants.

Figure 7.26: Greenhouse Gas Prices for High and Low Natural Gas Price Scenarios

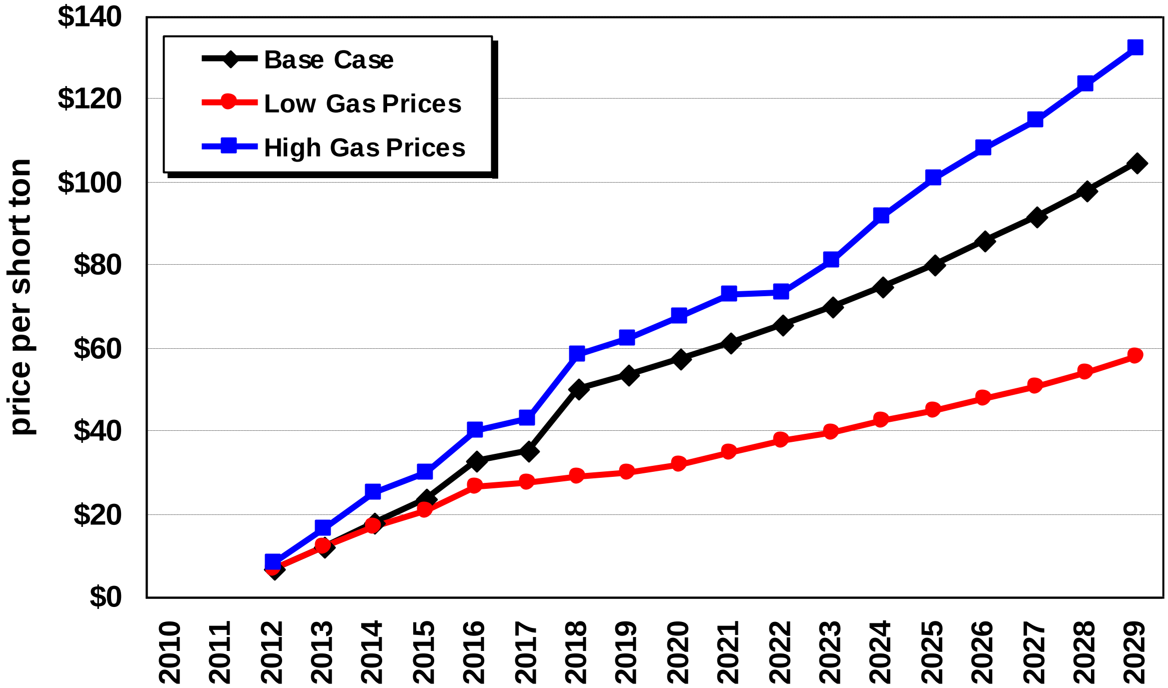


Figure 7.27: High Natural Gas Prices Scenario Resource Selection

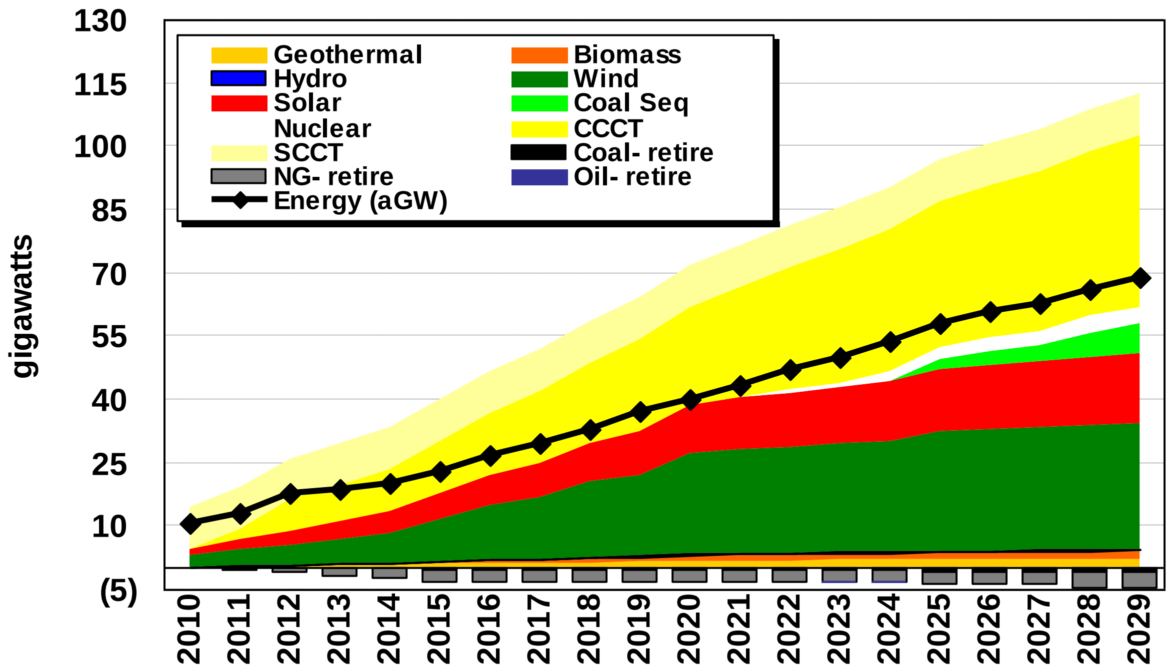
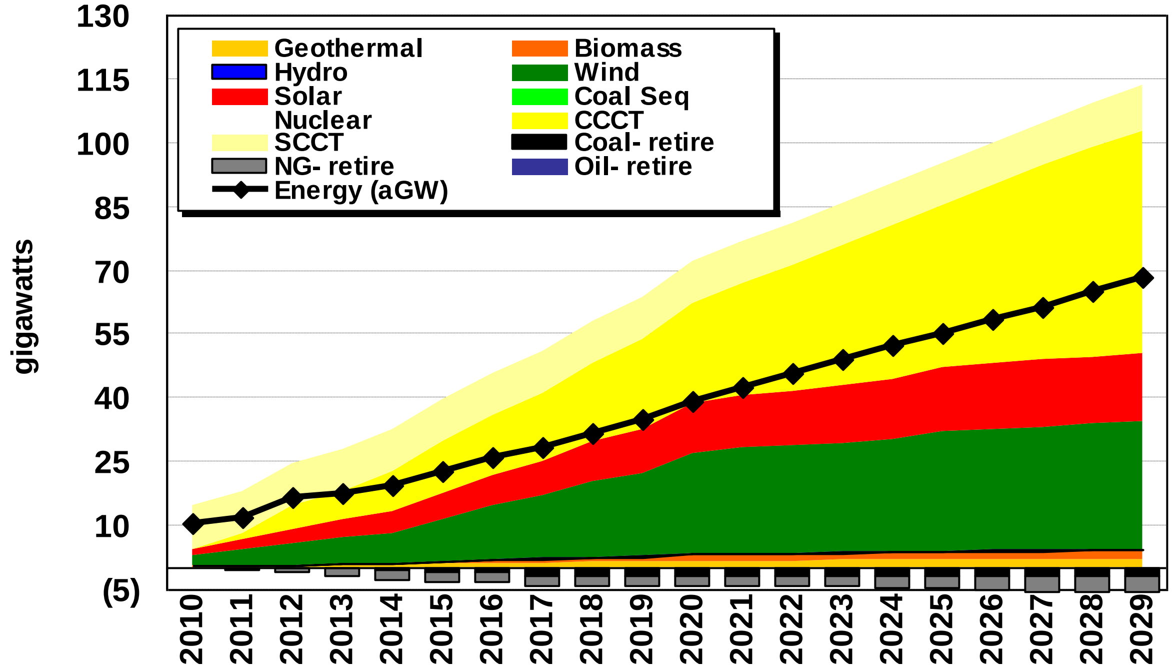


Figure 7.28: Low Natural Gas Prices Scenario Resource Selection



As expected, Mid-Columbia prices are higher in the high gas price scenario than in the Base Case or the low gas price scenarios. The nominal levelized price for the high gas price scenario is $102.61 per MWh. The low gas price scenario is $67.48 per MWh, compared to $86.36 per MWh in the Base Case. Prices are $87.10, $57.24 and $73.30 per MWh in 2009 dollars, respectively. These prices are graphically presented in Figure 7.29. Market prices follow natural gas prices because of the high correlation between these two variables.

The high gas price scenario lowers the contribution of natural gas in the Western Interconnect fuel mix, with coal sequestration and nuclear projects beginning in 2020 (see Figure 7.30). The low gas price scenario has a similar dispatch as the Base Case; it includes an increase in natural gas resources (see Figure 7.31). The contribution from traditional coal-fired resources shrinks to lower carbon emissions in both scenarios.

Figure 7.29: Mid-Columbia Electric Price Forecast

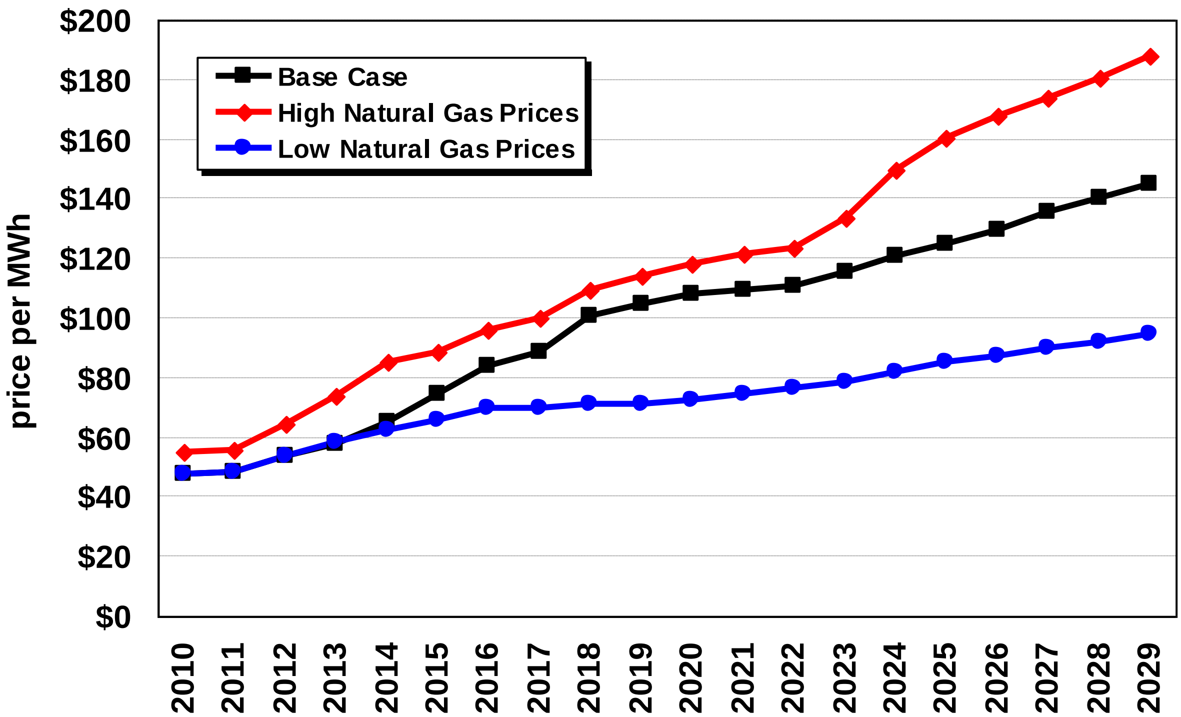


Figure 7.30: Resource Dispatch- High Gas Price Scenario

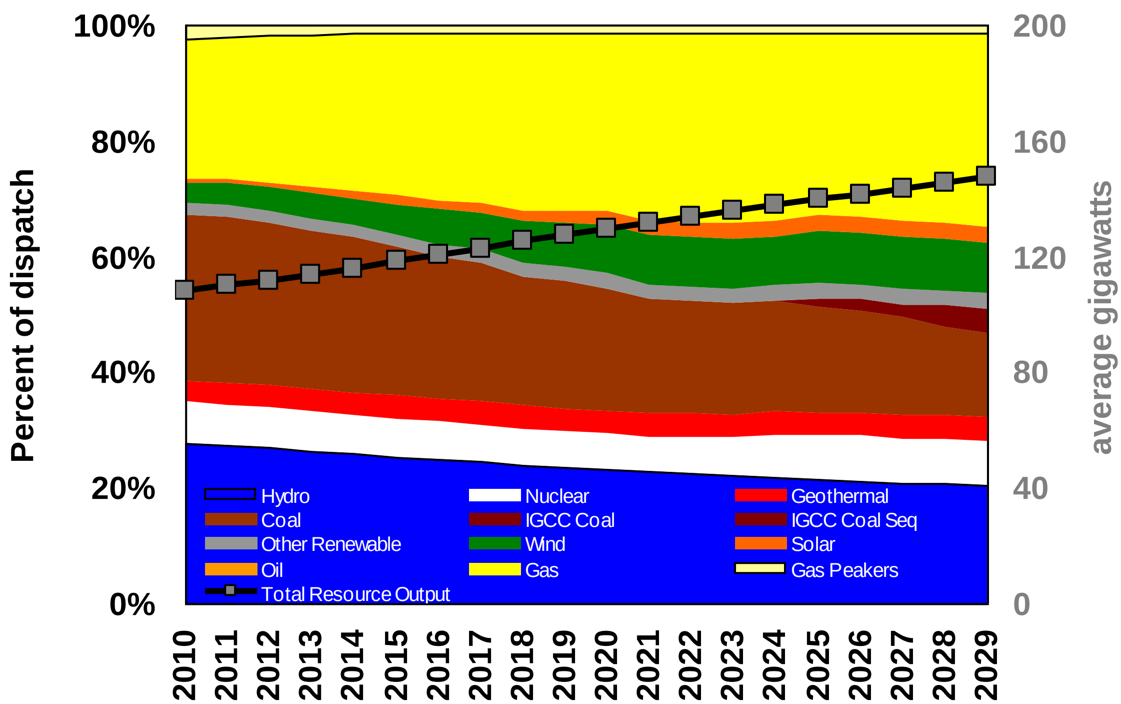
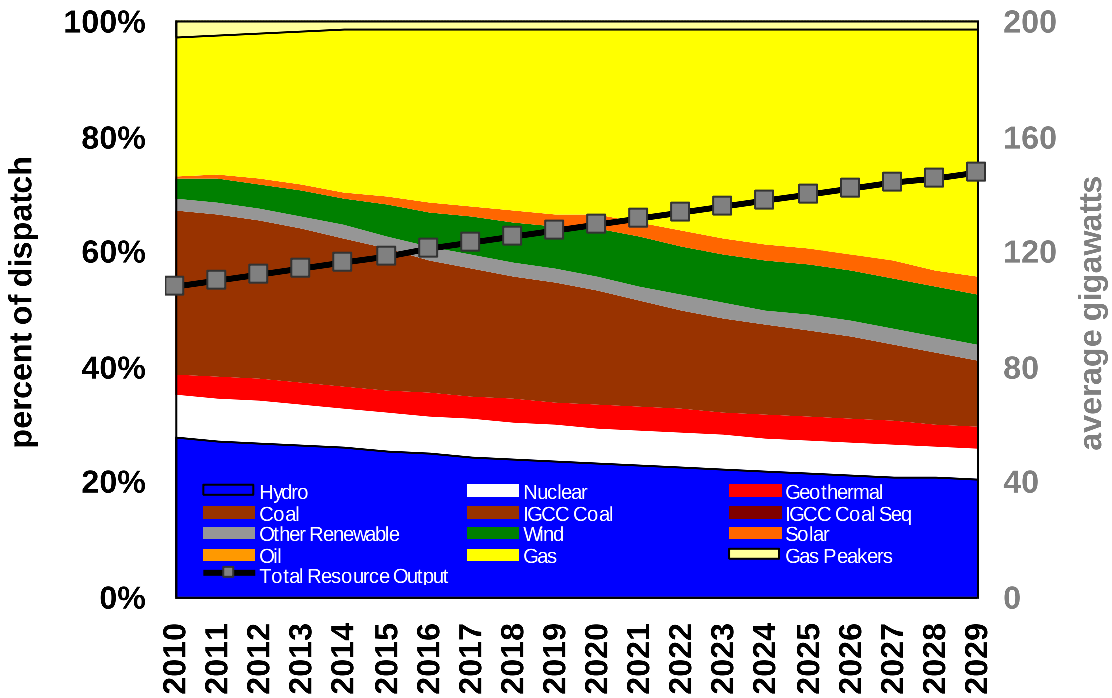


Figure 7.31: Resource Dispatch- Low Gas Price Scenario

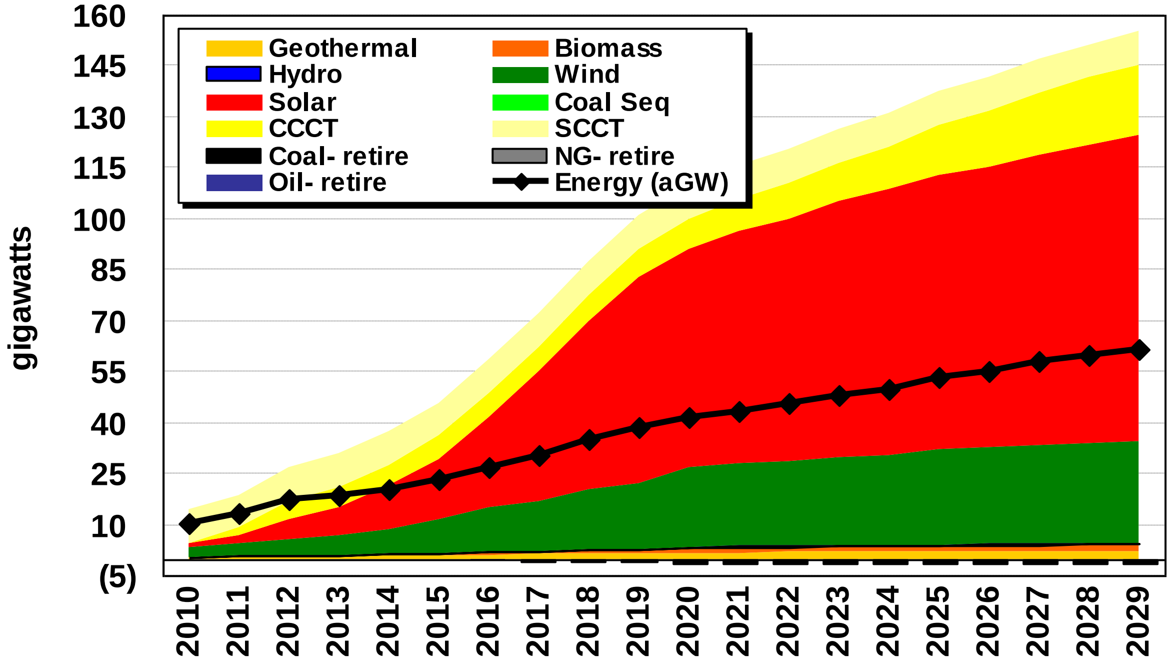


Solar Saturation

It is helpful to use the IRP process to identify and understand potential market changes, rather than only focus on what is or is not included in the Company's PRS. Solar has caught the attention of many utility planners, government officials and customers because of positive environmental characteristics, potential line loss reductions through distributed energy, free fuel and high correlation with on-peak load. Solar has many upside potentials, but is still financially prohibitive because of its high capital costs and limited generation on cloudy days. The solar saturation scenario was developed to understand the market reaction to a significant decrease in the price of photovoltaic solar. In this scenario, natural gas, carbon prices, and load remain the same. The only change is an 80-percent reduction in installed photovoltaic solar costs. The scenario is not used for the PRS, but is included to identify how market prices and greenhouse gas emissions would be impacted by a significant decrease in solar costs.

If photovoltaic solar became 80 percent less expensive, the amount of solar added above and beyond the RPS levels is 75 gigawatts, for a total of 90 gigawatts of solar capacity by 2029 (Figure 7.32). Even with the added solar, it only contributes 23,000 aMW of energy due to the low capacity factor. Solar is not an ideal fit to meet winter peak in northern areas (5 percent winter capacity contribution in northern states) so another technology must be used or additional solar must be added to compensate for the lower winter capacity.

Figure 7.32: Solar Saturation Scenario Resource Selection



Adding 75 gigawatts of solar did not have a significant impact on Mid-Columbia market prices. There was only a reduction of $3.50 per MWh levelized (nominal), though second and third quarters (high solar months in the Northwest) had lower on-peak power prices than in the Base Case. Prices did not change because the marginal cost of power was still set by gas-fired resources and because solar does not produce power at night. More solar would need to be added and a low-cost storage technology identified to effectively lower market prices. Greenhouse gas emissions were modestly reduced by 10 percent from the Base Case (see Figure 7.33) in this scenario.

More solar generation reduces the Western Interconnect's carbon footprint. Carbon reduction is primary driven by a decrease in natural gas-fired generation. Coal energy increased by 1,000 aMW over the Base Case and while natural gas-fired production fell by 18,000 aMW in this scenario (see Figure 7.34). The increase in coal generation was from existing plants operating in off peak hours to compensate for the lack of night time solar generation, while the reduction in natural gas-fired generation is a result of decreased need due to the influx of solar resources to serve on-peak load. This study illustrates that market prices in the Northwest will not radically change in spite of a large amount of new solar generation added to the system, but greenhouse gas emissions will fall along with natural gas prices.

Figure 7.33: Western Interconnect Carbon Emissions Comparison

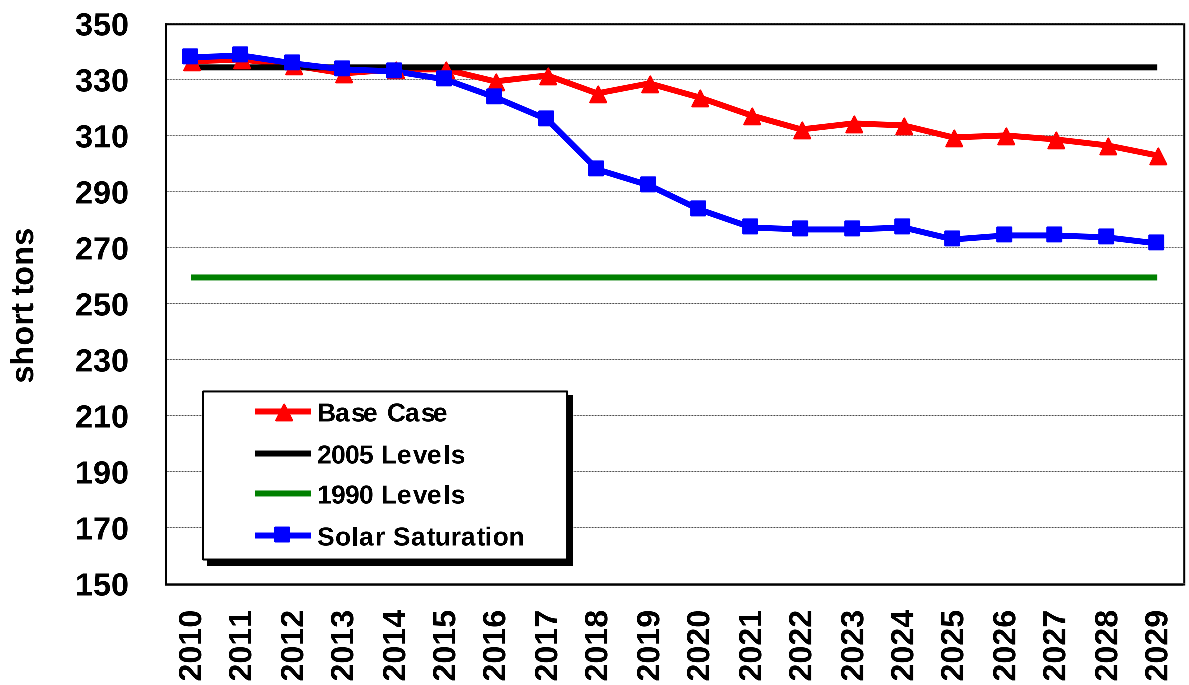
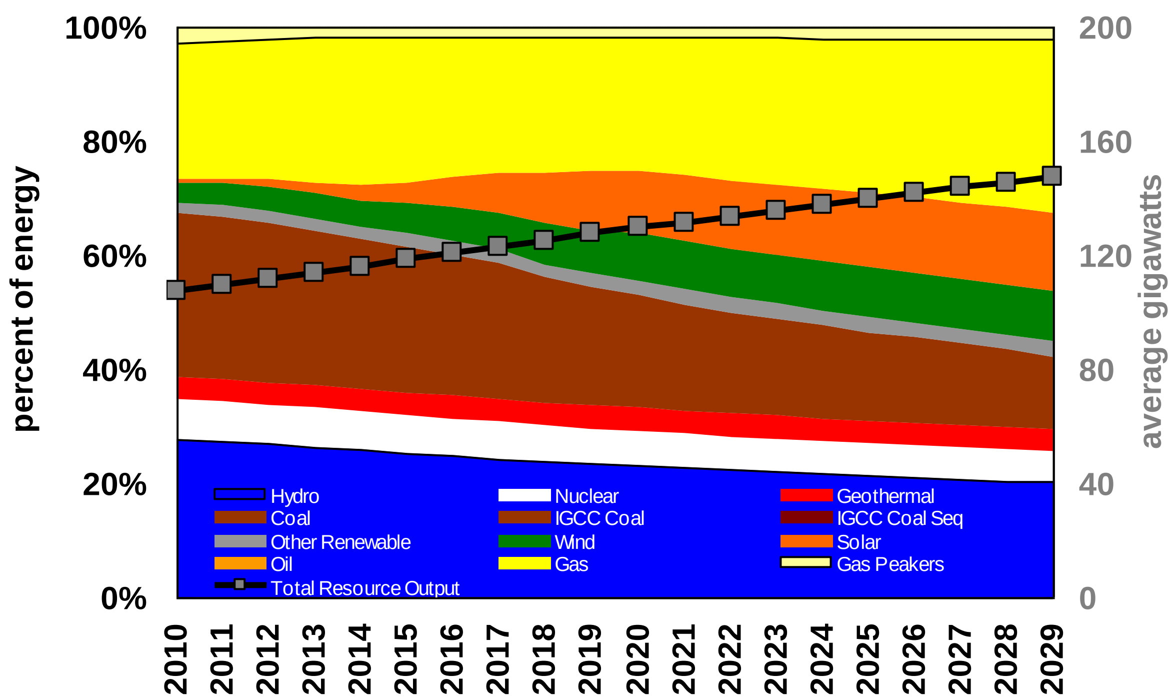


Figure 7.34: Resource Dispatch- Solar Saturation Scenario



Market Analysis Summary

Market analysis is a key component of the IRP. The market is where the Company trades and acquires energy. Without a firm understanding of the marketplace and how it is affected by public policy, it is difficult to provide a comprehensive examination of potential resource being evaluated by Avista. A summary of key drivers for the 2009 IRP market forecast are presented in Table 7.18 and Table 7.19. These tables present 10- and 20-year levelized costs in nominal and 2009 dollars. The 2007 IRP forecasts are included for comparison. Price expectations have increased since the 2007 IRP. The 10-year Malin natural gas price forecast increased 20 percent, and the Mid-Columbia electric price forecast increased 27 percent. Large increases are the result of carbon mitigation costs. Without greenhouse gas legislation, Malin natural gas and Mid-Columbia electric prices would only have increased seven percent from the previous IRP forecasts.

New legislation and regulations impacting the electric system are on the horizon. It does not matter if the intent is to decrease greenhouse gas emissions, make generation greener, promote energy independence or affect reliability—power costs will increase because new capacity and transmission resources are needed to replace aging resources and meet new load growth. Carbon and RPS legislation will diversify fuel supplies, but will also increase demand for cleaner burning natural gas. Policymakers and the public will need to determine if the ultimate benefits of these types of legislation are worth the increased costs.

Table 7.18: Malin and Mid-Columbia Forecast Results (Nominal Levelized)

		Stochastic		Deterministic					
		Base Case	Unconst-rained Carbon Emissions	Base Case	Unconst-rained Carbon Emissions	Low Gas Prices	High Gas Prices	Solar	2007 IRP Base Case
10 Year	Malin Natural Gas Prices	$7.43	$6.90	$7.37	$6.90	$6.49	$8.71	$7.37	$6.11
10 Year	Mid-Columbia Electric Price	$73.53	$60.18	$68.64	$56.84	$60.24	$80.28	$64.92	$53.76
10 Year	Mid-Columbia/Malin x 1000	9,898	8,719	9,311	8,238	9,279	9,212	8,807	8,792
20 Year	Malin Natural Gas Prices	$8.67	$7.87	$8.64	$7.86	$6.88	$10.52	$8.63	$7.15
20 Year	Mid-Columbia Electric Price	$93.74	$68.22	$86.36	$63.93	$67.48	$102.61	$82.87	$62.16
20 Year	Mid-Columbia/Malin x 1000	10,806	8,671	10,008	8,132	9,809	9,754	9,603	8,694

Table 7.19: Malin and Mid-Columbia Forecast Results (2009 Dollars Levelized)

		Stochastic		Deterministic					
		Base Case	Unconst-rained Carbon Emissions	Base Case	Unconst-rained Carbon Emissions	Low Gas Prices	High Gas Prices	Solar	2007 IRP Base Case
10 Year	Malin Natural Gas Prices	$6.73	$6.25	$6.68	$6.25	$5.88	$8.93	$6.68	$5.54
10 Year	Mid-Columbia Electric Price	$66.61	$54.51	$62.18	$51.49	$54.56	$72.72	$58.81	$48.70
10 Year	Mid-Columbia/Malin x 1000	9,898	8,718	9,311	8,238	9,279	8,146	8,807	8,792
20 Year	Malin Natural Gas Prices	$7.36	$6.67	$7.33	$6.67	$5.83	$8.93	$7.32	$5.76
20 Year	Mid-Columbia Electric Price	$79.56	$57.87	$73.30	$54.23	$57.24	$87.10	$70.33	$50.07
20 Year	Mid-Columbia/Malin x 1000	10,811	8,670	10,012	8,132	9,812	9,757	9,607	8,693

8. Preferred Resource Strategy

Introduction

This chapter summarizes the Preferred Resource Strategy (PRS), along with its potential cost and risks. It details the planning and resource decision methodologies; it describes strategy, climate change ramifications and how the PRS might evolve if certain forecasts of future conditions are different.

The 2009 PRS is the least-cost achievable plan accounting for climate change and fuel supply and cost risks. The major change compared to 2007 is a greater reliance on wind to meet renewable portfolio standards (RPS), rather than a combination of wind and other renewables. More wind was selected because it is the only renewable resource available in quantities large enough to affect utility planning. It also is more actionable and controllable by the utility, allowing for less reliance on third-party developers that might or might not respond to utility request for proposal (RFP) efforts. It is likely that the 2009 PRS will change as new information becomes available on cost, resource options, and legislative actions. However, the strategy contained in this chapter is based on the best information at this time.

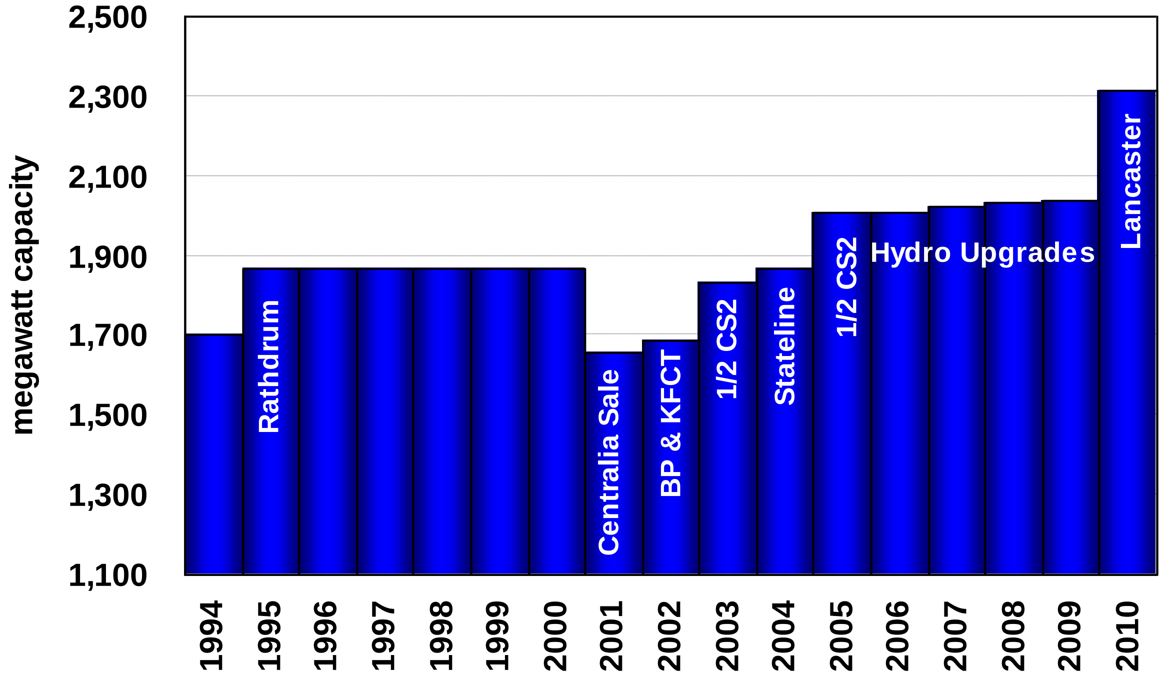
Section Highlights

- Avista's physical energy needs begin in 2018; capacity needs begin in 2016.
- The first supply-side acquisition is 150 MW of wind by the end of 2012.
- Conservation additions provide 26 percent of new supplies through 2020.
- A 250 MW natural gas-fired combined cycle project is required by 2020, but could be required by 2015.
- Large hydro upgrades could change the PRS if they are determined to be economically viable.

Supply-Side Resource Acquisition History

Avista sold its 210 MW share of the Centralia coal plant in 2001 and replaced its generation with natural gas-fired projects (see Figure 8.1). After the Centralia sale Avista acquired 32 MW of gas-fired peaking capacity and 287 MW of intermediate load gas-fired capacity. In addition to gas, Avista contracted for 35 MW of wind capacity from Stateline and added 35.5 MW of new capacity to its hydro fleet. Avista will gain control of the output for the 270 MW Lancaster Generating Facility (Rathdrum GS) on January 1, 2010. Avista also expects to upgrade its Nine Mile Falls and Noxon Rapids hydro facilities over the next five years.

Figure 8.1: Resource Acquisition History



Resource Selection Process

Avista uses several decision support systems to develop its resource strategy. The PRS is based on results from the PRiSM model. The model's objective function is to meet resource deficits, accounting for overall cost, risk, and other constraints. This method replaces the traditional hand-picked portfolio comparison approach. The AURORAxmp model, discussed in the Market Analysis chapter, calculates the operating margin (value) of each resource option in each of the 250 potential future outcomes, and then the PRiSM model uses these values combined with capital and fixed operating costs to select the best resource mix to meet capacity, energy, RPS and other requirements.

PRiSM

Avista staff developed the PRiSM model in 2002 to help select the PRS. The PRiSM model uses a linear programming routine to support complex decision making with single or multiple objectives. Linear programming has been used by many industries for decades, although the utility industry has been slow to adopt it for resource planning. Linear programs provide optimal values for variables, given system constraints. Developing these tools requires advanced portfolio and market analysis; both can be expensive and complicated.

Overview of the PRiSM Model

PRiSM has six basic inputs:

1. Load deficits (energy and capacity);
2. RPS standards;
3. Avista's existing portfolio's costs (load and resources) and operating margins (resources);
4. Fixed operating costs, return on capital, interest, and taxes for each resource option;
5. Generation levels for each resource and resource option; and
6. Carbon emission levels for each resource and resource option.

PRiSM uses these inputs to develop an optimal resource mix over time at varying levels of cost and its consummate risk level. It weights the first 10 years more heavily than the outer years to recognize the importance of near-term decisions on today's utility interests (i.e., customers and shareholders). A simplified view of the linear programming objective function formula is provided below.

PRiSM Objective Function

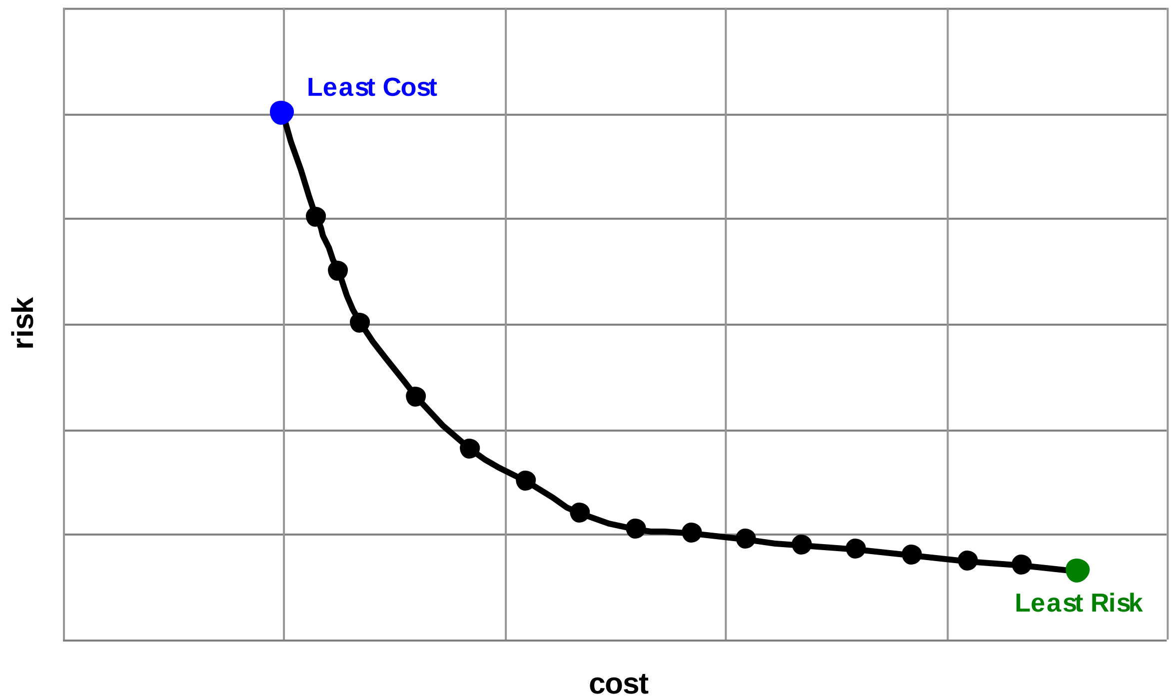
Minimize: $(X_1 * NPV_{2010\text{-}2019}) + (X_2 * NPV_{2010\text{-}2029}) + (X_3 * NPV_{2010\text{-}2059})$

Where: X_1 = Weight of net costs over the first 10 years
X_2 = Weight of net costs over 20 years of the plan
X_3 = Weight of net costs over the next 50 years
NPV is the net present value of total cost (existing resource marginal costs, all future resource fixed and variable costs, and all future conservation costs and the net short-term market sales/purchases).

Subject to: Capacity Needs
Energy Needs
Washington RPS
Resource Limitations
Resource Availability
Risk Tolerance

PRiSM creates a hypothetical set of resource options at various cost and risk levels. The hypothetical resource set is used to develop the Efficient Frontier. The Efficient Frontier captures the optimal resource selection, given constraints at each level of cost and risk; Figure 8.2 illustrates the Efficient Frontier. The optimal point on the curve depends on the level of risk Avista and its customers are willing to accept. As discussed in the 2007 IRP, utility-scale resource options are limited because of environmental legislation. Two portfolio planning assumptions from the 2007 IRP are not continued for this plan: RPS requirements can no longer be met entirely with utility purchases of renewable energy credits (RECs), and long-term fixed-price natural gas is not available to the portfolio. The loss of these options further limits resource choices compared with the 2007 IRP. Avista does not expect it will be able to acquire sufficient RECs at a reasonable price to meet the RPS, and REC purchases expose the Company to potential volatility that asset ownership would not. For resource planning purposes, REC purchases are an option, but not in excess of 45,000 per year. Work since the 2007 IRP found that a long-term fixed-price natural gas contract is prohibitively expensive because it consumes an inordinate amount of Company capital.

Figure 8.2: Efficient Frontier Curve



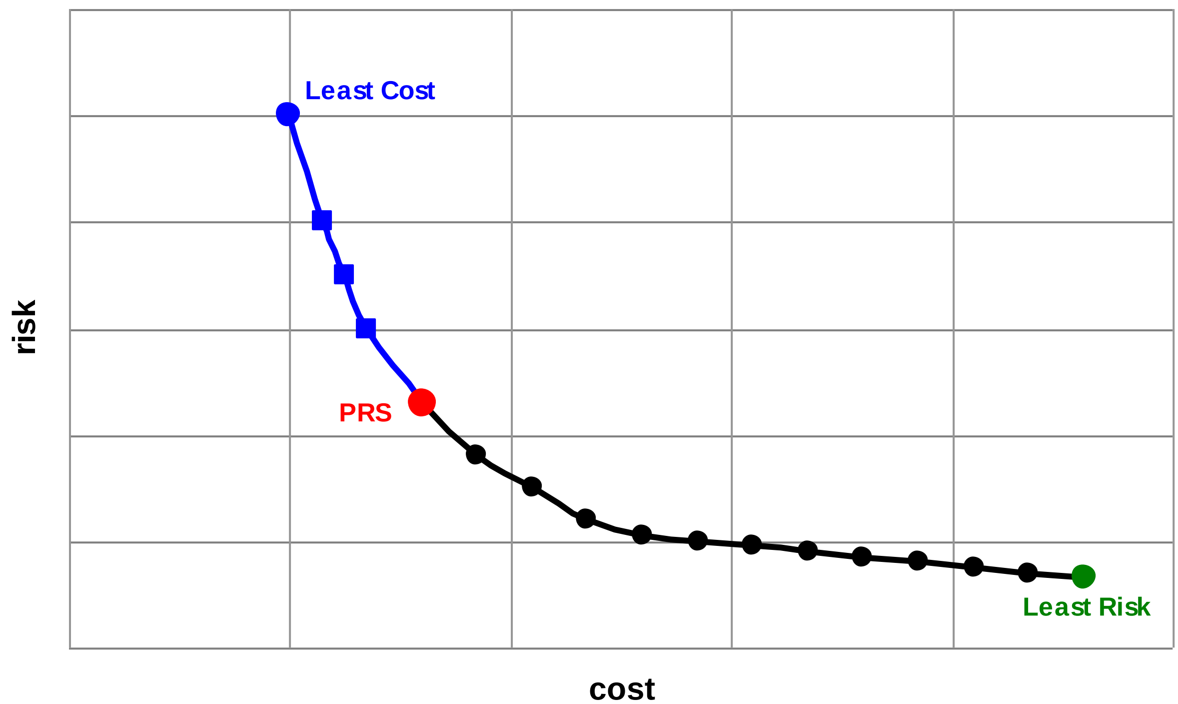
Constraints

As discussed earlier in this chapter, constraints are necessary to solve for the optimal resource strategy. Some constraints are physical and others are societal. The major resource constraints are: capacity and energy needs, Washington's RPS and greenhouse gases (SB 6001).

The PRiSM model is limited by resource type and size. It can select from combined- and simple-cycle natural gas-fired combustion turbines, wind, and small hydro upgrades. Sequestered coal plants are available beginning in 2023. A new enhancement to PRiSM allows it to select resources in minimum sizes rather than mathematically optimal increment. This change better reflects how Avista actually acquires resources. It also emulates how the Company manages lumpy resource additions and that resource positions are not perfectly balanced with load in each year. PRiSM is allowed to model Avista's portfolio to be as much as 50 MW short or 200 MW long in any given planning year.

Washington's RPS fundamentally changed how Avista plans to meet future loads. Historically an Efficient Frontier was created with the least-cost strategy on one end and the least-risk strategy on the other. Next, management decided where they wanted to be on the continuum, based on risk appetite. The least cost strategy typically consisted of gas-fired resources. Portfolios with less risk replaced some of the gas-fired resources with wind, other renewables and coal. Past IRPs identified strategies that included these risk-reduction resources. For illustration, these strategies are represented on the Efficient Frontier as a red dot in Figure 8.3. Washington's laws requiring the acquisition of renewable generation or RECs and essentially banning new coal-fired facilities, effectively remove the lowest-cost portion of the efficient frontier, illustrated in blue in Figure 8.3. The added constraints greatly reduce the Company's ability to reduce future costs. The 2009 IRP is therefore based on the least-cost strategy that still complies with state laws, rather than a portfolio selected on a full vetting of cost and risk.

Figure 8.3: Efficient Frontier in a Constrained Environment



Resource Shortages

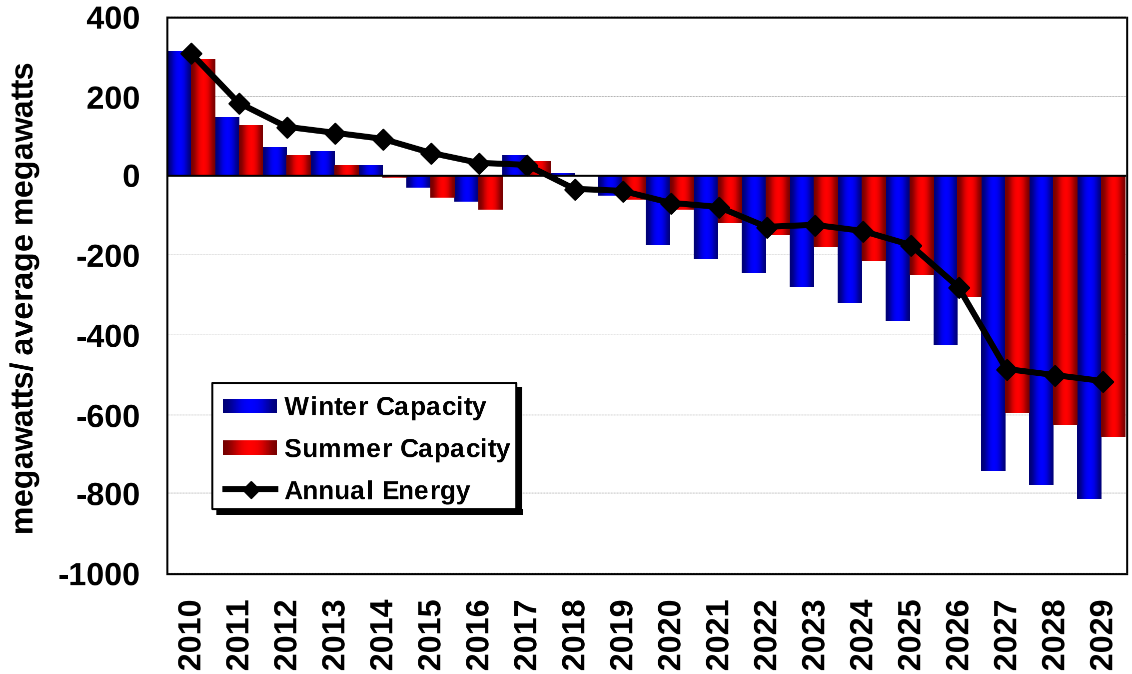
Avista has adequate resources to meet annual physical energy and capacity needs until 2014. See Figure 8.4. The graphic accounts for energy efficiency and conservation program impacts on the portfolio. In other words, absent these efficiency gains, our position would be deficit sooner. The first capacity deficit is short-lived because a 150 MW exchange contract ends in 2016. Avista plans to address the 2014-2016 capacity deficit with market purchases as 2014 approaches.

The Company's resource portfolio has 226 MW of natural gas-fired peaking plants available to serve winter loads. For long-term planning these resources are assumed to be available to generate energy at their full capabilities. Operationally, the resources likely will be displaced with less expensive purchases from the wholesale marketplace.

On an annual average basis, our loads and resources fall out of balance in 2018 for energy; the first quarterly energy deficit is in the fourth quarter of 2014.

PRiSM selects new resources to fill capacity and energy deficits, although the model might over- or under-build where economics support it. Because of its greater capacity need, Avista will retain large energy surpluses created by the acquisition of resources with capacity attributes.

Figure 8.4: Physical Resource Positions



Planning Criteria

Avista uses several risk mitigation methods to manage its energy and capacity positions. For the capacity, peak load is reflected at the higher of the median coldest or hottest daily temperature on record in the Spokane area. Resources are net against the peak load at their expected capacities at that time of system peak; long-term contracts are also netted in the calculation. A 15 percent planning margin is added to load to represent extreme weather and resource forced outages. The NPCC suggests Northwest planning margin levels of 25 percent for winter and 17 percent for summer. Avista staff has evaluated several methods to determine whether it has adequate reserves, including a sustained peak analysis and loss of load probability calculations. Its evaluations indicated that a 15 percent planning margin is adequate for planning purposes.

Avista uses a similar method for energy planning to the peak analysis. Load levels use historic temperatures and include an adjustment for extreme weather, set at a 90 percent confidence level (single-tail). Thermal resources include forced outage rates and planning maintenance downtimes. The largest adjustment is to hydro energy, where water levels are set to a level exceeded in nine out of 10 years.

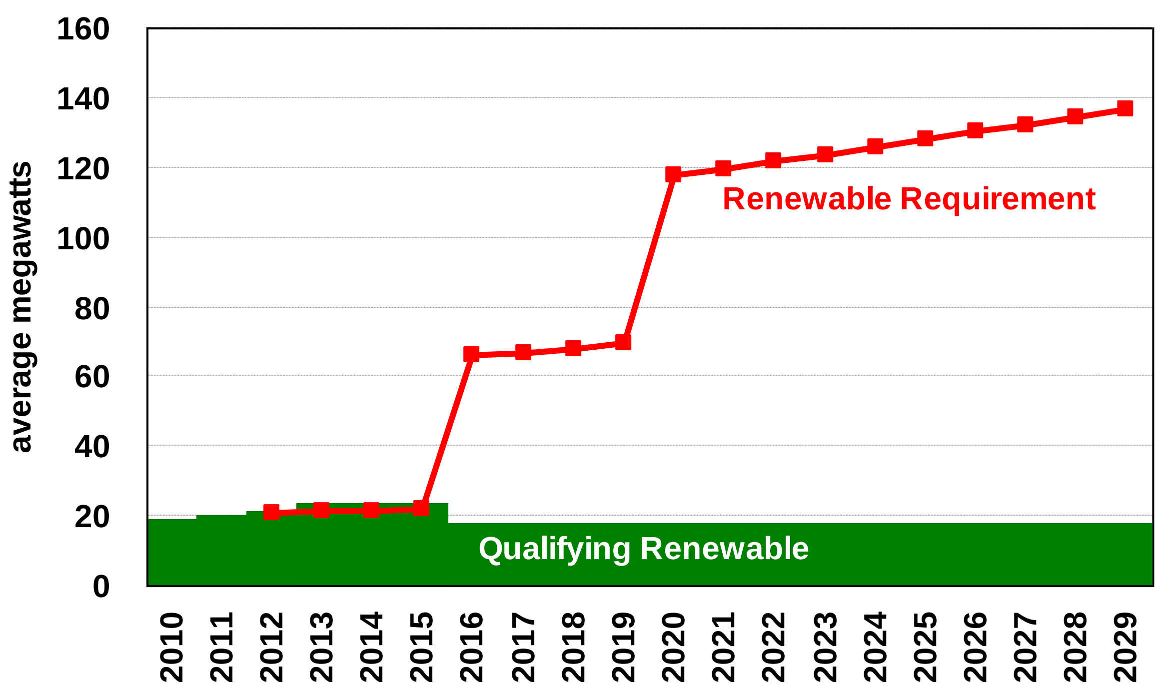
Renewable Portfolio Standards (I-937)

In the November 2006 general election, Washington voters approved Initiative 937, the Energy Independence Act. The initiative requires utilities with over 25,000 customers to meet three percent of load from qualified renewables by 2012, nine percent by 2016, and 15 percent by 2020. The initiative also requires utilities to acquire all cost effective conservation and energy efficiency measures.

Avista is projected to meet or exceed its renewable requirements between 2012 and 2015 through hydro upgrades and a REC purchase, as shown in green in Figure 8.5. Avista has the ability to bank RECs acquired from the Stateline Wind contract in 2011 for 2012, but these RECs are sold to customers as part of the buck-a-block program. As part of the REC analysis, Avista included a 10 percent margin so Avista is not forced to make REC purchases in a strained market when hydroelectric generation or load varies from its expectation and the Company would potentially be required to pay a $50 per MWh penalty.

The Company will need its next block of qualifying resources prior to 2016, and another block will be required prior to 2020. Assuming Avista meets RPS requirements with wind, as illustrated later in this section, it will require 150 MW of nameplate capacity by 2016 and a similar amount by 2020. After 2020 Avista will continue to acquire renewable resources to meet load growth as specified in the Washington RPS law.

Figure 8.5: REC Requirement vs. Qualifying RECs for Washington State RPS



Preferred Resource Strategy

The 2009 PRS consists of hydro upgrades, wind, conservation, efficiency programs, and natural gas-combined cycle gas turbines. The first resource acquisition is 150 MW of wind by the end of 2012 to take advantage of federal tax incentives. Based on expected capital cost growth rates and the likelihood of the tax credits not being extended beyond 2012, Avista will develop wind projects prior to its 2016 need.

Avista will also begin rebuilding distribution feeders over the next five years. The PRS includes five MW of capacity savings at time of peak and 2.7 aMW of energy savings. More discussion on this topic is included in the transmission upgrades section of the Transmission and Distribution chapter.

Avista already has committed itself to upgrades at its Noxon Rapids and Nine Mile Falls projects. The PRS identified further cost-effective upgrade opportunities at Little Falls and Upper Falls. These upgrades together provide 5 MW of capacity, 2 aMW of energy and generation qualifying for the Washington RPS.

The PRiSM model selected its first large capacity addition in 2019, a 250 MW combined cycle combustion turbine. Another 150 MW of wind capacity is also needed by the end of 2019 for the final 15 percent RPS goal, followed by a 50 MW wind resource in 2022 to meet additional RPS obligations for load growth. In 2024 and 2027 another 250 MW natural gas combined-cycle plant is needed to meet projected capacity deficits created by the expiration of the Lancaster tolling agreement. Table 8.1 presents PRS resources.

Table 8.1: 2009 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
NW Wind	2012	150.0	48.0
Distribution Efficiencies	2010-2015	5.0	2.7
Little Falls Unit Upgrades	2013-2016	3.0	0.9
NW Wind	2019	150.0	50.0
CCCT	2019	250.0	225.0
Upper Falls	2020	2.0	1.0
NW Wind	2022	50.0	17.0
CCCT	2024	250.0	225.0
CCCT	2027	250.0	225.0
Total		**1,110.0**	**794.6**

The 2007 PRS is shown in Table 8.2 for comparison. The major difference between the 2009 and 2007 IRPs is the absence of non-wind renewables and an earlier acquisition of wind resources in the 2009 plan. The 2014 share of a CCCT plant was removed, due to a lower load forecast and the decision to fill a temporary capacity shortfall with market purchases. The 2009 plan includes 750 MW of natural gas and 350 MW of wind. The 2007 plan included 677 MW of natural gas-fired generation and 300 MW of wind.

Table 8.2: 2007 Preferred Resource Strategy

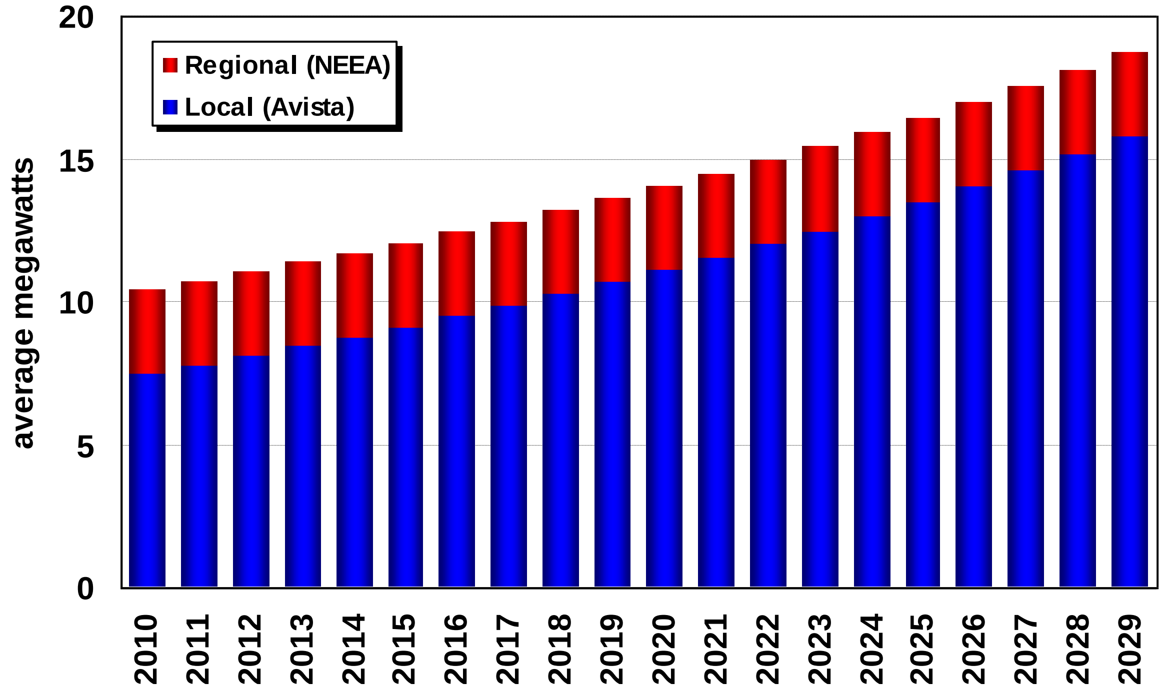
Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Non-Wind Renewable	2011	20.0	18.0
Non-Wind Renewable	2012	10.0	9.0
NW Wind	2013	100.0	33.0
Non Wind Renewable	2013	5.0	4.5
Share of CCCT	2014	75.0	67.5
NW Wind	2015	100.0	33.0
NW Wind	2016	100.0	33.0
Non Wind Renewable	2019	10.0	9.0
Non Wind Renewable	2020	10.0	9.0
Non Wind Renewable	2021	5.0	4.5
Share of CCCT[1]	2019	297.0	267.3
Share of CCCT	2027	305.0	274.5
Total		**1,037.0**	**762.3**

Energy Efficiency and Conservation

Energy efficiency is an integral part of the PRS analytical process. Energy Efficiency is also a critical part of the Washington RPS, where utilities are required to obtain all cost effective conservation. Avista uses internal analysis to develop its avoided energy costs and compares these figures against an acquirable supply curve of conservation. The 20-year forecast of acquired energy efficiency is shown in Figure 8.6. Avista will acquire 102 aMW of energy efficiency over the next 10 years and 226 aMW over 20 years. These acquisitions will also reduce the system peak. Efficiency gains are expected to shave 153 MW from the 2020 peak, and 339 MW from the 2029 peak.

[1] The 2007 IRP modeled CCCT resource acquisitions after the first 10 years, as the remaining capacity requirements would be served by a CCCT resource rather than resource sizes in specified years.

Figure 8.6: Energy Efficiency Annual Expected Acquisition



Reardan

Avista purchased the development rights for the Reardan wind site from Energy Northwest in 2008. The site is fully permitted for development and has several years of meteorological data. Reardan is an attractive wind site for Avista because of its close proximately to Spokane—the site is 23 miles west of downtown Spokane. The site is expected to deliver between 28 and 32 percent capacity factor depending on the final project configuration. This wind site is competitive to higher capacity factor sites since the project does not require any third party transmission and its proximity to Avista crews. The site has the potential to supply between 50 and 100 MW of wind.

Additional Northwest Wind

Avista anticipates issuing an all-renewables request for proposals (RFP) in 2009. The RFP will be for wind projects and other renewable generating facilities with expected generation up to 50 aMW. If Reardan is found to be cost-effective relative to the RFP, the total amount of generation acquired from the competitive bidding process will be reduced.

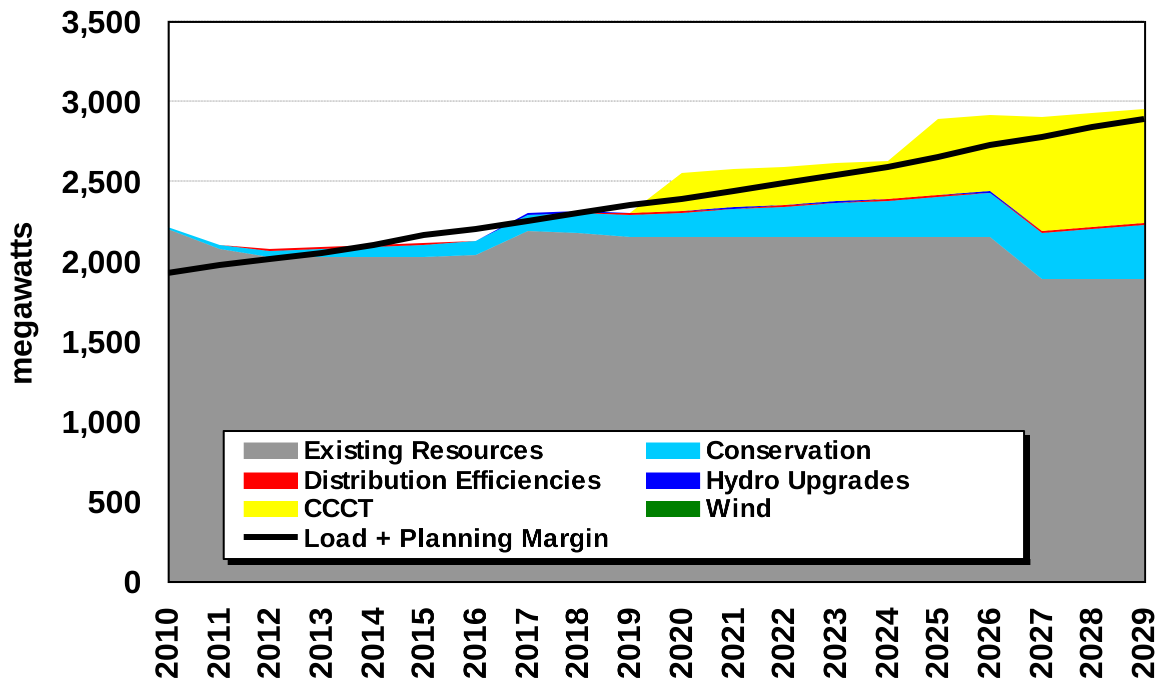
Hydro Upgrades

This IRP has analyzed the potential for upgrades on Avista's hydro system. Small upgrades are included in the PRS analysis, while larger projects are considered as scenarios since they will require more detailed engineering work to determine the ultimate cost of each project. The PRS analysis found four hydro upgrades should be pursued. Little Falls Units 1, 2 and 4 requires generator rewinds and replacement of their generator shafts. Two of the units will also require new runners. The upgrades will provide an additional 1 MW of capacity and 0.32 aMW of energy for each unit. The Upper Falls upgrade will require a generator rewind and runner replacement. The upgrade will add 2.0 MW of capacity and 1.0 aMW of energy. These hydro upgrades add system capacity and provide renewable energy credits.

Loads and Resource Balances

The load forecast has been reduced by assumed conservation levels identified in the 2007 IRP. The load forecasts shown in the following charts decrement conservation from the load forecast to show conservation as a resource. The peak load forecasts are reduced by 1.5 times the average conservation acquisition level. The energy load and resource balance (L&R) forecast (Figure 8.7) reaches its first negative net position in 2016 absent conservation; conservation efforts delay the resource deficit by two years, until 2018. The PRS additions remove all negative positions from the L&R position. The CCCT resource included in January 2020 could be brought online as early as 2015 without any significant impact on the PRS where loads differ from the present forecast or other factors make the resource attractive prior to that year (see the end of this chapter for detailed L&R tables).

Figure 8.7: Annual Average Load & Resource Balance



The first winter peak deficit without conservation occurs in 2014 and the deficit is delayed to 2015 with conservation (see Figure 8.8). The resource portfolio shows deficits for 2015 and 2016, but returns to a surplus position in 2017 with the expiration of a 150 MW capacity exchange contract. Avista intends to meet this short-term deficiency with market purchases rather than acquiring a resource prior to a sustained long-term need. However, if the Company determines that it cannot depend on the market during this time period, a capacity resource could be added without a significant impact on the long-term portfolio cost. PRiSM added the first CCCT resource in 2020, leaving a small short position in 2019 that would be filled with market purchases.

The summer peak L&R is similar to the winter peak L&R. While peak loads are lower in summer than winter, hydro and thermal generation capacity is also lower during the summer. As shown in Figure 8.9, summer resource deficits occur in 2013 without conservation and in 2014 with conservation measures. The Company plans to fill the short-term deficit position between 2014 and 2016 with market purchases.

Figure 8.8: Winter Peak Load & Resource Balance

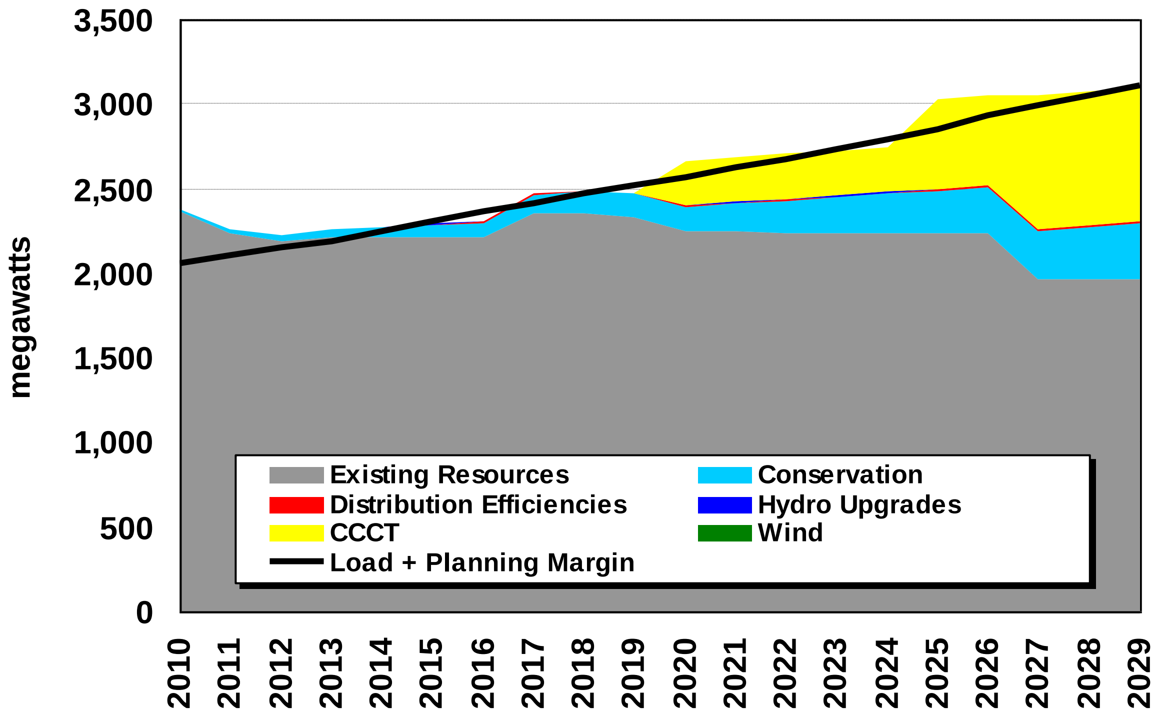
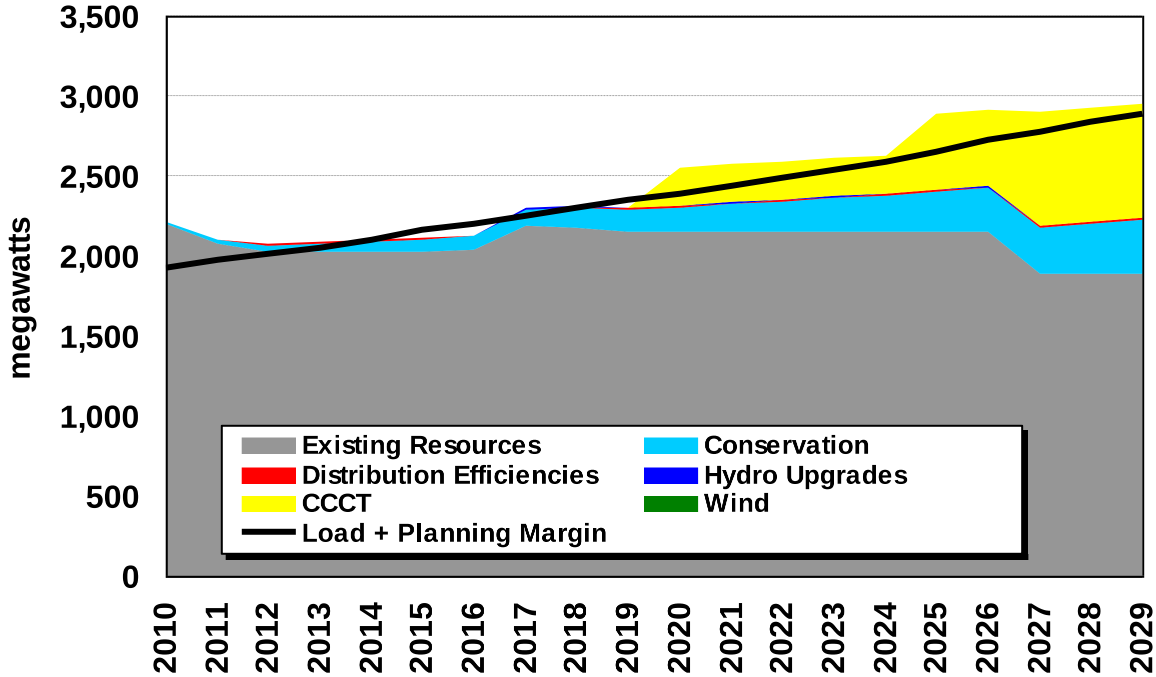


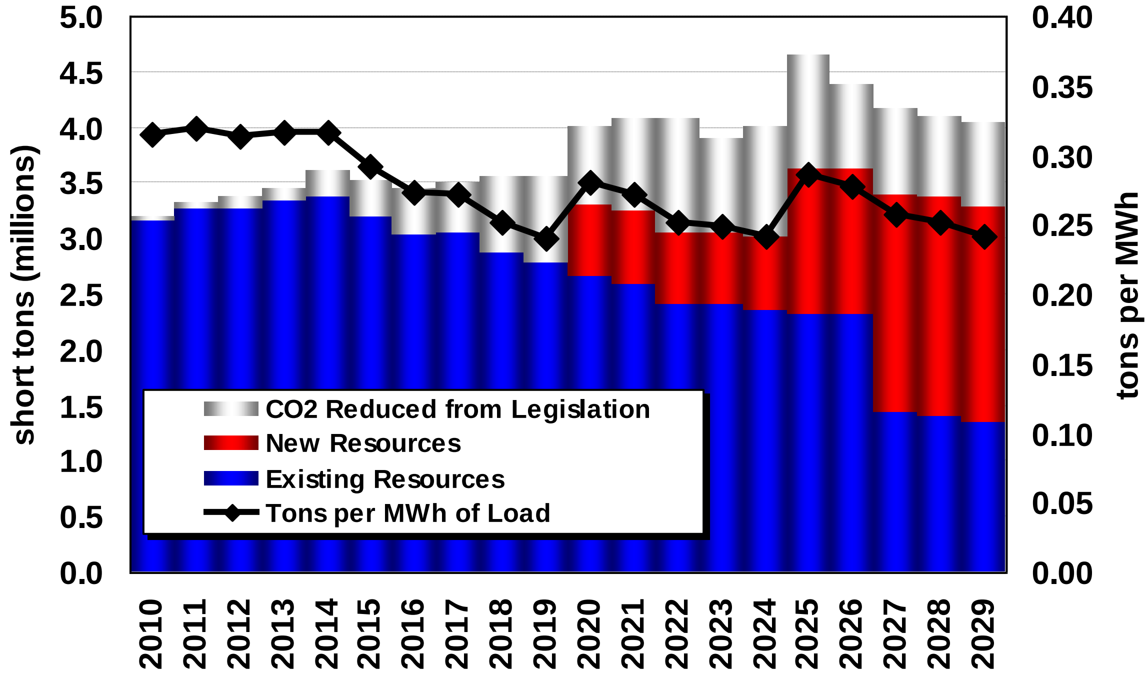
Figure 8.9: Summer Peak Load and Resource Balance



Greenhouse Gas Emissions

The Market Analysis chapter discusses how greenhouse gas emissions in the Western Interconnect will decrease. Avista's greenhouse gas emissions might not fall due to the cap and trade market. The projected cap and trade market interaction will first impact more costly carbon emitting facilities before reaching facilities with low operating cost. This will affect existing coal resources with high fuel and incremental operation costs as they will be replaced with new or underutilized natural gas-fired resources located closer to west coast load centers. Figure 8.10 shows Avista's expected PRS greenhouse gas emissions. Emissions will be near 2010 levels on an annual basis, but not decreasing, by the end of 2029. The emissions for the current resource portfolio will be reduced as Colstrip's output will decrease and the natural gas facilities will increase generation. The addition of new gas facilities to meet growing loads will contribute to the Company's emission total. Emissions by 2029 would be 23 percent higher if no carbon legislation was implemented. Avista's carbon intensity is projected to fall by 0.32 short tons per MWh to 0.24 short tons per MWh.

Figure 8.10: Avista Owned and Controlled Resource's Greenhouse Gas Emissions



Efficient Frontier Analysis

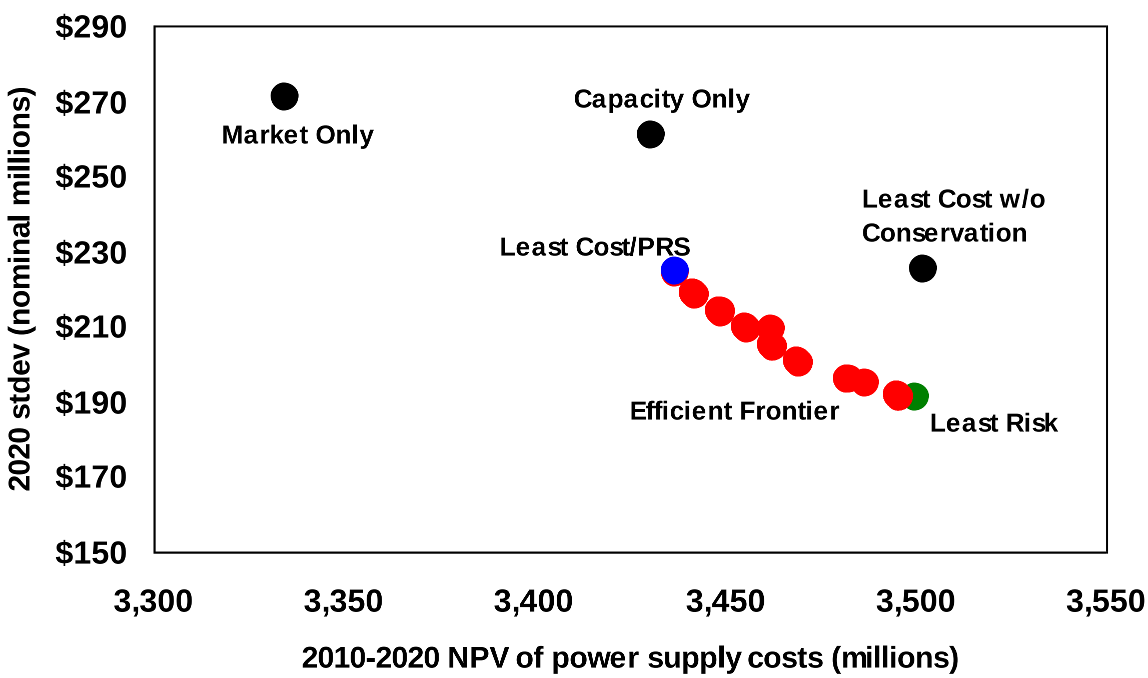
The backbone of the PRS is the efficient frontier analysis. This analysis illustrates the relative performance of potential portfolios to each other on a cost and risk basis. The curve created in the analysis represents the least-cost strategy at each level of risk. The PRS analyses examined the following portfolios, as detailed here and in Figure 8.11:

- **Market Only**: No conservation measures, deficits are met with spot market purchases, and capacity and RPS constraints are not met with new resources.
- **Capacity Only**: No conservation measures or resources are added to meet capacity needs and RPS requirements are ignored.
- **Least Cost without Conservation**: Least cost strategy (excluding conservation measures) meeting capacity and RPS requirements.
- **Least Cost**: Least cost strategy that includes conservation measures meeting all capacity and RPS requirements.
- **Least Risk**: Meets capacity and RPS requirements with the lowest risk.
- **Efficient Frontier:** A set of intermediate portfolios between the least risk and least cost options.

The Market Only strategy is the least cost strategy from a long-term financial perspective, but it has a high risk level. This strategy fails to meet RPS requirements unless REC purchases are made and does not acquire capacity resources for reliability.

The Capacity Only strategy meets reliability needs with CT plant additions, but its dispatch will be primarily displaced by wholesale market purchases in most hours. This strategy does not meet RPS requirements or relieve volatility, except for tail risk. Another strategy to consider is the Least Cost without Conservation strategy, it reduces risks with wind resource additions and selects CCCT resources rather than CTs; this portfolio meets RPS and capacity requirements. Each portfolio is used to develop the avoided costs for determining the cost effectiveness of conservation measures.

Figure 8.11: Base Case Efficient Frontier



The cost differentials between each portfolio quantifies the avoided costs of the following items:

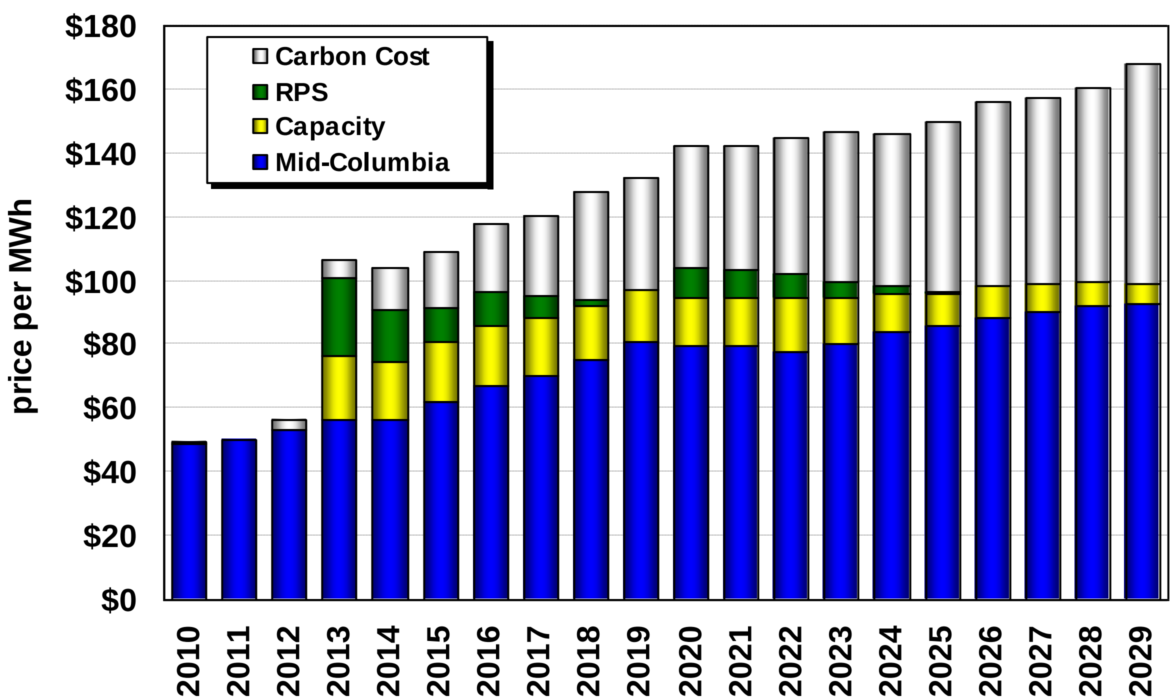
- Market costs: Market Only portfolio.
- Capacity costs: difference between the Market Only and Capacity Only strategies.
- RPS and risk reduction costs: difference between the Capacity Only and Least Cost without Conservation strategies.
- Carbon costs: difference between market prices in the Base Case and the Unconstrained Carbon scenario.

The levelized avoided costs for each item are shown in Table 8.3. The annual avoided conservation costs are shown in Figure 8.12. Avoided costs are determined by resource need and Mid-Columbia market prices. The first adder to Mid-Columbia prices is the carbon adder in 2012, and then capacity and RPS adders are included. The RPS cost-adder disappears in 2019 and 2025, as a result of the selected resources recovering their costs from the market place rather than rate payers.

Table 8.3: Levelized Avoided Costs ($/MWh)

	Nominal	2009 Dollars
Mid-Columbia	68.22	54.37
Carbon	25.52	19.83
Capacity	11.66	9.29
Risk	5.76	4.68
Total	**111.15**	**88.18**

Figure 8.12: Avoided Costs for Conservation

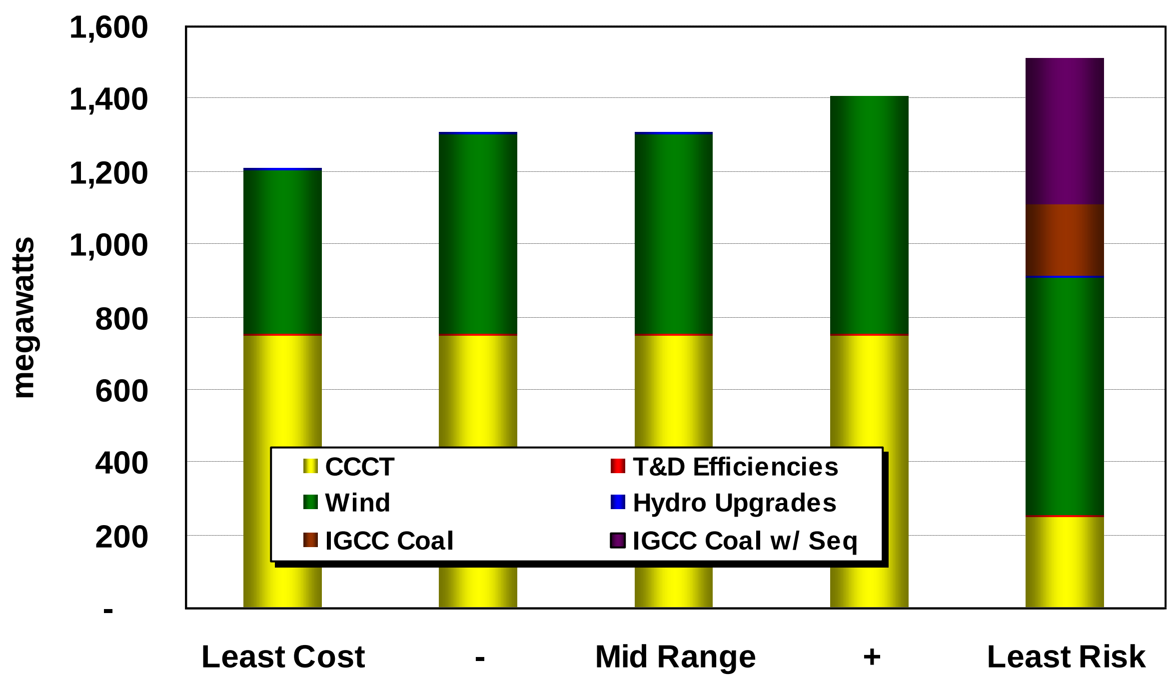


A $111.15 per MWh levelized avoided cost added enough conservation to lower costs by $65 million. This strategy reduces risk 14 percent with the addition of wind and conservation resources. The efficient frontier portfolios decrease risk but increase costs. These portfolios add wind resources beyond RPS levels and exchange CCCT plants at the end of the study for sequestered coal resources. Avista historically selected resources on the efficient frontier, but Washington law requires portfolios to include a certain percentage of RPS qualified renewables, effectively causing utilities to accept less market risk. The least-cost portfolio, with capacity and RPS constraints, was selected over alternative portfolios.

Efficient Frontier Portfolios

The efficient frontier analysis creates resource portfolios for given levels of risk and cost. Avista's management selected the least cost portfolio because of the significant risk reductions already present in it with the inclusion of RPS obligations. Figure 8.13 shows a range of resource portfolios from the efficient frontier. Resource portfolios are similar, but differ in the amount and timing of wind acquisitions.

Figure 8.13: Efficient Frontier Portfolios 2029 New Resources



Expected Costs

The stochastic market analysis illustrates a potential range of costs, using different market outcomes. The final discussion covers the range of carbon costs that might be added to power supply costs, given carbon legislation's potential impact on the natural gas market, reductions in coal-fired generation dispatch, and increases in the dispatch of natural gas-fired resources.

Capital

The PRS first requires capital in 2010 for distribution feeder upgrades, followed by additional capital needs for wind development. The capital cash flows in Table 8.4 include AFUDC costs and account for various tax incentives including the federal investment tax credit. Costs are shown for the years where capital would be placed in rate base, rather than when capital is actually expended. The present value of the required investment is just over $1 billion. Avista may not have to supply all of the capital that has been identified where it chooses to procure resources through power purchase agreements.

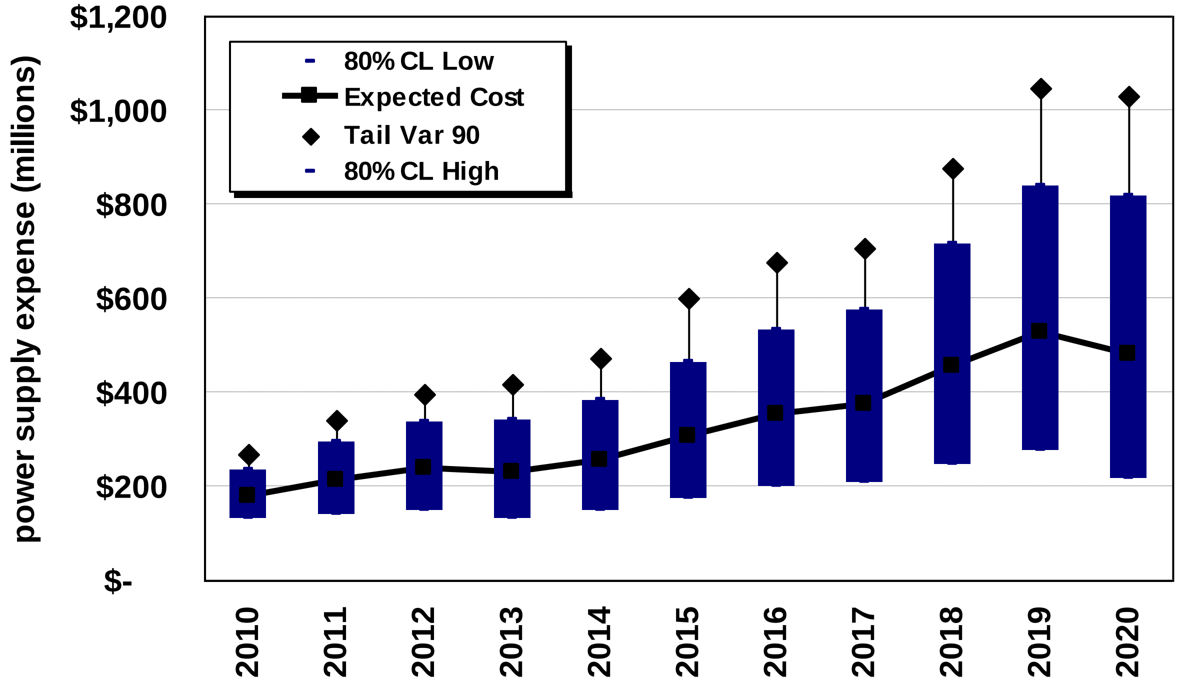
Table 8.4: PRS Rate Base Additions for Capital Expenditures (Millions of Dollars)

Year	Investment	Year	Investment
2010	4.9	2020	942.1
2011	5.0	2021	10.6
2012	5.1	2022	0.0
2013	278.1	2023	163.3
2014	7.7	2024	0.0
2015	2.3	2025	542.0
2016	0.0	2026	0.0
2017	1.7	2027	571.6
2018	0.0	2028	0.0
2019	0.0	2029	0.0
2010-2019 Total	304.8	2020-2029 Totals	2,229.6

Annual Power Supply Expenses and Volatility

The PRS analyses track fuel, variable O&M, emissions, and market transaction costs for the existing resource portfolio. These costs are captured for each of the 250 iterations of the Base Case risk analysis. In addition to existing portfolio costs, new resource capital, fuel, O&M, emissions, and other costs are tracked to provide a range in potential costs to serve future loads. Figure 8.14 shows expected PRS costs modeled through 2020 as the black line. In 2010 costs are expected to be $180 million. The 80 percent confidence interval, shown in blue, ranges between $130 and $233 million. The black diamonds represent the TailVar 90 risk level, or the top 10 percent of the worst outcomes; this 2010 cost is $270 million. As natural gas and greenhouse gas prices increase, power supply costs also increase. Price uncertainty increases with time and the confidence interval band expands. The 2020 reduction is created by the addition of wind and CCCT resources.

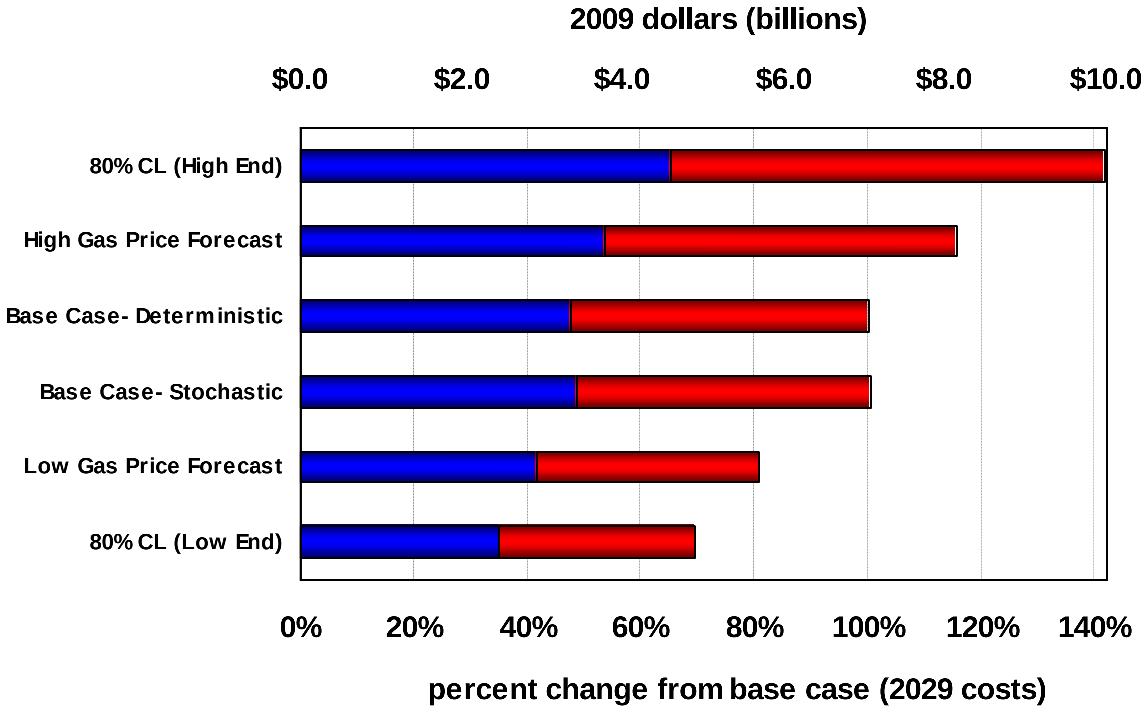
Figure 8.14: Power Supply Expense



Natural Gas Price Risk

The Market Analysis chapter showed the results of high and low natural gas price forecasts. The PRS includes 750 MW of gas-fired resources and this exposes Avista's customers to natural gas price risk. This section uses natural gas price forecast scenarios to calculate the range in expected costs resulting from the PRS. Figure 8.15 shows the total portfolio cost range using different natural gas points in comparison to the deterministic and stochastic Base Cases. The low gas price scenario reduces expected costs by 20 percent and the high gas price scenario increases costs by 15 percent. Using stochastic model results, rather then the deterministic scenarios, illustrates risk exposure to the wholesale market. The 80 percent confidence interval in Figure 8.5 shows variability due to drivers besides natural gas. The range in costs is logarithmic, meaning there is the potential for extremely high costs but that there is not a commensurate cost reduction where gas prices are low. For example, at the 80 percent confidence level, costs range between 30 percent lower and 40 percent higher than the mean values.

Figure 8.15: Power Supply Cost Sensitivities

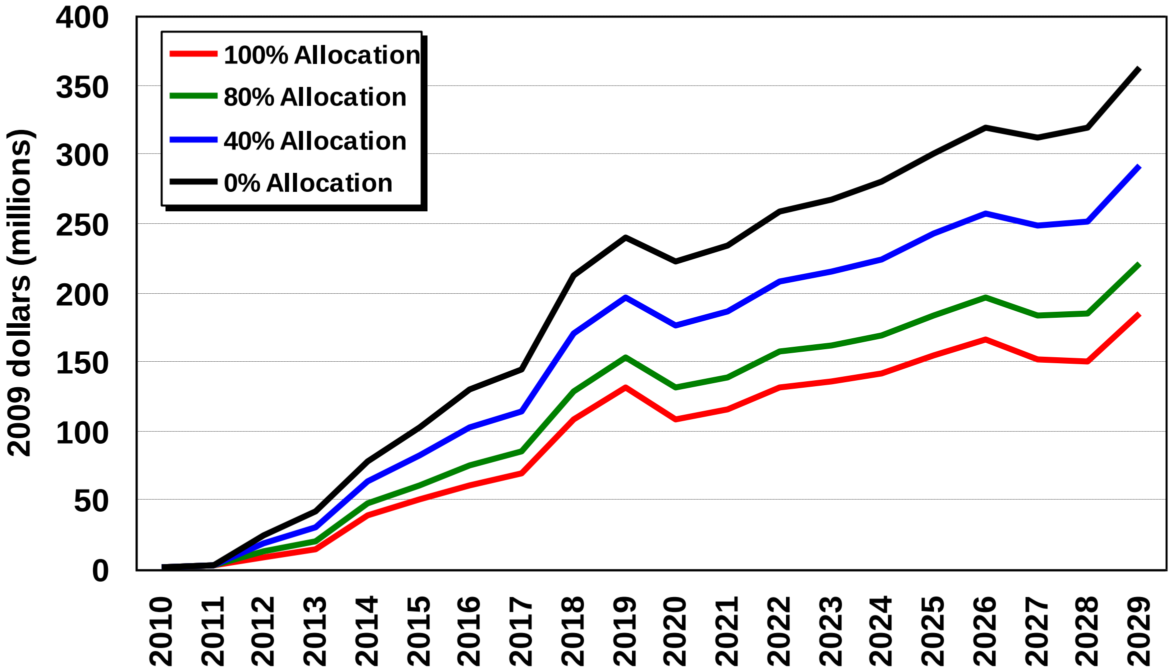


Greenhouse Gas Costs

Avista anticipates that federal greenhouse gas legislation will be enacted within the next three years, so greenhouse gas emission, or carbon cost estimates, are included in the IRP Base Case. The carbon price estimates rely on Wood Mackenzie's forecast from the end of 2008. These prices illustrate possible market and opportunity costs of carbon legislation, but ignore the potential for some level of free carbon allocations. The PRS analysis assumes all carbon credits are auctioned, rather than administratively allocated to utilities. This assumption does not affect the resource strategy because it analyzes the opportunity costs of trading credits for resource decision making. The ultimate number of credits granted versus auctioned to utilities is unknown at this time, and will affect Avista's system costs and rates. The costs shown in Figure 8.16 illustrate the range of total annual carbon costs.

Most of the overall carbon costs are a result of decreased Colstrip generation and increased natural gas and electricity market prices Low cost coal-fired plants are traded for higher-cost natural gas-fired resources. The cost of gas resources is higher than it would be absent carbon legislation because of increased demand for gas-fired resources. These additional costs represent up to 30 percent of total power supply expenses in the Base Case. The costs were calculated by taking the difference in cost between the Base Case against the same resource portfolio in a market without carbon legislation.

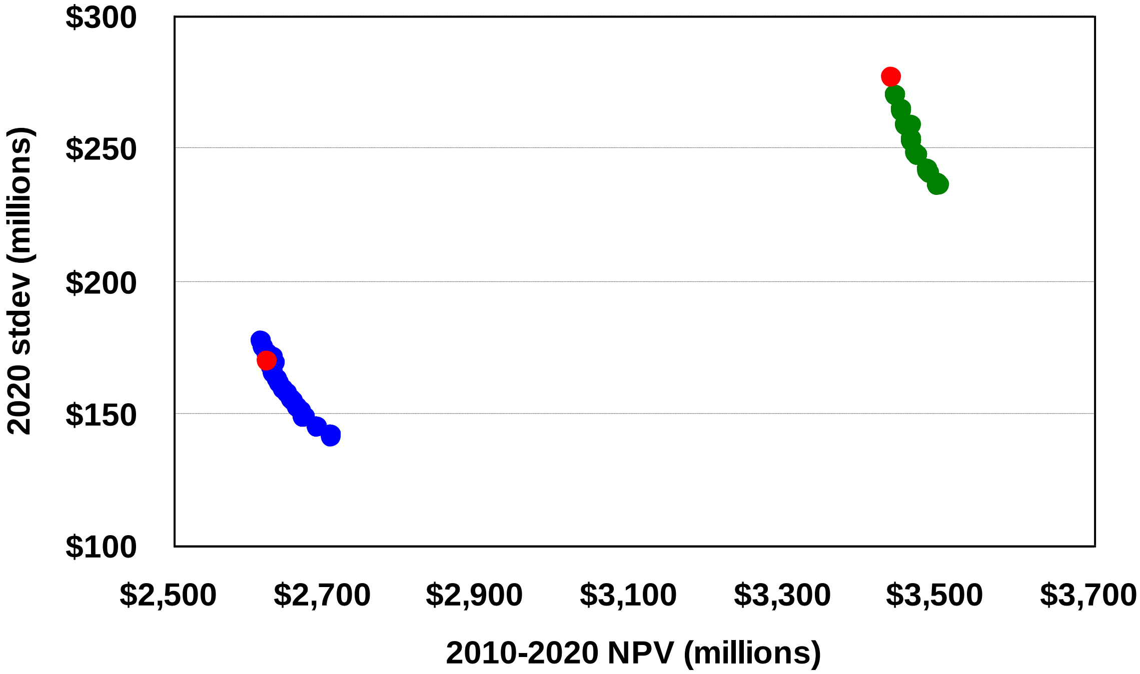
Figure 8.16: Carbon Related Power Supply Expense



Carbon Legislation Impact

The PRS would not differ substantially without carbon legislation because of Washington's RPS and emissions performance standards on new resources. Avista's carbon emissions would be higher, as Colstrip generation would remain at current levels, and the cost and risk to Avista's customers would be much lower. This is illustrated by efficient frontier analysis in Figure 8.17. The green curve on the upper right of the chart is the Base Case efficient frontier with the red dot representing the PRS. The blue curve on the lower left corner of Figure 8.17 represents the efficient frontier without carbon legislation; the curve is less risky and less costly than the Base Case. The red dot on this curve illustrates the non-carbon constrained PRS. A major difference between the resource selections in this scenario is that the least-cost portfolio includes gas-fired peaking plants, rather than combined cycle resources.

Figure 8.17: Efficient Frontier Comparison



The least cost portfolio in this scenario is very similar to the PRS, except 750 MW of combined cycle projects is exchanged for 800 MW of LMS100 type simple-cycle generators and one of the Little Falls Upgrades is dropped (see Table 8.5). The CCCT is the least cost resource in a carbon constrained world because of its low heat rate and the need for additional base load generation to replace coal. But without carbon constraints, the strategy relies instead on gas peaking plants that ultimately are displaced by market purchases.

The PRS in an unconstrained carbon market would decrease expected costs 24 percent to $807 million present value, as well as decrease annual power supply cost variation by 30 percent. Table 8.6 summarizes the cost and risk comparison among the PRS and the least cost scenario in an unconstrained carbon market. The least cost portfolio in the unconstrained carbon scenario decreases cost and increases risk. The strategy has lower carbon emissions from Avista's resources because the strategy uses peaking plants to meet capacity and buys energy from the market, meaning Avista will not directly emitting greenhouse gases.

Table 8.5: Unconstrained Carbon Scenario- Least Cost Portfolio

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
NW Wind	2012	100.0	48.0
Distribution Efficiencies	2010-2015	5.0	2.7
Little Falls 4	2016	1.0	0.3
NW Wind	2019	150.0	50.0
SCCT	2019	200.0	180.0
Little Falls 2	2021	1.0	0.3
Little Falls 1	2022	1.0	0.3
NW Wind	2022	50.0	17.0
SCCT	2022	100.0	90.0
SCCT	2025	100.0	90.0
SCCT	2026	300.0	270.0
SCCT	2028	100.0	90.0
Total		**1,159.0**	**838.6**

Table 8.6: Portfolio Cost and Risk Comparison

	Base Case PRS	UCC PRS	UCC Least Cost Strategy
2010-2020 Cost NPV	$3,430	$2,623	$2,610
2020 Expected Cost	$909	$634	$609
2020 Stdev	$277	$169	$179
2020 Stdev/Cost	30.5%	26.7%	29.4%
2010-2020 Capital	$1,247	$1,247	$1,101
2020 CO_2 Emissions (000's)	3,311	4,016	3,575
2029 CO_2 Emissions (000's)	3,286	4,041	2,928

Portfolio Scenarios

In many resource plans, a PRS is presented with a comparison to other portfolios to help illustrate cost and risk trade-offs. Avista wants to extend the portfolio analysis beyond simple portfolio comparisons for this IRP by focusing on how the portfolio would likely change if assumptions changed. This provides an array of strategies in reaction to fundamentally different futures instead of a single strategy. This section identifies assumptions that could alter the PRS, such as changes to load growth, capital costs, hydro upgrades, the emergence of other small renewable projects, and a nuclear revival.

The 2007 IRP pushed wind resources out to 2013 due to the federal production tax credit and other renewable resource expectations, but due to the lack of sizeable non-wind renewables and the extension of federal tax credits the 2009 IRP suggests that these resources be developed sooner to take advantage of tax savings. The exact online date will depend on the results from a competitive bidding process for wind, expected to be released in 2009. The timing of these resources could change depending on capital costs determined in the RFPs.

Wind Capital Costs Sensitivity

Avista owns the rights and permits to build the Reardan wind project, but has not secured turbines or completed engineering for the site. Most wind projects in this position could be completed by the end of 2010 or 2011. The PRiSM model selects this resource to be on-line by the end of 2012 with an estimated cost of $2,183 per kW (2009 dollars with AFUDC). There are certain tax advantages by beginning project development in 2010, such as taking advantage of the investment tax credit. This analysis determines the tipping point where lower capital costs would allow earlier wind development. The PRiSM model was re-run while lowering the capital cost of wind projects until the model changed the resource timing. The Reardan project was selected to be online by the end of 2010 with an all-in capital cost as high as $1,832 per kW (2009 dollars). This would take advantage of the full U.S. Treasury credit and competitive cost per MWh in a carbon constrained marketplace.

CCCT Capital Cost Sensitivity

The unconstrained market future would lead Avista to consider adding simple cycle CTs to the PRS mix to lower costs, but in the carbon constrained world, CCCT resources have lower net costs. Since CCCT acquisition in the PRS does not occur until the end of the next decade, the cost of this resource likely will change, and the cost relationship compared to a simple cycle CT might also change. This sensitivity analysis determines the maximum CCCT cost that would allow the least cost strategy to select a SCCT over a CCCT. The Base Case cost is $1,533 per kW (2009 dollars with AFUDC), but if the cost were to increase five percent to $1,611 per kW (2009 dollars), the least cost strategy would change to a SCCT.

CCCT in 2015

The PRS does not meet temporary resource deficits in 2015 or 2016 and will require market purchases to maintain a 15 percent planning margin. The return of capacity from the expiration of the Portland General Exchange contract corrects this deficit. If Avista acquired a combined cycle resource by 2015, costs to meet the earlier obligations would increase 10-year present value costs by $102 million or 2.3 percent and reduce power supply risk between 2015 and 2019 by 5.7 percent. The decision to acquire this resource earlier will depend on the Company's expectation the market has the capacity to meet regional peak load. Other scenarios that could impact this decision are dramatic charges in the load forecast, the availability of a sufficient amount of economic renewable resources with capacity, or attractive pricing on a new CCCT.

Load Forecast Alternatives

Loads will probably differ from the current forecast because of the recession, and the greater Spokane area could grow faster with future development activity after the economy recovers. This sensitivity analysis studies the impact to the PRS if loads grow faster or slower than the Base Case estimate. Faster load growth will increase the need for capital at a quicker rate and slower load growth will slow the need for increased capital. This analysis focuses on understanding the changes in timing of resource decisions. The Base Case forecast is for a 1.6 percent growth rate. The low load scenario cuts the growth rate by one percentage point to 0.6 percent and the high growth case increases by one percentage point to 2.6 percent. Table 8.7 shows the resource strategy adjusted for lower growth rates. The lower load growth projection would not change near-term resource acquisitions, but will eliminate the need for some wind and gas-fired resources, as shown in the Modification to Strategy column. Table 8.8 shows the resource strategy with higher growth rates. The amount of near-term wind would increase by 50 MW and additional peaking resources would be acquired by 2011 to compensate for higher growth rates. In later years of the study, additional gas-fired and wind resources would be needed to meet peak load growth and RPS requirements. This analysis indicates that lower load growth would not change near-term resource decisions.

The estimated cost for these portfolios is shown in Figure 8.18. The bars show the net present value of costs between 2010 and 2020 (left axis), and the yellow line represents the nominal capital expenditure for these resources (right axis).

Figure 8.18: High & Low Load Growth Cost Comparison

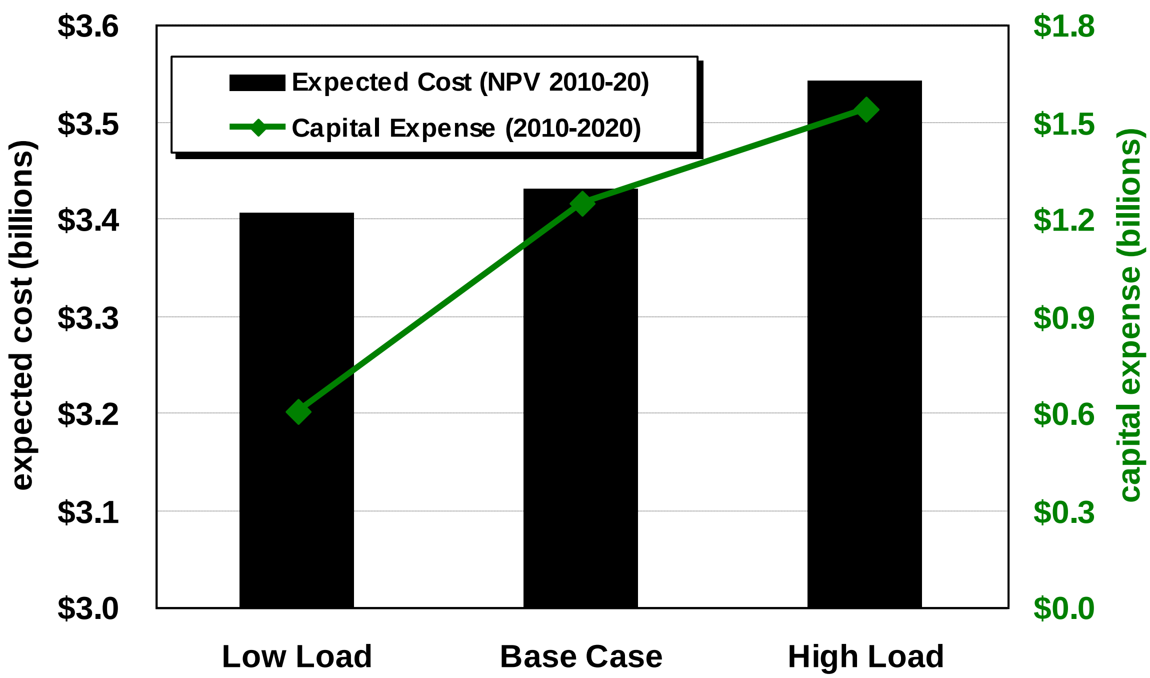


Table 8.7: Low Load Growth Resource Strategy Changes to PRS

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)	Modification to Strategy
NW Wind	2012	100.0	48.0	No Change
Distribution Efficiencies	2010-2015	5.0	2.7	No Change
Little Falls Unit Upgrades	2013-2016	3.0	0.9	No Change
NW Wind	2019	100.0	33.0	Reduced from 150 MW
CCCT				Removed 250 MW
Upper Falls	2020	2.0	1.0	Delayed to 2028
NW Wind				Removed 50 MW
CCCT	2024	250.0	225.0	Delayed to 2025
CCCT				Removed 250 MW
SCCT	2027	100.0	92.3	Added 100 MW
Total		**610.0**	**402.9**	

Table 8.8: High Load Growth Resource Strategy Changes to PRS

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)	Modification to Strategy
NW Wind	2012	200.0	64.5	Increased from 150 MW
Simple Cycle	2011	60.0	92.3	60 MW Added
Distribution Efficiencies	2010-2015	5.0	2.7	No Change
Little Falls Unit Upgrades	2013-2016	3.0	0.9	No Change
Simple Cycle	2013	100.0	92.3	100 MW Added
Simple Cycle	2017	100.0	92.2	100 MW Added
NW Wind	2019	200.0	66.0	Increased from 150 MW
CCCT	2020	250.0	225.0	Delayed from 2019
Simple Cycle	2019	100.0	92.2	100 MW Added
Upper Falls	2020	2.0	1.0	No Change
NW Wind	2022	50.0	17.0	No Change
CCCT	2024	250.0	225.0	No Change
CCCT	2027	250.0	225.0	No Change
Total		**1,570.0**	**1,196.1**	

Large Hydro Facility Scenarios

Renewable Portfolio Standards, capacity needs, and higher electricity market prices are drawing attention to large upgrades at Avista's hydroelectric facilities. Several projects were studied more than 20 years ago, but they were not financially feasible. Avista is reevaluating these projects to determine if there are market and environmental benefits making them cost effective today. The large hydro upgrades analyzed for this IRP are Cabinet Gorge Unit 5 (60 MW), Long Lake Unit 5 (24 MW) and Long Lake second power house (60 MW). Other possible hydro upgrades include a new powerhouse at Post Falls and a second powerhouse at Monroe Street. If studies determine these resources are economically viable, the resource strategy will change because these resources add peak capacity as well as renewable energy credits. Table 8.9 illustrates potential changes to the PRS under the large hydro upgrade scenario. These upgrades cannot be completed prior to the middle of the next decade, so they will not change the near-term resource acquisition plan.

Table 8.9: Large Hydro Upgrade Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)	Modification to Strategy
NW Wind	2012	100.0	48.0	No Change
Distribution Efficiencies	2010-2015	5.0	2.7	No Change
Little Falls Unit Upgrades	2013-2016	3.0	0.9	No Change
Cabinet Gorge 5	2014	60.0	10.2	60 MW Added
Long Lake 2 Powerhouse	2019	60.0	18.0	60 MW Added
NW Wind	2019	100.0	33.0	Reduced from 150 MW
CCCT	2019	250.0	225.0	No Change
NW Wind	2022	50.0	17.0	No Change
CCCT	2026	400.0	360.0	Delayed from 2024 and upgraded from 250 MW
CCCT				Removed 250 MW
Upper Falls	2029	2.0	1.0	Delayed from 2020
Totals		**1,080.0**	**715.8**	

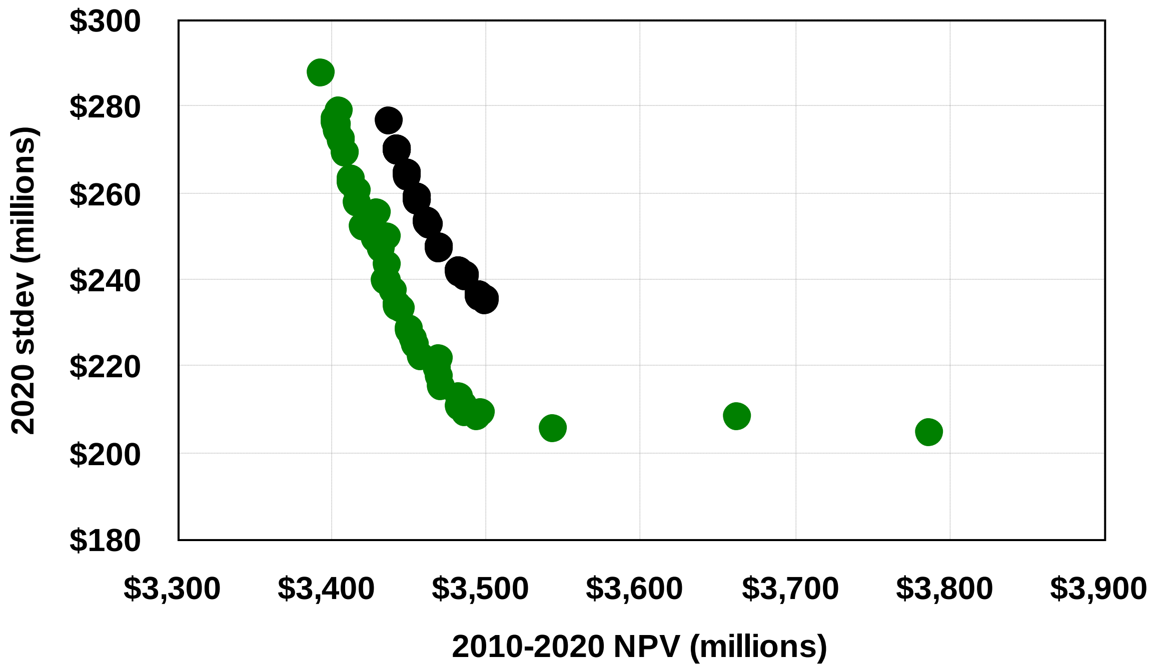
Capital cost sensitivities were performed to determine capital cost needed to select the hydro upgrades for the PRS. The analysis found that although higher in cost, a second power house at Long Lake is more favorable than a new Unit 5 at the plant because of the higher capacity value of that option. Both projects could be built at Long Lake to provide system capacity.

An initial review of capitals cost found that costs would need to be under $2,628 per kilowatt, including transmission upgrades and AFUDC, for the Long Lake second powerhouse to be selected in the least cost resource strategy. The Cabinet Gorge Unit 5 upgrade would need to be under $1,289 per kW, including AFUDC. Avista might pursue these upgrades even with higher capital costs depending on the value placed on reducing total dissolved gas and reduced market exposure.

Small Renewable Resources Scenario

The PRS in the 2005 and 2007 IRPs included small renewable resources. None were included for the 2009 IRP. These resources were available, but dependant on third party development. Small renewable resources have unique project characteristics that will affect project costs. This scenario illustrates changes in the PRS if these resources were included in the efficient frontier analysis. As Avista tries to acquire 150 MW of wind, it will include requests for other renewable resources in the RFP and give resources with dependable capacity more economic benefit in subsequent bidding analysis. Figure 8.19 presents the efficient frontier with the addition of small renewable resources. If non-wind renewables are available to Avista at the prices shown in the resource options chapter, these resources could reduce Avista's costs and risks modestly. Costs are lower because of a reduction in the quantity of resources needed where non-wind renewable resources are able to provide capacity. For example, a 25 MW wind project is not credited with any reliable capacity in this analysis, so it must be backed up with a resource that provides capacity. A 25 MW renewable resource with capacity does not require another resource to provide back-up capacity. These small renewable resources are not risk free because the owner might cease production at some point in the contract term. Biomass facilities require an industrial waste product as fuel, so a downturn in the industry reduces fuel availability. Geothermal resources are interesting to Avista because of the potential for low cost and stable base load power, but the availability of this resource has been questioned recently by the Northwest Power and Conservation Council and only one recent geothermal resource has been built in the Northwest.

Figure 8.19: Efficient Frontier Base Case vs. Other Renewables Available



Where Avista was able to find non-wind renewables, the new resource strategy will also lower greenhouse gas emissions (see Table 8.10). The PRS changes under the small renewable resource scenario are shown in Table 8.11. The strategy reduces wind capacity by 100 MW and trades 100 MW of CCCT for SCCT (the cause for increased risk).

Table 8.10: Portfolio Cost and Risk Comparison

	Base Case PRS	Non-Wind Renewable Least Cost
2010-2020 Cost NPV	$3,430	$3,393
2020 Expected Cost	$909	$875
2020 Standard Deviation	$277	$288
2020 Standard Deviation/Cost	30.5%	30.9%
2010-2020 Capital	$1,247	$840
2020 CO_2 Emissions ('000s)	3,311	2,771
2029 CO_2 Emissions ('000s)	3,286	3,145

Table 8.11: Other Renewables Available- Changes to PRS

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)	Modification to Strategy
Biomass/Geothermal	2011	10.0	9.1	10 MW Added
Reardan Wind	2012	50.0	15.0	No Change
NW Wind	2012	50.0	17.0	Reduced from 100 MW
Biomass/Geothermal	2012	5.0	4.5	5 MW Added
Biomass/Geothermal	2013	5.0	4.5	5 MW Added
Distribution Efficiencies	2010-2015	5.0	2.7	No Change
Little Falls Unit Upgrades	2013-2016	3.0	0.9	No Change
Wood Biomass	2017	5.0	4.5	5 MW Added
KFCT Wood Conversion	2019	7.0	0.0	Capacity/Energy Neutral RECs Added
NW Wind	2019	100.0	33.0	Reduced by 50 MW
Simple Cycle CT	2019	100.0	92.3	100 MW Added
CCCT	2020	250.0	225.0	Delayed from 2019
Upper Falls	2020	2.0	1.0	No Change
NW Wind	2023	50.0	17.0	Delayed from 2022
CCCT	2026	400.0	360.0	Delayed from 2024 and changed to 400 MW
CCCT				250 MW in 2027 Removed
Total		**1,092.0**	**802.5**	

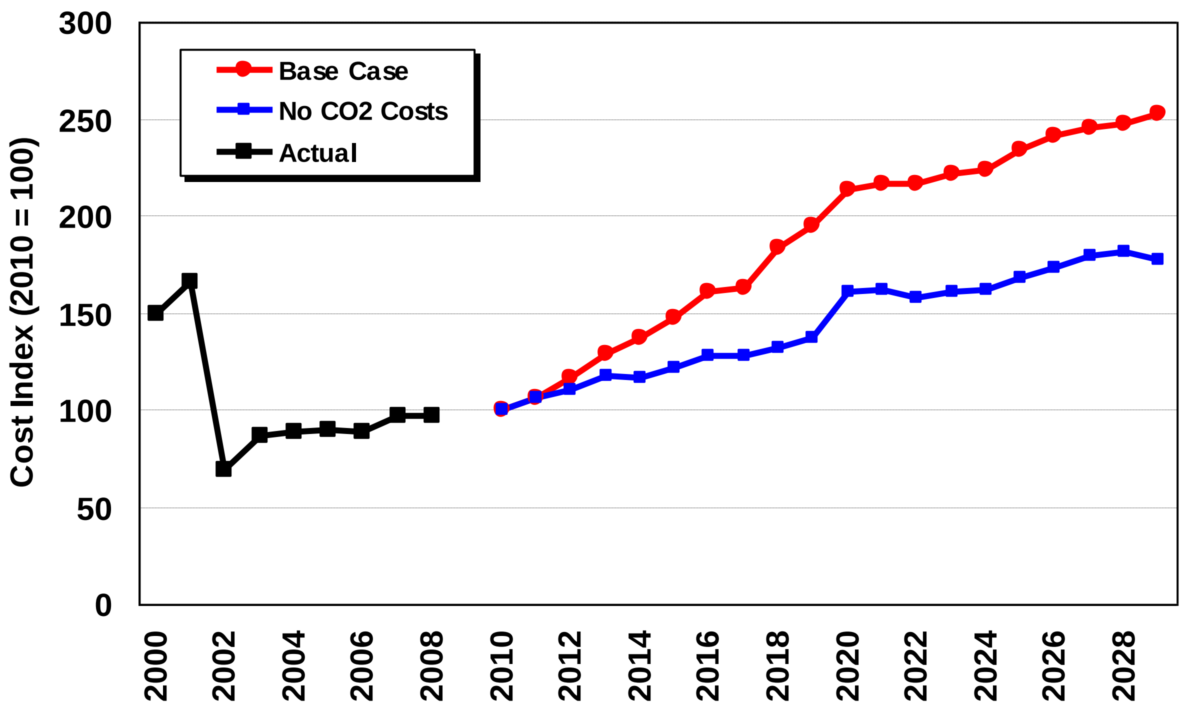
Nuclear

Nuclear resources were not included as a PRS option, but were studied as a resource scenario. This resource intrigues planners because of low operating costs, base-load capability, and lack of greenhouse gas emissions. However, nuclear power has high capital costs, and the projected capital and operating costs are speculative since no U.S. project has been completed in over 20 years. Long lead times require capital to be at risk during construction, forcing higher AFDUC costs. If Nuclear was an option in the PRS analysis after 2020 at $5,500 per KW (2009 dollars before AFUDC), the project would not be selected as least cost, but would lower power supply cost variation. At $3,800 per kW, a 250 MW nuclear project would be selected as a least cost resource after 2020. Avista will continue to monitor and investigate nuclear development as new projects are announced and developed.

Summary

The IRP is a continual effort to select cost- and risk-minimizing resources that complement existing resources and to help management and policy-makers make informed decisions for ratepayers. The PRS includes a combination of conservation, efficiency improvements, hydro upgrades, wind, and combined-cycle combustion turbines. The resource strategy identified in this report will change as new information becomes available, but Avista focuses on near-term acquisitions where changes are less likely. Avista will study large hydro upgrades on the Clark Fork and Spokane rivers to add system capacity and help meet renewable RPS requirements. Figure 8.20 shows power supply costs in 2019 are 38 percent higher in real terms absent carbon legislation, but up to 95 percent higher with carbon legislation. Power supply costs grow 2.9 percent in real terms absent carbon legislation and 4.7 percent with carbon legislation.

Figure 8.20: Real Power Supply Expected Cost Growth Index (2010 = 100)



The black line includes historical plant operations, maintenance, depreciation, return on capital, taxes, fuel costs, and net market purchases and sales. It does not include conservation spending, transmission, distribution, or other A&G costs. The red and blue forecasts include historical costs escalating at the average historical rate and future fuel costs for existing resources and all costs for new resources such as operations and maintenance, taxes, depreciation and return. The lines also include incremental conservation amounts, net market purchases and sales, and carbon costs assuming 100 percent auction.

L&R Tables

Table 8.12: Annual Load & Resources (aMW)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Retail Load	1,155	1,186	1,212	1,235	1,265	1,305	1,334	1,364	1,396	1,424	1,454	1,485	1,516	1,547	1,582	1,618	1,669	1,701	1,736	1,769
Existing Resources																				
Hydro	538	520	509	511	511	511	511	511	507	496	496	496	496	496	496	496	496	496	496	496
Net Contracts	464	382	348	356	335	356	346	357	334	336	301	311	289	310	310	299	244	50	50	50
Thermal Resources	528	528	527	526	542	517	526	528	519	520	530	530	519	520	529	531	519	523	529	530
Peaking Resources	153	153	153	144	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Existing Resources	**1,683**	**1,583**	**1,536**	**1,537**	**1,540**	**1,537**	**1,536**	**1,549**	**1,513**	**1,506**	**1,480**	**1,490**	**1,457**	**1,479**	**1,488**	**1,479**	**1,412**	**1,222**	**1,228**	**1,229**
Contingency	(227)	(228)	(224)	(225)	(226)	(227)	(227)	(228)	(229)	(212)	(195)	(196)	(197)	(198)	(199)	(200)	(201)	(202)	(202)	(203)
Net Position	**301**	**170**	**100**	**76**	**49**	**6**	**(26)**	**(43)**	**(112)**	**(131)**	**(170)**	**(191)**	**(256)**	**(265)**	**(292)**	**(339)**	**(458)**	**(681)**	**(710)**	**(743)**
Conservation	8	16	24	32	41	50	60	70	80	91	102	114	126	139	152	166	180	195	210	226
Net Position w/ Cons.	**309**	**186**	**124**	**108**	**90**	**56**	**34**	**27**	**(32)**	**(40)**	**(68)**	**(77)**	**(130)**	**(126)**	**(140)**	**(173)**	**(278)**	**(486)**	**(500)**	**(517)**
PRS Resources																				
Wind	-	-	-	47	47	47	47	47	47	47	96	96	96	112	112	112	112	112	112	112
CCCT	-	-	-	-	-	-	-	-	-	-	225	225	225	225	225	451	451	676	676	676
Distribution Efficiencies	1	1	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Hydro Upgrades	-	-	-	-	0	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2
Total PRS	**1**	**1**	**2**	**50**	**50**	**51**	**51**	**51**	**51**	**51**	**325**	**326**	**326**	**342**	**342**	**567**	**567**	**793**	**793**	**793**
Net Position w/ PRS	**310**	**187**	**125**	**158**	**141**	**107**	**85**	**78**	**19**	**11**	**257**	**249**	**196**	**216**	**202**	**395**	**290**	**307**	**292**	**276**

Table 8.13: Load & Resources at Winter Peak (MW)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Peak Demand	1,789	1,831	1,871	1,906	1,951	2,008	2,052	2,097	2,146	2,189	2,233	2,281	2,327	2,373	2,426	2,481	2,555	2,604	2,656	2,706
Planning Margin	268	275	281	286	293	301	308	315	322	328	335	342	349	356	364	372	383	391	398	406
Total Obligations	**2,057**	**2,106**	**2,152**	**2,192**	**2,244**	**2,309**	**2,360**	**2,412**	**2,468**	**2,517**	**2,568**	**2,623**	**2,676**	**2,729**	**2,790**	**2,853**	**2,938**	**2,995**	**3,054**	**3,112**
Existing Resources																				
Hydro	1,030	1,000	972	997	997	997	997	970	997	971	971	944	971	971	971	944	971	971	971	944
Net Contracts	417	318	300	300	300	301	301	451	451	450	361	361	360	359	359	359	359	78	78	78
Thermal Resources	580	584	584	584	584	584	584	584	584	584	584	584	584	584	584	584	584	584	584	584
Peaking Resources	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226
Capacity on Maintenance	106	105	105	100	100	100	100	127	100	100	100	127	100	100	100	127	100	100	100	127
Existing Resources	**2,359**	**2,231**	**2,187**	**2,207**	**2,207**	**2,207**	**2,208**	**2,358**	**2,358**	**2,330**	**2,241**	**2,241**	**2,241**	**2,240**	**2,240**	**2,240**	**2,240**	**1,959**	**1,959**	**1,959**
Net Position	**302**	**126**	**35**	**15**	**(36)**	**(102)**	**(152)**	**(54)**	**(110)**	**(187)**	**(327)**	**(382)**	**(435)**	**(489)**	**(550)**	**(613)**	**(698)**	**(1,036)**	**(1,095)**	**(1,153)**
Conservation	12	24	36	48	62	75	90	105	120	137	153	171	189	209	228	249	270	293	315	339
Net Position w/ Cons.	**314**	**150**	**71**	**63**	**25**	**(27)**	**(62)**	**51**	**10**	**(50)**	**(174)**	**(211)**	**(246)**	**(280)**	**(322)**	**(364)**	**(428)**	**(743)**	**(780)**	**(814)**
PRS Resources																				
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT	-	-	-	-	-	-	-	-	-	-	263	263	263	263	263	525	525	788	788	788
Distribution Efficiencies	1	2	3	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Hydro Upgrades	-	-	-	-	1	2	2	3	3	3	3	5	5	5	5	5	5	5	5	5
Total PRS	**1**	**2**	**3**	**4**	**6**	**7**	**7**	**8**	**8**	**8**	**271**	**273**	**273**	**273**	**273**	**535**	**535**	**798**	**798**	**798**
Net Position w/ PRS	**315**	**152**	**74**	**67**	**31**	**(20)**	**(55)**	**59**	**18**	**(42)**	**97**	**62**	**26**	**(8)**	**(49)**	**171**	**107**	**54**	**17**	**(16)**
Planning Margin	33%	24%	19%	19%	17%	15%	13%	19%	17%	14%	21%	19%	18%	16%	14%	24%	21%	19%	18%	16%

Table 8.14: Load & Resources at Summer Peak (MW)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Peak Demand	1,669	1,715	1,751	1,783	1,823	1,876	1,915	1,956	2,000	2,040	2,080	2,123	2,165	2,207	2,255	2,304	2,372	2,416	2,463	2,509
Planning Margin	250	257	263	267	273	281	287	293	300	306	312	318	325	331	338	346	356	362	369	376
Total Obligations	**1,919**	**1,972**	**2,014**	**2,050**	**2,096**	**2,157**	**2,202**	**2,249**	**2,300**	**2,346**	**2,392**	**2,441**	**2,490**	**2,538**	**2,593**	**2,650**	**2,728**	**2,778**	**2,832**	**2,885**
Existing Resources																				
Hydro	953	932	1,020	1,028	1,051	1,028	1,049	1,022	1,022	1,021	1,023	996	996	993	1,028	996	996	1,002	1,023	996
Net Contracts	304	204	185	185	185	185	185	335	335	333	333	333	333	332	332	332	332	68	68	68
Thermal Resources	577	581	581	581	581	581	581	581	581	581	581	581	581	581	581	581	581	581	581	581
Peaking Resources	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Maintenance at Peak	168	157	46	37	14	38	17	44	44	19	17	44	44	47	11	44	44	38	17	44
Existing Resources	**2,201**	**2,074**	**2,031**	**2,031**	**2,031**	**2,031**	**2,031**	**2,181**	**2,181**	**2,153**	**2,153**	**2,153**	**2,153**	**2,153**	**2,153**	**2,153**	**2,153**	**1,889**	**1,889**	**1,889**
Net Position	**282**	**102**	**17**	**(20)**	**(66)**	**(126)**	**(171)**	**(68)**	**(119)**	**(193)**	**(239)**	**(289)**	**(337)**	**(385)**	**(441)**	**(497)**	**(575)**	**(890)**	**(944)**	**(997)**
Conservation	12	24	36	48	62	75	90	105	120	137	153	171	189	209	228	249	270	293	315	339
Net Position w/ Cons.	**294**	**126**	**53**	**28**	**(4)**	**(51)**	**(81)**	**37**	**1**	**(56)**	**(86)**	**(118)**	**(148)**	**(177)**	**(213)**	**(248)**	**(305)**	**(597)**	**(629)**	**(658)**
PRS Resources																				
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT	-	-	-	-	-	-	-	-	-	-	238	238	238	238	238	475	475	713	713	713
Distribution Efficiencies	1	2	3	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Hydro Upgrades	-	-	-	-	1	2	2	3	3	3	3	5	5	5	5	5	5	5	5	5
Total PRS	**1**	**2**	**3**	**4**	**6**	**7**	**7**	**8**	**8**	**8**	**245**	**247**	**247**	**247**	**247**	**485**	**485**	**722**	**722**	**722**
Net Position	**295**	**128**	**56**	**32**	**2**	**(45)**	**(74)**	**45**	**9**	**(49)**	**159**	**129**	**99**	**70**	**34**	**236**	**179**	**125**	**93**	**64**
Planning Margin	33%	23%	19%	17%	16%	13%	12%	18%	16%	14%	24%	23%	21%	20%	18%	28%	25%	23%	22%	20%

9. Action Items

The Integrated Resource Plan (IRP) is an ongoing and iterative process balancing regular publication with pursuing the best 20-year strategy. The biennial publication date provides opportunities for ongoing improvements to the various modeling and forecasting procedures and tools, as well as additional research. This section provides an overview of the progress made regarding the 2007 IRP Action Plan, while the 2009 Action Plan provides details about the issues and improvements that were developed or raised during this planning cycle, but need to be deferred for treatment in the 2011 IRP.

Summary of the 2007 IRP Action Plan

The 2007 IRP Action Items were separated into five separate categories: renewable energy, demand side management, emissions, modeling and forecasting enhancements, and transmission planning.

Renewable Energy

- Continue studying wind potential in the Company's service territory, possibly including the placement of anemometers at the most promising wind sites.
- Commission a study of Montana wind resources that are strategically located near existing Company transmission assets
- Learn more about non-wind renewable resources to satisfy renewable portfolio standard requirements and decrease the Company's carbon footprint.

Avista has been actively studying wind development since the publication of the 2007 IRP. The Company purchased the rights to develop a large wind project located at Reardan, Washington in May 2008. The site is being developed as described in the PRS chapter. Met towers were placed at several areas in our service territory to measure wind potential. This wind development work is an ongoing project.

Preliminary work concerning a Montana wind study was done. Transmission limitations for power coming west and the concern over the acceptance of renewable projects in Montana being acceptable for the Washington RPS law made continued work on Montana wind projects less attractive than previously thought. Montana wind will continue to be re-evaluated as RPS laws change and as transmission upgrades are made.

Additional studies regarding non-wind renewable energy sources have continued throughout this IRP planning cycle. More details about non-wind renewables are included in the Generation Resource Options and Preferred Resource Strategy chapters. Avista's upcoming request for proposals (RFP) for wind and other renewables will provide more details for the availability and cost of non-renewable resources.

Demand Side Management

- Update processes and protocols for integrating energy efficiency programs into the IRP to improve and streamline the process.
- Study and quantify transmission and distribution efficiency concepts.
- Determine the potential impacts and costs of load management options currently being reviewed as part of the Heritage Project.
- Develop and quantify the long-term impacts of the newly signed contractual relationship with the Northwest Sustainable Energy for Economic Development organization.

The integration of DSM resources into the IRP is an ongoing process. Progress made on updating the processes and protocols for integrating energy efficiency programs into the IRP process can be found in the Energy Efficiency chapter. Transmission and distribution efficiency improvements have also been studied for this IRP. Details about the results of these studies can be found in the Transmission and Distribution chapter. Five megawatts of peak savings distribution feeder upgrades are included in the PRS for the 2009 IRP. Updates on the results of the Heritage Project and the Northwest Sustainable Energy for Economic Development organization are also included in the Energy Efficiency chapter.

Emissions

- Continue to evaluate the implications of new rules and regulations affecting power plant operations, most notably greenhouse gases.
- Continue to evaluate the merits of various carbon quantification methods and emissions markets.

Avista's Climate Change Committee and the Resource Planning team have been actively analyzing state and federal greenhouse gas legislation since the publication of the 2007 IRP. This work will continue until final rules are established for the Washington legislation and federal laws are passed. Then the focus will shift towards mitigating the cost of climate change to minimize the impact on customers. Carbon quantification has been done based on the WRI-WBCSD greenhouse gas (GHG) inventory protocol as part of the push to get ready for the state and eventual federal GHG reporting mandates. These inventories have also been used for Avista's participation in the Chicago Climate Exchange and the Carbon Disclosure Project. Details about the work that has been done since the 2007 IRP can be found in the Environmental Policy chapter.

Modeling and Forecasting Enhancements

- Study the potential for fixing natural gas prices through financial instruments, coal gasification, investments in gas fields, or other means.
- Continue studying the efficient frontier modeling approach to identify more and better uses for its information.
- Further enhance and refine the PRiSM LP model

- Continue to study the impact of climate on the load forecast.
- Monitor the following conditions relevant to the load forecast: large commercial load additions, Shoshone county mining developments, and the market penetration of electric cars.

As explained earlier in the IRP, more studies were done regarding several fixed natural gas schemes including coal gasification, investment in gas fields, or through financial instruments. The common theme from all of the studies that were undertaken and reviewed was that the necessary capital or credit costs would be too high for Avista to effectively participate in any projects or long-term contracts.

There have been several improvements to the efficient frontier and PRiSM modeling approaches such as solving for acquirable resource sizes and including emissions accounting. Projected impacts of climate change and impact of electric car market penetration have been included in the Company’s load forecast, as discussed in the Loads and Resources chapter. Details about changes to relevant load conditions are also included in the Loads and Resources chapter. Many of the possible load increases resulting from high commodity prices did not fully develop because of the current recession.

Transmission Planning

- Work to maintain/retain existing transmission rights on the Company’s transmission system, under applicable FERC policies, for transmission service to bundled retail native load.
- Continue involvement in BPA transmission practice processes and rate proceedings to minimize costs of integrating existing resources outside of the Company’s service area.
- Continue participation in regional and sub-regional efforts to establish new regional transmission structures (ColumbiaGrid and other forums) to facilitate long-term expansion of the regional transmission system.
- Evaluate costs to integrate new resources across Avista’s service territory and from regions outside of the Northwest.

Transmission planning Action Items are ongoing issues that will be revisited as items in the 2009 Action Plan. Details about progress made towards the maintenance of existing transmission rights, involvement in BPA processes, participation in regional transmission processes, and the evaluation of integrating different resources in the IRP can be found in the Transmission and Distribution chapter.

2009 IRP Action Plan

The Company’s 2009 Preferred Resource Strategy provides direction and guidance for the type, timing and size of future resource acquisitions. The 2009 IRP Action Plan provides an overview of the activities that are planned for inclusion in the 2011 IRP. Progress and results for each of the Action Plan items will be monitored and reported to the Technical Advisory Committee and in Avista’s 2011 Integrated Resource Plan. The

Action Plan was developed using input from Commission Staff, the Company's management team, and the Technical Advisory Committee.

Resource Additions and Analysis

- Continue to explore the potential for wind and non-renewable resources.
- Issue an RFP for turbines at Reardan and up to 100 MW of wind or other renewables in 2009.
- Finish studies regarding the costs and environmental benefits of the large hydro upgrades at Cabinet Gorge, Long Lake, Post Falls, and Monroe Street.
- Study potential locations for the natural gas fired resource identified to be online between 2015 and 2020.
- Continue participation in regional IRP processes and where agreeable find resource opportunities to meet resource requirements on a collaborative basis.

Demand Side Management

- Pursue American Reinvestment and Recovery Act of 2009 funding and its affect on the amount of low income weatherization.
- Analyze and report on the results of the July 2007 through December 2009 demand response pilot in Moscow and Sandpoint.
- Have an external party do an updated study on technical, economic, achievable potential for entire service territory.
- Study and quantify transmission and distribution efficiency concepts as they apply toward meeting Washington RPS goals.
- Update processes and protocols for conservation measurement, evaluation and verification.
- Determine the potential impacts and costs of load management options.

Environmental Policy

- Continue to study the potential impact of state and federal climate change legislation.
- Continue and report on the work of Avista's Climate Change Committee.

Modeling and Forecasting Enhancements

- Refine the stochastic model for cost driver relationships.
- Continue to refine the PRiSM model by developing a resource retirement function, adding the ability to solve for other risk measurements and by adding more resource options.
- Continue developing Loss of Load Probability and Sustained Peaking analysis for inclusion in the IRP process.
- Continue studying the impacts of climate change on the load forecast.

Transmission Planning

- Work to maintain/retain existing transmission rights on the Company's transmission system, under applicable FERC policies, for transmission service to bundled retail native load.
- Continue involvement in BPA transmission practice processes and rate proceedings to minimize costs of integrating existing resources outside of the Company's service area.
- Continue participation in regional and sub-regional efforts to establish new regional transmission structures (ColumbiaGrid and other forums) to facilitate long-term expansion of the regional transmission system.
- Evaluate costs to integrate new resources across Avista's service territory and from regions outside of the Northwest.
- Further study and implement distribution feeder rebuild projects to reduce system losses.
- Study transmission reconfigurations to economically reduce system losses.

Production Credits

Primary 2009 IRP Team

Individual	Contribution	Contact
Clint Kalich, Manager of Resource Planning & Analysis	Project Manager	clint.kalich@avistacorp.com
John Lyons, Power Supply Analyst	Research/Author/Editor	john.lyons@avistacorp.com
James Gall, Senior Power Supply Analyst	Modeling and Analysis /Author	james.gall@avistacorp.com
Randy Barcus, Chief Corporate Economist	Load Forecast	randy.barcus@avistacorp.com
Lori Hermanson, Partnership Solutions Manager	Conservation	lori.hermanson@avistacorp.com
John Gibson, Senior Efficiencies Engineer	Transmission & Distribution	john.gibson@avistacorp.com

Other Contributors

Jon Powell, Partnership Solutions Manager	Bob Lafferty, Director of Power Supply
Greg Rahn, Manager of Natural Gas Planning	Scott Waples, Chief System Planner
Kelly Irvine, Natural Gas Analyst	Tracy Rolstad, Senior Planning Engineer II
Thomas Dempsey, Manager of Thermal Engineering	Steve Silkworth, Manager of Wholesale Marketing & Contracts