2011

Electric Integrated Resource Plan

July 8, 2011

Draft

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Executive Summary

Avista's 2011 Integrated Resource Plan (IRP) guides the Company's resource acquisition strategy over the next two years and indicates the overall direction of Avista resource procurements for the remainder of a 20-year planning horizon. It provides a snapshot of the Company's resources and loads, and guidance for the acquisition of resources. The resultant Preferred Resource Strategy (PRS) is a mix of wind generation, energy efficiency, upgrades at existing generation and distribution facilities, and new gas-fired generation.

The PRS balances cost, service reliability, rate volatility, and renewable resource requirements. Avista's management and the Technical Advisory Committee (TAC) stakeholders play a central role in guiding the development of the PRS and the IRP as a whole by providing significant input on modeling and planning assumptions, and the general direction of the planning process. TAC members include customers, commission staff, the Northwest Power and Conservation Counsel, consumer advocates, academics, utility peers, government agencies, and interested internal parties.

Resource Needs

Plant upgrades and conservation measures are an integral part of Avista's 2011 IRP resource strategy, but they are ultimately inadequate to meet all expected future load growth. Annual energy deficits, without new resource acquisitions begin in 2020, with loads plus a planning margin exceeding resource capability by 49 aMW. Energy deficits rise to 218 aMW in 2026 and 475 aMW in 2031. The Company will be short 98 MW of summer capacity in 2019.[1] In 2026 and 2031, capacity deficits rise to 352 MW and 774 MW, respectively. Winter capacity deficits begin at 42 MW in 2020 and increase to 401 MW in 2026 and 883 MW in 2031.[2]

Increasing deficits are a result of forecasted 1.6 percent energy and capacity load growth through 2031. The expiration of various long-term purchase and sale contracts on a net basis also increases deficiencies. Figures 1 through 3 provide graphical representations of projected load and resource balances before the addition of PRS resources. Forecasted peak loads in each year are on a sustained 18-hour peak forecast basis inclusive of planning and operating reserve obligations.[3] The forecasted needs would be higher absent energy efficiency acquisitions. A more thorough discussion of loads and resources position is in Chapter 2.

[1] This position assumes Avista relies on its share of regional power surpluses through 2021 as identified by the Northwest Power and Conservation Council and documented further in Chapter 2.
[2] Ibid.
[3] The 18-hour sustained peak metric assumes six peak hours for three days in a row.

Figure 1: Load-Resource Balance—Winter 18 Hour Capacity

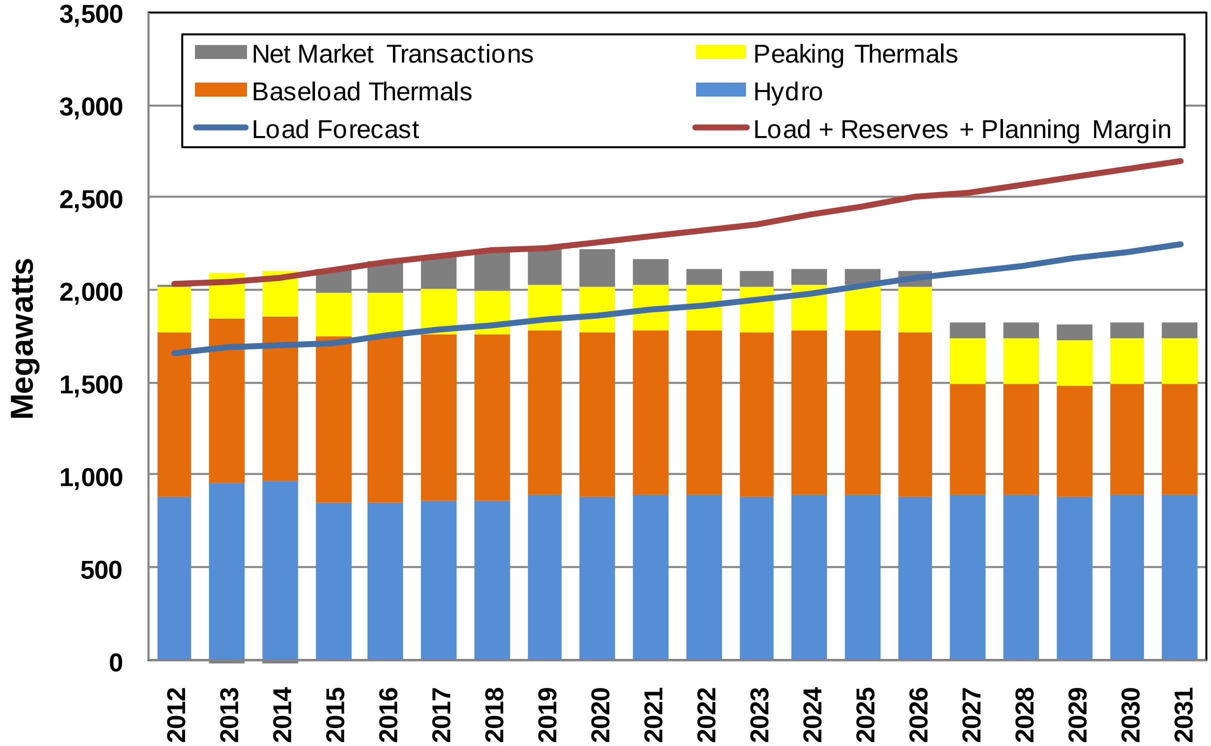


Figure 2: Load-Resource Balance—Summer 18 Hour Capacity

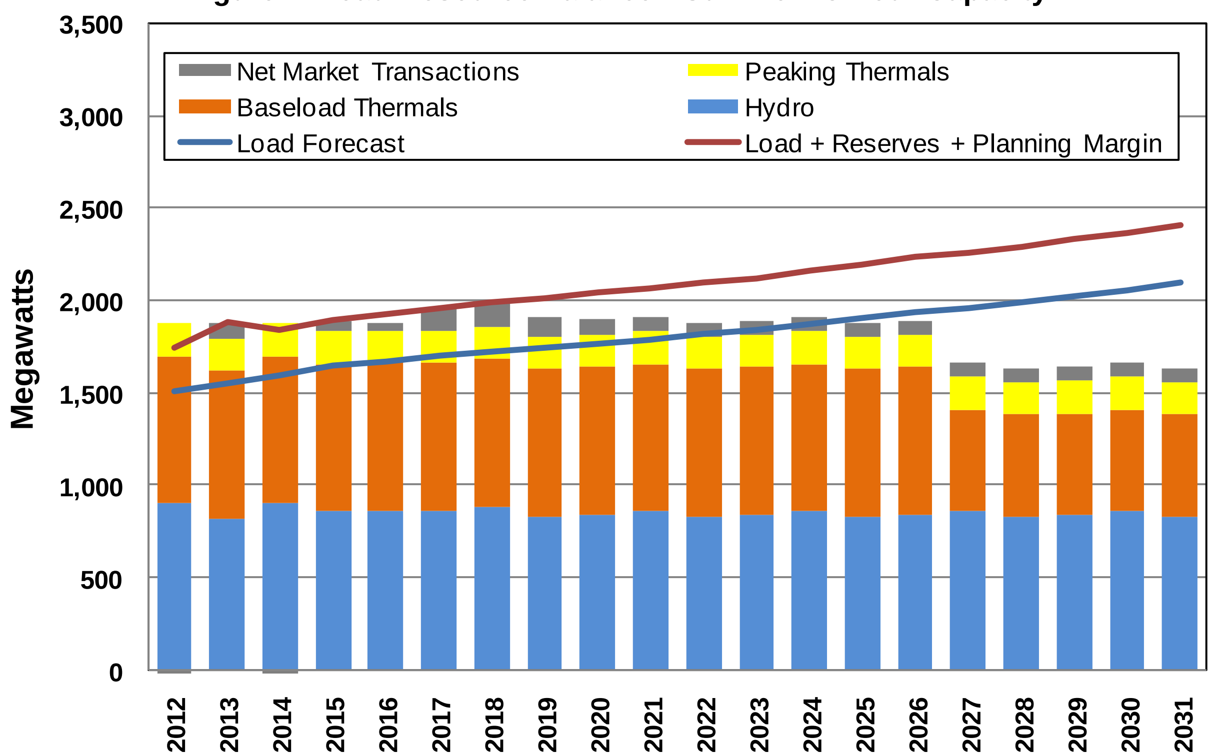
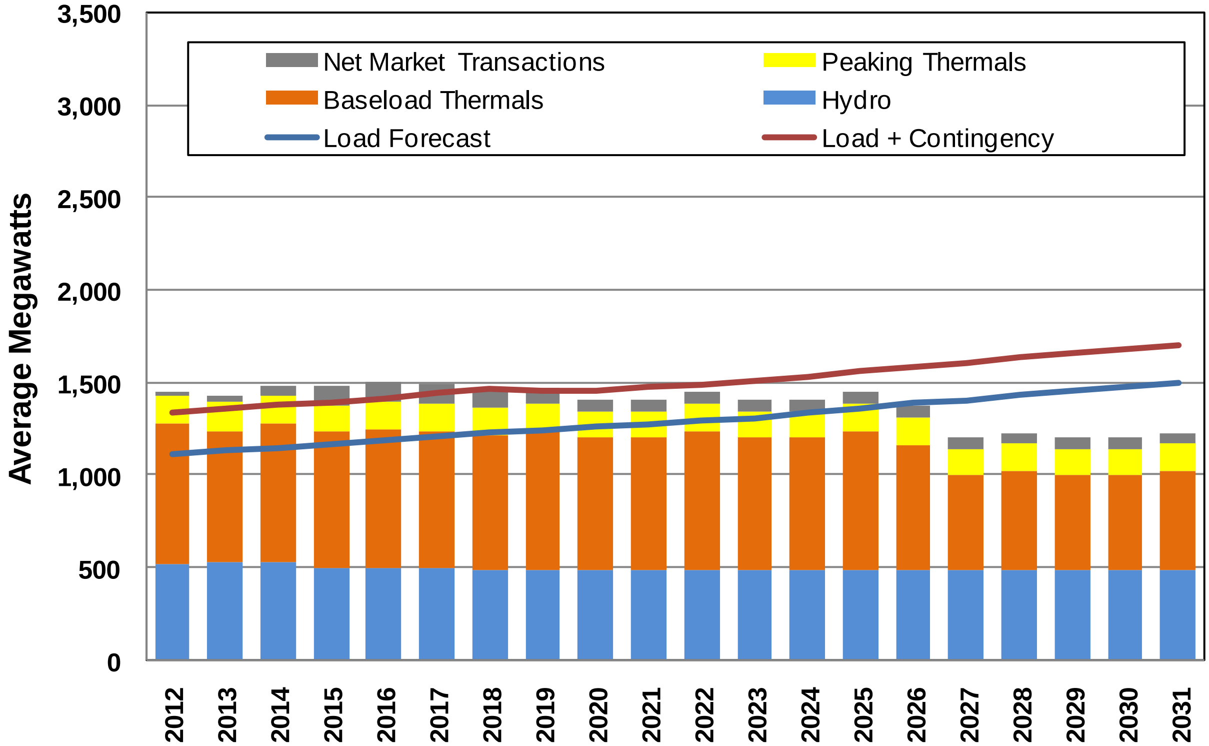


Figure 3: Load-Resource Balance—Energy



Modeling and Results

Avista uses a multiple-step approach to develop its Preferred Resource Strategy (PRS). It begins by identifying and quantifying potential new generation resources to serve projected demand needs across the West. A Western Interconnect-wide study explains the impact of regional markets on the Northwest electricity marketplace. Avista then maps its existing resources to the present transmission grid configuration in a model simulating hourly operations for the Western Interconnect from 2012 to 2031.

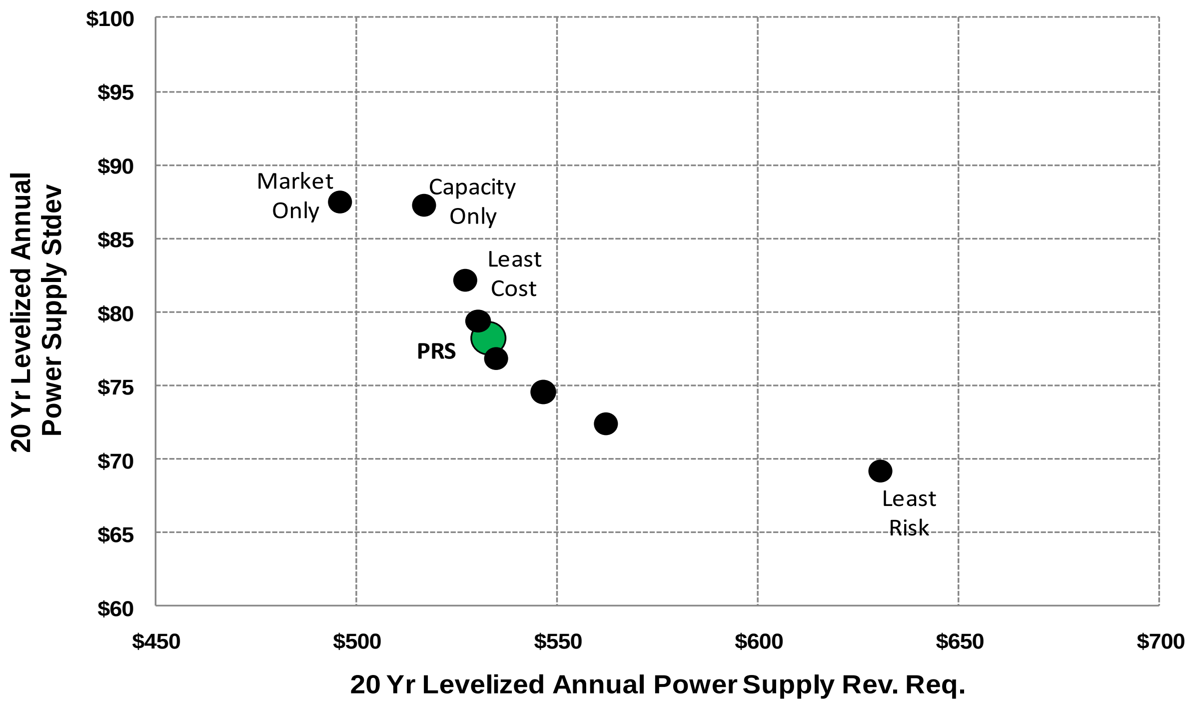
The model adds cost-effective new resources and transmission to meet growing loads. Monte Carlo-style analysis varies hydroelectric generation, wind generation, load, forced outages, greenhouse gas emission cost estimates, and natural gas price data over 500 iterations of potential future market conditions. The simulation estimates Mid-Columbia electricity markets, and the iterations collectively form the IRP Expected Case.

Each new resource and energy efficiency option is valued against the Expected Case Mid-Columbia electricity market to identify its future value to the Company, as well as its inherent risk measured as year-to-year cost volatility. These values, and their associated capital and fixed operation and maintenance (O&M) costs, form the input into Avista's Preferred Resource Strategy Linear Programming Model (PRiSM). PRiSM assists the Company by developing optimal mixes of new resources at each point on an efficient frontier.[4] The PRS provides a "least reasonable cost" portfolio that simultaneously minimizes future costs and risks given legislatively mandated or expected future environmental constraints. An efficient frontier helps determine the

[4] See Chapter 8 for a detailed discussion of the efficient frontier concept.

tradeoffs between risk and cost. The approach is similar to finding an optimal mix of risk and return when developing a personal investment portfolio. As expected returns increase, so do risks. Reducing risk reduces overall returns. Identifying the PRS is similar to an investor's dilemma. There is a trade-off between power supply costs and power supply cost variability. Figure 4 presents the change in cost and risk from the PRS on the Efficient Frontier.

Figure 4: Efficient Frontier



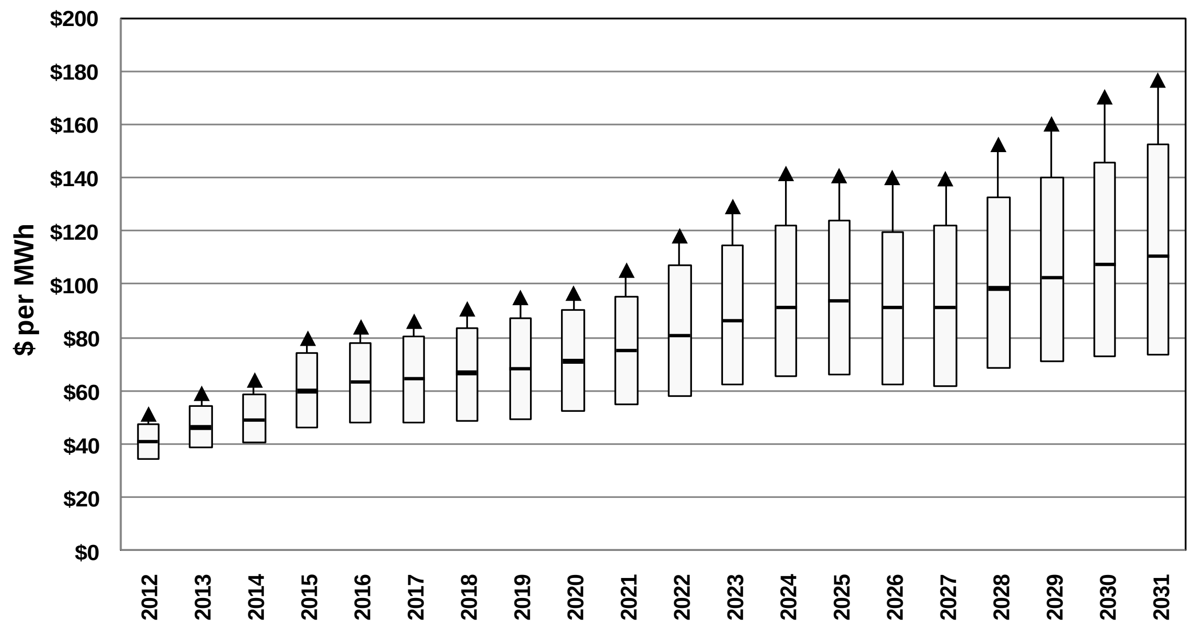
The IRP includes various scenarios that help identify tipping points where the PRS could change under conditions alternative to the Expected Case. Chapter 8 includes a number of scenarios to the Expected Case, including load growth, capital costs, higher energy efficiency acquisitions, and greenhouse gas mitigation strategies.

Electricity and Natural Gas Market Forecasts

Figure 5 shows the 2011 IRP electricity price forecast in the Expected Case, including the modeled range of prices over the 500 Monte Carlo iterations described previously. The forecasted levelized average Mid-Columbia market price is $70.50 per MWh in nominal dollars over the next 20 years; the off-peak price is $63.94 per MWh and the on-peak price is $75.42 per MWh. These prices include the market impacts of greenhouse gas mitigation beginning in 2015.[5]

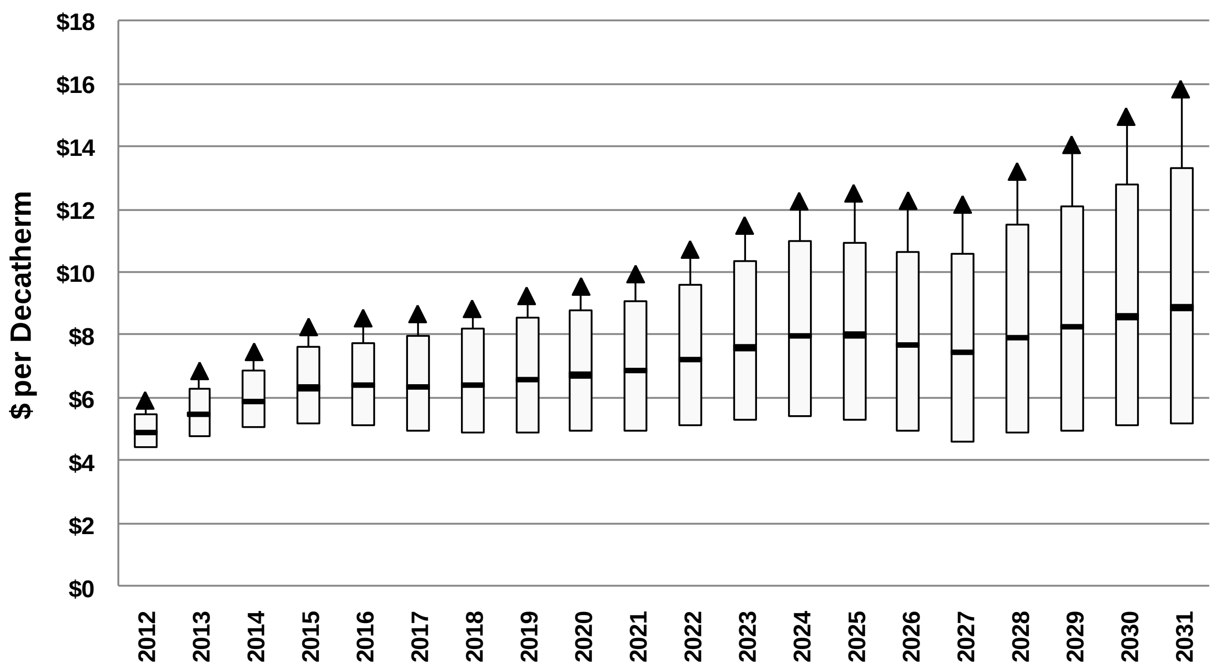
[5] The forecast assumes a western region reduction of 14 percent by 2032.

Figure 5: Average Mid-Columbia Electricity Price Forecast



Electricity and natural gas prices are highly correlated because natural gas fuels marginal generation resources in the northwest during most of the year. Figure 6 presents nominal levelized Expected Case natural gas prices at Henry Hub, as well as the range of forecasts from the 500 Monte Carlo iterations performed for the case. The average is $6.70 per decatherm over the next 20 years. For more detail on the Company's natural gas price forecast, see Chapter 7.

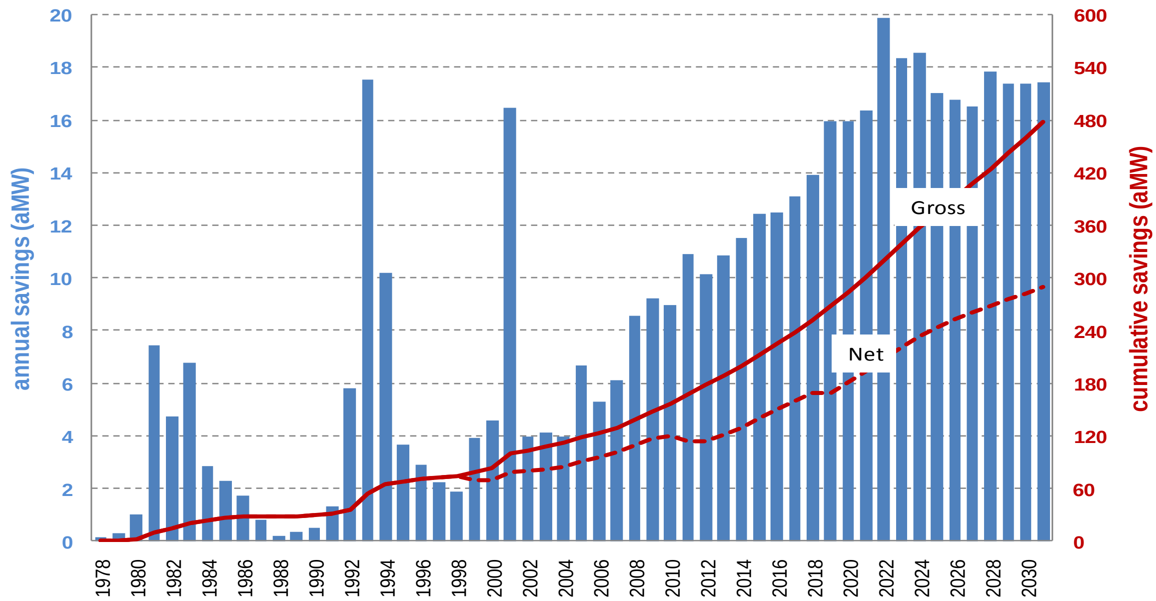
Figure 6: Henry Hub Natural Gas Price Forecast



Energy Efficiency Acquisition

Avista commissioned a 20-year Conservation Potential Assessment in 2010. The study analyzed over 4,300 equipment and measure options for residential, commercial, and industrial application. Data from this study formed the basis of the IRP conservation potential evaluation. Figure 7 shows how energy efficiency or conservation measures decrease the Company's energy requirements by 120.2 aMW, or approximately ten percent.[6] By the end of the IRP period, energy efficiency reduces load by 288 aMW. More detail about Avista's energy efficiency programs is contained in Chapter 3.

Figure 7: Cumulative Conservation Acquisitions

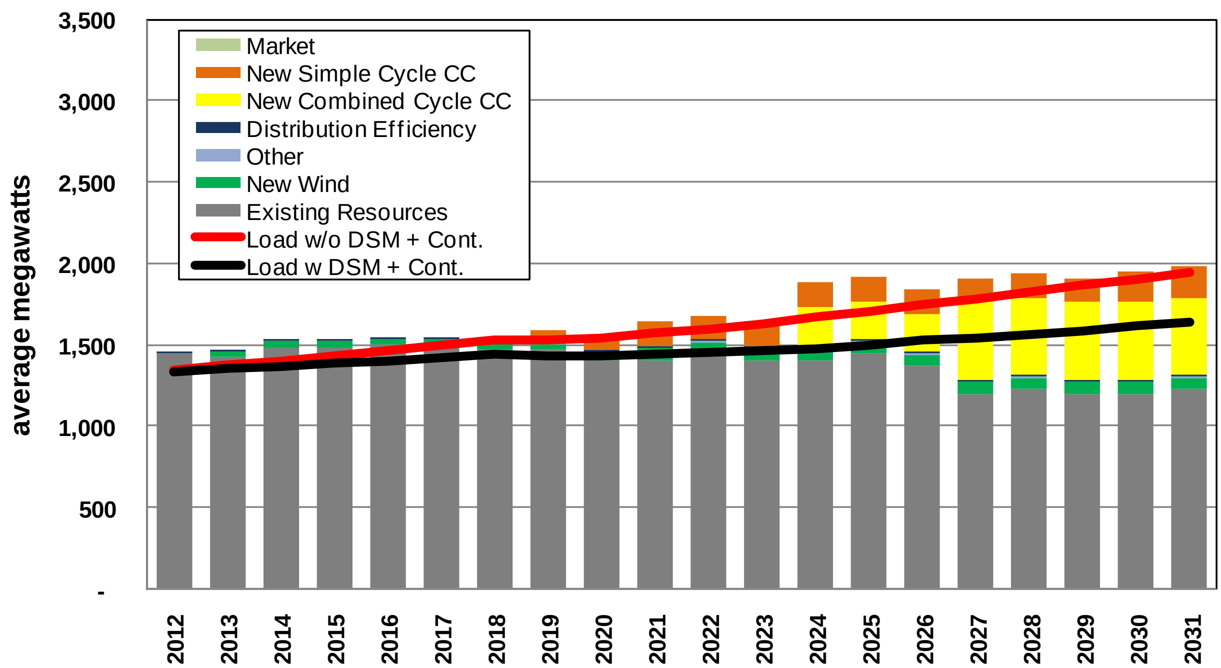


Preferred Resource Strategy

The PRS includes careful consideration by Avista's management and the Technical Advisory Committee of all information gathered and analyzed in the IRP process. It meets future load growth with efficiency upgrades at existing generation and distribution facilities, conservation, wind, and simple- and combined-cycle natural gas-fired combustion turbines. Figure 8 displays the 2011 Preferred Resource Strategy.

6 The Company has acquired 156.3 aMW of conservation since 1978; however, the assumed 18-year average life of the conservation portfolio means that some of the measures have reached the end of their useful lives and are no longer reducing loads. The 18-year assumed life of measures accounts for the difference between the Gross and Net lines in Figure 7.

Figure 8: 2011 Preferred Resource Strategy (Annual Average Energy)



The PRS has changed only modestly from the 2009 IRP. The PRS resources of both the 2009 and 2011 IRPs, on a nameplate capacity basis, are in Tables 1 and 2 below.

Table 1: The 2011 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Northwest Wind	2012	120	35
Distribution Efficiencies	2010-2015	28	13
Existing Thermal Resource Upgrades	2018-2019	4	3
Simple Cycle Combustion Turbine	2019	83	75
Northwest Wind	2018-2019	120	35
Simple Cycle Combustion Turbine	2020	83	75
Combined-Cycle Combustion Turbine	2023	270	237
Combined-Cycle Combustion Turbine	2026/27	270	237
Simple Cycle Combustion Turbine	2029	46	42
Total		**1,024**	**752**

Table 2: 2009 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Northwest Wind	2012	150	48
Distribution Efficiencies	2010-2015	5	3
Little Falls Unit Upgrades	2013-2016	3	1
Northwest Wind	2019	150	50
Combined-Cycle Combustion Turbine	2019	250	225
Upper Falls	2020	2	1
Northwest Wind	2022	50	17
Combined-Cycle Combustion Turbine	2024	250	225
Combined-Cycle Combustion Turbine	2027	250	225
Total		**1,110**	**795**

The present value of the investment required to support the 2011 PRS is just over $0.84 billion; the nominal total capital expense is $1.7 billion over the IRP timeframe.

Greenhouse Gas Emissions

As with all Avista IRPs since 2007, the costs of greenhouse gas mitigation are included in the Expected Case for this IRP. Since the 2009 IRP, there is much less certainty around the future of greenhouse gas mitigation. To address this lack of certainty, the 2011 IRP contains four policy models. Each represents a different policy alternative beginning in 2015. The policies are: 1) a regional cap and trade regime, 2) a national cap and trade regime, 3) a national carbon tax, and 4) the absence of any mitigation policy. The impacts of greenhouse gas mitigation on the Expected Case are the result of a weighted average of these policies as included in the stochastic analysis of the IRP. Figure 9 presents emissions cost assumptions on a per-ton basis.

Figure 9: Projected Price of Greenhouse Gas Emissions

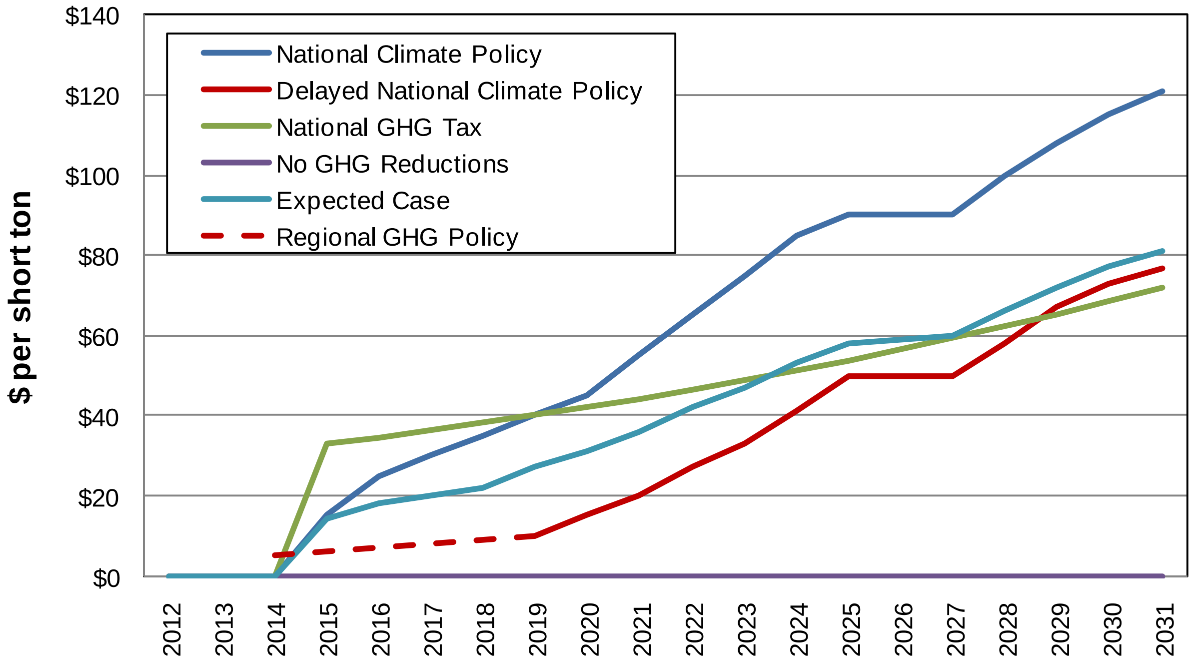
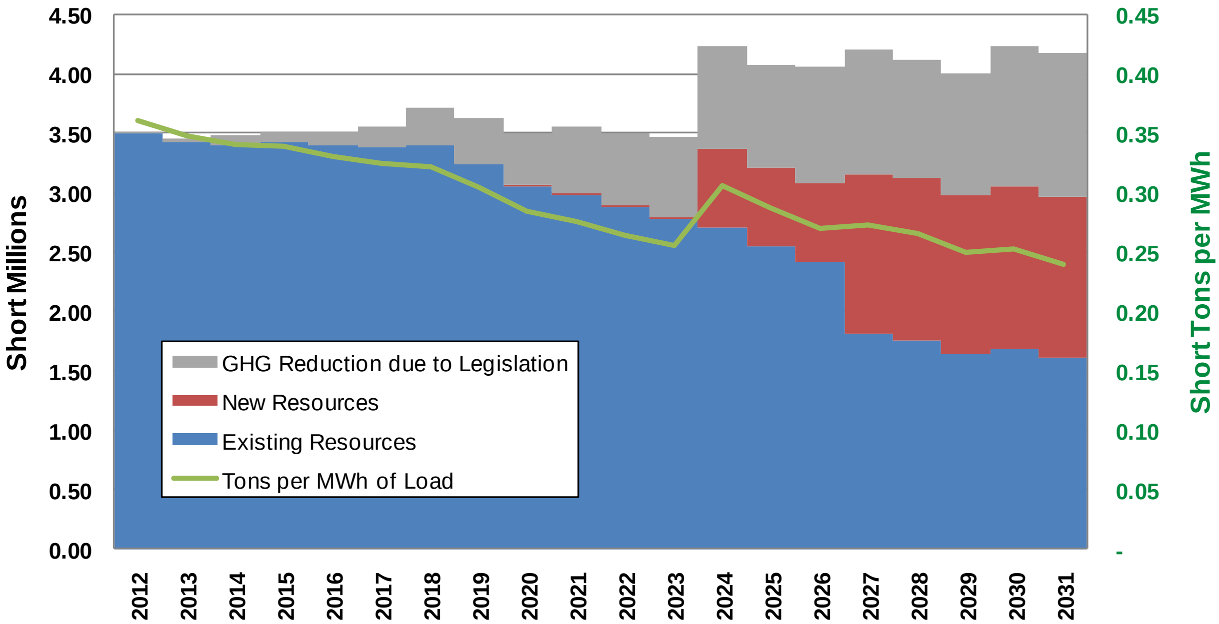


Figure 10 shows projected greenhouse gas emissions for existing and new Avista generation assets.[7] The grey area of Figure 10 represents incremental greenhouse emissions where there is no national or regional greenhouse gas policy.[8]

[7] Figure 10 does not include emissions from market or contract purchases. It also does not reduce Company emissions commensurate with market or contract sales.
[8] Existing Avista resources, and those selected to meet future load growth, under a scenario absent of greenhouse gas mitigation likely would generate higher emissions due primarily to increased operation at our Colstrip Coal plant shares.

Figure 10: Avista Owned and Controlled Resource's Greenhouse Gas Emissions



Action Items

The Company's 2011 Action Plan outlines activities and studies between now and the 2013 Integrated Resource Plan. It includes 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. Chapter 9 contains 2011 IRP Action Items.

1. Introduction and Stakeholder Involvement

Avista Utilities submits a biennial Integrated Resource Plan (IRP) to the Idaho and Washington public utility commissions.[1] The 2011 IRP is Avista's twelfth plan. It identifies and describes a Preferred Resource Strategy (PRS) for meeting load growth while balancing cost and risk measures with environmental mandates.

The Company is statutorily obligated to provide reliable electricity service to its customers at rates, terms, and conditions that are just, reasonable, and sufficient. Avista assesses different resource acquisition strategies and business plans to acquire resources to meet resource adequacy requirements and optimize the value of its current resource portfolio. We use the IRP as a resource evaluation tool rather than a plan for acquiring a particular set of assets. The 2011 IRP continues refining our resource acquisition efforts.

IRP Process

The 2011 IRP is developed and written with the aid of a public process. Avista actively seeks input for its IRPs from a variety of constituents through the Technical Advisory Committee (TAC). The TAC list of 75 individuals includes Commission Staff from Idaho and Washington, customers, academics, government agencies, consultants, utilities, and other interested parties who accepted an invitation to join, or had asked to be involved in, the planning process.

The Company sponsored six TAC meetings for the 2011 IRP. The first meeting was on May 27, 2010, and the last was on June 23, 2011. TAC meetings covered different aspects of the 2011 IRP planning activities and solicited contributions to, and assessments of, modeling assumptions, modeling processes, and results. Table 1.1 contains a list of TAC meeting dates and the agenda items covered in each meeting.

[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.

Table 1.1: TAC Meeting Dates and Agenda Items

Meeting Date	Agenda Items
TAC 1 – May 27, 2010	• Work Plan • Load & Resource Balance Update • Resource Planning Environment • 2011 IRP Topic Discussions – Analytical Process Changes, Hydro Modeling, Resource Adequacy, Loss of Load Probability, Energy Efficiency and Scoping the 2011 Plan
TAC 2 – September 8 and 9, 2010	• Lancaster Plant Tour • Upper Falls and Monroe Street Tour • Resource Assumptions • Reliability Planning • Sustainability Report • Combined Heat and Power Generation • Energy Efficiency
TAC 3 – December 2, 2010	• Transmission Costs and Issues • Potential Hydro Upgrades • Potential Thermal Upgrades • Load Forecast • Stochastic Modeling
TAC 4 – February 3, 2011	• Natural Gas Price Forecast • Electric Price Forecast • Resource Requirements Projections • Portfolio and Market Scenario Planning
TAC 5 – April 12, 2011	• Conservation Avoided Cost Methodology • Conservation • Smart Grid • Draft Preferred Resource Strategy • Portfolio Alternatives & Scenarios
TAC 6 – June 23, 2011	• High Wind Market Analysis • Preferred Resource Strategy and Scenario Analysis • IRP Action Items • IRP Section Highlights

Agendas and presentations from the TAC meetings are in Appendix A and on Avista's website at http://www.avistautilities.com/inside/resources/irp/electric. Past IRPs and TAC presentations are also here.

Avista wishes to acknowledge the contributions of a number of TAC participants in Table 1.1.

Table 1.2: Technical Advisory Committee Participants

Participant	Organization
Robin Toth	Greater Spokane Inc.
Dave Van Hersett	Resource Development Associates
John Dacquisto	Gonzaga University
Deborah Reynolds	Washington Utilities and Transportation Commission
Steve Johnson	Washington Utilities and Transportation Commission
David Nightingale	Washington Utilities and Transportation Commission
Nancy Hirsch	Northwest Energy Coalition
Kirsten Wilson	Washington State General Administration
Rick Sterling	Idaho Public Utilities Commission
Tom Noll	Idaho Power
Ken Corum	Northwest Power and Conservation Council
Keith Knitter	Grant County Public Utilities District
Becky King	Chelan County Public Utilities District
Villamour Gamponia	Puget Sound Energy
Kevin Rasler	Inland Empire Paper
Mike Connolley	Idaho Forest Group

Issue Specific Public Involvement Activities

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

External Energy Efficiency ("Triple E") Board

The Triple E Board, formed in 1995, provides stakeholders and public groups biannual opportunities to discuss Avista's energy efficiency efforts. The Triple E Board grew out of the DSM Issues group. This predecessor group was influential in developing the country's first conservation distribution surcharge in 1995.

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 efforts at the projects.

Low Income Rate Assistance Program (LIRAP)

LIRAP is coordinated with four community action agencies in Avista's Washington service territory. The program began in 2001 and reviews administrative issues and needs on a quarterly basis.

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 supplements Avista's IRP 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

As explained above, Avista actively solicits input from interested parties to enhance its IRP process. We continue to expand TAC membership and diversity, and maintain the TAC meetings as an open public process.

2011 IRP Outline

The 2011 IRP consists of nine 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 2011 IRP.

Chapter 1: Introduction and Stakeholder Involvement

This chapter introduces the IRP and details 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 related local economic forecasts. The last half describes the Company's owned generating resources, major contractual rights and obligations, capacity, energy and renewable energy credit tabulations, and reserve obligations.

Chapter 3: Energy Efficiency

This chapter discusses Avista's energy efficiency programs. It summarizes the energy efficiency modeling results for the 2011 IRP.

Chapter 4: Policy Considerations

This chapter focuses on some of the major policy issues for resource planning, such as state and federal greenhouse gas emissions policies and environmental regulations.

Chapter 5: Transmission and Distribution Planning

This chapter discusses Avista's distribution and transmission systems, as well as regional transmission planning issues. The chapter includes detail on transmission cost studies used in the IRP modeling, including a summary of our 10-year Transmission Plan. The chapter includes a discussion of Avista's distribution efficiency and grid modernization projects.

Chapter 6: Generation Resource Options

This chapter covers the costs and operating characteristics of the generation resource options modeled for the 2011 IRP.

Chapter 7: Market Analysis

This chapter details Avista's modeling and analysis of the various wholesale markets applicable to the 2011 IRP.

Chapter 8: Preferred Resource Strategy

This chapter details Avista's 2011 Preferred Resource Strategy and explains how the PRS could change in response to scenarios differing from the Expected Case.

Chapter 9: Action Items

This chapter provides an overview of the progress made on Action Items from the 2009 IRP. It details new Action Items to start and/or complete between the issuance of the 2011 IRP and prior to the 2013 IRP.

Regulatory Requirements

The IRP process for Washington has several requirements documented in Washington Administrative Code (WAC). Table 1.3 summarizes where within the IRP the applicable WACs are addressed.

Table 1.1 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 31, 2010; see Appendix B for a copy of the Work Plan.
WAC 480-100-238(5) – Work plan outlines timing and extent of public participation.	Appendix B
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	Chapter 2- Loads & Resources

current and future needs of utility ratepayers.	
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- Policy Considerations 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- Policy Considerations 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- Policy Considerations 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- Policy Considerations 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 & 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 & 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 & 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 and 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 B

2. Loads & Resources

Introduction & Highlights

An explanation and quantification of Avista's loads and resources are integral to the Integrated Resource Plan (IRP). The first half of this chapter summarizes customer and load forecasts, including forecast ranges, load growth scenarios, and an overview of enhancements to forecasting models and processes. The second half of the chapter covers Avista's current resource mix, including descriptions of owned and operated generation, as well as long-term power purchase contracts.

Section Highlights

- Historic conservation acquisitions are included in the load forecast; higher acquisition levels anticipated in the IRP reduce the load forecast further.
- Annual electricity sales growth from 2012 to 2031 averages 1.6 percent.
- Expected energy deficits begin in 2020, growing to 475 aMW by 2031.
- Expected capacity deficits begin in 2019, growing to 883 MW by 2031.
- Conservation pushes the need for resources out by one year for energy and six years for capacity.
- Renewable portfolio standard deficiencies drive near-term resource needs.

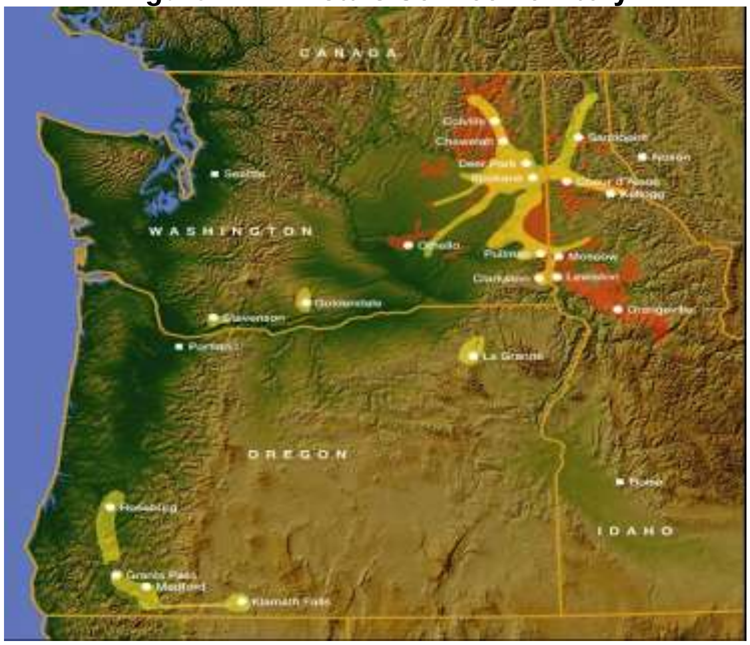
Economic Conditions in Avista's Service Territory

Avista serves electricity customers in most of the urban and suburban areas of 24 counties of eastern Washington and northern Idaho. The service territory is geographically and economically diverse. Figure 2.1 shows the Company's electricity and natural gas service territories.

The Inland Northwest has transformed over the past 25 years, from a natural resource-based manufacturing economy to a diversified light manufacturing and services economy. The United States Forest Service manages a significant portion of the mountainous areas of the region. Reduced timber harvests on federal lands have closed many local sawmills. Two pulp and paper plants served by Avista manage large forest holdings and face stiff domestic and international competition for their products.

Avista's service territory experienced periods of significant unemployment during the two national recessions of the 1980s. The 1991/92 national recession mostly bypassed Avista's service territory, but the 2001 recession greatly affected the area. The IRP Expected Case projects the present recession to end in 2011. The employment data reflects the effects of economic recession and expansion. Avista tracks employment data for the three principal counties in its electricity service territory: Bonner, Kootenai and Spokane.

Figure 2.1: Avista's Service Territory



Population is generally more stable than employment during times of economic change; however, population can contract during severe economic downturns as people leave in search of employment opportunities. Over the past 25 years, the region experienced a net population loss only in 1987. Figure 2.2 details historic and projected annual population changes in Kootenai and Spokane counties. Figure 2.3 shows total population.

Figure 2.2: Population Percent Change for Spokane and Kootenai Counties

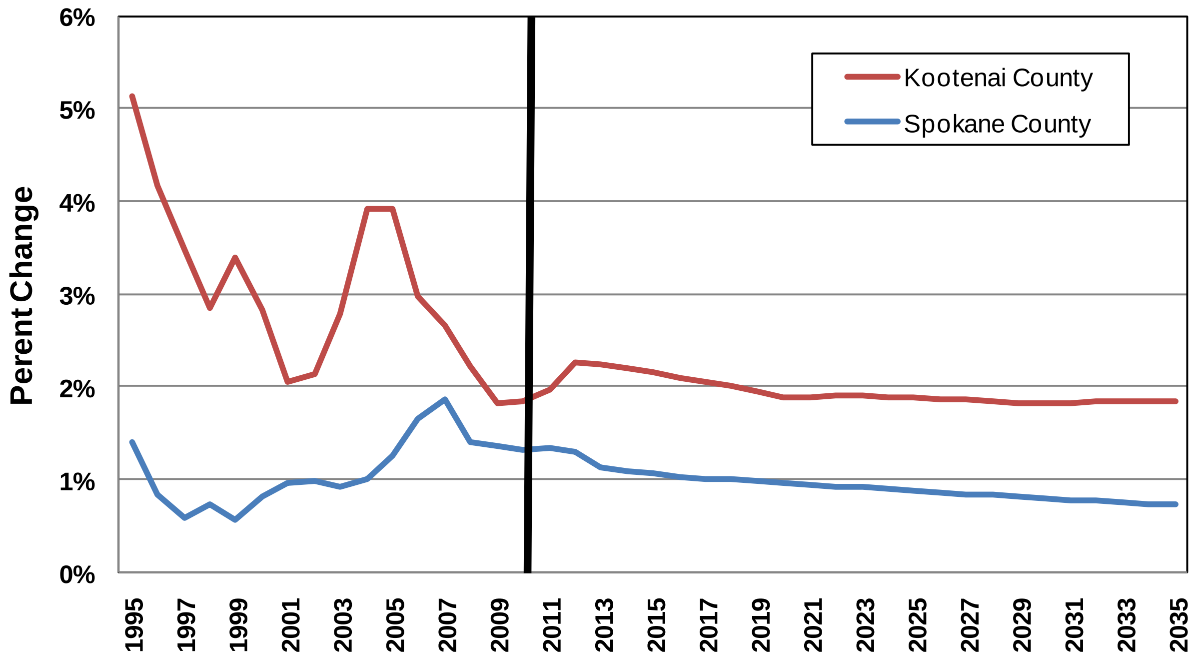
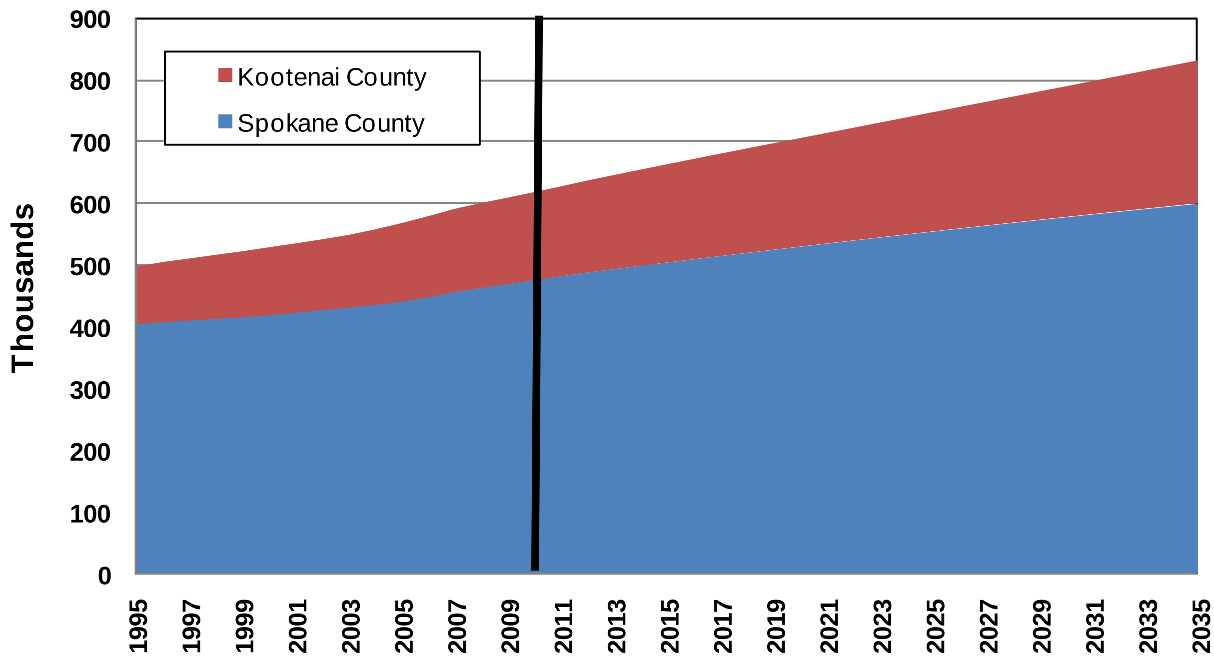


Figure 2.3: Total Population for Spokane and Kootenai Counties



People, Jobs and Customers

The October 2010 IRP forecast relies on an August 2010 national and September 2010 county-level forecasts. The data focus on two counties–Spokane County in Washington, and Kootenai County in Idaho–that comprise more than 80 percent of our service area economy. Avista purchases the employment and population forecasts from Global Insight, Inc., an internationally recognized economic forecasting consulting firm.

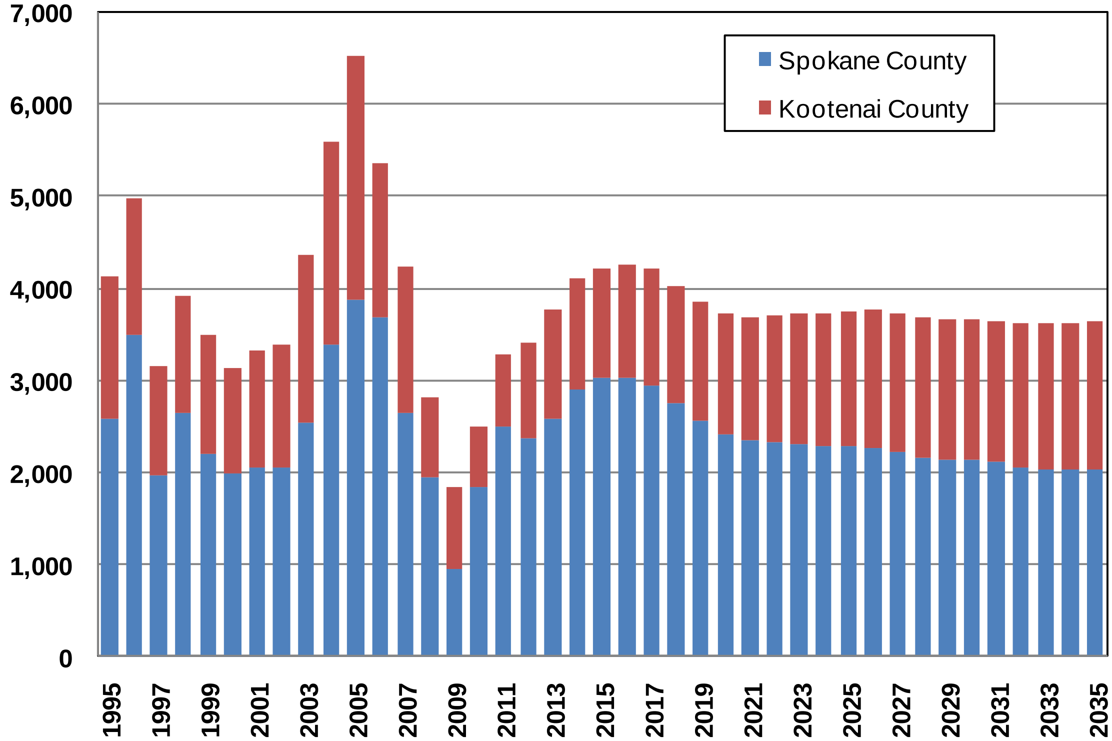
The Third Technical Advisory Committee included sections on the load forecast and its underlying assumptions. Table 2.1 presents the key forecast assumptions presented at that meeting.

Table 2.1: Global Insight National Long Range Forecast Assumptions

Assumption	Average	Assumption	Average
Gross Domestic Product	2.7%	Housing Starts (millions)	1.58/year
Consumer Price Index	1.9%	Job Growth	1.0%/year
Imported Crude 2000$	$70	Worker Productivity	2.0%
Federal Funds Rate	4.75%	Consumer Sentiment	90
Unemployment Rate	5.0%		

In 2010, as part of a revision in materials provided under contract to Avista, Global Insight began producing housing start forecasts consistent with the population and employment forecasts, as shown in Figure 2.4.

Figure 2.4: House Starts Total Private (SAAR)



Employment growth often drives population growth. Figure 2.5 shows historical employment trends from 1995, and forecast growth through 2035. Overall non-farm wage and salary employment over the past 15 years averaged 2.9 percent for Kootenai County and 1.0 percent for Spokane County.

Figure 2.5: Percent Change to Employment

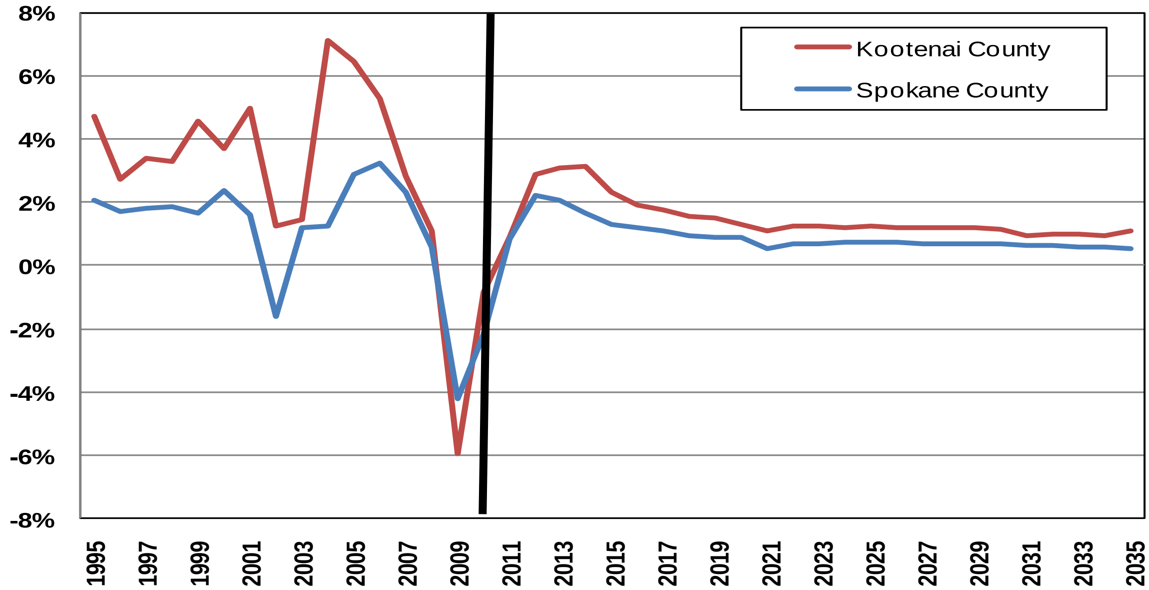
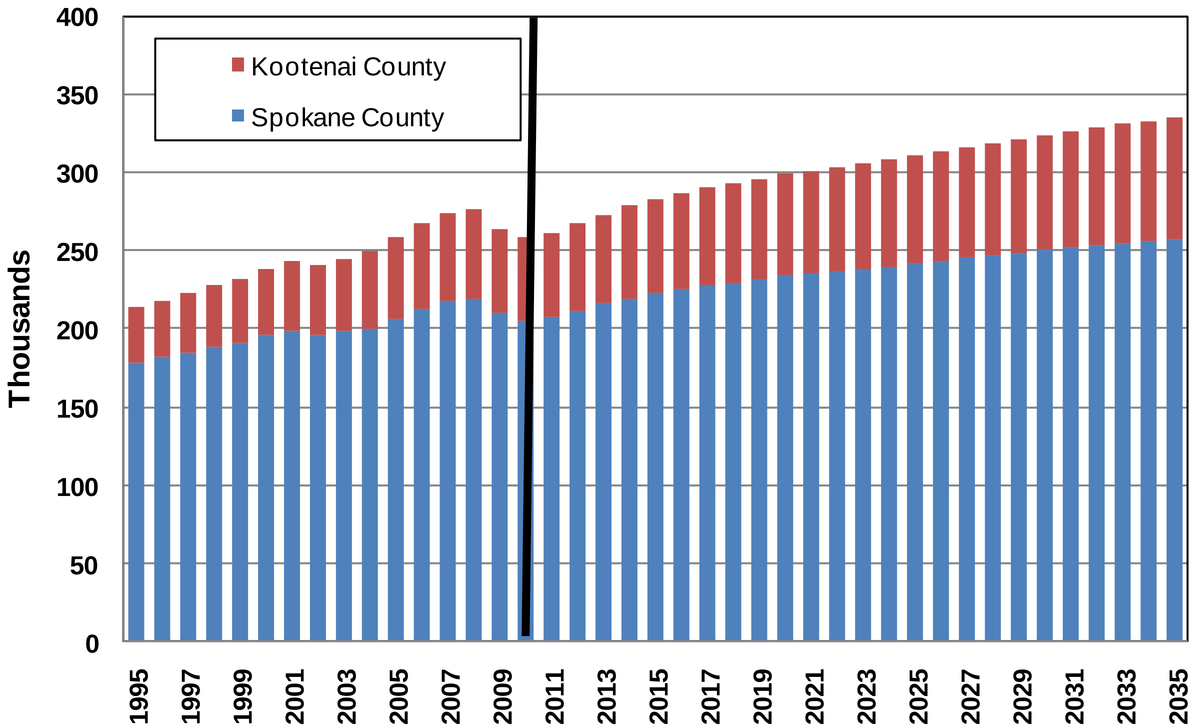


Figure 2.6 provides additional non-farm employment data. Over the forecast period, non-farm employment growth is 1.5 percent and 0.9 percent for Spokane and Kootenai counties, respectively. Employment growth is approximately 3,000 new jobs per year.

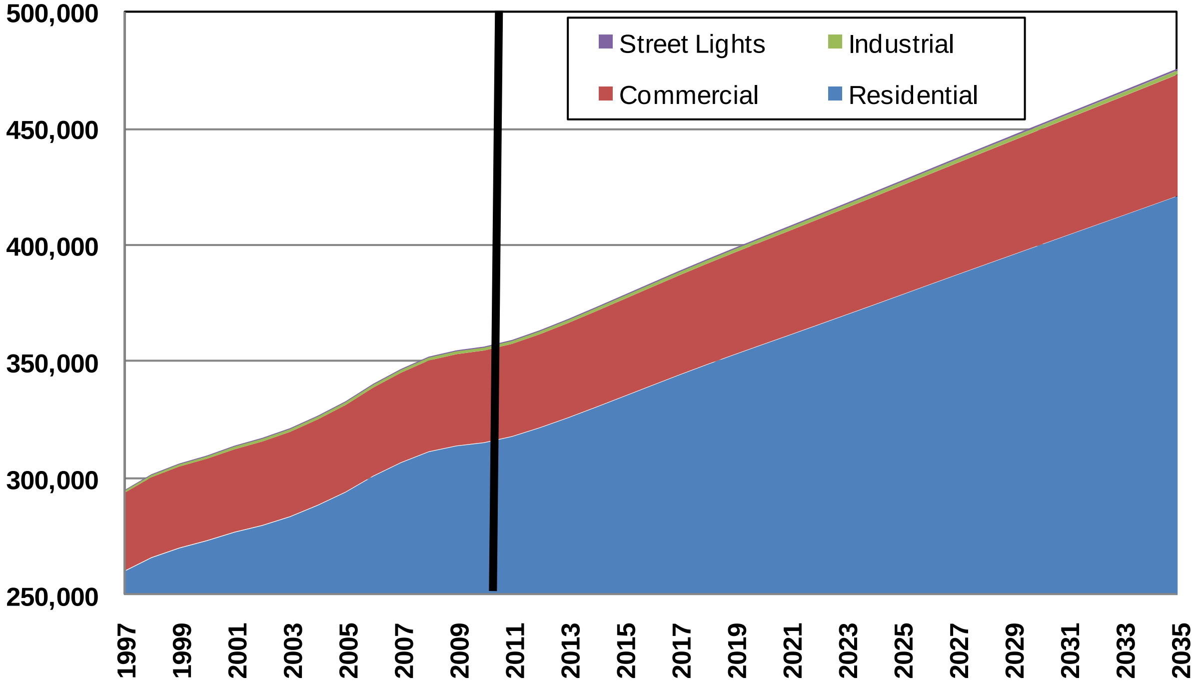
Figure 2.6: Non-Farm Employment



Customer growth projections follow baseline economic forecasts. Employment statistics have the greatest probability of near term change as the region emerges from the recession in 2011. Avista tracks four key customer classes: residential, commercial, industrial, and street lighting. A linear regression using housing starts as the independent variable is the basis for the residential customer forecasts. Commercial forecasts rely on a linear regression of residential growth. Industrial customer growth follows employment growth. Street lighting customer growth is trended with population growth.

Avista forecasts sales by rate schedule. Overall customer forecasts are a compilation of the various rate schedules. 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 for annual customer growth levels by rate class.

Figure 2.7: Avista Customer Forecast



On average during calendar 2010, Avista served 356,567 retail customers: 315,275 residential, 39,488 commercial, 1,375 industrial and 449 street lighting. This is a 15 percent increase from 309,871 retail customers in 2000. In 2010, 33.4 percent of residential customers, 42.0 percent of commercial customers, 34.6 percent of industrial customers, and 27.7 percent of street lighting customers were located in Idaho; the balance was located in Washington. The 2035 forecast predicts 474,316 retail customers: 419,739 residential, 52,172 commercial, 1,635 industrial and 770 street lighting. The 25-year compound growth rate averages 1.1 percent, down from 1.7 percent in the 2009 IRP and consistent with a lower population forecast.

Weather Forecasts

The Expected Case electricity sales forecast uses 30-year monthly temperature averages recorded at the Spokane International Airport weather station through 2009. Several other weather stations are located in Avista's service territory, but their data are available for a much shorter duration and high correlations exist between the Spokane International Airport and these weather stations.

Sales forecasts are prepared using monthly data, as more granular load information is not available. Heating degree-days measure cold weather load sensitivity; cooling degree-days measure hot weather load sensitivity.

The load forecast includes projection of climate change impact. Ample evidence of cooling and warming trends exists in the historical record. The recent trend is a warming climate compared to the 30-year average. Avista relies on the University of Washington

"Climate Change Scenarios" 2008 study converted to heating and cooling degree-days.[1] This study provides warming to 87.2 percent of the present 30-year average. Cooling degree-days are 144.3 percent.

Price Elasticity

Price elasticity is an important consideration in any electricity demand forecast. It measures the ratio between the demand for electricity and a change in its price. A consumer who is sensitive to price change 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 displayed increasing price sensitivity and reduced overall usage in response to relatively large changes in the price of electricity.

Cross elasticity of demand, or cross-price elasticity, measures the relationship between the quantities of electricity demanded and to the quantity of potential electricity substitutes (e.g., propane or natural gas for heat) when the price of electricity increases relative to the price of the substitute product. A positive cross elasticity coefficient indicates cross-price elasticity between electricity and the substitute. A negative cross elasticity coefficient indicates the absence of cross-price elasticity, and that considered product is not a substitute for electricity but is instead complementary to it. In other words, an increase in the price of electricity increases the use of the complementary good, and a decrease in the price of electricity decreases the use of the complementary good.

The principal application of cross elasticity impact in the IRP is its substitutability by natural gas in some applications, including water and space heating. The correlation between retail electricity prices and the commodity cost of natural gas has increased in recent years as the industry has become more reliant on gas-fired generation to meet load growth. This increased positive correlation has reduced the net effect of cross price elasticity because retail natural gas and electricity prices.

Income elasticity measures the relationship between a change in consumer income and the change in consumer demand for electricity. As incomes rise, the ability of a consumer to pay for more electricity increases. The ability to afford electricity-consuming appliances also increases. Simply stated, as incomes rise consumers are more likely to purchase more electricity-consuming equipment, live in larger dwellings that use more electricity, and use the electrical equipment they have more often. Two of the most cited present examples of income elasticity are the increased proliferation of mobile electronic devices and high definition televisions.

The IRP estimates price elasticity by customer class for use in our electricity and natural gas demand forecasts. The price elasticity statistics used in the 2011 IRP are negative 0.15 for residential and negative 0.10 for commercial customers. Natural gas and

[1] http://cses.washington.edu/cig/fpt/ccscenarios.shtml.

electricity cross-price elasticity is positive at 0.05. Income elasticity is positive 0.75, meaning electricity is more affordable as incomes rise.

The baseline forecast used in the Expected Case assumes that rising incomes offset rising electricity and natural gas prices. Thus, there is no net expected impact on electricity consumption other than that caused by climate change and energy efficiency programs.

Retail Price Forecast

The retail sales forecast assumes retail prices increase at an average annual rate of eight percent from 2010 to 2018, followed by increases at the rate of general economic inflation thereafter. Carbon legislation and renewable energy targets are responsible for approximately one-fourth of the rate rise.[2]

Conservation

It is difficult to separate the interrelated impacts of rising electricity and natural gas prices, rising incomes, and conservation programs on the load forecast. Avista collects data on total demand, and derives from this data consumption change impacts. Avista has encouraged its customers to conserve electricity by offering conservation programs to its customers since 1978. Electricity usage impacts of these programs affect historical data; therefore, we conclude that the forecast already contains the impacts of existing conservation levels (7.5 aMW per year of new acquisition). As the 2011 IRP forecasts increased levels of conservation acquisition relative to history, the increased quantities reduce retail loads below Expected Case forecast levels.

Use per Customer Projections

A database of monthly electricity sales and customer numbers by rate schedule forms the basis of the usage per customer forecasts by rate schedule, customer class, and state from 1997 to 2010. Historical data is weather-normalized to remove the impact of heating and cooling degree-day deviations from expected normal values, as discussed above. Retail electricity price increases reduce electricity usage per customer.

The 2011 IRP includes a forecast of electric vehicles in the Expected Case based on projections made by the Northwest Power and Conservation Council in its Sixth Power Plan. The electric fleet is a combination of plug-in hybrids and electric-only passenger vehicles.

The residential usage per customer forecast trends flat over the long term. This result is the combination of reductions from embedded conservation, warming temperatures, price elasticity effects, and increases from electricity vehicle use. The forecast of household size decreases over time, as shown in Figure 2.8.

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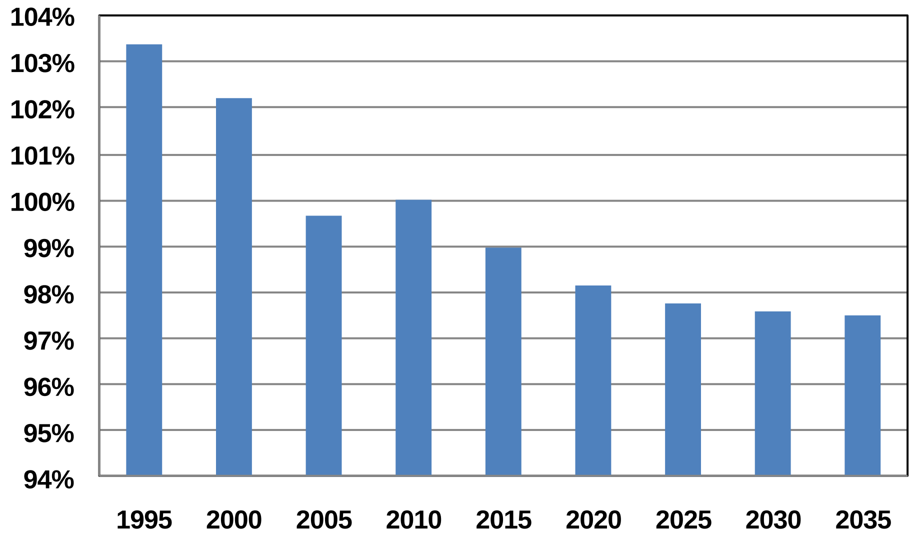
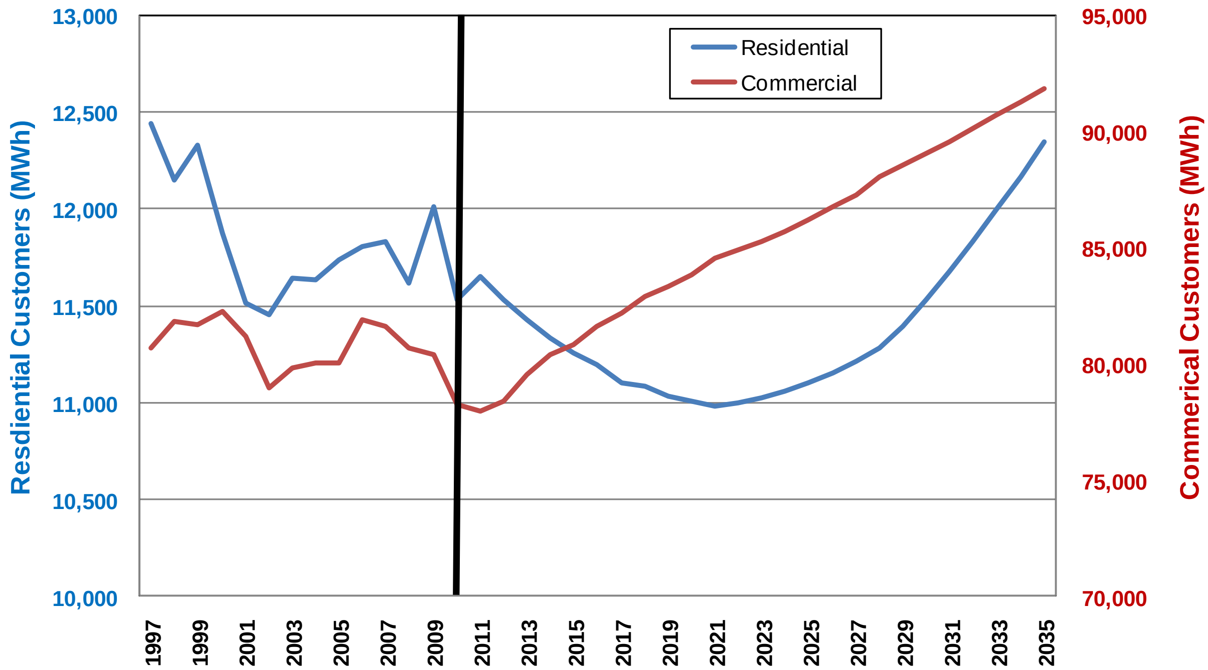
[2] This result assumes that the legislation does not mitigate the impacts of GHG legislation by issuing free utility allocations. Avista develops its load forecast independently of the IRP process. The load forecast mitigation assumption therefore differs from the Expected Case in the IRP where carbon mitigation legislation provides significant offsets and thereby limits the overall rate impact of carbon legislation. Avista does not expect this assumption difference to affect significantly the IRP results.

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, including additions to largest universities and hospitals, can greatly skew average use per average customer statistics. Usage forecasts for the residential and commercial sectors are contained in Figure 2.9.

Figure 2.9: Electricity Usage per Customer



Estimates for residential usage per customer across all schedules are relatively smooth. Commercial usage per customer increases for several years due to additional existing and new buildings housing very large customers, including Washington State University and Sacred Heart Medical Center. Expected additions for very large customers are included in the forecast through 2015; no additions are included after 2015. Avista includes only publicly announced long lead-time buildings in its load forecast.

Retail Electricity Sales Forecast

Major economic changes between 1997 and 2010 affected the region, not the least of which was a marked increase in wholesale and retail electricity prices. The energy crisis of 2000-01 included widespread and permanent conservation efforts by our customers. Several large industrial facilities closed permanently during the 2001-02 economic recession. In 2004, rising retail electricity rates further reinforced conservation efforts. Recently, the economy has experienced a significant recession from which it is slowly emerging. The recession reduced loads below what they otherwise would be.

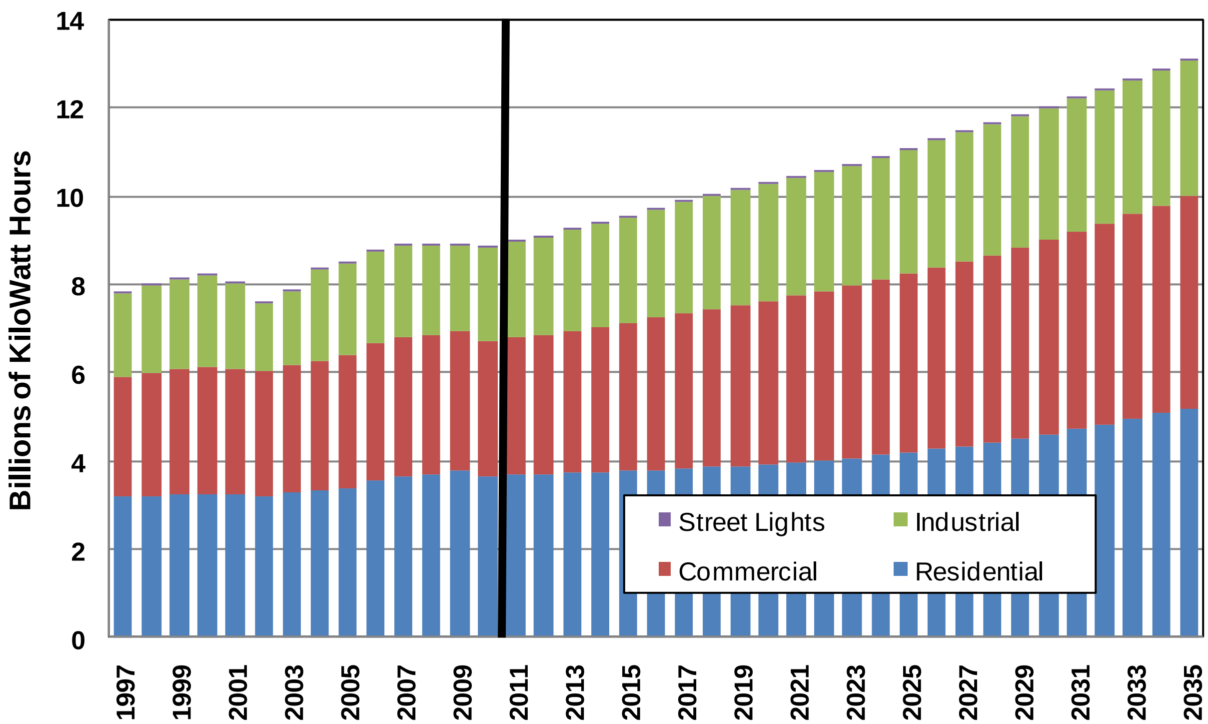
Retail electricity consumption rose from 8.2 million MWh in 2000 to 8.9 million MWh in 2010. This 0.75 percent annual average increase was net of the combined impacts of higher prices and resultant decreases in electricity demand from the Energy Crisis and economic recessions. Loads recover due to stabilizing electricity prices and recovery from the present recession. Forecasted average annual increase in retail sales over the 2010 to 2035 period is 1.6 percent.

The sales forecast takes a “bottom up” approach, summing individual customer class forecasts 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, consistent with the decline in housing starts at the national level caused by the present economic recession. Lumber and wood products sector load forecasts 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.

The forecast for 2035 is 13.11 billion kWh, representing a 1.6 percent compounded increase in retail sales. See Figure 2.10 for Avista's retail sales forecast.

Figure 2.10: Avista's Retail Sales Forecast

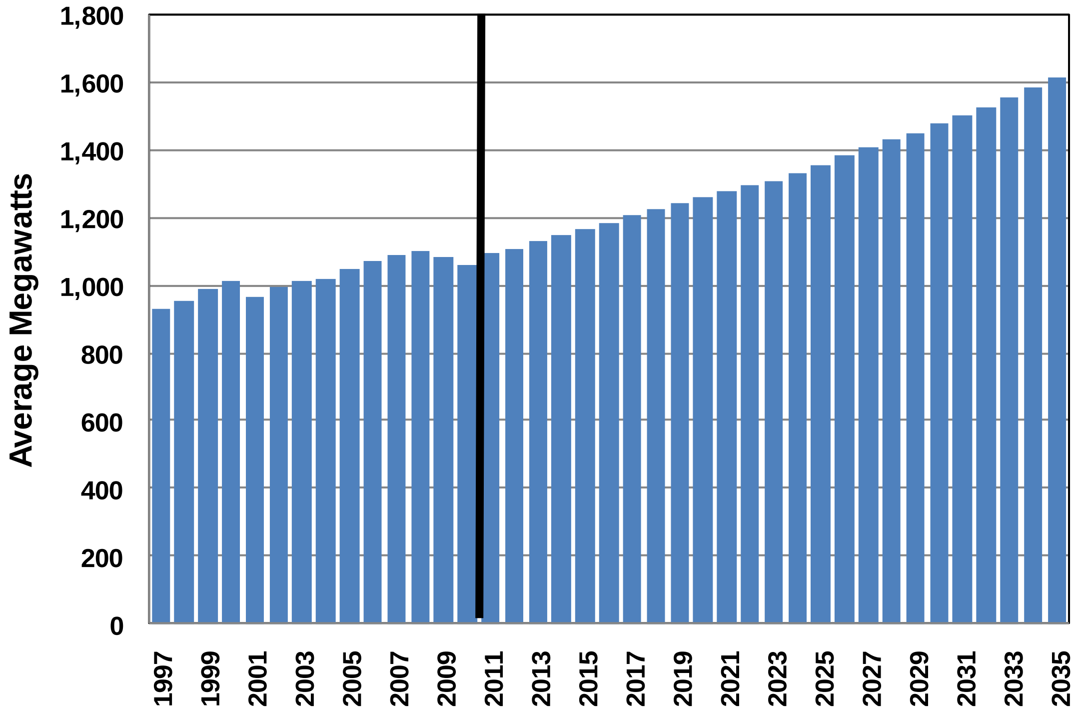


Load Forecast

Retail sales provide the data used to project load. Retail sales translate into average megawatt hours using a regression model ensuring monthly load shapes conform to history. The load forecast is a retail sales forecast combined with line losses across incurred in the delivery of electricity across the Avista transmission and distribution system.

Figure 2.11 presents annual net native load growth. Note the significant drop in the 2000-01 Energy Crisis, and smaller declines in the 2009-10 recession period. Loads from 1997 to 2010 are not weather normalized. Annual growth is expected to be 1.7 percent compounded over the next twenty and twenty-five years, the same growth rate as the 2009 IRP but from a lower base of 2010 instead of 2008.

Figure 2.11: Annual Net Native Load

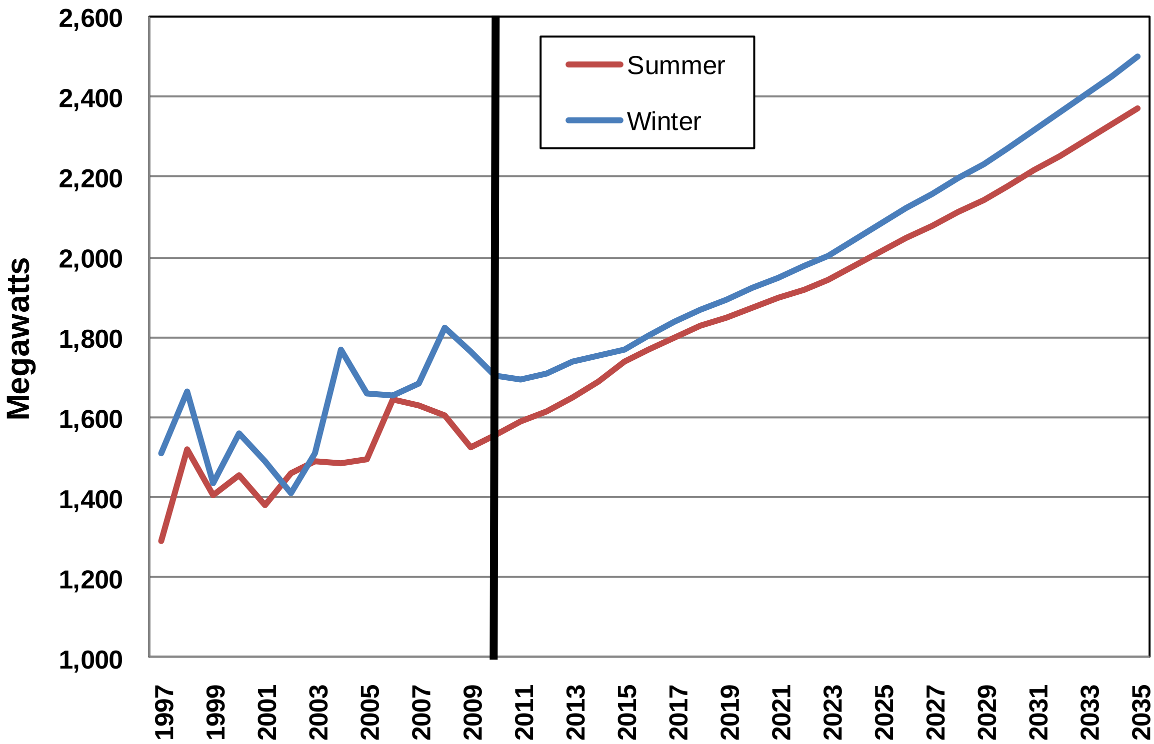


Peak Demand Forecast

The peak demand forecast represent expected peaks for each year of the IRP timeframe, not extreme weather peak demands.[3] The demand forecast is the product of an 11-year regression of actual peak demand and native load. Winter and summer peak demand forecasts are in Figure 2.12.[4] Peak loads grow at 1.2 percent compounded between 2010 and 2020 (219 MW), 1.5 percent over the 20-year IRP period (571 MW), and 1.55 percent over the 25-year forecast (796 MW).

[3] The expected peak demand has a 50 percent chance of exceedance in any year. Historical years present actual peak demands by year.
[4] Ibid.

Figure 2.12: Winter and Summer Peak Demand



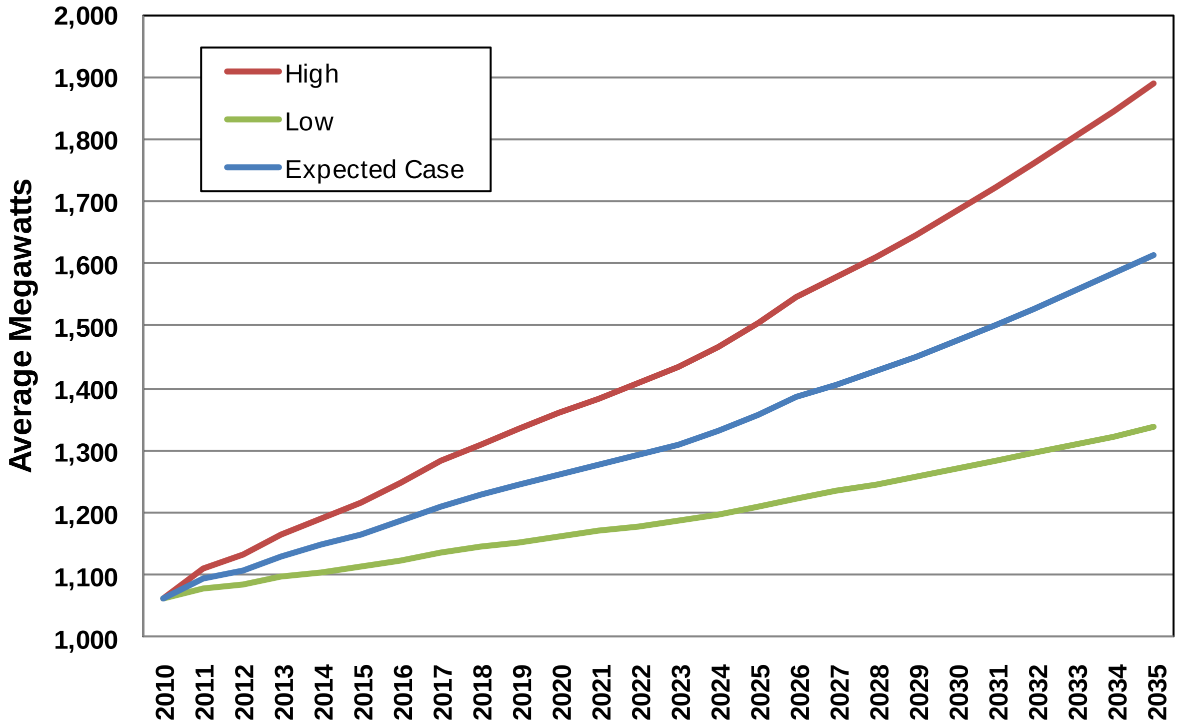
Extreme weather events influence historical peak load data. The comparatively low 1999 peak demand figure was the result of a warmer-than-average winter peak day; the peak in 2006 was the result of a below-average winter peak day. The 1999 and 2006 peak demand values illustrate why relying on compound growth rates and forecasted expected peak demand is an oversimplification, and why the Company plans to own or control enough generation assets and contracts to meet peak demand during extreme weather events.

Avista has witnessed significant summer load growth in recent years primarily due to rising air conditioning penetration in its service territory. However, Avista expects to remain a winter-peaking utility in the near future. It is possible, and we have seen it occur as recently as 2001, where very mild winter temperatures combined with extremely hot summer temperatures in a given calendar year results in our summer peak load exceeding our winter demand level.

The Company produced high and low load forecasts to test the IRPs Preferred Resource Strategy. These forecasts are very difficult to create because many factors influence the outcome, and because Avista is unable to obtain alternative economic forecasts at the county level from Global Insight. In past IRPs Avista used ranges from the Northwest Power and Conservation Council's Sixth Power Plan as a guide. This IRP relies on consultation with internal and external advisors and uses a growth multiplier on the Expected Case forecast of 1.5 for the high case and 0.5 for the low case.

The Expected Case load growth is 1.6 percent. The high growth case scenario is 2.33 percent and the low growth case scenario is 0.93 percent as shown in Figure 2.13. The Company believes these high and low growth ranges are consistent with the Sixth Power Plan's medium high and medium low ranges.

Figure 2.13: Electricity Load Forecast Scenario



Avista Resources and Contracts

Avista relies on a diverse portfolio of generating assets to meet customer loads, including owning and operating eight hydroelectricity projects located on the Spokane and Clark Fork Rivers. Its thermal assets include partial ownership of two coal-fired units in Montana, five natural gas-fired projects, and a biomass plant located 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 describes the Spokane River projects and provides the maximum on-peak capacity and nameplate capacity ratings for each plant. The maximum on-peak capacity of a generating unit is the total amount of electricity a plant can safely generate. This is often higher than the nameplate rating for hydroelectric projects. The nameplate, or installed capacity, is the capacity of a plant as rated by the manufacturer.

Post Falls
Post Falls is the upper most hydroelectricity facility on the Spokane River. It is located near the Washington/Idaho border. The project began operating in 1906, and during summer months maintains the elevation of Lake Coeur d'Alene. The project has six units, with the last unit added in 1980. The project is capable of producing 18.0 MW and has a 14.75 MW nameplate rating.

Upper Falls
The Upper Falls project began generating in 1922 in downtown Spokane, and now is within the boundaries of Riverfront Park. This project is comprised of a single 10.0 MW unit with a 10.26 MW maximum capacity rating.

Monroe Street
The Monroe Street facility was Avista's first generation facility. It began serving customers in 1890 near what is now Riverfront Park. Rebuilt in 1992, the single generating unit has a 15.0 MW maximum capacity rating and a 14.8 MW nameplate rating.

Nine Mile
A private developer built the Nine Mile project in 1908 near Nine Mile Falls, Washington, nine miles northwest of Spokane. The Company purchased the project in 1925 from the Spokane & Eastern Railway. Its four units have a 17.6 MW maximum capacity and a 26.4 MW nameplate rating.[5] The facility received a rubber dam in 2010, replacing the original flashboard system that maintained higher summer elevations.

The Nine Mile facility presently has major equipment outages. Unit 1 is out of service and Unit 2 is limited to half load. Unit 4 failed in the spring of 2011. Avista is evaluating options to restore the plant to full service. Restoration options include refurbishment of the existing powerhouse, including new turbine runners, or a new powerhouse located downstream from the existing powerhouse. A decision on the final configuration of Nine Mile is not yet determined. The Company expects any new generation at the plant will meet Washington State Energy Independence Act requirements.

Long Lake
The Long Lake project is located northwest of Spokane and maintains the Lake Spokane reservoir, also known as Long Lake. The facility was the highest spillway dam with the largest turbines in the world when completed in 1915. The plant received new runners in the 1990s, adding 2.2 aMW of additional energy. The project's four units provide 88.0 MW of combined capacity and have an 81.6 MW nameplate rating.

Little Falls
The Little Falls project, completed in 1910 near Ford, Washington, is the furthest downstream hydro facility on the Spokane River. A new runner upgrade in 2001 generates 0.6 aMW of renewable energy than the previous runner. The facility's four units generate 35.2 MW of on-peak capacity and have a 32.0 MW nameplate rating.

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[5] 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 located near Clark Fork, Idaho, and Noxon, Montana, 70 miles south of the Canadian border. The plants operate under a FERC license through 2046.

Cabinet Gorge

The Cabinet Gorge project started generating power in 1952 with two units. The plant added two additional generators in the following year. The current maximum on-peak 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 the turbine for Unit 1 in 1994. Unit 3 received an upgrade in 2001. Unit 2 received an upgrade in 2004. Unit 4 received a turbine runner upgrade in 2007, increasing its generating capacity from 55 MW to 64 MW, and adding 2.1 aMW of additional energy.

Noxon Rapids

The Noxon Rapids project includes four generators installed between 1959 and 1960, and a fifth unit added in 1977. The project is in the middle of a major turbine upgrade, with one unit receiving a new runner in each calendar year beginning in 2009. The upgrades add 6.6 aMW of total energy and qualify under Washington State's Energy Independence Act renewable energy goals.

Total Hydroelectric Generation

In total, Avista's hydroelectric plants have 1,065.4 MW of on-peak capacity. Table 2.2 summarizes the location and operational capacities of the Company's hydroelectric projects. This table includes the average annual energy output of each facility based on the 70-year hydrologic record for the year ending 2012.

Table 2.2: Company-Owned Hydro Resources

Project Name	River System	Location	Nameplate Capacity (MW)	Maximum Capability (MW)	Expected Energy (aMW)
Monroe Street	Spokane	Spokane, WA	14.8	15.0	11.6
Post Falls	Spokane	Post Falls, ID	14.8	18.0	10.0
Nine Mile	Spokane	Nine Mile Falls, WA	26.0	17.5	12.5
Little Falls	Spokane	Ford, WA	32.0	35.2	22.1
Long Lake	Spokane	Ford, WA	71.0	89.0	53.4
Upper Falls	Spokane	Spokane, WA	10.0	10.2	7.5
Cabinet Gorge	Clark Fork	Clark Fork, ID	270.9	270.5	124.8
Noxon Rapids	Clark Fork	Noxon, MT	518.0	610.0	198.3
Total			**957.5**	**1,065.4**	**440.2**

Thermal Resources

Avista owns seven thermal assets located across the Northwest. Each thermal plant operates through the 20-year duration of the 2011 IRP. The resources provide dependable energy and capacity to serve base loads and provide peak load serving capabilities. A summary of Avista thermal resources is in Table 2.3.

Colstrip

The Colstrip plant, located in Eastern Montana, consists of four multi-owner coal-fired steam plants. PPL Global operates the facilities on behalf of the owners. Avista owns 15 percent of Units 3 and 4. Unit 3 began operating 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. In 2006 and 2007 completed capital projects improved efficiency, reliability, and generation capacity at the plants. The upgrades include new high-pressure steam turbine rotors and digital (versus the old analog) control systems.

Rathdrum

Rathdrum is a two-unit simple-cycle combustion turbine. This natural gas-fired plant is located near Rathdrum, Idaho. It entered service in 1995 and has a maximum capacity of 178.0 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. The plant is currently limited to run no more than approximately 546 hours per year and provides reserve capacity to protect against reliability concerns and extreme market aberrations.

Boulder Park

The Boulder Park project entered service in Spokane Valley in 2002. The site uses six natural gas-fired internal combustion reciprocating 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 274 MW in the winter and 221 MW in the summer and the duct burner provides the unit with an additional capacity of up to 28 MW. The plant's nameplate rating is 287.3 MW.

Kettle Falls and Kettle Falls Combustion Turbine

The Kettle Falls biomass facility entered service in 1983 near Kettle Falls, Washington and is one of the largest biomass plants in North America. The open-loop biomass steam plant uses waste wood products from area mills and forest slash, but can also run on natural gas. A combustion turbine (CT), added to the facility in 2002, burns natural gas and increases overall plant efficiency by sending exhaust heat to the wood boiler.

The wood-fired portion of the plant has a maximum capacity of 50.0 MW and its nameplate rating is 50.7 MW. The plant typically operates between 45 and 47 MW because of fuel quality issues. The plant's capacity increases to 57.0 MW when operated in combined-cycle mode with the CT. The CT produces 8 MW of peaking capability in the summer and 11 MW in the winter. The CT resource is limited in winter when the gas pipeline is constrained; for IRP modeling, the plant does not run when temperatures fall below zero and pipeline capacity serves local natural distribution customers.

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	178.0	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	302.0	249.0	276.0
Kettle Falls	Kettle Falls, WA	Wood/Gas	1983	47.0	47.0	46.0
Kettle Falls CT[6]	Kettle Falls, WA	Gas	2002	11.0	8.0	7.5
Total				**852.6**	**718.6**	**828.8**

Power Purchase and Sale Contracts

The Company utilizes 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 2011 IRP. Contracts provide many benefits including environmentally low-impact and low-cost hydro and wind power. A 2012 annual summary of Avista large contracts is in Table 2.5.

Mid-Columbia Hydroelectric Contracts

During the 1950s and 1960s, 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 with public, municipal, and investor-owned utilities throughout the Northwest assisted with project financing, and ensured a market for generated surplus power.

Avista entered into long-term contracts for the output of four of these projects "at cost." Later, the Company competed in capacity auctions in 2009 through 2011 to purchase new short-term contracts at market-based prices. The Mid-Columbia contracts provide energy, capacity, and reserve capabilities; in 2012, contracts provide approximately 165 MW of capacity and 86 aMW of energy, see Table 2.4 for further details. Over the next

[6] Includes output of gas turbine plus benefit of its steam to the main units boiler.

20 years the Douglas PUD (2018) and Chelan PUD (2015) contracts will expire. Avista may extend these contracts or even gain additional capacity in auctions; however, we have no assurance that we will be successful in extending our contract rights. Due to this uncertainty, the IRP does not include these contracts in the resource mix beyond their expiration dates.

Table 2.4: Mid-Columbia Capacity and Energy Contracts

Counter Party	Project(s)	Percent Share (%)	Start Date	End Date	Estimated Capacity (MW)	Annual Energy (aMW)
Grant PUD	Priest Rapids	3.7	12/2001	12/2052	34	16
Grant PUD	Wanapum	3.7	12/2001	12/2052	37	18
Chelan PUD	Rocky Reach	4.5	11/2011	06/2012	57	32
Chelan PUD	Rocky Reach	3.0	07/2011	12/2014	38	21
Chelan PUD	Rock Island	3.0	07/2011	12/2015	19	11
Douglas PUD	Wells	3.3	02/1965	08/2018	29	15
2012 Total Contracted Capacity and Energy					**165**	**86**

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 (sometimes referred to in the industry as the Rathdrum Generating Station). Avista has the sole right to dispatch the plant, and is responsible for providing fuel and energy and capacity payments, under a tolling PPA with Energy Investors Funds expiring in October 2026.

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 Avista for certain WPPSS – Washington Nuclear Plant No. 3 (WNP-3) preservation costs and an irrevocable offer of WNP-3 capability under the Regional Power Act.

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 under the Planning Margin heading of this chapter.

Table 2.5: Large Contractual Rights and Obligations

Contract	Type	End Date	Winter Capacity (MW)	Summer Capacity (MW)	2012 Est. Annual Energy (aMW)
Canadian Entitlement	Sale	n/a	8	8	5
Clearwater	PURPA	06/2013	75	75	52
Douglas Settlement	Purchase	09/2018	2	3	3
Lancaster	Purchase	10/2026	290	249	222
Nichols Pumping	Sale	n/a	7	7	7
PGE Capacity Exchange	Exchange	12/2016	150	150	0
Small Power	PURPA	varies	2	1	2
Stateline	Purchase	03/2014	0	0	9
Stimson Lumber	Purchase	09/2011	4	5	4
Upriver (net load)	Purchase	12/2011	8	-1	6
WNP-3	Purchase	06/2019	82	0	42
Total			**628**	**497**	**352**

Reserve Margins

Planning reserves accommodate situations when loads exceed and/or resource outputs are below expectations due to adverse weather, forced outages, poor water conditions, or other contingencies. There are disagreements within the industry on reserve margin levels utilities should carry. Many disagreements stem from system differences, such as resource mix, system size, and transmission interconnections

Reserve margins, on average, increase customer rates when compared to resource portfolios without reserves, because of the cost of carrying additional generating capacity that is rarely used. Reserve resources have the physical capability to generate electricity, but high operating costs limit their economic dispatch and revenues to offset purchase costs.

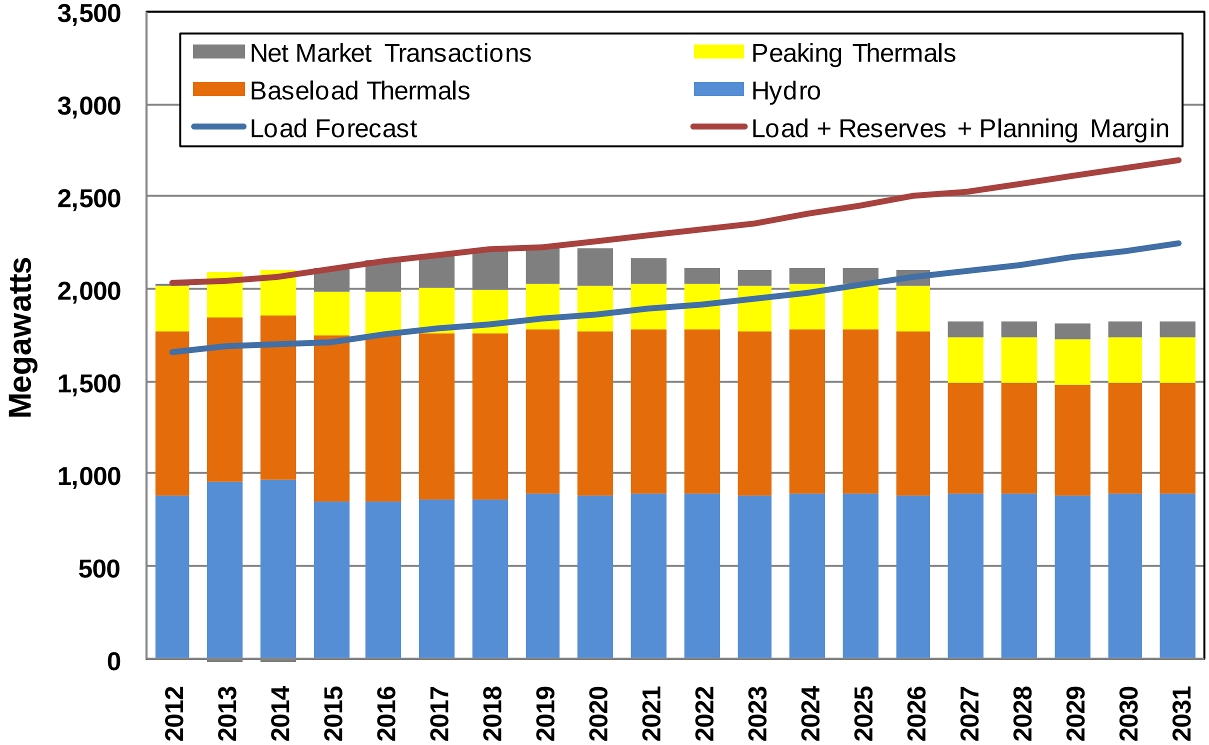
Avista Planning Margin

Avista retains two planning margin targets—capacity and energy. Capacity planning is a traditional metric ensuring that utilities can meet peak loads at times of system strain, and cover variability inherent in their generation resources with unpredictable fuel supplies, such as wind and hydro, and varying loads.

Capacity Planning

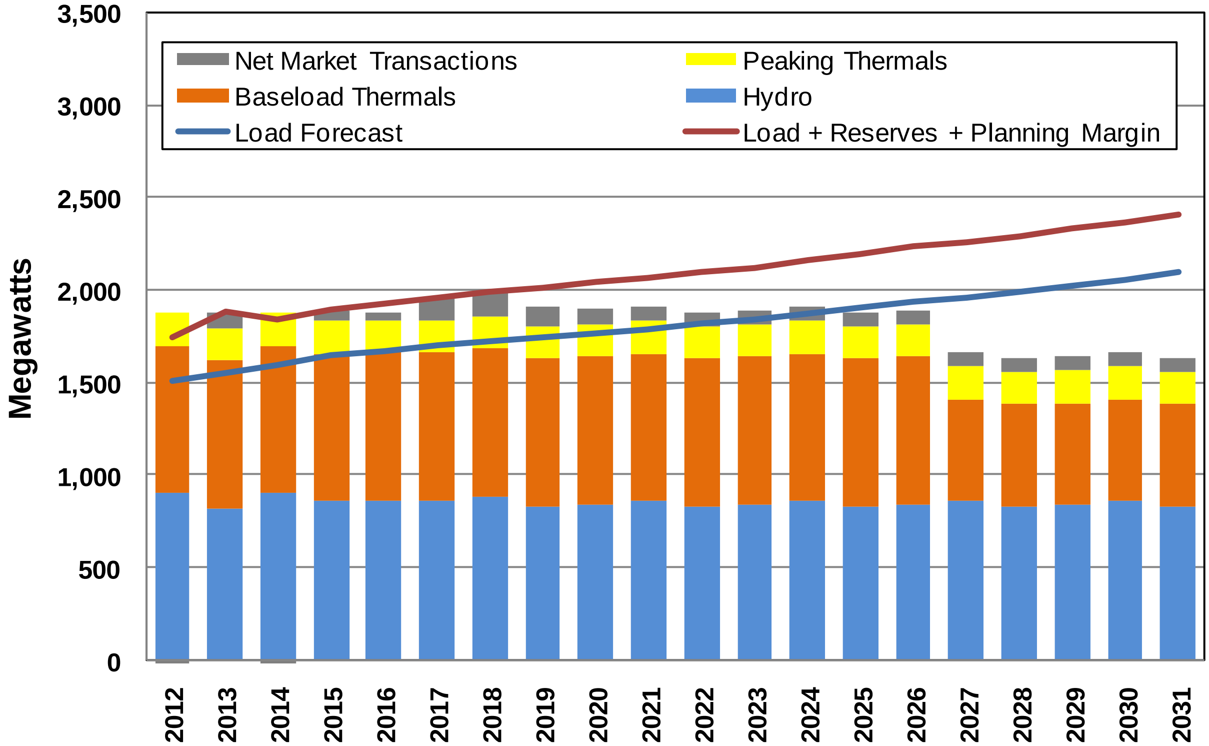
Avista plans for peak load events using the regional standard of an 18-hour peak event covering six hours each day for three consecutive days. Further, the IRP uses a planning margin level approximating the Northwest Power and Conservation Council's targets of 23 percent in the winter and 24 percent in the summer. Avista first estimates the amount of operating reserves required for on-system generation, load regulation, and wind integration. It then adds a planning margin of 15 percent to summer peak load and 14 percent to winter peak load. Adjustments to the net position include market purchases when the Northwest is long on regional capacity.[7] The planning margin equals 267 MW in 2010. Additional detail is in Appendix A. Figure 2.14 illustrates the winter peak position and Figure 2.15 shows the summer peak position.

Figure 2.14: Winter 18-Hour Capacity Load and Resources



[7] Avista relied on work by the Northwest Power and Conservation Council in its Resource Adequacy Forum exercises to determine the level of surplus summer energy and capacity. Reliance is limited to the Company's prorate share of regional load.

Figure 2.15: Summer 18-Hour Capacity Load and Resources



Energy Planning

For energy planning, resources must be adequate to meet customer requirements even where loads are high for extended periods or an outage limits the output of a resource. Extreme weather conditions can change monthly energy obligations by up to 30 percent. Where generation capability is not adequate to meet these variations, customers and the utility must rely on the volatile short-term electricity market. In addition to load variability, a planning margin accounts for variations in hydroelectricity generation.

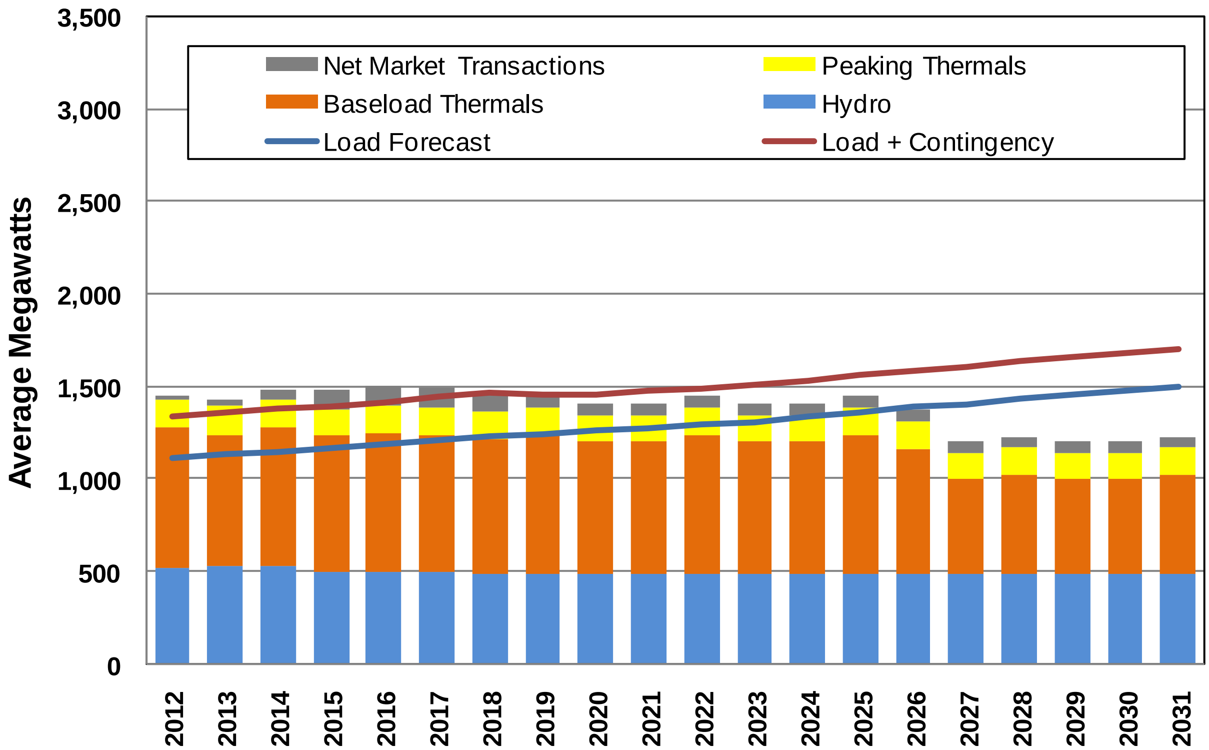
As with capacity planning, there are differences in regional opinion on a proper method for establishing resource planning margins. Many utilities in the Northwest base their planning on the amount of energy available during the critical water period of 1936/37.[8] The critical water year of 1936/37 is low on an annual basis, but it is not necessarily low in every month. The IRP could target resource development to reach a 99 percent confidence level on being able to deliver energy to its customers, and it would significantly decrease the frequency of its market purchases. However, this strategy requires investments in approximately 200 MW of generation in additional to the margins included in Expected Case of the IRP. Such expenditure to support this high level of reliability would put upward pressure on retail rates for a modest benefit. Avista instead targets a 90 percent monthly energy planning margin confidence interval based on load hydroelectricity variability. In other words, there is a 10 percent chance of needing to purchase energy from the market in any given month over the IRP

[8] The critical water year represents the lowest historical generation level in the streamflow record.

timeframe, but on average, the utility would have the ability to meet all of its energy requirements and be selling electricity into the marketplace.

Beyond load and hydroelectricity variability, Avista's WNP-3 contract with BPA contains supply risk. The contract includes a return energy provision in favor of BPA that can equal 32 aMW annually. Under adverse market conditions BPA almost certainly would be exercise its rights.BPA last exercised its contract rights in 2001. To account for this contract risk, the energy planning margin is increased by 32 aMW until the contract expires in 2019. With the addition of WNP-3, load and hydroelectricity variability, the total energy planning margin equals 227 aMW in 2010. Additional detail is contained in Appendix A. See Figure 2.16 for the summary of the annual average energy load and resource net position.

Figure 2.16: Annual Average Energy Load and Resources



Loss of Load Analysis

In the Northwest, loss-of-load analysis tools help address the issue of how much planning margin is required. Typical results of these models are Loss of Load Probability (LOLP), Loss of Load Hours (LOLH), and Loss of Load Expectation (LOLE) measures. A reliable system has typically been defined as having no more than one interruption event in twenty years, or 5 percent. These analyses can be helpful, but usually have an inherent flaw due to the need to assume how much out-of-area generation is available for the study. Avista developed a loss of load analysis model to simulate reliability events due to poor hydro, forced outages, and extreme weather conditions on its system, finding that forced outages are the main driver of reliability events. Avista has robust transmission rights to the wholesale energy markets, but the amount of generation actually available for purchase from third parties is difficult to estimate in a model. To address this concern, a sophisticated regional model must estimate required regional planning margins. Avista will continue to monitor and contribute to such regional model development, with the intent of using the regional model when it becomes available.

Washington State Renewable Portfolio Standard

In the November 2006 general election, Washington State voters approved Citizens Initiative 937, now known as the Washington state Energy Independence Act. The initiative requires utilities with more than 25,000 customers to source 3 percent of their energy from qualified non-hydroelectric 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 any new generation resources to meet forecasted loads through 2019, this new law requires the Company to acquire additional qualified renewable generation, or renewable energy certificates (RECs), to meet the initiative's renewable goals. Table 2.6 at the end of this chapter details the forecast amount of RECs required to meet Washington state law, and the amount of qualifying resources has already in the generation portfolio. The sales forecast uses the current load forecast and does not include additional conservation as detailed in the Preferred Resource Strategy chapter. It also illustrates how the Company will maintain a REC reserve margin of approximately 10 aMW in 2016.

Resource Requirements

The resource requirements discussed in this section do not include additional energy efficiency acquisitions beyond what is in the load forecast. The Preferred Resource Strategy chapter discusses conservation beyond the assumptions contained in the load forecast. The following tables present loads and resources to illustrate future resource requirements.

During winter peak periods (Table 2.7), a surplus of capacity exists through 2019 after taking into account non-firm market purchases. Without non-firm market purchases, a capacity deficit would occur in 2012. Avista believes that the present market can meet these minor capacity shortfalls and therefore will optimize its portfolio to postpone new resource investments to meet capacity deficits prior to 2020. In 2016, the Portland General Electricity (PGE) capacity contract expires, returning 150 MW of capacity to the generation portfolio. Accounting for the PGE contract, the Company's first resource deficiency is in 2020, requiring 42 aMW; by 2022, 216 aMW are required.

The summer peak projection (Table 2.8) has lower loads than in winter, but resource capabilities are also lower due to lower hydroelectricity output and reduced capacity at natural gas-fired resources due to decreased performance during high-temperature events. The IRP shows persistent summer deficits throughout the 20-year timeframe, but regional surpluses are adequate to fill in these gaps.[9] Many near-term deficits are from decreased hydroelectricity capacity during periods of planned maintenance and upgrades. Taking into account regional surpluses, the load and resource balance is 54 MW short only in 2016. After 2016 when the PGE capacity sale contract expires, the next capacity need of 98 aMW is in 2019.

The traditional measure of resource need in the region is the annual average energy position. The energy position using this methodology is in Table 2.9. There is enough energy on an annual average basis to meet customer requirements until 2020, when the utility is short 49 aMW. Avista will require 112 aMW of new energy by 2025, and 475 aMW in 2031.

[9] Avista relied on work by the Northwest Power and Conservation Council in its Resource Adequacy Forum exercises to determine the level of surplus summer energy and capacity. Reliance is limited to the Company's prorate share of regional load.

Table 2.6: 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	2027	2028	2029	2030	2031
WA State Retail Sales Forecast			628	630	636	646	654	663	671	678	687	693	701	708	714	721	730	738	746	754	763	772	782	793
RPS %				0%	3%	3%	3%	3%	9%	9%	9%	9%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
REQUIRED RENEWABLE ENERGY					**19**	**19**	**19**	**20**	**59**	**60**	**61**	**61**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**114**	**115**	**117**
Renewable Resources																								
Purchased RECs				0	6	6	6	6	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
Little Falls 4	2001	0.6		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Cabinet 2	2004	2.9		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Cabinet 3	2001	4.5		4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Cabinet 4	2007	2.0		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Noxon 1	2009	2.3		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Noxon 3	2010	1.9		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Noxon 2	2011	1.0		0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Noxon 4	2012	0.9		0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nine Mile	2012	3.7		0	0	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Total Qualifying Resources				*17*	*23*	*26*	*28*	*28*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*
NET REC POSITION				**17**	**5**	**7**	**8**	**8**	**(37)**	**(38)**	**(39)**	**(39)**	**(82)**	**(83)**	**(84)**	**(85)**	**(86)**	**(87)**	**(88)**	**(89)**	**(90)**	**(92)**	**(93)**	**(95)**
REC Bank																								
Previous Year Balance				0	17	21	26	28	28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REC's Required				0	(19)	(19)	(19)	(20)	(59)	(60)	(61)	(61)	(104)	(105)	(106)	(107)	(108)	(109)	(110)	(111)	(112)	(114)	(115)	(117)
REC's Generated/Purchased				17	23	26	28	28	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Expired/Sold RECs					0	(2)	(7)	(8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NET REC BANK				**17**	**21**	**26**	**28**	**28**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
REC Reserve Requirement (95th PERCENTILE)																								
Load				0	1	1	1	1	3	3	3	3	5	5	5	5	5	5	5	5	5	5	6	6
Existing Hydro Upgrades				0	6	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total REC Reserve Requirement				**0**	**7**	**8**	**8**	**8**	**10**	**10**	**10**	**10**	**12**	**12**	**12**	**12**	**12**	**12**	**13**	**13**	**13**	**13**	**13**	**13**
NET REC POSITION				**17**	**14**	**21**	**26**	**28**	**(20)**	**(48)**	**(49)**	**(50)**	**(94)**	**(95)**	**(96)**	**(97)**	**(98)**	**(99)**	**(101)**	**(102)**	**(103)**	**(105)**	**(106)**	**(108)**

Table 2.7: Winter 18-Hour Capacity Position (MW)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
REQUIREMENTS																				
Native Load	-1,661	-1,688	-1,704	-1,718	-1,751	-1,784	-1,814	-1,839	-1,866	-1,892	-1,919	-1,946	-1,982	-2,020	-2,062	-2,094	-2,131	-2,168	-2,208	-2,249
Firm Power Sales	-242	-242	-211	-158	-158	-8	-8	-7	-7	-7	-7	-7	-6	-6	-6	-6	-6	-6	-6	-6
Total Requirements	**-1,903**	**-1,930**	**-1,915**	**-1,876**	**-1,909**	**-1,792**	**-1,822**	**-1,846**	**-1,873**	**-1,899**	**-1,925**	**-1,953**	**-1,988**	**-2,027**	**-2,068**	**-2,101**	**-2,137**	**-2,174**	**-2,214**	**-2,255**
RESOURCES																				
Firm Power Purchases	175	175	175	175	175	175	174	173	90	90	90	90	90	90	90	90	90	90	90	90
Hydro Resources	880	955	965	854	854	865	861	889	881	889	889	881	889	889	881	889	889	881	889	889
Base Load Thermals	895	895	895	895	895	895	895	895	895	895	895	895	895	895	895	606	606	606	606	606
Wind Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking Units	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242
Total Resources	**2,192**	**2,267**	**2,277**	**2,166**	**2,166**	**2,177**	**2,172**	**2,199**	**2,108**	**2,116**	**2,116**	**2,108**	**2,116**	**2,116**	**2,108**	**1,826**	**1,826**	**1,818**	**1,826**	**1,826**
PEAK POSITION	**289**	**337**	**362**	**290**	**256**	**385**	**350**	**353**	**236**	**217**	**191**	**155**	**127**	**89**	**40**	**-275**	**-311**	**-356**	**-388**	**-429**
RESERVE PLANNING																				
Required Operating Reserves	-162	-164	-163	-162	-165	-159	-161	-163	-165	-167	-173	-176	-180	-182	-186	-170	-170	-171	-172	-173
Available Operating Reserves	23	42	42	8	8	8	8	34	34	34	34	34	34	34	34	34	34	34	34	34
Planning Margin	-233	-236	-239	-240	-245	-250	-254	-258	-261	-265	-269	-272	-277	-283	-289	-293	-298	-304	-309	-315
Total Reserve Planning	**-372**	**-358**	**-360**	**-394**	**-402**	**-400**	**-407**	**-387**	**-392**	**-398**	**-408**	**-414**	**-423**	**-431**	**-441**	**-429**	**-434**	**-441**	**-447**	**-454**
Peak Position Net Reserves Planning	**-83**	**-21**	**2**	**-105**	**-146**	**-15**	**-57**	**-34**	**-157**	**-181**	**-216**	**-259**	**-296**	**-342**	**-401**	**-704**	**-746**	**-796**	**-835**	**-883**
Planning Margin	**15%**	**17%**	**19%**	**15%**	**13%**	**21%**	**19%**	**19%**	**13%**	**11%**	**10%**	**8%**	**6%**	**4%**	**2%**	**-13%**	**-15%**	**-16%**	**-18%**	**-19%**
Avista Share of Excess NW Capacity	737	656	565	477	400	326	255	186	115	56	0	0	0	0	0	0	0	0	0	0
Peak Position Net Market	**654**	**635**	**567**	**373**	**254**	**311**	**199**	**152**	**-42**	**-125**	**-216**	**-259**	**-296**	**-342**	**-401**	**-704**	**-746**	**-796**	**-835**	**-883**

Table 2.8: Summer 18-Hour Capacity Position (MW)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
REQUIREMENTS																				
Native Load	-1,514	-1,556	-1,597	-1,644	-1,673	-1,701	-1,727	-1,748	-1,771	-1,793	-1,815	-1,838	-1,868	-1,900	-1,937	-1,964	-1,995	-2,026	-2,059	-2,094
Firm Power Sales	-243	-218	-212	-159	-159	-9	-9	-8	-8	-8	-8	-8	-8	-7	-7	-7	-7	-7	-7	-7
Total Requirements	**-1,757**	**-1,774**	**-1,809**	**-1,804**	**-1,832**	**-1,710**	**-1,736**	**-1,756**	**-1,778**	**-1,800**	**-1,822**	**-1,846**	**-1,876**	**-1,908**	**-1,944**	**-1,971**	**-2,002**	**-2,033**	**-2,067**	**-2,102**
RESOURCES																				
Firm Power Purchases	85	85	85	85	85	85	85	83	83	82	82	82	82	82	82	82	82	82	82	82
Hydro Resources	900	819	902	859	866	864	885	833	840	859	833	840	859	833	840	859	833	840	859	833
Base Load Thermals	799	799	799	799	799	799	799	799	799	799	799	799	799	799	799	551	551	551	551	551
Wind Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking Units	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176
Total Resources	**1,960**	**1,880**	**1,962**	**1,919**	**1,926**	**1,924**	**1,945**	**1,891**	**1,897**	**1,916**	**1,891**	**1,896**	**1,916**	**1,890**	**1,896**	**1,668**	**1,642**	**1,648**	**1,668**	**1,642**
PEAK POSITION	**203**	**106**	**152**	**116**	**94**	**214**	**209**	**135**	**119**	**116**	**68**	**51**	**41**	**-18**	**-48**	**-304**	**-361**	**-385**	**-399**	**-460**
RESERVE PLANNING																				
Required Operating Reserves	-153	-157	-159	-160	-162	-155	-157	-160	-161	-163	-165	-167	-169	-171	-172	-157	-156	-157	-158	-158
Available Operating Reserves	155	66	171	159	159	159	161	158	158	161	158	158	161	158	158	161	158	158	161	158
Planning Margin	-227	-233	-240	-247	-251	-255	-259	-262	-266	-269	-272	-276	-280	-285	-290	-295	-299	-304	-309	-314
Total Reserve Planning	**-227**	**-325**	**-240**	**-248**	**-255**	**-255**	**-259**	**-264**	**-269**	**-271**	**-279**	**-285**	**-289**	**-298**	**-304**	**-295**	**-299**	**-304**	**-309**	**-314**
Peak Position Net Reserves Planning	**-24**	**-220**	**-87**	**-132**	**-161**	**-41**	**-50**	**-129**	**-150**	**-155**	**-211**	**-234**	**-249**	**-316**	**-352**	**-599**	**-660**	**-689**	**-708**	**-774**
Planning Margin	**12%**	**6%**	**8%**	**6%**	**5%**	**13%**	**12%**	**8%**	**7%**	**6%**	**4%**	**3%**	**2%**	**-1%**	**-2%**	**-15%**	**-18%**	**-19%**	**-19%**	**-22%**
Avista Share of Excess NW Capacity	275	221	178	141	107	78	52	31	10	3	0	0	0	0	0	0	0	0	0	0
Peak Position Net Market	**251**	**1**	**91**	**9**	**-54**	**36**	**2**	**-98**	**-140**	**-152**	**-211**	**-234**	**-249**	**-316**	**-352**	**-599**	**-660**	**-689**	**-708**	**-774**

Table 2.9: Average Annual Energy Position (aMW)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
REQUIREMENTS																				
Native Load	-1,109	-1,131	-1,148	-1,165	-1,186	-1,209	-1,228	-1,244	-1,260	-1,277	-1,293	-1,310	-1,333	-1,357	-1,386	-1,406	-1,429	-1,452	-1,477	-1,502
Firm Power Sales	-140	-127	-109	-58	-58	-6	-6	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
Total Requirements	**-1,249**	**-1,258**	**-1,258**	**-1,223**	**-1,244**	**-1,215**	**-1,234**	**-1,249**	**-1,266**	**-1,282**	**-1,298**	**-1,316**	**-1,338**	**-1,362**	**-1,391**	**-1,411**	**-1,434**	**-1,457**	**-1,482**	**-1,507**
RESOURCES																				
Firm Power Purchases	163	164	163	165	163	112	111	91	66	66	65	65	65	65	65	65	65	65	65	65
Hydro	522	525	527	495	495	495	490	481	481	481	481	481	481	481	481	481	481	481	481	481
Base Load Thermals	755	714	751	744	746	741	724	758	721	721	758	721	721	758	684	515	541	515	515	541
Total Resources	**1,441**	**1,403**	**1,442**	**1,405**	**1,404**	**1,348**	**1,325**	**1,330**	**1,268**	**1,268**	**1,304**	**1,266**	**1,267**	**1,304**	**1,229**	**1,060**	**1,087**	**1,060**	**1,060**	**1,087**
PEAK POSITION	**191**	**145**	**184**	**182**	**161**	**133**	**91**	**81**	**2**	**-14**	**6**	**-49**	**-71**	**-58**	**-162**	**-351**	**-347**	**-397**	**-421**	**-421**
CONTINGENCY PLANNING																				
Peaking Resources	153	153	153	138	153	154	153	147	146	145	147	146	145	147	146	145	147	146	145	147
Contingency	-228	-229	-230	-231	-232	-233	-233	-216	-197	-198	-198	-199	-200	-201	-202	-203	-204	-205	-206	-200
CONTINGENCY NET POSITION	**116**	**69**	**108**	**89**	**82**	**54**	**11**	**13**	**-49**	**-67**	**-46**	**-103**	**-126**	**-112**	**-218**	**-408**	**-405**	**-456**	**-482**	**-475**
Energy Margin	**15%**	**12%**	**15%**	**15%**	**13%**	**11%**	**7%**	**7%**	**0%**	**-1%**	**0%**	**-4%**	**-5%**	**-4%**	**-12%**	**-25%**	**-24%**	**-27%**	**-28%**	**-28%**

3. Energy Efficiency

Introduction

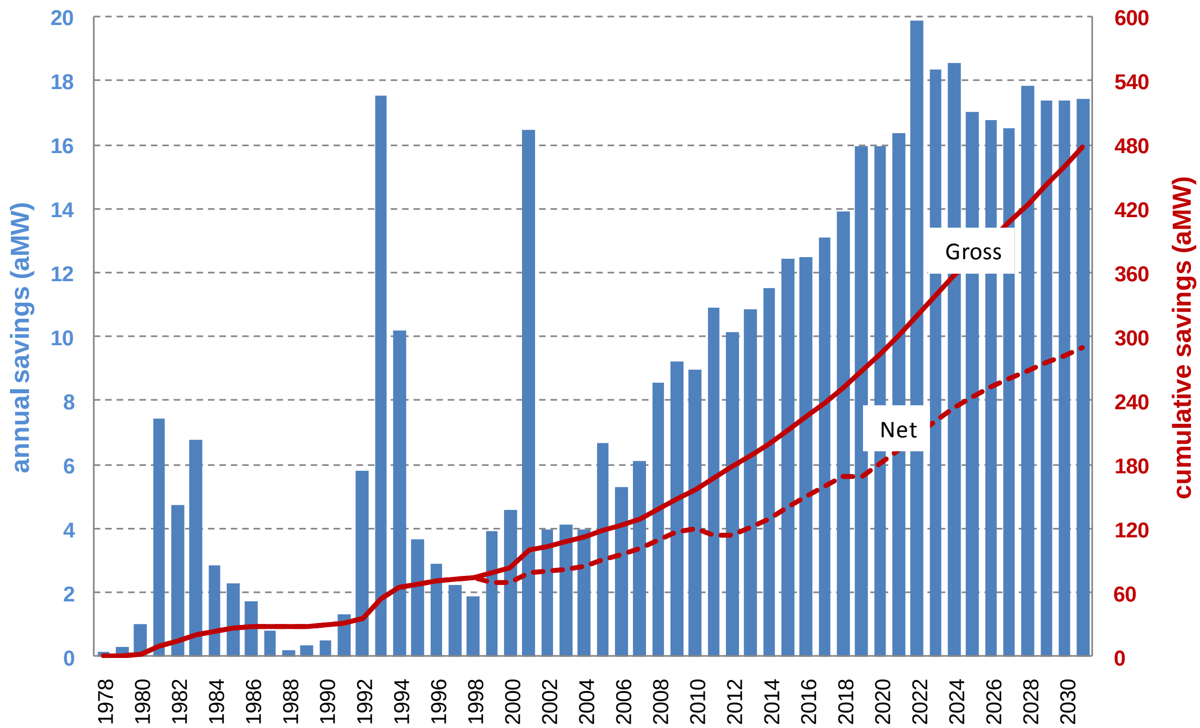
Avista began offering energy efficiency programs in 1978. Some of the most notable efficiency achievements include the Energy Exchanger program. It converted approximately 20,000 homes from electricity to natural gas space and/or water heating from 1992 to 1994. Avista pioneered the country's first system benefit charge for energy efficiency in 1995. Our conservation response during the 2001 Western Energy Crisis exceeded all expectations. Conservation programs regularly meet or exceed regional shares of energy efficiency gains as outlined by the Northwest Power Planning and Conservation Council (NPCC).

Section Highlights

- Avista began offering conservation programs in 1978.
- Conservation reduces load growth by 47 percent through the IRP timeframe.
- Company-sponsored conservation reduces retail loads by approximately 10 percent, or 120 aMW.
- Avista evaluated over 2,800 equipment options and over 1,500 measure options covering all major end-use equipment, as well as devices and actions to reduce energy consumption for this IRP.
- This IRP includes a Conservation Potential Assessment of the Company's Idaho and Washington service territories.

Figure 3.1 illustrates Avista's historical electricity conservation acquisitions. The Company has acquired 156.3 aMW of energy efficiency since 1978; however, the assumed 18-year average life of the conservation portfolio means that some of the measures have reached the end of their useful lives and are no longer reducing loads. The 18-year assumed measure life accounts for the difference between the Gross and Net lines in Figure 3.1.

Figure 3.1: Historical and Forecast Conservation Acquisition



Energy efficiency programs provide a range of conservation and education programs to residential, low-income, commercial, and industrial customer segments. The programs are either prescriptive or site-specific. Prescriptive programs, or standard offers, provide cash incentives for standardized products such as the installation of high efficiency appliances. Prescriptive programs are suitable in situations where uniform products or offerings are applicable for large groups of homogeneous customers. Standardized programs are primarily for residential and small commercial customers. Site-specific programs, or customized services, provide cash incentives for any cost-effective energy savings measure or equipment with an economic payback greater than one year and less than eight years for lighting projects or between one and 13 years for all other end-uses and technologies.

Efficiency programs with paybacks of less than one year are not eligible for incentives, though Avista will assist a customer in program design and implementation. Site-specific programs require customized services for commercial and industrial customers because of the unique characteristics of customers' premises and processes. In some cases, when it can be established that similar applications of energy efficiency measures results in somewhat consistent savings estimates and the technically achievable savings potential is high, a prescriptive approach is offered. An example is prescriptive lighting for commercial and industrial applications. While this application is not purely prescriptive in the traditional sense, such as with a residential program, a more prescriptive approach for these types of similar energy efficiency installations provides for an ease of marketability to customers and vendors.

To be consistent with I-937 conservation targets (WAC 480-109 and RCW 19.285) and the NPCC Sixth Power Plan, Avista supplements its energy efficiency activities by including potentials for transmissions and distribution efficiency measures. More details about the transmission and distribution efficiency projects are in the Transmission & Distribution chapter of this IRP.

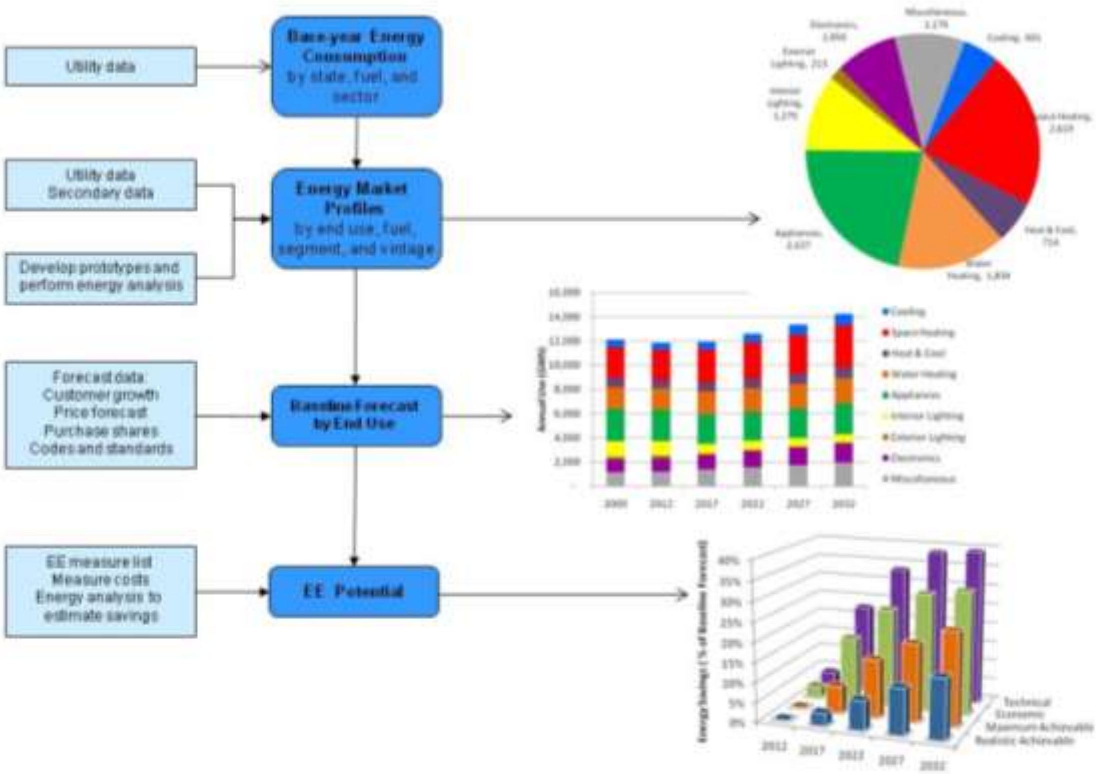
Conservation Potential Assessment Approach

After publication of the 2009 Electric IRP, the Washington Utilities and Transportation Commissions (WUTC) requested an external Conservation Potential Assessment (CPA) study for the 2011 IRP. Avista in 2010 retained Global Energy Partners (Global) to conduct this study for its Idaho and Washington electric service territories. The CPA identifies a 20-year potentials study for energy efficiency and demand response and provides data on resources specific to Avista's service territory for use in the 2011 IRP and in accordance with the energy efficiency goals in Washington's Energy Independence Act (I-937). The energy efficiency potentials consider such things as the impacts of existing programs, naturally occurring energy savings, the impacts of known building codes and standards as of 2010, technology developments and innovations, changes to the economy and energy prices.

Global took the following steps to assess and analyze energy efficiency and demand response potentials in the Company's service territory. Figure 3.2 illustrates the steps.

1. Perform a market assessment of base year consumption for the residential (including low income), commercial, and industrial sectors. The assessment uses utility and secondary data to characterize customers' electric usage behavior in Avista's service territory. Global uses this market assessment to develop energy market profiles that describe energy consumption by market segment, vintage (existing versus new construction), end-use, and technology.
2. Develop a baseline energy forecast by sector and by end-use for the entire study period.
3. Identify and analyze energy-efficiency measures appropriate for the Avista's service territory, including regional savings from energy efficiency measures acquired through the Northwest Energy Efficiency Alliance (NEEA) efforts.
4. Estimate technical, economic, and achievable energy efficiency potential. Technical potential involves choosing the most efficient measure, regardless of cost. Economic potential involves choosing the most efficient cost-effective measure. Achievable potential adjusts economic potential to account for factors other than pure economics, such as consumer behavior or market penetration rates.

Figure 3.2: Analysis Approach Overview



The CPA uses 2009 calendar year data, the first complete year of billing data available when the study began. Avista's recent load study, which also uses a 2009 baseline year, contributed to the selection of the 2009 baseline year for the CPA. This was Avista's first external CPA for its Idaho and Washington service territories.

The CPA segments Avista customers by state and by rate class. The rate classes used in this study included residential, commercial, industrial, general service, commercial and industrial large general service, extra large commercial, and extra large industrial. The residential class was further segmented into single family, multi-family, mobile home and low income customers. The low-income threshold used for this study was defined as 200 percent of the federal poverty level. Global used the NPCC calculator to determine future efficiency potentials for the pumping rate class, which represents 2 percent of total utility loads. Pumping schedules are included in the calculation of demand response potential, as discussed in the Demand Response section of this chapter. Within each segment, energy use was characterized by end-use (e.g., space heating, cooling, lighting, water heat, motors, etc.) and by technology (e.g., heat pump, resistance heating, or furnace for space heating).

The baseline forecast is the "business as usual" metric without new utility conservation programs. Energy savings from new energy efficiency measures are compared against this baseline. This baseline of annual electricity consumption and peak demand by customer segment and end-use supports projections of energy usage absent future efficiency programs. The baseline forecast includes projected impacts of known building codes and energy efficiency standards as of 2010 when the study was conducted that have direct bearings on the amount of utility program energy efficiency potential that exists over and above the effects of these efforts, including projected market condition changes. Market changes include customer and market growth, income growth, retail rates forecasts, trends in end-use and technology saturations, equipment purchase decisions, consumer price elasticity, income and persons per household, as well as customer potential estimates in the context of total energy use in the future so that projections of available energy efficiency savings can be derived.

The baseline forecast used in the CPA, prior to the consideration of efficiency potentials, projects overall electricity consumption growth of 48 percent. This compounded average annual growth rate of 1.7 percent during this 20-year period is consistent with Avista's current and previous IRP forecasts.

For each customer sector a robust list of electrical energy efficiency measures was compiled, drawing upon the NPCC Sixth Power Plan, the Regional Technical Forum (RTF), and other measures considered applicable to Avista. This list of energy efficiency equipment and measures included 2,808 equipment options and 1,524 measure options, representing a wide variety of end-use equipment, as well as devices and actions able to reduce energy consumption. A comprehensive equipment list and measure options are in Appendix C. Many do not pass the economic screen of avoided cost, but some might become part of the energy efficiency program as contributing factors evolve during the 20-year planning horizon. Measure cost, savings, estimated useful life, and other performance factors were characterized for the list of measures and economic screening was performed on each measure for each year of the study in order to develop the economic potential.

Overview of Energy Efficiency Potentials

Global utilized an approach adhering to the conventions outlined in the National Action Plan for Energy Efficiency (NAPEE) Guide for Conducting Potential Studies (November 2007).[1] This, in turn, follows protocols employed by the Northwest Power and Conservation Council. The NAPEE Guide represents the most credible and comprehensive national industry practice for specifying energy efficiency potential. Specifically, three types of potentials are in this study:

Technical Potential

Conservation potential uses the most efficient option commercially available to each purchase decision, regardless of cost. This theoretical case provides the broadest and highest definition of savings potential because it quantifies savings that would result if all current equipment, processes, and practices in all market sectors were replaced by the most efficient and feasible technology. Technical potential does not take into account the cost-effectiveness of the measures. Further, this study defines

[1] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025:* Developing a Framework for Change. www.epa.gov/eeactionplan.

technical potential as "phase-in technical potential," assuming only that the portion of the current equipment stock that has reached the end of its useful life and is due for turnover is changed out by the most efficient measures available. Non-equipment measures, such as controls and other devices (e.g., programmable thermostats) phase-in over time, just like the equipment measures. Lighting retrofits, which are in effect early replacements of existing lighting systems, count as a non-equipment measure in this CPA study.

Economic Potential

Economical conservation results from the purchase of the most cost-effective option available for a given equipment or non-equipment measure. Cost effectiveness is determined by applying the Total Resource Cost (TRC) test.[2] Measures that passed the economic screen represent aggregate economic potential. As with technical potential, economic potential calculations use a phased-in approach. Economic potential is a hypothetical upper-boundary of savings potential representing only economic measures; it does not consider customer acceptance and other factors.

Achievable Potential

Achievable potential refines economic potential by taking into account expected program participation, customer preferences, and budget constraints. Achievable potential represents a forecast of potential resulting from likely customer behavior and technology penetration rates. It also considers existing market, financial, political, and regulatory barriers that might limit achievable energy savings. It also considers customer incentive levels in line with typical industry practice, defined marketing campaigns, and internal budget constraints, as well as recent utility experience and reported savings from past and present programs.

To supplement potential estimates, and for operational planning purposes, Global used the NPCC Sixth Power Plan conservation curve ramp rates, historical acquisition at Avista, and information from other utility energy efficiency programs to bound two levels of achievable potential (realistic and maximum achievable potentials). While a significant degree of uncertainty associated with these adoption rates exists, Global believes this approach is reasonable and consistent with experience gained from other utility efforts.

The CPA forecasts annual achievable potential for all sectors at 5.7 aMW (or 49,804 MWh) in 2012, increasing to 231.2 aMW (or 2,025,679 MWh) by 2031. Table 3-1 and Figure 3-3 show the CPA results for baseline energy use, technical, economic, and achievable potential. The projected baseline electricity consumption forecast increases 43 percent during the 20-year planning horizon. Projected achievable energy savings, as a percentage of the baseline energy forecast, grows from 0.6 percent in 2012 to 16.1

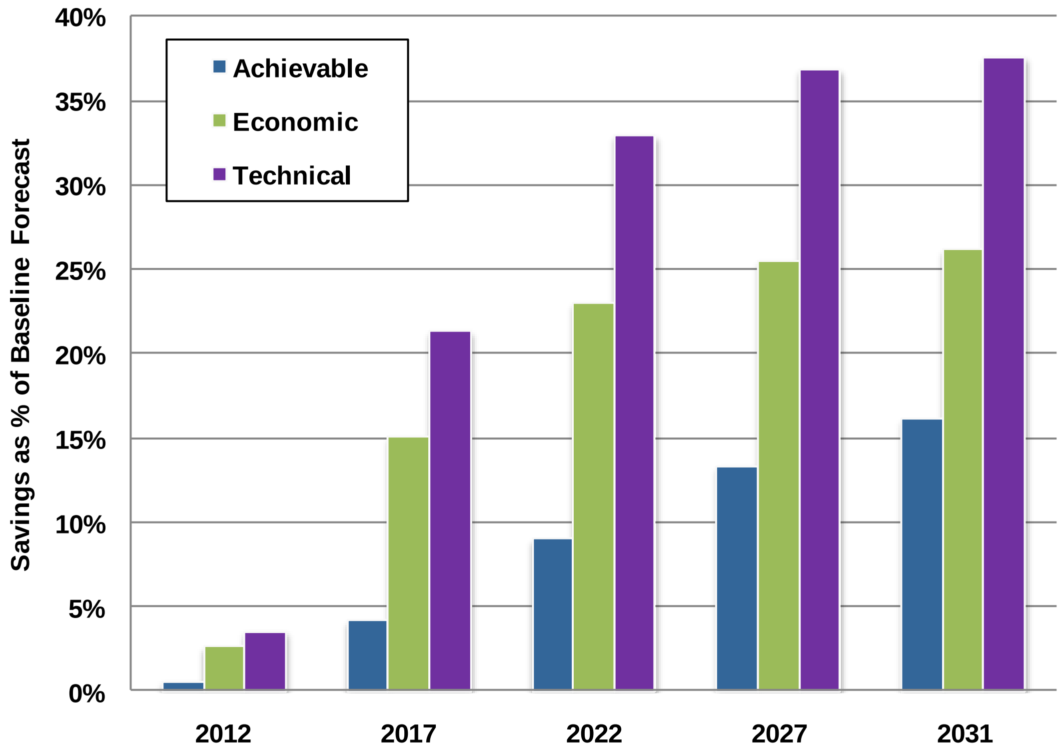
[2] There are other tests that can be used to represent the economic potential (e.g., Participant or Utility Cost), but the TRC is generally accepted as the most appropriate representation of economic potential because it tends to be most representative of the net benefits of energy efficiency to society as a whole. The economic screen uses the TRC as a proxy for moving forward and representing achievable energy efficiency savings potential for those measures that are most widely cost-effective.

percent in 2031. Figure 3.3 compares the technical, economic, achievable potentials, and cumulative first-year savings, at selected years.

Table 3.1: Energy Forecasts and Savings (Across All Sectors for Selected Years)

Energy Forecasts (MWh)	2012	2017	2022	2027	2031
Baseline Forecast	8,799,039	9,463,880	10,417,347	11,536,869	12,574,182
Achievable	8,749,236	9,068,483	9,476,769	9,998,002	10,548,503
Economic	8,569,382	8,037,426	8,018,993	8,594,412	9,282,289
Technical	8,487,766	7,441,765	6,981,872	7,281,206	7,842,616
Energy Savings (MWh)	**2012**	**2017**	**2022**	**2027**	**2031**
Achievable	49,804	395,397	940,578	1,538,868	2,025,679
Economic	229,657	1,426,454	2,398,355	2,942,457	3,291,894
Technical	311,274	2,022,115	3,435,475	4,255,664	4,731,566
Energy Savings (% of Baseline)	**2012**	**2017**	**2022**	**2027**	**2032**
Achievable	0.6%	4.2%	9.0%	13.3%	16.1%
Economic	2.6%	15.1%	23.0%	25.5%	26.2%
Technical	3.5%	21.4%	33.0%	36.9%	37.6%

Figure 3.3: Conservation Potentials, Selected Years



Conservation Targets

This IRP process includes conservation targets for Washington's energy efficiency portion of the Energy Independence Act (I-937) goal. Other components including conservation from distribution and transmission efficiency improvements also meeting this target would be additive for a complete target for Washington. Additionally, since this IRP uses the NPCC methodology, the conservation target for Idaho is more aggressive than required.

Based on first year and incremental savings, Table 3.2 illustrates achievable potential by sector from 2012 through 2015. During this period, lighting and appliance standards slow residential baseline growth rates, reducing the potential for savings from residential energy efficiency programs. Commercial and industrial potential shows consistent growth.

Achievable potential increases by the discontinuation of various measures such as residential windows, do-it-yourself (DIY) insulation upgrades, Leadership in Energy and Environmental Design (LEED) certification and non-residential T-8 fluorescent light bulb replacement resulting in a total annual goal for both Washington and Idaho.

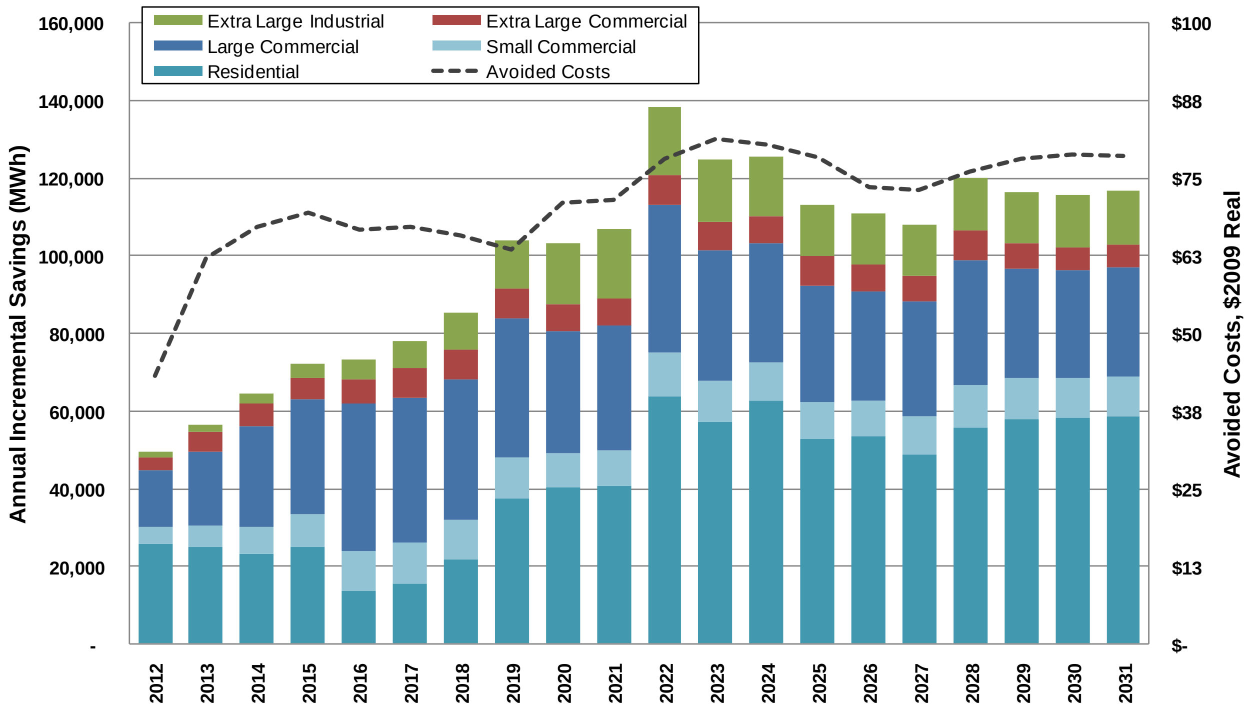
As compared with NPCC Sixth Power Plan goal for 2012-2013 compliance period, the goal resulting from the potential study is about 75 percent of that from the Sixth Plan. However, the Sixth Power Plan includes components other than conservation such as distribution and transmission efficiencies, thereby making its target similar to the potential study.

Table 3.2: Incremental Annual Achievable Potential Energy Efficiency (aMW)

	2012	2013	2014	2015
Incremental Achievable Potential				
Idaho	1.98	2.26	2.59	2.90
Washington	3.66	4.17	4.78	5.35
Total	**5.64**	**6.43**	**7.37**	**8.25**
Achievable from Existing Programs				
Idaho	1.59	1.55	1.47	1.47
Washington	2.93	2.85	2.71	2.71
Total	**4.51**	**4.40**	**4.17**	**4.17**
Goal per Conservation Potential Assessment				
Idaho	3.57	3.80	4.06	4.37
Washington	6.59	7.02	7.48	8.06
Total	**10.16**	**10.83**	**11.54**	**12.43**
NPCC Sixth Power Plan Target				
Idaho	5.17	5.60	6.03	6.24
Washington	8.22	8.90	9.59	9.93
Total	**13.39**	**14.50**	**15.62**	**16.17**

Figure 3.4 shows incremental achievable roughly tracking avoided costs throughout the study, but factors besides avoided cost can influence achievable potential, particularly where programs are ramping up or are ramping down. These impacts are particularly relevant in the early years of the CPA study.

Figure 3.4: Incremental Annual Achievable Energy Efficiency (MWh) vs. Avoided Cost[3]



Electricity to Natural Gas Fuel Switching

Fuel switching from electricity to natural gas is included in the targets as described above. Tables 3.3 and 3.4 illustrate savings potentials from converting electric furnaces and water heaters to natural gas. Nearly all savings are in the residential sector. Conversion ramps up slowly, but because it removes most of the electricity use from two of the largest residential end uses (water heating and space heating), it accounts for a substantial portion of savings by 2032. For water heating, about one-fourth of the savings from gas conversions occurs in new construction. For furnaces, new construction accounts for roughly one-third of the total.

Table 3.3: Achievable Savings from Conversion to Natural Gas

	2012	2017	2022	2027	2031
Water heater - convert to gas potential (MWh)	45.7	4,967	69,406	146,834	201,182
Water heater - convert to gas percentage of total potential	0.1%	1%	7%	10%	10%
Furnace - convert to gas potential (MWh)	10.1	2,527	45,979	108,447	158,470
Water heater - convert to gas percentage of total potential	0.0%	1%	5%	7%	8%

3 Avoided costs are 2009 real dollars and include energy costs, risk, and the 10 percent Power Act premium.

Table 3.4: Achievable Savings from Conversion to Natural Gas by State (MWh)

Washington Conversion Potential	2012	2017	2022	2027	2031
Water heater - convert to gas potential	36	3,966	55,623	117,942	161,411
Furnace - convert to gas potential	1	1,509	31,082	76,213	112,522
Total Washington conversion potential	37	5,475	86,705	194,155	273,933
Idaho Conversion Potential	**2012**	**2017**	**2022**	**2027**	**2031**
Water heater - convert to gas potential	10	1,001	13,783	28,893	39,770
Furnace - convert to gas potential	9	1,018	14,898	32,234	45,948
Total Idaho conversion potential	19	2,019	28,681	61,127	85,718

Comparison with the Sixth Power Plan Methodology

As required by Washington Administrative Code (WAC) Chapter 480-109-010 (3)(c), Avista below describes the technologies, data collection, processes, procedures and assumptions used to develop its I-937 biennial targets along with changes in assumptions or methodologies used in the Company's IRP or the NPCC Sixth Power Plan. WAC Chapter 480-109 requires WUTC approval, approval with modifications or rejection of the targets.

Global met with the NPCC staff to compare methodologies and approaches to ensure methodological consistency. The CPA methodology is consistent with the Sixth Power Plan in several key ways. Both the NPCC Sixth Power Plan and Global's approaches utilized end-use models employing a bottoms-up approach. The models draw on appliance stock, saturation levels and efficiencies information to construct future load requirements. Global conducted a thorough review of baseline and measure assumptions used by the NPCC and developed a baseline energy use projection, absent any additional energy efficiency measures while including the impact of known codes and standards currently approved. The study used NPCC assumptions when data was not available.

The CPA study developed a comprehensive list of energy-efficiency technologies and end-use measures, including those in the Sixth Power Plan. Since the efficiency measures, equipment, and other data used in the Sixth Power Plan are somewhat dated, information specific to measures and equipment such as saturation levels and measure costs were updated for the CPA. Global developed equipment saturations, measure costs, savings, estimated useful lifetimes and other parameters based on data from the Sixth Power Plan Conservation Supply Curve workbook databases, the Regional Technology Forum, NEEA reports, and other data sources. Similar to the Sixth Power Plan, the study accounts for the difference between lost and non-lost opportunities, and how this affects the rate at which energy efficiency measures penetrate the market. The study used the TRC test as the measure for judging cost-effectiveness. A comprehensive list of measures and equipment evaluated in the CPA study is included in Appendix C. For a more detailed discussion of measures and equipment evaluated within the potential study, please refer to the Conservation Potential Assessment report prepared by Global in Appendix D.

After screening measures for cost-effectiveness, the CPA applied a series of factors to evaluate realistic market acceptance rates and program implementation considerations. The resulting achievable potential reflects the realistic deployment rates of energy efficiency measures in Avista's service territory. These factors account for such things as market barriers, customer acceptance, and the time required to implement programs. To develop these factors, Global reviewed the ramp rates used in the Sixth Power Plan Conservation Supply Curve workbooks and considered Avista's experience.

The Sixth Power Plan assesses a 20-year period beginning in 2010, while the CPA study begins in 2012. Where the Sixth Power Plan relies on average regional data, the CPA utilized data from Avista's service territory that accounts for some result differences. Therefore, an allocation of regional potential based on sales as applied in the Sixth Power Plan might not account for Avista's unique service territory characteristics such as customer mix, use per customer, end-use saturations, fuel shares, and current measure saturations. In addition, some industries included in the Sixth Power Plan might not exist in Avista's service territory.

The Sixth Power Plan assumed that 85 percent of the cost-effective, or economic, non-lost opportunity potential will be achieved over the 20 years covered by the Sixth Power Plan. The projected achievement amount during the first 10 years (consistent with the I-937 timeframe) is around 60 percent. For lost opportunities, the plan assumes achievement of approximately 65 percent of the cost-effective, or economic, potential during the 20-year period. Due to ramp rates used within the plan, this equates to only 37 percent achievement within the first 10 years, the period considered for I-937. The CPA study assumed that cost-effective measures reach a maximum saturation level of 85 percent over the 20-year period for lost opportunities, and 65 percent to 85 percent for non-lost opportunities. These figures equal or exceed adoption rates assumed within the Sixth Power Plan.

Sensitivity of Potential to Customer and Economic Growth

The CPA study shows that energy efficiency offsets roughly 50 percent of load growth, whereas the Sixth Power Plan estimates that energy efficiency can offset 80 percent. While Avista's service territory differs from the larger region in many ways, including its climate and particular customer mix, there are other contributing factors to this difference. One significant factor may be the CPA customer and economic growth assumptions. To understand how growth affects the results of the study, we used the LoadMAP model to evaluate several scenarios with lower customer and economic growth, as indicated in Table 3.5.

Table 3.5: Varying Growth Scenario Descriptions

	Reference Scenario	Low Growth Scenario 1	Low Growth Scenario 2
Household size	~ 1% per year growth	Capped at 110% of existing household size	Capped at 110% of existing household size
Per capita income growth	1.6% 2011–2015; 2.2% 2016–2020; 2.1% thereafter	1.6% after 2016	1.6% after 2016
Residential sector market growth	1.30% after 2015 (WA) 1.25% after 2015 (ID)	no change	1.0% after 2015 (WA & ID)
Commercial sector market growth, WA & ID	~ 2.0% (varies by segment)	no change	1.0% all segments

Table 3.6 shows that as economic and customer growth decreases, the ability of energy efficiency to offset growth also increases. In the reference scenario, energy efficiency offsets 54 percent of growth in consumption, while in the lower growth scenarios, energy efficiency offsets 55 percent and 77 percent of growth. This is the case because with reduced levels of new construction, both load growth and energy savings drop, but savings from the retrofit of existing buildings are a greater proportion of overall growth.

Table 3.6: Varying Growth Scenario Results (MWh)

	Reference Scenario	Low Growth Scenario 1	Low Growth Scenario 2
Baseline forecast 2012	8,799,039	8,799,039	8,799,033
Baseline forecast 2031	12,574,182	12,272,136	11,025,256
Load Growth 2012-2031	3,775,143	3,473,097	2,226,222
Achievable potential case forecast 2031	10,697,432	10,361,667	9,302,736
Achievable potential savings 2031	2,025,679	1,910,469	1,722,519
Percentage of growth offset	54%	55%	77%

Avoided Cost Sensitivities

Global modeled several scenarios varying avoided costs assumptions in addition to the Expected Case used for the 2011 IRP to test sensitivity to changes in avoided costs. The scenarios included 150 percent, 125 percent, and 75 percent of the avoided costs relative to the Expected Case. Figure 3.5 illustrates the avoided cost scenarios. Overall, due to the technical potential ceiling, energy efficiency proved to be insensitive to avoided cost assumptions. In particular, acquiring incremental energy efficiency becomes increasingly expensive, so that increases in avoided costs do not provide equivalent percentage increases in achievable potential. The Expected Case achievable potential is approximately 16.8 percent of the baseline forecast by 2032. With the 150 percent avoided cost case, achievable potential increases by 15 percent of the baseline forecast, while the 125 percent and the 75 percent avoided cost cases yielded achievable potential equal to 79 percent and 108 percent of the baseline forecast respectively. Table 3.5 shows achievable potential under the four avoided cost scenarios.

In 2012, 52 percent of the projected achievable potential is from residential class measures. By 2017, a shift occurs whereby 67 percent of the achievable potential comes from non-residential classes, with the significant portion of these savings, 42 percent, estimated to come through the large general service segment. In the residential sector in 2017, approximately 40 percent of projected savings come from interior lighting, followed by water heating, space heating and electronics. In subsequent years, residential savings from lighting decreases, with space and water heating providing greater relative savings potential.

In the commercial and industrial sectors, lighting accounts for approximately 63 percent of savings potential in 2017, followed by heating, ventilation and air conditioning (HVAC), office equipment, exterior lighting and machine drives. Over time, the savings potential from lighting decreases, but still remains close to half of the savings potential in 2032.

Figure 3.5: Energy Savings, Achievable Potential Case by Avoided Costs Scenario

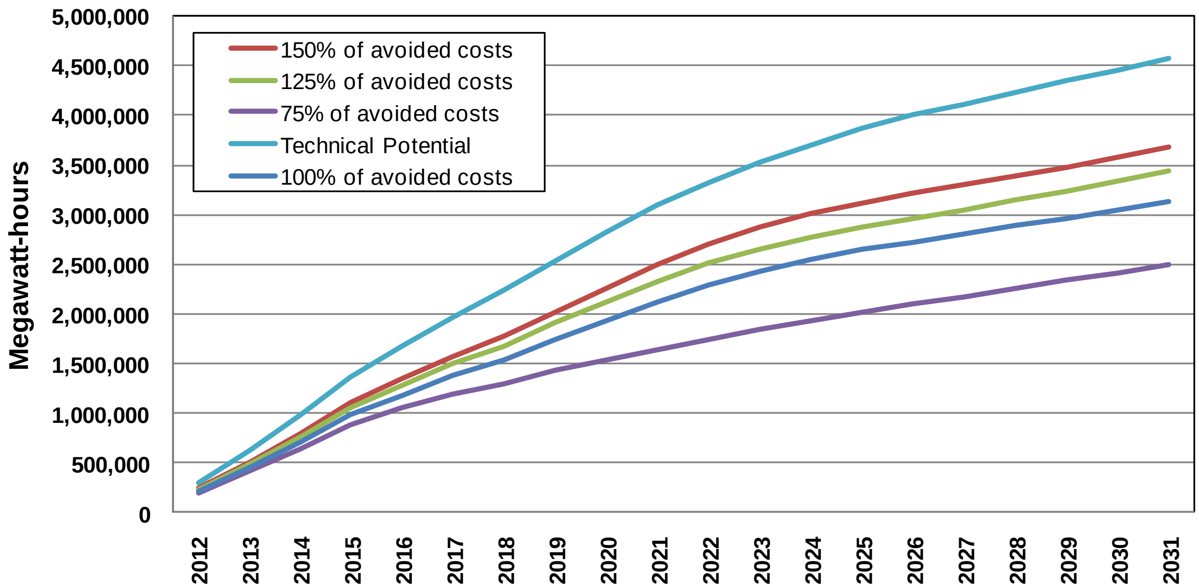


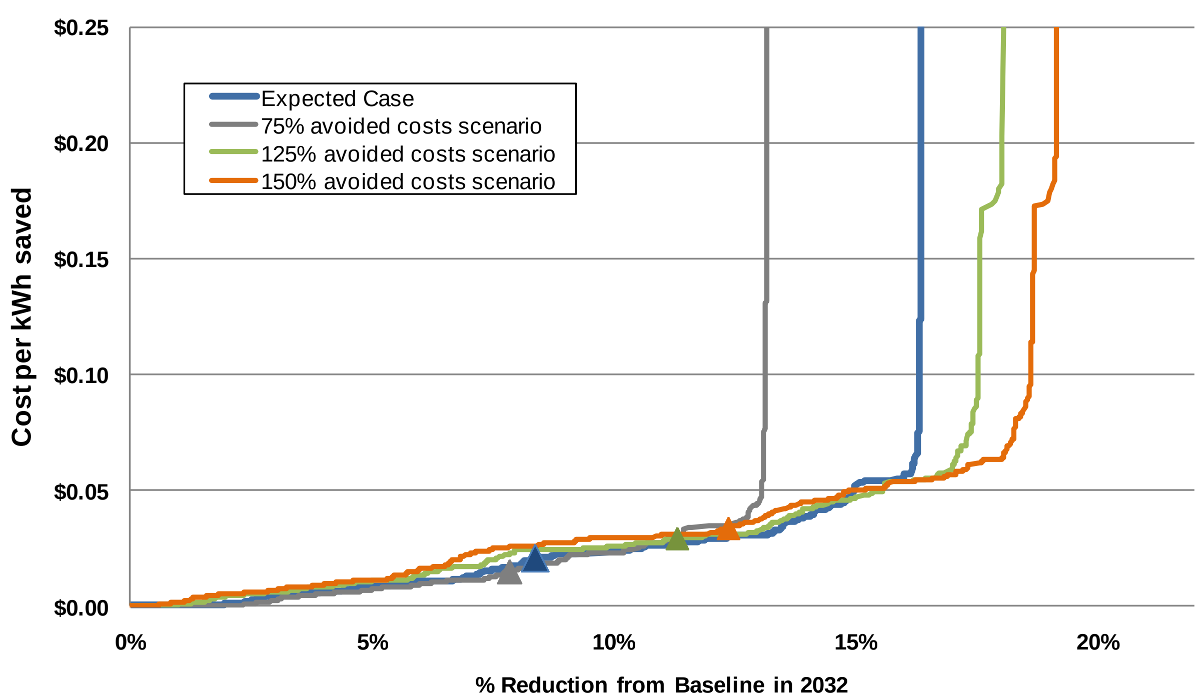
Table 3.7: Achievable Potential with Varying Avoided Costs

	Reference Scenario	75% of Avoided Costs	125% of Avoided Costs	150% of Avoided Costs
Achievable potential savings 2031 (MWh)	2,025,679	1,590,850	2,186,730	2,327,510
Percentage change in savings vs. 100% avoided cost scenario	n/a	-21%	8%	15%

The heat pump water heater measures in the Sixth Power Plan were contemplated to replace what compact fluorescent lights (CFLs) had contributed (i.e., significant savings at relatively lower costs) in earlier plans. The CPA found that heat pump water heaters are not cost-effective under the Expected Case. However, the measure becomes cost-effective under the 150 percent of avoided cost scenario.

Figure 3.6 shows supply curves made up of the stacked measures and equipment in 2031 in ascending order of avoided cost. As expected, the result is a traditional upward-sloping supply curve. Since there is a gap in the cost of the energy efficiency measures moving up the supply curve, the measures with a very high cost cause a rapid sloping of the supply curve. The portfolio average cost for each case is shown as well. The shift of the supply curve toward the right as avoided costs increase is a consequence of increasing amounts of cost-effective potential, but the average cost of acquiring that potential is increasing also.

Figure 3.6: Supply Curves of the Evaluated Conservation Measures



Energy Efficiency-Related Financial Impacts

I-937 requires utilities with over 25,000 customers to obtain a fixed percentage of their electricity from qualifying renewable resources and to acquire all cost-effective and achievable energy conservation. For the first 24-month period under the law (2010-2011), this equaled a ramped-in share of the regional ten-year target identified in the Sixth Power Plan. Penalties of at least $50 per MWh exist for utilities not achieving Washington targets for conservation resource acquisition.

Regional discussions were under way regarding the definition of “pro-rata” during the 2009 IRP. Avista proposed ramping the 10-year targets identified in the Sixth Power Plan instead of acquiring 20 percent of the first ten-year target identified in the Sixth Power Plan. The “pro-rata” amount would have created drastic ramping challenges, especially in the early years. Due to inconsistencies between the 2009 IRP and the Council’s methodology, the Company elected to use the NPCC’s Option #1 of the Sixth Power Plan to establish its conservation acquisition target, adjusted to include electric-to-natural gas space and water heating fuel conversions. The acquisition target was 11 percent greater than Avista’s IRP energy efficiency target for the same period. In April 2010, the WUTC approved the Company’s ten year Achievable Potential and Biennial Conservation Target Report in Docket UE-100176.

The I-937 requirement to acquire all cost-effective and achievable conservation poses significant financial implications for Washington customers. In 2012, the incremental annual cost to Washington customers is projected to be $2.0 million. This annual amount grows to $41.8 million by the tenth year, representing a total of $199.2 million over this ten-year period for Washington. Figure 3.7 shows the annual cost (in millions) for this acquisition of past and future conservation. As shown in the figure, future cost for new conservation reflects margin returns as compared to historical acquisition.

This incremental level of acquisition driven by Washington I-937 will result in annual rate increases to Washington electric customers of an approximate range of $8 to $302 per average customer across all classes. Figure 3.8 illustrate the annual cost associated with the energy efficiency acquisition required to meet I-937 goals.

Figure 3.7: Cost of Existing & Future Conservation

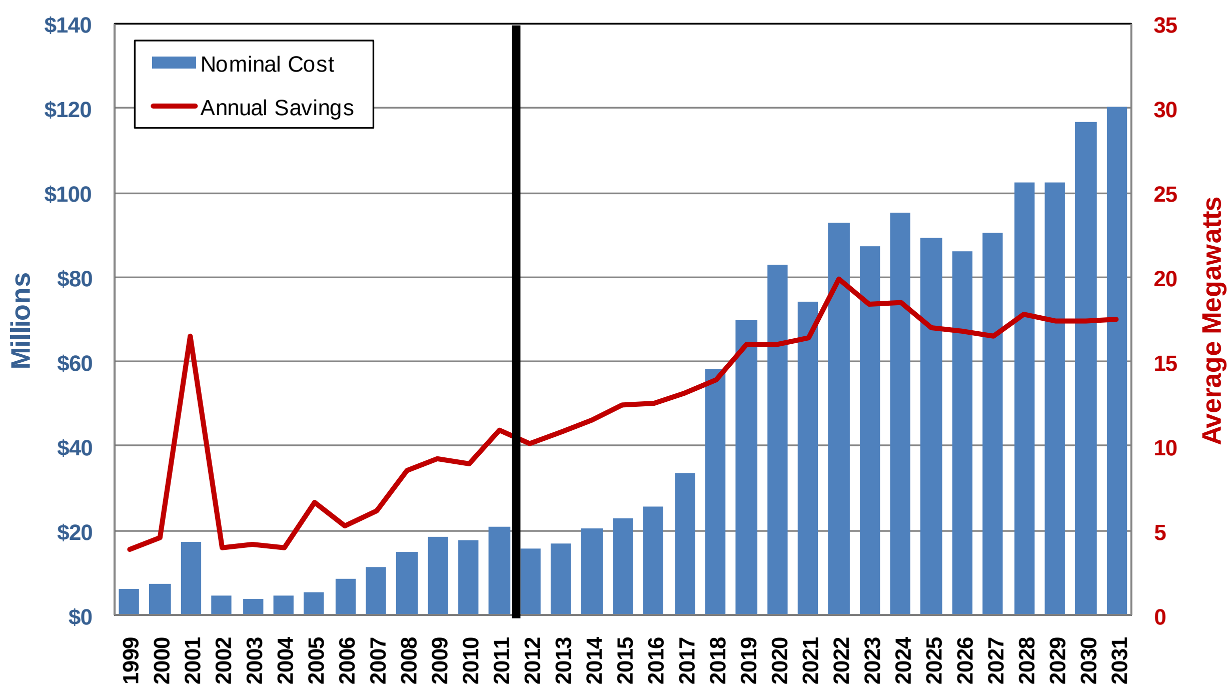
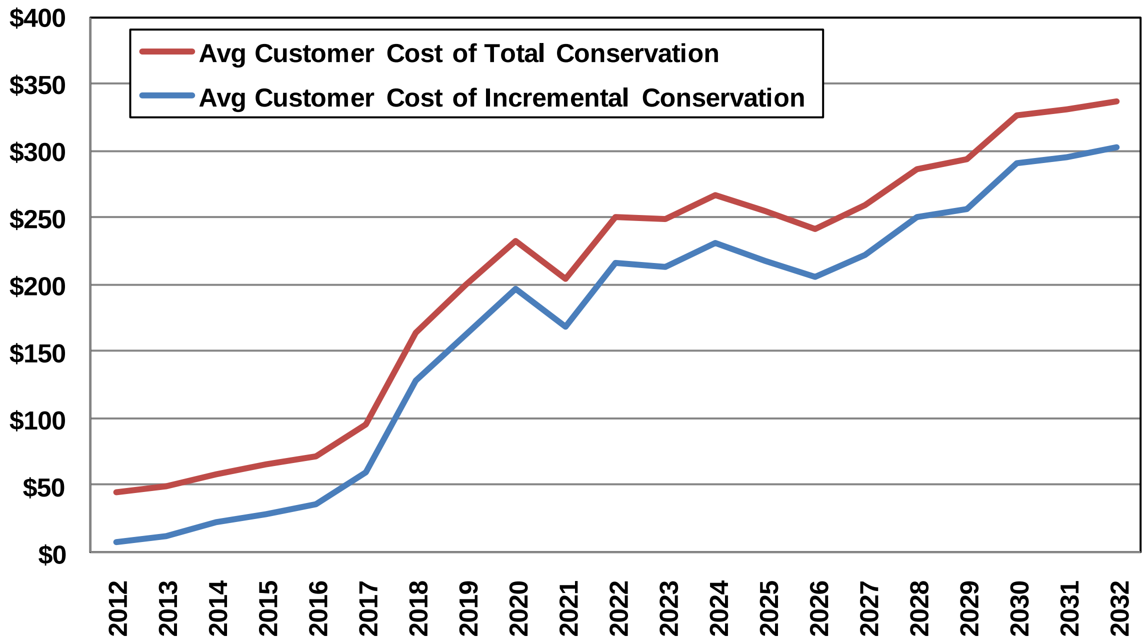


Figure 3.8: Cost of Conservation per Customer per I-937



Integrating Results into Business Planning and Operations

The CPA and IRP energy efficiency evaluation processes provide high-level estimates of cost-effective conservation acquisition opportunities. While results of the IRP analyses establish baseline goals for continued development and enhancement of conservation programs, the results are not detailed enough to form an acquisition plan. Avista uses IRP evaluation results to establish a budget for conservation measures, to help determine the size and skill sets necessary for future conservation operations, and for identifying general target markets for energy efficiency programs. This section provides an overview of recent operations of the individual sectors as well as conservation business planning.

For this IRP, the Company procured its first external conservation potential assessment study for Washington and Idaho from Global Energy Partners. This study is useful for the implementation of energy efficiency programs in the following ways.

- Identifying by sector, segment, end-use and measure where energy savings may come from during the next 20-year timeframe. The implementation staff can use CPA results to determine which segments and end-uses/measures to target through energy efficiency programs.
- Identifying measures with the highest TRC benefit-cost ratios and target those lowest cost resources with the greatest benefit.
- Identifying measures that appear to have great adoption barriers by looking at the economic versus achievable results by measure. Implementation staff can then better develop programs around barriers that may exist.
- Improving the design of current program offerings. Implementation staff can review the measure level results by sector and compare the savings with the

largest-savings measures currently offered by the Company. This analysis may lead to the elimination of some programs or the addition of other programs. Consideration might be given to identifying lost opportunities (i.e. “low-hanging fruit”) and whether to target one particular measure over another measure. One possibility may be to offer higher incentives on measures with higher benefits and lower incentives on measures with lower benefits.

In addition to how the IRP results and the potential study flow into operational planning, an overview of 2010 and 2011 energy efficiency acquisitions by sector is given below. This is prior to the implementing the actions mentioned above.

Residential Sector Overview

Avista offers most residential energy efficiency programs through prescriptive, or standard offer, programs targeting a range of end-uses. Programs offered through this prescriptive approach by Avista during 2010 included space and water heating conversions, ENERGRY STAR® appliances, ENERGY STAR® homes, space and water equipment upgrades and home weatherization.

Avista offers the remaining residential energy efficiency programs through other channels. For example, a third party administer JACO operates the refrigerator/freezer recycling program. CFL and specialty CFL buy-downs at the manufacturer level provide customers access to lower-priced CFL bulbs. Home energy audits, subsidized by a grant from the American Recovery and Reinvestment Act (ARRA), began in 2010. This program offers home inspections that include numerous diagnostic tests and provides a leave-behind kit containing CFLs and weatherization materials. Finally, Avista provides educational tips and CFLs at various rural and urban events in an effort to reach all areas within its service territory.

Avista processed over 36,000 energy efficiency rebates in 2010, benefiting approximately 25,000 households. Nearly $6.3 million in customer rebates offset the cost of implementing energy efficiency upgrades. Residential programs contributed 24,247 MWh and nearly 1.1 million therms of energy savings.

The results of an Ecotope study resulted in several planned modifications to the 2011 residential programs. These modifications include the discontinuation of the windows program, contractor installed weatherization requirements (eliminating do-it-yourself projects), reducing incentives for electric to natural gas water heater conversion, and the inclusion of the rooftop damper program on the residential form. We address these efficiency program modifications below.

The CPA study illustrates potential markets and provides a list of cost-effective measures analyzed through the on-going energy efficiency business planning process. This review of residential program concepts and their sensitivity to more detailed assumptions will feed into program plans for target markets. Potential measures not currently considered at the time of the CPA that may arise in the future will be reevaluated for possible inclusion in the Business Plan.

Residential Energy Efficiency Offering In Depth

Avista encourages customers to take part in home energy audits. Employees and customers in Spokane County can sign up for a comprehensive home energy audit offered by Avista for as low as $49. Funding for this pilot program comes from a combination of Avista energy efficiency funds and federal stimulus dollars through the Energy Efficiency Community Block Grant program. Avista collaborated with the City of Spokane, Spokane County and the City of Spokane Valley to provide this program at a significantly reduced cost.

The home energy audits use certified professionals with state-of-the-art equipment and techniques to identify home energy use and safety improvements. The auditor discusses existing energy use, if there are any energy efficiency concerns, and areas of the home that are not as comfortable as owners would like them to be. Once the audit is complete, the customer receives a detailed report on the findings, along with recommendations to make their home more energy efficient.

In addition to a wealth of information, participating homeowners receive an energy efficiency/weatherization kit with a retail value of approximately $50. It contains compact fluorescent light bulbs, low-flow showerheads, expanding foam sealant and other energy-saving materials. Customers are able to visit www.avistautilties.com to find out more and to view a video about this and other energy efficiency programs.

Limited Income Sector Overview

Six Community Action Agencies (CAAs) administer low-income programs. During 2010 these programs targeted a range of end-uses including space and water heating conversions, ENERGY STAR refrigerators, space and water heating equipment upgrades, and weatherization which are offered site-specifically through individualized home audits. The Company also funds health and human safety investments considered necessary to ensure habitability of homes and protect investments in energy efficiency, as well as administrative fees enabling CAAs to continue to deliver these programs.

During 2010, the Company convened the Low Income Collaborative to explore new approaches promoting low-income conservation, identify barriers to its development and to address issues raised by The Energy Project in Avista’s 2009 Washington General Rate Case. On September 1, 2010, the Company filed the conclusions of the Low Income Collaborative as requested by the WUTC.

Issues addressed through the low income collaborative included defining the low-income customer class, identifying market barriers to the success of low income energy efficiency programs, identifying measures for success, and identifying low income energy efficiency delivery mechanisms and funding sources.

The CAAs had 2010 budgets of $1.3 million for Washington and $660,000 for Idaho. The Company processed about 1,500 rebates, benefitting approximately 550 households. During 2010, the Company paid $1.7 million in rebates to the CAAs to provide fully subsidized energy efficiency upgrades, health and human safety, and administrative costs for the CAAs to administer these programs. The CAAs spent nearly $144,000 on health and human safety, which was 8.3 percent of their total expenditures and within their 15 percent allowance for this spending category. Low Income energy efficiency programs contributed 2,102 MWh of electricity savings and 61,271 therms of natural gas savings.

All of the CAAs received a funding increase in 2011 resulting from recent rate cases in both Washington and Idaho making the total funding $2 million for Washington, $940,000 for Idaho, and an additional $40,000 for conservation education.

CAAs submitting for reimbursement in 2011 must include the age of the home and square footage to improve billing analysis and other evaluation efforts. Energy savings claims are now consistent with the regular residential programs, rather than CAAs using various models to estimate their energy savings. Impact evaluation led the Company to believe that these models were treating the installation of measures individually, rather than incrementally, resulting in overestimates of savings achieved. This change should provide for higher realization rates since the original estimates should be closer to actual observations in billing analysis. This modification was made in response to Ecotope's 2011 Energy Impact Evaluation Report of Select 2008 Programs.

The CAAs are required to submit marginally cost-effective measures for "pre-approval" to protect the cost-effectiveness of the portfolio. This process has been in effect for the past three years and has allowed the Company to manage on a monthly basis the overall TRC for the Low Income Portfolio. Examples of measures that need pre-approval include natural gas furnaces, natural gas water heaters and ENERGY STAR refrigerators.

Non-Residential Sector Overview

For the non-residential sectors (commercial, industrial and multi-family applications), energy efficiency programs are offered on a site-specific or custom basis. We can offer a more prescriptive approach when treatments result in similar savings and the technical potential is high. An example is the prescriptive lighting program. The applications are not purely prescriptive in the traditional sense, such as with residential applications where homogenous programs are provided for all residential customers; however, a more prescriptive approach can be applied for these similar applications.

Non-residential prescriptive programs offered by Avista include, but are not limited to, space and water heating conversions, space and water heating equipment upgrades, appliance upgrades, cooking equipment upgrades, personal computer network controls, commercial clothes washers, lighting, motors, refrigerated warehouses, traffic signals, and vending controls. Also included are residential program offerings such as multi-family direct install through UCONS (which ended in December 2009, however, a handful of projects were reported in 2010) and multi-family market transformation since these projects are implemented site-specifically unlike other residential programs.

During 2010, the Company processed approximately 2,400 energy efficiency projects resulting in the payment of $7.9 million in rebates paid directly to customers to offset the cost of their energy efficiency projects. These projects contributed 43,430 MWh of electricity and 742,559 therms of natural gas savings.

In January 2011, Avista launched two new prescriptive programs – commercial windows and insulation and commercial natural gas HVAC. Another prescriptive program, for standby generator block heaters, was evaluated and launched April 1, 2011. A survey of various municipalities in 2010 to determine saturation levels of light-emitting diode traffic signals and as a result, this program will end. Participants submitting paperwork by December 15, 2011, will still be eligible to receive an incentive payment. The Leadership in Energy and Environmental Design building rating program ended December 31, 2010. Projects completed by December 31, 2011 with paperwork submitted by March 31, 2012, will be eligible for an incentive.

Energy Smart Grocer is a regional, turnkey program administrated through PECI. This program has been operating for several years. This program will approach saturation levels during the early part of this 20-year planning horizon. We implement the remaining programs in the site-specific sector through the Company’s energy efficiency infrastructure.

The programs highlighted by the recently completed CPA study will be reviewed for the development of target marketing and the creation of new energy efficiency programs. All electric-efficiency measures with a simple payback exceeding one year and less than eight years for lighting measures or thirteen years for other measures automatically qualify for the non-residential portfolio. The IRP provides account executives, program managers/coordinators and energy efficiency 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 for non-residential customers.

Non-Residential Energy Efficiency Example

The scope of this energy efficiency project included a solution to replace an existing compressor used to circulate water in Medical Lake. The existing equipment was a 50 horsepower screw compressor with a 1,750-RPM three-phase motor that operated 24 hours per day, seven days per week from May 1st through October 31st. The proposed replacement for the existing equipment was five Solar Bee solar-powered DC agitators used to circulate the lake. The compressor is projected to be removed after four of the five solar units have been installed. The estimated annual energy savings associated with this energy efficiency project is approximately 128,000 kWh, which is equivalent to the 50 horsepower compressor running at an estimated 80 percent of full load for six months. Non-quantified non-energy benefits (NEBs) associated with this project include improved water quality and reduced (or possibly eliminated) chemical treatment. The energy efficiency incremental measure cost for the customer is approximately $57,000 and estimated savings of $8,916 in annual energy costs at current rates. At completion, the customer would receive an estimated $25,000 incentive, which would reduce their 6.4-year simple payback to 3.6 years.

Demand Response

Prior to the addition of energy efficiency resources, additional capacity resources were estimated to be needed in 2013. Once energy efficiency resources were layered onto existing supply-side resources in the PRiSM model, this capacity need was moved out to 2019 for summer capacity and 2021 for winter capacity. This capacity need comes from expiring contracts as well as native load growth.

As part of the CPA study, Global evaluated typical demand response program options, including direct load control, curtailable and demand bidding/buy-back programs. Using the Company's capacity costs, prior to the inclusion of energy efficiency, Global found that these demand response programs were cost-effective. However, because energy efficiency is assumed to be acquired first consistent with I-937, the savings resulting from energy efficiency removed the need for additional capacity, making demand response not cost effective at this time.

Since Avista does not have an immediate capacity shortage, the Company will not continue to model demand response programs in the near term, but may continue to evaluate some of these demand response programs in the future.

Summary

The IRP evaluation process assists in developing a conservation business plan and in meeting regulatory requirements. Avista uses this opportunity for comprehensive evaluation as an integral part of the ongoing management of the Company's conservation portfolio. The acquisition targets provide information for future budgetary, staffing and resource planning needs. The numerical targets supplement the fundamental obligation to pursue a resource strategy that best meets customer needs in a continually changing environment. The efficiency targets established in this IRP planning process may change as necessary to meet these evolving obligations.

4. Policy Considerations

There are many environmental policy issues that could significantly affect the operation of the Company's current generation resources and could also affect the types of resources the Company could pursue in the future. Over time, the direction of these expected future policy considerations has changed, sometimes dramatically. The Company expects the nature and impact of future environmental policies to continue changing. The 2009 IRP included an Environmental Policy chapter that mainly focused on greenhouse gas policy and renewable portfolio standards. The current political and regulatory environments have changed significantly since the publication of the last IRP. The immediate prospects for implementation of cap and trade programs to reduce greenhouse gas emissions has diminished, leading to a new focus on regulatory measures pursued by the Environmental Protection Agency (EPA) and on political and legal initiatives commenced by environmental groups to apply pressure on thermal generation – specifically coal-fired generation. The areas of regulation have particular implications for coal generation, as they involve regulation of emissions affecting regional haze, coal ash disposal, mercury emissions, water quality, as well as greenhouse gas emissions. This chapter provides an overview and discussion about some of the more pertinent environmental policy issues facing the Company.

Chapter Highlights

- Avista supports national greenhouse gas legislation that is workable, cost effective, and fair.
- Avista supports national greenhouse gas legislation that protects the economy, supports technological innovation, and addresses emissions from developing nations.
- The Company is a member of the Clean Energy Group.
- Avista's Climate Change Council monitors greenhouse gas legislation and environmental regulation issues.

Environmental Concerns

Environmental concerns, such as greenhouse gas emissions, present a unique resource planning challenge due to the continuously evolving nature of environmental regulation and its ever-changing projections of the scope and costs of various environmental programs. If environmental concerns were the only issue faced by electric utilities, resource planning would be reduced to a determination of the required amounts and types of renewable generating technology and energy efficiency to acquire. However, utility planning is compounded by the need to maintain system reliability, acquire resources at least cost, mitigate price volatility, meet renewable generation requirements and manage financial risks. Each generating resource has distinctive operating characteristics, cost structures, and environmental challenges. Traditional generation technologies, like coal-fired and natural gas-fired plants, are well understood and provide capacity along with energy.

Coal-fired units have high capital costs, long permitting and construction lead times, and relatively low and stable fuel costs. They are difficult, if not impossible in some jurisdictions, to site due to state laws and local opposition, and environmental issues ranging from the impacts of coal mining to power plant emissions. Further, remote mine locations increase cost by either the transportation of coal to the plant or the transportation of the generated electricity to load. By comparison, natural gas-fired plants have relatively low capital costs as compared to coal, are typically located close to load centers, can be constructed in relatively short time frames, emit less than half the greenhouse gases emitted by coal, and are the only utility-scale baseload resource that can be developed in certain locations. However, natural gas-fired plants are affected by high fuel price volatility. They are also challenged by having diminished performance during periods of hot weather, by the difficulty of securing water rights for their efficient operation, and by the fact that the plants still emit significant greenhouse gases relative to renewable resources.

Renewable energy technologies such as wind, biomass, and solar generation have different challenges. Renewable resources are attractive because they have low or no fuel costs and few, if any, emissions. However, renewable generation can have limited or no capacity value to the operation of the Company's system, and intermittent renewable resources can present integration challenges and require additional non-renewable generation capacity investment. These resources also generally have high upfront capital costs, and have their own environmental challenges to overcome, particularly with respect to siting. Similar to coal plants, renewable resource projects are located near their fuel sources. The need to site renewable resources in remote locations often requires significant investments in transmission interconnection and capacity expansion, as well as raising possible wildlife and aesthetic issues, such as those that utility-scale solar projects in the southwestern U.S. have encountered. 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 and direct grants in lieu of tax incentives are scheduled to expire in 2012 or 2013, depending on the technology. The continuation of credits and grants 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 costs of renewable technologies are affected by many relatively unpredictable factors, such as renewable portfolio standard mandates, material prices and currency exchange rates, the effects of which cannot be accurately predicted. Capital costs for wind and solar have decreased since the 2009 IRP, but there are no guarantees that prices will continue to stay at current levels.

Though there appears to be very little, if any, chance that a national greenhouse gas cap and trade program being implemented soon, there still is a great deal of uncertainty around its regulation. There is strong regional and national support to address climate change. Since the 2009 IRP publication, many changes in the approach and potential for actual greenhouse gas emissions regulation have occurred, including:

- Consideration is presently being given toward a clean energy standard at the federal level, instead of a more direct form of greenhouse gas emission regulation, such as a cap and trade program;
- The current split of control between the U.S. House of Representatives and the Senate effectively postpones national cap and trade legislation for greenhouse gas emissions until after the 2012 election, at the earliest;
- The EPA has commenced actions to regulate greenhouse gas emissions under the Federal Clean Air Act, although some of these efforts have been delayed and the agency ‘s justification for advancing some of its initiatives are being judicially challenged ; and
- Development of economy-wide cap and trade regulation at the regional level are now focused primarily on California and British Columbia rather than on the broader Western Climate Initiative.

Avista’s Climate Change Policy Efforts

Avista’s Climate Change Council (CCC) is 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 participate as needed. The monthly meetings for this group include work divided into immediate and long-term concerns. The immediate concerns include reviewing and analyzing proposed or pending state and federal legislation, reviewing corporate climate change policy, and responding to internal and external data requests about climate change issues. Longer-term issues involve emissions tracking and certification, providing recommendations for greenhouse gas goals and activities, evaluating the merits of different greenhouse gas policies, actively participating in the development of legislation, and benchmarking climate change policies and activities against other organizations.

Avista maintains 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 policies. Avista also participates in national and regional discussions about hydroelectric and biomass issues through its membership in national hydroelectric and biomass associations.

Avista's Position on Climate Change Legislation

Avista anticipates the passage of federal greenhouse gas (climate change) legislation in some form within the next five years. A comprehensive national climate change policy could assume the form of a cap and trade program, carbon tax, national portfolio standard, emissions performance standard, or some combination of the four. The Expected Case in this IRP uses 2015 as the starting date for greenhouse gas emissions costs. The 2015 start date was chosen early in the development of the modeling exercises for this plan, and the actual effective date will most likely be after 2015 by the time legislation could be enacted and rules promulgated. The Company chose to develop a weighted cost using four different cases for greenhouse gas emissions because of the uncertainty about the timing and scope of this legislation. The four cases include regional cap and trade, national cap and trade, national carbon tax and no greenhouse gas reduction policies. More details about the different policies that were modeled for this IRP are located at the end of this chapter.

The current lack of a definitive greenhouse policy direction makes an uncertain planning environment as Avista plans to meet future customer loads. Avista does not have a preferred form of greenhouse gas policy 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 should be 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 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 technological innovations should be a key component of any greenhouse gas legislation because innovation can help contain costs, as well as provide a potential economic boost to the manufacturing sector. Climate change legislation must involve developing nations with increasing greenhouse gas emissions and legislation should include strategies for working with other nations directly or through international bodies to control worldwide emissions.

Greenhouse Gas Emissions 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 potential future emissions risks.

Complying with greenhouse gas 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. Enabling emission reductions on a utility-wide basis can entail any 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 it with lower emitting resources;
- Decommissioning or divesting of 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 costs and risks of the actions listed above cannot be adequately, let alone fully, be evaluated until the nature of greenhouse gas emission regulations is known; 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 uses the average cost of the weighted policies discussed at the end of this chapter. The 2011 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.

National Greenhouse Gas Emissions Legislation

Several themes have emerged from various climate change legislative proposals that have been considered since publication of the 2009 IRP. These include:

- Climate change is now viewed as largely an anthropogenic or human-developed phenomenon.
- A preference in certain economic sectors towards application of greenhouse gas regulations on an economy-wide basis, rather than on piecemeal regulatory approaches that target specific sectors or technologies.
- 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 because coal will continue to be an important part of the U.S. generation fleet into the near future.

- Developing countries must be involved in reducing global emissions as greenhouse gas emissions generally increase along with economic growth.
- The longer federal legislation takes to enact, the higher the probability of inconsistent state and regional regulatory schemes. 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 toward a need to develop national greenhouse gas legislation in a timely manner to ensure the best environmental and economic outcomes. The Waxman-Markey bill (H.R. 2454), passed in the U.S. House of Representatives in June 2009, importantly acknowledged these multi-jurisdiction problems by proposing to effectively supersede state and regional cap and trade regulation over emissions covered under federal law between 2012 and 2017.

Federal Policy Considerations

The direction of federal policies toward greenhouse gas emissions mitigation has changed since the 2009 IRP. In that document, the Company projected a national cap and trade program would be enacted and effective in 2012. This IRP assumes some version of a national greenhouse gas policy will be in place starting in 2015, but the type of policy is uncertain. If the models for this IRP did not have to be locked down early in the process, we would have pushed the timeframe out even further because of the uncertainty of any federal-level climate change policy with the current split between the House and the Senate, the soft state of the U.S. economy, and the upcoming 2012 elections. Given this low level of certainty, the Company developed four hypothetical greenhouse gas policy models. Details are provided later in this chapter.

Avista's main concern with any potential federal cap and trade legislation involves compliance costs, an issue centering primarily, though not exclusively, on emission allowances. Avista favors the Edison Electric Institute approach where half of the allowances allocated to electric utilities are load-based and the other half are emissions-based. This more equitable compromise would provide prevent a windfall for non-utility generators with large historical greenhouse gas emissions at the expense of utilities, like Avista, that already rely on non-emitting 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.

There currently is no pending federal climate change legislation before Congress. In lieu of comprehensive climate change legislation, early in 2011, President Obama endorsed the idea of a Clean Energy Standard that would result in the nation deriving 80 percent of its electricity by 2035 from renewable resources and lower greenhouse gas emitting generation, such as natural gas-fired generation, "clean coal" generation with captured and sequestered emissions, and nuclear power. Formal Clean Energy Standard legislation has yet to be introduced in Congress. At the time this IRP was prepared, members of the U.S. Senate had collected comments on a White Paper on a Clean Energy Standard and Senator Jeff Bingaman (D-New Mexico) was drafting legislation in coordination with the President's staff, which he said in early June 2011, likely would not pass the Senate Energy and Natural Resources Committee. Even greater doubts exist that such a proposal could pass the U.S. House of Representatives. Given that Clean Energy Standard legislation in not likely to be enacted during 2011and 2012, Avista did not model the Clean Energy Standard for this IRP.

The 111th Congress considered renewable energy standard legislation (RES), such as the Waxman-Markey bill; (H.R. 2454) and S. 1462 by Senator Bingaman. Such proposals contemplated a renewable energy standard of between 10 and 25 percent by specific dates. These measures generally included a "hydro netting" provision; this provision excludes loads served by hydropower energy from the RES requirement. For example, if a utility has 1,000 aMW of load, a 10 percent RES goal, and 200 aMW of hydroelectric generation; then the utility's RES goal would only be 80 aMW instead of 100 aMW because of the hydro-netting. Federal legislation has conceptually – and significantly – differed from the Energy Independence Act (I-937) in Washington State, in particular with respect to hydro-netting. The absence of hydro-netting in I-937 makes the Washington law more restrictive than proposed federal renewable energy requirements. Therefore, absent Idaho RPS legislation, Avista would need to meet only the federal renewable energy requirements for its Idaho service territory. National legislation so far also includes existing biomass generation 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 have allowed the Company to use renewable energy credits (RECs) from resources that were only eligible under federal law, but not I-937, to comply with Washington's renewable energy targets, but Avista would be able to make REC sales from federally eligible facilities into a national market and into states governed solely by federal requirements (i.e., Idaho) and those states whose renewable energy eligibility requirements are similar to federal ones. More details about I-937 are included in Washington policy consideration section later in this chapter.

The federal Production Tax Credit (PTC), Investment Tax Credit (ITC), and Treasury grant programs are key federal policy considerations for incenting the development of renewable generation. The current PTC and ITC programs are scheduled to be available through the end of 2012 for wind and through the end of 2013 for other renewable resources. We did not model an extension of these tax incentives because of the uncertainty of their continuation due to the current federal budget deficit situation. If the PTC or ITC are extended, it may accelerate the development of some regional renewable energy projects to meet the extended deadline.

State and Regional Level Policy Considerations

The failure of the federal government to enact greenhouse gas policies during the current decade encouraged several states, such as California and New Mexico, to develop their own climate change laws and regulations. Climate change legislation can take many forms, including economy-wide regulation in the form of a cap and trade system. However, comprehensive climate change policy can also have multiple individual components, such as renewable portfolio standards, energy efficiency standards, and emission performance standards; all of these standards have been enacted in Washington, but not necessarily in other jurisdictions where Avista operates. Individual state actions produce a patchwork of competing rules and regulations for utilities to follow, and may be particularly problematic for multi-jurisdictional utilities such as Avista. There are currently 29 states, including 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. New Jersey's Governor Christie announced in May 2011 that he was withdrawing his state from RGGI at the end of 2011. While the Governor still endorsed the need to reduce greenhouse gas emissions, he argues that RGGI is not the right mechanism for achieving reductions. Some claim that Governor Christie's action may severely undermine the future prospects for RGGI.

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 agreement included the following signatory jurisdictions: Arizona, British Columbia, California, Manitoba, Montana, New Mexico, Oregon, Utah, Quebec and Washington. In July 2010, the WCI released its Final Design for a regional cap and trade regulatory system to cover 90 percent of the societal greenhouse gas emissions within the region by 2015. So far, the only state to enact legislation authorizing the regulation of greenhouse gas emissions under a cap and trade system is California, (New Mexico adopted administrative regulations to regulate greenhouse gas emissions in conjunction with other states, but it did so absent legislative authorization).

At the municipal level, there are several cities participating in the U.S. Mayors Climate Protection Agreement to reduce GHG emissions to seven percent below 1990 levels by 2012.

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, can – as some of them have already – pursue complementary policies to regulate emission sources covered under cap and trade regulation, as well as those that will not be regulated under a cap and trade program.

The adoption of greenhouse gas goals and any associated regulations by Washington could directly affect 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 goals and potential future regulations could apply to the Coyote Springs 2 project.

Idaho Policy Considerations

Idaho is not a member of the Western Climate Initiative and currently does not regulate greenhouse gases or have a renewable portfolio standard (RPS). However, the Idaho Department of Environmental Quality will be administering greenhouse gas standards under its Clean Air Act delegation from the EPA.

Montana Policy Considerations

Montana has a non-statutory goal to reduce greenhouse gas emissions to 1990 levels by 2020. In 2007, the Legislature passed House Bill 25. This law requires new coal-fired facilities built in the state to sequester 50 percent of their emissions. Montana's renewable portfolio standard law, enacted through Senate Bill 415 in 2005, requires utilities to meet 10 percent of their load with qualified renewables from 2010 through 2014, and 15 percent beginning in 2015. While involved in the Western Climate Initiative, Montana has not considered any legislation to authorize its participation in and implementation of WCI's regional cap and trade system. The Montana Department of Environmental Quality does not handle regional haze issues affecting coal-fired generation located in the state as the agency does not have delegation under the Clean Air Act to regulate regional haze. The federal EPA is responsible for the application of regional haze criteria to the Colstrip coal-fired plants.

Montana had already implemented a mercury emission standard under Rule 17.8.771 that applies to Colstrip. The standard requires mercury reductions to 0.9 pounds per trillion Btu beginning January 1, 2010. Avista's generation at Colstrip already has emissions controls that meet Montana's mercury emissions goals.

Oregon Policy Considerations

The State of Oregon has a history of considering greenhouse gas emissions and renewable portfolio standards legislation. The Legislature enacted House Bill 3543 in 2007, 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 carbon dioxide (CO_2) emissions exceeding 83 percent of the emissions of a state-of-the-art gas-fired combined cycle combustion turbine (CCCT) by paying into the Climate Trust of Oregon. Senate Bill 838 created a renewable portfolio standard that requires large electric utilities to generate 25 percent of annual electricity sales with renewable resources by 2025. Intermediate term goals include five percent by 2011, 15 percent by 2015, and 20 percent by 2020. Oregon is an active member in the Western Climate Initiative, but it has not passed the legislation necessary to implement the WCI's cap and trade proposal. The Boardman Coal Plant, which is the only active coal-fired generation facility in Oregon, plans to cease using coal by 2020. The decision of Portland General Electric, the operator and owner of the largest share of the Boardman plant to make near-term investments to control emissions from the facility and to discontinue the use of coal serves as an example of how regulatory, environmental, political and economic pressure can culminate in an agreement that results in the early closure of a low-cost coal-fired power plant.

Washington State Policy Considerations

Circumstances similar to those that led to the close of the Boardman coal-fired facility in Oregon encouraged the owners of the Centralia Coal Plant (TransAlta) to agree to shut down one unit at the facility by December 31, 2020 and the other unit by December 31, 2025. The confluence of regulatory, environmental, political and economic pressure brought about the scheduled closure of the Centralia Plant.. The State of Washington enacted several measures concerning fossil-fueled generation emissions and generation resource diversification. A law, enacted in 2004, requires new fossil-fueled thermal electric generating facilities of more than 25 MW of generation capacity to mitigate CO_2 emissions through third party mitigation, purchased carbon credits, or cogeneration. Washington's Energy Independence Act (I-937), which was passed by the voters in the November 2006 General Election, established a requirement for utilities with more than 25,000 retail 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 these RPS requirements results in a $50 per MWh fine. The initiative also requires utilities to acquire all cost effective conservation and energy efficiency measures. Additional details about the energy efficiency portion of I-937 are located in the Energy Efficiency chapter.

Avista expects to meet or exceed its renewable requirements between 2012 and 2015 through a combination of qualified hydroelectric upgrades and renewable energy credit (REC) purchases. The 2011 IRP Expected Case ensures that the Company meets all I-937 RPS goals.

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

- 1990 levels by 2020;
- 25 percent below 1990 levels by 2035;
- 50 percent below 1990 levels by 2050 or 70 percent below Washington's 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 became law when the Legislature enacted Senate Bill 6001 in 2007. This law prohibits electric utilities from entering into long-term financial commitments beyond five years duration for fossil-fueled generation with greenhouse gas emissions exceeding 1,100 pounds per MWh. Beginning in 2013, the emissions performance standard can 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.

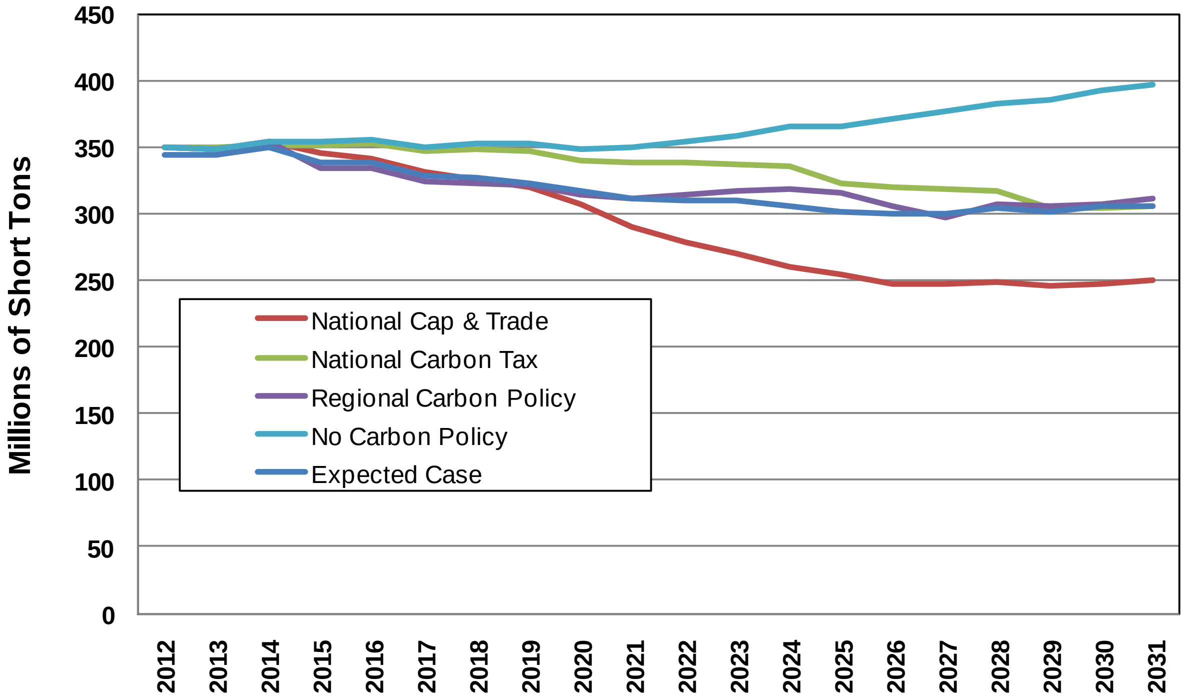
Taking the next step to achieve the State's greenhouse gas reduction goals, the governor introduced legislation (Senate Bill 5735 and House Bill 1819) during the 2009 Legislative Session to authorize the Department of Ecology to adopt rules, consistent from recommendations from the Western Climate Initiative, enabling the state to administer and enforce a regional cap and trade program. When that legislation failed, Governor Gregoire signed Executive Order 09-05 directing 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 requires the agency to "provide to 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 reduction 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.

Greenhouse Emissions Measurement and Modeling

Greenhouse gas tracking is an important part of the IRP modeling process because emissions policy poses a significant risk to Avista. Reducing greenhouse gas emissions from power plants will fundamentally alter the resource mix as society moves towards a carbon constrained future. Though there are currently no federal laws limiting greenhouse gas emissions, estimated costs still need to be projected for planning purposes because expectations for greenhouse gas regulation can significantly alter resource decisions.

Figure 4.1 shows the carbon price forecast for this IRP. The 2011 IRP assumes greenhouse gas emissions policies will not take effect until 2015.

Figure 4.1: Annual Greenhouse Gas Emissions for Alternative Greenhouse Gas Policies



To simulate the expected impacts of greenhouse gas regulation, the Company developed four policy models and estimated their assumed financial impact on the energy marketplace. Each policy represents a potential path governments could take over the next several years. We assigned weighting factors to each policy and the weighted average price of the policies is included in the Expected Case. The four greenhouse gas policies used in this IRP are defined in Table 4.1.

Table 4.1: Modeled Greenhouse Gas Policies

Strategy	Weighting (%)	Details
Regional Greenhouse Gas Policy	30	– Reductions in California, Oregon, Washington, and New Mexico between 2014 and 2019. – Shifts to National Climate Policy in 2020.
National Climate Policy	30	– Federal legislation only applies beginning in 2015 – About 15 percent below 2005 levels by 2020 and about 35 percent below 2005 levels by 2030.
National Carbon Tax	30	– Federal legislation only applies beginning in 2015. – $33 per short ton, then 5 percent per year escalation for the remainder of the study.
No Greenhouse Gas Reductions	10	– No carbon reduction program. – State-level emission performance standards apply and no new coal-plants are added in the Western U.S.

The Regional Greenhouse Gas policy simulates the decision by several western states to require greenhouse gas reductions under the auspices of the Western Climate Initiative (WCI) because a national policy has not been enacted. This policy does not include all of the WCI members because some states have enacted little, if any, legislation to allow their states to participate in the WCI cap and trade market. This policy begins in 2014 and is restricted to California, New Mexico, Oregon and Washington. The policy is superseded in 2020 by a National Climate Policy, described below. The Regional Greenhouse Gas Policy results in a 10 percent reduction of electric generation greenhouse gas emissions below 2005 levels by 2020. Projected prices start at $5 per short ton of CO_2 in 2014 and escalate by $1 per year to $9 per short ton in 2019. All greenhouse gas measurements and costs in this chapter are in short tons. In 2020, when the policy switches to a national focus, the price starts at $15 and escalates to $73 per ton in 2030. This policy was weighted by 30 percent in the model.

The National Climate Policy begins in 2015. No state level cap and trade programs are assumed in this scenario. The greenhouse gas emissions reductions are about 15 percent below 2005 levels by 2020 and about 35 percent below 2005 levels by 2030. Prices start at $15 per ton in 2015 and escalate to $115 per ton in 2030. This policy was weighted 30 percent in the model.

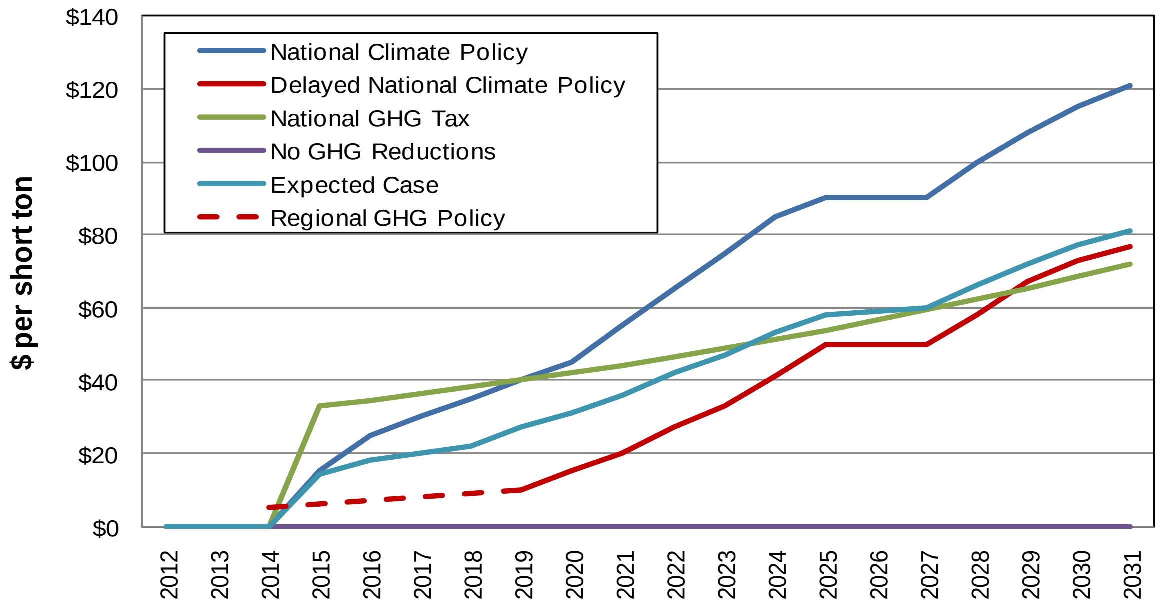
The National Carbon Tax is designed to loosely resemble the carbon tax in British Columbia and to show some of the implications of moving to a tax instead of a cap and trade program. The tax would start in 2015 at the national level and would supersede any state-level greenhouse gas cap and trade programs. The tax starts at $33 per ton in 2015 and increases to $69 in 2030. This policy was weighted 30 percent in the model.

The No Greenhouse Gas Reductions Policy is an unconstrained carbon case where there are no national or state-level greenhouse gas emissions reductions policies. This policy was included because there is a small probability of no greenhouse gas taxes or cap and trade program being instituted. This policy is also necessary to be able to determine the cost of the other greenhouse policies, since there is the actual cost of a tax or a credit, plus the additional cost of a less greenhouse gas intensive resource portfolio. Even though this unconstrained carbon policy does not have any national or state-level greenhouse gas reduction targets, state-level emissions performance standards are still applied and no new coal plants were allowed in the model. This policy received a 10 percent weighting in the model.

We also considered the addition of a regulatory model, to represent in spirit of the direction the EPA is using through the Clean Air Act and through other EPA actions that are fostering the early closing of coal-fired plants, such as Boardman and Centralia. These actions include regional haze, mercury abatement, cash ash handling and disposal, among others. The unique nature of each coal-fired facility, combined with the different political and environmental climates in each of the western states, made this type of policy too complex to model at this time. Future IRPs may include some of these EPA-related regulations as they are developed.

Figure 4.2 shows the greenhouse gas emissions costs per short ton under each of the policies and under the Expected Case.

Figure 4.2: Price of Greenhouse Gas Credits in each Carbon Policy



5. Transmission & Distribution

Introduction

This chapter describes Avista's transmission system, completed and planned upgrades, transmission planning issues, and estimated costs and issues of new generation resource integration.

Coordinating transmission system operations and planning activities among regional transmission providers is necessary to maintain reliable and economic transmission service for Avista customers. Transmission providers and interested stakeholders continue to modify the region's approach to planning, constructing, and operating the transmission system under Federal Energy Regulatory Commission (FERC) rules, and state and local siting agencies guidance. This chapter complies with Avista's FERC Standards of Conduct compliance program governing communications between Avista merchant and transmission functions.

Chapter Highlights

- Avista has received 43 requests for non-Avista resource integration.
- Projected costs of transmission upgrades are included in the 2011 Preferred Resource Strategy.
- The Company received matching federal grants and is investing in three grid modernization programs projected to reduce load by 5.57 aMW by 2013.
- Sixty distribution feeders passed preliminarily economic screening during the IRP timeframe, reducing system losses by 6.1 aMW.
- The Company participates in various regional transmission planning forums.
- Avista will upgrade various transmission paths over the next five years.

Avista's Transmission System

Avista owns and operates a system of over 2,200 miles of electric transmission facilities. The system includes approximately 685 miles of 230 kilovolt (kV) line and 1,527 miles of 115 kV line. The Company 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
- Grant County PUD
- Idaho Power Company
- NorthWestern Energy

- PacifiCorp
- Pend Oreille County PUD

Network interconnections enhance reliability and serve as points of receipt for power from generating facilities outside of a utility service area. Avista has interconnections to deliver its Colstrip, Coyote Springs 2, Lancaster, Washington Public Power Supply System Washington Nuclear Plant No. 3 settlement contract, and Mid-Columbia contract power. Avista serves various wholesale loads using government-owned and cooperative utility interconnections at transmission and distribution voltage levels.

Recent Transmission Improvements

Since the 2009 IRP, Avista made the following transmission enhancements:

- Added a 115 kV capacitor bank at Grangeville;
- Installed new 115 kV substation and transmission integration equipment at Idaho Road;
- Replaced a failed transformer at the Avondale 115 kV substation;
- Reconstructed the 115 kV switchyard and distribution substation, and added a capacitor bank to the Nez Perce 115 kV substation;

- Reconductored the Airway Heights to North Fairchild line section of the Airway Heights - Silver lake 115 kV line,
- Installed a new capacitor bank at the Airway Heights substation; and
- Reconductored selected portions of the Moscow area 115 kV system.

Future Upgrades and Interconnections

Station Upgrades

As reported in the 2009 IRP, Avista planned to upgrade its Moscow, Noxon, Pine Creek and Westside 230 kV substations. These stations have undersized transformers, do not provide 21st century reliability, and near the end of their useful lives. The Moscow station upgrades are complete. The new facility is a single 250 MVA 230/115 kV station using a double bus-double breaker configuration for 230 kV service. The 115 kV yard is in a breaker-and-a-half configuration. Over the next five to 10 years, the three remaining stations will be upgraded. Beyond these, plans exist for several new 115 kV capacitor banks throughout Avista's transmission system in the near future.

Transmission Upgrades

A number of 115 kV reconductor projects throughout Avista's transmission system are slated for completion within the next decade. These projects focus on replacing decades-old small conductor with much conductor capable of greater load-carrying capability and more efficient (i.e., fewer electrical losses) service. The overall Avista reductions in system losses will be measured in megawatts.

South Spokane 230 kV Reinforcement

Transmission studies continue to support a need for an additional 230 kV line to the south and west of Spokane. Avista currently has no 230 kV source in these areas, and instead relies on its 115 kV system for load service as well as bulk power flows through the area. The project scope is under development, and preliminary studies indicate the need for the following (or similar) projects:

- A new 230/115 kV station near Garden Springs. Property acquisition for the Garden Springs station and preliminary geo-technical station design work has commenced;
- Tap of the Benewah-Boulder 230 kV line southwest of the Liberty Lake area and construction of a new 230 kV switching station (for later development of a 230/115 kV substation); alternatively, reconstruction of the 115 kV circuits between Beacon and Ninth & Central, and the installation of a 230/115 kV station at that site could be pursued;
- Connecting the Liberty Lake 230 kV station with the Garden Springs 230 kV station; alternatively, connecting the Ninth & Central station to the Garden Springs station;
- Construction of a new 230 kV line from Garden Springs to Westside; and

- Origination and termination of the 115 kV lines from the new Spokane 230/115 kV station(s).

The South Spokane 230 kV Reinforcement project will be scoped by the end of 2012 with planned energization by the end of 2018. The project will enter service in a staged fashion beginning in 2014

Additional Work Required from the Avista Five and Ten-Year Plans

Following are examples of additional improvements to the Avista System in the next five to ten years. Since load growth rates in the various areas of the system are unknown, items presently on the list may or may not occur in this timeframe; more certainty is gained as time passes.

- West Plains 115 kV Reinforcement
- Irvin 115 kV Project
- Glenrose Tap – Ninth and Central 115 kV line
- Beacon 230/115 kV Station Partial Rebuild
- New Distribution Stations:
    - Otis Orchards (2011)
    - Hillyard (2013)
    - Hawthorne (2013)
    - North Moscow Additional Transformer (2013)
    - Spokane Downtown West (2014)
    - Greenacres (2014)

Canada/Northwest/California 500 kV Transmission Project (CNC) and Devils Gap 500/230 kV Interconnection

The Transmission Coordination Work Group (TCWG, see below) continues to evaluate a new transmission line involving four major projects.

- 500 kV high voltage alternating current 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, located near Spokane;
- 500 kV high voltage AC or high voltage direct current facilities running from the NEO Station to the Collinsville Substation in the San Francisco Bay Area;
- Interconnection near Cottonwood Substation in northern California (a direct current segment);
- Voltage support at the interconnecting substations; and
- Remedial actions for project outages.

The Canada-Northwest-California (CNC) project would allow access to new 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 could be aided by this project. Further, Avista expects that the project will increase the utilization of its existing transmission facilities. Through its participation in TCWG and other regional and sub-regional forums, Avista makes all project information available to group members, including resource developers, load serving entities, energy marketers, and independent transmission owners.

The CNC project continues to move forward with an altered set of ownership assumptions. The ultimate project size has not been determined. In late 2010, the CNC project was bifurcated into a northern section and a southern section. BC Hydro has taken responsible for the northern segment, comprised of the 500 kV interconnection between Selkirk and the proposed NEO station. The northern segment might be a double circuit 500 kV AC line with 3,000 MW of transfer capability, or a single circuit 500 kV AC line with 1,500 MW of capacity. Preferred line routing for the northern segment remains the “eastern route”, which would utilize the Avista Addy-Devils Gap 115 kV line corridor. A 500 MVA bi-directional 500/230 kV phase shifted interconnection between the CNC project and Avista’s transmission system remains the preferred option and would be the major impact to Avista.

The scope of the southern portion of the project has been reduced from a nominal 3,000 MW of transfer capability to 2,000 MW. Much work remains to determine if the southern portion should be an alternating current or a direct current line, and whether brownfield development (replacement of existing transmission with higher voltage and/or higher capacity facilities) can be accomplished while maintaining reliable system operation. Pacific Gas and Electric (PG&E) is no longer leading the southern segment project; the Western Area Power Administration (WAPA) has assumed its leadership.

Regional Transmission System

BPA owns and operates most of the regional transmission system in the Pacific Northwest. The federal entity operates over 15,000 miles of transmission-level facilities throughout the Pacific Northwest and owns the largest portion of the region’s high voltage (230 kV or higher) transmission grid. Avista uses BPA transmission to transfer output from its remote generation sources to Avista’s transmission system, including its Colstrip units, Coyote Springs 2, Lancaster 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.

The Company participates in the BPA transmission and 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 the BPA and other regional utilities to coordinate major transmission facility outages.

Future development likely will require new transmission assets by federal and other entities. BPA is developing several transmission projects in the Interstate 5 corridor, as well as projects in southern Washington that are necessary for integration wind generation resources located in the Columbia Gorge. Each project has the potential to increase BPA transmission rates and thereby affect Avista’s costs.

FERC Planning Requirements and Processes

The Federal Energy Regulatory Commission (FERC) provides guidance to both regional and local area transmission planning. This section describes several requirements and processes of the federal regulator important to Avista's transmission planning.

Attachment K

FERC approved Attachment K to Avista's Open Access Transmission Tariff (OATT). The attachment satisfies nine transmission principles in FERC Order 890 ensuring open planning processes, and formalizes coordination of local, regional, and sub-regional transmission planning.

Avista regularly develops a biannual Local Planning Report (in coordination with Avista's five- and ten-year Transmission Plans). Avista encourages participation of its interconnected utilities, 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 Western Electricity Coordinating Council (WECC) processes and groups, including 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.

Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) coordinates and promotes electric system reliability in the Western Interconnection. It 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

Avista is a member of the Northwest Power Pool (NWPP) through which it coordinates its transmission planning efforts. Formed in 1942 when the federal government directed utilities to coordinate operations in support of wartime production, NWPP committees include the Operating Committee, the Pacific Northwest Coordination Agreement (PNCA) Coordinating Group, and the Transmission Planning Committee (TPC). The TPC exists as a forum addressing northwest electric planning issues and concerns, including a structured interface with external stakeholders.

The NWPP serves as an electricity reliability forum, helping to coordinate present and future industry restructuring, promoting member cooperation to achieve reliable system operation, coordinating power system planning, and assisting the transmission planning process. NWPP membership is voluntary and includes the major generating utilities serving the Northwestern U.S., British Columbia and Alberta. Smaller, principally non-generating, utilities participate in an indirect manner through their member systems, such as the BPA.

ColumbiaGrid

ColumbiaGrid formed on March 31, 2006 to develop sub-regional transmission plans, assess transmission alternatives (including non-wires alternatives), provide a decision-making forum, and to provide a cost-allocation methodology for new transmission projects. This group formed in response to several FERC initiatives. Avista joined ColumbiaGrid in early 2007. The ColumbiaGrid agreements help different organizations and groups determine areas of transmission work, and establish agreements to carry out the plans.

Northern Tier Transmission Group

The Northern Tier Transmission Group (NTTG) formed on August 10, 2007. NTTG members include Deseret Power Electric Cooperative, Idaho Power, Northwestern Energy, PacifiCorp, Portland General Electric, and Utah Associated Municipal Power Systems. NTTG members coordinate with state governments to manage their transmission system operations, products, business practices, and high-voltage transmission network planning to meet and improve transmission delivery services. Avista's transmission network has a number of strong interconnections with three of the six NTTG member systems. Due to the geographical and electrical positions of Avista's transmission network related to NTTG members, Avista is evaluating membership in NTTG to foster collaborative relationships with our interconnected utilities.

Transmission Coordination Work Group

The Transmission Coordination Work Group (TCWG) is a 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 a proposed Northeast Oregon station near Boardman, Oregon. These projects follow WECC Regional Planning and Project Rating Guidelines. Detailed information on projects presently under consideration is at www.nwpp.org/tcwg.

Most of the projects developed through the TCWG transferred to their own Project Review Groups, placed on hold, or terminated. The TCWG work effort has been significantly reduced over the past year because of the number of terminated and on-hold projects.

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 NWPP. Through involvement in WECC and NWPP standing committees and sub-committees, it participates in developing new and revised criteria, and coordinates transmission system planning and operation 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 retail load service. Transmission capacity not reserved and scheduled to move power to satisfy long-term (greater than one year) obligations is marketed on a short-term basis and used by Avista for short-term resource optimization or by third parties seeking short-term transmission service pursuant to FERC requirements under Orders 888, 889 and 890.

Transmission Construction Costs

The following sections provide an overview of Avista's estimated resource integration costs for the 2011 IRP. Integration points are divided into locations where interconnection study work has been completed and additional points where new resources might be interconnected. Rigorous analyses are not performed 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 (and any decisions based on such work would be flawed) and it is therefore inappropriate to represent any figures as more than preliminary. Approximate worst-case estimates were developed based on engineering judgment for neighboring system impacts. Generation interconnection costs are for locations within the Avista transmission system. Internal cost estimates are in 2011 dollars and using engineering judgment with a 50 percent margin for error. Construction timelines are from the beginning of the permitting process to line energization.

Integration of Resources External to the Avista System

Avista's load serving entity function must 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.

At BPA's present wheeling rate, integrating 300 MW (assuming the transmission service were available from the off system resource to the Avista transmission system) would cost about $4.4 million per year plus $2.5 million per year for line losses.

It is likely that the Company would invest $50 million for a 300 MW resource to increase capacity to third-party transmission systems. These investments may not need to be made at the time of interconnect, but will have to be upgraded in time to maintain FERC's market power requirements and maintain present levels of access to the energy market. If Avista acquires a resource located on a third-party network, detailed studies will need to be completed to understand system impacts.

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 continues as a joint effort by Avista, BPA, NorthWestern Energy, PacifiCorp, and Puget Sound Energy. Preliminary results indicate that perhaps as much as 480 MW of additional transfer from Montana can be achieved, however engineering-level construction cost estimates to fix constraints within the various transmission systems have not yet been completed. It should also be noted that various facilities in the Avista transmission system would need to be upgraded to achieve this additional transfer.

Integration of Resources on the Avista Transmission System

The Avista-LSE requested a number of generator interconnection studies in several areas of the Avista transmission system for the 2011 IRP. The following project and cost information was presented at the Third Technical Advisory Committee meeting on December 2, 2010, these cost estimates are presented in Table 5.1.

Lancaster Integration

Avista has proposed and evaluated an interconnection with BPA at its Lancaster Substation. Avista and BPA have determined that the preferred alternative is to loop the Avista Boulder-Rathdrum 230 kV line into the BPA Lancaster 230 kV station.

This interconnection will allow Avista to eliminate or offset BPA wheeling charges for moving the output from Lancaster to Avista's system. Besides reduced transmission payments to BPA by Avista, the interconnection benefit both Avista and the BPA by increasing system reliability, decreasing losses, and delaying the need for additional transformation at the BPA Bell Substation. The proposed plan of service also represents the best option for service from Avista's sole perspective. Studies also 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 present Colstrip Upgrade Project study indicates that all of the upgrades (from AVA, BPA, and NWE) could increase the Montana to Northwest path by as much as 800 MW—the associated projects include much more than the Lancaster loop-in work. Construction on the Lancaster project could be completed by the end of 2012 or at some point in 2013, depending on BPA's construction schedule. Avista is working closely with BPA to assure the timely construction of the BPA facilities required to facilitate this interconnection.

Table 5.1: New Resource Integration Costs

Location	Notes	Size (MW)	Cost (millions $)
West of Spokane, WA	No transmission additions	4	0
West of Spokane, WA	Requires new 115 kV line	75	15
West of Spokane, WA	Requires two new 230 kV lines	254	30-55
Benewah, ID		300	5
Rosalia, WA		300	8
Rathdrum, ID	Requires generation dropping	300	5
Rathdrum, ID	Requires generation dropping	400	5
Othello, WA	No transmission additions	17	0
Othello, WA	Requires new 115 kV line and substation[1]	100	13-25
Othello, WA	Requires new 230 kV line and substation	250	21-32
Sandpoint, ID	Depends on BPA interconnection	50	2-5
Sandpoint, ID	Cost prohibitive and not studied	100	N/A
Cabinet Gorge, ID	115 kV reconductor	60	2-10
Spokane, WA	Monroe Street hydro project	20	3
Spokane, WA	Monroe Street hydro project	60	3
Post Falls, ID	Post Falls hydro project	14	1
Spokane, WA	Upper Falls hydro project	14	1

Distribution Efficiencies

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

Avista's categorizes its energy delivery systems between transmission and distribution voltages. Avista's transmission system operates at 230 kV and 115 kV nominal voltages. Avista's distribution system operates between 4.16 kV and 34.5 kV, but typically at 13.2 kV in its urban service centers. In addition to voltages, the transmission system operates distinctly from the distribution system. For example, the transmission system is a network linking multiple sources with multiple loads, while the distribution system configuration uses radial feeders to link a single source to multiple loads.

[1] Note that the 100 MW estimate is for 115 kV integration, and the 250 MW estimate is for 230 kV integration and does not include mitigation of contractual constraints on the Avista 230 kV system in the area

System Efficiencies Team

In 2008 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, combined transmission system topologies with “right sizing” distribution feeders to reduce system losses, improve system reliability, and meet future load growth.

Distribution Feeders

Avista’s distribution system consists of approximately 330 feeders covering 30,000 square miles. Its feeders range in length from three to 73 miles. For rural distribution, feeder lengths vary 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 losses, capital investments, and reductions in operations and maintenance (O&M) costs resulting from the individual efficiency programs being studied were combined on a per feeder basis. This approach provided a means to rank and compare the energy savings and net resource cost for each feeder.

Economic Analysis

Prior to the 2009 IRP an economic analysis was performed to determine 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. This economic value is calculated by estimating the capital investment, energy savings, and avoidance of operations and maintenance (O&M) and interim capital investments resulting from feeder upgrades.

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 develop the failure model for each studied feeder. Customer, material and labor costs incurred by outages, and equipment failure were the parameters used to measure the economic risk of a failure. The results were calibrated to the expected value model by industry indexes and Avista’s actual outage history. Many of the projects found to be cost effective in the study are now a part of the grid modernization project discussed below. There were 60 feeders remaining for potential re-builds and based upon preliminary energy and O&M savings estimates. All appear cost effective. However, these projects need further study to develop detailed cost and energy savings estimates. Based on the preliminary cost and energy estimates shown in Figure 5.1, losses could be reduced by 6.1 aMW by the end of the IRP planning period.

Grid Modernization

The Company is investing in grid modernization technology with the aid of three federal grants promoting the development of grid modernization applications. These grants require the Company to invest in grid modernization training and grid improvement. The following is a discussion of the programs, and the progress of the investment. A summary of projected energy savings is in Figure 5.1.

Smart Grid Workforce Training Grant

Avista received a three-year, $1.3 million government grant to invest in facility and training programs to educate workers for developing, managing, and maintaining the future grid. Workers are trained at the Jack Stewart Training Center, working in a model neighborhood and substation to learn about grid modernization technology. Avista is also developing a curriculum for local universities and an online portal to provide training opportunities outside of the organization. Another goal of this grant is to share best practices on Smart Grid training.

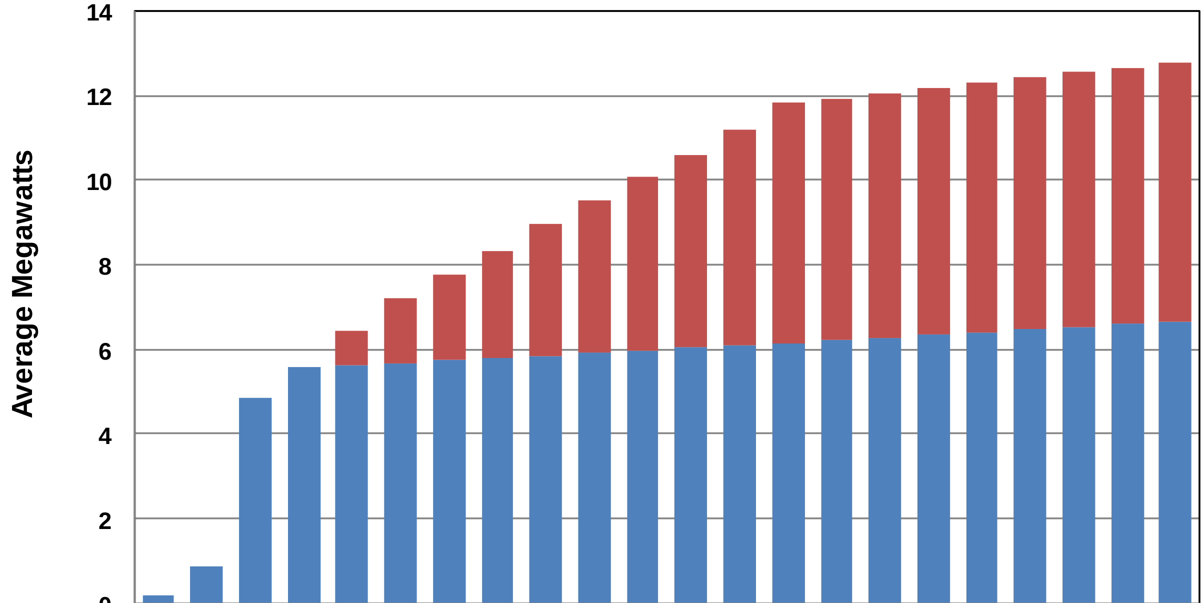
Smart Grid Investment Grant (SGIG)

The $20 million Smart Grid Investment Grant (SGIG) covers investment to the Spokane area grid improvement project. This project includes upgrades for 59 circuits, 14 substations, and 110,000 electric customers. Avista is contributing $42 million dollars to this project to automate the system. 42,000 MWh or 4.8 aMW of loss savings are expected. Conservation Voltage Reduction makes up 83 percent of the loss savings. This project will enable Avista to remotely control and operate the distribution system through a series of wireless controls and fiber communication between switches, reclosers, capacitor banks, and voltage regulators. The Distribution Management System will remotely operate the system and will be able to automatically detect and restore faults.

Smart Grid Demonstration Project (SGDP)

Avista is a partner in the regional Smart Grid Demonstration Project (SGDP). Avista is using an $18.9 million government grant to employ grid modernization technology in Pullman, Washington, as part of the Pacific Northwest Smart Grid Demonstration Project. Avista is contributing $14.9 million to the Pullman project and other parties are contributing an additional $4.0 million. The partners are Itron, HP, Washington State University, and Spirae. This project encompasses 13 circuits, three substations, and includes network automation. This project involves the replacement of 14,000 electric and 6,000 natural gas meters to digital meters with wireless communication. Customers with these new meters will be able to use a web portal to track energy usage in near real time. This project should reduce system losses by 6,763 MWh.

Figure 5.1: Distribution Loss Savings from Grid Modernization and Feeder Upgrades



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Dist. Feeders					0.8	1.5	2.0	2.5	3.1	3.6	4.1	4.5	5.1	5.6	5.7	5.7	5.8	5.9	5.9	6.0	6.0	6.1
Smart Grid	0.1	0.8	4.8	5.5	5.6	5.6	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1	6.2	6.2	6.3	6.4	6.4	6.5	6.6	6.6

Transmission Topologies and Distribution Feeder Sizing

Avista is planning a new modeling system that will incorporate transmissions topology, station locations and load growth. Historically, Avista's power grid was designed and built to adhere to reliability and capacity guidelines resulting in the lowest upfront cost. This approach was reasonable considering the low electricity costs of that time. As the cost of energy increases, life cycle economic analyses are warranted to evaluate power system losses corresponding to different power grid configurations.

The new and comprehensive analysis will review several different transmission topologies to determine the most efficient configuration for moving bulk power through and by Avista's system. 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 for evaluation;
- Identify reasonable guidelines for substation placement;
- Identify reasonable guidelines for distribution feeder sizes; and
- Bound the analysis to ensure the system remains reliable, compliant, and operationally flexible.

Summary

Avista's system consists of 2,720 miles of high voltage transmission lines and 18,200 miles of distribution facilities. System planning utilizes various local, sub-regional, 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; however, these costs tend to escalate rapidly as generation project size increases. This chapter includes planning and initial cost estimates for several potential 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 available 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.

Section Highlights

- Only resources with well-defined costs and operating histories are in the PRS analysis.
- Wind and solar resources represent renewable options available to the Company; future RFPs might identify competing renewable technologies.
- Renewable resource costs assume present state and federal incentive levels, but no extensions.
- For the first time, thermal generation upgrades are resource options.

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), simple cycle combustion turbines (SCCT), large-scale wind, and certain solar technologies proven on a large-scale commercial basis. Several other resource options described later in the chapter were not included the PRS analysis, but their costs were estimated for comparative analysis.

Levelized costs referred to throughout this section are at the generation busbar. The nominal discount rate used in the analyses is 6.8 percent. Nominal levelized costs result from discounting nominal cash flows at the rate of general inflation.

Renewable resources eligible for federal tax incentives receive such incentives based on the current federal law. Wind benefits end in 2012; solar tax benefits end in 2016, and all other renewable benefits end in 2013. The levelized costs in this chapter assume maximum available energy for each year instead of expected generation. For example, wind generation assumes 31 percent availability, CCCT generation assumes 90 percent availability, and SCCT generation assumes 92 percent availability. The following are definitions for the levelized cost components 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.

- *Allowance for Funds Used During Construction (AFUDC):* The cost of money for construction payments before the utility can recover costs of prudently acquired generation resources.
- *Federal Tax Incentives:* The estimated federal tax incentive (per MWh), whether in the form of a production tax credit (PTC), a cash grant, or an investment tax credit (ITC), attributable to certain generation options.
- *Fuel Costs*: The cost of fuels such as natural gas, coal, or wood per the efficiency of the generator. Additional details on fuel prices are in the Market Modeling section.
- *Fuel Transport*: The cost to transport fuel to the plant, including pipeline capacity charges.
- *Greenhouse Gas Emissions Adder:* Cost of carbon dioxide (greenhouse gas) emissions based on Wood Mackenzie forecast.
- *Fixed Operations and Maintenance (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.
- *Variable O&M:* Costs per MWh related to incremental generation.
- *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.
- *Excise Taxes and Other Overheads:* Includes miscellaneous charges for non-capital expenses.

At the end of this section, various tables show Incremental capacity, heat rates, generation capital costs, fixed O&M, variable costs, and peak credits.[1] Figure 6.2 shows the levelized costs of different resource types in comparison. All costs shown in this section are in nominal dollars unless otherwise noted. Further information on the plant assumptions used in this section is in the Northwest Power and Conservation Council's (NPCC) Sixth Power Plan.

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

Gas-Fired Combined Cycle Combustion Turbine (CCCT)

Gas-fired CCCT plants provide a reliable source of both capacity and energy for a relatively inexpensive capital investment. The main disadvantage is generation cost volatility due to a reliance on natural gas.

CCCTs in this IRP are of a "one-on-one" (1x1) configuration, using both water- and air-cooling technologies. The 1x1 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 have nameplate ratings of between 250 MW and 300 MW each. A "2x1" CCCT plant configuration is possible with two turbines and one HRSG, generating up to 600 MW. The most likely CCCT configuration for Avista is a 270 MW air-cooled plant located in the Idaho portion of Avista's service territory. Potential sites for a future combined cycle plant would likely be on the Avista transmission system to avoid third-party wheeling rates. Another advantage of siting a CCCT resource in Avista's service territory is access to a low cost natural gas pipeline and fuel sources. Within Avista's area, siting decisions then come down which state to locate a new plant in. While a majority of Avista's load is in Washington state, the state's natural gas excise tax and carbon dioxide mitigation requirements place a gas-fired plant at an economic disadvantage relative to siting the same plant in an adjoining state. Siting a CCCT in Idaho economically benefit ratepayers with due to a lower sales tax rate, the absence of a natural gas excise tax, and no fees for a carbon dioxide mitigation.

Cost and operational estimates for CCCTs modeled in the IRP use data from the NPCC's Sixth Power Plan, but adjusted to reflect air-cooled technology costs by Avista's engineering staff. The heat rate modeled for an air-cooled CCCT resource is 6,925 Btu/kWh in 2012. The projected CCCT heat rate falls by 0.5 percent annually to reflect an allowance for anticipated technological improvements. The plants include seven percent of rated capacity as duct firing at a heat rate of 9,690 Btu/kWh. If Avista were able to site a water-cooled plant, the heat rate would likely be two percent lower and net plant output might increase by five MW.

The IRP models forced outages at six percent per year, with 21 days of annual plant maintenance. CCCT plants are capable of backing down to 65 percent of nameplate capacity, and ramping from zero to full load in four hours. Carbon dioxide emissions are 117 pounds per decatherm of fuel burned. The maximum capability of each plant is highly dependent on ambient temperature and plant elevation. For modeling, winter capability is likely to increase by 4 percent and summer capability is likely to decrease by 6 percent, though these estimates are highly dependent upon ambient temperatures.

The capital cost used for this IRP for an air-cooled CCCT located in Idaho on Avista's transmission system with AFUDC is $1,323 per kW. Fixed O&M is $16 per kW-year. Table 6.1 shows the overnight-levelized cost for an air-cooled CCCT resource in nominal dollars per MWh.

Table 6.1: CCCT (Air Cooled) Levelized Costs

Item	Nominal $/MWh
Capital recovery and taxes	20.25
AFUDC	2.69
Federal Tax Incentives	0.00
Fuel Costs	48.81
Fuel Transport	5.18
Greenhouse Gas Emissions Adder	13.65
Fixed O&M	2.67
Variable O&M	2.35
Interconnection Capital Recovery	0.31
Excise taxes and Other Overheads	3.16
Total Cost	**99.07**

Gas-Fired Combustion Turbines and Reciprocating Engines

Gas-fired combustion turbines (CTs) and reciprocating engines, or peaking resources, provide low-cost capacity and are capable of providing energy as needed. Technology advances allow the plants to start and ramp quickly, enabling them to provide regulation services and reserves for load following and for variable resources such as wind generation.

The IRP models four peaking resource options: Frame (GE 7EA) and hybrid aero-derivative (GE LMS 100), Reciprocating Engines (Wartsila 20V34), and Aeroderivative (GE LM 6000). The different peaking technologies range in their abilities to follow load, their costs, their generating capabilities, and their energy-conversion efficiencies. Cost and operational estimates rely on the Northwest Planning and Conservation Council's Sixth Power Plan. Table 6.2 compares some of the peaking resource operating and cost characteristics. All plants assume the same 0.5 percent real dollar cost decrease and forced outage and maintenance rates. The levelized cost for each of the technologies is in Table 6.3.

Table 6.2: Simple Cycle Plant Cost and Operational Characteristics

Item	Frame	Hybrid	Reciprocating Engine	Aero-derivative
Capital Cost with AFUDC ($/kW)	679	1,272	1,308	1,186
Fixed O&M ($/kW- yr)	12.70	9.20	15.00	15.00
Heat Rate (Btu/kWh)	11,841	8,782	8,762	9,276
Variable O&M ($/MWh)	$1.13	$5.63	$11.25	$4.50
Segment Size (MW)	83	94	99	46

The lowest cost resource in Table 6.3 is the hybrid CT technology. However, this comparison can be misleading, as a peaking resource does not operate at its theoretical maximum operating levels. Peaking resources generally operate a small percentage of the time. Therefore, a lower capacity cost resource may be more appropriate than a lower per unit cost resource when considering the number of expected operating hours in the broader IRP modeling process.

Table 6.3: Simple Cycle Plant Levelized Costs per MWh

Item	Frame	Hybrid	Reciprocating Engine	Aero-derivative
Capital Recovery and Taxes	10.33	19.37	19.38	18.06
AFUDC	0.89	1.67	1.67	1.56
Federal Tax Incentives	0.00	0.00	0.00	0.00
Fuel Costs	81.33	60.32	60.18	63.72
Fuel Transport	0.00	0.00	0.00	0.00
Greenhouse Gas Emissions Adder	22.75	16.87	16.84	17.83
Fixed O&M	2.00	1.46	2.30	2.37
Variable O&M	1.38	6.91	13.82	5.53
Interconnection Capital Recovery	0.44	0.44	0.43	0.44
Excise Taxes and Other Overheads	4.67	3.72	4.05	3.89
Total Cost	**123.81**	**110.76**	**118.66**	**113.39**

Wind

Concerns over the environmental impact of carbon-based generation technologies have increased demand for wind generation. Governments are promoting wind generation through a combination of tax credits, renewable portfolio standards, and climate change legislation. The 2009 American Recovery and Reinvestment Act extended the PTC for wind through December 31, 2012, and provided an option for wind generation owners to select a 30 percent investment tax credit (ITC) or cash grant instead of the PTC.

The IRP includes two wind generation resources: on-system and off-system. Both resources have the same capital costs and wind pattern, but differ in the cost of transmission to deliver the energy to Avista's system. On-system projects must pay only transmission interconnection costs, whereas off-system projects must pay both interconnection and third party wheeling costs.

Wind resources benefit from having no emissions profile or fuel costs, but they are not dispatchable, and have high capital and labor costs relative to other resource options. Wind capital costs in 2012, including AFUDC and transmission interconnection, are expected to be $1,850 per kW with annual fixed O&M costs of $51 per kW-yr (including costs due to intermittent generation). These estimates come from Avista's experience in the wind market at the time of the IRP. The capacity factors in the Northwest are likely to vary depending upon the location. Northwest wind has a 31.2 percent average capacity factor; on-system wind projects have a 29.75 percent capacity. A statistical method, based on regional wind studies, derives a range of annual capacity factors depending on the wind regime in each year (see stochastic modeling assumptions for more details.

Levelized costs, using these expected capacity factors and capital and operating costs are in Table 6.4. These wind generation cost estimates assume the use of the federal cash grant for any project brought online by the IRP models before 2013 and assume Avista system interconnection cost of approximately $150 per kW. Actual wind resource cost will vary depending on a project's capacity factor, interconnection point, and the tax incentive eligibility. Further, this plan assumes that any wind resources selected in the PRS include the 20 percent renewable energy credit (REC) apprenticeship adder for Washington State eligible renewable resources. This adder applies only in the state of Washington for compliance in meeting its Energy Independence Act (I-937), requiring 15 percent of the construction labor to be apprentice through a state-certified apprenticeship program to qualify. The costs shown below do not reflect the consumption of (i.e., wind integration) or lack of ancillary services generated by wind relative to other generation technologies.

Table 6.4: Northwest Wind Project Levelized Costs per MWh

Item	On-System	Off-System	Off-System Montana
Capital Recovery and Taxes	77.59	73.98	58.40
AFUDC	8.19	7.80	6.16
Federal Tax Incentives (2012 only)	-23.93	-22.82	-18.01
Fuel Costs	-	-	-
Fuel Transport	-	-	-
Greenhouse Gas Emissions Adder	-	-	-
Fixed O&M	27.59	26.31	22.37
Variable O&M	2.76	2.76	2.76
Interconnection Capital Recovery	7.99	18.67	26.78
Excise Taxes and Other Overheads	1.66	2.07	2.25
Total Cost (without tax incentive)	**125.78**	**131.60**	**118.72**
Total Cost (with tax incentive)	**101.85**	**108.78**	**100.71**

Solar

Solar generation technology costs have fallen substantially in the last several years owing to help from renewable portfolio standards and government tax incentives, both inside and outside of the United States. Solar costs in this IRP are 27 percent lower than in the 2009 IRP. Even with these large cost reductions, solar still is uneconomic when compared to other generation resources because of its low capacity factor and still-high capital cost. Solar does provide predictable on-peak generation that generally complements the loads of summer-peaking utilities.

Utility-scale photovoltaic generation can be optimally located for the best solar radiation. Solar thermal can produce a higher capacity factor than photovoltaic projects (up to 30 percent) and can store energy for several hours. Capital costs in the IRP, including AFUDC, for solar generation technologies are $5,802 per kW for photovoltaic and $5,538 for solar-thermal or concentrating solar projects. A well-placed utility-scale photovoltaic system located in the Pacific Northwest would achieve a capacity factor of less than 20 percent. Two solar technologies were studied for this IRP (photovoltaic and solar-thermal), but only utility-scale photovoltaic was included as an option for the PRS.

Avista does not believe that solar-thermal is an economically viable option in Avista's service territory given our modest solar resource.

The levelized costs of solar resources, including federal incentives, are in Table 6.5. Even with declining prices, solar will continue to struggle as a cost-competitive resource in the Northwest until technology improves capacity factors, installation costs decline at a more rapid pace, or government entities create further policies or tax incentives to make this resource more attractive. One advantage solar has in the state of Washington is if the total plant is less than five megawatts it can generate two RECs that qualify for the Washington State Energy Independence Act for every megawatt hour of generation.

Table 6.5: Solar Nominal Levelized Cost ($/MWh)

Item	Photovoltaic	Concentrating
Capital Recovery and Taxes	370.14	201.85
AFUDC	29.49	22.44
Federal Tax Incentives	(117.60)	(64.58)
Fuel Costs	-	-
Fuel Transport	-	-
Greenhouse Gas Emissions Adder	-	-
Fixed O&M	39.73	30.00
Variable O&M	-	1.38
Interconnection Capital Recovery	1.67	9.75
Excise Taxes and Other Overheads	1.79	1.78
Total Cost	**325.22**	**202.62**

Coal

The coal generation industry is at a crossroads. In many states, like Washington, new coal-fired generation is unlikely due to emissions performance standards.[2] In other parts of the country, coal remains a viable option, but the risks associated with future carbon legislation make investments in this technology potentially subject to significant upward price pressures. Avista assumes it will not build any new coal-fired generation resources due to the risk of future national carbon mitigation legislation and the effective prohibition in Washington state law. Technologies reducing or capturing greenhouse gas emissions in coal-fired resources might enable coal to become a viable technology in the future, but the technology is not commercially available. Although Avista will not pursue coal in this plan, three coal technologies are shown to illustrate their costs: super critical pulverized, integrated gasification combined cycle (IGCC), and IGCC with sequestration. IGCC plants gasify coal, thereby creating a more efficient use of the fuel lowering carbon emissions and removing other toxic substances before combustion. Sequestration technologies, if they become commercially available, might potentially sequester 90 percent of carbon dioxide (CO_2) emissions, effectively reducing CO_2

[2] The Washington State legislature passed Senate Bill 6001 in 2007, effectively prohibiting in-state electric utilities from developing coal-fired facilities that do not sequester emissions or purchasing long-term contracts from coal-fired facilities.

emissions from 205 pounds per MMBtu to 20.5 pounds per MMBtu. Table 6.6 shows the costs, heat rates, and CO_2 emissions of the three coal-fired technologies based on estimates from the NPCC's Sixth Power plan and adjusted for Avista's projected inflation rates. Table 6.7 shows the nominal levelized cost per MWh based on the capital costs and plant efficiencies shown in Table 6.6.

Table 6.6: Coal Capital Costs (2012$)

Technology	Capital Cost ($/kW includes AFUDC)	Heat Rate (Btu/kWh)	CO_2 (lbs/MMBtu)
Super-Critical	3,583	8,910	205
IGCC	4,001	8,594	205
IGCC with Sequestration	5,334	10,652	25

Table 6.7: Coal Project Levelized Cost per MWh

Item	Super-Critical	IGCC	IGCC w/ Sequestration
Capital Recovery and Taxes	56.82	64.70	86.27
AFUDC	9.66	13.06	17.41
Federal Tax Incentives	0.00	0.00	0.00
Fuel Costs	14.28	13.77	17.07
Fuel Transport	0.00	0.00	0.00
Greenhouse Gas Emissions Adder	30.00	28.93	4.30
Fixed O&M	11.87	12.10	12.10
Variable O&M	3.80	8.70	11.74
Interconnection Capital Recovery	10.31	10.46	4.79
Excise taxes and Other Overheads	3.04	3.20	2.16
Total Cost	**139.79**	**154.94**	**155.86**

Other Generation Resource Options

A thorough IRP considers generation resources that are not generally available in large quantities or those not commercially or economically ready for utility-scale development, but may be over the 20-year IRP planning horizon. This is particularly true for some emerging technologies that are attractive from an environmental perspective, but are currently higher-cost than other resources. Avista analyzed the following resources for this IRP using estimates from the NPCC's Sixth Power Plan but did not select them for the Preferred Resource Strategy: biomass, geothermal, co-generation, nuclear, landfill gas, and anaerobic digesters. It is possible that these resources could compete with those assumed in the IRP. If so, Avista's RFP processes will identify them and their selection will displace resources otherwise included in the IRP strategy.

Woody Biomass

Avista's Kettle Falls Generation Station is a 50 MW wood-fired plant Avista built and has operated since 1983. The viability of another Avista biomass projects depends substantially on the availability and cost of the fuel supply. Many announced biomass projects fail because of problems securing long-term fuel sources. Where an RFP identifies a potential project, Avista will consider it for a future acquisition.

Geothermal

Northwest utilities have developed an increased interest in geothermal energy over the past several years. Geothermal energy provides renewable capacity and energy with minimal carbon dioxide emissions (zero to 200 pounds per MWh). The federal government has extended production tax credits to this technology through December 31, 2013. Geothermal energy struggles due to high upfront development costs and risks stemming from drilling several holes thousand feet below the earth's crust; each hole can cost over $3 million. Geothermal costs are low once drilling ends, but the risk capital required to locate and prove a viable site is significant. Costs shown in this section do not account for dry-hole risk associated with sites that do not prove to be viable resources after drilling has taken place.

Landfill Gas

The Northwest has successfully developed landfill gas resources. The Spokane area had a project, but it was retired after the fuel source depreciated to an unsustainable level. Based upon costs from the NPCC, landfill gas resources are economically promising, but are limited in their size, quantity, and location.

Anaerobic Digesters (Manure/Wastewater Treatment)

Like landfill gas, the number of anaerobic digesters is increasing in the Northwest. These plants typically capture methane from agricultural waste, such as manure or plant residuals, and burn the gas in reciprocating engines to power electricity generators. These facilities tend to be significantly smaller than utility-scale generation projects (less than five MW). A survey of Avista's service territory found no large-scale livestock operations capable of implementing this technology.

Wastewater treatment facilities can host anaerobic digesters. Digesters installed when a facility is constructed helps the economics of a project greatly, though costs range greatly depending on the system configuration. Retrofits to existing wastewater treatment facilities are possible, but tend to have higher costs. Many of these projects offset energy needs of the facility, so there may be little, if any, surplus generation capability.

Small Cogeneration

Avista has relatively few industrial customers capable of developing cost-effective cogeneration projects. If an interested customer was inclined to develop a small cogeneration project, it could provide benefits including reduced transmission and distribution losses, shared fuel/capital/emissions costs, and credit toward Washington's I-937 targets. The PRS does not include small cogeneration; where a customer pursues this resource, Avista will consider it along with other generation options.

Nuclear

Nuclear plants are not a resource option in the IRP given the uncertainty of their economics, the apparent lack of regional political support for the technology, U.S. policy implications, and the negative experience Avista had with its participation in WNP-3 in the 1980s. Like coal plants, nuclear resources could be in Avista's future because other utilities in the Western Interconnect may be able to incorporate nuclear power in their resource mix and offer Avista an ownership share. Given these considerations, Avista does not include any nuclear generation in its Preferred Resource Strategy. 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 there have been no new nuclear facilities built in the United States since the 1980s. Projected costs are from industry studies and recent nuclear plant license proposals.

Table 6.8: Other Resource Options Levelized Costs

	Landfill Gas	Manure Digester	Waste Water Treatment
Capital Recovery and Taxes	31.56	67.15	63.40
AFUDC	2.45	4.66	4.88
Federal Tax Incentives	-8.49	-8.49	-8.49
Fuel Costs	32.66	0.00	0.00
Fuel Transport	0.00	0.00	0.00
Greenhouse Gas Emissions Adder	0.00	0.00	0.00
Fixed O&M	4.87	8.42	7.07
Variable O&M	26.25	33.16	41.45
Interconnection Capital Recovery	4.54	4.54	0.34
Excise Taxes and Other Overheads	2.96	2.00	2.11
Total Cost	**96.80**	**111.45**	**110.76**

Table 6.9: Other Resource Options Levelized Costs ($/MWh)

	Small Co-Gen	Wood Biomass	Geothermal	Nuclear
Capital Recovery and Taxes	53.91	57.59	65.86	97.88
AFUDC	5.36	6.02	11.39	27.26
Federal Tax Incentives	0.00	-8.49	-16.98	-16.98
Fuel Costs	30.60	53.59	0.00	10.36
Fuel Transport	3.19	0.00	0.00	0.00
Greenhouse Gas Emissions Adder	8.56	0.00	4.63	0.00
Fixed O&M	0.00	34.80	32.16	16.85
Variable O&M	11.05	5.11	6.22	1.38
Interconnection Capital Recovery	0.36	4.65	4.49	4.55
Excise Taxes and Other Overheads	2.33	4.25	2.06	1.43
Total Cost	**115.36**	**157.52**	**109.83**	**142.72**

New Resources Cost Summary

Avista has several resource alternatives to select from for this IRP. Each provides differing benefits, costs, and risks. The role of the IRP is to identify the relevant characteristics and choose a set of resources that are actionable, meet customer's energy and capacity needs, balance renewable energy requirements, and minimize customer costs. Figure 6.1 shows the comparative cost per MWh of each of the new resource alternatives. Tables 6.13 and 6.14 provide detailed assumptions for each type of resource. The ultimate resource selection goes beyond simple levelized cost analyses and considers the capacity contribution (or lack thereof for wind and solar) of each resource, among other items discussed in the IRP.

Figure 6.1: New Resource Levelized Costs

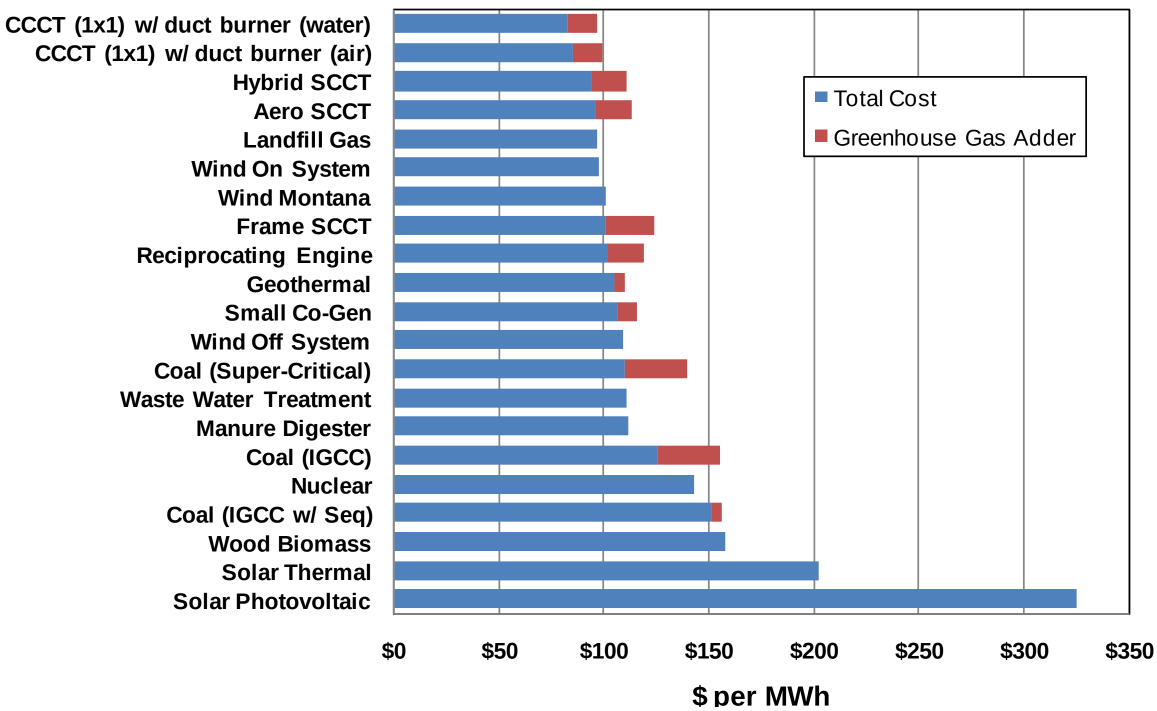


Table 6.10: New Resource Levelized Costs Considered in PRS Analysis

Resource	Size (MW)	Heat Rate (Btu/ kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Peak Credit (Winter/ Summer)
CCCT (water cooled)	275	6,722	1,261	16.1	2.14	104/96
CCCT (air cooled)	270	6,856	1,324	16.1	1.91	104/96
Frame CT	83	11,841	708	12.7	1.13	104/96
Hybrid CT	94	8,782	1,326	9.2	5.63	104/96
Reciprocating Engines	99	8,762	1,364	15.0	11.25	100/100
Aero CT	46	9,276	1,237	15.0	4.50	104/96
Wind (on-system)	40	n/a	1,896	51.4	2.25	0/0
Wind (off-system)	40	n/a	1,896	51.4	2.25	0/0
Solar (photovoltaic)	5	n/a	6,092	46.8	0.00	5/60

Table 6.11: New Resource Levelized Costs Not Considered in PRS Analysis

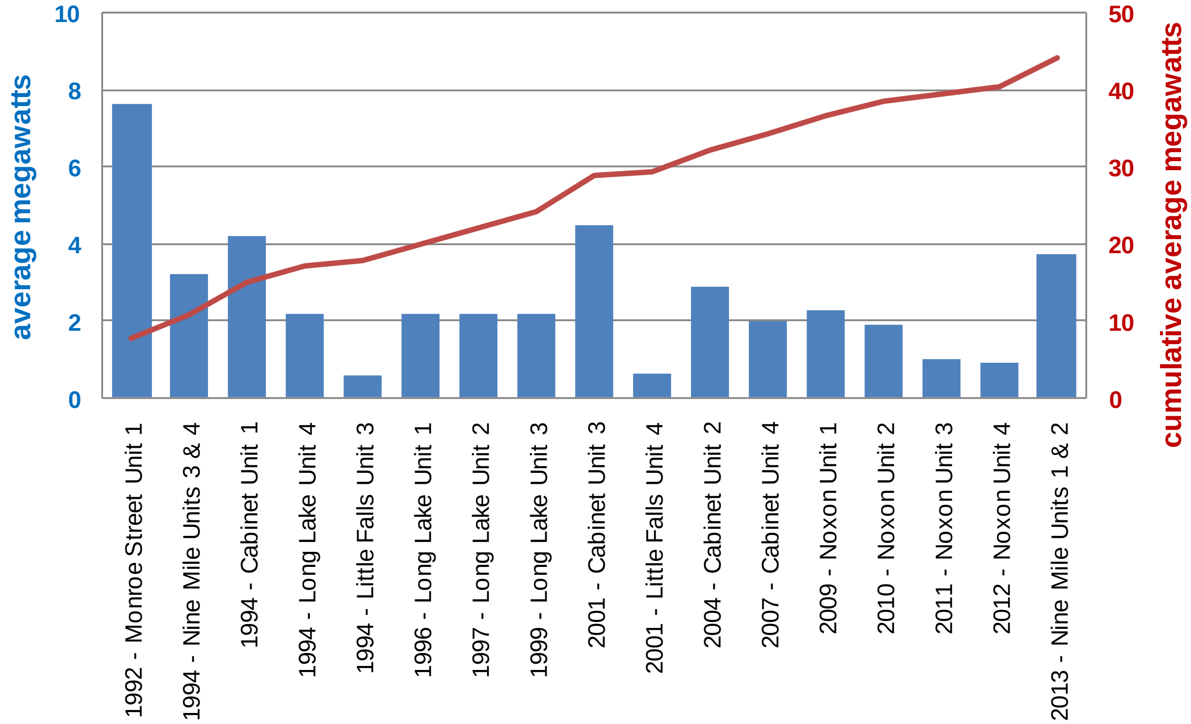
Resource	Size (MW)	Heat Rate (Btu/ kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Peak Credit (Winter/ Summer)
Pulverized Coal	300	8,910	3,583	69.0	3.09	100/100
IGCC Coal	300	8,594	4,001	69.0	7.09	105/95
IGCC Coal w/ Seq.	250	10,652	5,334	69.0	9.56	100/100
Solar (thermal)	25	n/a	5,646	69.0	1.13	5/100
Wind (off-system MT)	40	n/a	1,760	51.4	2.25	0/0
Woody Biomass	25	13,500	4,170	207.0	4.16	100/100
Geothermal	15	n/a	5,017	201.3	5.06	110/90
Landfill Gas	3.2	10,600	2,285	29.9	21.38	100/100
Manure Digester	0.85	10,250	4,862	51.8	27.01	100/100
Wastewater Treatment	0.85	10,250	4,862	46.0	33.76	100/100
Small Co-Generation	5	4,456	3,922	0.0	9.00	104/96
Nuclear	500	10,400	6,522	103.5	1.13	100/100

Hydroelectric Project Upgrades

Avista continues to upgrade many of its hydroelectric facilities. The latest hydroelectric upgrade added nine MW to the Noxon Rapids Development in April 2011. Upgraded Noxon Rapids Unit 4 will enter service in April 2012, and two new units at the Nine Mile project will begin operated in 2013.[3] Figure 6.1 shows the history of upgrades to Avista's hydroelectric system in additional average megawatts by year and cumulatively. Avista will have added 44.1 aMW of incremental hydroelectric energy between 1992 and 2013.

[3] Avista's plan for Nine Mile could change given the recent failure of Unit 4.

Figure 6.2: Historical and Planned Hydro Upgrades



Following upgrades at Nine Mile, Avista expects to pursue annual upgrades to the Little Falls project over a four-year period. The Little Falls upgrades will include new turbine runners, generators, and other electrical equipment. Several other potential hydroelectric upgrades might add capacity and energy at the Long Lake, Cabinet Gorge, Post Falls, and Monroe Street projects. These upgrades are not included in the portfolio analysis and no estimated costs are in this IRP because further study is required. Such studies are part of the IRP's Action Plan. Table 6.8 shows the hydroelectric upgrade studies. Large hydro upgrades can help meet Avista's renewable energy goals under I-937, benefit from federal tax incentives, and help mitigate dissolved gases.

Table 6.12: Hydro Upgrade Potential

Plant	Potential Capacity (MW)	Potential Energy (aMW)
Upper Falls	2	1
Long Lake Second Powerhouse	60 - 120	18 - 20
Cabinet Gorge Second Powerhouse	50	7
Post Falls New Powerhouse	19	4
Monroe Street Second Powerhouse	38	16

Upper Falls
The Upper Falls hydroelectric upgrade would consist of replacing the single unit's turbine runner and modifying the existing draft tube to improve efficiency. Initial costs estimates are $7 million or $3,500 per kW, for an additional two MW of capacity and 8,760 MWh of energy. This upgrade would require FERC licensing changes and help meet Avista's I-937 renewable energy goals.

Long Lake Second Powerhouse
Avista studied a second powerhouse at Long Lake about 20 years ago using a small arch dam located on the south end of the project site. See Figure 6.3 for a concept of the project. The potential cost of this resource could exceed $120 million and provide an additional 158,000 to 178,000 MWh of energy per year and 60 to 120 MW of added capacity. This project would be a major undertaking and would take several years to complete. It would require major changes to the Spokane River license, but could help reduce total dissolved gas concerns by reducing spill at the project. The incremental capacity would also help meet future winter peak loads, but may not contribute greatly to summer peak needs. The incremental energy might qualify under I-937.

Figure 6.3: Long Lake Second Powerhouse Concept Drawing

Cabinet Gorge Second Powerhouse
Avista is exploring the addition of a second powerhouse at the Cabinet Gorge project site to mitigate total dissolved gas. A new powerhouse would benefit from an existing diversion tube around the dam. The potential cost of this resource could be as high as $115 million. The new powerhouse could provide 57,000 MWh of additional energy per year, and 50 MW of additional capacity. This project would be a major engineering

project, take several years to complete, and require major changes to the Clark Fork River FERC license. As with the other potential hydroelectric upgrade projects, this project might help Avista meet its I-937 renewable energy goals.

Post Falls Refurbishment

The Post Falls hydroelectric project is 105 years old. An upgrade to this project includes a total rebuild of the powerhouse and equipment while leaving the exterior intact. The project would remove the existing horizontal units, replacing them with higher efficiency and higher capacity vertical units. The cost of this upgrade could be as high as $75 million. It would add 33,000 MWh of energy each year and provide an additional 19 MW of capacity. Like the other potential hydroelectric projects, this would require a reopening of the Spokane River FERC license and might help meet Avista's I-937 renewable energy goals.

Monroe Street Second Power House

Avista replaced the powerhouse at its Monroe Street project on the Spokane River in 1992. An upgrade option would include the addition of a new powerhouse to capture additional flows and be a major undertaking requiring substantial cooperation with the city because of disruption in the Riverfront Park and downtown Spokane area during construction. This project would require dredging the river on the western edge of the park and creating a tunnel between city hall and the Monroe street substation. The expected cost for this project would be $95 million, and it could create an additional 142,000 MWh of energy per year and 37.5 MW of incremental capacity. The incremental generation of the upgraded facility might help meet Avista's I-937 renewable energy goals.

Thermal Resource Upgrades

Several upgrade opportunities exist in Avista's thermal fleet that would add capacity and/or increase operating efficiency. Avista plans an economic viability study for each option prior to the 2013 IRP. The following is a list of potential upgrades to the Rathdrum and Coyote Springs 2 projects that the Avista may consider. Table 6.9 is a summary of the nominal levelized costs of each of the upgrade options for the Rathdrum CT and Table 6.10 provides nominal levelized costs for the Coyote Springs 2 upgrade options.

Rathdrum CT to CCCT Conversion

The Rathdrum CT has two GE 7EA units in simple cycle configuration built in 1994 with an approximate 160 MW of combined output used to serve customers in peak load conditions. It is possible to convert this peaking facility to a combined cycle plant by adding between 78 and 91 MW of steam-turbine capacity (depending upon temperature) and increasing its operating efficiency from a heat rate of 11,612 Btu/kWh, in its existing configuration, to a heat rate of about 7,986 Btu/kWh. The capital cost for this upgrade is $81.5 million. Two major issues challenge this conversion. The first is cooling water. Avista does not have water rights adequate to cool the plant with water. Therefore, it is likely that air-cooling at the plant is necessary at higher cost. The second major issue is noise. Major residential development now exists at the plant site. Given these concerns, this option is not in the PRS.

Rathdrum CT Water Demineralizer
Another potential upgrade at Rathdrum is to add a water demineralizer to allow inlet fogging in the summer. This upgrade would increase plant capacity by 17.6 MW and increase its operating efficiency by 0.5 percent on hot summer days. The upgrade will cost approximately $1 million.

Table 6.13: Rathdrum CT Upgrade Options ($/MWh)

	Rathdrum CT: Convert to CCCT (Air Cooled)	Rathdrum CT: Convert to CCCT (Water Cooled)	Rathdrum CT: Add De-mineralizer
Capital recovery and taxes	18.62	15.39	4.92
AFUDC	1.94	1.61	0.08
Federal Tax Incentives	0.00	0.00	0.00
Fuel Costs	54.31	53.25	80.89
Fuel Transport	5.53	5.42	8.06
Greenhouse Gas emissions adder	15.19	14.90	22.63
Fixed O&M	2.45	2.45	0.00
Variable O&M	1.62	1.87	1.24
Interconnection capital recovery	0.54	0.54	0.00
Other Emissions	0.00	0.00	0.00
Excise taxes and other overheads	3.45	3.39	4.88
Total Cost	**103.64**	**98.80**	**122.72**

Coyote Springs 2 Inlet Chiller
There are two potential inlet chiller options for increasing summer capacity at the Coyote Springs 2 CCCT plant in Boardman, Oregon. One is to add an inlet chiller to cool the air going into the machine; the second is to add a thermal unit in addition to a chiller to optimize chiller operations. Avista estimates this upgrade to add 30 MW of capacity on a 100-degree day at a cost of $10 million. Adding the thermal storage technology capacity in conjunction with an inlet chiller would increase plant capacity by an additional 2.2 MW for an additional $1.0 million.

Coyote Springs 2 Cold Day Controls
Another upgrade option at the Coyote Springs 2 plant is to install an upgraded CT control system to increase its operating performance on cold days. This software upgrade could increase capacity by 17.6 MW on a zero-degree day at an estimated cost of $4.5 million.

Coyote Springs 2 Advanced Hot Gas Path Components
Coyote Springs 2 could benefit from the installation of advanced hot gas path components. This upgrade could add approximately 8 MW of capacity around the year

and increase efficiency by one percent. The estimated cost for this upgrade is $18 million with additional annual plant maintenance costs of $3.9 million.

Coyote Springs 2 Cooling Optimization Hardware

Adding cooling optimization hardware to Coyote Springs may add 2.6 MW of capacity around the year and improve plant efficiency by 0.5 percent. The estimated cost of this project is $7.2 million.

Table 6.14: Coyote Springs 2 Upgrade Options ($/MWh)

	Inlet Chiller	Inlet Chiller & Thermal Storage	Cold Day Controls	Enhanced Hot Gas Path Comp.	Optional Cooling Package
Capital recovery and taxes	53.23	55.79	20.20	17.41	47.12
AFUDC	0.91	0.95	0.17	0.30	0.80
Federal Tax Incentives	-	-	-	-	-
Fuel Costs	46.42	46.42	46.42	45.91	46.19
Fuel Transport	4.53	4.53	4.53	4.67	4.70
Greenhouse Gas emissions adder	12.99	12.99	12.99	12.84	12.92
Fixed O&M	-	-	-	36.10	-
Variable O&M	-	-	-	-	-
Interconnection capital recovery	4.32	4.32	4.32	4.44	4.44
Other Emissions	-	-	-	-	-
Excise taxes and other overheads	2.95	2.96	2.96	4.50	2.95
Total Cost	**125.35**	**127.96**	**91.60**	**126.18**	**119.13**

7. Market Analysis

Introduction

This section describes the electricity and natural gas market environment developed for the 2011 IRP. Contained in this chapter are risks Avista considers when meeting customer demands at lowest reasonable cost. The analytical foundation for the 2011 IRP is a fundamentals-based electricity model of the entire Western Interconnect. The market analysis compares potential resource options on their net value when operated in the wholesale marketplace, rather than on the simple summation of their installation, operation, maintenance, and fuel costs. The Preferred Resource Strategy (PRS) analysis uses these net values when selecting future resource portfolios.

Understanding market conditions in the 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 values 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, hydroelectric 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.

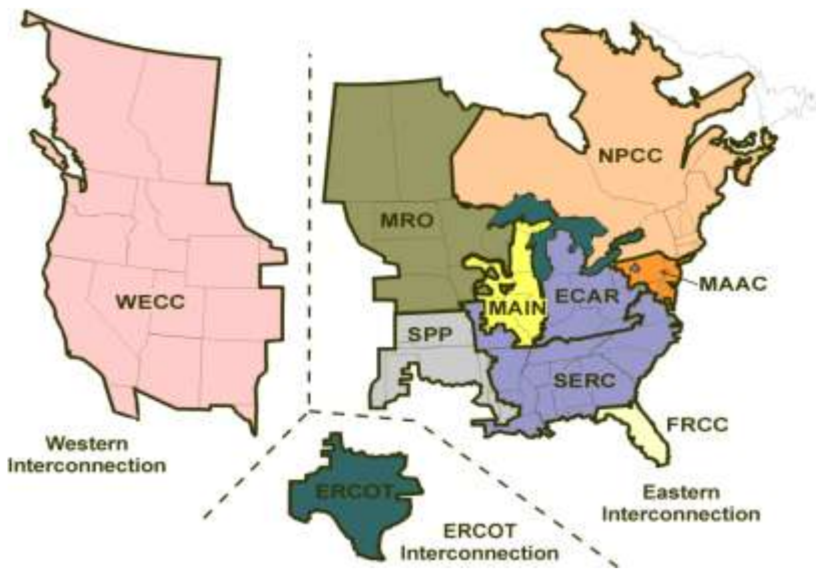
Section Highlights

- Gas and wind resources dominate new generation additions in the West.
- Shale gas lowers IRP gas and electricity price forecasts.
- A growing Northwest wind fleet reduces springtime market prices below zero in some hours.
- Federal greenhouse gas mitigation policy is uncertain; the IRP quantifies this uncertainty by modeling four different mitigation regimes.
- The Expected Case reduces Western Interconnect greenhouse gas emissions by 28 percent (18 percent from current levels) relative to a case without a carbon mitigation regime.
- Carbon mitigation policy increases Western Interconnect costs by $3.5 billion annually.

Marketplace

AURORAxmp is a fundamentals-based modeling tool used by Avista to simulate the Western Interconnect electricity market. 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 240,000 MW, and an average load of approximately half that level.

Figure 7.1: NERC Interconnection Map



The Western Interconnect is separated from interconnects to the east and ERCOT 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 in the 2009 IRP, Avista models the Northwest region as a single zone because this configuration dispatches resources in a manner most reflective of historical operations. Table 7.1 describes the specific zones modeled in this IRP.

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

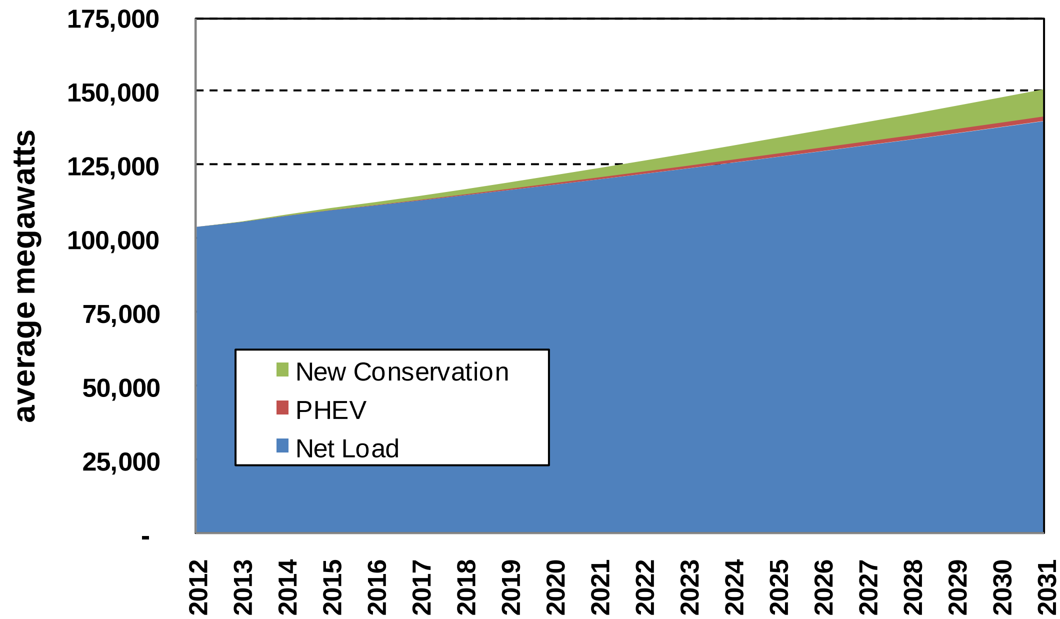
Fundamentals-based electricity models range in their abilities to accurately emulate power system operations. Some models account for every bus and transmission line, while other models utilize regions or zones. An IRP requires regional price and plant dispatch information but does not require detailed modeling at the bus level.

Western Interconnect Loads

The 2011 IRP relies on a load forecast for each zone of the Western Interconnect. Avista uses external sources to quantify load growth estimates across the west. These load estimates include impacts of increasing demand destruction and energy efficiency caused by potential emissions legislation and the associated price increases are expected to reduce loads over time from their present trajectory.

Specific regional load growth levels are presented in Table 7.2. Avista projects that overall Western Interconnect loads rise 1.65 percent annually over the next 20 years, from 103,840 aMW in 2012 to 141,654 aMW in 2031. Included in this forecast are rising plug-in electric vehicle (PHEV) loads. Load growth rates without PHEV would be 1.57 percent. Absent conservation efforts, Western Interconnect loads are 9,000 aMW higher in 2031. Figure 7.2 illustrates the load forecast and the impacts of new conservation and PHEVs. The Northwest grows more slowly than the Western Interconnect at large. Loads rise one percent per year over the IRP timeframe.

Figure 7.2: 20-Year Annual Average Western Interconnect Energy



Transmission

The IRP reflects various regional transmission projects announced over the past several years. Many of these projects move distant renewable resources to load centers in support of state-level renewable portfolio standards (RPS). Transmission upgrades included in the IRP are in Table 7.2. Transmission upgrades within AURORAxmp zones were not included explicitly in the model, as they do not impact power transactions between zones.

Table 7.2: 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	3,000
Eastern Nevada Intertie	North Nevada	South Nevada	2015	1,600
Gateway South	Wyoming	Utah	2015	3,000
Gateway Central	Idaho	Utah	2015	1,320
Gateway West	Wyoming	Idaho	2016	1,500
SunZia/Navajo Transmission	Arizona	New Mexico	2016	3,000
Wyoming – Colorado Intertie	Wyoming	Colorado	2013	900
Hemingway to Boardman	Idaho	Northwest	2019	1,500

New Resource Additions

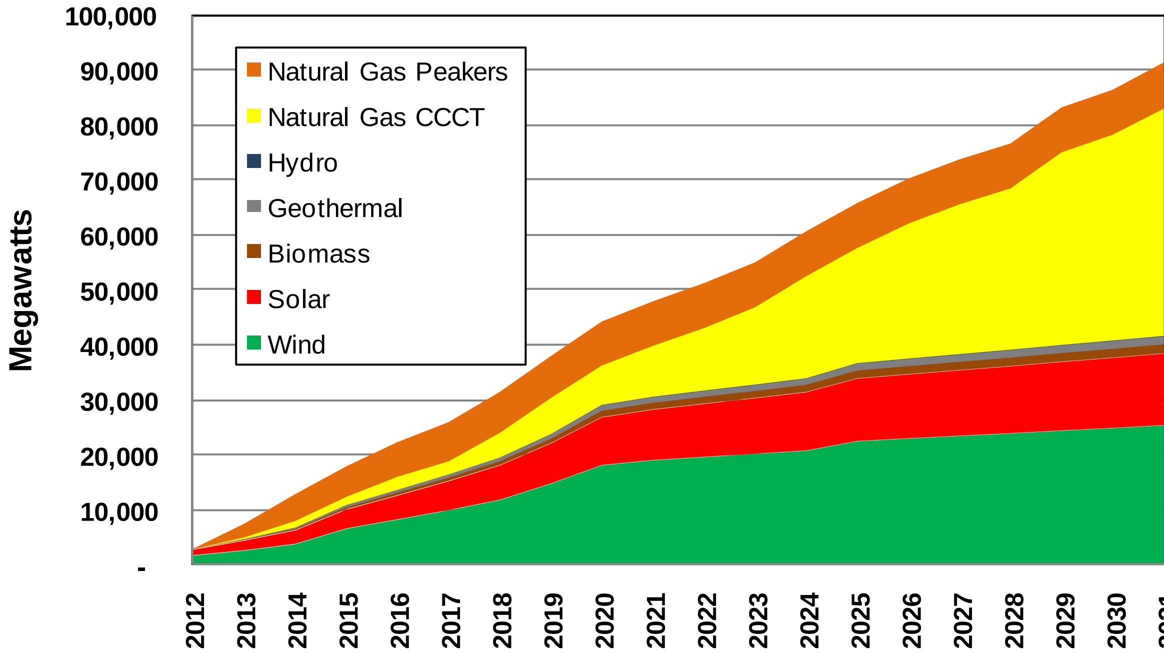
An estimate for new resource capacity in the Western Interconnect id made as part of the long-term electric market price forecast. It accounts for load growth and various other mandates. These additions meet capacity, energy, ancillary services, and renewable portfolio mandates. To meet capacity requirements, gas-fired CCCT or SCCT, solar, wind, coal IGCC, coal IGCC with sequestration, and nuclear were options were considered.[1] For the first time, Avista assumes that no new pulverized coal additions in the Western Interconnect over the forecast horizon.

Many states have created RPS requirements promoting renewable generation to curb greenhouse gas emissions, provide jobs, and to diversify the energy mix of the United States. RPS legislation generally requires utilities to meet a portion of their load with qualified renewable resources. No federal RPS mandate exists presently; therefore, each state defines their RPS obligations differently. AURORAxmp cannot model RPS levels explicitly. Instead, Avista input RPS requirements into the model at levels satisfying state laws. Renewable resource portfolios adequate to meet Western Interconnect RPS obligations were input using work by the Northwest Power and Conservation Council (NPCC); these percentages formed the basis for RPS shortfalls in each state. Beyond the manually input RPS resources, the model selected no additional renewables.

Figure 7.3 illustrates new capacity and RPS additions made in the modeling process. Most renewable energy requirements are met by wind and solar facilities. Geothermal, biomass, and hydroelectric resources provide a more limited contribution to RPS needs. Renewable resource choices are modeled to differ by state depending on the requirements of state laws and the availability of renewable resources in a region. For example, the Southwest will meet RPS requirements with solar and wind given policy choices by those states; the Northwest will use a combination of wind and hydroelectric upgrades because the economic costs of these resources are lowest; and the Rocky Mountain states will predominately use wind to meet RPS requirements, again due to the fact that wind is the least-cost renewable resource modeled in the IRP.

[1] Wind receives a five percent capacity credit on a regional basis; it receives no capacity credit where selected to meet Avista requirements.

Figure 7.3: New Resource Added (Nameplate Capacity)



Fuel Prices and Conditions

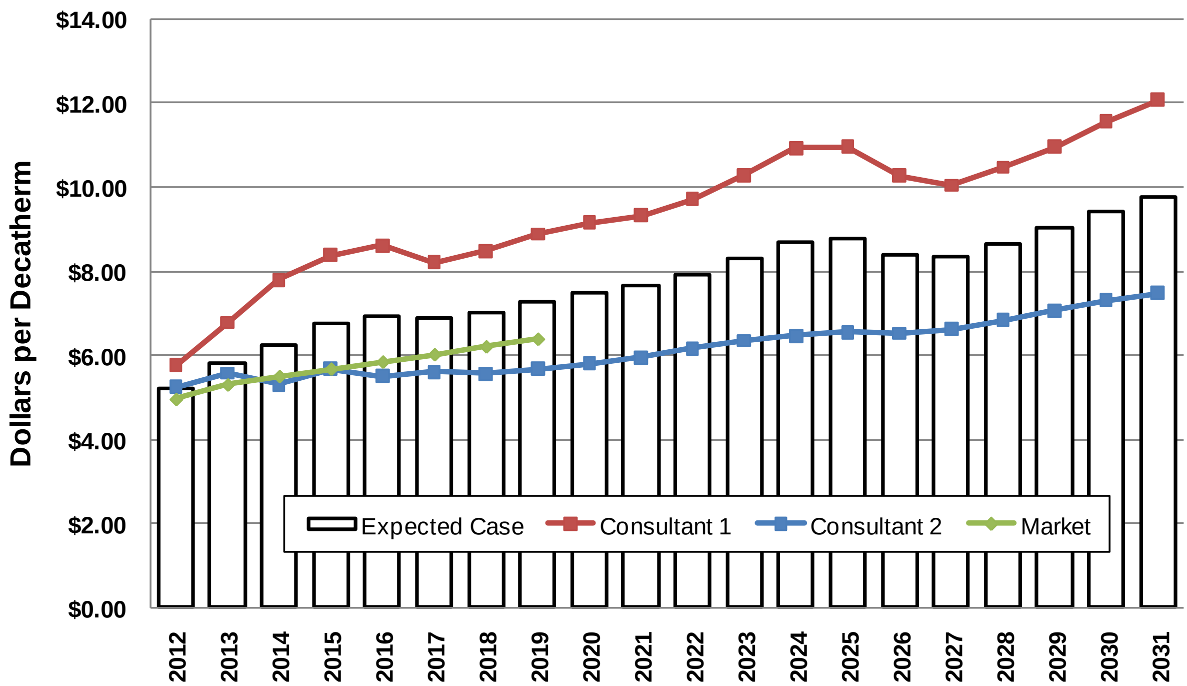
Fuel cost and availability are some of the most important drivers of resource values. Some resources, including geothermal and biomass, have limited fuel options or sources, while coal and natural gas have more fuel sources. Hydro and wind use free fuel sources, but are highly dependent on weather.

Natural Gas

The fuel of choice for new base load and peaking capability continues to be natural gas. Natural gas suffers due to price volatility, though increasing unconventional sources may reduce future volatility. Avista uses forward market prices and a combination of two forecasts from prominent energy industry consultant to develop its natural gas price forecast for this IRP.[2] The forecast uses an equal weighting of the consultant forecasts and forward prices in 2012.[3] After 2012, the weighting of forward prices fell by 10 percent each year through 2016. After 2016, the forecast includes a 50/50 weighting of the two consultant forecasts. For example, in 2015 the price forecast is a weighted average of the market (20 percent), Consultant 1 (40 percent) and Consultant 2 (40 percent). The long-term forecasts include impacts of potential national carbon legislation. Carbon legislation will increase demand for natural gas as generation shifts away from coal. Figure 7.4 shows the price forecast for Henry Hub; the levelized nominal price is $7.30 per Dth. The forecast without carbon legislation is $6.78 per Dth.

[2] Consultant forecasts as of December 2010.
[3] The 50% weighting applies to the average of the two consultant forecasts.

Figure 7.4: Henry Hub Natural Gas Price Forecast



The forecast from Consultant 1 assumes a timely and moderate economic recovery and aggressive long term demand growth from the power sector in part due to an improved competitive position relative to coal. The forecast includes a modest federal carbon price of $14 per metric ton beginning 2016 and rising to $25/metric ton by 2025. This in turn results in accelerated coal retirements pressuring prices early in the forecast. A brief price respite occurs following carbon legislation but prices resume their build as competition for capital, equipment and labor from strong recovery in oil demand drive up gas drilling costs and supply growth from shale gas moderates. An Alaskan gas pipeline around 2026 produces a brief gas glut but is quickly absorbed and the uptrend in prices resumes.

The forecast from consultant 2 assumes a more gradual and modest economic recovery including a more moderate rebound in power demand early in the forecast. Their outlook reflects an expectation of significant low cost supplies from shale gas resources that quickly respond to rising demand. The improved predictability of shale gas volumes and costs prompt active hedging by producers when prices escalate counteracting the trend and resulting in more stable pricing. This forecast does not include carbon legislation or an Alaskan natural gas pipeline.

Price differences across North America depend on demand at the trading hubs and the pipeline constraints between them. Many pipeline projects are in the works in the Northwest and the west to access historically cheaper gas supplies located in the Rocky

Mountains. Table 7.3 presents western gas basin differentials from Henry Hub prices. 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, monthly Stanfield price shapes in Table 7.4 show various forecast years.

Table 7.3: Natural Gas Price Basin Differentials from Henry Hub

Basin	2012	2015	2020	2025	2030
Stanfield	93.4%	94.4%	90.3%	92.6%	90.6%
Malin	94.7%	95.7%	92.5%	94.9%	92.9%
Sumas	93.7%	94.6%	88.5%	90.5%	88.3%
AECO	89.1%	90.6%	86.3%	88.1%	85.8%
Rockies	93.6%	94.9%	90.6%	89.4%	87.2%
Southern CA	97.5%	99.3%	99.3%	100.0%	102.7%
Stanfield	93.4%	94.4%	90.3%	92.6%	90.6%

Table 7.4: Monthly Price Differentials for Stanfield

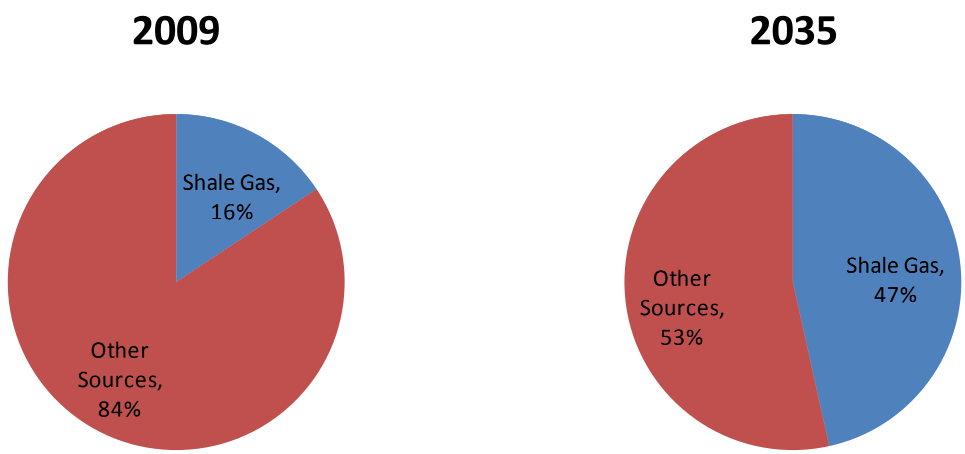
Month	2012	2015	2020	2025	2030
Jan	94.4%	95.9%	92.2%	94.7%	92.5%
Feb	94.4%	96.1%	92.0%	94.7%	92.5%
Mar	94.0%	95.6%	92.0%	94.3%	93.9%
Apr	92.6%	94.1%	89.4%	91.3%	90.0%
May	92.2%	93.1%	88.2%	90.4%	88.8%
Jun	92.3%	93.1%	88.2%	90.5%	88.5%
Jul	92.6%	92.9%	87.8%	90.0%	88.0%
Aug	92.7%	93.1%	88.0%	90.0%	88.3%
Sep	93.0%	93.9%	89.7%	92.1%	89.2%
Oct	93.3%	94.8%	90.6%	93.6%	90.4%
Nov	94.4%	95.0%	92.5%	95.3%	92.7%
Dec	94.9%	95.0%	92.7%	94.9%	92.5%

Unconventional Natural Gas Supplies

Shale natural gas production has game-changing impacts on the natural gas industry, dramatically revising the amount of economical natural gas production. Shale gas often is lower in cost than conventional natural gas production. This is achieved primarily as a result of economies of scale, near elimination of exploration risks and standardized, sophisticated production techniques that streamline costs and minimize the time from drilling to market delivery. Shale gas could continue to greatly alter the natural gas marketplace, holding down both price and volatility over the long run as production quickly responds to changing market conditions. This in turn leads to numerous ripple effects, including longer-term bilateral hedging transactions, new financing structures including cost index pricing, and/or vertical integration by utilities choosing to limit their exposure to natural gas price increases and volatility through the acquisition of shale-gas reserves as illustrated by the recent purchase of reserves by Northwest Natural

Gas Company. See Figure 7.5 for the projected change in contribution of shale to other sources of natural gas between 2009 and 2035.

Figure 7.5: Shale Gas Production Forecast[4]



Shale gas is not free of controversy. Concerns include water, air, noise, and seismic environmental impacts arising from unconventional extraction techniques. Water issues include availability, chemical mixing, groundwater contamination, and disposal. Air quality concerns stem from methane leaks during production and processing. Mitigating excessive noise in urban drilling and elevated seismic activity near drilling sites are also fomenting apprehension. State and federal agencies are reviewing the environmental impacts of this new production method. As a result, unconventional natural gas production in some areas has stopped. Increased environmental protections might increase costs and environmental uncertainty could precipitate increased price volatility.

Shale gas production influences the U.S. liquid natural gas (LNG) market. It has broken the link between North American natural gas global LNG prices. Numerous planned re-gasification terminals are on hold or cancelled. Some facilities now seek approvals to become LNG exporters rather than importers. These changes appear to down affect gas storage and transportation infrastructure. For example, the Kitimat LNG export terminal in northern British Columbia, if built, will export significant LNG quantities to Asian markets. These exports will affect overall market conditions for natural gas in the United States and the Pacific Northwest.

Coal

As discussed earlier in this chapter, there are no new coal plants built for the Western Interconnect. Therefore, the coal price forecasts affect only existing coal facilities. Each plant's historical fuel costs escalate by rates contained in a consultant's study. The average annual price increase over the IRP timeframe is 1.4 percent. For the Colstrip facility, where Avista has access to project-specific information, Avista did not rely on the consultant study. Instead, it used an escalation rate based on existing contracts.

[4] Source: Energy Information Administration (EIA)

Woody Biomass

The future price and availability of woody biomass (or hog fuel) is critical to understanding the viability of new wood-fired facilities. Hog fuel availability is highly dependent on overall lumber demand. Avista has operated its Kettle Falls wood-fired generator since 1983. When it was constructed, hog fuel was a waste product from area sawmills that procured at a near-zero cost. The plant had surplus fuel even into the mid-2000s, but has struggled since then to procure enough reasonably priced fuel because of the impacts of a recession on the housing market, and the resultant decrease in lumber demand. The IRP projects biomass prices in the west to extend from historical levels at a rate of three percent per year to reflect ongoing tight market conditions.

Hydroelectric

The Northwest and British Columbia have substantial hydroelectric generation capacity. A favorable characteristic of hydroelectric power is its ability to provide near-instantaneous generation up to and potentially beyond its nameplate rating. 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 variable generation resources. The key drawback to hydroelectricity is its output variability a month-to-month and year-to-year.

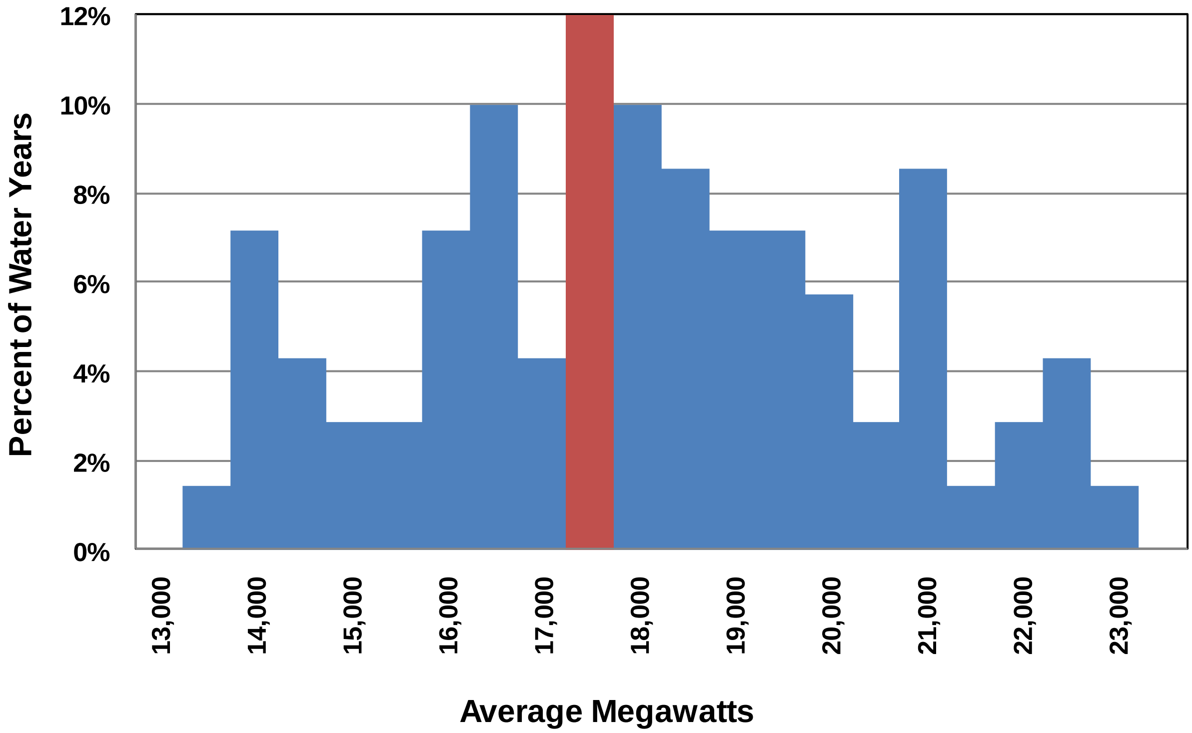
This IRP uses the results of the Northwest Power Pool's (NWPP) 2009-10 Headwater Benefits Study to model regional hydro availability. The NWPP study provides energy levels for each hydroelectric facility by month over a 70-year hydrological record spanning the years 1928 to 1999. British Columbia's hydroelectric plants are modeled using data from the Canadian government[5].

Many of the analyses in the 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), as the historical distribution of hydroelectric generation is not normally distributed. AURORAxmp maps each hydroelectric plant to a load zone.

For Avista hydroelectric plants, proprietary software provides a more detailed representation of operating characteristics and capabilities. Figure 7.6 shows average hydroelectric energy (in red) of 18,172 aMW in Washington, Oregon, Idaho, Western Montana, and British Columbia. The chart also show the range in potential energy used in the stochastic study, with a 10th percentile water year of 14,395 aMW (-21 percent), and a 90th percentile water year of 21,629 aMW (+40 percent).

[5] Statistics Canada, www.statcan.gc.ca

Figure 7.6: Northwest Expected Energy

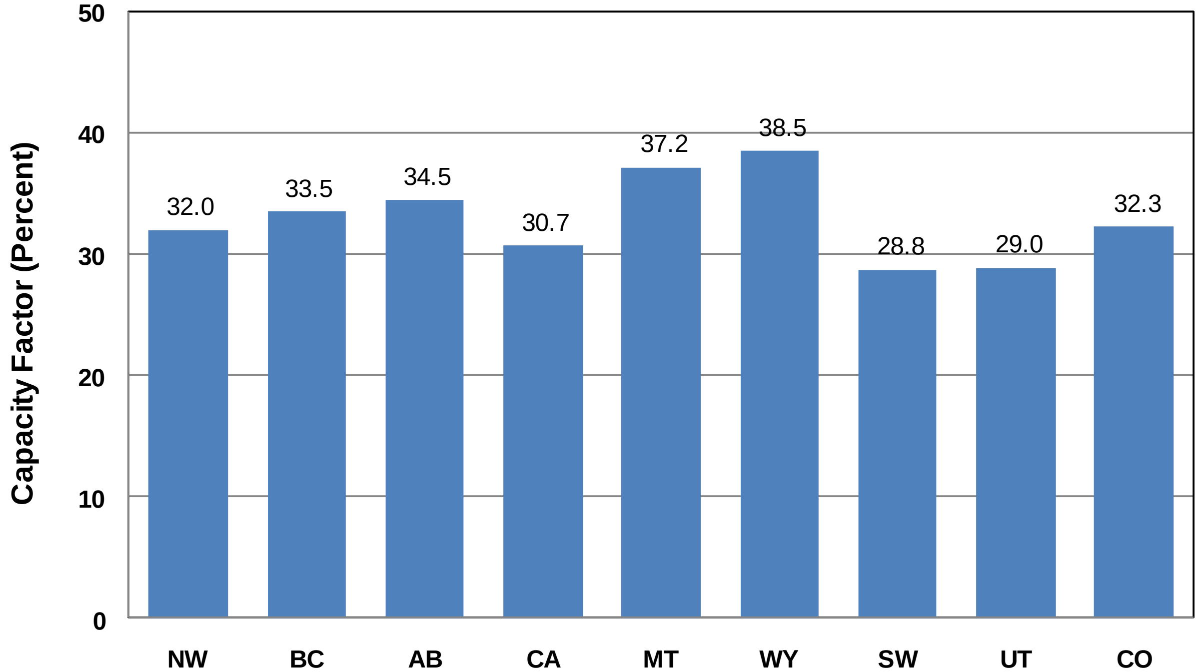


AURORAxmp represents hydroelectric plants using annual and monthly capacity factors, minimum and maximum generation levels, and sustained peaking generation capabilities. The model's objective, subject to constraints, is to move hydroelectric generation into peak hours to follow daily load changes; this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

Wind

Additional wind resources are necessary to satisfy renewable portfolio standards. These additions mean significant competition for the remaining higher-quality wind sites. The capacity factors in Figure 7.7 present average generation for the entire area, not for specific projects. The IRP uses capacity factors from a review of the Bonneville Power Administration (BPA) and the National Renewable Energy Laboratory (NREL) data.

Figure 7.7: Regional Wind Expected Capacity Factors



Greenhouse Gas Emissions

Greenhouse gas legislation is one the greatest fundamental risks facing the electricity marketplace today because of the industry's heavy reliance on carbon-emitting thermal power generation plants. Reducing carbon emissions at existing power plants, and the construction of low- and non-carbon-emitting technologies, changes the resource mix over time. No federal regulations presently constrain greenhouse emissions, but federal legislation in the next few years is expected. In the interim, several western states and Canadian provinces are promoting the Western Climate Initiative as an alternative to federal legislation. The goal is to develop a multi-jurisdictional greenhouse gas policy.

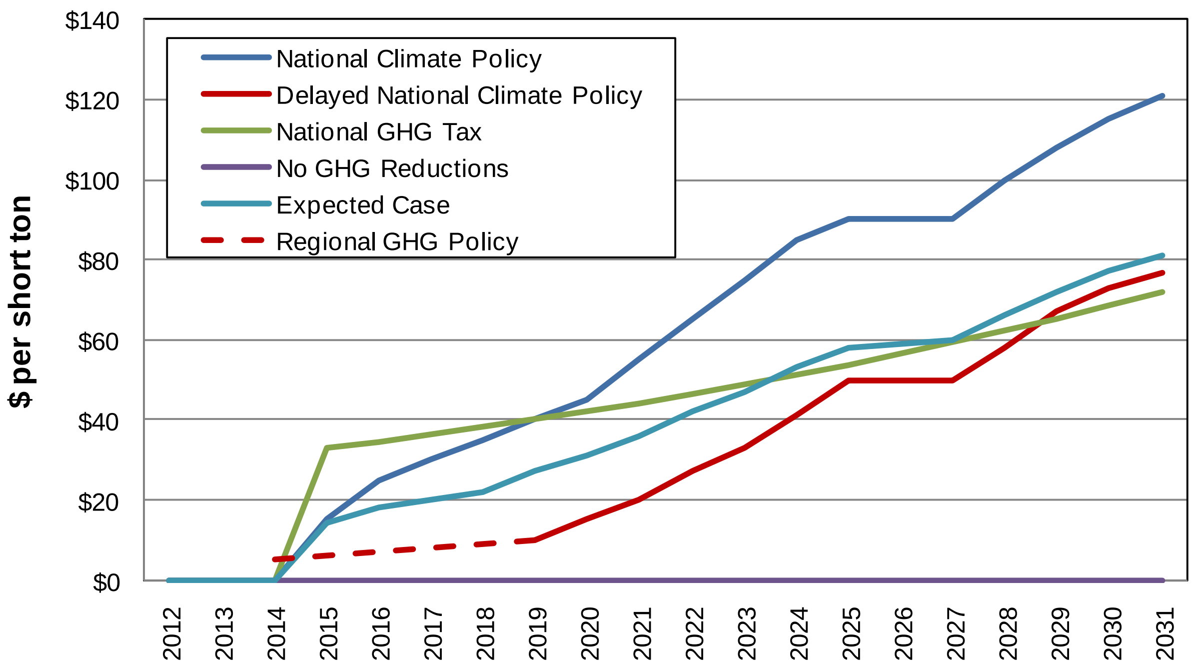
To simulate greenhouse gas regulation, Avista developed four policy models and their assumed financial impact on the energy marketplace. Each policy represents a potential path governments could take over the next several years. The policies received weighting factors, with the weighted average price of the policies forming the Expected Case. The four greenhouse gas policies used in this IRP are in Table 7.5:

Table 7.5: Monthly Price Differentials for Stanfield

Strategy	Weight (%)	Details
Regional Greenhouse Gas Policies	30	– State-level greenhouse gas reductions in California, Oregon, Washington, and New Mexico between 2014 and 2019. – About a 10 percent reduction below 2005 levels by 2020. – Beginning in 2020, shift to National Climate Policy with 15 percent below 2005 levels by 2030.
National Climate Policy	30	– Federal legislation only applies beginning in 2015 – About 15 percent below 2005 levels by 2020 and about 35 percent below 2005 levels by 2030.
National Carbon Tax	30	– Federal legislation only applies. – $33 per short ton, then 5 percent per year escalation for the remainder of the study. – Begins in 2015.
No Greenhouse Gas Reductions	10	– No carbon reduction program. – State-level emission performance standards apply and no new coal-plants are added in the Western United States.

Figure 7.8 shows the expected price of greenhouse gas emission for each policy described in Table 7.5 and the weighted average price comprising of the Expected Case. The carbon policy in each stochastic study comes from the distribution of the four cases described above.

Figure 7.8: Price of Greenhouse Gas Credits in each Carbon Policy



Risk Analysis

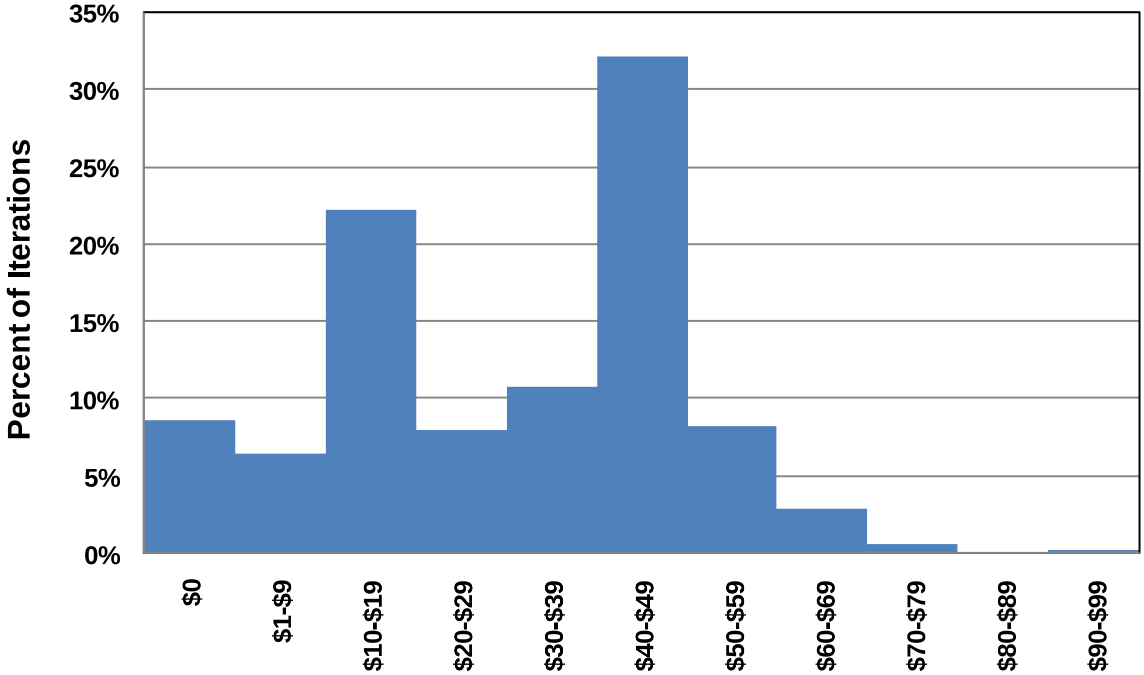
To account for the uncertainty of future electric prices, a stochastic study is preformed using the variables discussed earlier in this chapter. It is better to represent the electricity price forecast as a range rather than a point estimate. Point estimates are unlikely to forecast any of the underlying assumptions perfectly, whereas stochastic price forecasts develop a more robust resource strategy. For example, fuel price volatility and carbon risk directly affect natural gas-fired resources but not wind resources. Wind resources, on the other hand, are subject to varying output on an hourly, daily, monthly, and annual basis. In prior IRP's Avista modeled 250 to 300 stochastic iterations or scenarios. This IRP developed 500 iterations to provide a more robust results distribution to better illustrate potential tail outcomes. The increased number of studies will affect the overall results of the IRP, but should assist in explaining the results better, especially at the tails. The next several pages discuss input variables driving market prices, and describe the methodology and the range in inputs used in the modeling process.

Greenhouse Gas Prices

Without established federal legislation and no formal rules for western carbon markets, the expected price of carbon emission is difficult to determine without resorting to a macroeconomic model. Even with carbon rules in place, prices in a cap and trade program reflect the tradeoff and interaction between natural gas and coal prices and the ultimate maximum emissions level allowed by the program. Further, is it is likely that certain states might stop pursuing cap and trade programs because of recent successes in shutting down northwest coal-fired facilitates. As discussed earlier, four possible legislative outcomes reflect the uncertainty surrounding future legislation. Each was included in the stochastic analysis based on its weighting.

The price of carbon mitigation will vary over time, as the natural gas price affects the cost efficiency of displacing coal-fired generation. When natural gas prices rise, so too must carbon prices. To account for this relationship, once the carbon policy is randomly selected based for each scenario the resultant carbon price is adjusted up or down to reflect the natural gas price forecast in a manner to attain the required carbon mitigation goal. An example of this adjustment is in Figure 7.9 for the year 2020. The predominant market prices are between $40 and $49 per short ton of carbon. The distribution reflected the Carbon Tax policy strategy by approximately 100 of these iterations has a price of $42.12 per short ton of carbon.

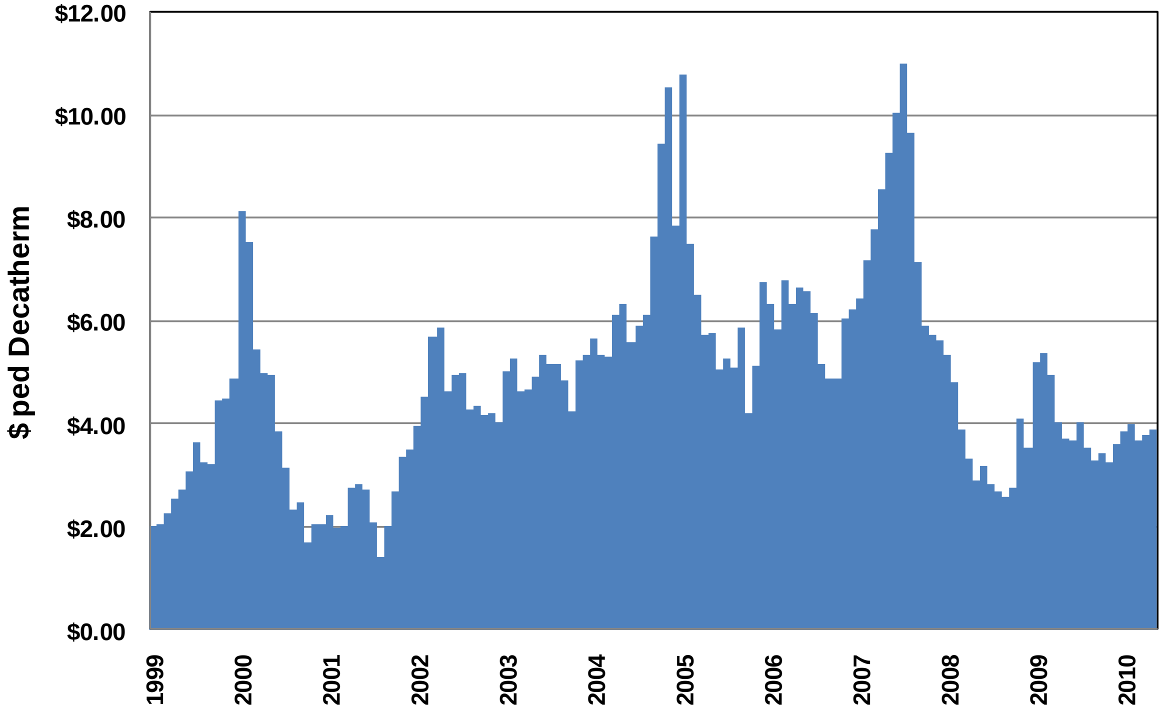
Figure 7.9: Distribution of Annual Average Carbon Prices for 2020



Natural Gas

Natural gas prices are among the most highly volatile of any traded commodity. Daily AECO prices ranged between $0.78 and $12.92 per Dth between 2002 and 2010. Average AECO monthly prices since December 1999 are in Figure 7.10. Prices retreated from their 2008 highs to a low of $2.69 per Dth in July 2009, but prices have stabilized in the $3 to $4 range over the past year. This stabilization likely is a result of both waning demand due to the U.S. recession and shale gas discoveries.

Figure 7.10: Historical AECO Natural Gas Prices



There are several valid methods to stochastically model natural gas prices. For this IRP, Avista uses a new method to represent the price history our industry has witnessed. The mean prices discussed above are the starting point. Prices then vary using historical month-to-month volatility using a lognormal distribution. The lognormal distribution's standard deviation differs monthly depending on historical month-to-month changes.

The Stanfield hub natural gas price distribution is in Figure 7.11 for 2012, 2020, and 2030. Mean prices in 2012 are $4.89 per Dth and the median level is $4.80 per Dth. The 90th percentile is $5.49 per Dth and the TailVar90, or average of the highest 10 percent of the iterations, is $5.92 per Dth. Figure 7.12 illustrates the range of gas prices for each year of the price forecast. Stanfield prices are black bars; white bars represent the range between the 10th and 90th percentiles; triangles represent TailVar90.

Figure 7.11: Stanfield Annual Average Natural Gas Price Distribution

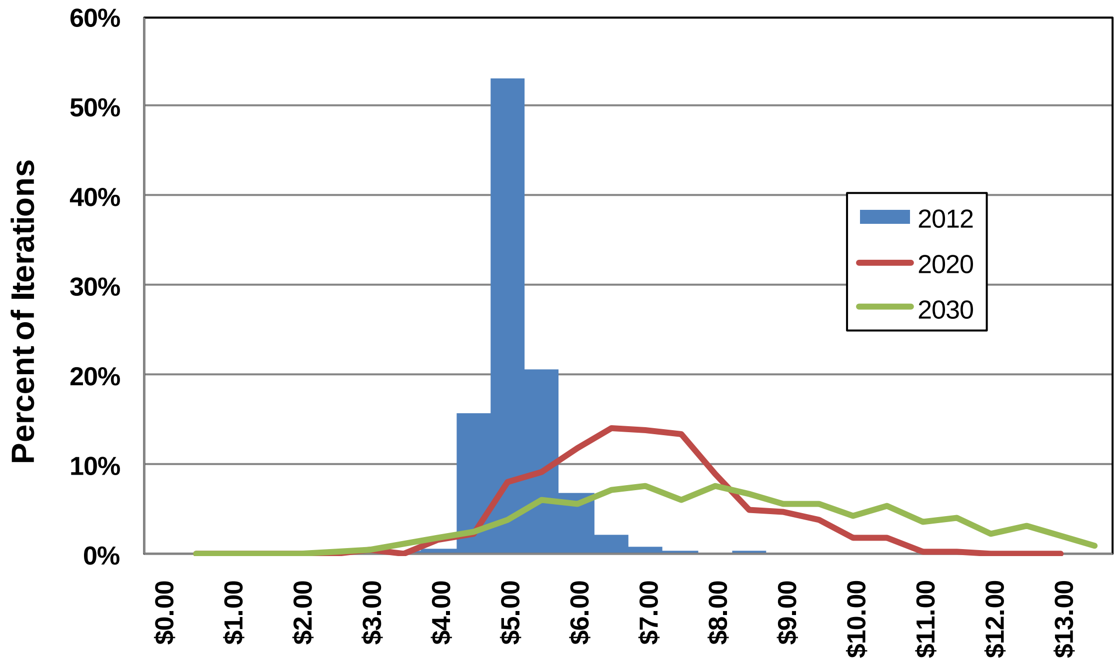
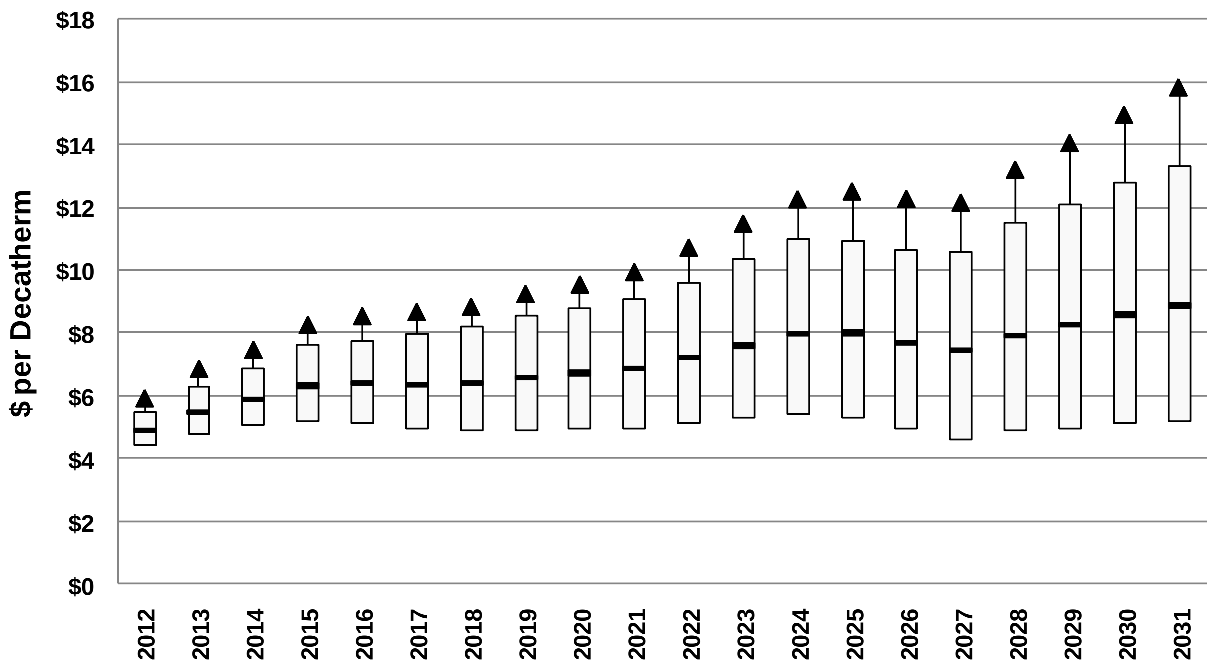


Figure 7.12: Stanfield Natural Gas Distributions



Load

Several factors drive load uncertainty. The largest short-run driver run is weather. Over the long-run economic conditions, such as the recent economic downturn, tend to have a more significant effect on the load forecast. Underlying IRP loads increase at the levels discussed earlier in this chapter, but risk analyses emulate the varying of weather conditions and resultant load impacts.

To model weather variation, Avista continues to use a method it adopted for its 2003 IRP. FERC Form 714 data for the years 2005 through 2009 for the Western Interconnect form the basis for the analysis. Correlations between the Northwest and other Western Interconnect load areas represent how loads move across the larger system. This method avoids oversimplifying the Western Interconnect load picture. Absent the use of correlation, stochastic models merely offset changes in one variable with changes in another, thereby virtually eliminating the possibility of modeling correlated excursions. Given the high degree of interdependency across the Western Interconnect created by significant intertie connections, the additional accuracy in modeling loads in this matter is crucial for understanding variation in wholesale electricity market prices. It is also crucial for understanding the value of resources used to meet variation (i.e., peaking generation).

Tables 7.6 and 7.7 present the load correlations. Statistics are relative to the Northwest load area (Oregon, Washington, and North Idaho). “NotSig” in the table indicates that no statistically valid correlation exists in the evaluated load data. “Mix” indicates the relationship was not consistent across the 2005 to 2009 period. For regions and periods with NotSig and Mix results, no correlation exists. Tables 7.8 and 7.9 provide the coefficient of determination (standard deviation divided by the average) values for each zone. The weather adjustments are consistent for each area, except for shoulder months where loads tend to diverge from one another.

Table 7.6: January through June Area Correlations

	Jan	Feb	Mar	Apr	May	Jun
Alberta	74%	29%	70%	64%	18%	65%
Arizona	73%	75%	74%	8%	Not Sig	8%
Avista	90%	87%	82%	80%	60%	42%
British Columbia	84%	84%	75%	46%	Not Sig	Mix
Colorado	Mix	Mix	Mix	Mix	Not Sig	Not Sig
Montana	82%	76%	69%	55%	33%	28%
New Mexico	8%	Not Sig	Not Sig	Not Sig	16%	Not Sig
North California	34%	36%	8%	Not Sig	34%	8%
North Nevada	73%	65%	Not Sig	8%	25%	27%
South California	74%	45%	69%	31%	10%	44%
South Idaho	87%	86%	65%	40%	66%	28%
South Nevada	67%	83%	37%	Not Sig	Mix	16%
Utah	25%	Not Sig	8%	Not Sig	17%	Not Sig
Wyoming	67%	54%	72%	36%	41%	18%

Table 7.7: July through December Area Correlations

	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	39%	45%	68%	55%	66%	66%
Arizona	9%	26%	9%	Mix	Mix	55%
Avista	60%	54%	19%	78%	88%	89%
British Columbia	8%	Mix	Mix	9%	72%	77%
Colorado	Mix	Mix	Mix	54%	71%	49%
Montana	Mix	Not Sig	27%	53%	81%	86%
New Mexico	25%	27%	43%	17%	35%	Not Sig
North California	Not Sig	Mix	63%	Not Sig	26%	25%
North Nevada	29%	48%	Not Sig	8%	74%	67%
South California	26%	27%	18%	Not Sig	Mix	54%
South Idaho	44%	47%	Not Sig	46%	84%	83%
South Nevada	16%	18%	Not Sig	Mix	Mix	64%
Utah	Not Sig	16%	42%	27%	53%	17%
Wyoming	8%	9%	9%	8%	Not Sig	53%

Table 7.8: Area Load Coefficient of Determination (Std Dev/Mean)

	Jan	Feb	Mar	Apr	May	Jun
Alberta	2.7%	2.4%	2.8%	2.6%	2.9%	3.2%
Arizona	5.5%	4.2%	3.4%	6.1%	10.2%	9.5%
Avista	6.7%	5.3%	6.3%	5.6%	5.3%	6.4%
Baja Mexico	9.5%	7.9%	8.5%	9.2%	10.5%	7.6%
British Columbia	5.0%	3.9%	4.5%	5.2%	4.6%	4.0%
North California	5.1%	5.1%	5.0%	5.6%	8.7%	9.5%
Colorado	4.5%	4.2%	4.6%	4.0%	5.4%	8.4%
South Idaho	5.4%	5.7%	5.4%	6.0%	10.2%	13.9%
Montana	5.3%	4.1%	4.0%	4.4%	4.0%	5.9%
Northern Nevada	2.6%	3.0%	2.9%	2.8%	4.8%	5.7%
Southern Nevada	4.8%	3.6%	3.3%	6.6%	13.0%	11.2%
New Mexico	4.5%	4.1%	4.3%	4.5%	7.4%	6.9%
Pacific Northwest	6.6%	5.9%	5.9%	5.7%	4.9%	4.9%
South California	6.0%	5.6%	6.0%	7.0%	8.6%	8.8%
Utah	4.1%	4.3%	4.5%	4.4%	6.3%	9.0%
Wyoming	7.0%	6.7%	6.5%	5.9%	5.0%	8.3%

Table 7.9: Area Load Coefficient of Determination (Std Dev/Mean)

	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	3.1%	3.2%	2.8%	2.7%	2.6%	3.3%
Arizona	7.0%	6.5%	8.4%	10.0%	4.7%	5.3%
Avista	6.9%	7.2%	5.8%	5.4%	6.6%	7.6%
Baja Mexico	6.4%	6.3%	11.6%	9.9%	7.6%	10.2%
British Columbia	4.7%	4.1%	4.4%	5.0%	6.2%	6.2%
North California	9.6%	7.9%	8.4%	5.3%	5.6%	5.6%
Colorado	7.2%	6.8%	5.8%	4.0%	5.1%	5.0%
South Idaho	5.9%	6.9%	10.5%	4.7%	6.8%	7.1%
Montana	5.1%	5.6%	3.7%	4.0%	5.0%	5.7%
Northern Nevada	5.1%	4.2%	4.9%	2.7%	3.6%	3.5%
Southern Nevada	6.9%	6.3%	12.0%	7.8%	3.8%	4.4%
New Mexico	6.0%	5.7%	5.8%	5.3%	5.0%	4.9%
Pacific Northwest	6.5%	5.2%	4.6%	5.3%	7.0%	8.6%
South California	7.7%	7.8%	10.3%	7.4%	6.8%	6.4%
Utah	5.1%	6.2%	6.7%	4.1%	4.9%	4.4%
Wyoming	8.3%	9.1%	6.1%	5.3%	7.1%	7.6%

Hydroelectric

Hydroelectric generation is historically the most commonly modeled stochastic variable in the Northwest because it has a large impact on regional electricity prices. The IRP uses a 70-year hydro record starting with the 1928-29 water year. A randomly drawn water year is selected from the record using a “bootstrapping” method, meaning that each water year is used approximately 143 times in the study (500 scenarios x 20 years / 70 water year records). There is some debate in the Northwest over whether the hydroelectric record has year-to-year correlation. Avista’s preliminary work in this area has not found significant year-over-year correlation; the 70-year water record shows a modest 41 percent correlation. Low correlation does not necessarily mean that the correlation is zero. Further study of year-to-year correlation is an action item coming out of this planning cycle.

Wind

Wind has the most volatile short-term generation profile of any resource presently available to utilities. Storage, apart from some integration with hydroelectric projects, is not a financially viable. This makes it necessary to capture wind volatility in the power supply model to determine its value and impacts on the wholesale power markets. Accurately modeling wind resources requires hourly and intra-hour generation shapes. For regional market modeling, the representation is similar to how AURORAxmp models hydroelectric resources. A single wind generation shape represents all wind resources in each load area. This shape is smoother than it would be for individual wind plant, but it closely represents the diversity that a large number of wind farms located across a zone would create.

This simplified wind methodology works well for forecasting electricity prices across a large market, but it does not accurately represent the volatility of specific wind resources Avista might select as part of its Preferred Resource Strategy. Therefore individual wind farm shapes form the basis of resource options for Avista.

Ten potential 8,760-hour wind shapes represent each geographic region or facility. Each year contains a wind shape drawn from the ten representations, as is done with the hydro record. The IRP relies on two data sources for the wind shapes. The first is BPA balancing area wind data. The second is NREL-modeled data between 2004 and 2006.

Avista believes that an accurate representation of a wind shape across the West requires meeting several conditions:

1. The data is correlated between areas and reflective of history.
2. Data within load areas needs to be auto-correlated (each hour correlated to each other).
3. The average and standard deviation of each load area’s wind capacity factor needs to be consistent with the expected amount of energy for a particular area in the year and in each month.

4. The relationship between on- and off-peak wind energy needs to be consistent with historic wind conditions. For example, more energy in off-peak hours than on-peak hours where this has been experience historically.
5. Capacity factors for a diversified wind region should never be greater than about 90 percent due to turbine outages and wind diversity within-area.

Absent meeting these conditions, it is unlikely that any wind study provides an adequate level of accuracy for planning efforts. The methodology developed for this IRP attempts to keep the five requirements by first using a regression model of the historic data for each region. The independent variables used in the analysis were: month, hour type (night or day), and the generation levels from the prior two hours. To reflect correlation between regions, a capacity factor adjustment reflects historic regional correlation using an assumed normal distribution with the historic correlation as the mean. After this adjustment, a capacity factor adjustment takes account of those hours with generation levels exceeding a 90 percent capacity factor. The resulting capacity factors for each region are in Table 7.10. An example of an 8,760-hour wind generation profile is in Figure 7.13 for the Northwest region. This example, shown in blue, has a 33 percent capacity factor. Figure 7.14 shows the actual 2010 generation as recorded by BPA Transmission; in 2010 the average wind fleet in BPA's balancing authority had a 27.5 percent capacity factor.

Table 7.10: Expected Capacity factor by Region

Area	Capacity Factor	Area	Capacity Factor
Northwest	32.0%	Southwest	28.9%
California	30.9%	Utah	28.8%
Montana	37.2%	Colorado	32.2%
Wyoming	38.5%	British Columbia	33.4%
Eastern Washington	30.7%	Alberta	34.5%

Figure 7.13: Wind Model Output for the Northwest Region

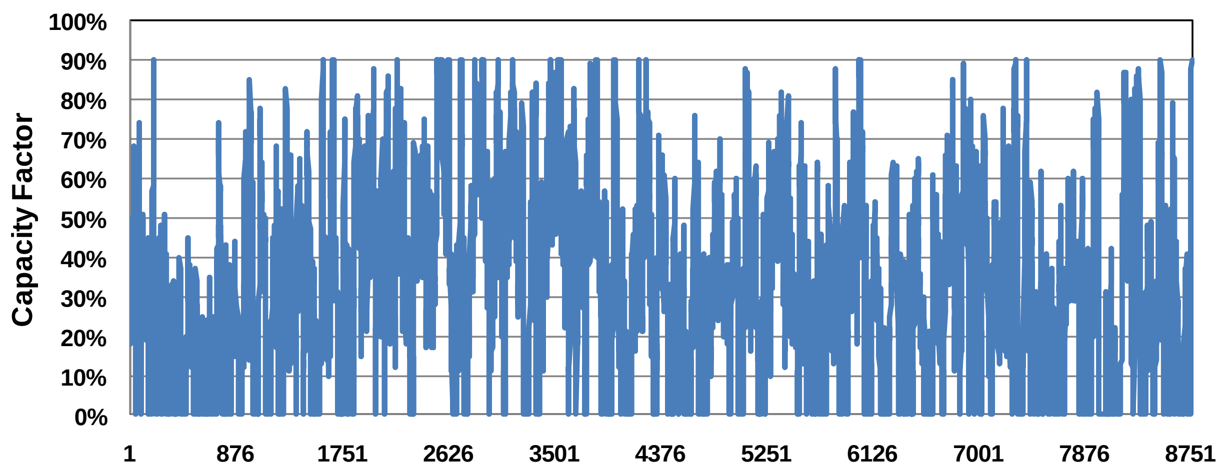
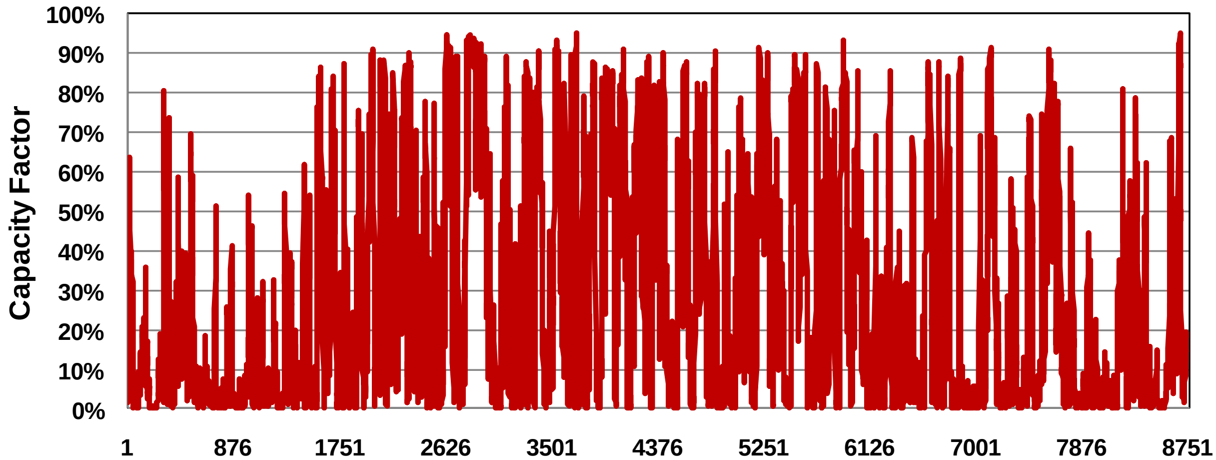


Figure 7.14: 2010 Actual Wind Output BPA Balancing Authority[6]



There is speculation that a correlation exists between wind and hydro, especially outside of the winter months where storm events bring both rain to the river system and wind to the wind farms. This IRP does not correlate wind and hydro due to a lack of historical data to confirm or invalidate this hypothesis. Where correlation exists, it would be optimal to run the model 70 historical wind years with matching historical water years. A continual study of this relationship is an action item for this plan.

Forced Outages

In most deterministic market modeling studies, plant forced outages are represented by a simple average reduction to maximum capability. This over simplification generally represents expected values well; however, in stochastic modeling, it is better to represent the system more accurately by randomly placing non-hydro units out of service based on a mean time to repair and an average forced outage rate. Internal studies show that this level of modeling detail is necessary only for large natural gas-fired (greater than 100 MW), coal, and nuclear plants. Forced outage rates and the mean time to repair data come from analyzing the North American Electric Reliability Corporation's Generating Availability Data System (GADS) database.

Other Variables

Coal, hog fuel, fuel oil, and variable O&M variables are modeled stochastically. These included either normal or lognormal distributions in the study. Due to their moderate affects on market prices, their details are not discussed here and are instead included in Appendix A.

Market Price Forecast

An optimal resource portfolio cannot ignore the extrinsic value inherent in its resource choices. The 2011 IRP simulation compares each resource's expected hourly output

[6] Chart data is from the BPA at: http://transmission.bpa.gov/Business/Operations/Wind/default.aspx.

using forecasted Mid-Columbia hourly prices over 500 iterations of Monte Carlo-style scenario analysis.

Hourly electricity prices are either the operating cost of the marginal unit in the Northwest or the economic cost to move power into or out of the Northwest. A forecast of available future resources helps create an electricity market price projection. The IRP uses regional planning margins to set minimum capacity requirements, rather than using a summation of the capacity needs of individual utilities in the region. Western regions can have resource surpluses even where some individual utilities may be in deficit. This imbalance can be due in part to the ownership of regional generation by independent power producers, and possible differences in planning methodologies used by utilities in the region.

AURORAxmp assigns market values to each resource alternative available to the PRS, but the AURORAxmp model does not itself select PRS resources. Several market price forecasts determine the value and volatility of a resource portfolio. As Avista does not know what will happen in the future, it relies on risk analysis to help determine an optimal resource strategy. Risk analysis uses several market price forecasts with different assumptions than the expected case or changes the underlying statistics of a study. The modeling splits alternate cases are into stochastic and deterministic studies.

A stochastic study uses Monte Carlo analysis to quantify the variability in future market prices. These analyses include 500 iterations of varying natural gas prices, loads, hydroelectric generation, thermal outages, wind generation shapes, and greenhouse gas emissions prices. Four stochastic studies—an Expected Case, one case without greenhouse gas limitations, a high natural gas volatility case, and an early coal plant retirement case are used. The remaining studies were deterministic scenario analyses.

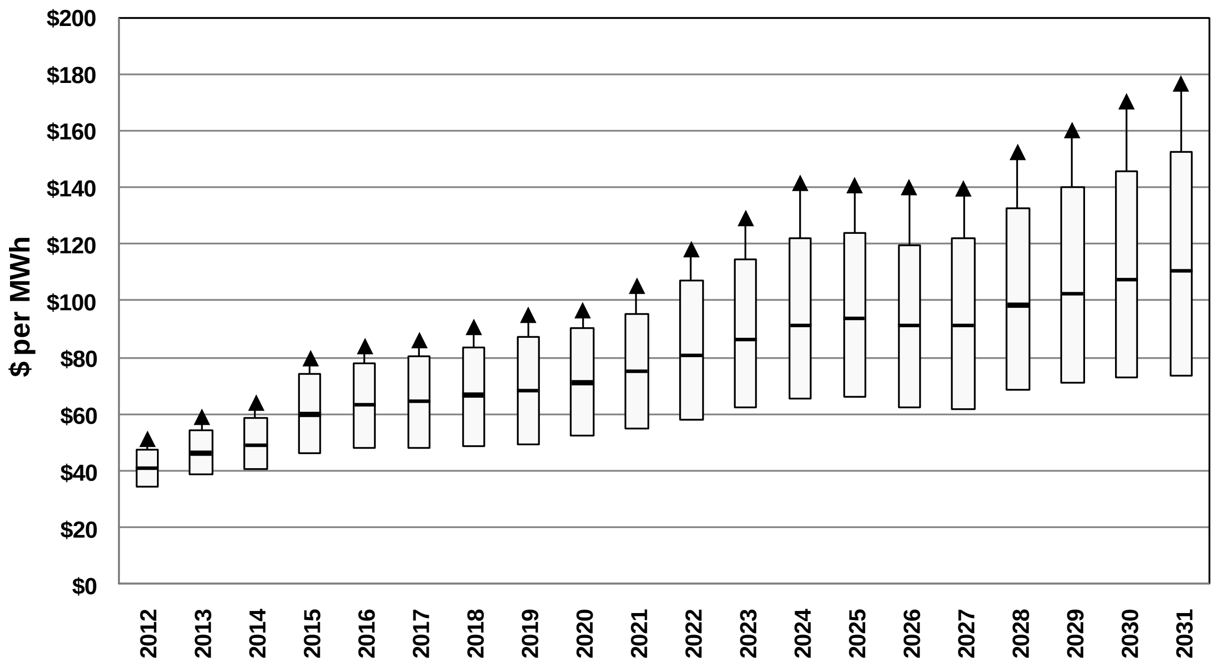
Mid-Columbia Price Forecast

The Mid-Columbia is Avista's primary electricity 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 because of low cost hydroelectric generation, though other markets can at times be less expensive when Rocky Mountain area natural gas prices are low and gas-fired generation is setting marginal power prices.

Fundamentals-based market analysis is critical to understanding the market environment Avista operates in. The Expected case includes two studies. The first is a deterministic market view using expected levels for the key assumptions discussed in the first part of this chapter. The second is a risk or stochastic study with 500 unique scenarios based on different underlining assumptions for gas prices, load, greenhouse gas emissions prices, wind generation, hydroelectric generation, forced outages, and others. Each study simulates the entire Western Interconnect hourly between 2012 and 2031. The analysis used 18 central processing units (CPUs) linked to a SQL server to simulate the studies, creating over 45 GB of data requiring 2,000 hours of computing time.

The resultant average market prices developed from the stochastic model are similar to the results from the deterministic model. Figure 7.15 shows the stochastic market price results as the horizontal bar and the vertical bars represent the 10th and 90th percentile for annual average prices. The triangle represents the Tail Var 90. The nominal levelized price for the 20-year expected prices is $70.50 per MWh. The deterministic prices are $0.87 per MWh lower than the stochastic prices presented in Figure 7.15.

Figure 7.15: Mid-Columbia Electric Price Forecast Range



The annual averages of the stochastic case on-peak, off-peak and levelized prices are in Table 7.10. The Mid-Columbia market price averages $70.50 per MWh over the next 20 years. The 2009 IRP annual average nominal price was $93.74 per MWh. Spreads between on- and off-peak prices are $11.48 per MWh over 20 years.

Table 7.11: Annual Average Mid-Columbia Electric Prices ($/MWh)

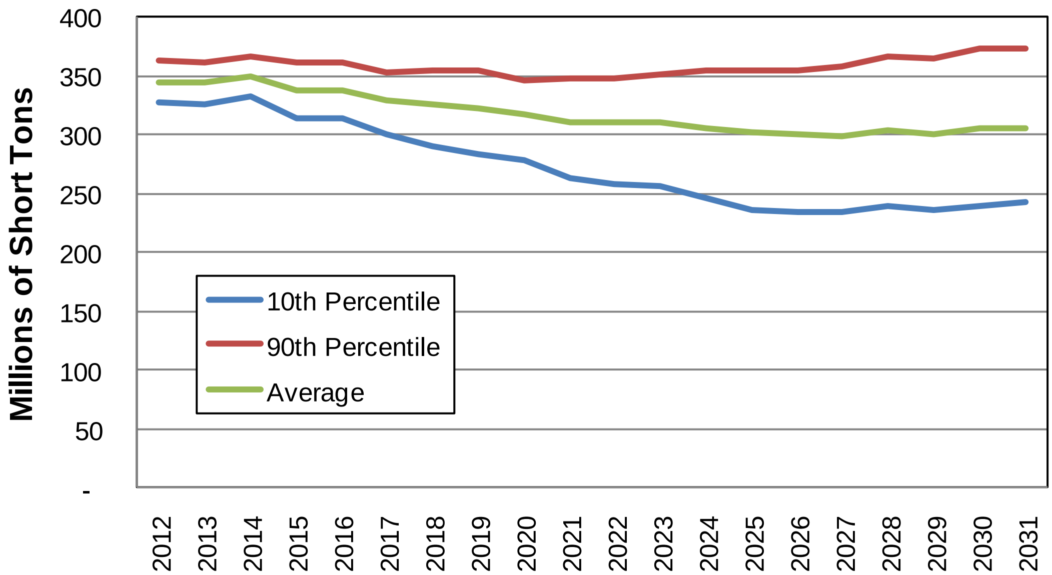
Year	On Peak	Off Peak	Flat
2012	40.87	36.51	44.16
2013	46.13	41.19	49.84
2014	49.11	43.62	53.23
2015	59.86	54.08	64.19
2016	63.25	57.12	67.84
2017	64.53	58.65	68.96
2018	66.55	60.33	71.21
2019	68.26	62.03	72.92
2020	71.05	64.56	75.91
2021	74.88	68.30	79.81
2022	80.49	73.65	85.62
2023	86.28	79.24	91.59
2024	91.26	83.55	97.04
2025	93.71	85.18	100.10
2026	91.35	83.08	97.54
2027	91.37	83.17	97.52
2028	98.30	89.92	104.63
2029	102.25	93.52	108.80
2030	107.56	97.77	114.89
2031	110.55	99.90	118.53
Nominal Levelized	**70.50**	**63.94**	**75.42**

Greenhouse Gas Emission Levels

Greenhouse gas levels increase over the study period absent social policies intended to reverse the trend. The compliance costs of meeting potential greenhouse gas mitigation discussed earlier in this chapter provide price signals to encourage reductions in greenhouse gas emissions. Figure 7.16 shows the expected greenhouse gas emissions from the 500 market forecast simulations. The average level of greenhouse gas emissions from electric generation decrease by 11.2 percent over the 20–year study. The figure also includes the 10th and 90th percentile statistics of the dataset. As discussed earlier, ten percent of the cases assume no future carbon mitigation policies; in these cases the incremental emissions are partly offset by now-expected coal plant retirements[7], low natural gas prices, and increased in wind generation that make coal resources uncompetitive in some months of the forecast.

[7] Recently announced retirements included in the 2011 IRP are 1,561 MW in Colorado, 585 MW in Oregon, and 172 MW in Utah. The 2011 IRP analyses occurred prior to the announcement of the future closure of the 1,376 MW Centralia Coal Plant in Washington State. Its closure should further carbon emission reductions beyond those projected in this plan.

Figure 7.16: Western States Greenhouse Gas Emissions

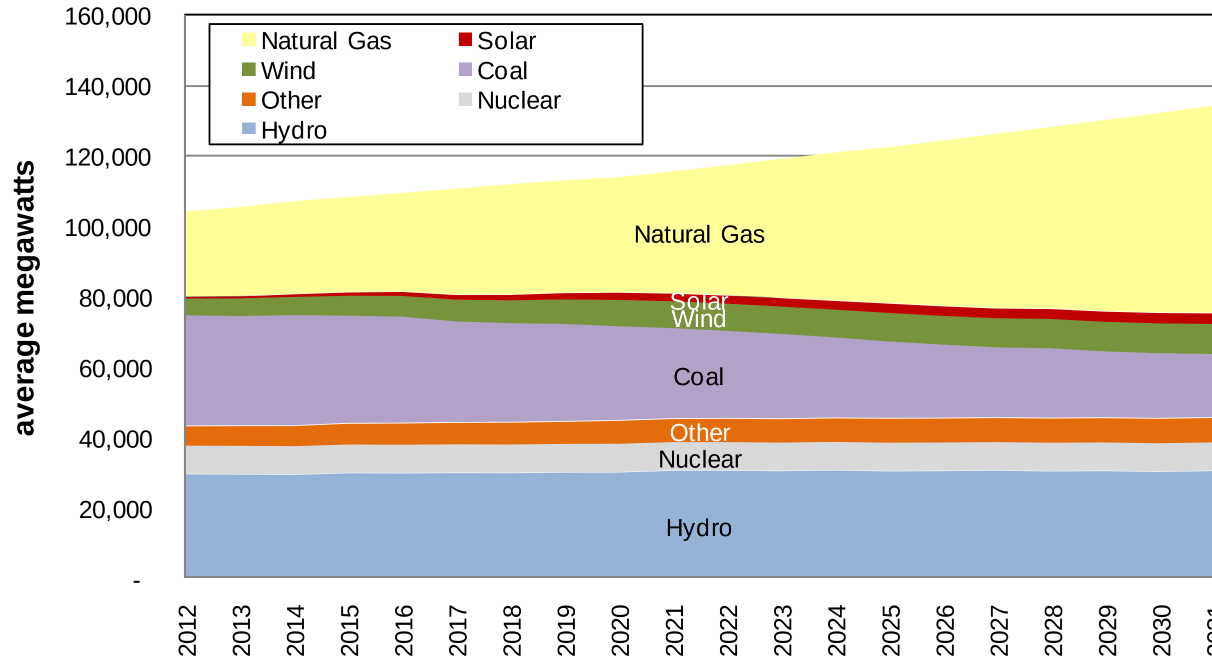


Resource Dispatch

State-level RPS goals and greenhouse gas legislation will change resource dispatch decisions and affect future power prices. The Northwest already is witnessing the market-changing effects of a 5,000+ MW wind fleet. Figure 7.17 illustrates that natural gas fuels 23 percent of total generation in 2012, and 41 percent in 2031. Coal generation decreases from 30 percent of Western Interconnect generation in 2012 to 13 percent in 2031. Solar and wind increase from 5 percent in 2012 to 13 percent in 2031. New renewable generation sources offset coal generation reductions, but natural gas-fired resources meet load growth.

Public policy changes to encourage renewable energy development and reduce greenhouse gas emissions have the potential to change the electricity marketplace. On its present trajectory, policy changes are likely to move the generation fleet toward its potentially most volatile contributor—natural gas. These policies will displace low-cost coal-fired generation with higher-cost renewables and gas-fired generation having lower capacity factors (wind) and higher marginal costs (natural gas). If history is our guide, regulated utilities will recover their costs from stranded coal plants, requiring customers to pay even more. Further, wholesale prices likely will increase with the effects of the changing resource dispatch driven by carbon emission limitations. New environmental policy driven investment, combined with higher market prices, will necessarily lead to retail rates that are higher than they would be absent greenhouse reduction policies.

Figure 7.17: Base Case Western Interconnect Resource Mix



Scenario Analysis

Scenario analysis evaluates the impact of specific changes in underlying assumptions on the market. Four stochastic studies were performed to help understand potential market price changes and to examine the potential risk to Avista's PRS if certain assumptions were changed. The scenarios studied used 500 iterations to model the effects of unconstrained carbon emissions, doubling of natural gas price volatility, and the early retirement of coal plants. In addition to the stochastic market scenarios, deterministic scenarios explained the impacts of low natural gas prices, high natural gas prices, and high wind penetration. Prior IPRs used market scenarios to stress test the PRS. Since the PRS accounts for a range of possible outcomes in its risk analysis, the market scenario analysis section is more limited in this IRP. Additional scenarios illustrate the impacts potential policies might have on the industry, and how Avista could respond.

Unconstrained Carbon Emissions

The Unconstrained Carbon Emissions scenario is necessary to quantify projected greenhouse gas policy costs. The first study is a deterministic scenario. A second stochastic study models 500 individual iterations of varying natural gas prices, loads, wind generation, forced outages, and hydroelectric conditions. The assumptions are similar to the Expected Case with a few notable exceptions. First, natural gas prices are lower because of less demand for natural gas caused by the continued use of coal-fired generation. Without carbon legislation, natural gas prices are $0.52 per Dth lower levelized over 20 years, a 7.1 percent decrease.

Without projected greenhouse gas mitigation, Mid-Columbia market prices are lower and the total cost to serve customers is lower. The average of the 500 simulations finds wholesale market prices $17.64 per MWh lower, on a nominal levelized basis, compared to the Expected Case; this represents a 33.4 percent market price increase for greenhouse gas emissions mitigation (Figure 7.18). The total cost of fuel in the Western Interconnect with greenhouse gas mitigation is 7.65 percent higher than without the greenhouse gas mitigation.

Figure 7.18: Mid-Columbia Prices Comparison with and without Carbon Legislation

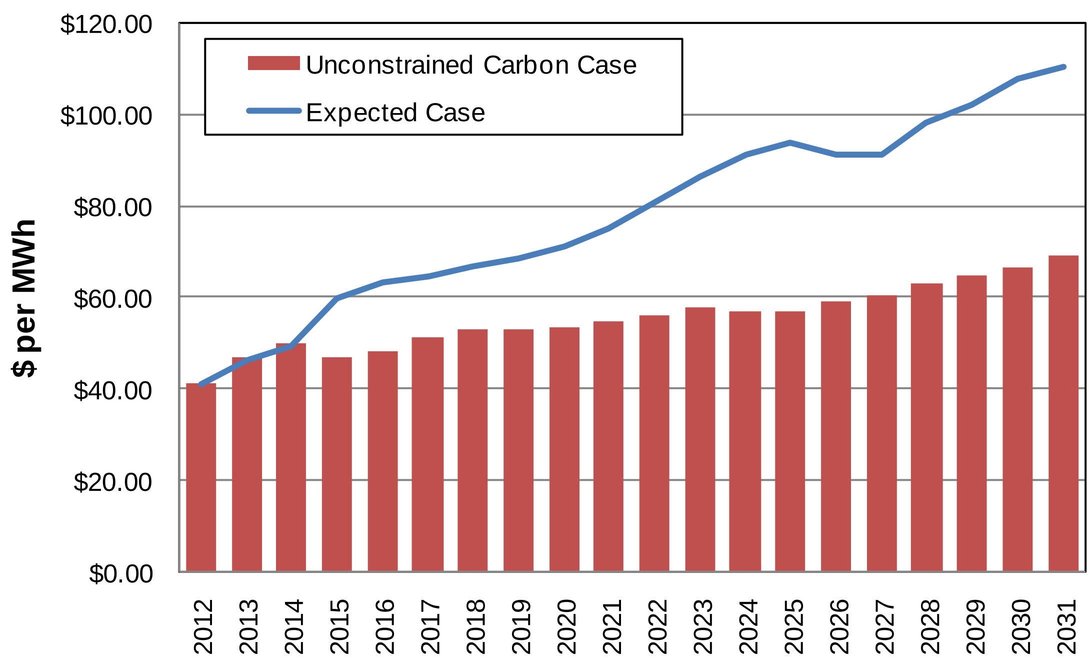


Figure 7.19 illustrates the difference between greenhouse gas emissions with and without the emissions costs included in the Expected Case. Based on the model results and assumptions, emissions would be 8.5 percent higher in 2020 and 21.5 percent higher in 2031 without the assumed greenhouse gas penalty. Increased greenhouse gas emissions from higher coal-fired dispatch levels are the cause (see Figure 7.20). The Expected Case, which includes greenhouse gas costs, reduces coal dispatch by 36 percent compared to the unconstrained greenhouse gas scenario, while natural gas generation production increases by 19 percent.

Figure 7.19: Western U.S. Carbon Emissions Comparison

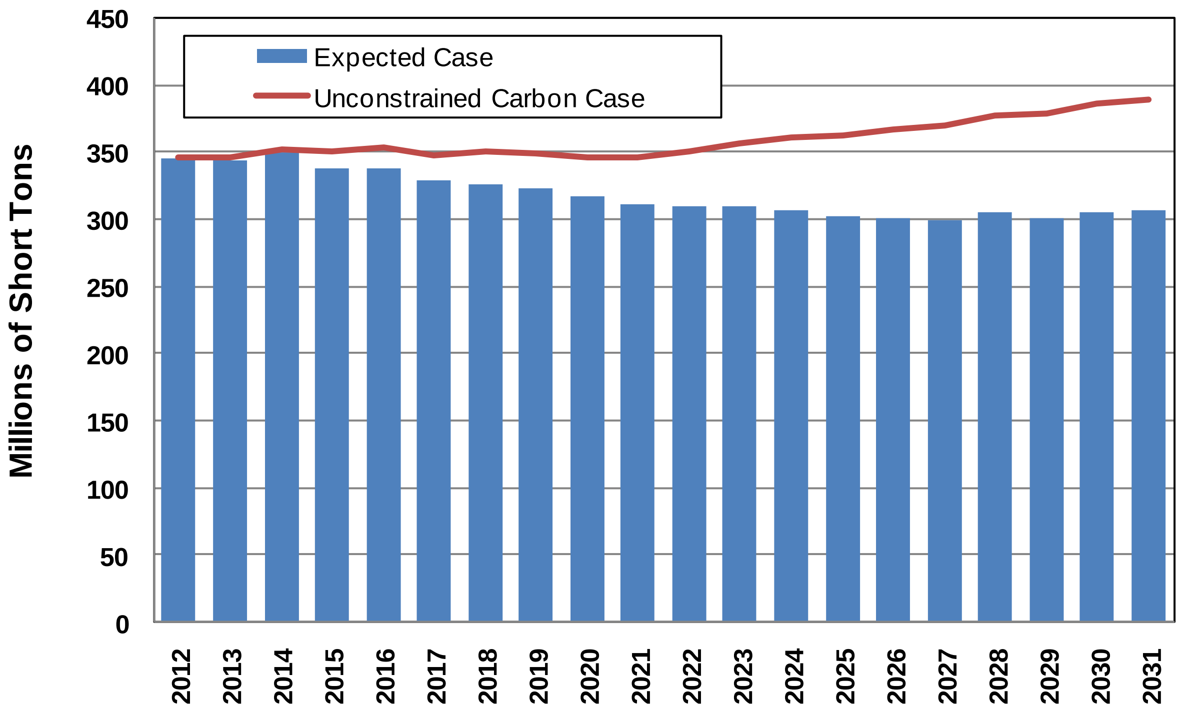
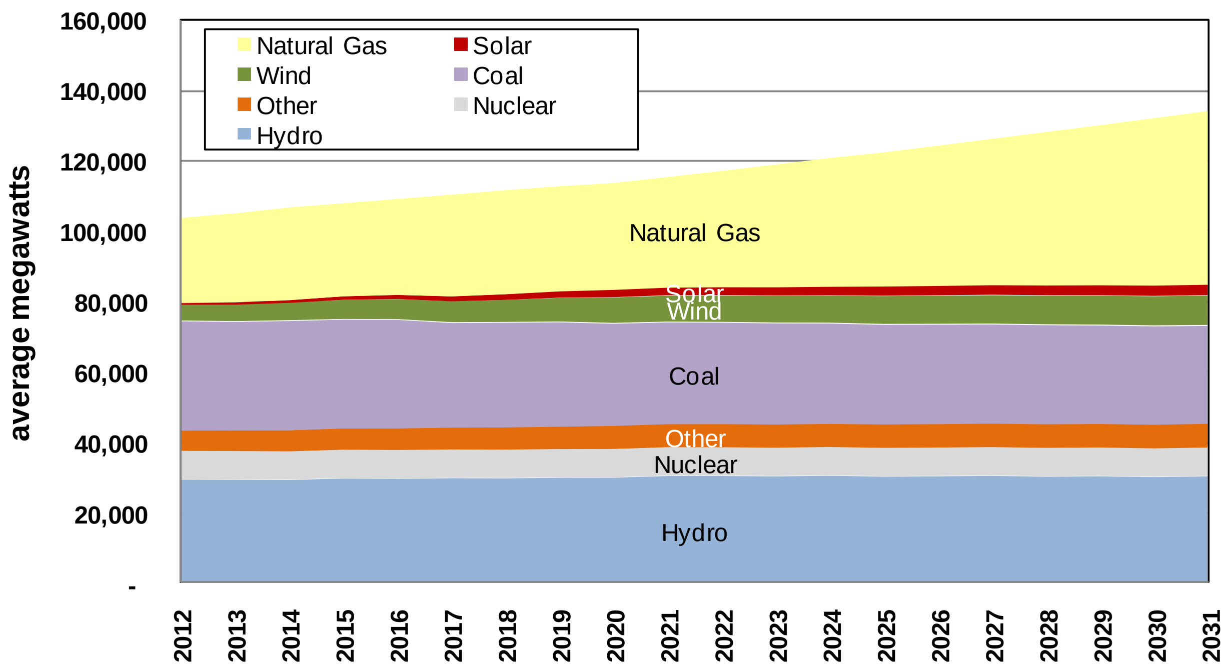


Figure 7.20: Unconstrained Carbon Scenario Resource Dispatch



Alternative Greenhouse Gas Mitigation Methods

As part of the development of the Expected Case's four greenhouse gas policies, market simulations were conducted to calculate the price of greenhouse gas required to meet the stated objective of the reduction goal. Figure 7.8, shown earlier, illustrates the prices required to meet the objectives. Figure 7.21 illustrates the corresponding forecasted electric market prices at Mid-Columbia on an average annual basis. The Expected Case line is the average of the 500 simulations and the other lines represent the deterministic study results for each of the potential greenhouse gas policies modeled. The values shown in Figure 7.22 are discounted and levelized over the 20-year study period to represent the average price of power.

Figure 7.21: Average Annual Mid-Columbia Electric Prices for Alternative Greenhouse Gas Policies

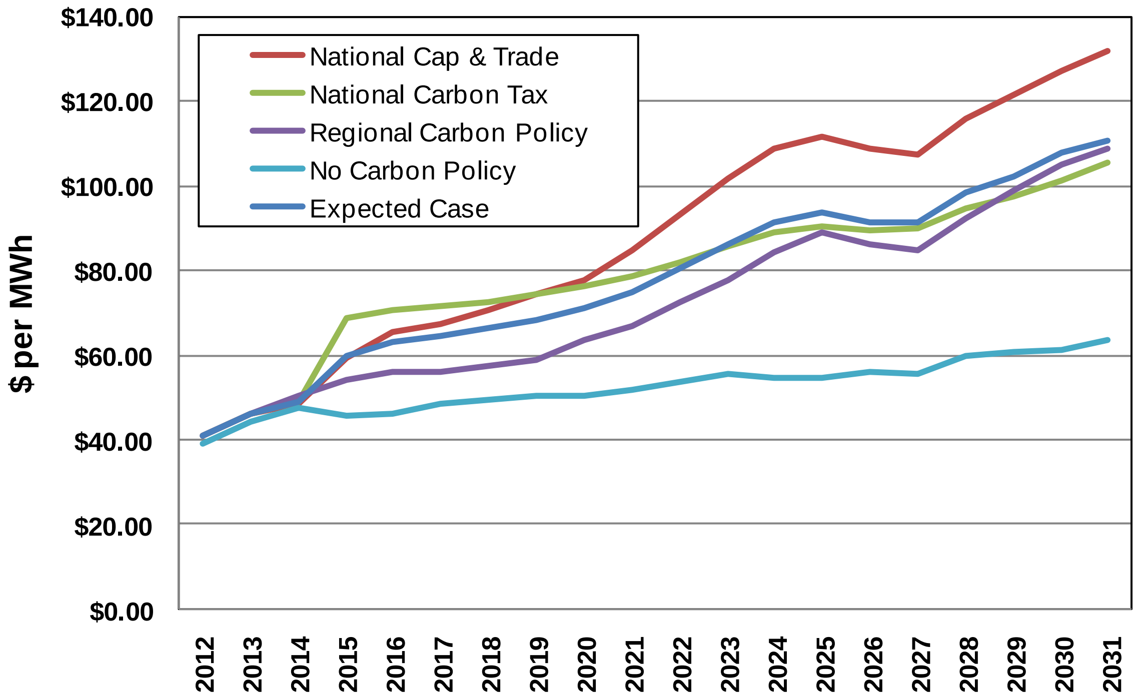


Figure 7.22: Nominal Levelized Mid-Columbia Electric Prices for Alternative Greenhouse Gas Policies

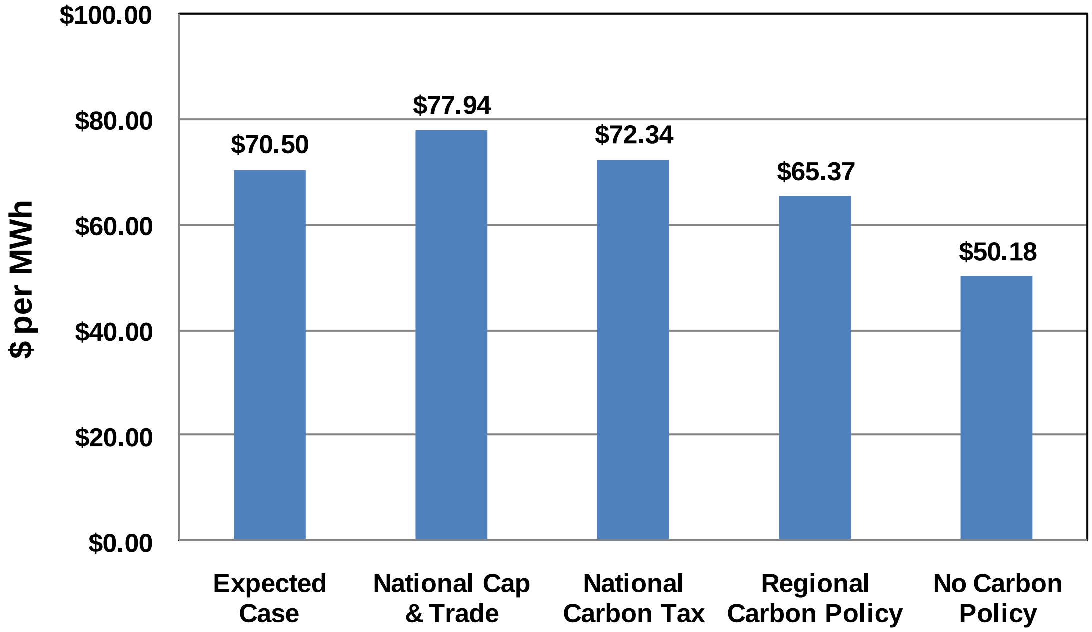
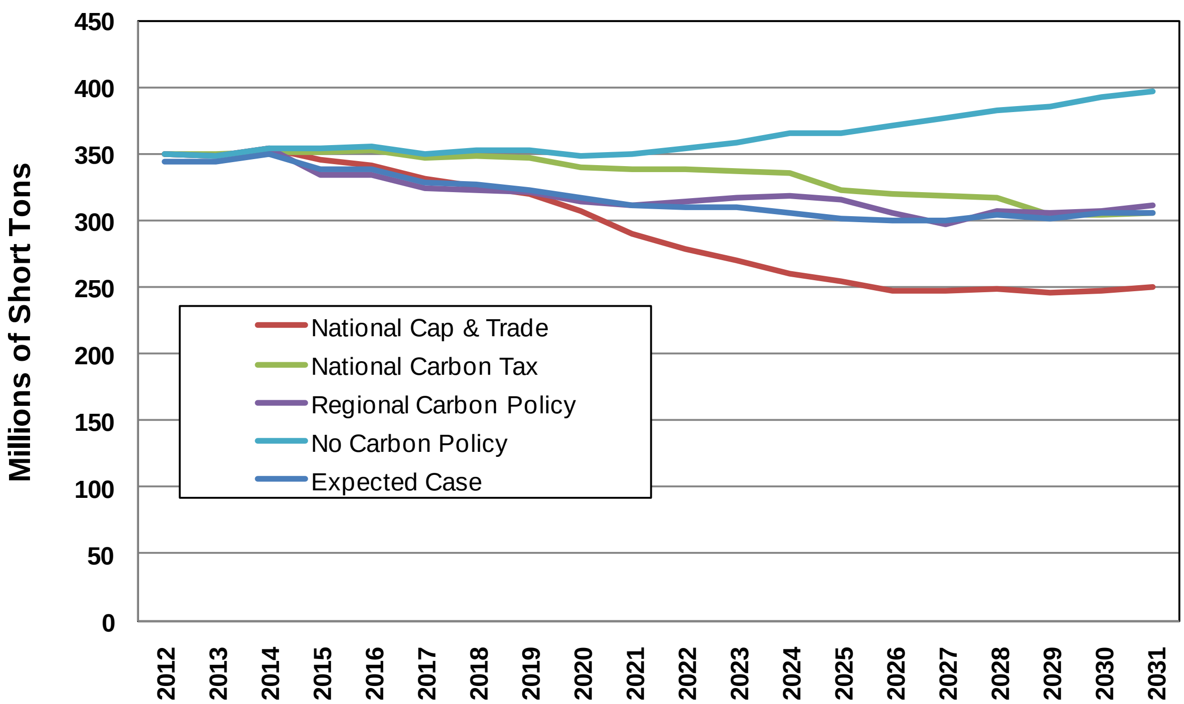


Figure 7.23 shows the annual expected greenhouse gas emissions levels for each of the policies in. The four potential outcomes represent a range of futures under different forms of greenhouse gas emissions legislation.

Figure 7.23: Annual Greenhouse Gas Emissions for Alternative Greenhouse Gas Policies



Mandatory Coal Retirement

Proposed federal greenhouse gas cap and trade legislation is not law. The Environmental Protection Agency and other organizations have pursued alternative methods to reduce greenhouse gases from electric generation through regulatory means. More details surrounding these policy alternatives are in the Planning Environment chapter. The goal of this scenario is to illustrate the affect on electricity market prices and system fuel costs where a policy is put in place requiring all coal plants to retire at the end of 40 years of life, or to be phased out by 2020 if the plant is already over 40 years old. The study uses 500 iterations as conducted on other studies.

In Figure 7.24 the average annual prices for this scenario are compared to the Expected Case. The resulting prices levelized are $57.01 per MWh, 19 percent lower than the Expected Case and 27 percent lower than the national Cap and Trade strategy. The surprising fact about this greenhouse gas policy is that Mid-Columbia prices are only 7.3 percent higher than the no carbon penalty case and the policy still achieves substantial greenhouse gas reductions as shown in Figure 7.25. The driver of these results is that natural gas-fired units face no carbon costs. Without the emissions adder to natural gas, the marginal price of power remains as a natural gas-fired plant, and the increase in power cost is more driven by the increased demand driving natural gas prices higher and the inclusion of less low cost base load capacity in shoulder months. Although lower market prices make this greenhouse gas strategy appealing, it does have a negative consequence. In Table 7.12 annual incremental costs of each potential strategy are compared and the Early Coal Plant Retirement strategy is $3.2 billion more costly for the Western Interconnect as compared to the Cap and Trade strategy. This increase results from the forced addition of new resources to replace coal plants rather than letting coal plants remain on line, but instead dispatching them much less frequently, thus avoiding new capital investment. One thing to keep in mind, is this a 20 year study of the western interconnect. A longer-term national model may illustrate different results. Taking into account national economics may also change opinions on the results as well. In the end, any greenhouse reduction strategy needs to be a low cost solution that does not affect the electricity marketplace in a negative manner.

Figure 7.24: Average Annual Mid-Columbia Price Comparison of Greenhouse Gas Policies

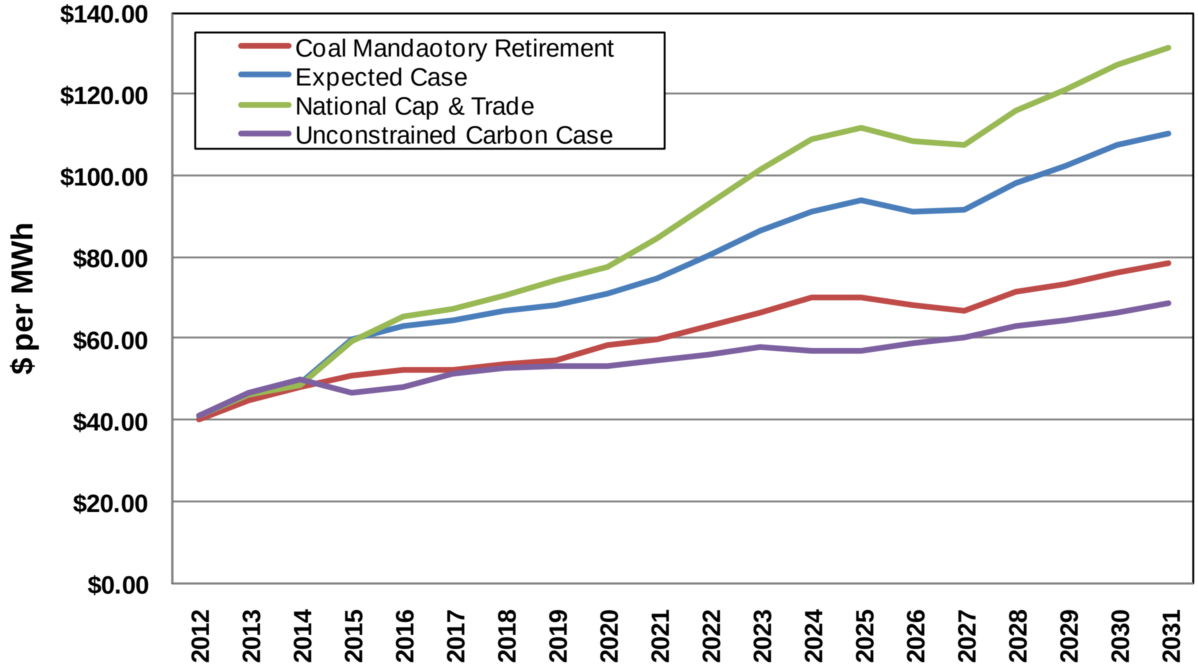


Figure 7.25: Expected Greenhouse Gas Emissions Comparison

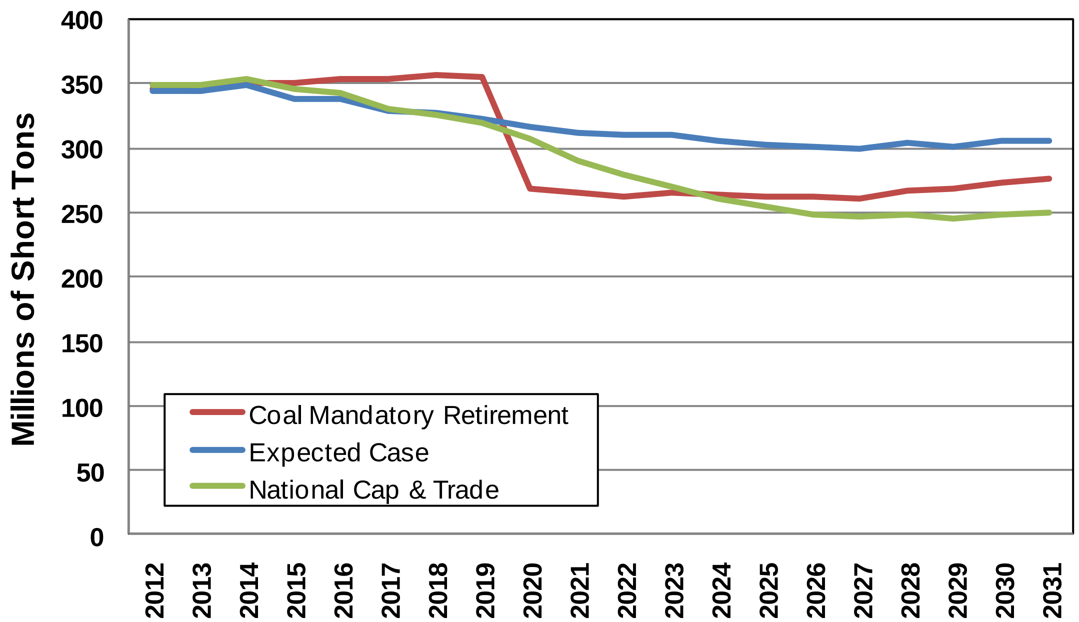


Table 7.12: Impacts of Greenhouse Gas Mitigation Policies in the West

Market Scenario	Change to GHG Emissions by 2031	Added Levelized Cost per Year (Billions)
Unconstrained GHG Gas Case	14%	0.0
Expected Case	-18%	3.5
Coal Mandatory Retirement	-22%	8.1
National Cap & Trade	-29%	4.9

High and Low Natural Gas Price Scenarios

The High and Low Natural Gas Price scenarios illustrate Mid-Columbia electric prices for differing natural gas prices. These scenarios maintain carbon emissions at the same level as the Expected Case to determine carbon prices at lower natural gas prices. Figure 7.4, located earlier in the chapter, shows the low and high natural gas price forecasts used in this scenario as Consultant 1 and Consultant 2 prices. Using these prices, the resulting greenhouse gas price forecast assuming a cap and trade mechanism that achieves the same reductions as the Expected Case is in Figure 7.26. The natural gas prices in this scenario are approximately plus or minus 20 percent compared to the Expected Case, but the greenhouse gas prices must increase or decrease, respectively, by approximately 31 percent to achieve the same greenhouse gas emission levels as the Expected Case. The Mid-Columbia market price forecasts for the high and low natural gas price cases are in Figure 7.27. The nominal levelized electric price for the low gas price case is $57.00 per MWh and the market price for the high gas price case is $82.17 per MWh.

Figure 7.26: Natural Gas Price Scenario's Greenhouse Gas Emission Prices

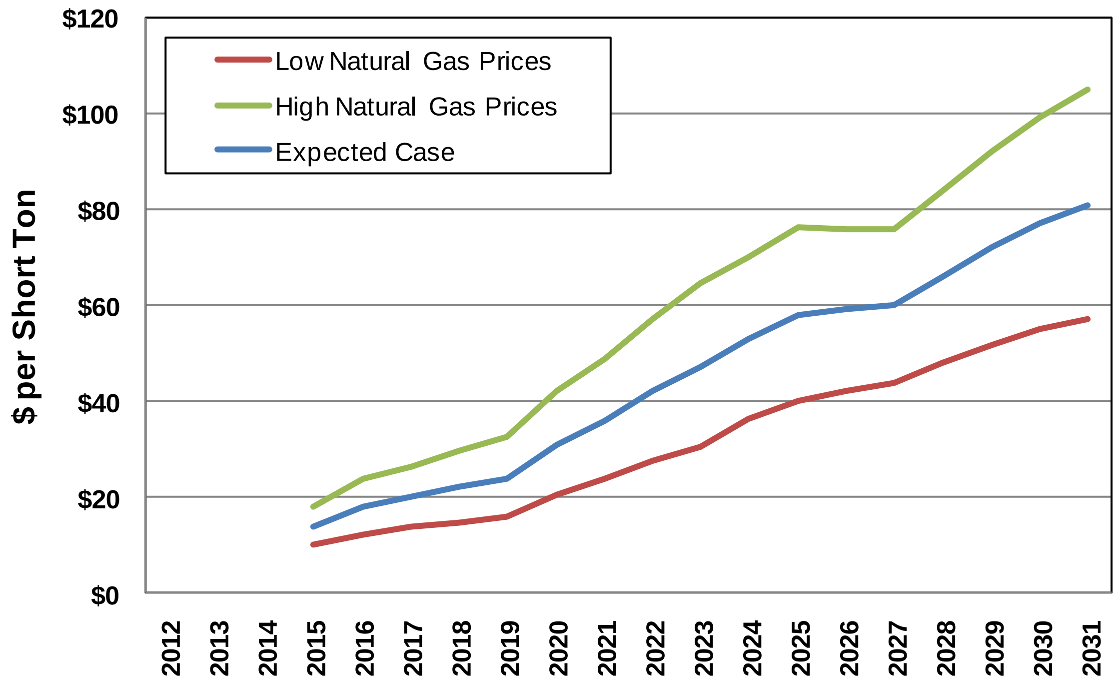
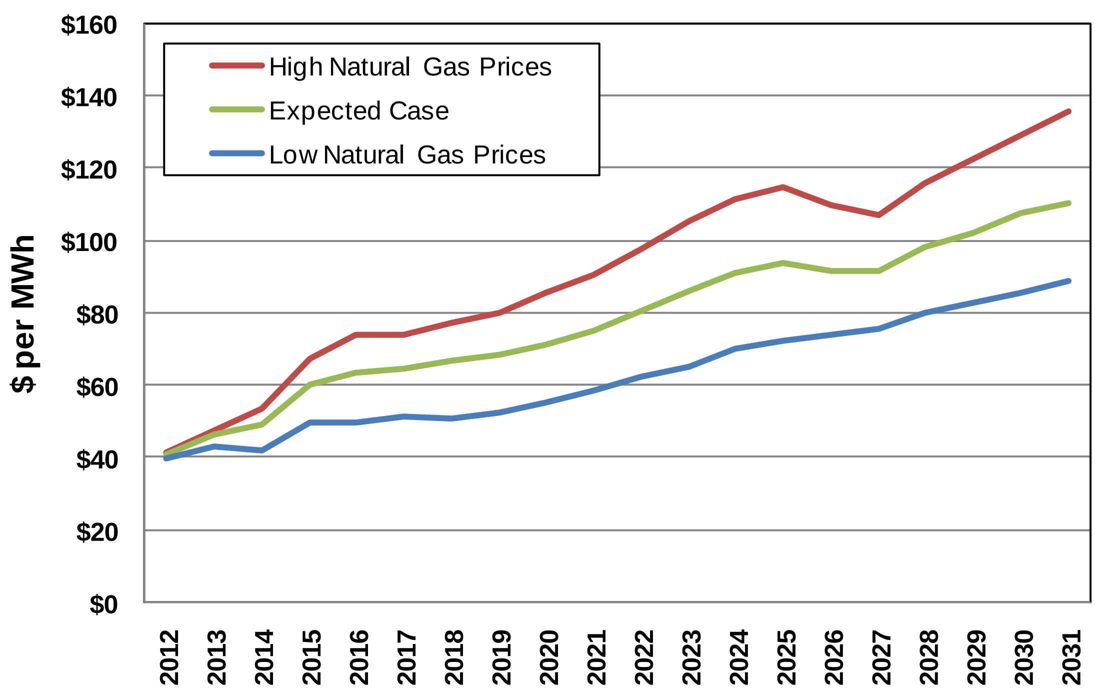


Figure 7.27: Natural Gas Price Scenario's Mid-Columbia Price Forecasts



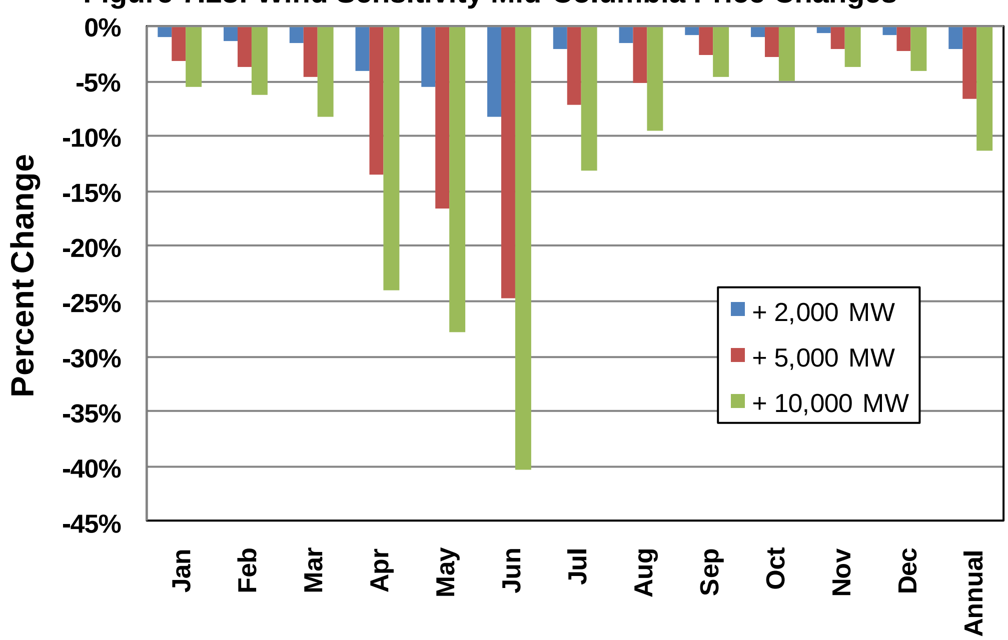
Wind Proliferation and Negative Pricing

Avista uses the IRP process to identify and understand the impacts of potential market changes, rather than only focusing on Avista's PRS. In past IRPs, Avista has studied the market impacts of electric cars and the addition of large amounts of solar generation to the grid. For this IRP, the non-PRS study focuses on the growing penetration of wind generation in the Northwest. 2015 was chosen as the period for this study and includes four sensitivities; the sensitivity included 100 iterations of potential outcomes.

The sensitivities in this case range from 7,000 MW to 17,000 MW (additions of between zero MW and 10,000 MW to the Expected Case wind penetration forecast) of total wind capacity in the Northwest. Currently, there is approximately 5,000 MW in the four northwest states and the Expected Case includes approximately 7,000 MW of wind by 2015. The key results of this study include the change in market prices, the amount of negative price episodes, and the overall effect of additional wind generation on the margins of existing Avista facilities.

The first major change to the power market by high wind penetration is the change to wholesale market prices. Based on the average of the 100 iterations of each case, Figure 7.28 illustrates the percent change to Mid-Columbia average monthly prices in cases that increase wind capacity by 2,000, 5,000, and 10,000 MW above the Expected Case forecast. The major price changes occur in the second quarter of the year. On average, market price changes are 2 percent lower than the Expected Case with 2,000 MW of additional wind by 2015, 7 percent lower with 5,000 MW, and 11 percent lower with 10,000 MW.

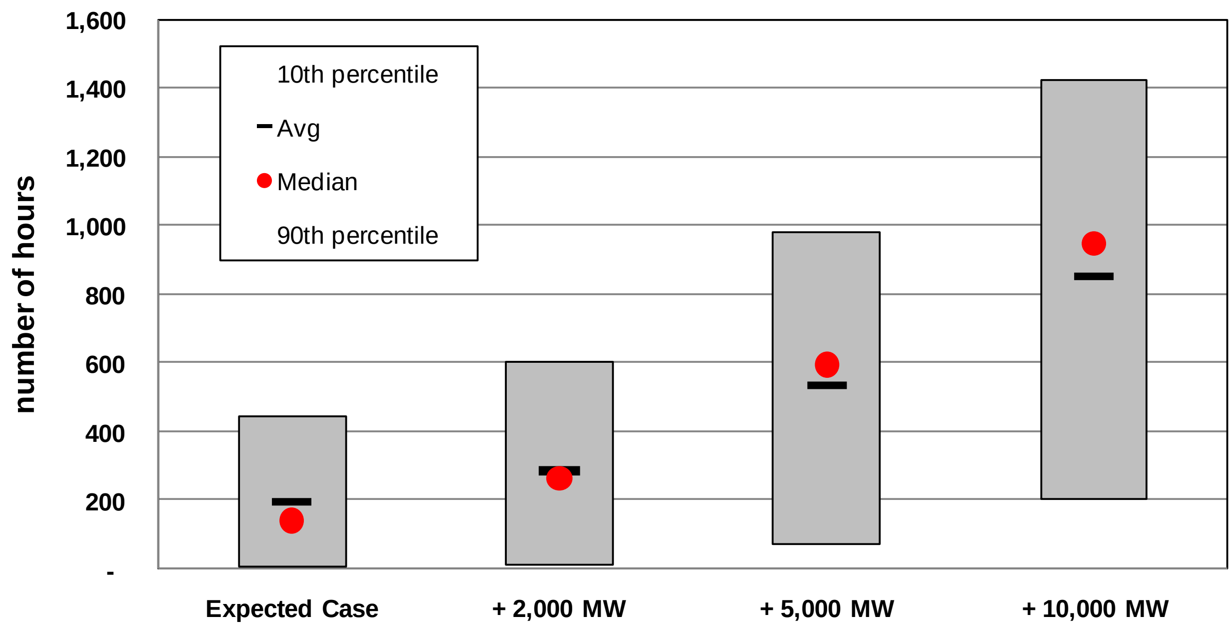
Figure 7.28: Wind Sensitivity Mid-Columbia Price Changes



The reduction in overall wholesale prices comes substantially from negative prices. Negative pricing can occur when resources must operate irrespective of the price offered in the wholesale marketplace, and when a resource receives economic benefit for generation beyond market prices (tax credits and RECs). In some markets negative prices occur when certain base-load generation resources (e.g., nuclear plants) in total exceed nighttime loads but must be operated to ensure their availability during the next day's peak demand periods. Negative pricing is an issue today in the Northwest when the region's hydroelectric system is experiencing high flow condition (generally during spring runoff) and when there is no wind generation curtailment.

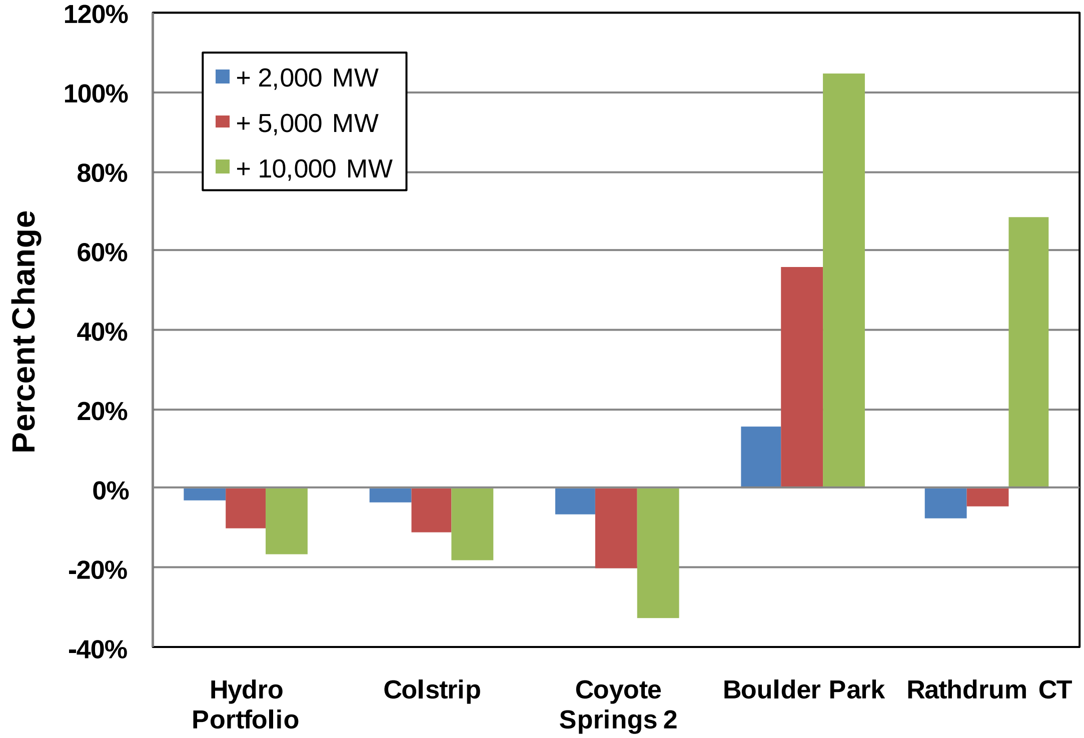
Many hydroelectric facilities must generate electricity and not spill water under varying licensing requirements. This situation compounds when generation resources, such as wind, receive federal production tax and renewable energy credits. Wind facilities in the Expected Case contribute to 193 hours of negative prices, or 2.2 percent of the hours, as shown in Figure 7.29. With 2,000 MW of additional wind capacity, the frequency of negative pricing increases to 3.2 percent. With 5,000 MW, prices fall by 6.1 percent. And with 10,000 MW, prices fall by 9.7 percent.

Figure 7.29: Wind Sensitivity Negative Pricing



The final item reviewed as part of this high wind penetration study is the effect to the profitability of non-wind and hydro resources and total power supply costs. Figure 7.30 shows that Avista's coal-fired, combined cycle natural gas-fired, and hydroelectric revenues decline, but that the value of gas-fired peaking resources will increase. The estimated impact of increased wind penetration to Avista net power supply cost is a net increase between 0.03 percent and 0.37 percent.

Figure 7.30: Change to Resource Revenues



Market Analysis Summary

Market analysis is a key component of the IRP. The market is where Avista trades its electricity surpluses and deficits. It is difficult to examine all potential resources evaluated by Avista for possible inclusion in the PRS without a firm understanding of the marketplace and how public policy and changes to resource and cost assumptions affect the market. As prices have declined since the 2009 IRP, and have the potential to fall farther, the market price forecasts could have an effect on the cost to bring new resources on to the Avista system and their potential rate effects.

New legislation and regulations affecting the electric system are on the horizon. Regardless of policies 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 infrastructure and serve new load growth. Greenhouse gas emissions and RPS legislation will diversify fuel supplies, but will also increase demand for natural gas-fired resources. Policymakers and the public will need to determine if the ultimate benefits of these types of legislation outweigh the increased costs.

8. Preferred Resource Strategy

Introduction

The Preferred Resource Strategy (PRS) chapter describes potential costs and financial risks of the Company's resource acquisition strategy. It details the planning and resource decision methodologies, describes strategy, considers climate change policy, and shows how the strategy may evolve if certain expected future conditions change.

The 2011 PRS describes a reasonable low-cost plan along the efficient frontier accounting for fuel supply risk, price risk, and greenhouse gas mitigation. Major changes from the 2009 plan include reduced amounts of wind generation and the introduction of natural gas-fired peaking resources. The plan includes less wind because of lower expected retail loads resulting from the present economic downturn and increased conservation acquisition. Expected wind generation needs are lower due to a modest change in the modeling method used to represent annual variability from RPS-qualifying resources. The selection of gas-fired peaking resources resulted from a lower natural gas price forecast, lower retail loads, and the need for more flexible generation resources to manage the variability associated with renewable generation.

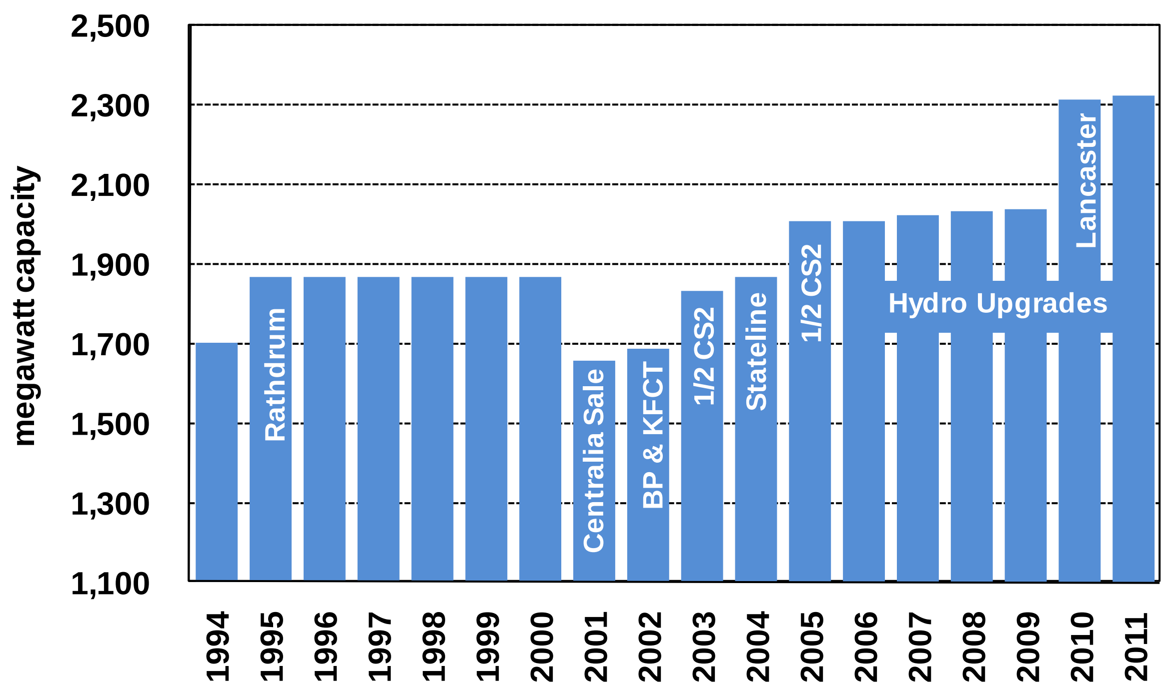
Section Highlights

- A contract for the 101 MW Palouse Wind project located near Spokane, Washington will meet 2016 RPS requirements.
- Avista's first load-driven acquisition is a gas-fired peaking plant in 2019; total gas-fired acquisition is 752 MW over the IRP timeframe.
- The 2011 plan splits natural gas-fired generation between simple- and combined-cycle plants in anticipation of a growing need for system flexibility to integrate variable resources.
- Efficiency improvements, both on the customer and utility sides of the meter, are at the highest expected level in our planning history.
- Total capital needs for generation resources in the PRS are $1.6 billion.
- Conservation and system efficiency spending will increase over time; a total of $1.5 billion will acquire 323 aMW over 20 years.

Supply-Side Resource Acquisitions

Avista began its shift away from coal-fired resources with the sale of its 210 MW share of the Centralia coal plant in 2001 and its replacement 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, Avista contracted for 35 MW of wind capacity from the Stateline Wind Project and added 42 MW of new capacity to its hydroelectric fleet through project upgrades. Avista gained control of the output for the 270 MW Lancaster Generating Facility (Rathdrum GS) through a long-term tolling arrangement on January 1, 2010. The Company plans to upgrade its Nine Mile Falls project. The upgrade could involve replacement with in-kind equipment or a new powerhouse. Avista plans to complete the last turbine runner upgrade at Noxon Rapids in 2012, adding seven MW (1 aMW) to the project's capability.

Figure 8.1: Resource Acquisition History



Resource Selection Process

Avista uses several decision support systems to develop its resource strategy. The PRS relies on results from the PRiSM model whose objective function is to meet resource deficits while accounting for overall cost, risk, renewable energy requirements, and other constraints. The AURORAxmp model, discussed in detail in the Market Analysis chapter, calculates the operating margin (value) of every resource option considered in each of 500 potential future outcomes. PRiSM evaluates resource values by combining operating margins with capital and fixed operating costs. From an efficient frontier, Avista selects a resource mix meeting all capacity, energy, RPS, and other requirements.

PRiSM

Avista staff developed the PRiSM model in 2002 to support the selection of the PRS. The PRiSM model uses a linear programming routine to support complex decision making with multiple objectives. Linear programming tools provide optimal values for variables, given system constraints.

Overview of the PRiSM Model

The PRiSM model requires a number of inputs:

1. Expected Future Deficiencies
    - Summer 18-hour capacity
    - Winter 18-hour capacity
    - Annual energy
    - I-937 RPS Requirements
2. Costs to Serve Future Retail Loads
3. Existing Resource Contributions
    - Operating margins
    - Carbon emission levels
4. Resource Options
    - Fixed operating costs
    - Return on capital
    - Interest expense
    - Taxes
    - Generation levels
    - Emission levels
5. Limitations
    - Market reliance (surplus/deficit limits on energy, capacity and RPS)
    - Resources available to meet future deficits
    - Resource retirement limits (function disabled for 2011 IRP)
    - Capital expenditure limits (function disabled for 2011 IRP)
    - Emission levels (function disabled for 2011 IRP)

PRiSM uses these inputs to develop an optimal resource mix over time at varying levels of cost and resultant risk levels. It weights the first decade more heavily than the later years to highlight the importance of near-term decisions. A simplified view of the PRiSM linear programming objective function is below.

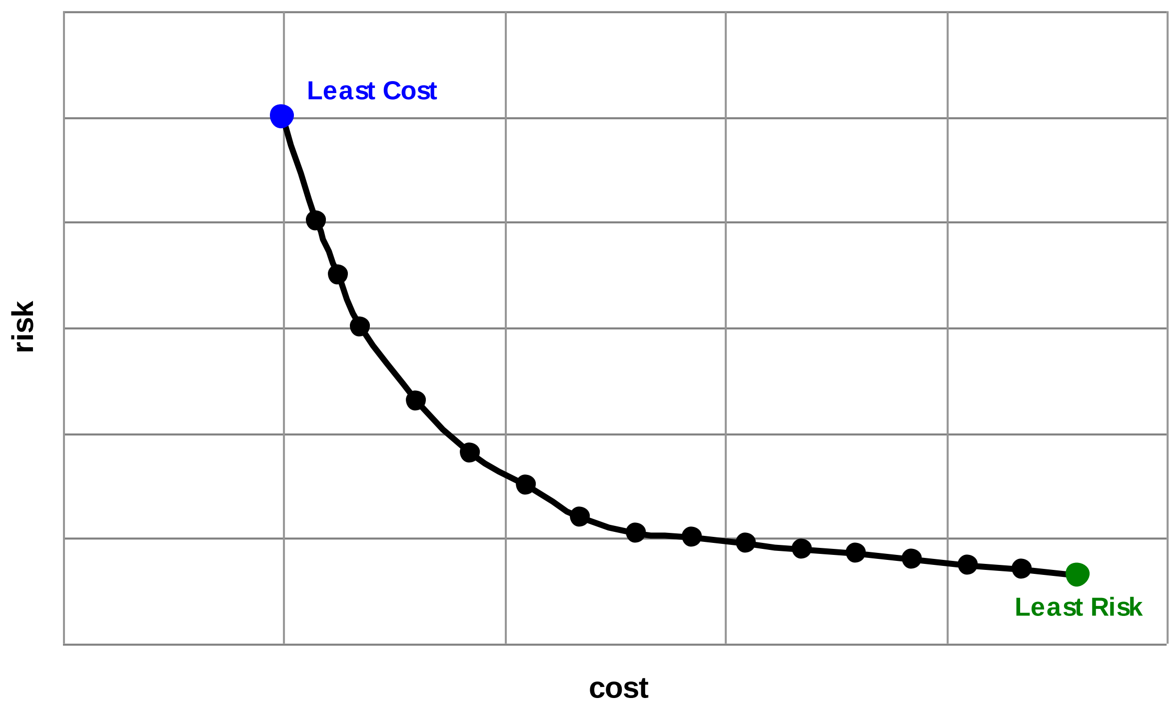
PRiSM Objective Function

Minimize: $(X_1 * NPV_{2012\text{-}2022}) + (X_2 * NPV_{2012\text{-}2031}) + (X_3 * NPV_{2012\text{-}2061})$

Where: X_1 = Weight of net costs over the first 10 years (75 percent)
X_2 = Weight of net costs over 20 years of the plan (20 percent)
X_3 = Weight of net costs over the next 50 years (5 percent)
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).

An efficient frontier captures the optimal mix of resources, given varying levels of cost and risk. Figure 8.2 illustrates the efficient frontier concept. The optimal point on the efficient frontier curve depends on the level of risk Avista and its customers are willing to accept. Environmental legislation, cost, regulation, and the availability of commercially ready technologies greatly limit utility-scale resource options. The model does not meet deficits with market purchases, or that resources are available in any increment needed. The model only uses market purchases to fill short-term gaps.

Figure 8.2: Conceptual Efficient Frontier Curve



Constraints

As discussed earlier in this chapter, reflecting real-world constraints in the model is necessary to create a realistic representation of the future. Some constraints are physical and others are societal. The major resource constraints are capacity and energy needs, Washington's RPS, and the greenhouse gas emissions performance standard.

The PRiSM model is limited to choosing resources by type and by size. It can select from combined- and simple-cycle natural gas-fired combustion turbines, wind, and upgrades to existing thermal resources, and conservation. Sequestered and non-sequestered coal plants are not an option in this IRP because of Washington's emissions performance standard. Detailed hydroelectric upgrade potentials were not available during PRS development and are not included as resource options.

Washington's RPS fundamentally changed how the Company meets future loads. Before the addition of an RPS obligation, the efficient frontier contained a least-cost strategy on one axis and the least-risk strategy on the other axis, and all of the points in between. Next, management used the efficient frontier to determine where they wanted to be on the cost-risk continuum. The least cost strategy typically consisted of gas-fired peaking resources. Portfolios with less risk generally replaced some of the gas-fired peaking resources with wind generation, other renewables, combined cycle gas-fired plants, or coal-fired resources. Past IRPs identified resource strategies that included all of these risk-reducing resources.

Added environmental and legislative constraints greatly reduce the ability to reduce future costs and/or risks and require the procurement of renewable generation resources that previously were included for risk-mitigation. Because significant levels of renewable generation are required under Washington law, the 2011 IRP strategy simply complies with environmental and legislative constraints.

Resource Shortages

Avista no longer uses a one-hour peak planning methodology. It now uses the peak planning methodology recommended by the Northwest Power and Conservation Council – three-day, 18-hour (6 hours each day) peak events occurring both in the summer and winter. This method better emulates the Northwest and Avista's actual ability to meet short-term peak events with hydroelectric facilities. Avista accounts for the regional view of surplus power and includes an adjustment to the Company's short position if Avista's pro-rata share of regional surplus power is available. Finally, the peak planning methodology includes other operating reserves and a planning margin.

Even with the new peak planning methodology, Avista currently projects having adequate resources between owned and contractually controlled generation to meet annual physical energy and capacity needs until 2016.[1] See Figure 8.3 for Avista's physical resource positions for annual energy, summer capacity, and winter capacity.

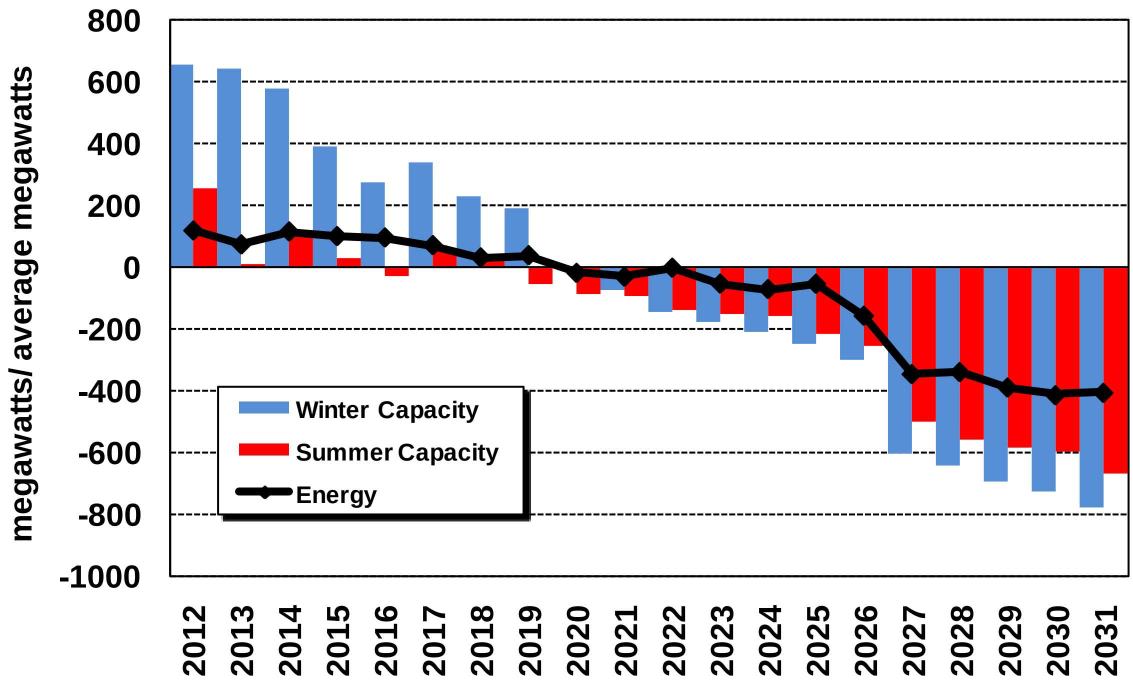
[1] See Chapter 2 for further details on this peak planning methodology.

This figure accounts for the affect of new energy efficiency programs to the load forecast. Absent energy efficiency, our resource position would be deficit earlier. The first capacity deficit is short-lived because a 150 MW capacity sale contract ends in 2016. Avista plans to address the 2016 capacity deficit with market purchases as 2016 approaches, therefore the first long-term capacity deficient begins in the summer of 2019.

The Company's resource portfolio has 281 MW of natural gas-fired peaking plants available to serve winter loads and 201 MW available in the summer. For long-term planning, these resources are available to generate energy at their full capabilities. Operationally, less expensive wholesale marketplace purchases may displace Avista's available resources. On an annual average basis, our loads and resources fall out of balance in 2020 for energy; the first quarterly energy deficit is in the first quarter of 2013.

PRiSM selects new resources to fill capacity and energy deficits, although the model may over- or under-build where economics support it. Because of acquisitions driven by capacity RPS compliance, large energy surpluses result. See figure 8.3.

Figure 8.3: Physical Resource Positions (Includes Conservation)

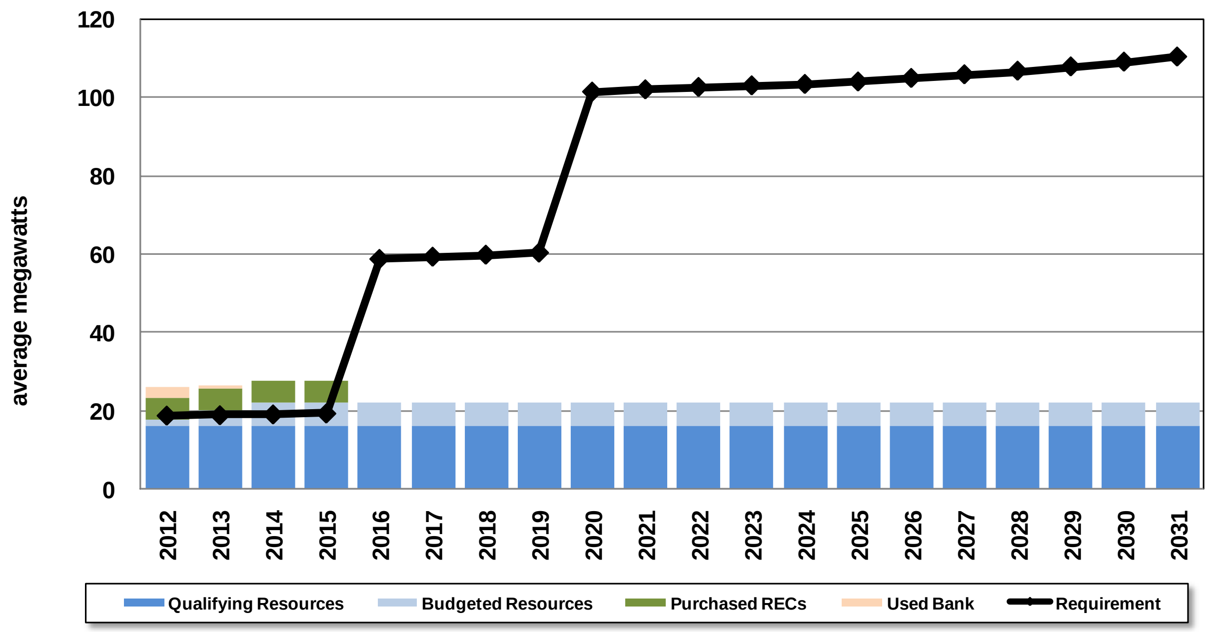


Renewable Portfolio Standards

Washington voters approved the Energy Independence Act through Initiative 937 (I-937) in the November 2006 general election. I-937 requires utilities with over 25,000 customers to meet three percent of retail load from qualified renewable resources 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 expects to meet or exceed its renewable energy requirements between 2012 and 2015 through a combination of qualifying hydroelectric upgrades, the Palouse Wind project, and a REC purchase. Projected REC positions are in Figure 8.4. I-937 includes the flexibility to use RECs from the current year, from the previous year, or from the following year for compliance. REC contingency reserves will be "banked" each year to account for compliance variability driven by loads and hydroelectric and wind generation variation.

Figure 8.4: REC Requirements vs. Qualifying RECs for Washington State RPS



Preferred Resource Strategy

The 2011 PRS consists of existing thermal resource upgrades, wind, conservation, and natural gas-fired simple and combined cycle gas turbines. The first resource acquisition is approximately 42 aMW of wind RECs by the end of 2012 to take advantage of federal tax incentives.[2]

Avista will rebuild distribution feeders over the next twenty years. The PRS includes 27 MW of peak capacity savings and 13 aMW of energy savings from smart grid and

[2] This requirement was met through a 2011 RFP process that selected the Palouse Wind Project.

distribution feeder initiatives. More discussion on this topic is included in the distribution upgrades section of the Transmission and Distribution chapter.

The PRiSM model selected an 83 MW simple cycle combustion turbine as its first large capacity addition in 2019. Another 83 MW simple cycle combustion turbine follows in 2020. Also in the 2018 to 20 period, existing thermal unit upgrades add 7 MW of capacity. The PRS adds 43 aMW of additional wind by the end of 2019 to meet the 15 percent renewable energy goal.

The PRS includes a 270 MW natural gas-fired combined-cycle combustion turbine (CCCT) in 2023, and another 270 MW CCCT in 2026, to meet projected capacity deficits created by the expiration of the Lancaster tolling agreement. Following this need is a 46 MW simple cycle turbine. In total, the PRS adds 1,024 MW of new generation capacity by the end of the IRP forecast. Table 8.1 presents the 2011 PRS resource types, timing and sizes.

Table 8.1: 2011 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Northwest Wind	2012	120	35
Distribution Efficiencies	2012-2024+	28	13
Existing Thermal Resource Upgrades	2018-2019	4	3
Simple Cycle Combustion Turbine	2019	83	75
Northwest Wind	2018-2019	120	35
Simple Cycle Combustion Turbine	2020	83	75
Combined-Cycle Combustion Turbine	2023	270	237
Combined-Cycle Combustion Turbine	2026/27	270	237
Simple Cycle Combustion Turbine	2029	46	42
Total		**1,024**	**752**

Table 8.2 shows the 2009 Preferred Resource Strategy. The major differences in the 2011 plan are a reduction in the quantity of wind resources and a switch to a combination of simple and combined cycle resources from only combined cycle gas-fired resources.

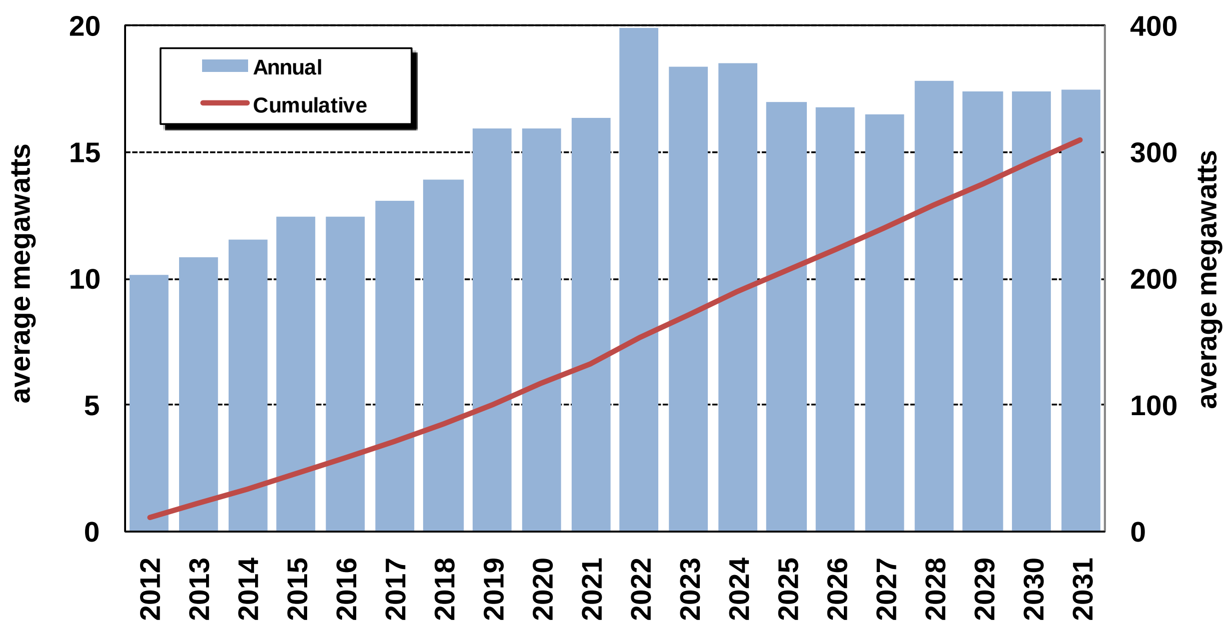
Table 8.2: 2009 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Northwest Wind	2012	150	48
Distribution Efficiencies	2010-2015	5	2.7
Little Falls Unit Upgrades	2013-2016	3	0.9
Northwest Wind	2019	150	50
Combined Cycle Combustion Turbine	2019	250	225
Upper Falls Upgrade	2020	2	1
Northwest Wind	2022	50	17
Combined Cycle Combustion Turbine	2024	250	225
Combined Cycle Combustion Turbine	2027	250	225
Total		**1,110**	**795**

Energy Efficiency

Energy efficiency is an integral part of the PRS analytical process. Energy efficiency is also a critical component of I-937, where utilities are required to obtain all cost effective conservation. Avista developed avoided energy costs and compared those figures against a conservation supply curve developed by Global Energy Partners. The 20-year forecast of energy efficiency acquisitions is in Figure 8.5. Avista plans to acquire 133 aMW of energy efficiency over the next 10 years and 310 aMW over 20. These acquisitions will reduce system peak, shaving 207 MW from by 2022, and 419 MW in 2031. Please refer to Chapter 3 for a more detailed discussion of energy efficiency resources.

Figure 8.5: Energy Efficiency Annual Expected Acquisition



Reardan Wind Project

Avista purchased the development rights for a wind site located in its service territory near Reardan, Washington, from Energy Northwest in 2008. The fully permitted site has several years of meteorological data and is ready for construction. This wind site is competitive to higher capacity factor sites, as the project does not require any third-party transmission and is located near Avista work crews.[3] The Reardan site could supply between 50 MW and 100 MW of wind generation. With the acquisition of the Palouse Wind project, development at Reardan is not likely prior to 2018-19.

Palouse Wind

On February 22, 2011, Avista issued a request for proposals (RFP) for I-937-qualifying renewable energy. Following the RFP, Avista selected the Palouse Wind project located near Rosalia and Oakesdale, Washington. The project will have a maximum capability of approximately 100 MW and an expected annual average energy output of 40 aMW. The contract is a 30-year power purchase agreement with a purchase option after year 10. The project should be on-line in the second half of 2012.

Little Falls Hydro Upgrades

The 2009 PRS included 0.9 aMW of incremental energy from upgrades to the Little Falls project between 2013 and 2016. When preparing this plan, Avista expected in-kind turbine replacements and no incremental energy. Additional study and modeling identified up to three aMW of incremental energy that will qualify for Washington’s Energy Independence Act. Final decisions about the upgrades are still pending. Analysis around this option continues and an update will be in the 2013 IRP.

Distribution Feeder Upgrades

Distribution feeder upgrades were in the PRS for the first time in the 2009 IRP. The feeder upgrade process began with an upgrade to the Ninth & Central Streets feeder in Spokane. The decision to rebuild a feeder considers energy savings, operation and maintenance savings, the age of existing equipment, reliability indexes, and the number of customers on the feeder. Based on analyses performed for this IRP, Avista likely will rebuild many of its distribution feeders, limited to five or six per year due to financial and staffing limitations. Feeder rebuild projects will begin in 2012 or 2013 and the Company will allocate resources after prioritizing the projects. Savings might change after further detailed cost analyses and rebuild schedules are completed.

Simple Cycle Combustion Turbines

Avista plans to identify potential sites for new gas-fired generation capacity within its service territory ahead of an anticipated 2019 need. Avista’s service territory has areas with different combinations of benefits and costs. Locations in Washington would have higher generation costs because of natural gas fuel taxes and carbon mitigation fees. However, the potential benefits of a Washington location, including proximity to natural gas pipelines and Avista’s transmission system; lower project elevations that provide higher on-peak capacity contributions per investment dollar; and water to cool the facility, might outweigh the costs. In Idaho, lower taxes and fees decrease the cost of a

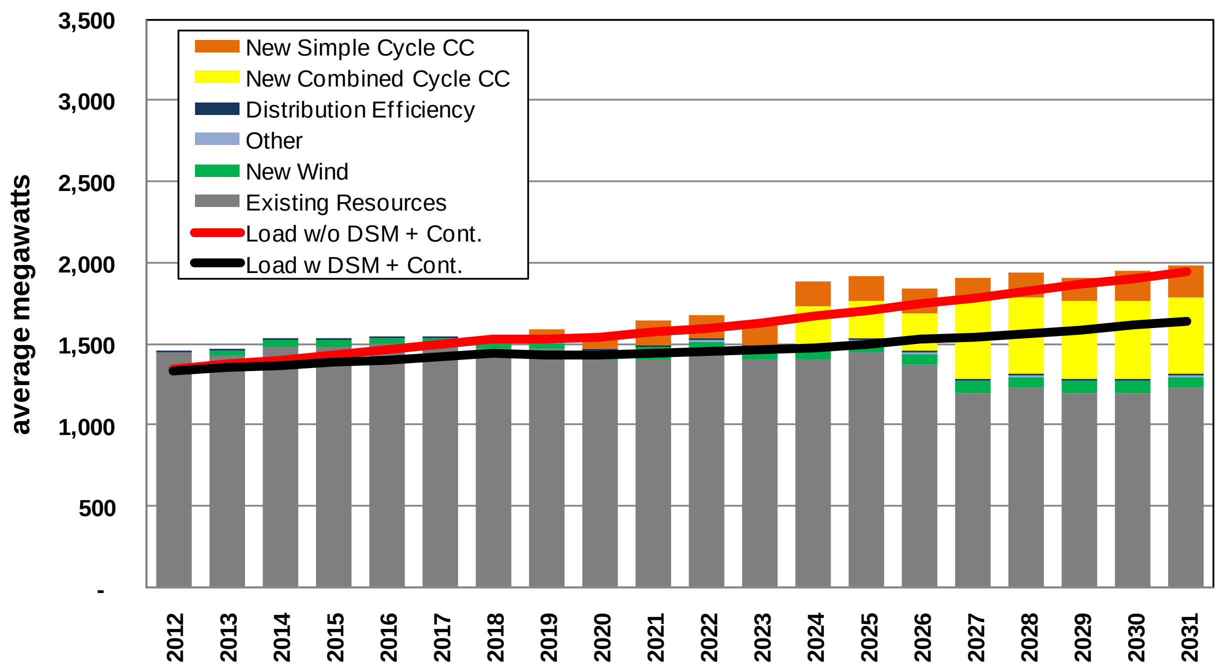
[3] Higher capacity sites are generally located outside of Avista’s service territory.

potential facility, but there are fewer locations to site a facility near natural gas pipelines, fewer low cost transmission interconnections, and fewer sites with adequate cooling water. The identification and procurement of a natural gas project site option is an Action Item for this IRP.

Loads and Resource Positions

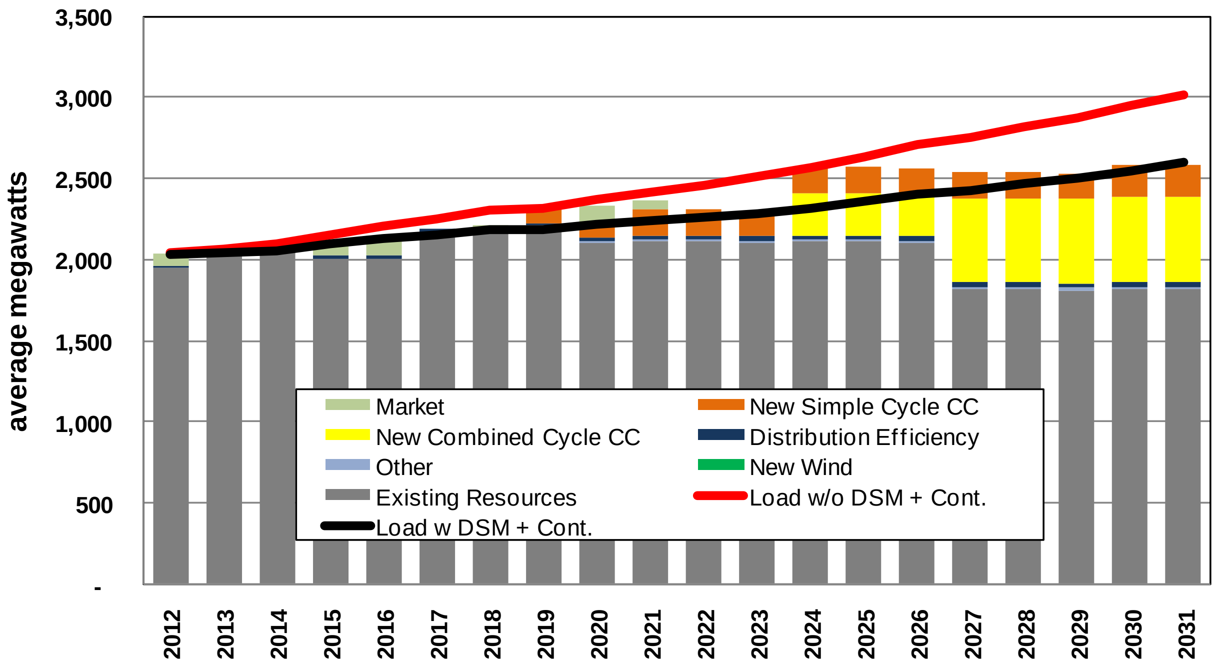
Conservation acquisitions identified in this IRP reduced the load forecast, as shown in Figure 8.6. The red line illustrates the load level the Company would need to meet absent energy efficiency programs. Absent conservation, Avista would need new resources in 2018 rather than 2020.

Figure 8.6: Annual Average Load and Resource Balance



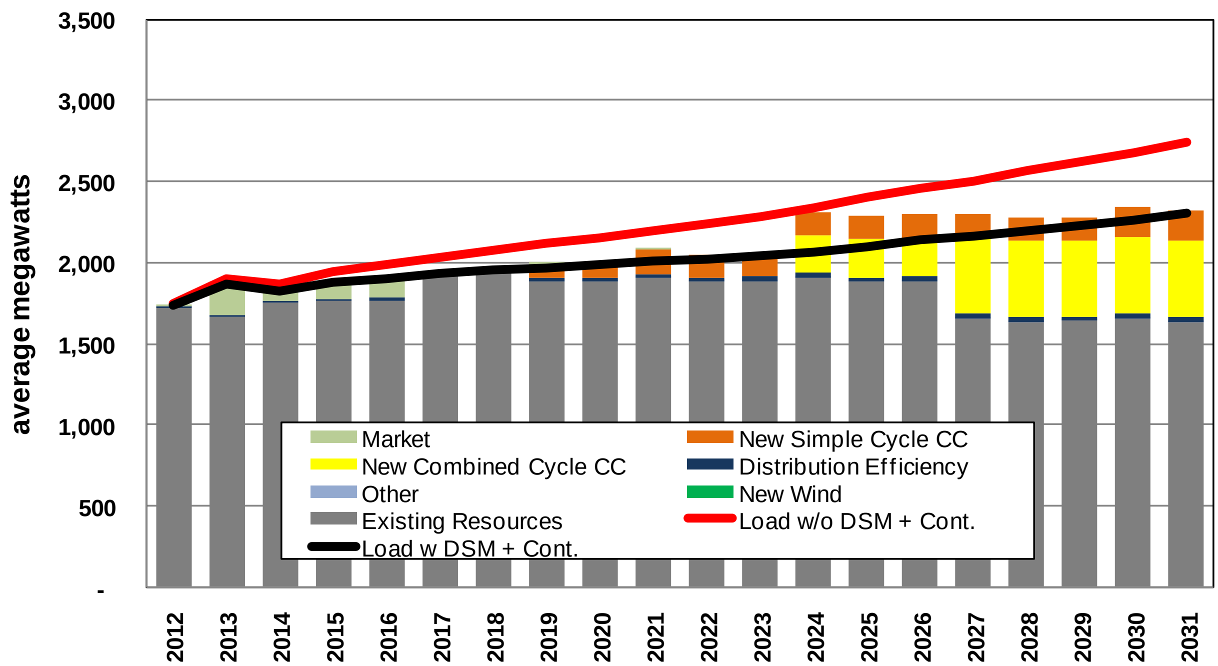
The first winter peak deficit without the conservation resource would occur in 2020, but the deficit does not occur until 2020 with the acquisition of energy efficiency measures (see Figure 8.7). Avista expects to have modest short-term resource deficits prior to 2022 and intends to meet these deficiencies with market purchases rather than acquiring a resource prior to a sustained need. An analysis of regional loads and resources support the Company's position that existing regional capacity should be available to support a robust short-term wholesale market in the timeframe required. A capacity resource could replace market purchases, without a significant impact on the long-term portfolio cost, if conditions change and the Company determines that it cannot depend on the market during this period.

Figure 8.7: Winter Peak Load and Resource Balance



The summer peak load and resource position shows a capacity need prior to the first winter need. Avista's peak loads are lower in summer than in the winter, but the impacts on hydroelectric and thermal generation capacity in the summer, due to lower flow conditions and high temperatures, are greater than the load differences. As shown in Figure 8.8, summer resource deficits occur in 2013 without conservation and in 2016 (short-term) and 2019 (long-term) with conservation measures. The Company plans to fill the short-term summer capacity deficit in 2016 with market purchases. Beginning in 2022, summer deficits no longer drive Avista's capacity needs due to the expiration of the WNP-3 contract in 2019.

Figure 8.8: Summer Peak Load and Resource Balance

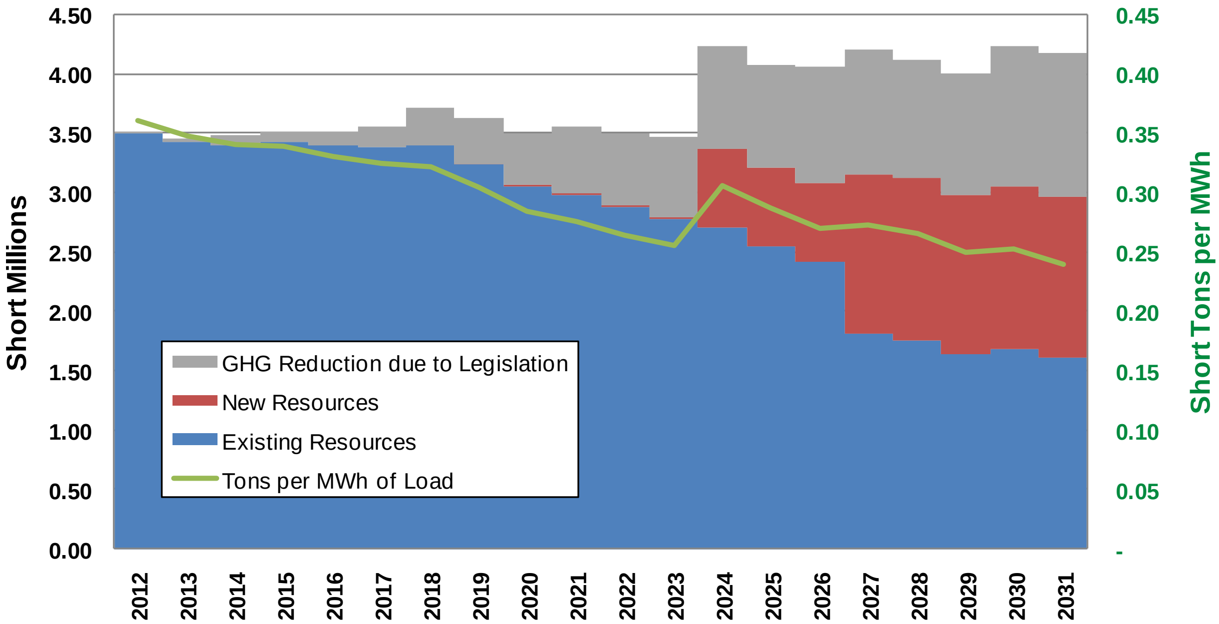


Greenhouse Gas Emissions

The Market Analysis chapter discusses how greenhouse gas emissions from electric generation in the Western Interconnect decrease due to of the addition of carbon emission penalties. Avista's greenhouse gas emissions should fall because of anticipated carbon reduction policies. Greenhouse gas policies will affect higher-cost coal facilities before affecting low operating cost facilities, such as Colstrip. New or underutilized natural gas-fired resources located closer to west coast load centers will replace the coal-fired facilities. Figure 8.9 presents expected greenhouse gas emissions with the addition of PRS resources. Overall Company greenhouse gas emissions should fall starting in 2020 as Colstrip output decreases and natural gas-fired generation increases. The 2024 increase in emissions shown in Figure 8.9 comes from a new CCCT resource. These emission estimates do not include emissions produced from purchased power or include a reduction in emissions for off-system sales. The Company expects its greenhouse gas emissions intensity from owned and controlled generation to fall from 0.36 short tons per MWh to 0.24 short tons per MWh with the current resource mix and the generation identified in the PRS[4].

[4] Greenhouse gas emissions are not included for the Kettle Falls plant because biomass is a carbon neutral resource.

Figure 8.9: Avista Owned and Controlled Resource's Greenhouse Gas Emissions



Greenhouse gas policy has a clear impact on Avista's future resource mix. Absent carbon policy, cumulative greenhouse gas emissions over the 20-year IRP timeframe would be 18 percent higher, with the difference growing each year of the forecast. By 2031, annual emissions would be 29 percent higher without carbon mitigation. The gray area illustrates these differences in Figure 8.9.

Efficient Frontier Analysis

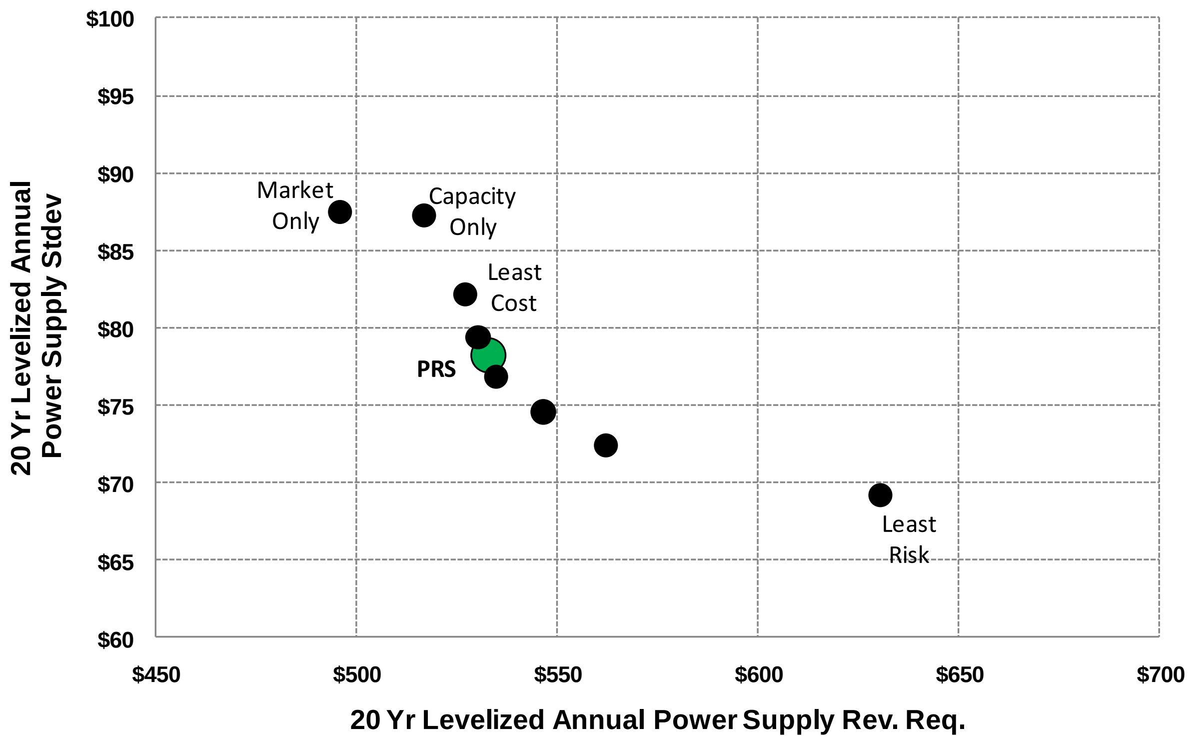
Efficient frontier analysis is the backbone of the Preferred Resource Strategy. PRiSM helps develop the efficient frontier by simulating the costs and risks of several different resource portfolios. The analysis illustrates the relative performance of potential portfolios to each other on a cost and risk basis. Thought of a different way, the curve represents the least-cost strategy at each risk level. The PRS analyses examined the following portfolios, as detailed here and in Figure 8.10:

- **Market Only**: All resource deficits met with spot market purchases.
- **Capacity Only**: Only capacity deficits met with new resources. Energy and RPS requirements ignored.
- **Least Cost**: All capacity, energy and RPS requirements met with new least-cost resources. This portfolio ignores power supply expense volatility in favor of lowest cost resources.
- **Least Risk**: All capacity, energy and RPS requirements met with least-risk resources. This portfolio ignores the overall cost of the selected portfolio in favor of minimizing risk.
- **Efficient Frontier:** All capacity, energy and RPS requirements met with sets of intermediate portfolios between the least risk and least cost options.

- **PRS**: All capacity, energy and RPS requirements met while recognizing both the overall cost and risk inherent in the portfolio.

Figure 8.10 presents the Efficient Frontier. The x-axis is the levelized nominal cost per year for power supply costs and the y-axis is the levelized standard deviation of power supply costs.

Figure 8.10: Expected Case Efficient Frontier



The Market Only portfolio is least cost from a long-term financial perspective, but it has the highest level of risk. The strategy fails to meet capacity, energy, and RPS requirements with Company-controlled assets.

The Capacity Only strategy meets capacity requirements by adding gas-fired peaking plants, but wholesale market purchases displace them in most hours. This strategy does not meet RPS requirements and does not decrease power supply cost volatility, except at the tail of the distribution. The Least Cost strategy meets capacity, energy and RPS requirements at the lowest possible cost by adding gas-fired peaking plants and minimum levels of wind generation to meet Washington State RPS requirements. The Least Risk strategy substantially replaces gas-fired peaking plants with gas-fired combined-cycle combustion turbines, increases the quantity of wind resources, and adds solar resources to the mix.

All portfolios along the efficient frontier are the least cost portfolio for a given level of risk and portfolio constraints. The decision to select a particular portfolio along the efficient frontier curve focuses on volatility reductions gained by spending more capital. Avista management determines the ultimate selection of the PRS over other potential resource strategies in an effort to balance overall long-term customer costs with the risks of year-over-year expense variability. The PRS includes 1.2 percent more costs on average and 4.5 percent less volatility compared to the Least Cost portfolio.

Avoided Costs

The efficient frontier methodology can determine the avoided cost of new resource additions. There are two avoided cost calculations for this IRP; one for energy efficiency and one for new generation resources.

Avoided Cost of Conservation

Three portfolios are required to estimate the supply-side cost components necessary to estimate the avoided cost for conservation. The differences between each portfolio sum to the avoided cost of conservation:

- **Market Only:** This resource portfolio includes no new resource additions and the incremental cost of new power supply is the cost to buy power from the short-term market. The price difference between the Expected Case and the Unconstrained Carbon scenario is the greenhouse gas policy cost.
- **Capacity Only:** This resource portfolio builds new resource capacity to meet resource deficits to meet peak load. The difference between the Market Only and Capacity Only strategies equals the capacity value of the new resources. This estimate typically shows the incremental cost divided by the incremental kilowatts of installed capacity. For this example the $/kW adder is translated to $/MWh assuming a flat energy delivery.
- **Pre-Preferred Resource Strategy:** This resource portfolio is similar to the PRS resource mix assuming the Company does not pursue the conservation resource.

Table 8.3 shows the 20-year levelized avoided cost of conservation. The avoided cost for conservation includes value only for those periods realizing avoided costs. For example, the avoided costs of conservation programs only include a capacity value in the years where the Company is short capacity. Further, the market component (Energy Forecast) applies to each conservation program depending upon the timing of energy delivery. For example, an air conditioning program receives an energy value depending upon prices in the summer months when actual energy savings occur.

Table 8.3: Nominal Levelized Avoided Costs ($/MWh)

	2012-2031
Energy Forecast	52.86
Carbon Adder Forecast	17.64
Capacity Value	10.51
Risk Premium	7.38
Total	**88.39**

I-937 requires that the avoided costs used for conservation include additional items beyond the actual cost of avoided energy and capacity. Avoided costs increase by 10 percent to bias the IRP toward a preference for conservation. Additionally, reduced transmission and distribution losses, and operations and maintenance are also included. The following formula identifies the costs included in the avoided cost for energy efficiency measures.

$$\{(E + PC + R) * (1 + P)\} * (1 + L) + DC * (1 + L)$$

Where:

E = Market energy price. The price calculated with AURORAxmp is $70.50 per MWh and includes projected greenhouse gas costs.

PC = New resource capacity savings. This value is calculated using PRiSM and is estimated to be $10.51 per MWh.

R = Risk premium to account for RPS and rate volatility reductions. This PRiSM-calculated value is $7.38 per MWh.

P = Power Act preference premium. This is the additional 10 percent premium given as a preference towards energy efficiency measures.

L = Transmission and distribution losses. This component is 6.1 percent based on Avista's estimated system average losses.

DC = Distribution capacity savings. This value is approximately $10/kW-year or $1.14 per MWh.

The following calculation shows the estimated levelized avoided cost for a theoretical conservation program that reduces load by one megawatt each hour of the year:

$$\{[(52.86 + 17.64 + 10.51 + 7.38) * (1 + 10\%)] * (1 + 6.1\%) + [1.14 * (1 + 6.1\%)]\}$$
$$= \$104.37 \text{ per MWh}$$

Resource Avoided Costs

An avoided cost calculation for supply-side resources is developed using the conservation avoided cost estimates and final PRS data. These estimates use the same basic methodology as avoided cost of conservation calculation. However, the resource avoided cost represents a portfolio that includes conservation measures and excludes the greenhouse gas emission adder.[5]

Table 8.4 presents the avoided cost for new supply-side resources; Table 8.5 translates these estimates into a 20-year nominal levelized cost per MWh. The 20-year levelized cost of $84.64/MWh is higher than what would be expected based on the information presented in Table 8.3 where carbon costs are not included ($88.39 – $17.64 = $70.75/MWh). The higher cost is due to the lower operating margin in the Unconstrained Carbon scenario than in the Expected Case, so higher capacity/risk premiums would result if capital costs remain equal. Further, the risk premium assumes the utility receives I-937-qualifying RECs; a potential new project would not receive this value without providing qualified RECs. The risk premium is also a tilted cost with the same present value as compared to the modeled cost. The avoided cost is tilted due to the fact developer's cost would not be front loaded like the utilities recovery mechanism.

Table 8.4: Annual Avoided Costs ($/MWh)

Year	Energy	Capacity	Risk	Total
2012	41.19	0.00	0.00	41.19
2013	46.58	0.00	15.20	61.78
2014	49.73	0.00	16.21	65.93
2015	46.76	0.00	17.28	64.04
2016	48.20	0.00	18.42	66.62
2017	51.15	0.00	19.64	70.79
2018	52.91	0.00	20.94	73.85
2019	52.97	16.16	22.33	91.46
2020	53.25	17.52	23.81	94.58
2021	54.45	17.00	25.39	96.83
2022	56.15	16.71	27.07	99.93
2023	57.82	17.18	28.86	103.86
2024	56.89	17.24	30.77	104.90
2025	56.80	17.16	32.81	106.77
2026	58.82	17.42	34.98	111.23
2027	60.36	17.72	37.30	115.38
2028	63.08	18.86	39.77	121.71
2029	64.51	18.54	42.41	125.45
2030	66.29	18.21	45.21	129.71
2031	68.89	17.70	48.21	134.79

Where Avista acquires the wind resource (such as the Palouse Wind Project) identified in the PRS of this plan, the risk premium would no longer benefit Avista, and an adjustment to the avoided costs is necessary as shown in Table 8.5. Table 8.6 presents

[5] There are no greenhouse gas emissions policies in place to justify the adder at this time. The resource avoided cost calculation will include this adder when state or federally imposed greenhouse gas costs are assessed for electric generation.

the comparison in levelized avoided resource costs after completion of the First Wind PRS acquisition.

Table 8.5: Annual Avoided Costs ($/MWh)

Year	Energy	Capacity	Risk	Total
2012	41.19	0.00	0.00	41.19
2013	46.58	0.00	15.20	61.78
2014	49.73	0.00	16.21	65.93
2015	46.76	0.00	17.28	64.04
2016	48.20	0.00	18.42	66.62
2017	51.15	0.00	19.64	70.79
2018	52.91	0.00	20.94	73.85
2019	52.97	16.16	22.33	91.46
2020	53.25	17.52	23.81	94.58
2021	54.45	17.00	25.39	96.83
2022	56.15	16.71	27.07	99.93
2023	57.82	17.18	28.86	103.86
2024	56.89	17.24	30.77	104.90
2025	56.80	17.16	32.81	106.77
2026	58.82	17.42	34.98	111.23
2027	60.36	17.72	37.30	115.38
2028	63.08	18.86	39.77	121.71
2029	64.51	18.54	42.41	125.45
2030	66.29	18.21	45.21	129.71
2031	68.89	17.70	48.21	134.79

Table 8.6: Nominal Levelized Avoided Costs ($/MWh)

Cost Component	2012-2031 (Table 8.4)	2012-2031 (Table 8.5)
Energy	52.86	52.86
Capacity	8.60	8.60
Risk	23.18	15.78
Total	**84.64**	**77.24**

Preferred Resource Strategy

Earlier in this chapter, the PRS and summary levelized costs and risk were illustrated and compared to portfolios along the efficient frontier. This section provides more detail about the PRS, the associated financial risks of the PRS, the cost of its resultant emissions, and an index of resultant power supply expenses.

Capital Spending Requirements

One of the major assumptions in this IRP is that Avista finances and owns all new resources. Using this assumption, and the resources identified in the PRS, the first capital outlay begins in 2013 for distribution feeder upgrades, followed by additional capital needs for PRS wind development. Wind or other generation resources acquired via a power purchase agreement may reduce expected PRS capital spending. Distribution feeder upgrades may begin in 2012 depending upon operational availability of resources needed for the work.

The capital cash flows in Table 8.7 include allowance for funds used during construction (AFUDC) and account for tax incentives and sales taxes. Costs in Table 8.7 are shown when capital would be placed in rate base, rather than when capital is actually spent. The present value of the required investment is just over $0.84 billion and the nominal total capital expense is $1.7 billion over the IRP timeframe.

Table 8.7: PRS Rate Base Additions from Capital Expenditures (Millions of Dollars)

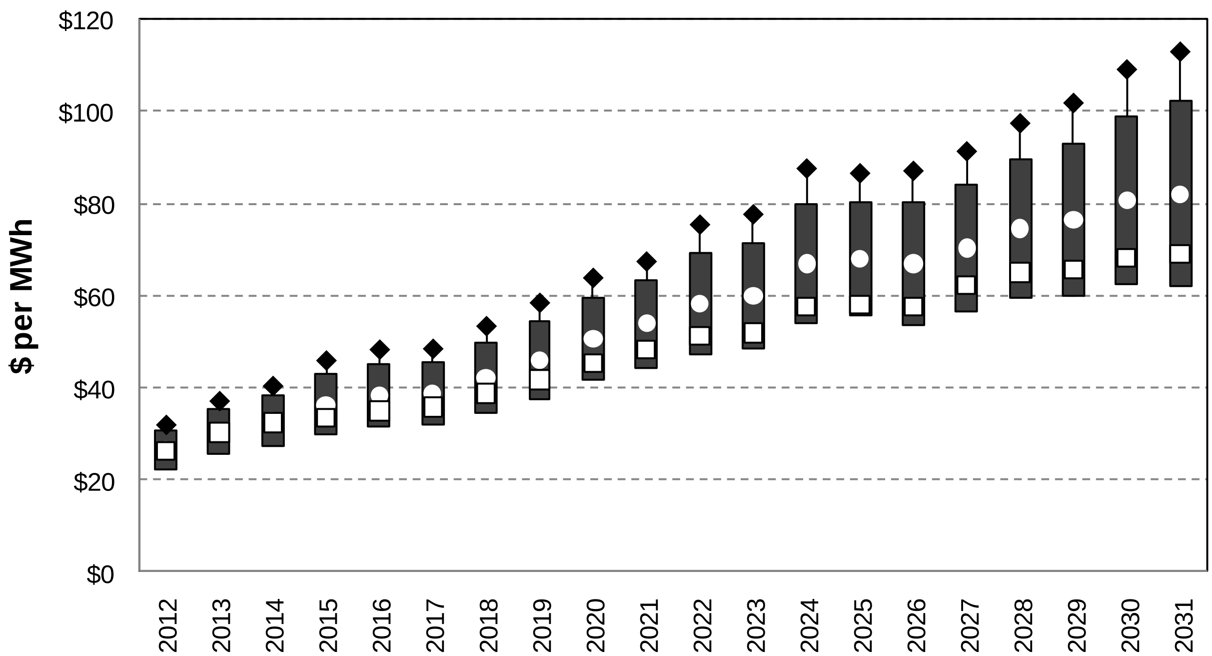
Year	Investment	Year	Investment
2012	0	2022	6
2013	243	2023	6
2014	6	2024	448
2015	6	2025	0
2016	6	2026	0
2017	4	2027	461
2018	7	2028	0
2019	77	2029	0
2020	90	2030	74
2021	251	2031	0
2012-2021 Total	**690**	**2022-2031 Totals**	**994**

Annual Power Supply Expenses and Volatility

The PRS variance analysis tracks fuel, variable O&M, emissions, and market transaction costs for the existing resource portfolio. These costs are captured for each of the 500 iterations of the Expected 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 of potential costs to serve future loads. Figure 8.11 shows expected PRS costs modeled through 2031 as the white circle (Nominal). In 2012, costs are expected to be $26 per MWh. The 80 percent confidence interval, represented as the black bar, ranges between $22 and $31 per MWh. The black diamonds in the figure represent the TailVar 90 risk level, or the average of the top 10 percent of the worst outcomes; the 2010 TailVar cost is $32 per MWh, or $6 per MWh above the expected value.

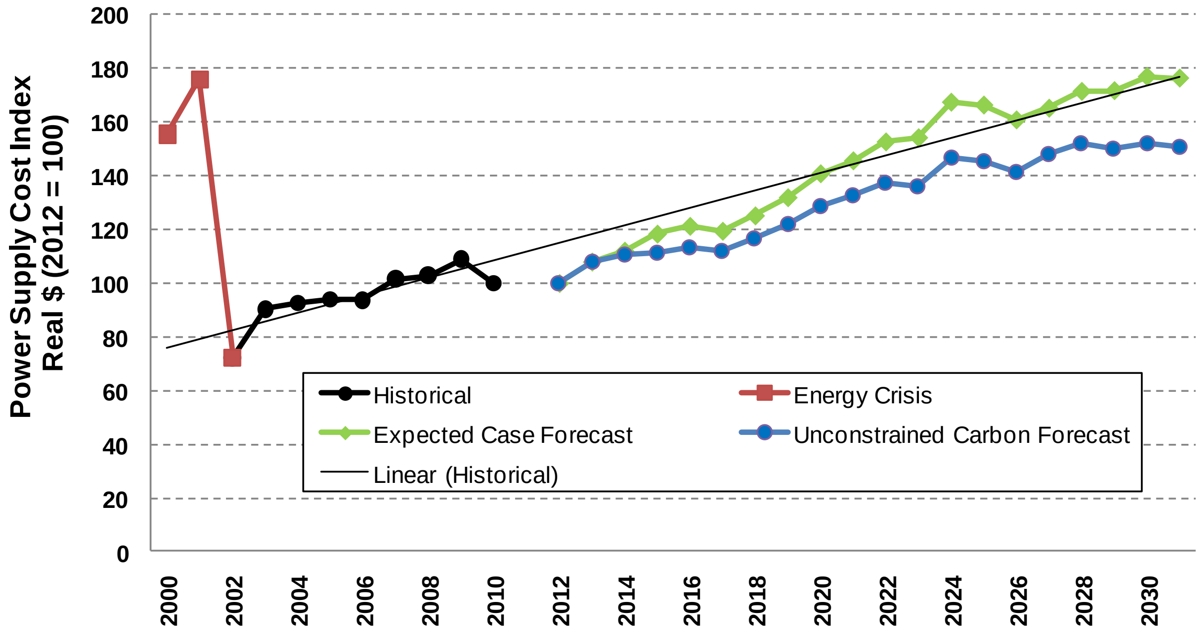
Power supply costs increase with natural gas and greenhouse gas price increases. Uncertainty increases over time and the confidence interval band expands. The white boxes in Figure 8.11 represent the cost per MWh without greenhouse gas costs. For example, in 2020 the average system costs would be 8.8 percent lower without carbon mitigation. The expected levelized cost for the expected case is $48.59 per MWh and $43.73 per MWh (10 percent lower) without greenhouse gas costs.

Figure 8.11: Power Supply Expense Range



A common question regarding IRPs is what will be the change to power supply costs over the time horizon of the plan. Figure 8.12 illustrates expected power supply cost changes compared to historical power supply costs under the Preferred Resource Strategy. It shows that power supply costs, on a per-MWh basis have increased 4.1 percent per year over inflation between 2002 and 2010. This 4.1 percent annual growth rate increase is shown in Figure 8.12 as a linear black line. By 2021, absent greenhouse gas emissions costs, power supply costs are expected to be 32 percent higher than 2010, but up to 41 percent higher with the addition of greenhouse gas emissions costs for an annual growth rate of 2.6 percent and 3.8 percent respectively.

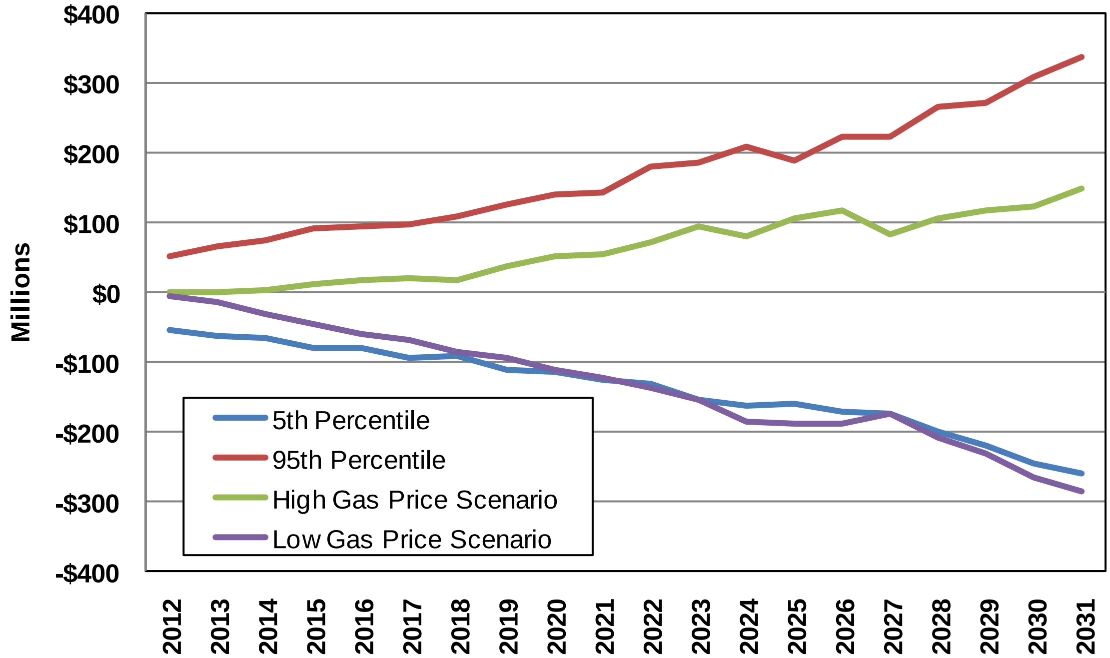
Figure 8.12: Real Power Supply Expected Rate Growth Index $/MWh (2012 = 100)



Natural Gas Price Risk

The Market Analysis chapter showed the results of high and low natural gas price forecasts. The PRS includes 752 MW of natural gas-fired resources and exposes Avista's customers to increasing levels of natural gas price risk. This section uses natural gas price forecast scenarios, including changes to expected greenhouse gas prices, to explain the range of costs resulting from the PRS. Figure 8.13 shows the total portfolio cost range using different natural gas scenarios compared to the expected cost of the PRS. The low natural gas price scenario reduces expected costs by 19.5 percent and the high gas price scenario increases costs by 8.7 percent on a present value basis. Lower natural gas prices have greater effect on prices than higher prices as the Using stochastic model results, rather than the deterministic scenarios, illustrates risk exposure to the wholesale market. The 5th and 95th percentiles reflect variability from natural gas and other variables. The low natural gas price scenario is reflective of a low cost future, but the high natural gas price scenario does not reflect the potential cost excursions that could affect the PRS that is not natural gas price related.

Figure 8.13: Power Supply Cost Sensitivities

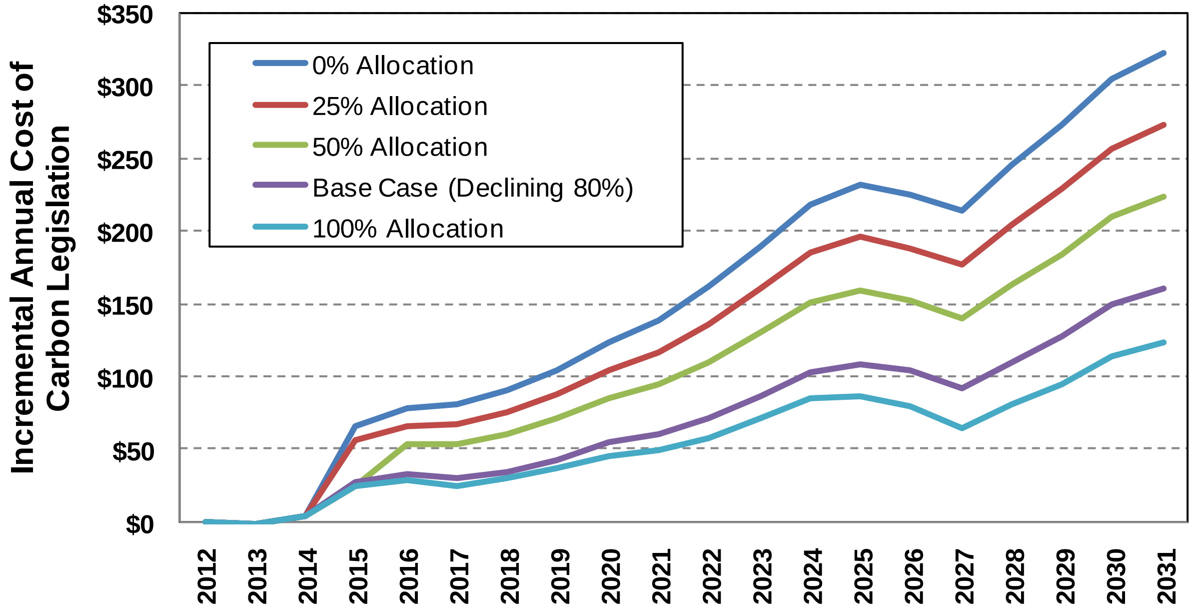


Greenhouse Gas Costs

Avista anticipates some form of federal greenhouse gas policy, although the exact nature, timing and scope of the policy is not known. As described in the Market Analysis chapter, four potential greenhouse gas policies are modeled to estimate marginal electricity costs. The estimate of greenhouse gas emission costs depends on the number of free allowances provided by the government. Figure 8.14 illustrates the range of total annual greenhouse gas costs as the percent of free credits allocated to Avista are changed. For example, if no credits are allocated to Avista in 2022, Avista's cost to serve customers will be $91 million ($162 million in total) higher than the Expected Case where 80 percent of the credits are free and mitigation costs $71 million.

A reduction in output from the Colstrip generators, increased natural gas prices and increased wholesale electricity prices drive most of the greenhouse gas policy cost increases. In the marketplace, low marginal cost coal-fired plants dispatch less, or even turn off, and higher marginal cost natural gas-fired resources replaces their output. The cost of natural gas resources is higher than it would be absent greenhouse gas costs because of increased demand for gas-fired resources. These additional costs represent up to 11 percent of total power supply expenses in the Expected Case.

Figure 8.14: Greenhouse Gas Related Power Supply Expense



Efficient Frontier Comparison of Greenhouse Gas Policies

Three stochastic market studies studied the cost of different greenhouse gas policies: 1) the Expected Case, 2) Unconstrained Carbon, and 3) Mandatory Coal Retirement. These three stochastic market forecasts were than assumed to be potential markets in PRiSM and an efficient frontier for each market future was created, as shown in Figure 8.15. Table 8.8 provides more details about the study results. The PRS portfolio is the same in the Expected Case and the Unconstrained Carbon Case, but the Mandatory Coal Retirement Case retires Colstrip Unit 3 in 2023 and Unit 4 in 2026, replacing them with a CCCT. Colstrip decommissioning costs is not included in figures.

Figure 8.15: Efficient Frontier Comparison

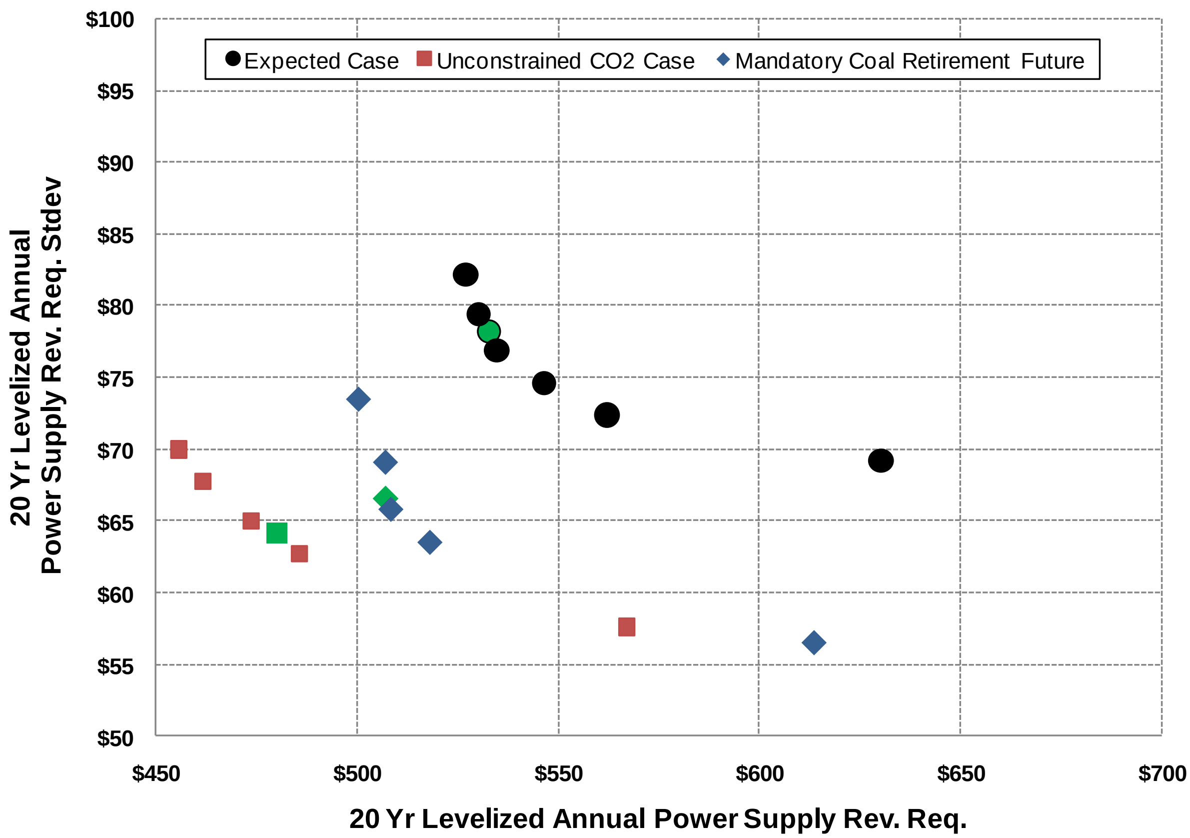


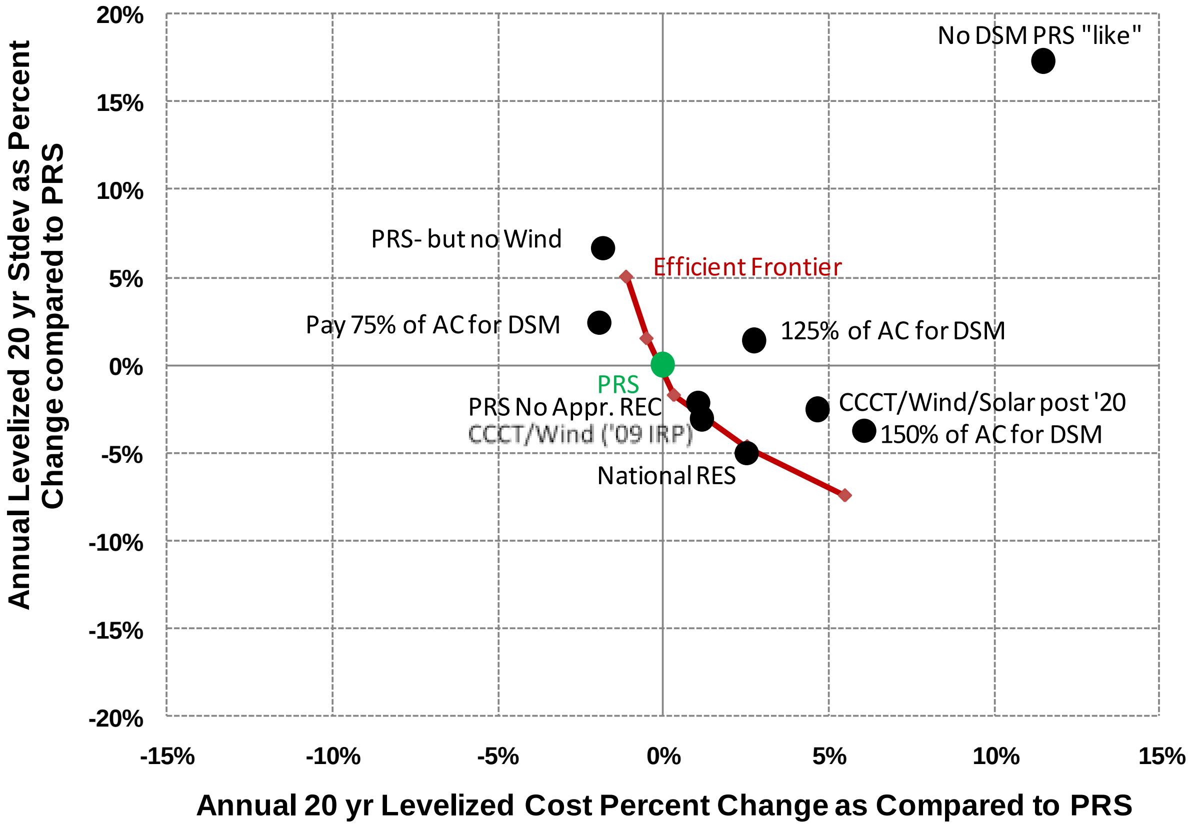
Table 8.8: Preferred Portfolio Cost and Risk Comparison (Millions $)

	Expected Case	Unconstrained Carbon	Coal Retirement
2012-2022 Cost NPV	3,094	2,886	2,937
2012-2031 Cost NPV	5,735	5,168	5,458
2022 Expected Cost	636	564	576
2022 Stdev	91	68	71
2022 Stdev/Cost	14%	12%	0
2022 CO_2 Emissions (000's)	2,894	3,498	3,752
2031 CO_2 Emissions (000's)	2,972	4,177	3,560

Portfolio Scenarios

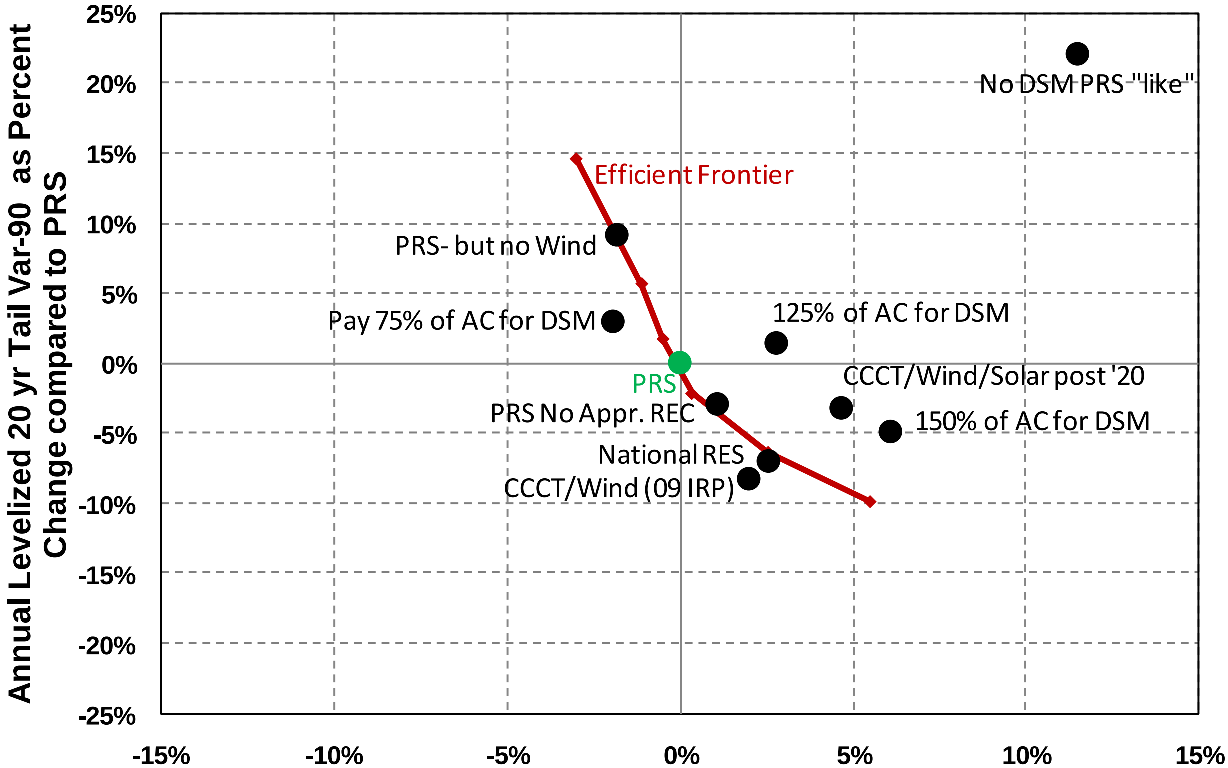
The efficient frontier analysis creates resource portfolios for alternative levels of risk and cost. Avista's management selected the PRS to the balance costs and risk inherent in our resource portfolio. The following list of portfolios shows details of alternatives to the PRS, either along the efficient frontier or "hand-picked" so that the costs of these choices could be considered. Figure 8.16 illustrates the levelized cost percent change and the levelized annual standard deviation percent change for each of the portfolios in comparison to the PRS.

Figure 8.16: Efficient Frontier Comparison



The Technical Advisory Committee requested Avista to show the efficient frontier and other portfolios using Tail Var 90 rather than standard deviation as a measure of risk (Figure 8.17). The TAC wanted to know if we measured risk differently would the Company draw a different conclusion on its resource choice. The result of this study shows using Tail Var 90 changes the magnitude of risk as compared to the standard deviation, but the PRS remains the Company's best choice. Using Tail Var 90 magnifies the risk savings of moving from Simple Cycle CTs to Combined Cycle CTs, as the standard deviation method shows a 5 percent reduction in risk for 2 percent more in cost, while the Tail Var 90 method shows a 15 percent risk reduction for the same cost increase.

Figure 8.17: Efficient Frontier Comparison with Tail Var90



The following section describes the resources selected in each of the portfolios designated in Figure 8.16. Table 8.9 summarizes the PRS.

Table 8.9: Preferred Resource Strategy

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	166	0	46	**166**	**212**
CCCT (Nameplate)	0	0	270	270	**0**	**540**
Thermal Upgrades	0	4	0	0	**4**	**4**
Wind (Energy)	35	36	0	0	**71**	**71**
Solar (Energy)	0	0	0	0	**0**	**0**
Conservation (Energy)	57	75	91	87	**133**	**310**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

Least Cost Portfolio

The Least Cost portfolio is the PRiSM model's resulting portfolio that meets capacity, energy and RPS needs at the least expected cost. This portfolio is a combination of wind and natural gas-fired SCCT generation. Table 8.10 illustrates the generation resources added in the Least Cost portfolio.

Table 8.10: Least Cost Portfolio

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	83	249	415	**83**	**747**
CCCT (Nameplate)	0	0	0	0	**0**	**0**
Thermal Upgrades	0	0	0	0	**0**	**0**
Wind (Energy)	35	24	12	0	**59**	**71**
Solar (Energy)	0	0	0	0	**0**	**0**
Conservation (Energy)	57	75	91	87	**133**	**310**
Distribution Feeders (Energy)	8	3	2	1	**11**	**13**

Least Risk Portfolio

The Least Risk portfolio is the portfolio selected by the PRiSM model meeting all capacity, energy and RPS needs at the least expected risk. PRiSM measures risk using levelized annual power supply cost variance. This portfolio is a combination of wind, solar, natural gas-fired SCCT and CCCT generation resources. Table 8.11 illustrates the resources added in the Least Risk portfolio.

Table 8.11: Least Risk Portfolio

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	0	3	184	**0**	**187**
CCCT (Nameplate)	0	270	270	0	**270**	**540**
Thermal Upgrades	0	3	14	0	**3**	**17**
Wind (Energy)	61	37	0	0	**98**	**98**
Solar (Energy)	25	27	6	6	**52**	**64**
Conservation (Energy)	57	75	91	87	**133**	**310**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

50/50Cost and Risk Midpoint Portfolio

The 50/50 Cost and Risk Midpoint portfolio is the PRiSM model's portfolio selection that meets capacity, energy and RPS needs at the midpoint between the least risk and least cost resource portfolios. This resource portfolio is a combination of wind, solar and natural gas-fired SCCT and CCCT generation. Table 8.12 illustrates the resources added in this portfolio.

Table 8.12: 50/50 Cost and Risk Midpoint Portfolio

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	83	0	94	**83**	**177**
CCCT (Nameplate)	0	0	270	270	**0**	**540**
Thermal Upgrades	0	0	4	0	**0**	**4**
Wind (Energy)	35	23	23	12	**58**	**93**
Solar (Energy)	0	0	0	9	**0**	**9**
Conservation (Energy)	57	75	91	87	**133**	**310**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

75/25 Cost and Risk Portfolio
The 75/25 Cost and Risk portfolio is the PRiSM model's portfolio selection that meets capacity, energy and RPS needs at the midpoint between the least cost portfolio and the 50/50 portfolio. This portfolio is similar to the PRS with a combination of wind and natural gas-fired SCCT generation. Table 8.13 illustrates the resources added under the 75/25 Cost and Risk portfolio.

Table 8.13: 75/25 Cost Risk Portfolio

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	83	249	0	**83**	**332**
CCCT (Nameplate)	0	0	0	540	**0**	**540**
Thermal Upgrades	0	0	0	0	**0**	**0**
Wind (Energy)	35	23	12	12	**58**	**82**
Solar (Energy)	0	0	0	0	**0**	**0**
Conservation (Energy)	57	75	91	87	**133**	**310**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

25/75 Cost and Risk Portfolio
The 25/75 Cost Risk portfolio is the PRiSM model's portfolio selection meeting capacity, energy and RPS needs at the midpoint between the Least Risk portfolio and the 50/50 Cost and Risk portfolio. The 25/75 Cost and Risk portfolio includes a combination of wind, solar, and natural gas-fired SCCT and CCCT generation. Table 8.14 illustrates the resources added in the 25/75 Cost and Risk portfolio.

Table 8.14: 25/75 Cost Risk Portfolio

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	83	0	0	**83**	**83**
CCCT (Nameplate)	0	0	540	270	**0**	**810**
Thermal Upgrades	0	0	4	0	**0**	**4**
Wind (Energy)	35	23	37	0	**58**	**95**
Solar (Energy)	0	0	0	5	**0**	**5**
Conservation (Energy)	57	75	91	87	**133**	**310**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

PRS without Apprentice Credits

The PRS without Apprentice Credits portfolio represents a resource strategy that assumes the Company is unable to contract for apprentice labor for new wind resources and therefore the acquisitions do not qualify for the 20 percent REC credit adder in I-937. This portfolio is a similar to the PRS, but includes 25 aMW of additional wind energy. Where wind resources have an average capacity factor of 31 percent, Avista would need to procure an additional 80 MW of nameplate wind capacity. Table 8.15 illustrates the PRS without Apprenticeship Credits portfolio resource additions.

Table 8.15: PRS without Apprentice Credits

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	166	0	46	**166**	**212**
CCCT (Nameplate)	0	0	270	270	**0**	**540**
Thermal Upgrades	0	4	0	0	**4**	**4**
Wind (Energy)	35	49	12	0	**84**	**96**
Solar (Energy)	0	0	0	0	**0**	**0**
Conservation (Energy)	57	75	91	87	**133**	**310**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

2009 IRP Portfolio

The PRS from the 2009 IRP included 350 MW of wind generation and 750 MW of gas-fired CCCT generation. The 2009 IRP Portfolio emulates the 2009 PRS with 2011 IRP adjustments for lower load projections and lower natural gas and market electricity prices. Table 8.16 illustrates the resource additions under the 2009 IRP Portfolio.

Table 8.16: 2009 IRP Portfolio

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	0	0	0	**0**	**0**
CCCT (Nameplate)	0	270	270	270	**270**	**810**
Thermal Upgrades	0	0	0	0	**0**	**0**
Wind (Energy)	44	44	15	0	**87**	**102**
Solar (Energy)	0	0	0	0	**0**	**0**
Conservation (Energy)	57	75	91	87	**133**	**310**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

PRS without Wind Portfolio

The PRS without Wind Portfolio illustrates the cost of wind additions to the PRS. This portfolio is the same as the 2011 PRS, but excludes the qualified renewable generation required by the Energy Independence Act. Table 8.17 illustrates the resources added under the PRS without Wind Portfolio.

Table 8.17: PRS without Wind Portfolio

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	166	0	46	**166**	**212**
CCCT (Nameplate)	0	0	270	270	**0**	**540**
Thermal Upgrades	0	4	0	0	**4**	**4**
Wind (Energy)	0	0	0	0	**0**	**0**
Solar (Energy)	0	0	0	0	**0**	**0**
Conservation (Energy)	57	75	91	87	**133**	**310**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

CCCT with Solar after 2015 Portfolio

The CCCT with Solar after 2015 Portfolio illustrates the additional cost of using solar, rather than wind, to meet Washington's I-937 requirements. Table 8.18 shows the resources added under the CCCT with Solar after 2015 Portfolio.

Table 8.18: CCCT with Solar after 2015 Portfolio

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	0	0	0	**0**	**0**
CCCT (Nameplate)	0	0	270	540	**0**	**810**
Thermal Upgrades	0	7	3	0	**10**	**10**
Wind (Energy)	36	0	0	0	**36**	**36**
Solar (Energy)	0	26	7	0	**26**	**33**
Conservation (Energy)	57	75	91	87	**133**	**310**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

National Renewable Energy Standard Portfolio

There have been several attempts to implement a federal renewable energy standard. The National Renewable Energy Standard Portfolio illustrates changes to the PRS needed to meet renewable requirements at the national level. Depending on the legislation, Avista may be required to secure an additional 106 aMW[6] to cover the Company's retail loads in the Idaho service territory. The actual level of wind required under a federal renewable energy standard would depend upon how the legislation treats our existing renewable resources and how it considers hydroelectric generation.[7] The portfolio assumes that hydroelectric netting would be included and that the federal law would not supersede state law. We did not model a national energy standard, as proposed by President Obama, because the PRS most likely would meet the standard because Avista is already subject to Washington's emission performance standards. Table 8.19 illustrates the resources added under the National Renewable Energy Standard portfolio.

Table 8.19: National Renewable Energy Standard

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	166	0	46	**166**	**212**
CCCT (Nameplate)	0	0	270	270	**0**	**540**
Thermal Upgrades	0	4	0	0	**4**	**4**
Wind (Energy)	47	47	35	49	**93**	**177**
Solar (Energy)	0	0	0	1	**0**	**1**
Conservation (Energy)	57	75	91	87	**133**	**310**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

[6] 106 aMW is equal to 341 MW of nameplate capacity wind generation at a 31 percent capacity factor.
[7] Proposed federal legislation has allowed utilities to "net" hydroelectric generation against retail loads prior to calculating RPS obligations.

PRS without Conservation Portfolio

The PRS without Conservation Portfolio illustrates the benefits of conservation. This portfolio meets capacity, energy and RPS needs in a similar manner as the PRS. Table 8.20 illustrates the resources added under the PRS without Conservation Portfolio.

Table 8.20: PRS without Conservation

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	83	212	83	97	**295**	**475**
CCCT (Nameplate)	0	0	270	545	**0**	**815**
Thermal Upgrades	7	0	0	3	**7**	**10**
Wind (Energy)	35	36	23	0	**71**	**94**
Solar (Energy)	0	0	0	0	**0**	**0**
Conservation (Energy)	0	0	0	0	**0**	**0**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

PRS Conservation Avoided Costs 25% Lower Portfolio

The PRS Conservation Avoided Costs 25% Lower Portfolio illustrates resulting changes to cost and risk if avoided costs for conservation was set at the avoided cost of generation resources, or if natural gas prices included in this IRP are too high. This portfolio represents conservation estimates without discretionary adders. Table 8.21 illustrates the resources added under this portfolio.

Table 8.21: PRS Conservation Avoided Costs 25% Lower

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	166	83	0	**166**	**249**
CCCT (Nameplate)	0	0	270	270	**0**	**540**
Thermal Upgrades	0	0	4	0	**0**	**4**
Wind (Energy)	35	24	23	0	**59**	**82**
Solar (Energy)	0	0	0	0	**0**	**0**
Conservation (Energy)	54	61	75	76	**115**	**266**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

PRS Conservation Avoided Costs 25% Higher Portfolio
The PRS Conservation Avoided Costs 25% Higher Portfolio illustrates the resource changes that would occur if Avista spent additional dollars toward the acquisition of additional conservation. This portfolio represents the added conservation at a spending level of an additional 25 percent and the resulting offset in supply-side resources. Table 8.22 illustrates the resources added under this portfolio.

Table 8.22: PRS Conservation Avoided Costs 25% Higher

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	166	83	0	**166**	**415**
CCCT (Nameplate)	0	0	0	270	**0**	**270**
Thermal Upgrades	0	4	4	0	**4**	**7**
Wind (Energy)	35	23	12	0	**58**	**70**
Solar (Energy)	0	0	0	0	**0**	**0**
Conservation (Energy)	61	83	95	94	**144**	**334**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

PRS Conservation Avoided Costs 50% Higher Portfolio
The PRS Conservation Avoided Costs 50% Higher Portfolio illustrates the resource changes that would occur if Avista spent an additional 50 percent on the acquisition of conservation resources. Table 8.23 illustrates the resources obtained in this portfolio.

Table 8.23: PRS Conservation Avoided Costs 50% Higher

Resource	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	46	0	83	**46**	**129**
CCCT (Nameplate)	0	0	270	270	**0**	**540**
Thermal Upgrades	0	0	4	0	**0**	**4**
Wind (Energy)	35	23	12	0	**58**	**70**
Solar (Energy)	0	0	0	0	**0**	**0**
Conservation (Energy)	62	91	103	94	**153**	**350**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

Resource Tipping Point Analysis
In many resource plans, a PRS is presented with a comparison to other portfolios to help illustrate cost and risk trade-offs. This IRP extends the portfolio analysis beyond this simple exercise by focusing on how the portfolio might change if key assumptions were 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, varying resource capital costs, hydroelectric upgrade opportunities, the emergence of other non-wind and non-solar renewable options, or an expansion of the region’s nuclear generation fleet.

Solar Capital Costs Sensitivity

The capital costs of photovoltaic solar generation significantly decreased since the 2009 IRP and the 30 percent Investment Tax Credit for solar generation was extended through the end of 2015. Solar generation still is not competitive with wind in the Northwest, even with lower capital costs and tax credits. A sensitivity analysis determined the price reduction that would be necessary to make photovoltaic solar generation competitive with wind generation. The analysis reduced solar capital costs in the year 2020 until the PRiSM model selected solar over wind. This analysis also assumed the double solar REC credit for I-937. The results of the study were that the capital costs for solar would need to decrease 53 percent, to $2,020/kW (2020 nominal dollars including AFUDC), in order to make solar competitive with wind generation.

CCCT Capital Cost Sensitivity

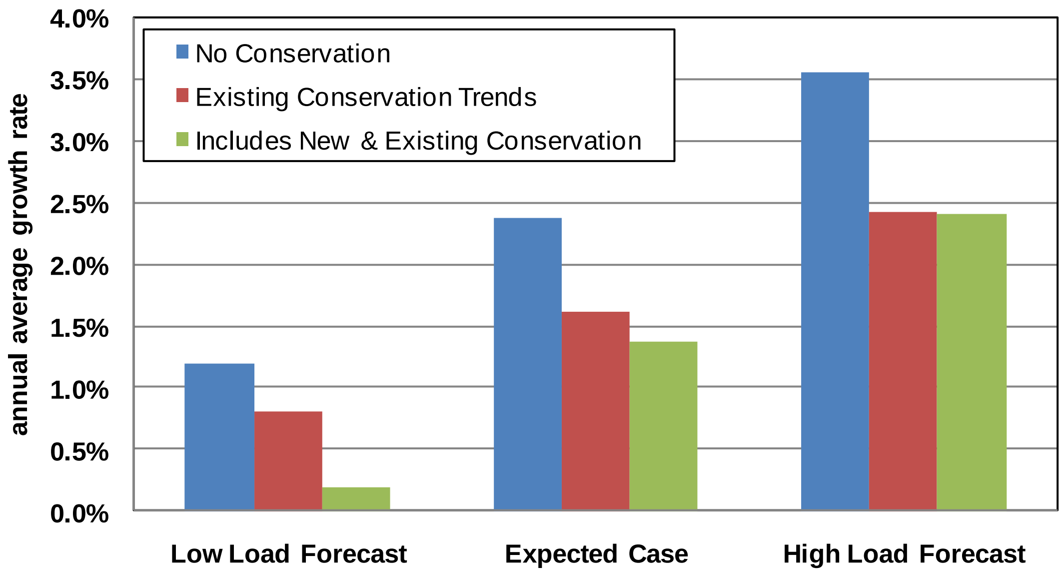
CCCTs were the lowest cost resource option in the 2009 IRP. SCCTs are again the lowest cost resource option, similar to all Avista IRPs prior to its 2009 IRP. A sensitivity analysis determined why CCCTs were more cost-effective than SCCTs in the 2009 IRP. The first test involved an analysis of capital costs. The model found that CCCT capital costs had to be 22 percent lower than forecasted in this IRP to be selected over SCCTs. Another indication of the change is that O&M cost estimates were lower in the 2009 IRP ($11/kW-year) as compared to the 2011 IRP ($16/kW-year). The 2009 IRP also assumed that a lower-cost water-cooled plant rather than an air-cooled plant would be developed. This IRP assumes an air-cooled CCCT due to the increasing difficulty in obtaining water rights near customer loads. Additional analysis could indicate that changes in the spark spread, fuel transportation costs, heat rates, or greenhouse gas policies could affect the selection of CCCTs over SCCTs more than changes in capital costs. Further, natural gas prices could affect this choice, such as lower or higher prices could affect this decision, to fully study this theory would require two additional stochastic studies and this scope of work would extend the timeline for this IRP's completion.

Load Forecast Alternatives

An important test in an IRP is its performance across varying load growth sensitivities. Avista's loads could grow faster with future development activity after the economy recovers, or could stagnate in a continued recession. This sensitivity analysis studies the impact to the PRS if loads grows faster or slower than the Expected Case estimate. Faster load growth will increase the need for capital and slower load growth will decrease the need for capital spending on new generation. This analysis focuses on understanding the changes in the timing of resource decisions based on changes in load growth.

Loads are expected to grow, net of conservation, at a rate of 1.37 percent over the IRP timeframe. The Low Load Growth scenario cuts the underlying load growth rate by 50 percent and the High Load Growth case increases expected load growth rate by 50 percent. The sensitivity analysis indicated that, net of conservation, the Low Load case's growth rate is 0.19% and the High Load Growth case is 2.4 percent. See Figure 8.18 for load forecast estimates in each case. The load forecast change is not linear since conservation will make up a greater amount of new load growth in the low case as conservation programs target existing load (85 percent of load growth). However, in a high case conservation only makes up 40 percent of load growth that is assumed to be code requirement driven energy efficiency. As a comparison, the Expected Case forecast assumes conservation meets 48 percent of new load.

Figure 8.18: Load Growth Scenario's Cost/Risk Comparison



The lower load growth case's resource strategy would not change near-term resource acquisitions (see Table 8.24), but would eliminate the need for some wind and gas-fired resources later in the IRP time horizon.

Table 8.24: Low Load Growth Resource Strategy

Resources	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	0	0	0	212	**0**	**212**
CCCT (Nameplate)	0	0	0	0	**0**	**0**
Thermal Upgrades	0	0	0	4	**0**	**4**
Wind (Energy)	35	12	24	0	**47**	**71**
Solar (Energy)	0	0	0	0	**0**	**0**
Conservation (Energy)	49	60	69	70	**108**	**247**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

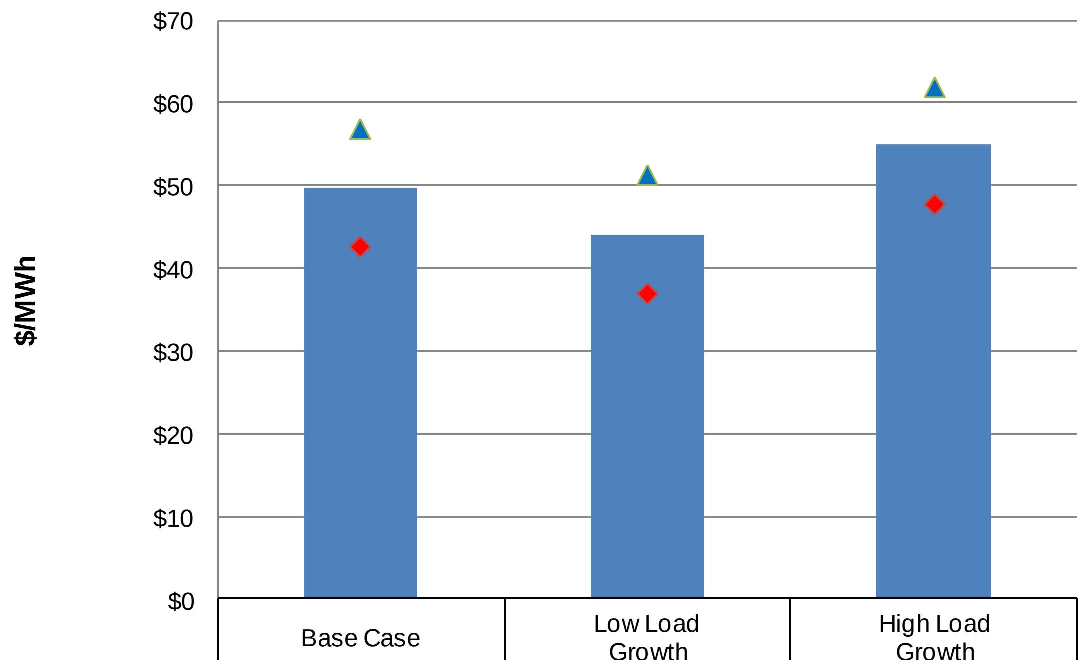
Table 8.25 shows the resource strategy with higher growth rates. The amount of wind acquisitions would increase by 22 aMW and additional peaking resources would be required to compensate for higher growth rates. In the later years of the study, additional gas-fired and wind generation resources would be needed to meet peak load growth and RPS requirements.

Table 8.25: High Load Growth Resource Strategy

Resources	2012-16	2017-21	2022-26	2027-31	First 10 Years	All 20 Years
SCCT (Nameplate)	83	298	83	46	**381**	**510**
CCCT (Nameplate)	0	0	270	540	**0**	**810**
Thermal Upgrades	4	6	0	0	**10**	**10**
Wind (Energy)	35	23	35	0	**58**	**93**
Solar (Energy)	0	0	0	1	**0**	**1**
Conservation (Energy)	71	94	122	156	**165**	**443**
Dist. Feeders (Energy)	8	3	2	1	**11**	**13**

Figure 8.19 shows the cost, and cost range, for each load growth scenario from a dollar per megawatt-hour perspective. The chart explains a positive correlation between load growth and the average cost to serve customers.

Figure 8.19: Load Growth Scenario's Cost/Risk Comparison



	Base Case	Low Load Growth	High Load Growth
Levelized Cost $/MWh	49.75	44.11	54.86
1 Sigma Lower	42.67	36.99	47.80
1 Sigma Higher	56.83	51.23	61.92

Summary

The Preferred Resource Strategy is the roadmap for a resource acquisition plan that which balances the tradeoff between cost and risk while preparing the Company to provide reliable electricity service to its customers. Table 8.25 provides a summary of the total resources selected for each of the portfolios discussed in this chapter. Distribution Feeder upgrades are included at the same level (13 aMW) in all portfolios but are not included in the table.

Table 8.26: Summary of Resource Portfolios

Portfolio	SCCT (Nameplate)	CCCT (Nameplate)	Thermal Upgrades	Wind (Energy)	Solar (Energy)	Conservation (Energy)
Preferred Resource Strategy	212	540	4	71	0	310
Least Cost	747	0	0	71	0	310
Least Risk	187	540	17	98	64	310
50/50 Cost Risk	177	540	4	93	9	310
75/25 Cost Risk	332	540	0	82	0	310
25/75 Cost Risk	83	810	4	95	5	310
PRS without Apprentice Credits	212	540	4	96	0	310
2009 PRS	0	810	0	102	0	310
PRS Without Wind	212	540	4	0	0	310
CCCT with Solar	0	810	10	36	33	310
National Renewable Energy Standard	212	540	4	177	1	310
PRS without Conservation	475	815	10	94	0	0
PRS Conservation A/C 25% Lower	249	540	4	82	0	266
PRS Conservation A/C 25% Higher	415	270	7	70	0	334
PRS Conservation A/C 50% Higher	129	540	4	70	0	350
Low Load Growth	212	0	4	71	0	247
High Load Growth	510	810	10	93	1	443

The IRP is a continual effort to select cost- and risk-minimizing resources complementing the Company's existing resource mix. Its results and insights help management and policy-makers formulate good decisions on behalf of ratepayers. The PRS includes a combination of conservation, efficiency improvements including feeder upgrades, hydroelectric upgrades, wind, and gas-fired simple and combined-cycle combustion turbines. The resource strategy identified in this report will change in response to new information, but Avista focuses decision making on near-term resource acquisitions where substantial changes concerning the data needed to make decisions are less likely to occur.

9. Action Items

The Integrated Resource Plan (IRP) is an ongoing and iterative process balancing regular publication timelines with pursuing the best 20-year resource strategies. The biennial publication date provides opportunities for ongoing improvements to the modeling and forecasting procedures and tools, as well as the opportunity to enhance the process with new research as the planning environment changes. This section provides an overview of the progress made on the 2009 IRP Action Plan and provides the 2011 Action Plan.

Summary of the 2009 IRP Action Plan

The 2009 Action Plan included five separate categories: resource additions and analysis, energy efficiency, environmental policies, modeling and forecasting enhancements, and transmission planning.

2009 Action Plan – 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 on the costs and environmental benefits of 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.

Progress Report – Resource Additions and Analysis

After filing the 2009 IRP, the Company issued two RFPs: (1) a 35 aMW Renewable RFP and (2) a wind turbine RFP for the Reardan development. The 2009 RFP showed that the anticipated benefits of early construction of Reardan, or a third party acquisition, identified in the 2009 IRP were not available. The Company retains the Reardan Wind Project site as an option to meet future RPS goals. Site control provides a hedge against escalating costs and the limited number of viable Pacific Northwest wind sites. Additional studies on non-wind renewable energy sources continued throughout this planning cycle. More details about non-wind renewables are included in the Generation Resource Options and Preferred Resource Strategy chapters.

Following the 2009 RFP, several wind development firms asked when another RFP would be issued, indicating that wind turbine prices had fallen greatly since the 2009 RFP and that prices in a new RFP issuance would be competitive to the wholesale market prices (when including REC sales) when including federal and state tax subsidies. In response, the Company issued an RFP for approximately 35 aMW of Washington renewable portfolio standard-qualified renewable energy contracts. The Company did not include its Reardan Wind Project as it could not be completed in time to take advantage of the expiring Federal tax subsidies.[1] The Company's February 2011

[1] Federal tax incentives for wind expire at the end of calendar year 2012.

RFP received bids for 774 MW of qualifying projects (769 MW of wind and 5 MW of landfill gas). The Company selected the 105 MW Palouse Wind Project, located near Oakesdale, Washington. The proposal is a 30-year power purchase agreement with a buyout option after year 10. Further details regarding this acquisition are contained in the Preferred Resource Strategy Chapter.

The Company is continuing to research system hydroelectric upgrade options. The results of these studies are not yet complete, and we therefore were unable to include the results of these studies in this IRP. Some preliminary results are in the Generation Resource Options Chapter, and in presentations to the third Technical Advisory Committee on December 2, 2010. The slides from that presentation are contained in Appendix A.

Preliminary work on identifying potential locations for future natural gas-fired resources identified in the 2009 IRP is complete, but a final site selection is not complete. The 2011 PRS pushes the need for the next gas-fired plant until 2019 and changes the technology from combined to simple cycle. This work will continue and an update given as an Action Item in the 2013 IRP.

The Company continues to participate in regional IRP processes, attending peer-utility meetings. Regional utilities participated in our Technical Advisory Committee meetings to share the latest concepts in resource planning.

2009 Action Plan – Energy Efficiency

- Pursue American Reinvestment and Recovery Act of 2009 (ARRA) funding for 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 perform a study on technical, economic, and achievable potential for energy efficiency in Avista's entire service territory.
- Study and quantify transmission and distribution efficiency concepts as they apply to meeting Washington's RPS goals.
- Update processes and protocols for conservation measurement, evaluation and verification.
- Determine the potential impacts and costs of load management options.

Progress Report – Energy Efficiency

Avista's Community Action Agencies received significant increases for low-income weatherization through ARRA funds. The Idaho Load Management Pilot Final Report, issued on March 1, 2010, provides details on the Moscow and Sandpoint demand response project. The pilot included ten successful trial events, including the cycling of heating and air conditioning units and the short-term interruption of water heaters. Five percent of the eligible participants agreed to participate in the volunteer program; two percent of customers participating in the study opted-out of the program during events. Even though the program successfully showed the capability of a load interruption program as a reliable capacity resource, the regional power market does not support the present costs of such a program at this time. The Company will continue to monitor the marketplace to determine if this type of load management program will become cost effective in the future.

Global Energy Partners (Global) completed a 20-year conservation potential assessment for our residential, commercial and industrial customers in Idaho and Washington. Global presented the assessment results at the fifth Technical Advisory Committee meeting on April 12, 2011. A copy of the presentation is included in Appendix D, and more details are in the Energy Efficiency chapter.

The study and quantification of transmission and distribution efficiency concepts, as they apply to meeting Washington's renewable portfolio standard goals is part of an ongoing process. It will be refined as the Company prepares its initial Washington Energy Independence Act compliance report to the Washington Utility and Transportation Commission. Additional details are in the Energy Efficiency and Transmission and Distribution chapters of this IRP.

The Company continues to update the processes and protocols for conservation measurement, evaluation and verification (EM&V). The Company participated in an EM&V Collaborative in 2010 resulting in an EM&V framework, annual EM&V plans and development of individual program EM&V plans. This continual EM&V loop will feed improved processes and protocols for conservation measurement, evaluation and verification. As part of the conservation potential study, Global Energy Partners looked at demand response potential and costs. More details about this work are in the Energy Efficiency chapter.

2009 Action Plan – 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 Council.

Progress Report – Environmental Policy

Avista's Climate Change Council and the Resource Planning team actively analyze state and federal greenhouse gas legislation. This work will continue until final rules are established and laws passed. The focus will then shift to mitigating the costs of meeting these laws and regulations. Avista has quantified its greenhouse gas emissions using the World Resources Initiative–World Business Council for Sustainable Development (WRI-WBCSD) inventory protocol in anticipation of state and federal greenhouse gas reporting mandates. Details about Climate Change Council efforts are in the Policy Considerations chapter.

2009 Action Plan – Modeling and Forecasting Enhancements

- Refine cost driver relationships in the stochastic model.
- Continue to refine PRiSM by developing a resource retirement capability 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, and confirm appropriateness of the 15 percent capacity planning margin assumed for this IRP.
- Continue studying the impacts of climate change on the load forecast.
- Study load growth trends and their correlation to weather patterns.

Progress Report – Modeling and Forecasting Enhancements

Improvements have continued on stochastic modeling for the IRP. This plan relies on new methods for modeling natural gas and wind. Work continues on developing a method to correlate temperature, wind and hydro in the stochastic model. This work will continue and be reported in the 2013 IRP.

The 2011 IRP includes several refinements to the PRiSM model. A resource retirement capability was developed, but not utilized for this IRP. We developed a method to evaluate the true standard deviation of power supply costs for the 2011 IRP, but long solution times prevented its adoption. This plan also includes more resource options, and modeling of generators by state and by location on the regional transmission system.

Loss of Load Probability (LOLP) and Sustained Peaking analysis models were developed and used for the 2011 IRP. This IRP uses an 18-hour sustained peak over three days to estimate the need for new resources. Avista developed an LOLP model for this IRP and presented it to the TAC on September 9, 2010; however, subsequent testing of the model found that the LOLP study was driven primarily by regional market availability assumptions that were beyond the scope of the study. The Company will continue to work with the Northwest Power and Conservation Council to determine the best methods for identifying regional market availability. More details are in the Loads & Resources and Preferred Resource Strategy chapters.

The IRP load forecast continues to estimate the impacts of climate change on customer load growth. More details are included in the Load and Resource chapter of this IRP. Any changes will be in the 2013 IRP.

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 to participate in BPA transmission practice processes and rate proceedings to minimize the costs of integrating existing resources outside of the Company’s service area.
- Continue to participate 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.
- Study and implement distribution feeder rebuilds to reduce system losses.

- Study transmission reconfigurations that economically reduce system losses.

Progress Report – Transmission Planning

The 2009 IRP transmission planning action item studies continue and are included in the 2013 Action Plan. Details about progress made toward 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 are in the Transmission and Distribution chapter.

Avista has completed a feeder rebuild pilot project at its 9th and Central 12F4 feeder. The Company received federal stimulus dollars for several “Smart Grid” initiatives that include projects contained in the 2009 IRP. The Company is developing a program to rebuild additional feeders as outlined in this plan. Additional details on these projects are included in the Transmission and Distribution Chapter.

2011 IRP Action Plan

The Company’s 2011 Preferred Resource Strategy provides direction and guidance for the type, timing and size of future resource acquisitions. The 2011 IRP Action Plan highlights the activities planned for possible inclusion in the 2013 IRP. Progress and results for each of the 2011 Action Plan items will be monitored and reported to the Technical Advisory Committee and the results will be included in Avista’s 2013 IRP. The 2011 Action Plan includes input from Commission Staff, the Company’s management team, and the Technical Advisory Committee.

Resource Additions and Analysis

- Continue to explore and follow potential new resources opportunities.
- Continue studies on the costs, energy, capacity and environmental benefits of 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 in 2019.
- Continue participation in regional IRP processes and, where agreeable, find opportunities to meet resource requirements on a collaborative basis with other utilities.
- Provide an update on the Little Falls and Nine Mile hydroelectric project upgrades.

Energy Efficiency

- Study and quantify transmission and distribution efficiency projects as they apply to Washington RPS goals.
- Update processes and protocols for conservation measurement, evaluation and verification.
- Continue to determine the potential impacts and costs of load management options.

Environmental Policy

- Continue studies of state and federal climate change policies.

- Continue and report on the work of Avista's Climate Change Council.

Modeling and Forecasting Enhancements

- Continue following regional reliability processes and develop Avista-centric modeling for possible inclusion in the 2013 IRP.
- Continue studying the impacts of climate change on retail loads.
- Refine the stochastic model for cost driver relationships, including further analyzing year-to-year hydro correlation and the correlation between wind, load, and hydro.

Transmission and Distribution Planning

- Work to maintain the Company's existing transmission rights, under applicable FERC policies, for transmission service to bundled retail native load.
- Continue to participate in BPA transmission processes and rate proceedings to minimize costs of integrating existing resources outside of Avista's service area.
- Continue to participate in regional and sub-regional efforts to establish new regional transmission structures to facilitate long-term expansion of the regional transmission system.
- Evaluate the costs to integrate new resources across Avista's service territory and from regions outside of the Northwest.
- Study and implement distribution feeder rebuilds to reduce system losses.
- Study transmission reconfigurations that economically reduce system losses.

Production Credits

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