2013 Electric Integrated Resource Plan

August 31, 2013

Safe Harbor Statement

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

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

Acronym List

AC: Alternating Current

aMW: Average Megawatt

AFUDC: Allowance for Funds Used During Construction

ARIMA: Auto Regressive Integrated Moving Average

BART: Best Available Retrofit Technology

BPA: Bonneville Power Administration

Btu: British Thermal Unit

CAA: Clean Air Act

CDD: Cooling Degree Days

CFL: Compact Fluorescent Light

CPA: Conservation Potential Assessment

CO_2: Carbon Dioxide

COB: California Oregon Boarder

CT: Combustion Turbine

CCCT: Combined-Cycle Combustion Turbine

CPU: Central Processing Unit

DC: Direct Current

DLC: Direct Load Control

EIA: Energy Independence Act

EPA: Environmental Protection Agency

FERC: Federal Energy Regulatory Commission

FIPs: Federal Implementation Plans

GDP: Gross Domestic Product

HAPs: Hazardous Air Pollutants

HDD: Heating Degree Days

HRSG: Heat Recovery Steam Generator

HVAC: Heating, Ventilation, and Air Conditioning

IGCC: Integrated Gasification Combined-Cycle

IMHR: Implied Market Heat Rate

IPPs: Independent Power Producers

IPUC: Idaho Public Utilities Commission

IRP: Integrated Resource Plan

ITC: Investment Tax Credit

kV: Kilovolt

LGIR: Large Generator Interconnection Request

LNG: Liquid Natural Gas

LOLE: Loss of Load Expectation

LOLH: Loss of Load Hours

LOLP: Loss of Load Probability

LRC: Least Resource Cost

MATS: Mercury Air Toxic Standards

MSA: Metropolitan Statistical Area

MW: Megawatt

MWh: Megawatt Hours

NEEA: Northwest Energy Efficiency Alliance

NERC: North American Reliability Corporation

NO_x: Nitrous Oxides

NPCC: Northwest Power and Conservation Council

NREL: National Renewable Energy Laboratory

NTTG: Northern Tier Transmission Group

NWPP: Northwest Power Pool

O&M: Operations and Maintenance

OATT: Open Access Transmission Tariff

OTC: Once Through Cooling

PNCA: Pacific Northwest Coordination Agreement

PRiSM: Preferred Resource Strategy Linear Programming Model

PRS: Preferred Resource Strategy

PSD: Prevention of Significant Deterioration

PM: Planning Margin

PTC: Production Tax Credit

PUDs: Public Utility Districts

RPS: Renewable Portfolio Standard

SCCT: Simple Cycle Combustion Turbine

SGDP: Smart Grid Demonstration Project

TAC: Technical Advisory Committee

TPC: Transmission Planning Committee

TRC: Total Resource Cost

UPC: Use-per-customer

UTC: Washington Utilities and Transportation Commission

WAC: Washington Administrative Code

WCI: Western Climate Initiative

WECC: Western Electricity Coordinating Council

WNP-3: Washington Nuclear Plant No. 3

WNU: Weather Normalized Usage

WSU: Washington State University

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2013 Electric IRP Introduction

Avista has a long tradition of innovation as a provider of a safe, reliable, low-cost, and clean, mix of generation resources. The 2013 Integrated Resource Plan (IRP) continues this legacy by looking into the future energy needs of our customers. The IRP analyzes and outlines a strategy to meet projected demand and renewable portfolio standards through energy efficiency and a careful mix of new renewable and traditional energy resources.

Avista currently projects having adequate resources, between owned and contractually controlled generation, to meet our customers' needs until 2020. Plant upgrades, energy efficiency measures and in the longer term additional natural gas-fired generation are integral parts of Avista's 2013 IRP resource strategy.

Two significant changes from the 2011 IRP should be noted:

- The 2011 IRP recommendations for new renewable resources have been met with a 30-year purchased power agreement with Palouse Wind, and the Kettle Falls Generating Station being qualified as a renewable energy resource under Washington state's Energy Independence Act; and
- Load growth is expected to be at just over 1 percent, a decline from the growth of 1.6 percent forecast in 2011. This delays the need for a new natural gas-fired resource by one year.

Each IRP is a thoroughly researched and data-driven document to guide responsible resource planning for the company. The IRP is updated every two years and looks 20 years into the future. This plan is developed by Avista's professional energy analysts using sophisticated modeling tools and with input from interested community, educational and state utility commission stakeholders.

The plan's Preferred Resource Strategy (PRS) section covers Avista's projected resource acquisitions over the next 20 years.

Some highlights of the 2013 PRS include:

- Demand response (temporarily reducing the demand for energy) is included in the PRS for the first time and could provide 19 MW of peak energy reduction in the 2022 – 2027 timeframe.
- Energy efficiency (using less energy to perform activities) reduces load growth by 42 percent over the next 20 years.
- 486 MW of additional clean-burning natural gas-fired generation facilities are required between 2020 and 2033.
- Transmission upgrades will be needed to carry the output from new generation. Avista will continue to participate in regional efforts to expand the region's transmission system.

This document is mostly technical in nature. The IRP has an Executive Summary and chapter highlights at the beginning of each section to help guide the reader. Avista expects to begin developing the 2015 IRP in early 2014. Stakeholder involvement is encouraged and interested parties may contact John Lyons at 509-495-8515 or john.lyons@avistacorp.com for more information on participating in the IRP process.

Executive Summary

Avista Corporation's 2013 Electric Integrated Resource Plan (IRP) guides its resource strategy over the next two years and directs resource procurements over the 20-year plan. It provides a snapshot of Avista's resources and loads and guides future resource acquisitions over a range of expected and possible future conditions. The 2013 Preferred Resource Strategy (PRS) includes energy efficiency, upgrades at existing generation and distribution facilities, demand response and new gas-fired generation.

The PRS balances cost, reliability, rate volatility, and renewable resource requirements. Avista's management and the Technical Advisory Committee (TAC) guide the development of the PRS and the IRP by providing significant input on modeling and planning assumptions. TAC members include customers, commission staff, the Northwest Power and Conservation Council, consumer advocates, academics, utility peers, government agencies, and interested internal parties.

Resource Needs

Avista's peak planning methodology includes operating reserves, regulation, load following, wind integration and a planning margin. Avista currently projects having adequate resources between owned and contractually controlled generation to meet annual physical energy and capacity needs until 2020. Chapter 2 explains the peak planning methodology. See Figures 1 – 3 for Avista's physical resource positions for winter capacity, summer capacity, and annual energy load and resource balances.

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

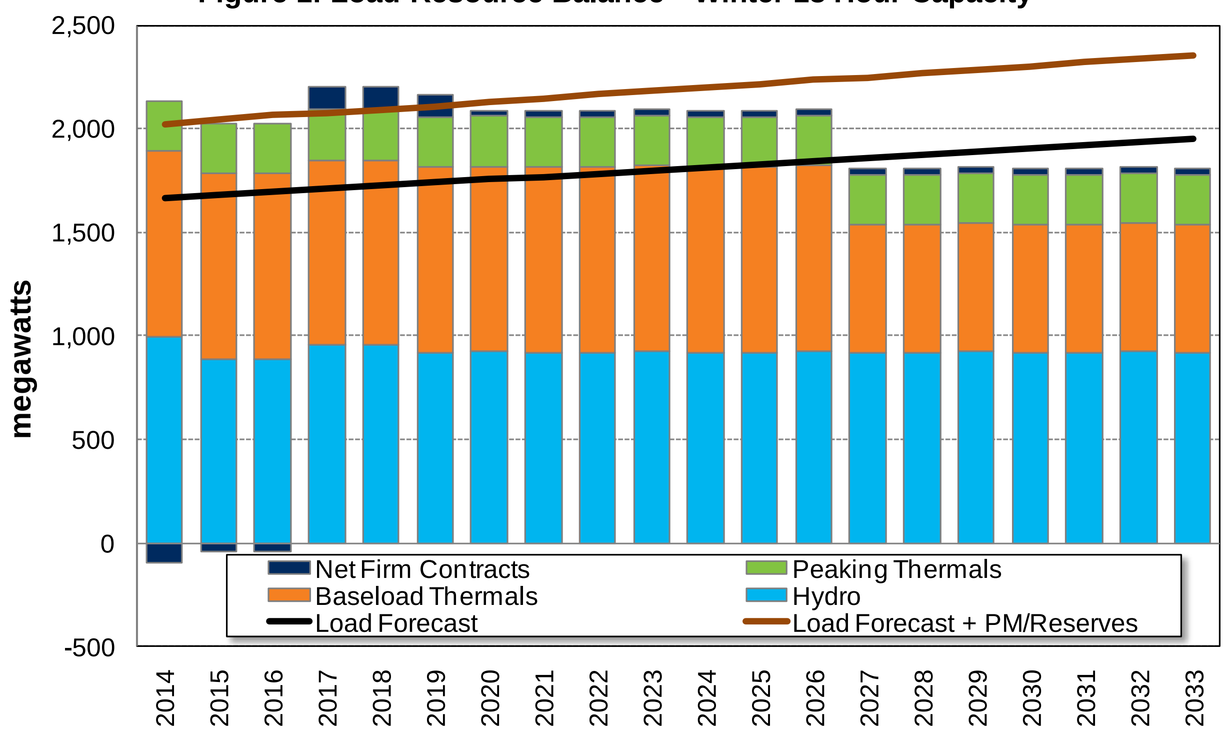


Figure 2: Load-Resource Balance—Summer 18 Hour Capacity

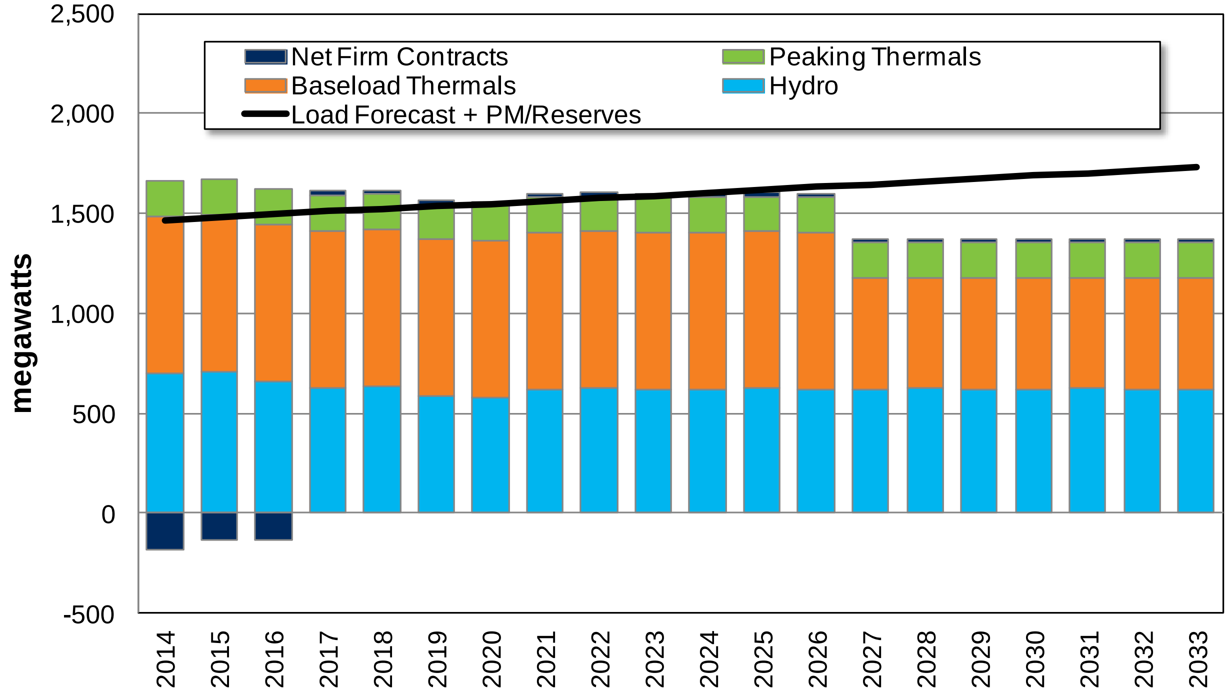
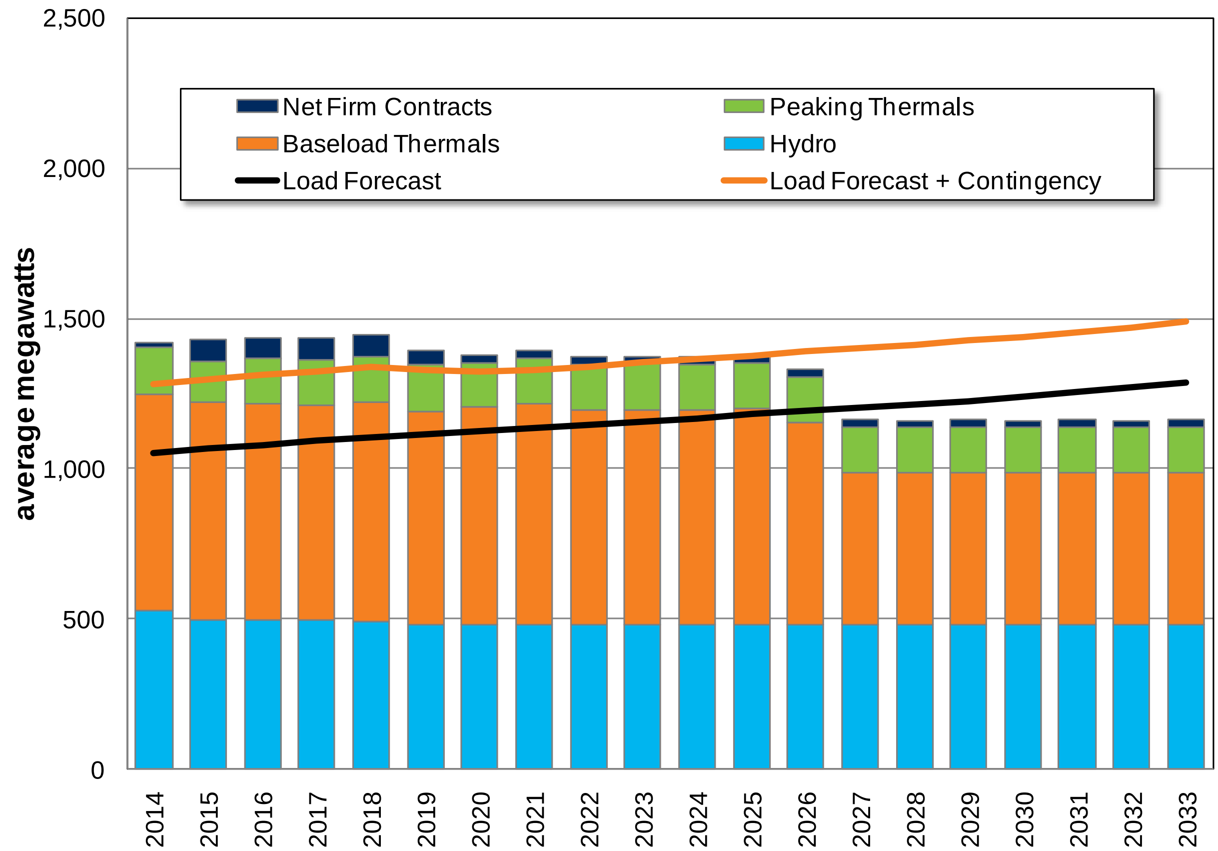


Figure 3: Load-Resource Balance—Energy



Figures 1 – 3 include the effects of new energy efficiency programs on the load forecast. Absent energy efficiency, Avista would be resource deficient earlier. The region has a significant summer capacity surplus; Avista plans to meet all summer capacity needs with term purchases. A short-term capacity need exists in the winters of 2014/15 and 2015/16. This capacity need is short-lived because a 150 MW capacity sale contract ends in 2016. Avista expects to address these short-term deficits with market purchases; therefore, the first long-term capacity deficit begins in 2020.

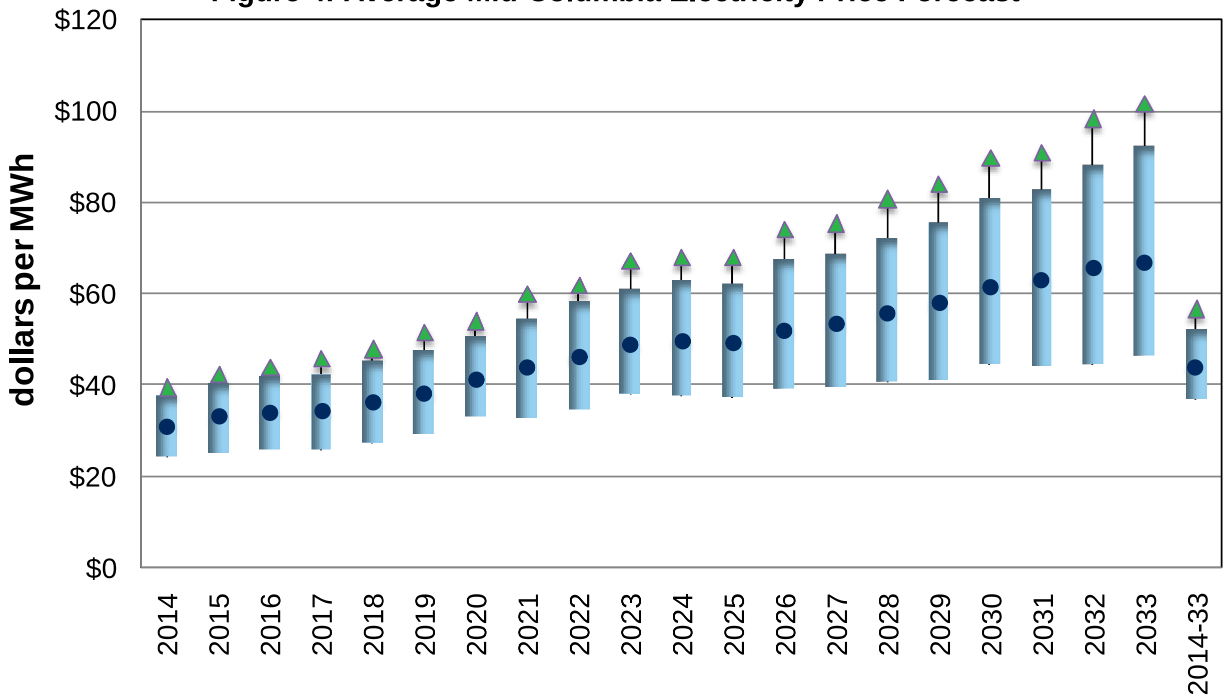
Modeling and Results

Avista uses a multiple-step approach to develop its PRS. It begins by identifying and quantifying potential new generation resources to serve projected electricity demand 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 2014 to 2033. The model adds cost-effective new resources and transmission across the Western Interconnect to meet overall projected loads. Monte Carlo-style analysis varies hydroelectric and wind generation, loads, forced outages and natural gas price data over 500 iterations of potential future market conditions. The simulation estimates Mid-Columbia electricity market prices by iteration and the results of the 500 iterations form the Expected Case.

Electricity and Natural Gas Market Forecasts

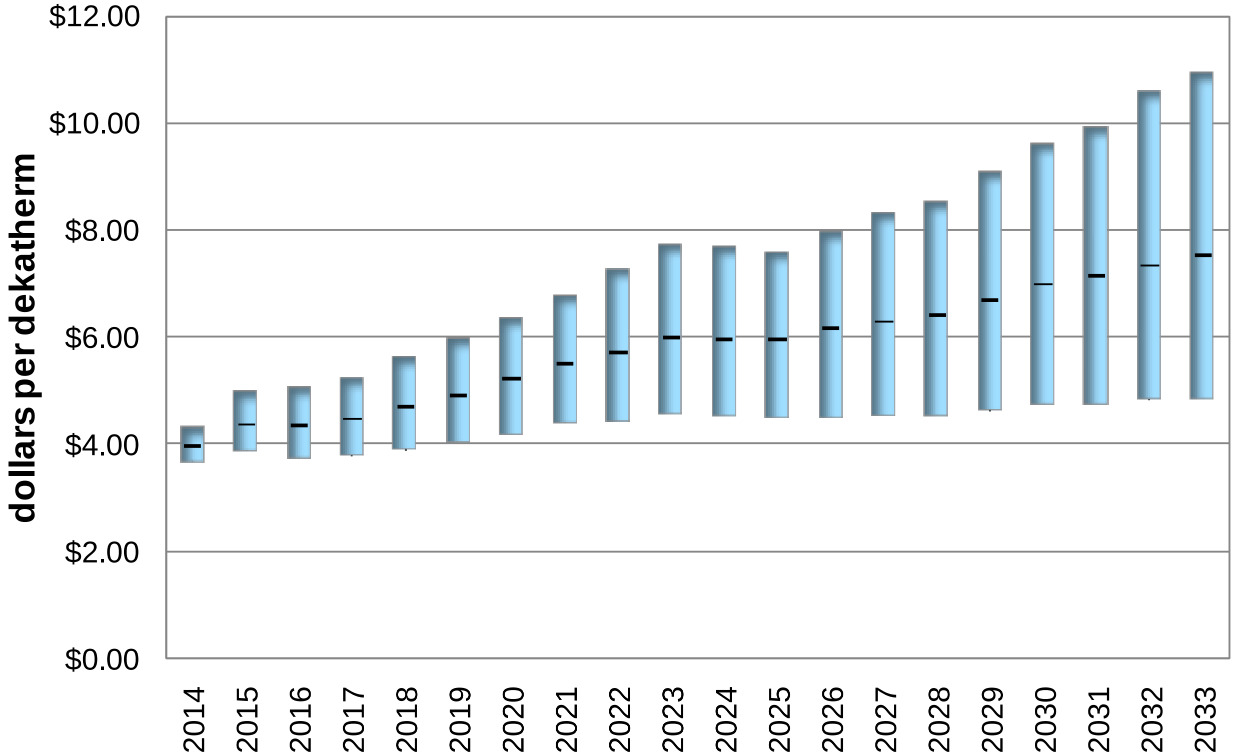
Figure 4 shows the 2013 IRP electricity price forecast for the Expected Case, including the price range over the 500 Monte Carlo iterations. The forecasted levelized average Mid-Columbia market price is $44.08 per MWh in nominal dollars over 20 years.

Figure 4: Average Mid-Columbia Electricity Price Forecast



Electricity and natural gas prices are highly correlated because natural gas fuels marginal generation in the Northwest during most of the year. Figure 5 presents nominal levelized Expected Case natural gas prices at the Stanfield trading hub, located in northeastern Oregon, as well as the forecast range from the 500 Monte Carlo iterations performed for the case. The average is $5.40 per dekatherm over the next 20 years. See Chapter 7 for details on the company's natural gas price forecast.

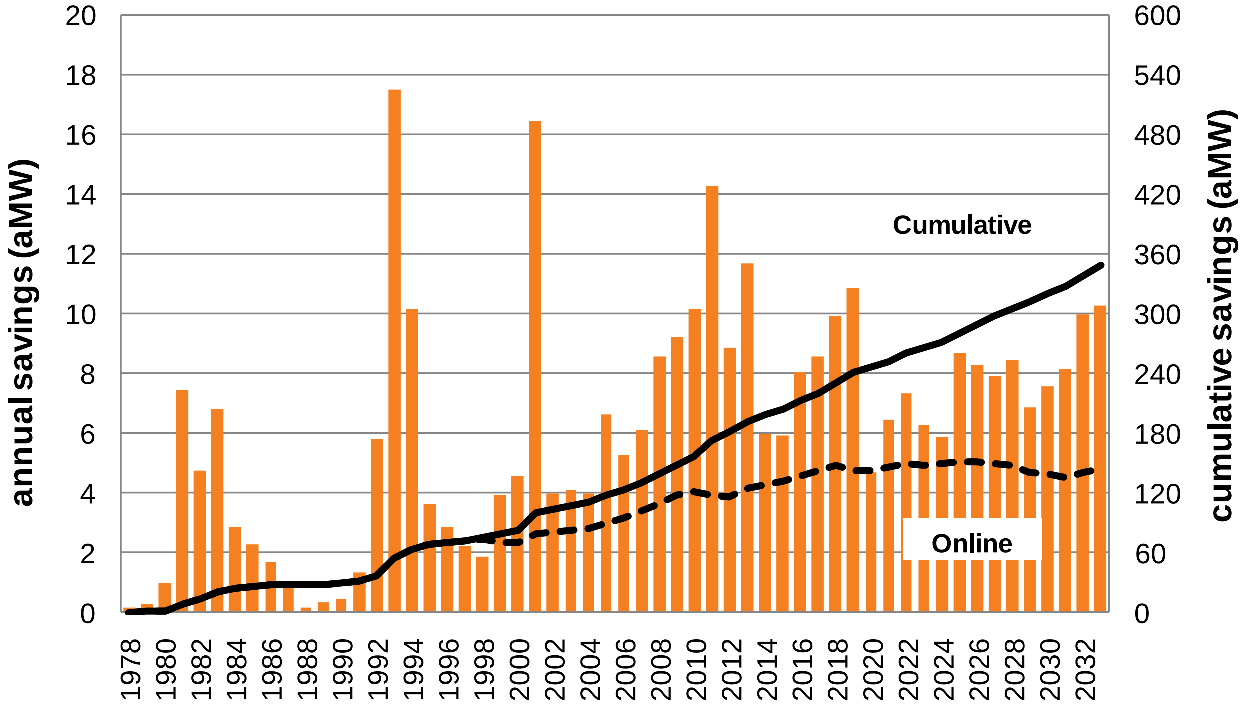
Figure 5: Stanfield Natural Gas Price Forecast



Energy Efficiency Acquisition

Avista commissioned a 20-year Conservation Potential Assessment in 2013. The study analyzed over 4,300 energy efficiency equipment and measure options for residential, commercial, and industrial applications. Data from this study formed the basis of the IRP conservation potential evaluations. Figure 6 shows how historical efforts in energy efficiency decrease Avista's energy requirements by 125 aMW, or approximately ten percent. By 2033, energy efficiency reduces load by 164 aMW. More detail about Avista's energy efficiency programs is contained in Chapter 3.

Figure 6: Cumulative Energy Efficiency Acquisitions



Preferred Resource Strategy

The PRS includes careful consideration by Avista's management and the TAC of the 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 natural gas-fired technologies as shown in Table 1.

Table 1: The 2013 Preferred Resource Strategy

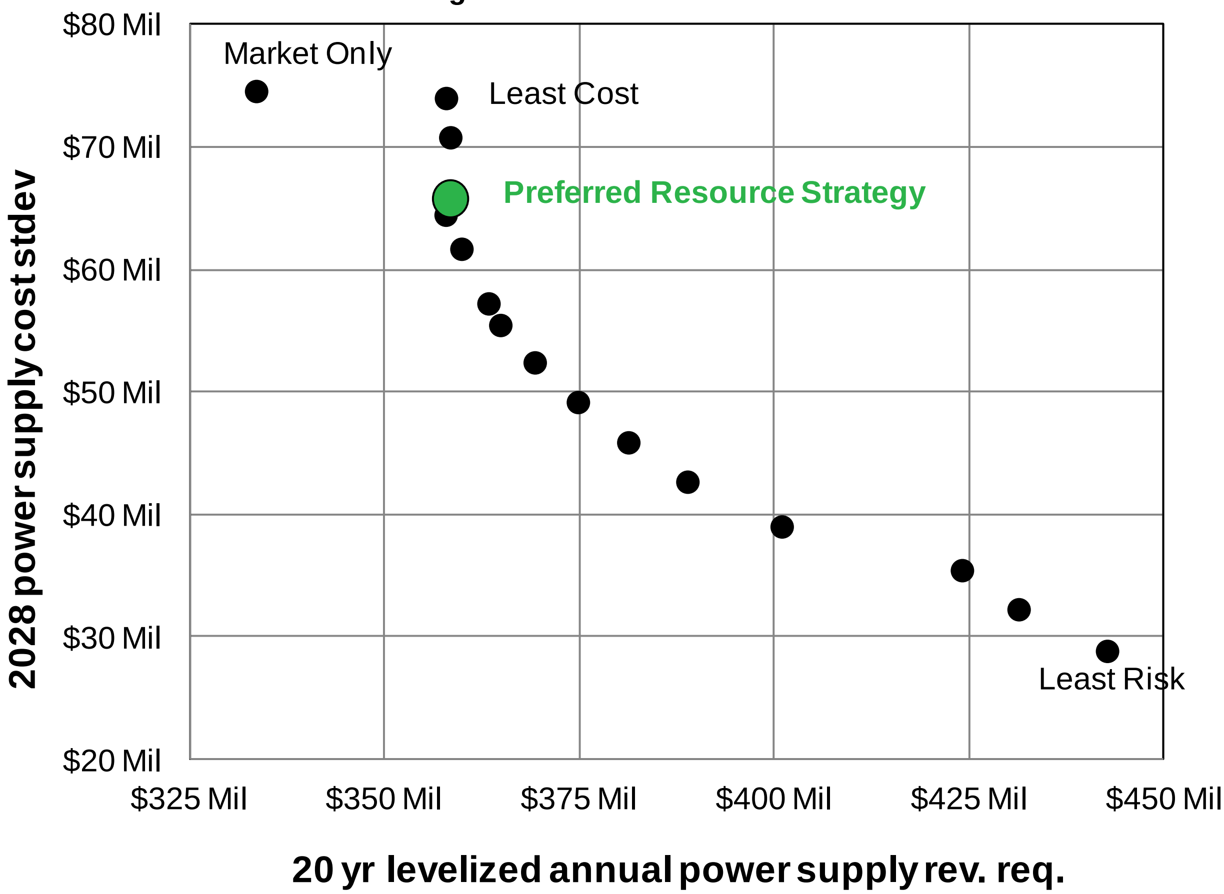
Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Simple Cycle CT	2019	83	76
Simple Cycle CT	2023	83	76
Combined Cycle CT	2026	270	248
Rathdrum CT Upgrade	2028	6	5
Simple Cycle CT	2032	50	46
Total		**492**	**451**
Efficiency Improvements	**Acquisition Range**	**Peak Reduction**	**Energy (aMW)**
Energy Efficiency	2014-2033	221	164
Demand Response	2022-2027	19	0
Distribution Efficiencies	2014-2017	<1	<1
Total		**240**	**164**

The 2013 PRS describes a reasonable low-cost plan along the efficient frontier of potential resource portfolios accounting for fuel supply risk and price risk. Major changes from the 2011 PRS include reduced contributions from conservation, wind, and natural gas-fired resources. For the first time the PRS includes a modest contribution from demand response.

Each new resource and energy efficiency option is valued against the Expected Case Mid-Columbia electricity market to identify its future value to Avista, as well as its inherent risk measured by year-to-year portfolio 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 Avista by developing optimal mixes of new resources along an efficient frontier. Chapter 8 provides a detailed discussion of the efficient frontier concept.

The PRS provides a "least reasonable cost" portfolio that minimizes future costs and risks given actual or expected environmental constraints. An efficient frontier helps determine the tradeoffs between risk and cost. The approach is similar to finding an optimal mix of risk and return in an investment portfolio. As expected returns increase, so do risks. Reducing risk reduces overall returns. There is a trade-off between power supply costs and power supply cost variability. Figure 7 presents the change in cost and risk from the PRS on the Efficient Frontier. Lower power cost variability comes from investments in more expensive, but less risky, resources. The PRS selection is the location on the efficient frontier where reduced risk justifies the increased cost.

Figure 7: Efficient Frontier



The IRP includes several scenarios to identify tipping points where the PRS could change under conditions alternative to the Expected Case. Chapter 8 includes scenarios for load growth, capital costs, higher energy efficiency acquisitions, and greenhouse gas policies.

The 2013 PRS is significantly different from the 2011 IRP resource strategy; the 2011 PRS is in Table 2. Since the prior plan, Avista's renewable and capacity needs have changed. Adding Palouse Wind to Avista's resource mix in December 2012 satisfied the 2012 Northwest Wind component of the 2011 PRS. Changes in the Washington State Energy Independence Act (EIA) eliminated the need for a 2019/2020 wind resource. The amendment under SB 5575 adds the Kettle Falls Generating Station, and other legacy biomass plants, as EIA qualifying resources beginning in 2016. The 2011 IRP forecast 1.6 percent annual load growth, while this IRP forecasts just over 1 percent growth (see Chapter 2). Lower expected load growth delays the first natural gas-fired resource need by one year and eliminates the need for a combined cycle combustion turbine in 2023.

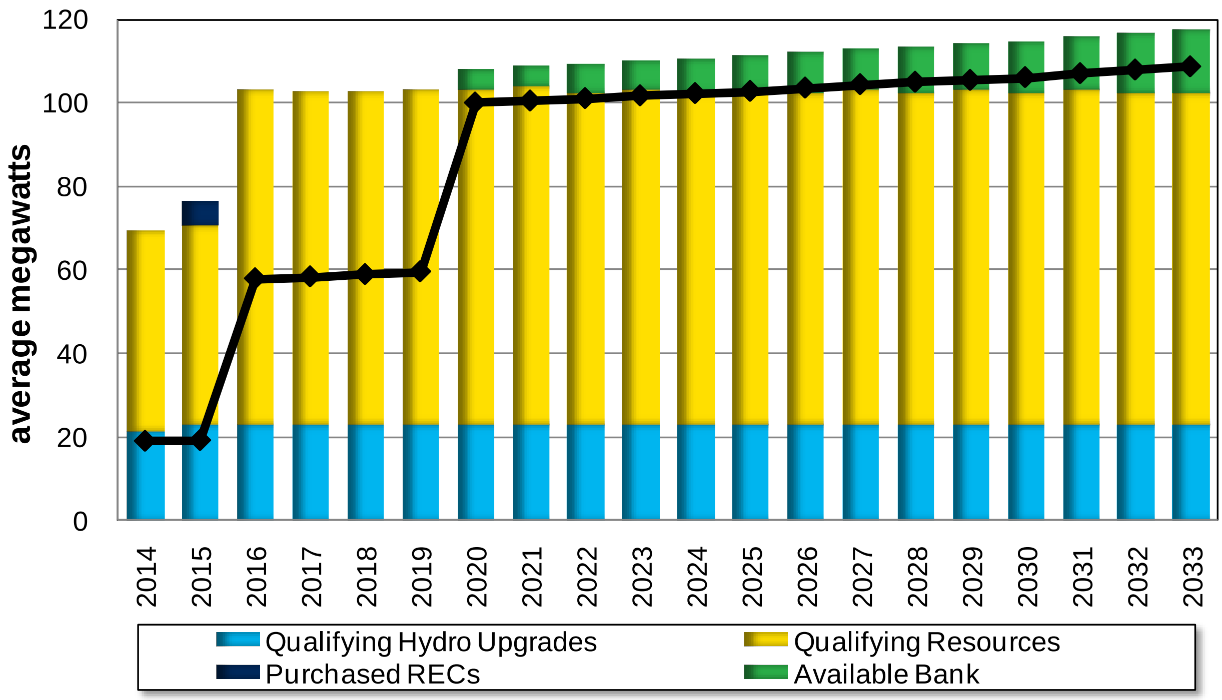
Table 2: The 2011 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Northwest Wind	2012	120	35
Simple Cycle CT	2018	83	75
Existing Thermal Resource Upgrades	2019	4	3
Northwest Wind	2019-2020	120	35
Simple Cycle CT	2020	83	75
Combined Cycle CT	2023	270	237
Combined Cycle CT	2026	270	237
Simple Cycle CT	2029	46	42
Total		**996**	**739**
Efficiency Improvements	**Acquisition Range**	**Peak Reduction (MW)**	**Energy (aMW)**
Distribution Efficiencies	2012-2031	28	13
Energy Efficiency	2012-2031	419	310
Total		**447**	**323**

Washington voters approved the EIA through Initiative 937 in the November 2006 general election. The EIA requires utilities with over 25,000 customers to meet 3 percent of retail load from qualified renewable resources by 2012, 9 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 through the 20-year plan with a combination of qualifying hydroelectric upgrades, the Palouse Wind project, the Kettle Falls Generating Station and selective renewable energy certificate (REC) purchases. A list of the qualifying generation projects and the associated expected output is in Table 8 below. The flexibility of I-937 to use RECs from the current year, from the previous year, or from the following year for compliance helps Avista mitigate year-to-year variability in the output of qualifying renewable resources.

Figure 8: Avista's Qualifying Renewables for Washington State's EIA



Greenhouse Gas Emissions

Forecasts of greenhouse gas emissions costs have been included as part of Avista's Expected Case since the 2007 IRP. Based on current legislative priorities and the President's Climate Action Plan, a national greenhouse gas cap-and-trade system or tax is no longer likely. Therefore, the Expected Case does not include a market or tax solution to reduce emissions. Instead, because the states and the EPA are implementing regulatory models limiting emissions for new facilities, and requiring current facilities to either implement best available control technologies or shut down, this IRP forecasts significant numbers of plant retirements to meet these environmental rules. Figure 9 shows projected greenhouse gas emissions for existing and new Avista generation assets, but it does not account for emissions from market purchases or sales. While Avista's emissions increase modestly, western region emissions fall from historic levels as less-cost-effective coal and older natural gas-fired plants retire (see Figure 10). Avista does not follow this overall trajectory because the carbon intensity of its portfolio already is relatively low. More details about state and federal greenhouse gas policies are in chapter 4.

Figure 9: Avista Owned and Controlled Resource's Greenhouse Gas Emissions

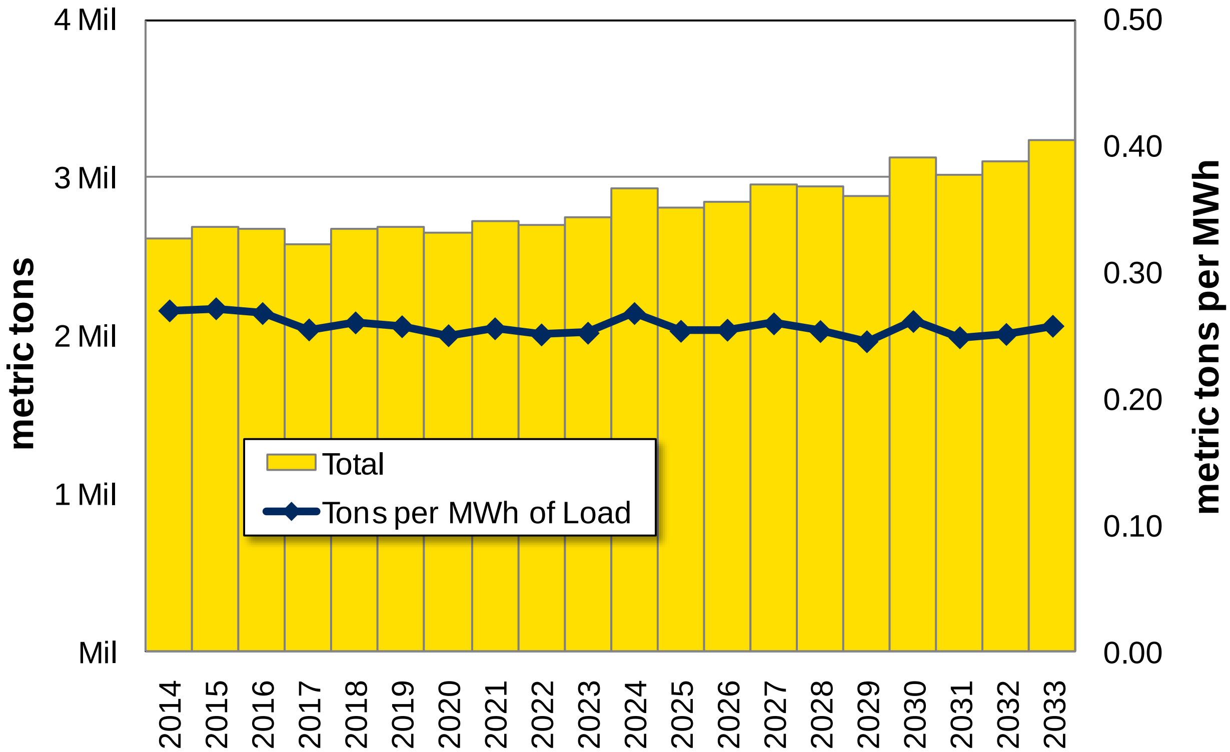
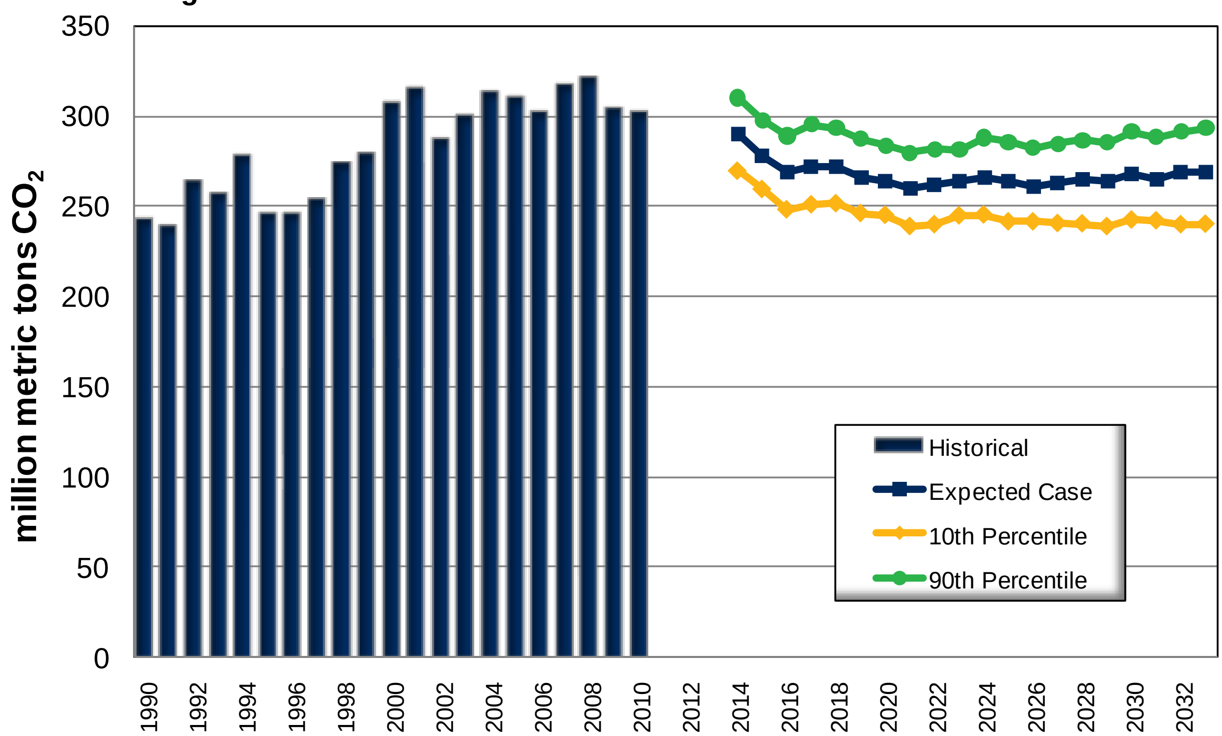


Figure 10: U.S. Western Interconnect Greenhouse Gas Emissions



Action Items

The 2013 Action Plan updates progress on the 2011 Action Items and outlines activities Avista intends to perform for the 2015 IRP. It includes input from Commission Staff, Avista's management team, and the TAC. Action Item categories include resource additions and analysis, demand side management, environmental policy, modeling and forecasting enhancements, and transmission planning. Chapter 9 and discusses the new Action Items.

1. Introduction and Stakeholder Involvement

Avista submits an IRP to the Idaho and Washington public utility commissions biennially.[1] The 2013 IRP is Avista's thirteenth plan. It identifies and describes a PRS for meeting load growth while balancing cost and risk measures with environmental mandates.

Avista is statutorily obligated to provide reliable electricity service to its customers at rates, terms, and conditions that are fair, 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. The IRP is a resource evaluation tool rather than a plan for acquiring a particular set of assets. The 2013 IRP continues refining Avista's resource acquisition efforts.

IRP Process

The 2013 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 TAC. The TAC is 75 participants including 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.

Avista sponsored six TAC meetings for the 2013 IRP. The first meeting was on May 23, 2012, and the last was on June 19, 2013. TAC meetings cover different aspects of the 2013 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.

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.

[1] Washington IRP requirements are contained in WAC 480-100-238 Integrated Resource Planning. Idaho IRP requirements are 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 23, 2012	• Powering our Future Game • 2011 Renewable RFP • Palouse Wind Project Update • 2011 IRP Acknowledgement • Energy Independence Act Compliance and Forecast • Work Plan
TAC 2 – September 4 and 5, 2012	• Palouse Wind Project Tour • Avista REC Planning Methods • Energy and Economic Forecast • Shared Value Report • Generation Options • Spokane River Assessment
TAC 3 – November 7, 2012	• Electricity Market Modeling • Colstrip Discussion • Energy Efficiency • Peak Load Forecast • Reliability Planning • Energy Storage
TAC 4 – February 6, 2013	• Natural Gas Price Forecast • Electric Price Forecast • Transmission Planning • Resource Needs Assessment Market & Portfolio Scenario Development
TAC 5 – March 20, 2013	• Market Forecast Scenario Results • Conservation Avoided Costs • Demand Response • Draft 2013 IRP Preferred Resource Strategy • Portfolio Scenarios
TAC 6 – June 19, 2013	• 2013 Final Preferred Resource Strategy • Portfolio Scenario Analysis • Net Metering and Buck-A-Block • Action Plan • 2013 IRP Document Introduction

Avista wishes to acknowledge and thank all of the organizations identified in Table 1.2 who participated in the TAC process.

Table 1.2: External Technical Advisory Committee Participating Organizations

Organization
AES Corporation
Alexander Boats, LLC
Ameresco Quantum
City of Spokane
Clearwater Paper
Eastern Washington University
EnerNOC Utility Solutions
Eugene Water & Electric Board
First Wind
GE Energy
Gonzaga University
Grant PUD
Greater Spokane Incorporated
Idaho Power
Idaho Public Utilities Commission
Inland Power & Light
Puget Sound Energy
Residential and Small Commercial Customers
Sierra Club
TransAlta
Washington Department of Enterprise Services
Washington State Legislature
Washington Utilities and Transportation Commission
Winfiniti

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.

FERC Hydro Relicensing – Clark Fork and Spokane 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. This collaborative process continues in the implementation of the license and Clark Fork Settlement Agreement, with stakeholders participating in various protection, mitigation, and enhancement efforts. More recently, Avista received a 50-year license for the Spokane River Project following a multi-year collaborative process involving several hundred stakeholders. Implementation began in 2009 with a variety of collaborating parties.

Low Income Rate Assistance Program
This program 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 operates 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
- North American Electric Reliability Council

Future Public Involvement
As previously explained, 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.

2013 IRP Outline

The 2013 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 2013 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 Avista'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 provides an overview of the conservation potential assessment and summarizes the energy efficiency modeling results for the 2013 IRP.

Chapter 4: Policy Considerations

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

Chapter 5: Transmission & Distribution

This chapter discusses Avista's distribution and transmission systems, as well as regional transmission planning issues. It includes detail on transmission cost studies used in the IRP modeling and a summary of the 10-year Transmission Plan. The chapter finishes with 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 2013 IRP.

Chapter 7: Market Analysis

This chapter details Avista's IRP modeling and analysis of the various wholesale markets applicable to the 2013 IRP.

Chapter 8: Preferred Resource Strategy

This chapter details Avista's 2013 Preferred Resource Strategy (PRS) and explains how the PRS could change in response to scenarios differing from the Expected Case.

Chapter 9: Action Items

This chapter discusses progress made on Action Items from the 2011 IRP. It details new Action Items for the 2015 IRP.

Regulatory Requirements

The IRP process for Idaho has several requirements documented in IPUC Orders Nos. 22299 and 24729. Table 1.3 summarizes the applicable IRP requirements.

Table 1.3 Idaho IRP Requirements

Requirement	Plan Citation
Identify and list relevant operating characteristics of existing resources by categories including: hydroelectric, coal-fired, oil or gas-fired, PURPA (by type), exchanges, contracts, transmission resources, and others.	Chapter 2- Loads & Resources
Identify and discuss the 20-year load forecast plus scenarios for the different customer classes. Identify the assumptions and models used to develop the load forecast.	Chapter 2- Loads & Resources Chapter 8- Preferred Resource Strategy
Identify the utility's plan to meet load over the 20-year planning horizon. Include costs and risks of the plan under a range of plausible scenarios.	Chapter 8- Preferred Resource Strategy
Identify energy efficiency resources and costs.	Chapter 3- Energy Efficiency
Provide opportunities for public participation and involvement.	Chapter 1- Introduction and Stakeholder Involvement

The IRP process for Washington has several requirements documented in Washington Administrative Code (WAC). Table 1.4 summarizes where within the IRP the applicable WACs are addressed.

Table 1.4 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 UTC on August 31, 2012; 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 current and future needs of utility ratepayers.	Chapter 2- Loads & Resources
WAC 480-100-238(2)(b) – Plan uses lowest reasonable cost (LRC) analysis to select mix of resources.	Chapter 8- Preferred Resource Strategy
WAC 480-100-238(2)(b) – LRC analysis considers resource costs.	Chapter 8- Preferred Resource Strategy
WAC 480-100-238(2)(b) – LRC analysis considers market-volatility risks.	Chapter 4- 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 Chapter 8- Preferred Resource Strategy
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
WAC 480-107-015(3) – Proposed request for proposals for new capacity needed within three years of the IRP.	Chapter 8- Preferred Resource Strategy

2. Loads & Resources

Introduction & Highlights

An explanation and quantification of Avista's loads and resources are integral to the IRP. The load section of this chapter summarizes customer and load forecasts, load growth scenarios, and enhancements to forecasting models and processes. The resource section of the chapter covers Avista's current resource mix, including descriptions of owned and operated generation, as well as long-term power purchase contracts. The combination of the load forecast and current generation mix show the future resource need to meet energy, peak demand, and renewable energy requirements.

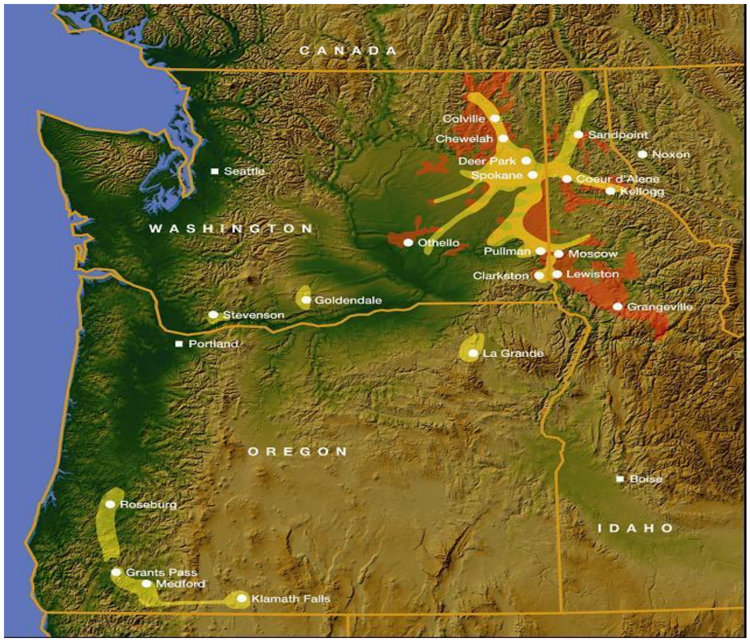
Section Highlights

- The 2013 IRP energy forecast grows 1.0 percent per year, replacing the 1.4 percent annual growth rate in the 2011 IRP.
- Peak load growth is slower than energy growth, at 0.84 percent in the winter and 0.90 percent in the summer.
- Avista's first long-term capacity deficit is in 2020; the first energy deficit is in 2026.
- Palouse Wind became operational December 13, 2012.
- Kettle Falls qualifies for the Washington State Energy Independence Act (EIA) beginning in 2016.
- This IRP meets all EIA mandates over the next 20 years with a combination of qualifying hydro upgrades, Palouse Wind, and Kettle Falls.

Economic Characteristics of Avista's Service Territory

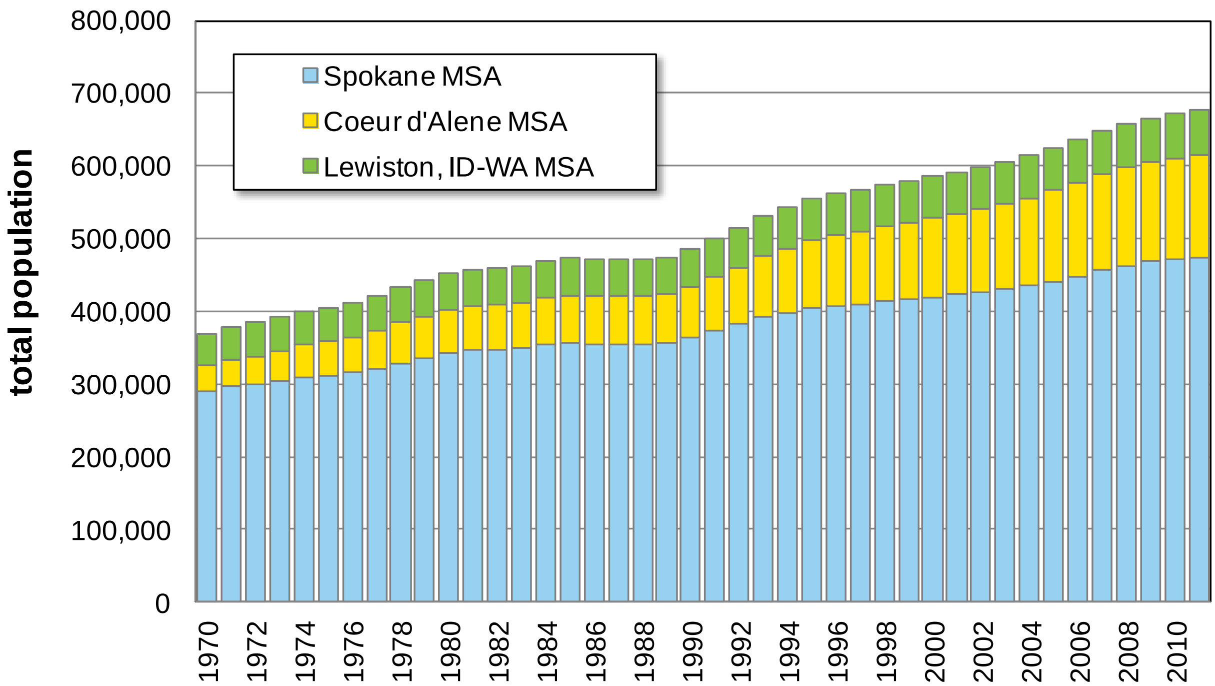
Avista serves electricity customers in most of the urban and suburban areas of 24 counties of eastern Washington and northern Idaho. Figure 2.1 shows Avista's electricity and natural gas service territories. Over 80 percent of Avista's customers are located in three Metropolitan Statistical Areas (MSAs): Spokane MSA (Spokane County, WA), Coeur d'Alene MSA (Kootenai County, ID), and Lewiston, ID-WA MSA (Nez Perce County, ID and Asotin County, WA). The load portion of this chapter focuses on population, employment and personal income for the three MSAs combined.

Figure 2.1: Avista's Service Territory



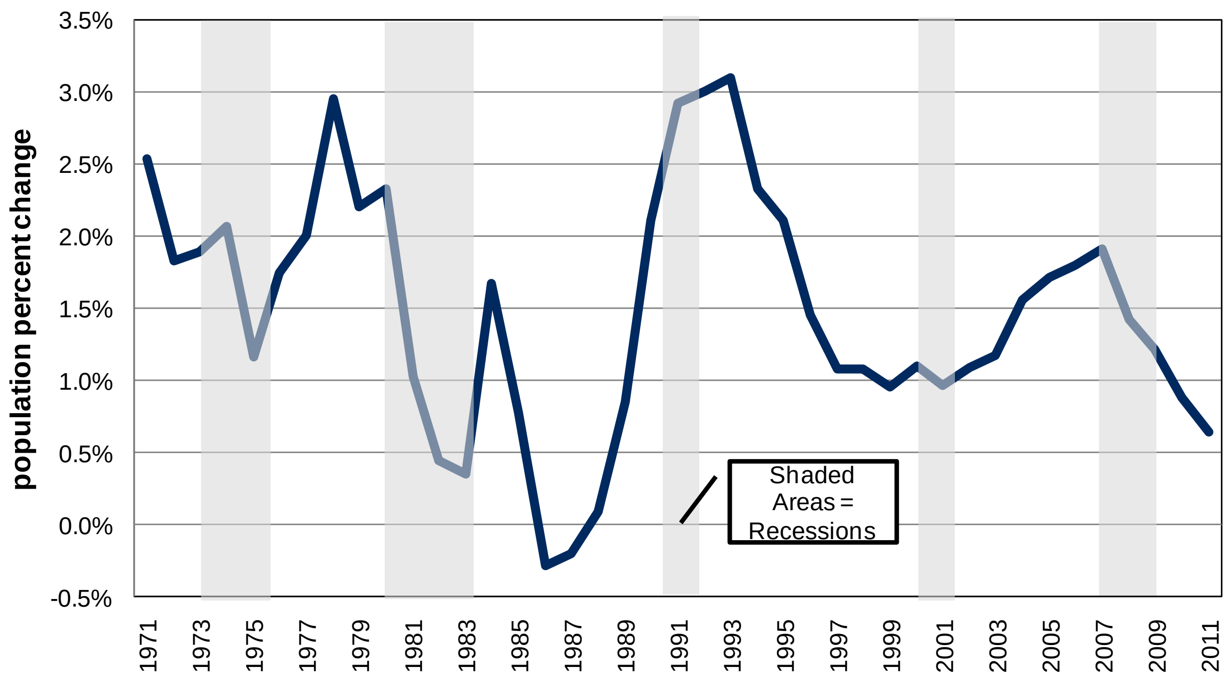
Population across the three MSAs is approximately 680,000. Since 1970, average annual population growth is about 1 percent. Figure 2.2 shows population in the three main MSAs. The Coeur d'Alene MSA has enjoyed the most rapid population growth since the early 1990s, increasing its share of service area population from 15 percent in 1990 to over 20 percent today.

Figure 2.2: Population Levels 1970 – 2011



Population growth is a function of both regional and national employment growth. The regional business cycle follows the U.S. business cycle, meaning regional economic expansions or contractions follow national trends. A study done by Eastern Washington University's Institute for Public Policy and Economic Analysis documents this correlation between the regional and national business cycles.[1] Econometric analysis shows that when regional employment growth is stronger than U.S. growth (see Equation 2.2) over expansionary periods; regional population growth tends to accelerate. The reverse also holds true. Figure 2.3 shows annual population growth since 1971. In the deep economic downturns of the mid-1970s, early 1980s and the recent Great Recession, reduced population growth rates in Avista's service territory led to lower load growth. The Great Recession reduced population growth from nearly 2 percent in 2007 to less than 1 percent from 2010-2012.

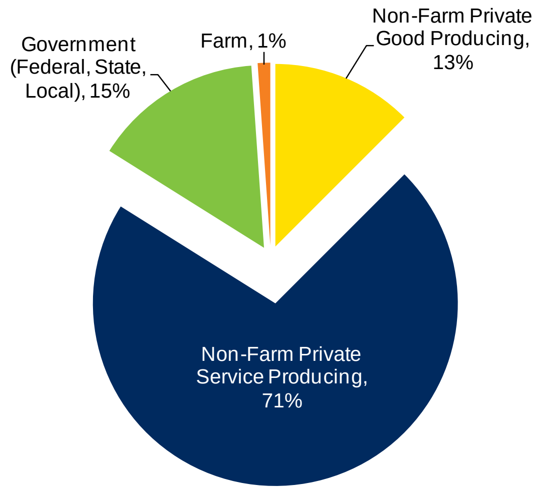
Figure 2.3: Population Growth and U.S. Recessions, 1971-2011



The Inland Northwest has transitioned from a natural resources-based manufacturing economy to a services-based economy. Figure 2.4 shows the breakdown of employment for all three MSAs. Just over 70 percent of employment is in private services, followed by government (15 percent) and private goods-producing sectors (13 percent). Government employment in the three MSAs is notably higher than in the Portland and Puget Sound MSAs. Farming now accounts for one percent of employment.

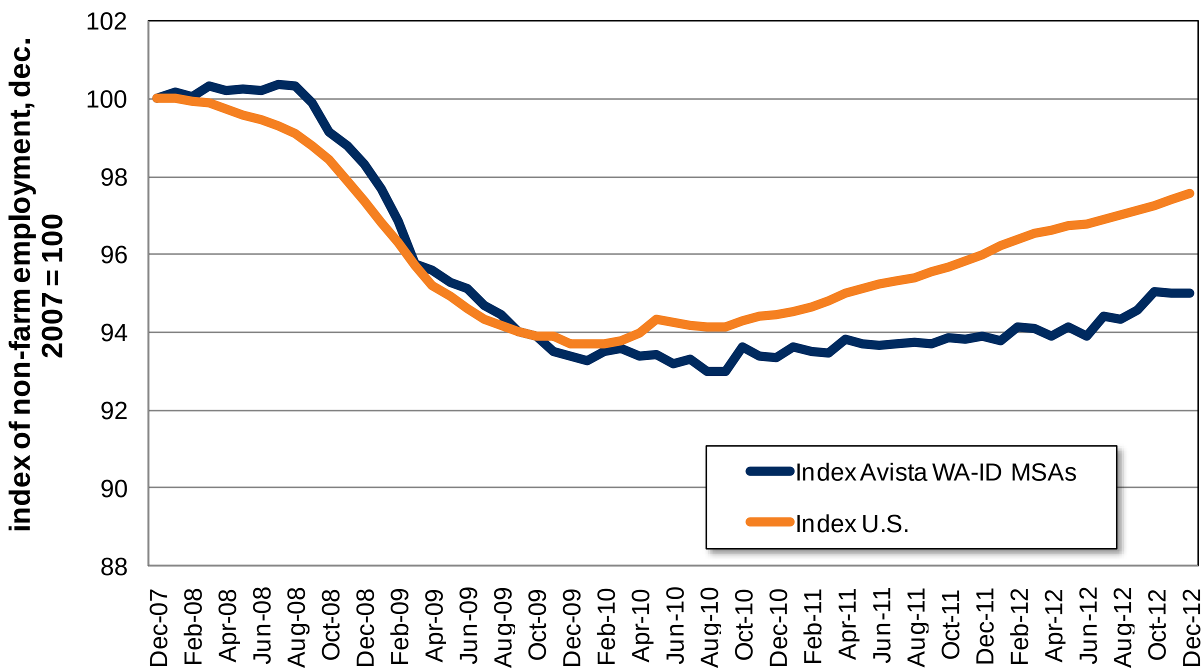
[1] *An Exploration of Similarities between National and Regional Economic Activity in the Inland Northwest*, Monograph No. 11, May 2006. http://www.ewu.edu/cbpa/centers-and-institutes/ippea/monograph-series.xml.

Figure 2.4: Employment Breakdown by Major Sector, 2011



Between 1990 and 2007, non-farm employment growth averaged 2.5 percent per year. However, Figure 2.5 shows that since the end of the Great Recession in 2009, there has been no regional economic growth, and a significant regional lag relative to national employment recovery over the same period. Regional employment growth did not materialize until the second half of 2012, when services employment started to grow. Prior to this, reductions in federal, state, and local government offset employment gains in the goods producing sector.

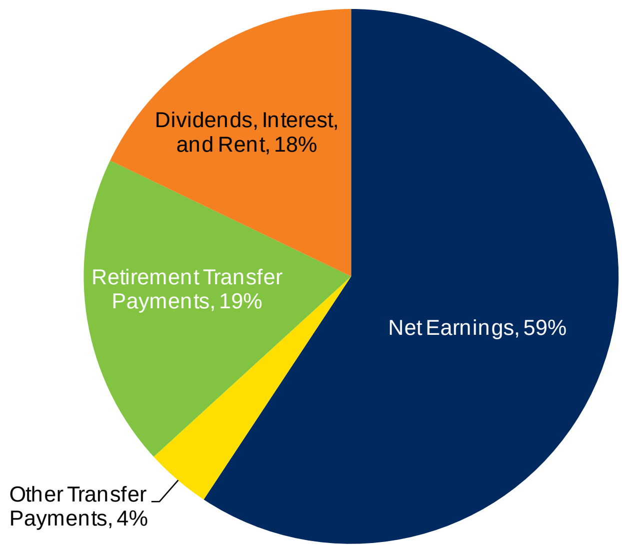
Figure 2.5: Post Recession Employment Growth, June 2009-December 2012



On a brighter economic note, the Spokane and Coeur d'Alene MSAs have emerged as major providers of health and higher education services to the Inland Northwest. A recent addition to these sectors is a new University of Washington medical school branch located in the City of Spokane. Public and private universities and the regional medical system will support the new medical school.

Finally, Figure 2.6 shows the distribution of personal income, a broad measure of both earned income and transfer payments, for Avista's Washington-Idaho MSAs. Regular income consists of net earnings from employment and investment income in the form of dividends interest and rent. Personal current transfer payments include money income and in-kind transfers received through unemployment benefits, low-income food assistance, Social Security, Medicare and Medicaid.

Figure 2.6: Personal Income Breakdown by Major Source, 2011



Although roughly 60 percent of personal income is from net earnings, transfer payments account for 23 percent, or more than one in every five dollars of personal income. Transfer payments have been the fastest growing component of personal income in the region. This reflects an aging regional population, a surge of military veterans, and the Great Recession, which significantly increased payments from unemployment insurance and other low-income assistance programs. In 1970, the share of net earnings and transfer payments in WA-ID MSAs accounted for 64 percent and 12 percent, respectively. The income share of transfer payments has nearly doubled over the last 40 years. The relatively high regional dependence on government employment and transfer payments means continued fiscal consolidation at the federal level would be an economic drag on future growth.

Customer and Load Forecast Assumptions

The customer and load forecasts use: (1) forecasts of U.S. and county-level economic growth; (2) forecasts of heating and cooling degree-days; and (3) forecasts of use-per-customer trends. Topics discussed below provide background to the final customer and load forecasts.

Avista's load forecasting methodology is undergoing significant restructuring. The restructuring involves using an Auto Regressive Integrated Moving Average (ARIMA) technique. ARIMA improves the modeling of economic drivers involving population, industrial production, income levels and energy prices to predict long-term energy demand. This new methodology will improve forecasts used in the 2015 IRP.

Assumptions for U.S. and County-level Economic Growth

The forecast used for this IRP, finalized July 2012, relies on national and county-level forecasts from multiple sources. However, forecasts developed "in-house" and from Global Insight are the principle forecast sources. Avista purchases forecasts from Global Insight, an internationally recognized economic forecasting consulting firm. Table 2.1 presents key U.S. forecast assumptions.

Table 2.1: U.S. Long-run Baseline Forecast Assumptions, 2013-2035

Assumption	Average (%)	Source
Gross Domestic Product	2.5	Global Insight, Federal Reserve, Bloomberg Consensus Forecasts, Energy Information Administration, and Avista Forecasts
Consumer Inflation	2.0	Federal Reserve
Worker Productivity	2.0	Global Insight
Employment Growth	0.9	Global Insight
Industrial Production	2.3	Global Insight
Population Growth	0.9	Global Insight

Long-run gross domestic product (GDP) growth reflects an average of multiple forecast sources, including Avista's own in-house forecasts. In theory, long-run GDP growth should be the sum of productivity growth plus population growth—2.9 percent using the numbers above. However, the forecast sources above generally assume fiscal consolidation (reducing the size of government deficits and debt accumulation) in the U.S. and other developing countries. Fiscal consolidation, along with less consumer credit, will keep U.S. GDP growth under 2.9 percent over the next 20-years. Prior to the Great Recession, U.S. long-run GDP growth was around 3 percent. Consumer inflation reflects the U.S. Federal Reserve's implied anchor for long-run inflation.

Table 2.2 presents key assumptions for the Spokane, Coeur d'Alene and Lewiston, ID-WA MSAs. These three areas comprise more than 80 percent of Avista's service area economy.

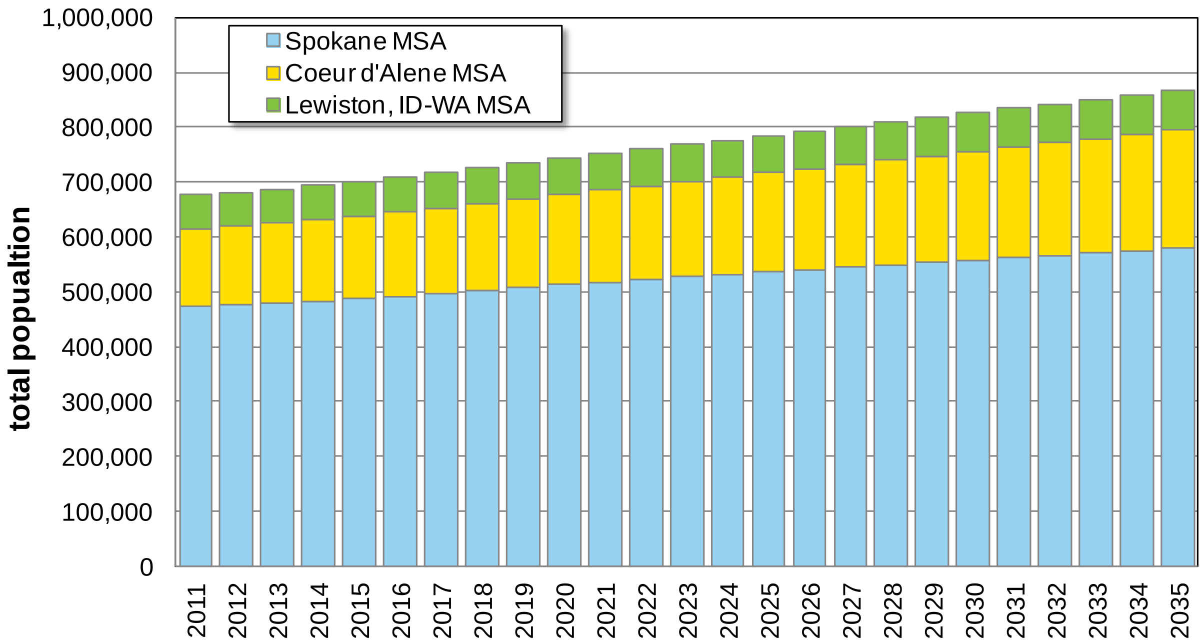
Table 2.2: Avista WA-ID MSAs Baseline Forecast Assumptions, 2013-2035

Assumption	Average	Source
Employment Growth	0.8%	Global Insight and Avista Forecasts
Housing Starts	4,200 per yr.	Global Insight
Population Growth	1.1%	Global Insight and Avista Forecasts

Employment growth and housing starts are key predictors of customer and population growth. Modest forecasts in these areas translate into modest customer growth forecasts. Long-run population growth in Avista's service area is nearly identical to long-run growth rates of total customers over the same period. Therefore, population growth forecasts are a proxy for long-run customer growth, especially for the residential and commercial customer classes.

In addition to Global Insight's population forecasts for the major MSAs, Avista uses two other in-house methods for generating customer growth forecasts. Both methods provide a baseline reasonableness test of Global Insight's population forecasts, which forms the basis of Avista's long-run customer forecasts. Figure 2.7 shows Global Insight's population forecasts.

Figure 2.7: Population Forecast, 2013-2035



While one method uses Global Insight's annual housing forecasts to project annual changes in residential and commercial customers in the MSAs, the second forecast method uses the following simple time-series regression estimated from historical data:

Equation 2.1: Conservation Avoided Costs

$$\Delta C_t = \alpha_0 + \alpha_1 M_{t-1} + \varepsilon_t$$

Where:

α_0 = Intercept value of the estimated equation.

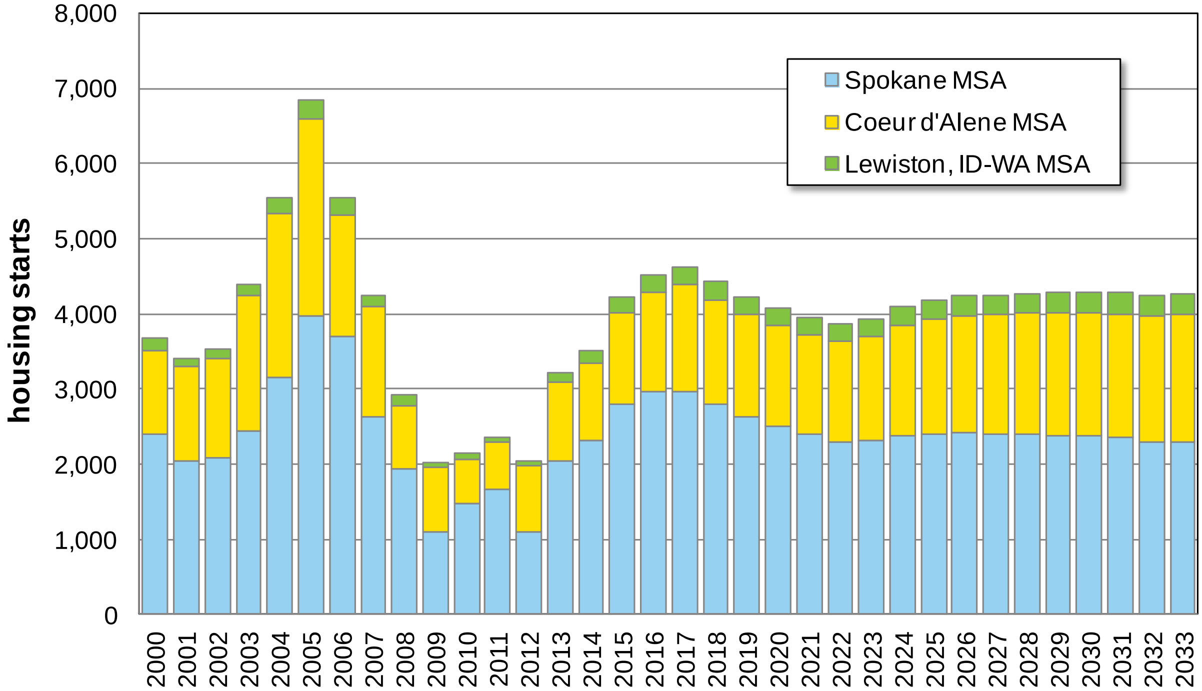
ΔC_t = Change in Avista's total residential electric customers from year t to year t-1 (annual numbers are 12 month averages).

M_{t-1} = The number of housing starts (single family homes and multi-family units) reported at time t-1 for Avista's three combined WA-ID MSAs.

ε_t = Random error term.

Figure 2.8 shows housing start forecasts to the end of the IRP period using the Global Insight forecasts.

Figure 2.8: House Start History and Forecast (2000-2035)



Annual regional and U.S. employment growth is used to forecast annual population growth in the MSAs. The population forecast uses the simple time-series regression model estimated from historical data in Equation 2.2.

Equation 2.2: Population Forecast

$$P_t = \alpha_0 + \alpha_1 E_{t-1,MSA} + \alpha_2 E_{t-1,US} + \alpha_3 D_{2002}, + \varepsilon_t,$$

Where:

α_0 = Intercept value of the estimated equation.

P_t = Population growth rate in year t in Avista's WA-ID MSAs.

$E_{t-1,MSA}$ = Growth rate in non-farm employment in year t-1 in Avista's WA-ID MSAs.

$E_{t-1,US}$ = U.S. growth in non-farm employment in year t-1.

D_{2002} = Dummy for 2002 outlier.

ε_t = Random error term.

Avista's forecast uses Global Insight's forecasts for U.S. employment growth and in-house forecasts for local employment growth. This approach reflects the statistically significant one-year lag between regional and U.S. employment and local population growth rates. Higher or lower employment growth in Avista's service area relative to the U.S. in time t-1 is associated with higher or lower population growth in time t.

The in-house employment forecasts developed using Equation 2.2 are generated through a time-series model linking regional employment growth (the dependent variable) to national GDP growth (the independent variable). As discussed below, this modeling approach can generate high- and low-growth cases for load by altering assumptions about future local employment growth.

Weather Forecasts

The load forecast uses 30-year monthly temperature averages recorded at the Spokane International Airport weather station through 2012. Several other weather stations are located in Avista's service territory, but their data is available for much shorter durations and they are highly correlated with the Spokane International Airport data.

Avista uses heating degree-days (HDD) to measure cold-weather load sensitivity and cooling degree-days (CDD) to measure hot-weather load sensitivity. The weather normalization process uses regressions of the following form:

Equation 2.3: Weather Normalization

$$kWh/C_{t,y,s} = \alpha_0 + \alpha_1 HDD_{t,y,s} + \alpha_2 QHDD_{t,y,s} + \alpha_3 CDD_{t,y,s} + \varepsilon_{t,y,s} \quad \text{for month t, year y, schedule s}$$

Where:

- $kWh/C_{t,y,s}$ = Weather normalization.
- α = Marginal effect of each degree-day type.
- $HDD_{t,y,s}$ = The HDDs for month t, year y and schedule s.
- $QHDD_{t,y,s}$ = The coldest HDD months, December through March.
- $CDD_{t,y,s}$ = The CDDs for month t, year y and schedule s.
- $\varepsilon_{t,y,s}$ = Random error term.

The estimated regressions are used to produce two predicted values of $kWh/C_{t,y,s}$. One estimate uses the actual data to produce $kWh/C_{t,y,s}$, measuring usage driven by weather conditions in month "t". This represents the weather-predicted value of usage per customer for month t in year y. The second estimate, $kWh/C_{t,y,s}$, reflects the predicted usage per customer for month t in year y, based on the 30-year National Oceanic and Atmospheric Administration average. The difference between the two estimates reflects the deviation of month t weather-driven usage from the usage predicted by long-run degree-days:

Equation 2.4: Weather Normalization Adjustment Factor

$$T_{t,y,s} = \text{Usage predicted by normal weather} - \text{Usage predicted by actual weather}$$

The deviation $T_{t,y,s}$ is then added to the actual value of $kWh/C_{t,y,s}$ to obtain weather normalized usage (WNU).

Equation 2.5: Weather Normalized Amount

$$(kWh/C_{t,y,s})^{WNU} = kWh/C_{t,y,s} + T_{t,y,s}$$

Where:

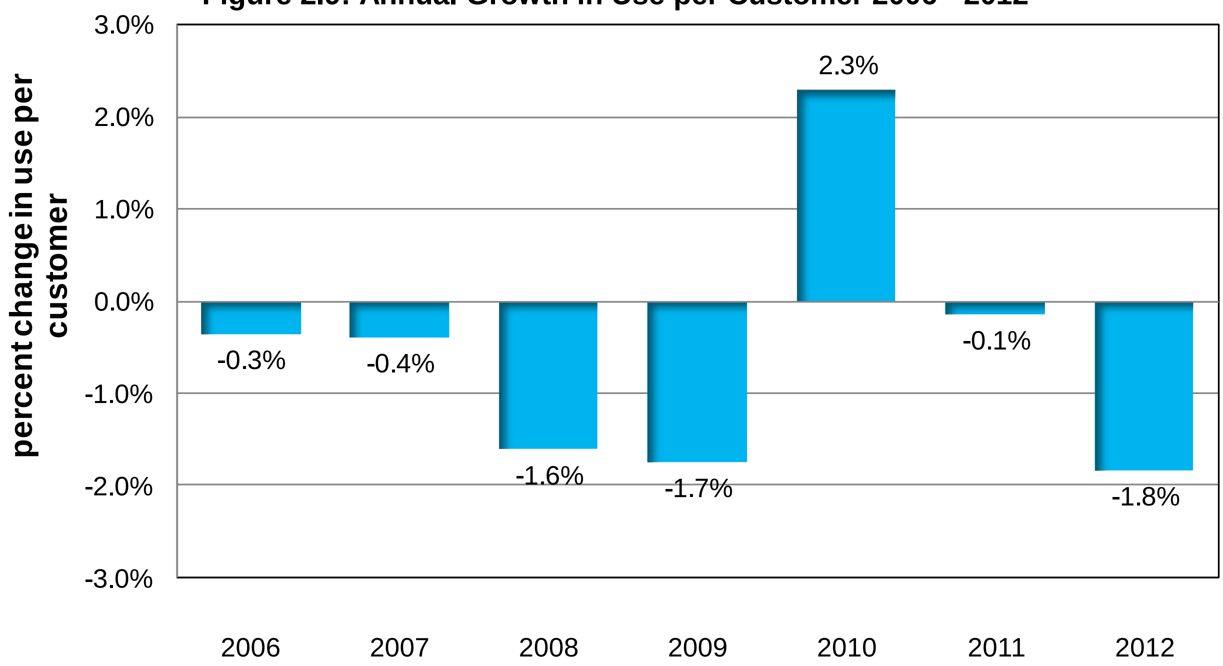
$(kWh/C_{t,y,s})^{WNU}$ = Weather normalized usage in kWh.
$kWh/C_{t,y,s}$ = Actual usage that was observed.
$T_{t,y,s}$ = Weather normalization adjustment factor.

If weather conditions in month t are hotter than average (more CDD than average), then the adjustment factor will be negative. When added to $kWh/C_{t,y,s,}$ WNU will be lower, reflecting an adjustment back to what usage should have been with "average" weather.

Use per Customer Projections
A database of monthly electricity sales and customer numbers by rate schedule forms the basis of use-per-customer (UPC) forecasts by rate schedule, customer class and state. Historical data is weather-normalized to remove the impact of HDD and CDD deviations from expected normal values, as discussed above. Weather normalized UPC forecasts multiplied by tariff schedule customer forecasts result in a total load forecast.

Historical data for Avista's service area shows that weather normalized UPC in the service area is declining. Figure 2.9 shows annual growth in UPC since 2006. Over this period, the average annual rate of decline in UPC was about 0.5 percent and largely reflected a declining trend in the residential sector. The key factors influencing long-run UPC are: (1) own-price and cross-price elasticity; (2) income elasticity as related to consumer purchases of energy-related goods; (3) conservation programs; and (4) changes in household size.

Figure 2.9: Annual Growth in Use per Customer 2006 - 2012



Retail electricity price increases reduce electricity UPC. Own-price elasticity is an important consideration in any electricity demand forecast because it measures the sensitivity of quantity demanded for a given change in price. A consumer who is sensitive to a 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 subsequently reduced electricity usage in response to relatively large price changes. Recent research shows that the more in-home information consumers have about electricity usage and costs, the more price sensitive they become.[2]

Cross-price elasticity measures the relationship between the quantity of electricity demanded and the quantity of potential substitutes (e.g., propane or natural gas for heat) when the price of electricity increases relative to the price of the substitute. A positive cross elasticity coefficient indicates cross-price elasticity between electricity and the substitute. A negative coefficient indicates the absence of cross-price elasticity, and that considered product is not a substitute for electricity, but is instead complementary to it. 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 as the industry relies on more natural gas-fired generation to meet loads. This increased positive correlation has reduced the net effect of cross price elasticity between 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-related products also increases. As incomes rise, consumers are more likely to purchase more electricity-consuming products that increase UPC, such as larger dwellings, mobile electronic devices, high definition televisions and electric vehicles. However, it also enables them to buy more energy efficient products reducing UPC, including more energy efficient windows and appliances, in addition to rooftop solar photovoltaic cells.

Although elasticity plays a key role in customer behavior, estimating elasticity is problematic. Currently Avista lacks sufficient data to estimate elasticity values for its service area. National estimates of elasticity exist; however, for a variety of reasons, there is no guarantee they reflect regional consumer behavior.
Elasticity comes in two forms: short-run and long-run. In terms of own-price elasticity, quantity responses are less sensitive to price increases in the short-run because consumers lack sufficient time to implement efficiency programs or find lower cost

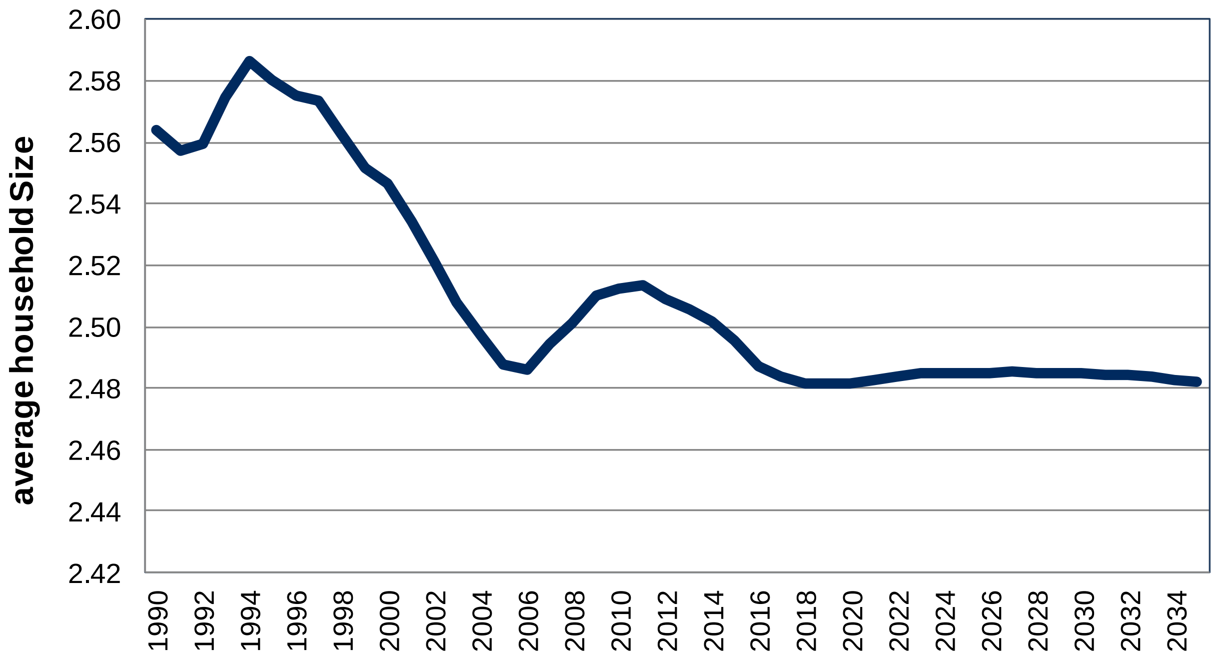
[2] Jessoe and Rapson (2012), *The Short-run and Long-run Effects of Behavioral Interventions: Experimental Evidence from Energy Conservation*, NBER working paper 18492. Allcot and Rogers (2012), *Knowledge is (Less) Power: Experimental Evidence from Residential Energy Use*, NBER work paper 18344.

substitutes. This is not the case in the long-run, so elasticity should increase as the time for adjustment increases. For example, the Energy Information Administration currently uses a value of -0.3 for short-run own-price elasticity for residential electricity, accounting for the "…successful deployment of smart grid projects funded under the American Recovery and Reinvestment Act of 2009."[3] However, the Energy Information Administration estimates long-run elasticity ranges from -0.04 to -1.45.[4]

Recent research (Arimura, Li, Newell, and Palmer, 2011) indicates that conservation programs reduce long-run residential usage.[5] However, empirical problems arise when estimating the impact of energy efficiency on load. These programs affect historical data; therefore, the forecast already contains the impacts of existing conservation levels. However, Avista is currently working with the EnerNOC consulting group to estimate energy efficiency savings. Future IRPs will address a more concrete empirical estimate on the impact of energy efficiency programs to avoid double counting.

Figure 2.10 shows average household size in Avista's electric service area since 1990. The size has fallen to 2.5 people per household or about 2 percent smaller than in 1990. The forecast is for average household size to stay below the current level through 2035.

Figure 2.10: Area Average Household Size, Historical and Forecast 1990-2035



3 See U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2012*, Residential Demand Module, p. 32.

4 See U.S. Energy Information Administration, Working Memorandum from George Lady, *NEMS Price Elasticities of Demand for Residential and Commercial Energy Use*, Table 2, p. 4.

5 Arimura, Li, Newell, and Palmer (2011), *Cost-effectiveness of Electricity Energy Efficiency Programs*, NBER working paper 17556.

Residential use accounts for 88 percent of customers and 40 percent of load, the factors discussed above impact the long-run trend UPC as follows:

Equation 2.6: Use per Customer

UPC Trend = ƒ(long- and short-run price and income elasticity, conservation programs, household size, long-run weather factors)

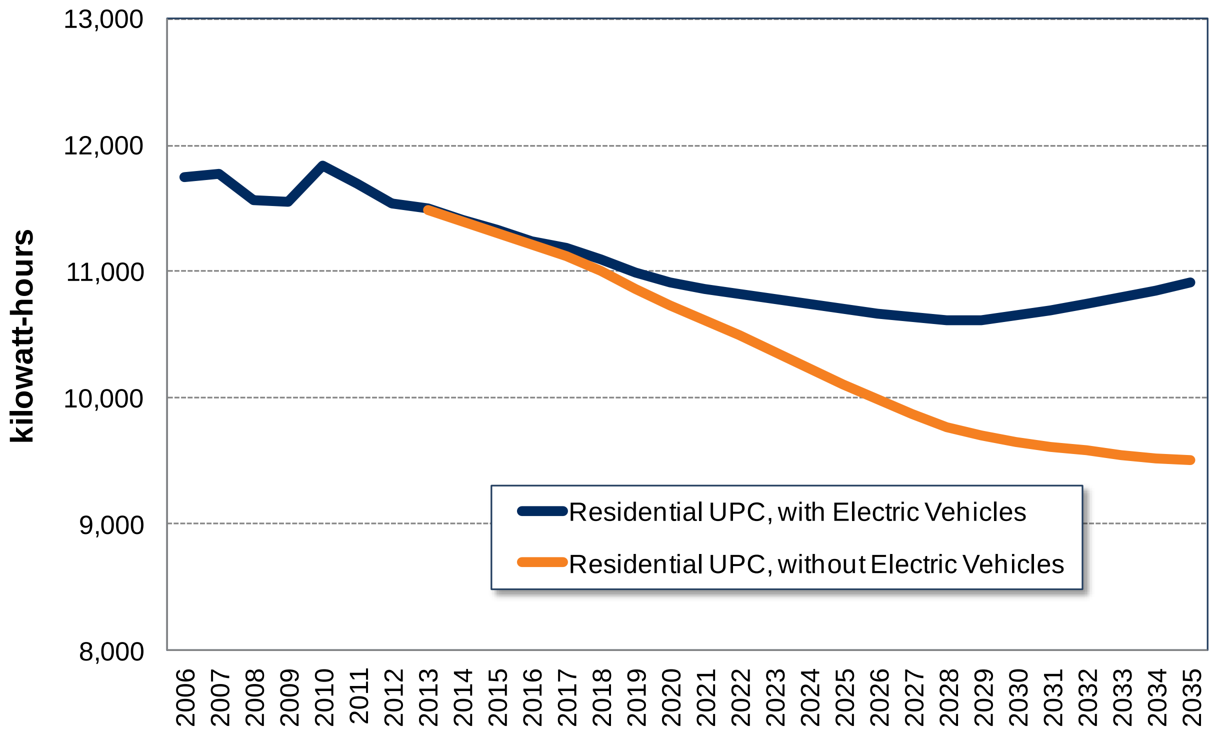
Rather than modeling each piece on the right side of Equation 2.6, the forecast attempts to model the long-run UPC trend as a whole using historical UPC data. An analysis of data since 2005 shows the UPC can be modeled using a linear trend in the residential forecast. This trend is alongside other explanatory variables related to heating and cooling degree-days. Future forecast models will explicitly include variables that influence UPC trends, such as household size, price and consumer income. Besides long-run potential climate change, the only individual component related in Equation 2.6 explicitly considered is the adoption of electric vehicles in Avista's service area.

The 2013 IRP electric vehicle adoption scenario is half of the 2011 IRP forecast. This revision reflects evidence indicating the adoption of electric vehicles is occurring at a slower pace than previously expected. The electric vehicle fleet is a combination of plug-in hybrids and electric-only passenger vehicles. The 2011 IRP forecast of electric vehicles utilized the Northwest Power and Conservation Council's (NPCCs) forecast from the Sixth Northwest Conservation and Power Plan.[6] The slow rate of electric vehicle adoption in Avista's service area likely coincides to the service area's post-recession employment recovery (discussed above), including a 10 percent decline in inflation-adjusted median household income since 2007, and the continued high price of electric vehicles relative to traditional alternatives.

One forecast shown in Figure 2.11 assumes the long-run UPC will continue to decline until 2028 when it could slowly increase due to electric vehicle adoption. The other forecast is the no-electric vehicle case where they are not widely adopted. Here, UPC continues to decline, but more slowly after 2028. Given current electric vehicle adoption rates, the no-electric vehicle case seems more likely.

[6] http://www.nwcouncil.org/energy/powerplan/6/plan/

Figure 2.11: Residential Use per Customer, 2006-2035



Customer Forecast

Table 2.3 shows the historical correlation of year-over-year customer growth across the four main customer groups: residential, commercial, industrial and streetlights. The correlation between residential and commercial is high, meaning forecasted growth rates should behave similarly. As a result, both the residential and commercial groups correlate to population growth. Industrial and streetlights change very slowly; so these forecasts use simple trending and smoothing methods.

Table 2.3: Customer Growth Correlations, January 2006-December 2012

Customer Class (Year-over-Year)	Residential, Year-over-Year	Commercial, Year-over-Year	Industrial, Year-over-Year	Streetlights, Year-over-Year
Residential	1			
Commercial	0.899	1		
Industrial	-0.320	-0.169	1	
Streetlights	-0.246	-0.205	0.280	1

To reproduce the high correlation between residential and commercial customers in the forecast, the residential customer forecast is used as a driver for the commercial forecast. This is done by regressing past commercial customer changes against past residential customer changes, as shown in Equation 2.7. Using the estimated equation, forecasted customer changes are inserted to generate the forecasted change in commercial customers.

Equation 2.7: Customer Forecast

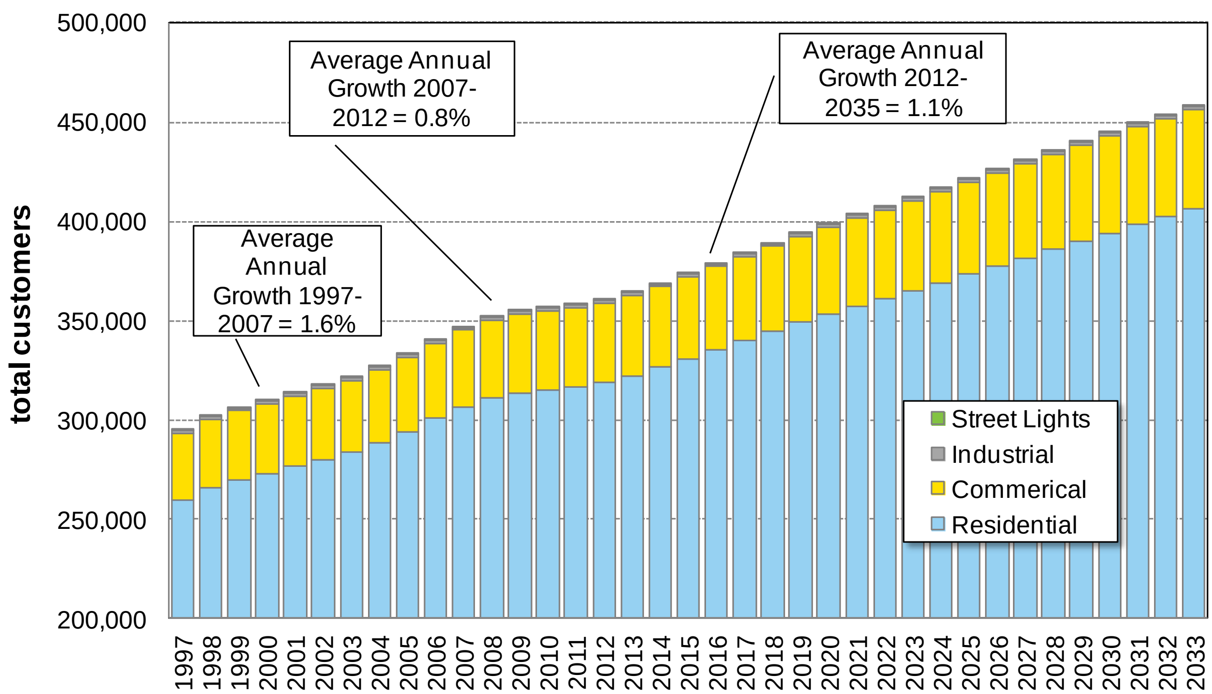
$$\Delta C_{t,commerical} = \alpha_0 + \alpha_1 \Delta C_{t,residential} + \varepsilon_{t,}$$

Where:

α_0 = Intercept value of the estimated equation.
$\Delta C_{t,commerical}$ = Change in Avista's total commercial electric customers from year t to year t-1 (annual numbers are 12-month averages).
$\Delta C_{t,residential}$ = Change in Avista's total residential electric customers from year t to year t-1 (annual numbers are 12-month averages).
ε_t = Random error term.

In aggregate, average annual customer growth is 1.1 percent out to 2035, with residential and commercial driving most of the growth at 1.1 percent annually. Industrial growth is 0.3 percent annually. The aggregate growth forecast is considerably below the pre-Great Recession growth rate of 1.6 percent. See Figure 2.12.

Figure 2.12: Avista's Customer Growth, 1997-2033

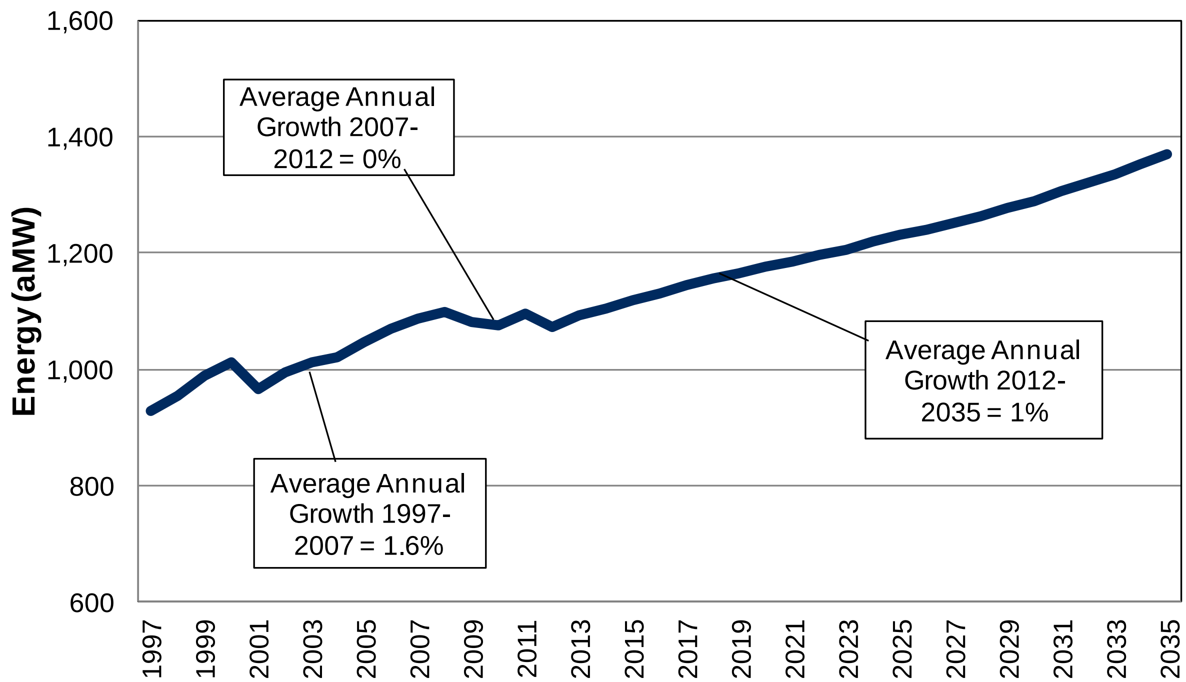


Native Load Forecast

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

Figure 2.13 presents annual net native load growth. Note the significant drop in the 2000-01 Western Energy Crisis and smaller declines in the Great Recession. Annual growth averages 1 percent through 2035.

Figure 2.13: Native Load History and Forecast, 1997-2035



Peak Demand Forecast

The energy or load forecast is important to the development of the IRP because retail sales growth drives many future system costs. When planning to meet the needs of all of Avista's customers, a forecast of peak demand is also crucial to determine the need for new capacity. In other words, Avista must not only meet the energy needs of its customers, but also have enough capacity to meet demands in its highest load hour.

Avista's typical peak hour is in the winter months, between November and early February. Recent warm winters, hot summers and added air conditioning load have created some summer months where loads were higher than the winter. This phenomenon has transformed Avista into a dual peaking utility. Even though summer peaks may be higher than winter, Avista still expects to have its highest electricity load in the winter.

Avista's peak load forecast began by normalizing historical data to set a base peak level adjusted for temperatures. After the adjustment, peak loads trend with economic factors similar to the energy forecast. Normalizing base peak loads begins with adjusting the 2012 peak for temperature variation from normal. Using daily peak load data for 24 months an econometric model isolates the relationship between load and temperatures, day of the week, holidays, school days, season and other factors. These relationships are normalized using a 123-year average of historical Spokane temperatures. For the winter forecast, the coldest day of each year is averaged to determine the base planning temperature.[7] For the summer, the same process is used but for the hottest day. In the winter the average coldest day is 3.9 degrees Fahrenheit, the coldest temperature on record was -17 degrees on December 30, 1968. Avista last saw an extreme winter peak temperature in 2004 with a -9 degrees day average. For summer peak planning, the average hottest day (average of daily high and low temperature) is 82.3 degrees. The hottest average day on record is 90 degrees on July 27, 1928. Avista's last extreme summer temperature was 86 degrees in 2008. See Table 2.4 for details. One caution using the average of extreme annual temperatures is the extreme temperature may land on a Friday, weekend, or on a holiday, the extreme temperature is not going to have a large impact on peak load these days. This base forecast weights the days of the week to reflect the average temperature given extreme temperatures can happen on any given day.

Table 2.4: Average Day Spokane Temperatures 1890-2012 (Degrees Fahrenheit)

Customer Class	Coldest Day	Hottest Day
Extreme	-17.0	90.0
Average	3.9	82.3
Standard Deviation	8.9	2.8
90th Percentile	-8.8	86.0
Recent Extreme Temperatures	2004: -9.0	2008: 86.0

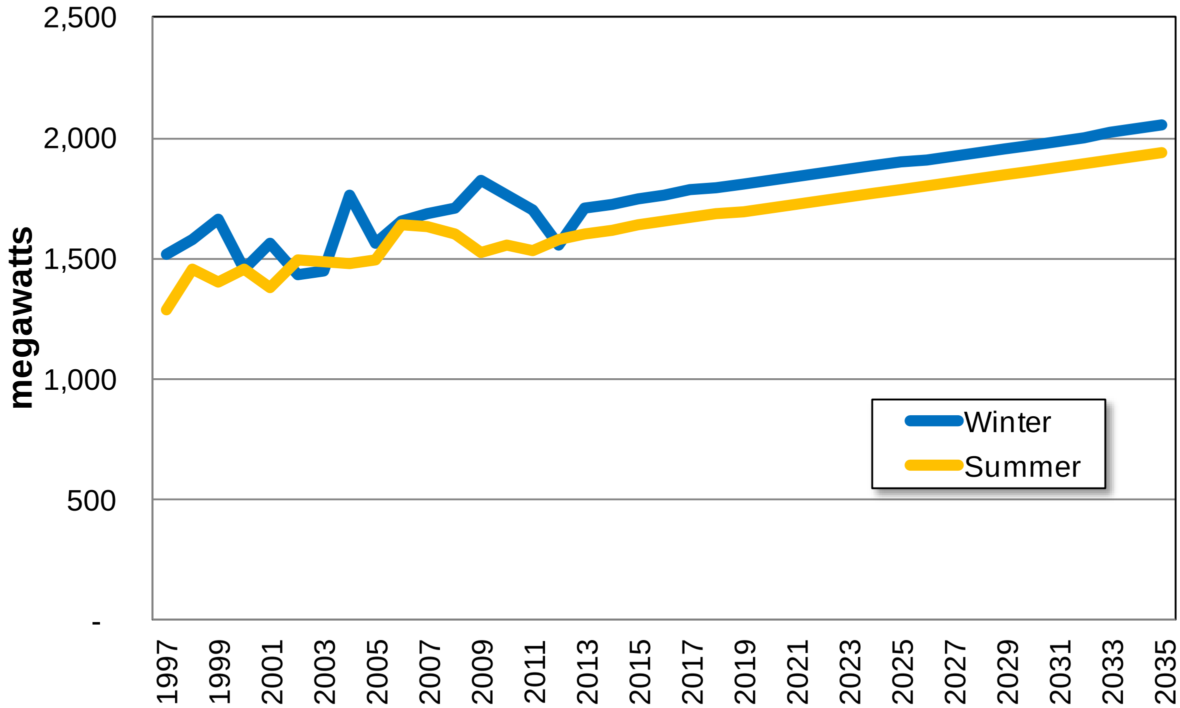
Using the normalized base peak levels from 2012, the peak load forecast uses an econometric model relying on GDP growth as its primary driver, similar to the energy forecast. With this regression relationship, peak load growth is simulated using assumptions about future GDP growth. GDP growth out to 2017 was set at the average of multiple forecast sources.[8] Using this average shapes the near term impacts of the business cycle on peak load growth. From 2018-35 the long-run GDP growth was 2.5 percent.

This analysis resulted in a 20-year peak growth rate of 0.84 percent in the winter and a 0.90 percent growth rate in the summer. Figure 2.14 illustrates these growth levels compared to historical peaks for both summer and winter (other monthly peaks are developed but not shown). Avista's all-time native load peak was in 2009 with peak loads at 1,821 MW, on this day the average temperature reached -7 degrees. The historical summer peak occurred in July 2006 when average temperatures reached 87 degrees. The historical winter and summer annual average growth rates between 1997 and 2012 were 0.85 and 1.0 percent, respectively. The forecast peaks represent an

[7] The coldest day based on the average of daily high and low temperatures.
[8] The forecast sources are the U.S. Federal Reserve, Bloomberg's survey of forecasters, Reuter's survey of forecasters, The Economist's survey of forecasters, Global Insight, Economy.com, Blue Chip consensus forecast. Averaging these sources reduces the systematic forecast error that can arise from using a single source forecast.

expected peak level given average extreme temperatures; actual peak loads are expected to deviate from this forecast. Avista resources meet the deviated peak loads first, and market purchases meet the remaining peak loads.[9]

Figure 2.14: Winter and Summer Peak Demand, 1997-2035



High and Low Load Growth Cases

Avista produces high and low load forecasts to test the PRS. These forecasts are very difficult to create because many factors influence the outcome. In past IRPs, Avista used ranges from the NPCC's Sixth Power Plan as a guide. This IRP relies on this basic relationship to derive the high and low load growth rates:

Equation 2.8: Long Run Load to Customer Relationship

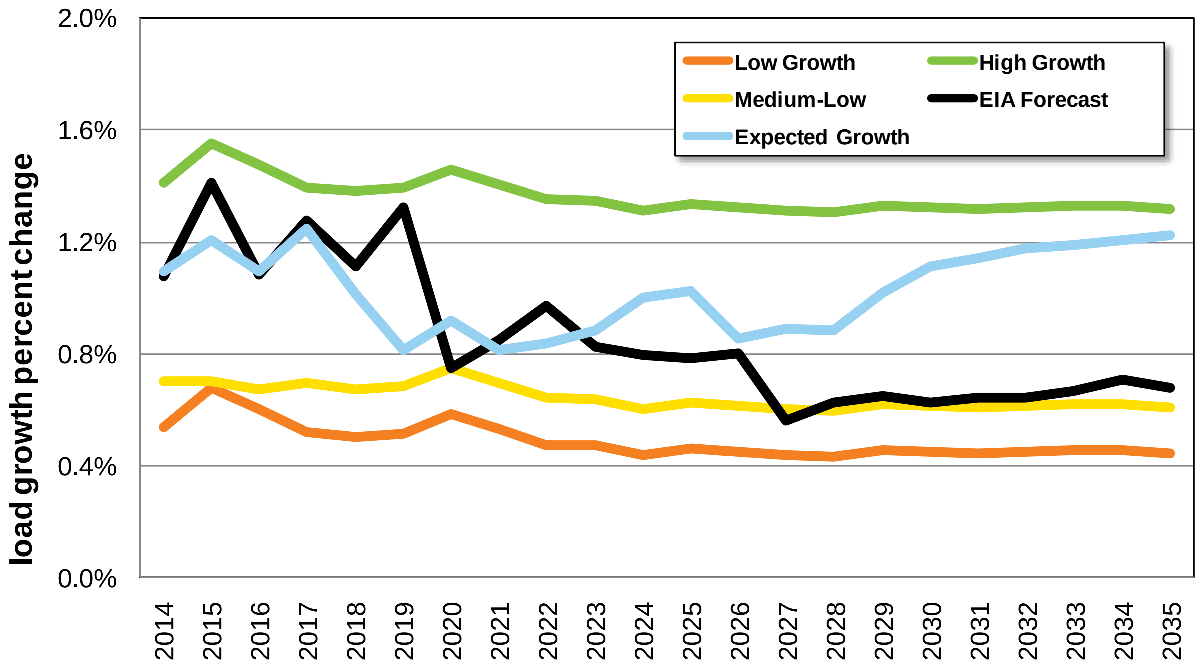
% change in load ≈ % change in customers + % change in UPC.[10]

Recalling the discussion above, population growth approximates long-run customer growth, and population growth approximates employment growth. Therefore using Equation 2.2 to simulate population growth should be under differing assumptions of regional employment growth, holding U.S. employment and UPC growth rates constant. Avista uses this method to forecast alternative load growth cases. The low case

[9] Avista maintains a 14 percent planning margin above these peak levels, and operating reserves.
[10] Since UPC = load/customers, calculus shows that the annual percentage change UPC ≈ percentage change in load - percentage change in customers. Rearranging terms, we have, the annual percentage change in load ≈ percentage change in customers + percentage change in UPC.

assumes regional employment growth averages 0.5 percent out to 2035; the high-growth case assumes 2.5 percent. Figure 2.15 shows the results of these assumptions. Figure 2.15 also shows the U.S. baseline forecast from the Energy Information Administration and a low-medium forecast uses Global Insight's base-line forecasts for employment growth to forecast population growth.

Figure 2.15: Load Growth Scenarios, 2014-2035



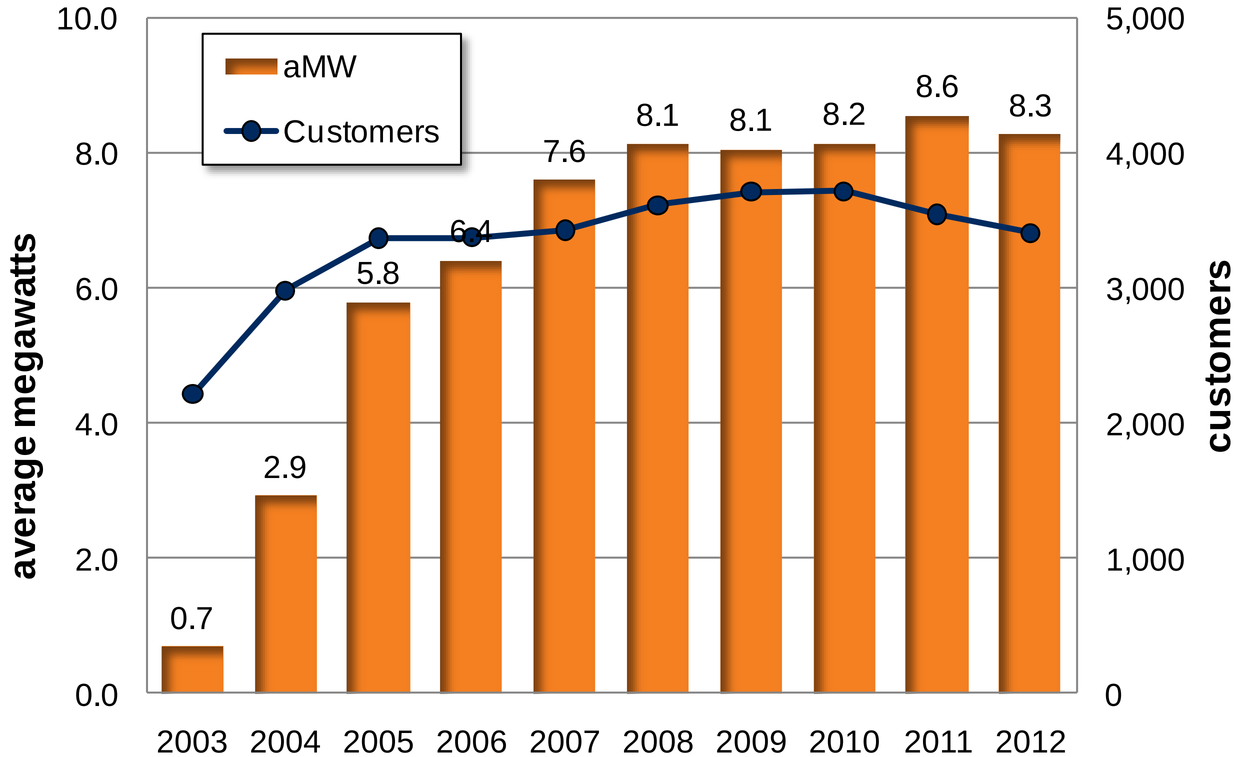
Voluntary Renewable Energy Program (Buck-A-Block)

Since 2002, Avista has offered customers the opportunity to purchase renewable energy voluntarily as part of their utility billing process. Customers currently can purchase 300 kWh blocks for $1.00 to meet their personal renewable energy goals. This program is rate neutral and funded by participating customers. Avista's 35 MW share of the Stateline Wind project supplies most of the program through March 2014. Along with the wind energy, the purchase agreement includes renewable energy credits. The current mix of renewable credits used by Buck-A-Block customers is 85 percent from wind, 14.8 percent from biomass and the remaining 0.2 percent from the 15 kW Rathdrum Solar project (see Figure 2.16).

Since inception, participants purchased an average of 8.1 aMW of renewable energy through the Buck-A-Block program. Figure 2.17 shows the growth of customers and purchased energy in the program. After initial growth in the program, purchases leveled off in 2008 at just over 8.0 aMW per year.

Figure 2.16: 15 kW Photovoltaic Installation in Rathdrum, ID

Figure 2.17: Buck-A-Block Customer and Demand Growth

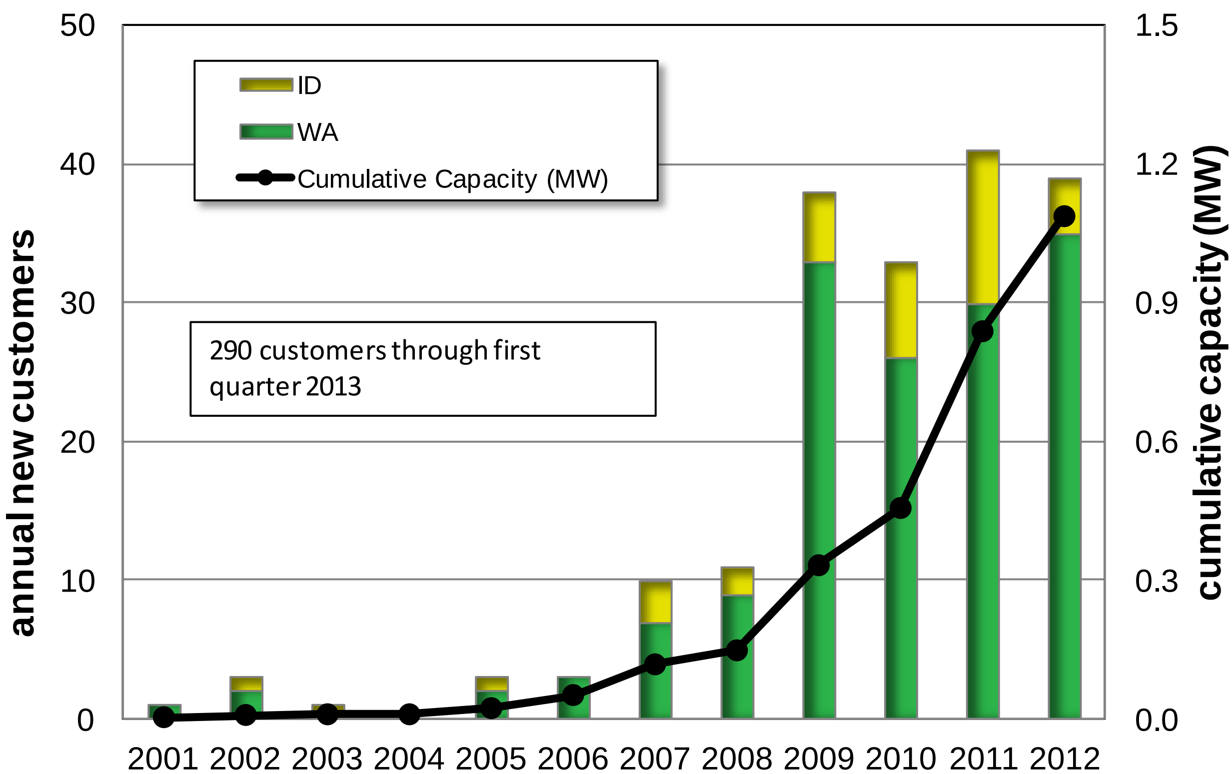


Customer-Owned Generation

A small but growing number of customers continue to install their own generation at an increasing pace. In 2007 and 2008, the average new net-metering customers were 10, and between 2009 and 2012, the average increased to 38 per year, likely in response to generous federal and state tax incentives. These projects qualify for the federal government's 30 percent tax credit and in the state of Washington, customer-owned projects can qualify for additional tax incentives of up to $5,000 per year. The quantity of generation each year through 2020 determines the amount of incentives paid. The Washington state utility taxes credit finances the incentives. Solar projects can qualify for total incentives worth up to $0.54 per kWh with solar panels and inverters manufactured in Washington. All other customer-owned generation receives a minimum payment of $0.12 per kWh, increasing depending upon the manufacturing location of the installed equipment.

At this time, 190 customers have installed net-metered generation equipment for a total of 1.1 MW of capacity. This level equals approximately 0.5 percent of Avista's generation capacity. Eighty percent of the installations are in Washington, with most in Spokane County. Figure 2.18 shows annual net metering customer additions. Solar is 83 percent of net metered technology; the remaining is a mix of wind, combined solar and wind systems, and biogas. The average annual capacity factor of the solar facilities is 13 percent. Small wind turbines typically produce less than a 10 percent capacity factor depending on location. At current tax incentive levels, the number of new net-metered systems will continue at their current pace or may even increase. Where tax subsidies end without a significant reduction in technology cost, the interest in net metering likely will return to pre-tax incentive levels. If the number of net-metering customers continues to increase, Avista may need to adjust rate structures for customers who rely on the utility's infrastructure but do not contribute financially for infrastructure costs.

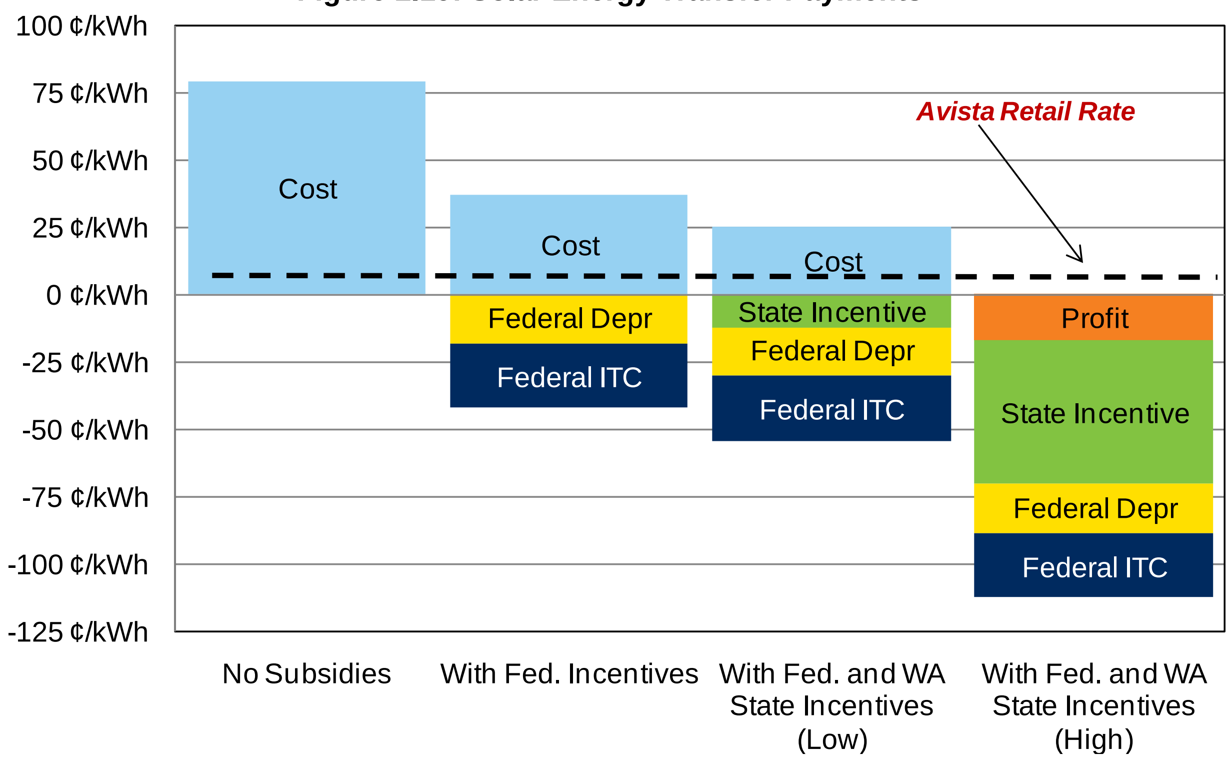
Figure 2.18: Net Metering Customers



The reason for increased interest in customer-owned generation may have more to do with economics than environmental benefits. Figure 2.19 shows how current government subsidies make solar energy attractive to customers. This example uses a

5 kW system at $7,000 per kW, or a $35,000 total installation cost.[11] The cost without government assistance is 80 cents per kWh, roughly ten times Avista's retail electricity rate. The federal tax Investment Tax Credit (ITC) and favorable federal depreciation rules transfers up to 42 cents per kWh from the system owner to taxpayers. Washington state picks up an additional 12 to 54 cents per KWh. With combined federal and state subsidies, a customer has the potential to install "made in Washington" panels and inverters and have not only its entire costs paid for, but also make a profit and receive free energy. Given these generous incentives, the potential exists for additional net metering customers on Avista's system, especially where present funding is limited under RCW 82.16.130 to the lesser of 0.5 percent of taxable power sales or $100,000.

Figure 2.19: Solar Energy Transfer Payments



Avista Resources and Contracts

Avista relies on a diverse portfolio of generating assets to meet customer loads, including owning and operating eight hydroelectric developments located on the Spokane and Clark Fork rivers. Avista's 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.

[11] A higher cost of solar is used to represent the costs of panels and inverters manufactured in Washington with typically higher installation costs to illustrate the costs/benefits of the "made in Washington" Renewable Energy Systems Cost Recovery Incentive Payments.

Spokane River Hydroelectric Developments

Avista owns and operates six hydroelectric developments on the Spokane River. Five of these developments received a new 50-year FERC operating license in June 2009. The following section describes the Spokane River developments 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 developments. The nameplate, or installed capacity, is the capacity of a plant as rated by the manufacturer. All six of the hydroelectric developments on the Spokane River connect to Avista's transmission system.

Post Falls

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

Upper Falls

The Upper Falls development 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 nameplate unit with a 10.26 MW maximum capacity rating.

Monroe Street

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

Nine Mile

A private developer built the Nine Mile development in 1908 near Nine Mile Falls, Washington, nine miles northwest of Spokane. Avista (then Washington Water Power) purchased the project in 1925 from the Spokane & Inland Empire Railroad Company. Its four units have a 26.4 MW nameplate rating and 17.6 MW maximum capacity rating.[12] A new hydraulic control system was installed in 2010, replacing the original flashboard system that maintained full pool conditions seasonally.

Nine Mile is currently undergoing substantial multi-year upgrades. Nine Mile Units 1 and 2 upgrades to two 8 MW generators/turbines, replace both existing 3 MW units. Once operational in 2016, the new units will add 1.4 aMW of energy beyond the original configuration and 6.4 MW of capacity above current generation levels. In addition to these capacity upgrades, the facility will receive upgrades to the hydraulic governors, static excitation system, switchgear, station service, control and protection packages, ventilation upgrades, rehabilitation of intake gates and sediment bypass system, and

[12] This is the de-rated capacity considering the outage of Nine Mile Unit 1 and de-rate of Unit 2.

other investments. The fall 2013 Unit 4 overhaul includes new turbine runners, thrust bearings, and operating system. Avista plans to overhaul Unit 3 in 2018-19.

Long Lake

The Long Lake development is located northwest of Spokane and maintains the Lake Spokane reservoir, also known as Long Lake. The plant received new runners in the 1990s, adding 2.2 aMW of additional energy. The project’s four units have an 81.6 MW nameplate rating and provide 88.0 MW of combined capacity.

Little Falls

The Little Falls development, 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 more energy. The facility’s four units generate 35.2 MW of on-peak capacity and have a 32.0 MW nameplate rating. Avista is carrying out a series of upgrades to the Little Falls development. Much of the new electrical equipment and the installation of a new generator excitation system are complete. Current projects include replacing station service equipment, updating the powerhouse crane, and developing new control schemes and panels. After the preliminary work is completed, replacing generators, turbines, and unit protection and control systems on the four units will start.

Clark Fork River Hydroelectric Developments

The Clark Fork River Developments 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. Both hydroelectric projects on the Clark Fork River connect to Avista’s transmission system.

Cabinet Gorge

The Cabinet Gorge development started generating power in 1952 with two units. The plant added two additional generators 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 Unit 1 turbine 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.

Noxon Rapids

The Noxon Rapids development includes four generators installed between 1959 and 1960, and a fifth unit added in 1977. Avista recently completed a major turbine upgrade, with Units 1 through 4 receiving new runners between 2009 and 2012. The upgrades increased the capacity of each unit from 105 MW to 112.5 MW and added a total of 6.6 aMW of EIA qualified energy.

Total Hydroelectric Generation

In total, Avista’s hydroelectric plants have 1,065.4 MW of on-peak capacity. Table 2.5 summarizes the location and operational capacities of Avista’s hydroelectric projects. This table includes the expected energy output of each facility based on the 70-year hydrologic record for the year ending 2012.

Table 2.5: Avista-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	81.6	89.0	53.4
Upper Falls	Spokane	Spokane, WA	10.0	10.2	7.5
Cabinet Gorge	Clark Fork	Clark Fork, ID	265.2	270.5	124.8
Noxon Rapids	Clark Fork	Noxon, MT	518.0	610.0	198.3
Total			**962.4**	**1,065.4**	**440.2**

Thermal Resources

Avista owns seven thermal generation assets located across the Northwest. Based on IRP analysis, Avista expects each plant to continue operation through the 20-year IRP planning horizon. 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 2.6.

Colstrip Units 3 and 4

The Colstrip plant, located in Eastern Montana, consists of four coal-fired steam plants connected to the double circuit 500 kV BPA transmission line under a long-term wheeling agreement. PPL Global operates the facilities on behalf of the six owners. Avista owns 15 percent of Units 3 and 4. Unit 3 began operating in 1984 and Unit 4 was finished in 1986. Avista’s share of Colstrip Units 3 and 4 has a maximum net capacity of 111.0 MW, and a nameplate rating of 123.5 MW per unit. Avista has no ownership interests in Colstrip Unites 1 and 2.

Rathdrum

Rathdrum consists of two simple-cycle combustion turbine units. This natural gas-fired plant is located near Rathdrum, Idaho and connects to Avista’s transmission system. 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 Spokane, is two aero-derivative simple-cycle units completed in 1978 and connects to Avista’s transmission system. The plant is capable of burning natural gas or fuel oil, but current air permits preclude 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 550 hours per year.

Boulder Park

The Boulder Park project entered service in Spokane Valley in 2002 and connects to Avista's transmission system. 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. This plant connects to BPA's 500 kV transmission system under a long-term transmission agreement. The plant began service in 2003. Its maximum capacity is 274 MW in the winter and 221 MW in the summer with a duct burner providing additional capacity of up to 28 MW. The plant's nameplate rating is 287.3 MW.

Avista is in the process of upgrading Coyote Springs 2. Upgrades include cooling optimization and cold day controls. The 2011 IRP process studied both of these updates. The cold day controls remove firing temperature suppression that occurs when ambient temperatures are below 60 degrees. The upgrade improves the heat rate by 0.5 percent and output by approximately 2.0 MW during cold temperature operations. The cooling optimization package improves compressor and natural gas turbine efficiency, resulting in an overall increase in plant output of 2.0 MW. In addition to these upgrades, Coyote Springs 2 now has a Mark VIe control upgrade, a new digital front end on the EX2100 gas turbine exciter, and model-based control with enhanced transient capability. Each of these projects allows Avista to maintain high reliability, reduce future O&M costs, improve our ability to maintain compliance with WECC reliability standards, and help prevent damage that might occur to the machine when electrical system disturbances occur.

Kettle Falls Generation Station and Kettle Falls Combustion Turbine

The Kettle Falls Generating Station, a biomass facility, entered service in 1983 near Kettle Falls, Washington. It is among the largest biomass plants in North America and connects to Avista's 115 kV transmission system. The open-loop biomass steam plant uses waste wood products from area mills and forest slash, but can also burn 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 approximately 50.0 MW, and its nameplate rating is 50.7 MW. The plant typically operates between 45 and 47 MW because of fuel conditions. 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 natural gas pipeline is capacity constrained; for IRP modeling, the CT does not run when temperatures fall below zero and natural gas pipeline capacity is assumed to serve local natural gas distribution demand.

Table 2.6: Avista-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	312.0	251.0	290.0
Kettle Falls	Kettle Falls, WA	Wood	1983	47.0	47.0	50.7
Kettle Falls CT[13]	Kettle Falls, WA	Gas	2002	11.0	8.0	7.5
Total				**862.6**	**720.6**	**847.5**

Power Purchase and Sale Contracts

Avista utilizes power supply purchase and sale arrangements of varying lengths to meet a portion of its load requirements. This chapter describes the contracts in effect during the scope of the 2013 IRP. Contracts provide many benefits, including environmentally low-impact and low-cost hydro and wind power. A 2012 annual summary of Avista's large contracts is in Table 2.7.

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 large when compared to 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 the surplus power. The contract terms obligate the PUDs to deliver power to Avista points of interconnection.

Avista entered into long-term contracts for the output of four of these projects "at cost." Later, Avista competed in capacity auctions in 2009 through 2013 to purchase new short-term contracts at market-based prices. The Mid-Columbia contracts in Table 2.7 provide energy, capacity, and reserve capabilities; in 2014, the contracts provide approximately 127 MW of capacity and 76 aMW of energy. Over the next 20 years the Douglas PUD (2018) and Chelan PUD (2014) contracts will expire. Avista may extend these contracts or even gain additional capacity in auctions; however, we have no assurance that we will successfully extend our contract rights. Due to this uncertainty around future availability and cost, the IRP does not include these contracts in the resource mix beyond their expiration dates.

The timing of the power received from the Mid-Columbia projects is also a result of agreements including the Columbia River Treaty signed in 1961 and the Pacific

[13] The Kettle Falls CT numbers include output of the gas turbine plus the benefit of its steam to the main unit's boiler.

Northwest Coordination Agreement (PNCA) signed in 1964. Both agreements optimize hydro project operations in the Northwest United States and Canada. In return for these benefits, Canada receives return energy (Canadian Entitlement). The Columbia River Treaty and the PNCA call for storage water in upstream reservoirs for coordinated flood control and power generation optimization. On September 16, 2024, given a minimum of 10 years written advance notice, the Columbia River Treaty may end. Studies are underway by U.S. and Canadian entities to determine possible post-2024 Columbia River operations. Federal agencies are soliciting feedback from stakeholders and soon negotiations will begin in earnest to decide whether the current treaty will continue, should be ended, or if a new agreement will be struck. This IRP does not model potential alternative outcomes regarding the treaty negotiation, as it is not expected to impact long-term resource acquisition and we cannot speculate on future wholesale electricity market impacts of the treaty.

Table 2.7: Mid-Columbia Capacity and Energy Contracts

Counter Party	Project(s)	Percent Share (%)	Start Date	End Date	Estimated On-Peak Capability (MW)	Annual Energy (aMW)
Grant PUD	Priest Rapids	3.7	Dec-01	Dec-52	28.2	16.7
Grant PUD	Wanapum	3.7	Dec-01	Dec-52	31.0	17.9
Chelan PUD	Rocky Reach	3.0	Jul-11	Dec-14	34.5	21.0
Chelan PUD	Rock Island	3.0	Jul-11	Dec-14	13.9	10.7
Douglas PUD	Wells	3.3	Feb-65	Aug-18	27.9	14.7
Canadian Entitlement					**-8.1**	**-4.6**
2014 Total Net Contracted Capacity and Energy					**127.4**	**76.4**
2015 Total Net Contracted Capacity and Energy					**81.9**	**46.3**

Lancaster Power Purchase Agreement

Avista acquired the output rights to the Lancaster combined-cycle generating station, located in Rathdrum, Idaho, as part of the sale of Avista Energy in 2007. Lancaster presently connects to the BPA transmission system under a long-term wheeling agreement, but Avista is working with the federal agency to interconnect the plant directly with Avista's transmission system at the BPA Lancaster substation. Avista has the sole right to dispatch the plant, and is responsible for providing fuel and energy and capacity payments, under a tolling contract expiring in October 2026.

Public Utility Regulatory Policies Act (PURPA)

In 1978, Congress passed PURPA requiring utilities to purchase power from Independent Power Producers (IPPs) meeting certain criteria depending on their size and fuel source. Over the years, Avista has entered into many such contracts. Current PURPA contracts are in Table 2.8. Avista will renegotiate many of these contracts after the term of the current contract has ended.

Table 2.8: PURPA Agreements

Contract	Owner	Fuel Source	Location	End Date	Size (MW)	Annual Energy (aMW)
Meyers Falls	Hydro Technology Systems Inc	Hydro	Kettle Falls, WA	12/2013	1.30	1.05
Fighting Creek Landfill Gas to Energy Station	Kootenai Electric Cooperative	Municipal Waste	Coeur d'Alene, ID	12/2013	3.20	1.31
Spokane Waste to Energy	City of Spokane	Municipal Waste	Spokane, WA	11/2014	18.00	16.00
Spokane County Digester	Spokane County	Municipal Waste	Spokane, WA	8/2016	0.26	0.14
Plummer Saw Mill	Stimson Lumber	Wood Waste	Plummer, ID	11/2016	5.80	4.00
Deep Creek	Deep Creek Energy	Hydro	Northpoint, WA	12/2016	0.41	0.23
Clark Fork Hydro	James White	Hydro	Clark Fork, ID	12/2017	0.22	0.12
Upriver Dam[14]	City of Spokane	Hydro	Spokane, WA	12/2019	17.60	6.17
Sheep Creek Hydro	Sheep Creek Hydro Inc	Hydro	Northpoint, WA	6/2021	1.40	0.79
Ford Hydro LP	Ford Hydro Ltd Partnership	Hydro	Weippe, ID	6/2022	1.41	0.39
John Day Hydro	David Cereghino	Hydro	Lucille, ID	9/2022	0.90	0.25
Phillips Ranch	Glenn Phillips	Hydro	Northpoint, WA	n/a	0.02	0.01
Total					**50.52**	**30.45**

Bonneville Power Administration – WNP-3 Settlement

Avista signed settlement agreements with BPA and Energy Northwest 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 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 Avista 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.

[14] Energy estimate is net of pumping load.

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

Palouse Wind – Power Purchase Agreement

Avista signed a 30-year power purchase agreement in 2011 with Palouse Wind for the entire output of the 105 MW project. Avista has the option to purchase the project after year 10 of the contract. Commercial operation began in December 2012. The project is EIA qualified and directly connected to Avista's transmission system.

Table 2.9: Other Contractual Rights and Obligations

Contract	Type	Fuel Source	End Date	Winter Capacity (MW)	Summer Capacity (MW)	Annual Energy (aMW)
Stateline	Purchase	Wind	3/2014	0	0	9
Sacramento Municipal Utility District	Sale	System	12/2014	-50	-50	-50
PGE Capacity Exchange	Exchange	System	12/2016	-150	-150	0
Douglas Settlement	Purchase	Hydro	9/2018	2	2	3
WNP-3	Purchase	System	6/2019	82	0	42
Lancaster	Purchase	Natural Gas	10/2026	290	249	222
Palouse Wind	Purchase	Wind	12/2042	0	0	40
Nichols Pumping	Sale	System	n/a	-1	-1	-1
Total				**173**	**50**	**265**

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 additional 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.

Avista Planning Margin

Avista retains two planning margin targets—capacity and energy. Capacity planning is the traditional metric ensuring 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

Utility capacity planning begins with regional planning. Resource and load positions of the region as a whole affect individual utility resource acquisition decisions. The Pacific Northwest has a history of being capacity surplus and energy deficit. The 2000-01 energy crisis led to the rapid development of 3,425 MW of natural gas-fired generation in the Northwest. Over the following 10 years, the Northwest added 2,000 MW of natural gas-fired generation. During this same time, Oregon and Washington added 6,000 MW of wind. With recent wind additions, and their lack of capacity contribution, the region is approaching a capacity balance with loads; but the region remains long on energy due to the quantity of wind generation added to the system.

In recognition of these regional changes, the NPCC has done a considerable amount of analytical work to understand and develop methodologies to identify capacity needs in the region. Based on their work, the Northwest begins to fail a five percent Loss of Load Probability (LOLP) test in the winter of 2017-18.[15] Five percent LOLP means utilities meet all customer demand in 19 of 20 years, or one loss of load event permitted on a planning basis in 20 years due to insufficient generation. The NPCC identifies a need of 350 MW of new capacity, or 300 aMW of peak load reduction, to eliminate potential 2017-18 resource shortfall. The identified regional problem months are in the winter, with a small change of problems in the summer months. The NPCC also studied load growth and market availability scenarios. In the event of higher loads or reduced market availability, the NPCC study indicated that the region should add 2,850 MW of new capacity by 2017.

Because Avista often relies on the Northwest market to serve a portion of its peak load needs, it requested additional data from the NPCC to develop regional load and resource balance reports to understand the regional load and resource system balance. With the NPCC data, Avista developed the information shown in Table 2.10. This table illustrates the region’s substantial summer surplus and dwindling winter supplies. The table also illustrates the resource capability based on the length of the peak event. The table shows one, four, and ten-hour peaks, illustrating the unique impact that hydro has on the Northwest’s ability to meet peak loads. These regional balances do not include wind capacity.

In January 2018, the one hour implied planning margin is 24.3 percent, but with regional IPPs included, the margin improves to 34.3 percent. During a one-hour event the system has 8,050 excess MW or 11,374 with the IPPs. The real problem lies in a ten-hour event, where only a 4.3 percent planning margin exists absent the IPPs, and a 15 percent margin with them. This translates into modest surpluses of 1,334 MW and 4,658 MW, respectively.

The region is long by more than 11,000 MW without, and over 14,000 MW with, the IPPs in the summer. The main concern during a summer peak load event is that excess power may be scheduled outside of the region on a pre-schedule basis, leaving limited

[15] John Fazio, NPCC, “Adequacy Assessment of the 2017 Pacific Northwest Power Supply”, NW Resource Adequacy Forum Steering Committee Meeting, October 26, 2012 in Portland, OR.

resource available for the Northwest. The maximum regional export to California is estimated to be up to 7,980 MW absent any transmission derates. Power could also be exported east through Idaho, but the limit east is 2,250 MW.[16] The Northwest region has options to import power from British Columbia and Montana. The NPCC believes the region has sufficient capacity in the summer, but lacks capacity beginning in 2017 in the winter.

Table 2.10: Regional Load & Resource Balance

	January 2018			August 2018		
	1 Hour	4 Hour	10 Hour	1 Hour	4 Hour	10 Hour
Implied Planning Margin (PM)	24.3%	11.7%	4.3%	44.7%	46.4%	49.3%
w/ IPP Implied PM	34.3%	21.9%	15.0%	56.6%	58.6%	62.0%
Length (MW)	8,050	3,789	1,334	11,687	11,894	12,113
w/ IPP Length (MW)	11,374	7,112	4,658	14,804	15,010	15,229
	January 2025			August 2025		
	1 Hour	4 Hour	10 Hour	1 Hour	4 Hour	10 Hour
Implied Planning Margin (PM)	12.5%	-1.5%	-12.0%	30.7%	29.3%	28.7%
w/ IPP Implied PM	19.1%	5.2%	-5.0%	38.4%	37.1%	36.8%
Length (MW)	4,489	-533	-4,042	8,706	8,141	7,631
w/ IPP Length (MW)	6,853	1,831	-1,679	10,862	10,297	9,788

Avista's Loss of Load Analysis

In the Northwest, reliability matrices can help address the issue of how much planning margin is required. Typical results of these models are LOLP, Loss of Load Hours (LOLH), and Loss of Load Expectation (LOLE) measures. A reliable system is typically defined as having no more than one interruption event in twenty years, or a five percent LOLP. These analyses can be helpful, but usually have an inherent flaw due to the need to assume how much out-of-area imported generation is available for the study.

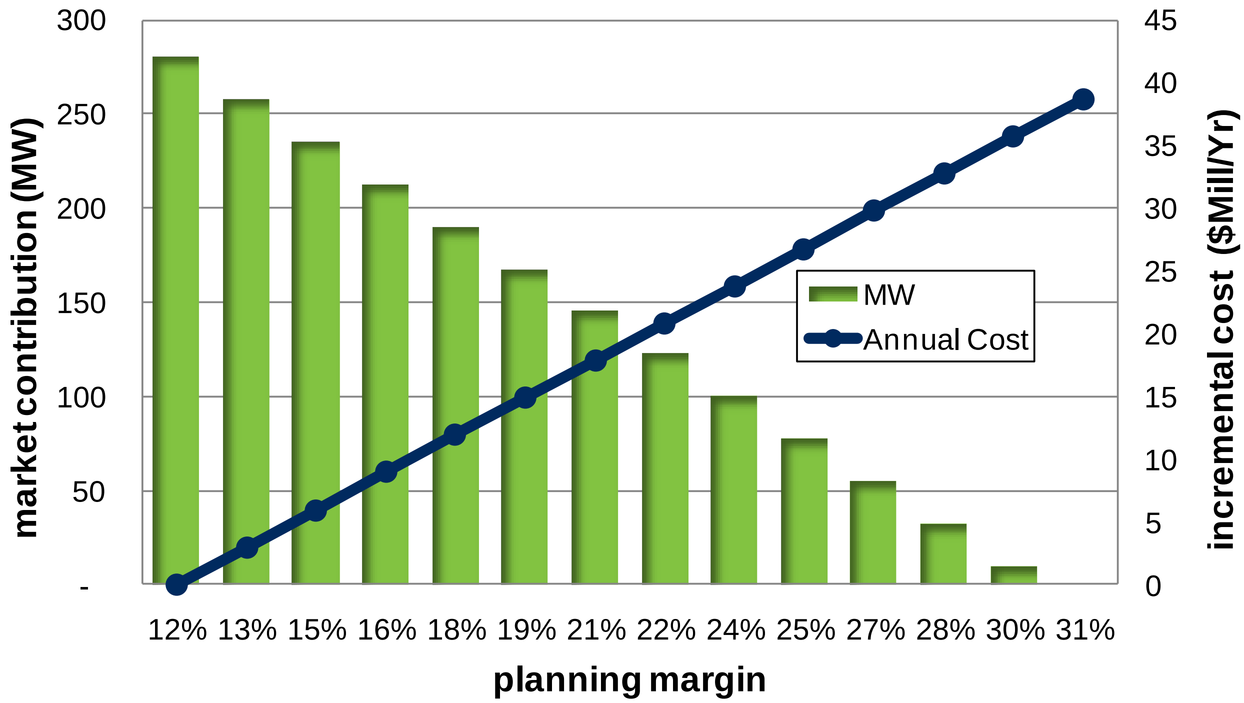
Avista developed its LOLP model to simulate reliability events caused by to poor hydro runoff, forced outages, and extreme weather conditions on its system, finding that forced outages are the main driver of reliability events and/or the need for imported power. Avista is well positioned to import power. It has adequate transmission capabilities to import power from the wholesale energy markets, but the amount of generation actually available for purchase from third parties at times of system peak is difficult to estimate. To address this concern, a sophisticated regional model must estimate required regional planning margins. As discussed above, the NPCC has performed this regional assessment. The challenge, even at the regional level, is modeling market imports into or exports from the region. To address this shortfall the NPCC and Avista use scenario analyses.[17]

The results of Avista's LOLP study are in Figure 2.20. The results use scenario analyses to illustrate potential planning margins using a test year of 2020. The scenarios change the amount of market reliance compared with new resource

[16] Ibid.
[17] Ibid.

acquisitions by Avista. This chart indicates that with a 12 percent planning margin Avista would rely on 275 MW from the market to meet a 5 percent LOLP metric. To eliminate market reliance, Avista would require a 31 percent planning margin at an additional power supply cost of $40 million per year.

Figure 2.20: 2020 Market Reliance & Capacity Cost Tradeoffs to Achieve 5 Percent LOLP



While scenario analysis helps management understand the tradeoffs between imports and new plant construction, it does not help identify the actual planning margin. For this IRP, Avista chose a 14 percent basic planning margin. The addition of operating reserves and other ancillary services results in a total planning margin of 22 percent. This level is similar to the planning margin used in the 2011 IRP and is similar to other utilities. Further, the planning margin is similar to NPCC's 23 percent recommendation for the region.[18] The 14 percent planning margin implies Avista will rely on 240 MW of market power in some peak events.

In addition to understanding the level of imports Avista will depend on during extreme peak events, it considers the regional resource position before deciding to procure new resources. Based on the current regional surplus shown in Table 2.10, Avista does not believe it is necessary procure new resources for future summer deficits. During summer months, the regional resource position is longer than the winter position. As a dual-peaking utility, Avista is concerned with summer reliability, but with the regional resource length described above, the addition of new resources likely is unnecessary.

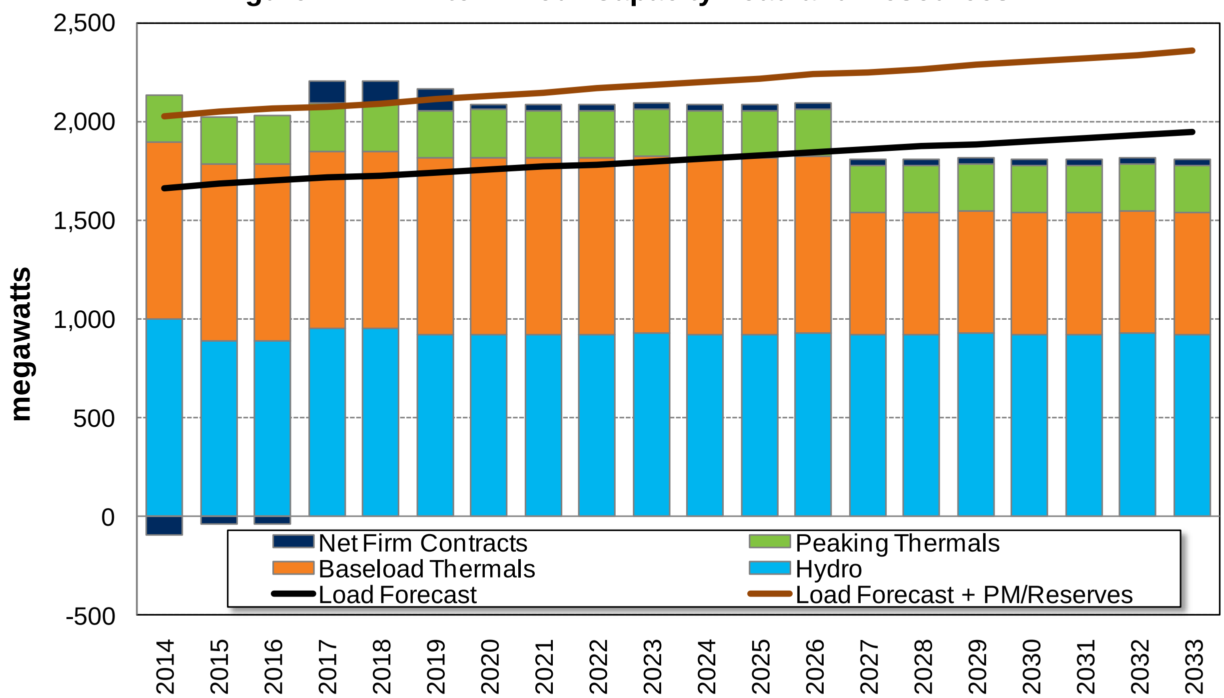
[18] The NPCC does not consider operating reserves and ancillary services separately from the planning margin, but instead combines them together into one figure.

Where the region shows signs of becoming resource deficient in the future, Avista will re-evaluate its positions.

Balancing Loads and Resources

Both the single-hour and sustained-peak requirements compare future projections of utility loads and resources. The single peak hour is more of a concern in the winter than the three-day sustained 18-hour peak. During winter months, the hydro system is able to sustain generation levels for longer periods than in the summer months due to higher inflows. Figure 2.21 illustrates the winter balance of loads and resources; the first year Avista identifies a significant winter capacity deficit is January 2020. Avista has small deficits in 2015 and 2016, but regional surplus and the expiration of the 150 MW capacity contract with Portland General Electric at the end of 2016 suggests the utility should rely on the short-term marketplace to meet these deficits. A detailed table of Avista's annual loads and resources is at the end of this chapter in Tables 2.12 through 2.14.

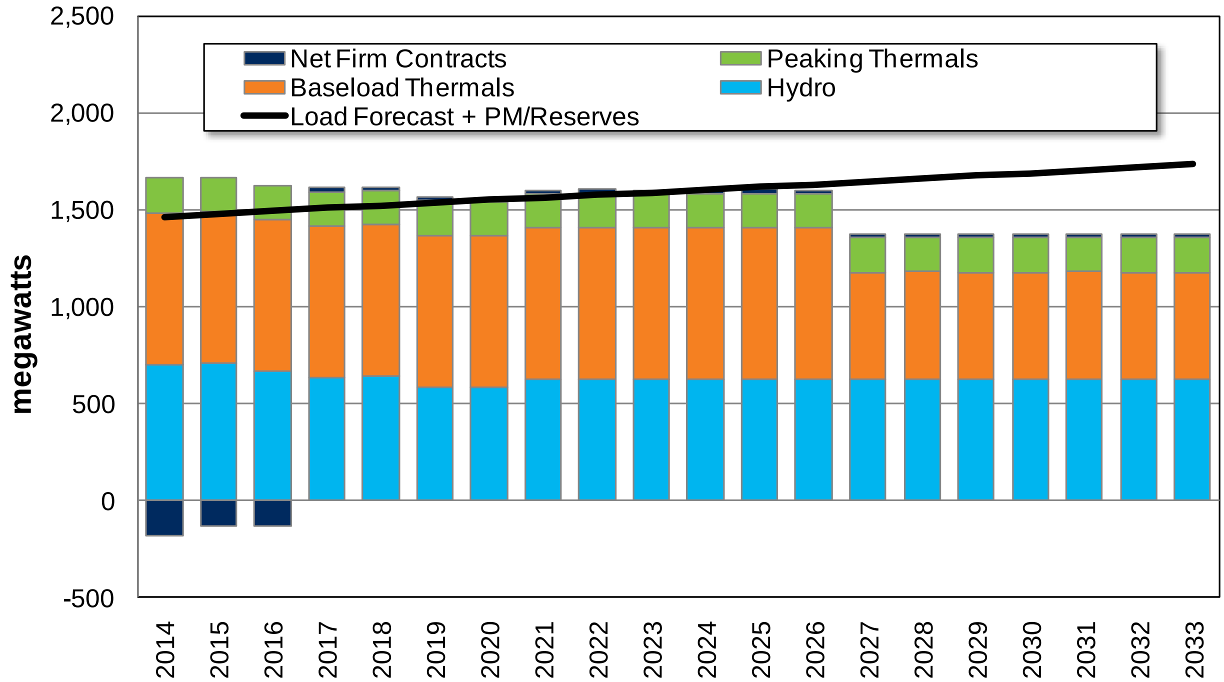
Figure 2.21: Winter 1 Hour Capacity Load and Resources



The 2013 IRP does not anticipate meeting summer capacity deficits with new resources, because of the significant regional surplus in the summer. Similar to the region, Avista's generation additions to meet winter peaks will substantially eliminate summer deficits.

Avista's summer resource balance is in Figure 2.22. This chart differs from the winter load and resource balance by using an 18-hour sustained peak rather than the single hour peak. The sustained peak is more constraining in the summer months due to reservoir restrictions and lower river flows reducing the amount of continuous hydro generation available to meet load. This chart also differs from the winter because Avista is not adding a planning margin to the summer due to expected regional surpluses. See Table 2.13 for more details.

Figure 2.22: Summer 18-Hour Capacity Load and Resources



Energy Planning

For energy planning, resources must be adequate to meet customer requirements even when loads are high for extended periods or an outage limits the output of a resource. 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, planning margins accounts for variations in hydroelectric generation.

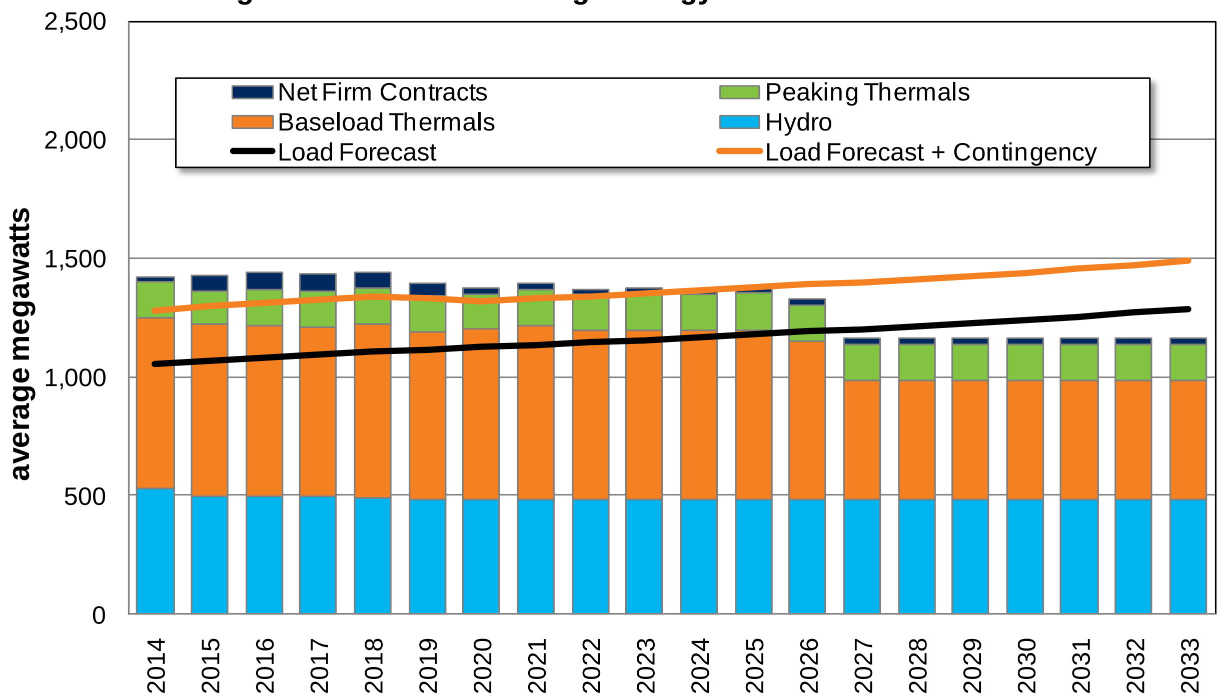
As with capacity planning, there are differences in regional opinion on the proper method for establishing energy-planning margins. Many utilities in the Northwest base their planning on the amount of energy available during the critical water period of 1936/37.[19] The critical water year of 1936/37 was low on an annual basis, but it was 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 addition to the margins included in Expected Case of the IRP. Expenditures to support this high level of reliability would put upward pressure on retail rates for a modest benefit. Avista instead plans to the 90th percentile for hydro. There is a 10 percent chance of needing to purchase energy from the market in any given month over the IRP timeframe, but in

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

nine of ten years, Avista would meet all of its energy requirements and sell surplus 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 exercise this right, as it did during the 2001 Energy Crisis. To account for contract risk, the energy contingency is increased by 32 aMW until the contract expires in 2019. With the addition of WNP-3 to load and hydroelectricity variability, the total energy contingency equals 228 aMW in 2014. See Figure 2.23 for the summary of the annual average energy load and resource net position.

Figure 2.23: Annual Average Energy Load and Resources



Washington State Renewable Portfolio Standard

In the November 2006 general election, Washington voters approved the EIA. The EIA 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. In 2011, Avista acquired the Palouse Wind project through a 30-year power purchase agreement to help meet the renewable goal. In 2012, an amendment to the EIA allowed biomass facilities built prior to 1999 to qualify under the law beginning in 2016. This amendment allows Avista's 50 MW Kettle Falls project to qualify and further help the company meet EIA requirements. Table 2.11 shows the forecast amount of RECs required to meet Washington state law, and the amount of qualifying resources already in Avista's generation portfolio. The sales forecast uses the Washington portion of the current load forecast. It illustrates how Avista will maintain a modest surplus of approximately 10 aMW in 2016 to account for annual generation variability at its EIA-qualifying plants.

Resource Requirements

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

During winter peak periods (Table 2.12), surplus capacity exists through 2019 after taking into account market purchases.[20] Without these purchases, a capacity deficit would exist in 2012. Avista believes that the present market can meet these minor winter capacity shortfalls and therefore will optimize its portfolio to postpone new resource investments for winter capacity until 2020.

The summer peak projection in Table 2.13shows lower loads than in winter, but resource capabilities are also lower due to lower hydroelectricity output and reduced capacity at natural gas-fired resources. The IRP shows persistent summer deficits throughout the 20-year timeframe, but regional surpluses are adequate to fill in these gaps. 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 Portland General Electricity capacity sale contract expires, the next capacity need is in 2019 at 98 MW.

The traditional measure of resource need in the region is the annual average energy position. Table 2.14 shows the energy position. 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.

[20] Avista relied on work by the NPCC in its Resource Adequacy Forum exercises to determine the level of surplus summer energy and capacity. Reliance is limited to Avista’s prorated share of regional load.

Table 2.11: Washington State RPS Detail (aMW)

	On-line Year	Apprentice Labor Credit	Energy	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
WA State Retail Sales Forecast				628	633	640	646	650	658	665	668	671	676	680	684	687	694	698	702	704	711	716	722	726	735
RPS %				3%	3%	3%	3%	9%	9%	9%	9%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
REQUIRED RENEWABLE ENERGY				**19.0**	**19.0**	**18.9**	**19.1**	**57.9**	**58.3**	**58.9**	**59.5**	**100.0**	**100.5**	**101.0**	**101.7**	**102.2**	**102.8**	**103.6**	**104.4**	**105.0**	**105.4**	**106.1**	**107.0**	**107.9**	**108.6**
Incremental Hydro																									
Long Lake 3	1999	1.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Little Falls 4	2001	1.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Cabinet 2	2004	1.0	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Cabinet 3	2001	1.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Cabinet 4	2007	1.0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Noxon 1	2009	1.0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Noxon 3	2010	1.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Noxon 2	2011	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Noxon 4	2012	1.0	1.4	0.7	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Nine Mile	2015	1.0	1.4	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Wanapum Fish Bypass	2008	1.0		2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Total Qualifying Resources				**21.3**	**23.3**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**	**23.2**
REC POSITION NET OF INCREMENTAL HYDRO				**0.0**	**0.0**	**0.0**	**0.0**	**-34.7**	**-35.2**	**-35.7**	**-36.4**	**-76.8**	**-77.3**	**-77.9**	**-78.5**	**-79.1**	**-79.6**	**-80.4**	**-81.2**	**-81.8**	**-82.2**	**-82.9**	**-83.8**	**-84.7**	**-85.5**
Qualifying Renewable Resources/RECs																									
Purchased RECs				0.0	0.0	0.0	5.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kettle Falls	1983	1.0		0.0	0.0	0.0	0.0	32.5	32.1	31.9	32.5	32.4	33.2	31.8	32.5	31.8	32.5	31.8	32.5	31.8	32.5	31.8	32.5	31.8	31.8
Palouse Wind	2012	1.2	39.9	0.0	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9
Total Qualifying Resources				**0.0**	**47.9**	**47.9**	**53.6**	**80.4**	**80.0**	**79.9**	**80.4**	**80.3**	**81.2**	**79.7**	**80.4**	**79.7**	**80.4**	**79.7**	**80.4**	**79.7**	**80.4**	**79.7**	**80.4**	**79.7**	**79.7**
NET REC POSITION BEFORE BANKING & RESERVES				**0.0**	**47.9**	**47.9**	**53.6**	**45.7**	**44.8**	**44.2**	**44.1**	**3.5**	**3.9**	**1.8**	**1.9**	**0.6**	**0.8**	**-0.7**	**-0.8**	**-2.1**	**-1.8**	**-3.2**	**-3.4**	**-5.0**	**-5.8**

Table 2.12: Winter 18-Hour Capacity Position (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
REQUIREMENTS																				
Native Load	-1,665	-1,683	-1,700	-1,713	-1,727	-1,741	-1,755	-1,769	-1,783	-1,798	-1,812	-1,827	-1,842	-1,856	-1,871	-1,887	-1,902	-1,917	-1,933	-1,948
Firm Power Sales	-211	-158	-158	-8	-8	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
Total Requirements	**-1,875**	**-1,841**	**-1,857**	**-1,721**	**-1,735**	**-1,747**	**-1,761**	**-1,775**	**-1,789**	**-1,804**	**-1,818**	**-1,833**	**-1,848**	**-1,863**	**-1,878**	**-1,893**	**-1,908**	**-1,923**	**-1,939**	**-1,954**
RESOURCES																				
Firm Power Purchases	117	117	117	117	117	116	34	34	33	33	33	33	33	33	33	33	33	33	33	33
Hydro Resources	998	888	889	955	955	919	924	920	920	928	920	920	928	920	920	928	920	920	928	920
Base Load Thermals	895	895	895	895	895	895	895	895	895	895	895	895	895	617	617	617	617	617	617	617
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	**2,252**	**2,143**	**2,143**	**2,210**	**2,210**	**2,172**	**2,095**	**2,091**	**2,091**	**2,098**	**2,090**	**2,090**	**2,098**	**1,811**	**1,811**	**1,819**	**1,811**	**1,811**	**1,819**	**1,811**
Peak Position Before Reserve Plai	**377**	**302**	**286**	**489**	**475**	**425**	**334**	**316**	**301**	**294**	**272**	**257**	**250**	**-51**	**-66**	**-74**	**-97**	**-112**	**-120**	**-143**
RESERVE PLANNING																				
Planning Margin	-233	-236	-238	-240	-242	-244	-246	-248	-250	-252	-254	-256	-258	-260	-262	-264	-266	-268	-271	-273
Total Ancillary Services Required	-139	-136	-137	-128	-129	-131	-136	-137	-138	-139	-141	-142	-143	-139	-139	-140	-140	-140	-140	-140
Reserve & Contingency Availability	13	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Reserve Planning	**-359**	**-366**	**-369**	**-362**	**-366**	**-369**	**-376**	**-379**	**-382**	**-386**	**-389**	**-392**	**-395**	**-393**	**-396**	**-398**	**-400**	**-403**	**-406**	**-408**
Peak Position w/ Reserve Plannin	**17**	**-64**	**-84**	**126**	**110**	**56**	**-42**	**-64**	**-81**	**-92**	**-117**	**-135**	**-145**	**-445**	**-462**	**-472**	**-497**	**-515**	**-525**	**-551**
Implied Planning Margin	**21%**	**17%**	**16%**	**29%**	**28%**	**25%**	**19%**	**18%**	**17%**	**17%**	**15%**	**14%**	**14%**	**-2%**	**-3%**	**-4%**	**-5%**	**-6%**	**-6%**	**-7%**

Table 2.13: Summer 18-Hour Capacity Position (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
REQUIREMENTS																				
Native Load	-1,465	-1,482	-1,498	-1,510	-1,523	-1,536	-1,550	-1,563	-1,576	-1,590	-1,604	-1,618	-1,631	-1,646	-1,660	-1,674	-1,689	-1,703	-1,718	-1,733
Firm Power Sales	-212	-159	-159	-9	-9	-8	-8	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7
Total Requirements	**-1,677**	**-1,641**	**-1,657**	**-1,519**	**-1,532**	**-1,544**	**-1,557**	**-1,570**	**-1,584**	**-1,597**	**-1,611**	**-1,625**	**-1,639**	**-1,653**	**-1,667**	**-1,681**	**-1,696**	**-1,710**	**-1,725**	**-1,740**
RESOURCES																				
Firm Power Purchases	29	29	29	29	29	26	26	26	26	25	25	25	25	25	25	25	25	25	25	25
Hydro Resources	701	707	663	631	638	583	580	622	624	622	622	624	622	622	624	622	622	624	622	622
Base Load Thermals	785	785	785	785	785	785	785	785	785	785	785	785	785	556	556	556	556	556	556	556
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	**1,691**	**1,698**	**1,653**	**1,621**	**1,628**	**1,571**	**1,568**	**1,609**	**1,611**	**1,609**	**1,609**	**1,611**	**1,609**	**1,379**	**1,381**	**1,379**	**1,379**	**1,381**	**1,379**	**1,379**
Peak Position Before Reserve Plar	**14**	**57**	**-3**	**102**	**96**	**27**	**11**	**39**	**27**	**11**	**-2**	**-14**	**-30**	**-274**	**-286**	**-302**	**-317**	**-330**	**-346**	**-361**
RESERVE PLANNING																				
Planning Margin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Ancillary Services Required	-177	-176	-177	-170	-172	-173	-175	-176	-177	-179	-180	-181	-182	-166	-167	-167	-168	-169	-169	-170
Reserve & Contingency Availability	177	176	177	170	172	173	175	176	177	179	180	181	182	166	167	167	168	169	169	170
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Reserve Planning	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Peak Position w/ Reserve Planning	**14**	**57**	**-3**	**102**	**96**	**27**	**11**	**39**	**27**	**11**	**-2**	**-14**	**-30**	**-274**	**-286**	**-302**	**-317**	**-330**	**-346**	**-361**
Implied Planning Margin	**11%**	**14%**	**10%**	**18%**	**17%**	**13%**	**12%**	**14%**	**13%**	**12%**	**11%**	**10%**	**9%**	**-7%**	**-7%**	**-8%**	**-9%**	**-9%**	**-10%**	**-11%**

Table 2.14: Average Annual Energy Position (aMW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
REQUIREMENTS																				
Native Load	-1,054	-1,067	-1,079	-1,093	-1,105	-1,114	-1,125	-1,135	-1,145	-1,155	-1,167	-1,180	-1,190	-1,201	-1,212	-1,225	-1,239	-1,254	-1,270	-1,285
Firm Power Sales	-109	-58	-58	-6	-6	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
Total Requirements	**-1,163**	**-1,125**	**-1,137**	**-1,099**	**-1,111**	**-1,119**	**-1,130**	**-1,140**	**-1,150**	**-1,160**	**-1,172**	**-1,185**	**-1,195**	**-1,206**	**-1,217**	**-1,230**	**-1,244**	**-1,259**	**-1,274**	**-1,290**
RESOURCES																				
Firm Power Purchases	128	129	128	76	76	56	31	30	30	29	29	29	29	29	29	29	29	29	29	29
Hydro Resources	527	495	495	495	490	481	481	481	481	481	481	481	481	481	481	481	481	481	481	481
Base Load Thermals	723	725	718	715	732	711	724	736	713	717	714	719	673	506	504	506	504	506	504	506
Wind Resources	42	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Peaking Units	153	139	154	153	153	153	147	151	152	153	152	153	152	153	152	153	152	153	152	153
Total Resources	**1,573**	**1,528**	**1,535**	**1,479**	**1,490**	**1,440**	**1,422**	**1,438**	**1,416**	**1,420**	**1,415**	**1,421**	**1,374**	**1,208**	**1,206**	**1,208**	**1,206**	**1,208**	**1,206**	**1,208**
Peak Position Before Reserve Plai	**410**	**404**	**398**	**380**	**379**	**321**	**292**	**299**	**266**	**259**	**243**	**237**	**179**	**2**	**-12**	**-22**	**-39**	**-51**	**-69**	**-82**
RESERVE PLANNING																				
Contingency	-228	-231	-231	-232	-232	-214	-195	-196	-196	-197	-197	-198	-198	-199	-199	-200	-200	-201	-202	-202
Peak Position w/ Reserve Planninç	**182**	**173**	**167**	**148**	**147**	**106**	**96**	**103**	**70**	**63**	**46**	**39**	**-19**	**-197**	**-211**	**-221**	**-239**	**-252**	**-270**	**-284**

3. Energy Efficiency

Introduction

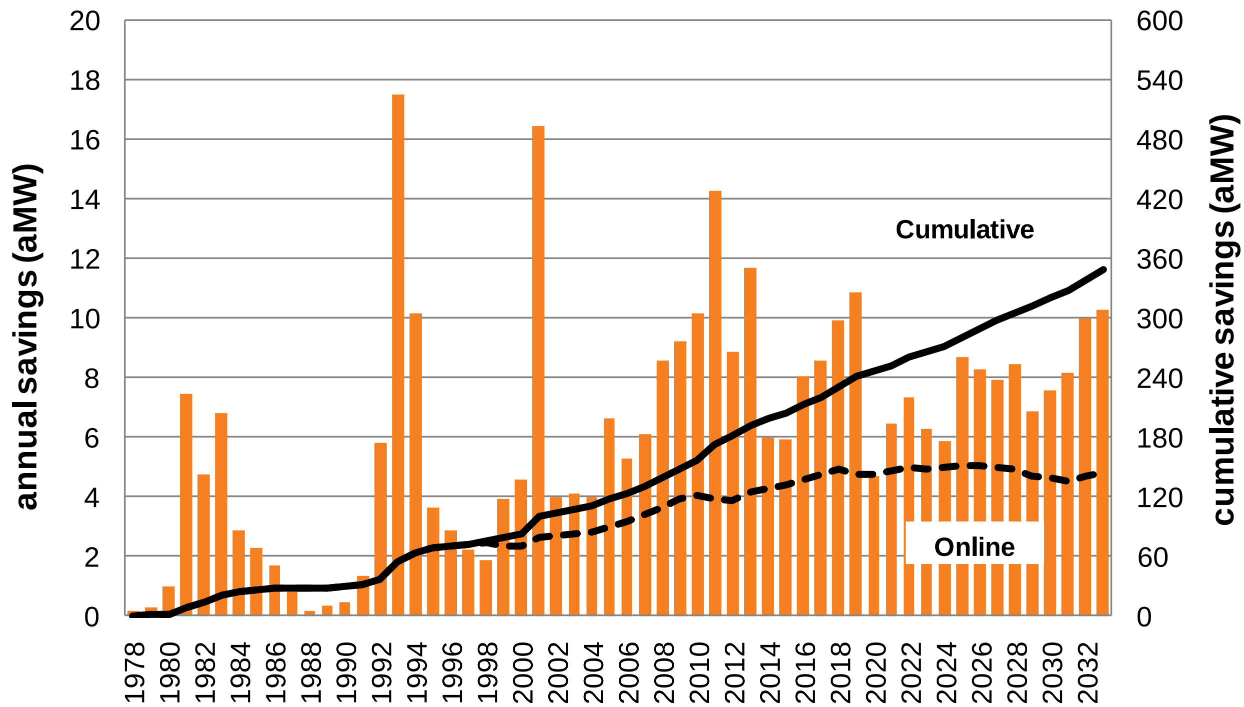
Avista began offering energy efficiency programs to customers in 1978. Notable efficiency achievements include the Energy Exchanger program (1992 to 1994) converting approximately 20,000 homes from electricity to natural gas space and/or water heat. Avista pioneered the country's first system benefit charge for energy efficiency in 1995. In response to the 2001 Western Energy Crisis, Avista acquired over three times the annual acquisition at only double the cost over a six-month period. During the summer of 2011, Avista distributed 2.3 million compact fluorescent lights (CFLs) to residential and commercial customers for an estimated energy savings of 39,005 MWh. Conservation programs regularly meet or exceed regional shares of energy efficiency gains as outlined by the NPCC.

Section Highlights

- This IRP includes a Conservation Potential Assessment of Avista's Idaho and Washington service territories.
- Current Avista-sponsored conservation reduces retail loads by nearly 10 percent, or 115 aMW.
- Avista evaluated over 3,000 equipment options, and over 1,700 measure options covering all major end use equipment, as well as devices and actions to reduce energy consumption for this IRP.

Figure 3.1 illustrates Avista's historical electricity conservation acquisitions. Avista has acquired 168 aMW of energy efficiency since 1978; however, the 18-year average life of the conservation portfolio means some 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 Cumulative and Online lines in Figure 3.1.

Figure 3.1: Historical and Forecast Conservation Acquisition (system)



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

Efficiency programs with economic paybacks of less than one year are ineligible for incentives, although Avista assists in educating and informing customers about these types of efficiency measures. Site-specific programs require customized services for commercial and industrial customers because of the unique characteristics of each of their premises and processes. In some cases, Avista uses a prescriptive approach where similar applications of energy efficiency measures result in reasonably consistent savings estimates in conjunction with a high achievable savings potential. An example is prescriptive lighting for commercial and industrial applications.

Conservation Potential Assessment Approach

The EIA obligates Avista to complete an independent Conservation Potential Assessment (CPA) biennially.[1] This study forms the basis for the conservation portion of

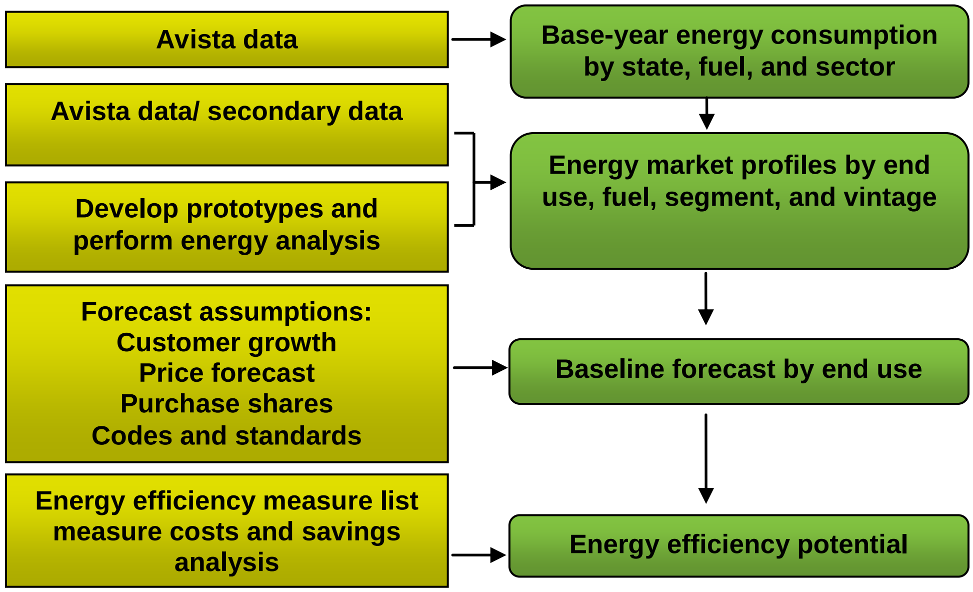
[1] See WAC 480-109 and RCW 19.285

this IRP. In 2010, Avista retained Global Energy Partners to conduct this study for its Idaho and Washington electric service territories. EnerNOC acquired the company in 2011 and updated the previous study for this IRP. The CPA identifies the 20-year potential for energy efficiency and provides data on resources specific to Avista's service territory for use in the 2013 IRP, in accordance with the EIA energy efficiency goals. The energy efficiency potential considers the impacts of existing programs, the influence of known building codes and standards, technology developments and innovations, changes to the economic influences, and energy prices.

EnerNOC took the following steps to assess and analyze energy efficiency and potential within Avista's service territory. Figure 3.2 illustrates the steps of the analysis.

1. **Market Assessment:** Categorizes energy consumption in the residential (including low-income customers), commercial, and industrial sectors. This assessment uses utility and secondary data to characterize customers' electric usage behavior in Avista's service territory. EnerNOC uses this assessment to develop energy market profiles describing energy consumption by market segment, vintage (existing or new construction), end use, and technology.
2. **Demand Forecast:** Develops a demand forecast absent the effects of future conservation program by sector and by end use for the entire study period.
3. **Program Assessment:** Identifies energy-efficiency measures appropriate for Avista's service territory, including regional savings from energy efficiency measures acquired through Northwest Energy Efficiency Alliance (NEEA) efforts.
4. **Potential:** Analyzes programs to identify the technical, economic and achievable potential. Technical potential chooses the most efficient measure, regardless of cost. Economic potential chooses 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



Market Segmentation

The CPA segments Avista customers by state and rate schedule, translating to residential, commercial and industrial general, commercial and industrial large general, extra large commercial, and extra large industrial services. The residential class segments include single family, multi-family, manufactured home and low-income customers. The low-income threshold for this study is 200 percent of the federal poverty level[2].

Pumping represents only about 2 percent of total utility loads; the energy savings projected for the pumping customer classification by the NPCC calculator is approximately 4 percent of total savings potential. Within each segment, energy use is characterized by end use, such as space heating, cooling, lighting, water heat or motors and by technology including heat pump, resistance heating and furnace for space heating.

The baseline projection is the "business as usual" metric without future utility conservation programs. It indicates annual electricity consumption and peak demand by customer segment and end use absent future efficiency programs. The baseline projection includes projected impacts of known building codes and energy efficiency standards as of 2012 when the study began. Codes and standards have direct bearing on the amount of energy efficiency potential that exists beyond the impact of these efforts. The baseline projection accounts for market changes including:

- customer and market growth;
- income growth;
- retail rates forecasts;

[2] Available from census data and the American Community Survey data.

- trends in end use and technology saturations;
- equipment purchase decisions;
- consumer price elasticity;
- income; and
- persons per household.

For each customer segment, a robust list of electrical energy efficiency measures and equipment is compiled, drawing upon the NPCC's Sixth Power Plan, the Regional Technical Forum, and other measures applicable to Avista. This list of energy efficiency equipment and measures includes 3,076 equipment and 1,774 measure options, representing a wide variety of end use applications, as well as devices and actions able to reduce customer energy consumption. A comprehensive list of equipment and measure options is available in Appendix C. Measure cost, savings, estimated useful life, and other performance factors identified for the list of measures and economic screening performed on each measure for every year of the study to develop the economic potential. Many measures initially do not pass the economic screen using current avoided costs, but some measures may become part of the energy efficiency program as contributing factors evolve during the 20-year planning horizon.

Avista supplements its energy efficiency activities by including potentials for distribution efficiency measures for consistency with the EIA conservation targets and the NPCC Sixth Power Plan. Details about the distribution efficiency projects are in the Transmission and Distribution chapter of this IRP.

Overview of Energy Efficiency Potentials

EnerNOC utilized an approach adhering to the conventions outlined in the National Action Plan for Energy Efficiency Guide for Conducting Potential Studies.[3] The guide represents the most credible and comprehensive national industry standard practice for specifying energy efficiency potential. Specifically, three types of potentials are in this study, as discussed below.

Technical Potential

Technical 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 potentials 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. Technical potential is defined 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.

[3] 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.

Economic Potential

Economic potential conservation includes the purchase of the most efficient cost-effective option available for each given equipment or non-equipment measure.[4] Cost effectiveness is determined by applying the Total Resource Cost (TRC) test using all quantifiable costs and benefits regardless of who accrues them and inclusive of non-energy benefits as identified by the NPCC.[5] Measures that pass 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. This level of potential estimates the achievable savings that could be attained through Avista's energy efficiency programs when considering market maturity and barriers, customer willingness to adopt new technologies, incentive levels, as well as whether the program is mature or represents the addition of a new program. During this stage, EnerNOC applied market acceptance rates based upon NPCC-defined ramp rates from the Sixth Power Plan taking into account market barriers and measure lives. However, EnerNOC adjusted the ramp rates for the measures and equipment to reflect Avista's market-specific conditions and program history. In some cases, Avista's ramp rates exceed the Council's, illustrating a mature energy efficiency program reaching a greater percentage of the market than estimated by the NPCC's Sixth Power Plan. In other cases, where a program does not currently exist, a ramp rate could be less than the NPCC's ramp rate, acknowledging additional design and implementation time is necessary to launch a new program. Other examples of changes to ramp rates include measures or equipment where the regional market shows lower adoption rates than estimated by the NPCC, such as heat pump water heaters.

The CPA forecasts incremental annual achievable potential for all sectors at 6.0 aMW (52,657 MWh) in 2014, increasing to cumulative savings of 156.1 aMW (1,367,490 MWh) by 2033. Table 3.1 and Figure 3.3 show the CPA results for technical, economic, and achievable potentials. The projected baseline electricity consumption forecast increases 44 percent during the 20-year planning horizon. Figure 3.3 compares the technical, economic, achievable potentials, and cumulative first-year savings, for selected years.

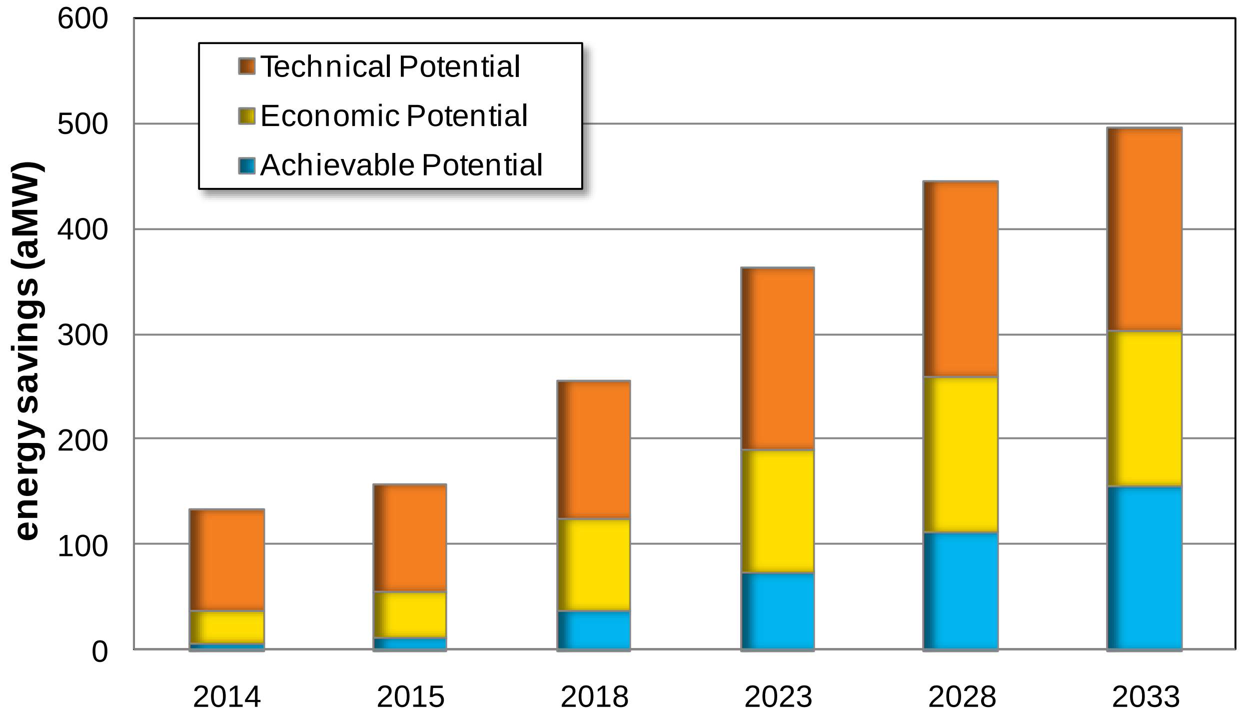
[4] The Industry definition of economic potential and the definition of economic potential referred to in this document are consistent with the definition of "realizable potential for all realistically achievable units".

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

Table 3.1: Cumulative Potential Savings (Across All Sectors for Selected Years[6])

	2014	2015	2018	2023	2028	2033
Cumulative Annual Savings (MWh)						
Achievable Potential	52,657	104,806	337,150	648,778	991,979	1,367,490
Economic Potential	316,722	480,967	1,091,669	1,670,165	2,274,053	2,667,367
Technical Potential	1,163,373	1,372,283	2,251,749	3,188,349	3,899,655	4,355,152
Cumulative Annual Savings (aMW)						
Achievable Potential	6.0	12.0	38.5	74.1	113.2	156.1
Economic Potential	36.2	54.9	124.6	190.7	259.6	304.5
Technical Potential	132.8	156.7	257.0	364.0	445.2	497.2

Figure 3.3: Cumulative Conservation Potentials, Selected Years



[6] Projections include pumping as derived from the Sixth Power Plan's calculator as well as Schedule 25P being modeled separately based on that customer's historical program participation. The decision to model Schedule 25P separately was due to this rate schedule being one large industrial customer and this method seemed more accurate than treating and modeling this customer as a generic industrial customer.

Conservation Targets

This IRP process provides a biennial conservation target for the EIA Biennial Conservation Plan. Other components, such as conservation from distribution and transmission efficiency improvements, combined with the energy efficiency target to arrive at the full Biennial Conservation Plan target for Washington comparable to what is included in the NPCC Sixth Power Plan target.

Based on first year incremental savings, Table 3.2 illustrates Avista's achievable potential for 2014-2015, as well as a comparison with the Sixth Power Plan's calculator option 1. The Sixth Power Plan includes components other than conservation such as distribution system efficiencies. Table 3.2 compares the CPA results with the calculator's energy efficiency portion, excluding distribution efficiency.

Table 3.2: Annual Achievable Potential Energy Efficiency (aMW)

	2014	2015
NPCC Sixth Power Plan Target		
Idaho	5.92	6.13
Washington	9.47	9.81
Total	**15.39**	**15.94**
Less Distribution Efficiency from the Sixth Power Plan		
Idaho	(0.33)	(0.45)
Washington	(0.69)	(0.96)
Total	**(1.02)**	**(1.42)**
Sixth Power Plan Conservation Target		
Idaho	5.59	5.68
Washington	8.78	8.84
Total	**14.37**	**14.52**
Achievable Potential (i.e. Target), net of conversions		
Idaho	1.75	1.57
Washington	3.80	3.87
Total	**5.55**	**5.44**

The 2014-15 Biennial Conservation Plan compliance period targets are below those from the Sixth Power Plan for several reasons. First, the calculator provides an approximation of the level of conservation utilities should pursue using regional assumptions; these assumptions may differ from the specifics of a utility's service territory. Avista's CPA study employs a methodology consistent with the NPCC while incorporating Avista-specific assumptions to develop an estimate of savings potential for acquisition through energy efficiency programs. Second, the Sixth Power Plan is relatively dated and was developed prior to the Great Recession. It thus contains assumptions of higher growth than observed in recent years. Lower growth reduces potential savings. The Sixth Power Plan does not incorporate the effects of various residential appliance equipment standards promulgated after the Sixth Power Plan. Further, the higher than projected 2010-11 conservation acquisition results decreased baseline use, thereby diminishing future conservation potential since Avista had already captured those savings. Finally, avoided costs are significantly lower than projected when the Sixth Power Plan was developed.

Electricity to Natural Gas Fuel Switching

While fuel efficiency is not included in the NPCC Sixth Power Plan, Avista has a history of fuel switching from electricity to natural gas, and continues to target natural gas direct use as the most efficient resource option when available. Incremental to the targets listed above are energy savings potential attributable to space and water heat electric to natural gas conversions. Table 3.3 illustrates energy savings potentials from converting electric furnaces and water heaters to natural gas. Nearly all savings are in the residential sector. Conversions ramp up slowly, but because it removes most of the electricity use from two of the largest residential end uses (water and space heating). Space and water heating conversions account for approximately 19 percent of the residential savings during the 20-year IRP period.

Table 3.3: Cumulative Achievable Savings from Conversion to Natural Gas (MWh)

Washington Conversion Potential	2014	2015	2018	2023	2033
Water heater - convert to gas potential	825	1,586	4,112	9,924	20,221
Furnace - convert to gas potential	2,322	5,047	12,715	25,105	55,787
Total Washington conversion potential	3,147	6.633	16,827	35,028	76,009
Idaho Conversion Potential	**2014**	**2015**	**2018**	**2023**	**2033**
Water heater - convert to gas potential	47	121	602	4,264	16,451
Furnace - convert to gas potential	837	1,792	4,460	8,698	19,598
Total Idaho conversion potential	884	1,913	5,062	12,961	36,049
Total Service Territory Savings	4,031	1,920	21,889	47,989	112,058

Comparison with the Sixth Power Plan Methodology

As required by Washington Administrative Code (WAC) Chapter 480-109-010 (3)(c), this section describes the technologies, data collection, processes, procedures and assumptions used to develop its biennial targets, along with changes in assumptions or methodologies used in Avista's IRP or the NPCC Sixth Power Plan. WAC Chapter 480-109-010 (4)(c) requires the Washington Utilities and Transportation Commission's (UTC) approval, approval with modifications, or rejection of the targets.

EnerNOC worked 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 Sixth Power Plan and EnerNOC's approaches utilized end use models employing a bottom-up approach. The models draw on appliance stock, saturation levels and efficiencies information to construct future load requirements. EnerNOC 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 at the time of this study. The study reviewed and incorporated NPCC assumptions when Avista-specific or more updated 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 from the latest Regional Technical Forum workbooks were used, as well as additional information on measures and equipment specific to Avista. EnerNOC developed equipment saturations, measure costs, savings, estimated useful lives and other parameters based on data from the Sixth Power Plan Conservation Supply Curve workbook databases, the Regional Technical Forum, Avista's Technical Reference Manual, 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. For a more detailed discussion of measures and equipment evaluated within the potential study, please refer to the CPA report prepared by EnerNOC in Appendix C.

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 market barriers, customer acceptance, and the time required to implement programs. To develop these factors, EnerNOC reviewed the ramp rates used in the Sixth Power Plan Conservation Supply Curve workbooks and considered Avista's experience.

The Sixth Power Plan assessed a 20-year period beginning in 2010, while this CPA study begins in 2014. Where the Sixth Power Plan relied on average regional data, the CPA utilized data from Avista's service territory, as well as current economic data. Therefore, an allocation of regional potential based on sales, as applied in the Sixth Power Plan, would not necessarily account for Avista's unique service territory characteristics such as customer mix, use per customer, end use saturations, fuel shares, current measure saturations, and expected customer and economic growth. In addition, some industries included in the Sixth Power Plan may not exist in Avista's service territory. While the Sixth Power Plan incorporates distribution system efficiencies, the Avista CPA includes only energy efficiency from energy conservation while distribution system efficiencies and thermal system efficiencies are part of Avista's targets from other sources. A detailed discussion of Avista's distribution feeder program is in Chapter 5, Transmission & Distribution.

Avoided Cost Sensitivities

EnerNOC modeled several scenarios with varying avoided costs assumptions in addition to the Expected Case used for the 2013 IRP to test sensitivity to changes in avoided costs. The scenarios included 150 percent, 125 percent, 100 percent, and 75 percent of the avoided costs relative to the 110 percent level used in the Expected Case. Figure 3.4 illustrates the avoided cost scenarios. Overall, energy efficiency proved to be sensitive to avoided cost assumptions. In particular, acquiring incremental energy efficiency becomes increasingly expensive, so increases in avoided costs do not provide equivalent percentage increases in achievable potential. The Expected Case achievable potential is approximately 154 aMW by 2033, excluding savings from distribution line losses. With the 150 percent avoided cost case, cumulative achievable potential increases by 23 percent compared with the Expected Case reference scenario, while the 125 percent, 100 percent, and the 75 percent avoided cost cases yielded achievable potential equal to 85 percent, 94 percent and 113 percent of the reference scenario, respectively. Table 3.4 shows achievable potential under the five avoided cost scenarios and the cost impact over the IRP timeframe.

Table 3.4: Achievable Potential with Varying Avoided Costs

	75% AC	100% AC	Expected Case	125% AC	150% AC
Cumulative energy savings (aMW)	131	145	154	174	189
Savings percentage change compared to Expected Case	-15%	-6%	0%	13%	23%
20-Year Nominal Spending (millions)	$459	$560	$711	$949	$1,150
Cost percentage change compared to Expected Case	-35%	-21%	0%	34%	62%

In 2014, 41 percent of the projected achievable potential is from residential class measures. This roughly 40/60 allocation between residential and nonresidential savings is consistent with a finding from the previous CPA that the nonresidential sector is becoming the source of a larger share of savings potential. This shift is occurring because many low-cost residential measures are implemented and residential equipment codes and standards are capturing savings previously incented through utility programs.

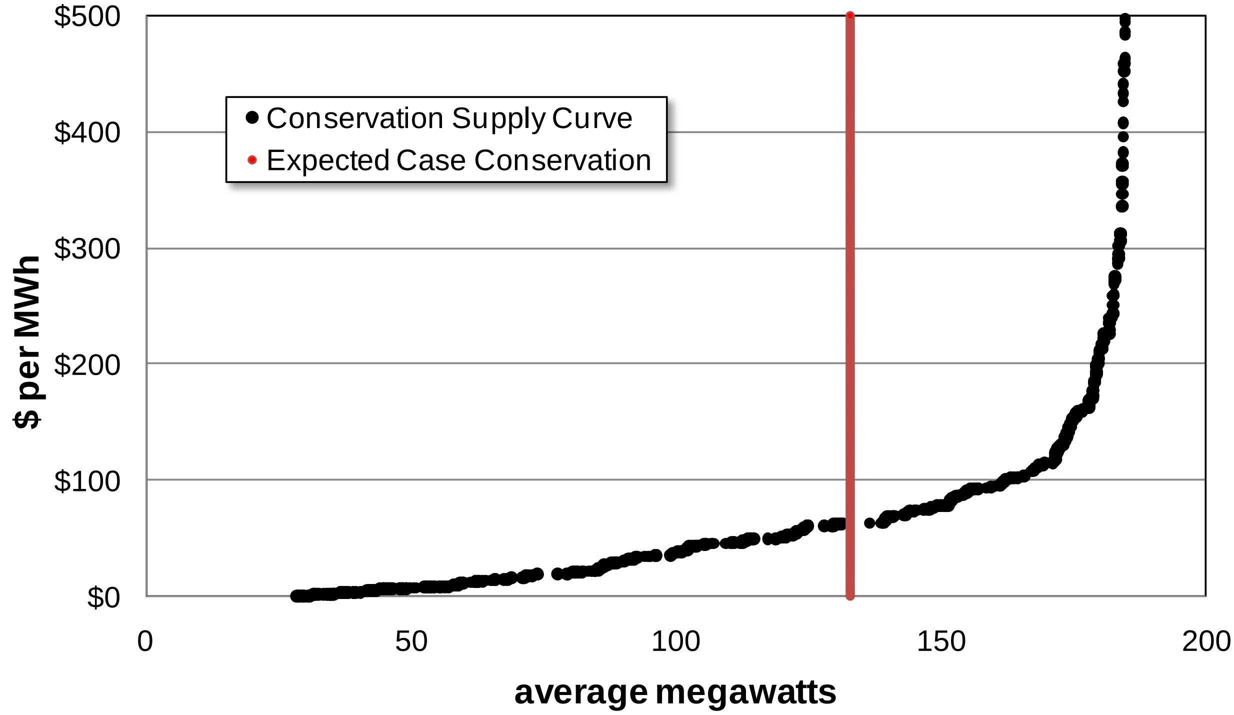
Approximately 48 percent of residential projected savings come from lighting in 2018, followed by water and space heating. In subsequent years, the percentage of residential savings from lighting decreases as lighting codes and standards are enacted. As a result, space and water heating measures provide greater relative savings potential in the later years of the study.

In the commercial and industrial sectors, lighting accounts for approximately 64 percent of savings potential in 2018 followed by office equipment, heating, ventilation and air conditioning (HVAC), refrigeration, and machine drives. Similar to the residential sector, the savings potential from lighting decreases to about one-third of cumulative potential in 2033, with HVAC, water heating and industrial measures gaining an increasing share of long-term potential.

Heat pump water heater measures in the Sixth Power Plan were projected to replace the CFLs contribution (i.e. significant savings at relatively low costs) in earlier plans. The CPA found heat pump water heaters begin to pass the cost-effectiveness screen in 2014. However, because they are unsuitable for installation in conditioned spaces, the CPA assumes they are not applicable in multifamily and mobile homes. The market for this technology remains immature, limiting the number of near-term installations.

Figure 3.4 shows supply curves composed of the stacked measures and equipment for the IRP time horizon in ascending order of avoided cost. 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 curve. 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.

Figure 3.4: Conservation Supply Curve (2033- No Fuel Switching, Pumping and Losses)



Energy Efficiency-Related Financial Impacts

The EIA 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.[7] For the first 24-month period under the law (2010-11), this equaled a ramped-in share of the regional 10-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.

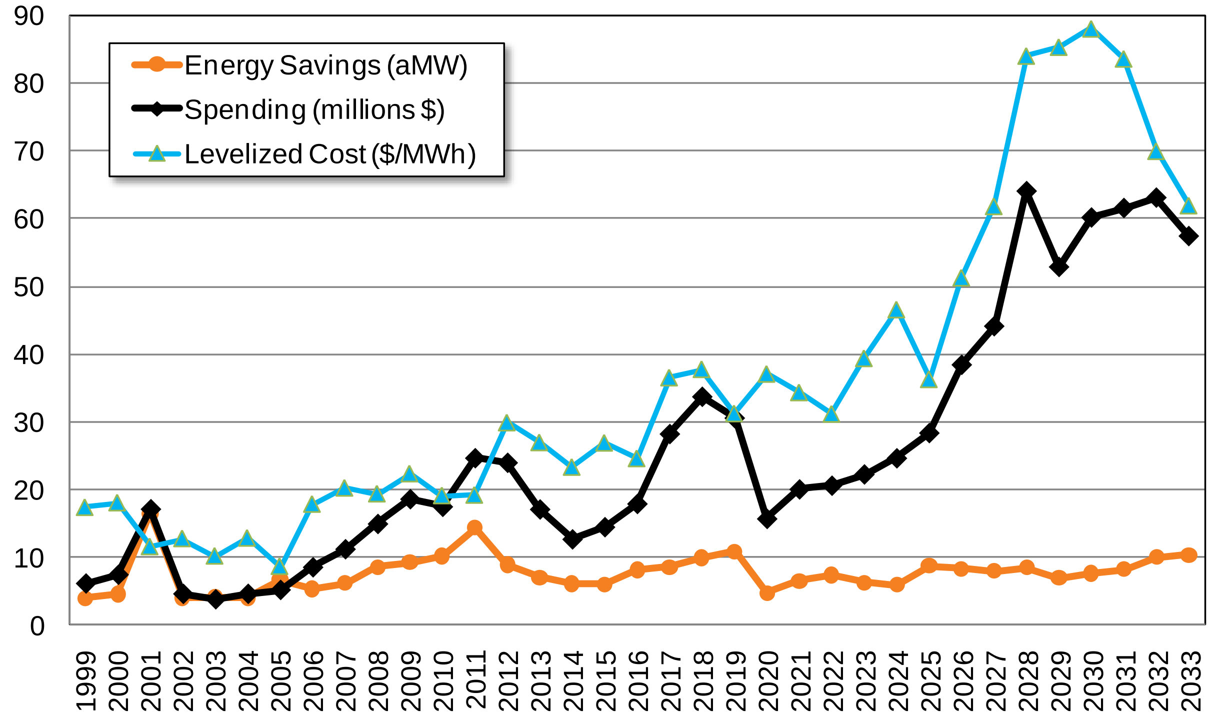
Regional discussions were under way regarding the definition of “pro-rata” during the 2009 IRP. Avista proposed ramping the 10-year targets identified in the Sixth Power Plan instead of acquiring 20 percent of the first 10-year target identified in the Sixth Power Plan. The “pro-rata” amount would have created drastic ramping challenges, especially in the early years. Due to inconsistencies between the 2009 IRP and the Council’s methodology, Avista elected to use 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

[7] The EIA defines cost effective as 10 percent higher than the cost a utility would otherwise spend on energy acquisition.

greater than Avista's IRP energy efficiency target for the same period. In April 2010, the UTC approved Avista's 10-year Achievable Potential and Biennial Conservation Target Report in Docket UE-100176.

The EIA requirement to acquire all cost-effective and achievable conservation may pose significant financial implications for Washington customers. Based on the CPA results, the projected 2014 cost to electric customers is $12.6 million (1.7 percent of total electric revenue requirement) with approximately $9 million of that projected to be for Washington. This annual amount grows to $22.2 million by the tenth year, representing a total of $215.8 million over this 10-year period for electric customers. Figure 3.5 shows the annual cost (in millions of nominal dollars) for the utility to acquire the projected electric achievable potential.

Figure 3.5: Existing & Future Energy Efficiency Costs and Energy Savings



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 energy efficiency programs, the results are not detailed enough to form an acquisition plan. Avista uses both CPA and IRP evaluation results to establish a budget for energy efficiency measures, to help determine the size and skill sets necessary for future 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 energy efficiency business planning.

Avista retained EnerNOC to develop an independent conservation potential assessment study for its Washington and Idaho electric service territory. This study is useful for the implementation of energy efficiency programs in the following ways.

- Identify conservation resource potential by sector, segment, end use and measure of where energy savings may come from. The energy efficiency implementation staff can use CPA results to determine the segments and end uses/measures to target.
- Identify the measures with the highest TRC benefit-cost ratios, resulting in the lowest cost resources with the greatest benefit.
- Identify measures with great adoption barriers based on the economic versus achievable results by measure. With this information, staff can develop effective programs for measures with slow adoption or significant barriers.
- Improve the design of current program offerings. Staff can review the measure level results by sector and compare the savings with the largest-saving measures currently offered. This analysis may lead to the addition or elimination of programs. Consideration for lost opportunities, and whether to target one particular measure over another measure, are made. One possibility may be to offer higher incentives on measures with higher benefits and lower incentives on measures with lower benefits.

The CPA study illustrates potential markets and provides a list of cost-effective measures to analyze through the on-going energy efficiency business planning process. This review of residential and non-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 may develop in the future will be evaluated for possible inclusion in Avista's Business Plan.

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 during 2012 included space and water heating conversions, ENERGY STAR® appliances, ENERGY STAR® homes, space and water equipment upgrades and home weatherization. The ENERGY STAR® appliance program phases out in 2013 due to results of a Cadmus net-to-gross study indicating market transformation to a point that incentives are no longer required.

Avista offers its remaining residential energy efficiency programs through other channels. For example, a third-party administer, JACO, operates the refrigerator/freezer recycling program. UCONS administers a manufactured home duct-sealing program. CFL and specialty CFL buy-downs at the manufacturer level provide customers access to lower-priced lamps. Home energy audits, subsidized by a grant from the American Recovery and Reinvestment Act (ARRA), ended in 2012. This program offered home inspections including numerous diagnostic tests and provided a leave-behind kit containing CFLs and weatherization materials. 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 14,300 energy efficiency rebates in 2012, benefiting approximately 14,000 households. Over $2.3 million of rebates offset the cost of implementing energy efficiency upgrades for our customers. Third-party contractors implemented a second appliance-recycling program and a manufactured home duct-sealing program. Avista participated in a regional upstream buy-down program called Simple Steps Smart Savings where lighting and showerheads were provided through participating retailers at a reduced amount for customers. Finally, Avista distributed over 26,000 CFLs at various community events throughout the service territory. Residential programs contributed 17,744 MWh and 341,187 therms of energy savings.

Low Income Sector Overview

Six Community Action Agencies administer low-income programs. During 2012 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 offered site-specifically through individualized home audits. Avista 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 Community Action Agencies to continue to deliver these programs.

The Community Action Agencies had 2012 budgets of $2.0 million for Washington and $940,000 for Idaho as well as an additional $50,000 for conservation education in Idaho. Avista processed approximately 1,400 rebates, benefitting 400 households. During 2012, Avista paid $2.6 million in rebates to the Community Action Agencies to provide fully-subsidized energy efficiency upgrades, health and human safety, and administrative costs for the agencies to administer these programs. The agencies spent nearly $394,000 on health and human safety or 13 percent of their total expenditures and within their 15 percent allowance for this spending category. Low-income energy efficiency programs contributed 1,111 MWh of electricity savings and 33,029 therms of natural gas savings.

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. Avista offers 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 and multi-family market transformation since these projects are implemented site-specifically unlike other residential programs.

During 2012, Avista processed 4,167 energy efficiency projects resulting in the payment of over $13.5 million in rebates paid directly to customers to offset the cost of their energy efficiency projects. These projects contributed 58,756 MWh of electricity and 399,733 therms of natural gas savings.

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.

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.

Demand Response

Over the past decade, demand response has gained attention in the industry as an alternative method to meet peak load growth instead of constructing new generation. Demand response cuts load to specific customers during peak demand use. Typically, customers enroll in programs allowing the utility to change its usage in exchange for discounts. National attention focuses on residential programs to control water heaters, space heating and air conditioners.

Past and Current Programs

Avista's experience with demand response or load management dates back to the 2001 Energy Crisis. Avista responded with an All-Customer Buy-Back program, an Irrigation Buy-Back program and bi-lateral agreements with large industrial customers. These methods along with commercial and residential enhanced energy efficiency programs were effective and enabled Avista to reduce its need for purchases in a very high cost Western energy market. Experience was gained in July 2006 when a multi-day heat wave required Avista to invoke immediate demand response through a media request for customers to conserve and a large customer reduction, Avista was able to reduce same day load by an estimated 50 MW.

Avista conducted a two-year residential load control pilot between 2007 and 2009 to study specific technologies, examine cost-effectiveness and customer acceptance. The intent of this pilot was to be scalable with Direct Load Control (DLC) devices installed in approximately 100 volunteer households in Sandpoint and Moscow, Idaho. This small sample allowed Avista to test the product and systems with the same benefits as if this were a larger scale project, but in a controlled and customer-friendly manner. DLC devices were installed on heat pumps, water heaters, electric forced-air furnaces and air conditioners to control operation during 10 scheduled events at peak times ranging from two hours to four hours. A separate group within those communities participated in an

In-Home-Display device study as part of this pilot. The program intended to gain customer experience with "near-real time" energy usage feedback equipment. Information gained from the pilot is detailed in the report filed with the Idaho Public Utilities Commission (IPUC).

Avista is engaged in a new demand response program as part of the Northwest Regional Smart Grid Demonstration Project (SGDP) with Washington State University (WSU) and approximately 70 residential customers in the Pullman and Albion, Washington communities. Residential customer assets include a forced-air electric furnace, heat pump, and central air-conditioning with enabling control technology of a Smart Communicating Thermostat provided and installed by Avista. The control approach is non-traditional in several ways. First, the demand response "events" are not prescheduled, but assets are directly controlled by predefined customer preferences (no more than a 2 degree offset for the residential customers, and an energy management system at WSU with a consol operator) at anytime the regional Transactive signal needs the curtailment. More importantly, the technology used in this demand response portion of the SGDP predicts if equipment is available for participation in the control event. Lastly, value quantification extends beyond demand and energy savings and explores bill management options for customers with whole house usage data analyzed in conjunction with smart thermostat data. Inefficient homes identified through this analysis prompt customer engagement.

Experiences from the both residential DLC pilots (North Idaho Pilot and the SGDP) show participating customer engagement is high; however, recruiting participants is challenging. Avista's service territory has a high penetration of natural gas for both typical DLC appliance types of space heat and water heat. Customers who have interest may not have qualifying equipment making them ineligible for participation in the Program. Secondly, customers initially are not interested enough in DLC programs. Supporting evidence of this second aspect is in recent regional DLC programs conducted by the BPA. Lastly, Avista is unable at this time to offer pricing strategies other then direct incentives to compensate customers for participation in the program, which limits customer interest.

The amount of demand and energy reductions per household is lower than a commercial and/or industrial DLC program. Consequently, many households are required to yield significant peak reduction savings, which is why residential DLC programs are commonly mass-market programs. Mass-market scale is needed for program cost effectiveness. Rather than focusing on residential demand response, Avista will focus its Demand Response studies towards commercial and industrial customers. Fewer but larger loads are anticipated to yield adequate acquisition. For this IRP, Avista assumes a potential of five MW per year for a 20 MW total acquisition, assuming a cost of $120 per kW-year (2012 dollars). As an Action Item, Avista will need to complete an assessment of potential demand response in its commercial and industrial customers, including, a measure of peak reduction, flexibility capability (i.e. spinning reserves) and costs to implement programs.

4. Policy Considerations

Public policy can significantly affect Avista's current generation resources and the types of resources Avista pursues. The political and regulatory environments have changed significantly since publication of the last IRP. Prospects for implementing a federal cap and trade program to reduce greenhouse gases have greatly diminished. At the same time, a range of regulatory measures pursued by the Environmental Protection Agency (EPA), coupled with political and legal efforts initiated by environmental groups and others, has increased pressures on thermal generation – specifically coal-fired generation. New regulations have particular implications for coal generation, as they involve regional haze, coal ash disposal, mercury emissions, water quality, and greenhouse gas emissions. This chapter provides an overview and discussion about some of the more pertinent public policy issues relevant to the IRP.

Chapter Highlights

- The 2013 IRP uses regulatory means instead of a federal cap and trade or greenhouse gas emissions tax in its Expected Case to reduce emissions.
- Scenario analyses address the impacts of potential greenhouse gas policies.
- The plan anticipates specific regulatory policies to reduce greenhouse gas emissions.
- Avista's Climate Policy Council monitors greenhouse gas legislation and environmental regulation issues.

Environmental Issues

Environmental concerns present unique resource planning challenges due to the continuously evolving nature of environmental regulation. If avoiding certain air emissions were the only issue faced by electric utilities, resource planning would only require a determination of the amounts and types of renewable generating technology and energy efficiency to acquire. However, the need to maintain system reliability, acquire resources at least cost, mitigate price volatility, meet renewable generation requirements, manage financial risks, and meet environmental laws complicates utility planning. Each generating resource has distinctive operating characteristics, cost structures, and environmental regulatory challenges.

Traditional thermal generation technologies, like coal-fired and natural gas-fired plants, are reliable 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. New coal plants are currently difficult, if not impossible, to site due to state and federal laws and regulations, local opposition, and environmental concerns ranging from the impacts of coal mining to power plant emissions. Remote mine locations increase costs from either the transportation of coal to the plant or the transportation of the generated electricity to load centers. By comparison, natural gas-fired plants have relatively low capital costs compared to coal, can typically be located near 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 many locations. Higher fuel price volatility has historically affected the economics of natural gas-fired plants. Their performance also decreases in hot weather conditions, it is increasingly difficult to secure sufficient water rights for their efficient operation, and they 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, direct emissions. However, solar- and wind-based renewable generation has limited or no capacity value for the operation of Avista's system, and their variable output presents integration challenges requiring additional non-variable capacity investments.

Renewable projects also draw the attention of environmental groups interested in protecting visual aspects of landscapes and wildlife populations. Similar to coal plants, renewable resource projects are located near their fuel sources rather than load centers. The need to site renewable resources in remote locations often requires significant investments in transmission interconnection and capacity expansion, as well as mitigating possible wildlife and aesthetic issues. Unlike coal or natural gas-fired plants, the fuel for non-biomass renewable resources may not be transportable from one location to another to utilize existing transmission facilities or to minimize opposition to project development. Dependence on the health of the forest products industry and access to biomass materials, often located in publicly owned forests, poses challenges to biomass facilities.

The long-term economic viability of renewable resources is uncertain for at least two important reasons. First, federal investment and production tax credits will begin expiring for projects beginning construction after 2013. 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 and solar technology development. Second, many relatively unpredictable factors affect the costs of renewable technologies, such as renewable portfolio standard mandates, material prices and currency exchange rates. Capital costs for wind and solar have decreased since the 2011 IRP, but future costs remain uncertain.

Even though there appears to be very little, if any, chance of a national greenhouse gas cap and trade program, uncertainty still exists about greenhouse gas regulation at this IRP's writing. There are pockets of strong regional and national support to address climate change, but little political will at the national level to implement significant new laws to reduce greenhouse gas emissions. However, since the 2011 IRP publication, changes in the approach to greenhouse gas emissions regulation have occurred, including:

- 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 most of these initiatives are being legally challenged; and
- California has established economy-wide cap and trade regulation.

Avista's Climate Change Policy Efforts

Avista's Climate Policy Council is an interdisciplinary team of management and non-management employees that:

- Facilitates internal and external communications regarding climate change issues;
- Analyzes policy impacts, anticipates opportunities and evaluates strategies for Avista Corporation; and
- Develops recommendations on climate related policy positions and action plans.

The core team of the Climate Policy Council includes members from Environmental Affairs, Government Relations, External Communications, Engineering, Energy Solutions and Resource Planning groups. Other areas of Avista participate as needed to provide input on certain topics. 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, considering the merits of different greenhouse gas policies, actively participating in the development of legislation, and benchmarking climate change policies and activities against other organizations.

Membership in the Edison Electric Institute is Avista's vehicle to engage in federal-level climate change dialog. Avista participates in discussions about hydroelectric and biomass issues through membership in national hydroelectric and biomass associations.

Greenhouse Gas Emissions Concerns for Resource Planning

Resource planning in the context of greenhouse gas emissions regulation raises concerns about the balance between Avista's obligations for environmental stewardship, and cost implications for its customers. Resource planning must consider the cost effectiveness of resource decisions, as well as the need to mitigate the financial impact of potential future emissions risks. Although some parties would advocate for the immediate reduction or elimination of certain resource technologies, such as coal or even natural gas-fired plants, there are economic and reliability limitations and other concerns related to pursuing this type of policy. Technologically, it is possible to replace fossil-fueled generation with renewables, but the increased prices to customers and the challenges of obtaining enough renewable generation while maintaining system reliability are daunting.

Complying with greenhouse gas regulations, particularly in the form of a cap and trade mechanism, involves at least two approaches: ensuring Avista maintains sufficient allowances and/or offsets to correspond with its emissions during a compliance period, and undertaking measures to reduce Avista's future emissions. Enabling emission reductions on a utility-wide basis could entail any or all of the following:

- Increasing the 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 resources with lower greenhouse gas emissions;
- Decommissioning or divesting of a fossil-fueled generation and substituting with 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, thereby displacing future resource needs.

With the exception of Avista's commitment to energy efficiency, the specific costs and risks of the actions listed above cannot be adequately evaluated until greenhouse gas emission regulations are established. After a regulatory regime has been implemented the economic effects can be modeled. A specific reduction strategy in a future IRP may occur when greater regulatory clarity and better modeling parameters exist. In the meantime, greenhouse gas emissions reductions in this IRP rely upon EPA and state regulations, established renewable portfolio policies, and established state level greenhouse gas emissions laws.

State and Federal Environmental Policy Considerations

The direction of federal greenhouse gas emissions policies has changed significantly since the 2011 IRP. In the prior plan, Avista based greenhouse gas emissions costs on a weighted average of four different reduction policies that included various levels of state and federal cap and trade programs and carbon taxes. The state of political discourse during the development of this IRP indicates there is no imminent federal cap and trade or carbon tax. Even though there is no national greenhouse gas emissions cost in the Expected Case, this IRP includes a greenhouse gas reduction scenario, with high and low prices for offset/taxes as a proxy to model the possible impacts of future regulation. Chapter 7, Market Analysis, describes the greenhouse gas scenarios and the modeling results.

The President's Climate Action Plan was released on June 25, 2013, after the modeling for this IRP was completed. The plan outlines the Obama administration's three pillars of executive action regarding climate change, which include the following:

- Reduce U.S. carbon emissions;
- Make infrastructure preparations to mitigate the impacts of climate change; and
- Work on efforts to reduce international greenhouse gas emissions and prepare for the impacts of climate change.

A presidential memo was also sent to the Administrator of the EPA on the same day as the Climate Action Plan with several climate change related policy targets. The memo directed the EPA to do the following:

- Issue new proposed greenhouse gas emissions standards for new electric generation resources by September 30, 2013.
- Issue new proposed standards for existing and modified sources by June 1, 2014, final standards by June 1, 2015, and require State implementation plans by June 30, 2016.

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 available for projects that begin construction before the end of 2013. The date is 2016 for solar projects. 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. Extension of the PTC may accelerate the development of some regional renewable energy projects. This may affect the development of renewable projects in the Western Interconnect, but not necessarily for Avista, because the current resource mix and low projected load growth do not necessitate the development of new renewables in this IRP.

EPA Regulations

The EPA regulations that directly, or indirectly, affect electricity generation include the Clean Air Act, along with its various components, such as the Acid Rain Program, National Ambient Air Quality Standard, Hazardous Air Pollutant rules and the Regional Haze Programs. The U.S. Supreme Court ruled the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles and has issued such regulations. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program. Both of these programs apply to power plants and other commercial and industrial facilities. In 2010, the EPA issued a final rule, known as the Tailoring Rule, governing the application of these programs to stationary sources, such as power plants. Most recently, EPA proposed a rule in early 2012 setting standards of performance for greenhouse gas emissions from new and modified fossil-fuel-fired electric generating units and announced plans to issue greenhouse gas guidelines for existing sources.

Promulgated PSD permit rules may affect Avista’s thermal generation facilities in the future. These rules can affect the amount of time it takes to obtain permits for new generation and major modifications to existing generating units and the final limitations contained in permits. The promulgated and proposed greenhouse gas rulemakings mentioned above have been legally challenged in multiple venues so we cannot fully anticipate the outcome or extent our facilities may be impacted, nor the timing of rule finalization.

Clean Air Act

The Clean Air Act (CAA), originally adopted in 1970 and modified significantly since, intends to control covered air pollutants to protect and improve air quality. Avista complies with the requirements under the CAA in operating our thermal generating plants. The CAA currently requires a Title V operating permit for Colstrip Units 3 and 4 (expires in 2017), Coyote Springs 2 (renewal expected in 2013), the Kettle Falls GS (renewal expected in 2013), and the Rathdrum CT (expires in 2016). Boulder Park, Northeast CT, and other small activities only require minor source operating or registration permits based on their limited operation and emissions. Title V operating permits renewals occur every five years and typically update all applicable CAA requirements for each facility. Discussion of some major CAA programs follows.

Acid Rain Program
The Acid Rain Program is an emission-trading program for reducing nitrous dioxide by two million tons and sulfur dioxide by 10 million tons below 1980 levels from electric generation facilities. Avista manages annual emissions under this program for Colstrip Units 3 and 4, Coyote Springs 2, and Rathdrum Generating Stations.

National Ambient Air Quality Standards
EPA sets National Ambient Air Quality Standards for pollutants considered harmful to public health and the environment. The CAA requires regular court-mandated updates to occur in June 2013 for nitrogen dioxide, ozone, and particulate matter. Avista does not anticipate any material impacts on its generation facilities from the revised standards at this time.

Hazardous Air Pollutants (HAPs)
HAPs, often known as toxic air pollutants or air toxics, are those pollutants that may cause cancer or other serious health effects. EPA regulates toxic air pollutants from a published list of industrial sources referred to as "source categories". These pollutants must meet control technology requirements if they emit one or more of the pollutants in significant quantities. EPA recently finalized the Mercury Air Toxic Standards (MATS) for the coal and oil-fired source category. Colstrip Units 3 and 4’s existing emission control systems should be sufficient to meet mercury limits. For the remaining portion of the rule that specifically addresses air toxics (including metals and acid gases), the joint owners of Colstrip are currently evaluating what type of new emission control systems will be required to meet MATS compliance in 2015. Avista is unable to determine to what extent, or if there will be any, material impact to Colstrip Units 3 and 4 at this time.

Regional Haze Program
EPA set a national goal to eliminate man-made visibility degradation in Class I areas by the year 2064. Individual states are to take actions to make “reasonable progress” through 10-year plans, including application of Best Available Retrofit Technology (BART) requirements. BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In the absence of state programs, EPA may adopt Federal Implementation Plans (FIPs). On September 18, 2012, EPA finalized the Regional Haze FIP for Montana. The FIP includes both emission limitations and pollution controls for Colstrip Units 1 and 2. Colstrip Units 3 and 4 are not currently affected, although the units will be evaluated for Reasonable Progress at the next review period in September 2017. Avista does not anticipate any material impacts on Colstrip Units 3 and 4 at this time.

EPA Mandatory Reporting Rule

Any facility emitting over 25,000 metric tons of greenhouse gases per year must report its emissions to EPA. Colstrip Units 3 and 4, Coyote Springs 2, and Rathdrum CT are currently reporting under this requirement. The Mandatory Reporting Rule also requires greenhouse gas reporting for natural gas distribution system throughput, fugitive emissions from electric power transmission and distribution systems, fugitive emissions from natural gas distribution systems, and from natural gas storage facilities. Avista reported the applicable greenhouse gas emissions in 2012. The State of Washington requires mandatory greenhouse gas emissions reporting similar to the EPA requirements. Oregon has similar reporting requirements.

State and Regional Level Policy Considerations

The lack of a comprehensive federal greenhouse gas policy encouraged several states, such as California, 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, tax or emissions performance standards for power plants. Comprehensive climate change policy can have multiple individual components, such as renewable portfolio standards, energy efficiency standards, and emission performance standards. Washington enacted all of these components, but other jurisdictions where Avista operates have not. 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 29 states, plus the District of Columbia, with active renewable portfolio standards, and eight additional states have adopted voluntary standards.[1]

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. Arizona, Montana, New Mexico, Oregon, Utah and Washington formally left WCI in November 2011.[2] The only remaining WCI members are British Columbia, California, Manitoba, Ontario, and Quebec.

Idaho Policy Considerations

Idaho currently does not regulate greenhouse gases or have a renewable portfolio standard (RPS). There is no indication that Idaho is moving toward the active regulation of greenhouse gas emissions. However, the Idaho Department of Environmental Quality would administer greenhouse gas standards under its CAA delegation from the EPA.

Montana Policy Considerations

Montana has a non-statutory goal to reduce greenhouse gas emissions to 1990 levels by 2020. Montana’s RPS law, enacted through Senate Bill 415 in 2005, requires utilities

[1] http://www.dsireusa.org/rpsdata/index.cfm
[2] http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/6695863

to meet 10 percent of their load with qualified renewables from 2010 through 2014, and 15 percent beginning in 2015. Avista is exempt from the Montana RPS and its reporting requirements beginning on January 2, 2013, with the passage of SB 164 and its signature by the Governor.

Montana implemented a mercury emission standard under Rule 17.8.771 in 2009. The standard exceeds the most recently adopted federal mercury limit. Avista's generation at Colstrip Units 3 and 4 have emissions controls meeting Montana's mercury emissions goal.

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, but not requiring, reductions of greenhouse gas emissions to 10 percent below 1990 levels by 2020, and 75 percent below 1990 levels by 2050. Compliance is expected through a combination of the RPS and other complementary policies, like low carbon fuel standards and energy efficiency measures. The state has not adopted any comprehensive requirements. These reduction goals are in addition to a 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 by paying into the Climate Trust of Oregon. Senate Bill 838 created a renewable portfolio standard requiring 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 ceased being an active member in the Western Climate Initiative in November 2011. The Boardman coal plant is the only active coal-fired generation facility in Oregon; by 2020, it will cease burning coal. The decision by Portland General Electric 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 pressures can culminate in an agreement that results in the early closure of a coal-fired power plant.

Washington State Policy Considerations

Similar circumstances leading to the closure of the Boardman facility in Oregon encouraged TransAlta, the owner of the Centralia Coal Plant, 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 pressures 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 2004 law 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 EIA, passed 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 3 percent of retail load by 2012, 9 percent by 2016 and 15 percent by 2020. Failure to meet these RPS requirements results in at least a $50 per MWh fine. The initiative also requires utilities to acquire all cost effective conservation and energy efficiency measures up to 110 percent of avoided cost. Additional details about the energy efficiency portion of the EIA are in Chapter 3.

A utility can also comply with the renewable energy standard by investing in at least 4 percent of its total annual retail revenue requirement on the incremental costs of renewable energy resources and/or renewable energy credits. In 2012, Senate Bill 5575 amended the EIA to define Kettle Falls Generating Station and other legacy biomass facilities that commenced operation before March 31, 1999, as EIA qualified resources beginning in 2016. A 2013 amendment allows multistate utilities to import RECs from outside the Pacific Northwest to meet renewable goals and allows utilities to acquire output from the Centralia coal plant without jeopardizing alternative compliance methods.

Avista will meet or exceed its renewable requirements in this IRP planning period through a combination of qualified hydroelectric upgrades, wind generation from the Palouse Wind PPA, and output from Kettle Falls beginning in 2016. The 2013 IRP Expected Case ensures that Avista meets all EIA RPS goals.

Former 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.

Washington state's Department of Ecology has adopted regulations to ensure that its State Implementation Plan comports with the requirements of the EPA's regulation of greenhouse gas emissions. We will continue to monitor actions by the Department as it may proceed to adopt additional regulations under its CAA authorities. In 2007, Senate Bill 6001 prohibited electric utilities from entering into long-term financial commitments beyond five years duration for fossil-fueled generation creating 1,100 pounds per MWh or more of greenhouse gases. Beginning in 2013, the emissions performance standard is 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 electricity deliveries that include more than 12 percent of the total power from unspecified sources. The Department of Commerce (Commerce) has commenced a process expected to result in the adoption of a lower emissions performance standard in 2013; a new standard would not be applicable until at least

2017. Commerce filed a final rule with 970 pounds per MWh for greenhouse gas emissions on March 6, 2013, with rules becoming effective on April 6, 2013.[3]

Washington Governor Inslee signed the Climate Action bill (Senate Bill 5802) on April 2, 2013. This law established an independent evaluation of the costs and benefits of established greenhouse gas emissions reductions programs. Results of this study are due by October 15, 2013 and will help inform development of a climate strategy to meet Washington's greenhouse gas reduction goals.

[3] http://www.commerce.wa.gov/Programs/Energy/Office/Utilities/Pages/EmissionPerfStandards.aspx

5. Transmission & Distribution

Introduction

Avista delivers electricity from generators to customer meters through a network of conductors, or links and stations, or nodes. The network system is operated at higher voltages where the energy must travel longer distances 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 within 13 miles.

Avista categorizes its energy delivery systems between transmission and distribution voltages. Avista's transmission system operates at 230 kV and 115 kV nominal voltages; the 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.

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

This chapter describes Avista's completed and planned distribution upgrade feeder program, the transmission system, completed and planned upgrades, and estimated costs and issues of new generation resource integration.

Chapter Highlights

- Avista continues to participate in regional transmission planning forums.
- The Spokane Valley Reinforcement Project includes both station update and conductor upgrades.
- A large upgrade project is under construction at the Moscow substation to maintain adequate load service and a Noxon substation rebuild project is in the design phase.
- Five distribution feeder rebuilds are complete since the last IRP, six additional feeders rebuilds are planned for 2014.
- Significant generation interconnection study work around Thornton and Lind substations continues.

FERC Planning Requirements and Processes

FERC provides guidance to both regional and local area transmission planning. This section describes several of its requirements and processes important to Avista transmission planning.

FERC Tariff Attachment K

Avista's Open Access Transmission Tariff (OATT) includes Attachment K, satisfying nine transmission planning principles outlined in FERC Order 890. Avista's Attachment K process ensures open and transparent coordination of local, regional, and sub-regional transmission planning. Avista develops a biannual Local Planning Report (in coordination with Avista's five- and ten-year Transmission Plans). Avista encourages participation by interconnected utilities, transmission customers, and other stakeholders in the Local Planning Process. Avista satisfies its sub-regional and regional FERC transmission planning requirements through its membership in ColumbiaGrid. Avista also participates in the Northern Tier Transmission Group and several Western Electricity Coordinating Council (WECC) processes and groups. Participation in these efforts supports regional coordination of Avista's transmission projects.

Western Electricity Coordinating Council

WECC coordinates and promotes electric system reliability in the Western Interconnection. It supports training in power system operations and scheduling functions, and coordinated transmission planning activities throughout the Western Interconnection. Avista participates in WECC's Planning Coordination, Operations, Transmission Expansion Planning Policy and Market Interface Committees, as well as sub groups and other processes such as the Transmission Coordination Work Group.

Northwest Power Pool

Avista is a member of the Northwest Power Pool (NWPP). Formed in 1942 when the federal government directed utilities to coordinate operations in support of wartime production, NWPP committees include the Operating Committee, the Reserve Sharing Group 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, and its membership includes Avista, BPA, Chelan County PUD, Grant County PUD, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. ColumbiaGrid was formed to enhance and improve the operational efficiency, reliability, and planned expansion of the Pacific Northwest transmission grid. Consistent with FERC requirements issued in Orders 890 and 1000, ColumbiaGrid develops sub-regional transmission plans, assesses transmission alternatives (including non-wires alternatives), and provides a decision-making forum and cost-allocation methodology for new transmission projects.

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. These members rely upon the NTTG committee structure to meet FERC's coordinated transmission planning requirements. 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 participates in the NTTG planning process to foster collaborative relationships with our interconnected utilities.

Transmission Coordination Work Group
The Transmission Coordination Work Group is a joint effort between 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 available at www.nwpp.org/tcwg. Many of the projects from this effort are on hold or have been terminated.

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, Avista participates in developing new and revised criteria while coordinating 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.

Avista's transmission system is constructed for the primary purposes of providing reliable and efficient transmission service from the company's portfolio of power resources to its retail native load customers. Portions of Avista's transmission system are fully subscribed for retail load service. Transmission capacity that is not reserved and scheduled for native load service is made available to third parties pursuant to FERC regulations and the terms and conditions of Avista's OATT. Such surplus transmission capacity that is not sold on a long-term (greater than one year) basis is marketed on a short-term basis to third parties and used by Avista for short-term resource optimization.

Regional Transmission System

BPA owns and operates over 15,000 miles of transmission-level facilities, and it 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 share in Colstrip Units 3 and 4, Coyote Springs 2, Lancaster, and its WNP-3 settlement contract. Avista also contracts with BPA for Network Integration Transmission Service to transfer power to several delivery points on the BPA system to serve portions of Avista's retail load, and to sell power surplus to its needs to other parties in the region.

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

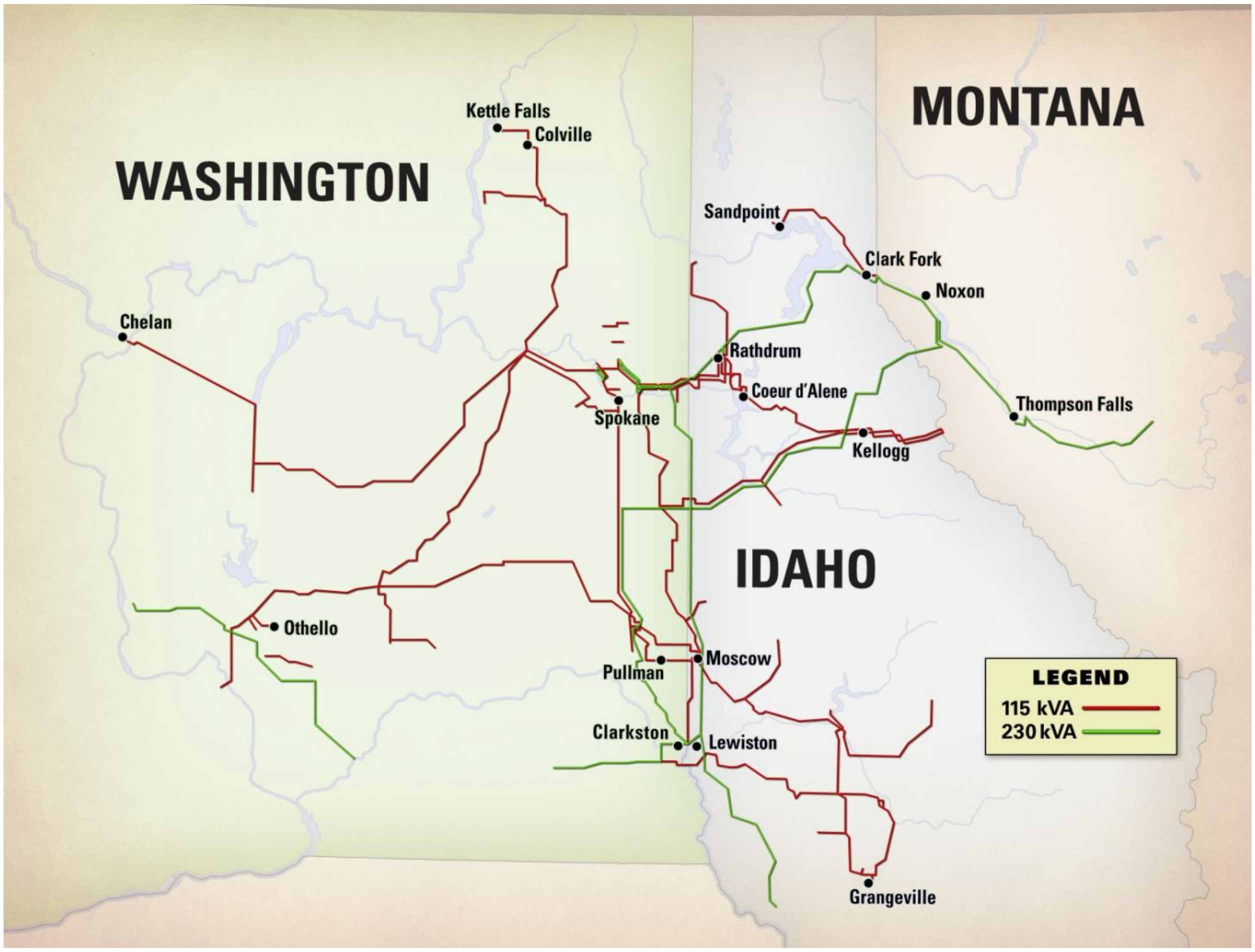
Future electricity grid expansion will likely require new transmission assets by federal and other entities. BPA is developing several transmission projects in the Interstate-5 corridor, as well as projects in southern Washington necessary for integrating wind generation resources located in the Columbia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

Avista's Transmission System

Avista owns and operates a system of over 2,200 miles of electric transmission facilities. This includes approximately 685 miles of 230 kV line and 1,527 miles of 115 kV line. Figure 5.1 illustrates Avista's transmission system. Avista owns an 11 percent interest in 495 miles of double circuit 500 kV lines 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:

- BPA
- Chelan County PUD
- Grant County PUD
- Idaho Power Company
- NorthWestern Energy
- PacifiCorp
- Pend Oreille County PUD

Figure 5.1: Avista Transmission Map



Transmission System Information for the 2013 IRP

Since the 2011 IRP, Avista completed transmission projects to support new generation, increase reliability, and provide system voltage support including;

- Thornton 230 kV switching station
- Garden Springs to Hallet & White section of South Fairchild 115 kV Tap
- Irvin – Opportunity 115 kV line
- Burke Substation to Montana border section of Burke – Thompson Falls A&B 115 kV lines
- Southern half of Bronx – Cabinet Gorge 115 kV line
- Capacitor bank installed at the Lind 115 kV switching station.

Lancaster Integration

Avista has evaluated and proposed an interconnection with BPA at its Lancaster 230 kV Switching Station. Avista and BPA have determined the preferred alternative is to loop the Avista Boulder-Rathdrum 230 kV line into the BPA Lancaster 230 kV station. This interconnection allows Avista to eliminate or offset BPA wheeling charges for moving the output from Lancaster to Avista's system. Besides reducing transmission payments to BPA by Avista, the interconnection benefits both Avista and the BPA by increasing system reliability, decreasing losses, and delaying the need for additional transformation at BPA's Bell Substation. Studies indicate this project may allow more transfer capability across the combined transmission interconnections of Avista and BPA. This project, in conjunction with other Avista upgrades, also supports increasing the Montana-to-Northwest path rating by as much as 800 MW. Avista has worked collaboratively with BPA and the Lancaster 230 kV interconnection project is planned for completion by the end of 2013.

South Spokane 230 kV Reinforcement

Transmission studies continue to support the 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 and 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 area 230/115 kV station(s).

The South Spokane 230 kV Reinforcement project was scoped at the end of 2012 with a planned in-service date by the end of 2018. The project is planned to enter service in a staged fashion beginning in 2014.

Avista Station Upgrades

As reported in the 2011 IRP, Avista planned to upgrade its Moscow, Noxon, and Westside 230 kV substations. These upgrades improve reliability, add capacity, and update aging components. The Moscow station upgrades, scheduled for completion in 2014, will result in a new facility with a single 250 MVA 230/115 kV station doubling the current station capacity over the next five to 10 years. Further upgrades or rebuilds are planned at the following substations:

- Irvin 115 kV Switching Station [Spokane Valley Reinforcement] (2016)
- Millwood 115 kV Distribution Substation [Spokane Valley Reinforcement] (2013)
- North Lewiston 115 kV Distribution Substation (2014)
- Moscow 230/115 kV Substation (2011-2014)
- Stratford 115 kV Switching Station (2014)

- Blue Creek 115 kV Distribution Substation (2014)
- Harrington 115 kV Distribution Substation (2014)
- Noxon 230 kV Switching Station (2013-2016)
- 9th & Central 115 kV Distribution Substation (2015)
- Greenacres 115 kV Distribution Substation (2014)
- Beacon 230/115 kV Station Partial Rebuild (2017+)

Avista Transmission Upgrades

Avista plans to complete several 115 kV reconductor projects throughout its transmission system over the next decade. These projects focus on replacing decades-old small conductor with conductor capable of greater load-carrying capability and provide more efficient (i.e., fewer electrical losses) service. The following list gives an example of planned transmission projects:

- Spokane Valley Reinforcement Project (2011-2016)
- Bronx – Cabinet Gorge 115 kV (2011-2015)
- Burke – Pine Creek 115 kV (2012-2014)
- Benton – Othello 115 kV (2014-2016)
- Devils Gap – Lind 115 kV (2014-2016)
- Coeur d'Alene – Pine Creek 115 kV (2014-2017)

Generation Interconnection Requests

Avista's Power Supply Department requested generator interconnection studies in several areas of Avista's transmission system for the 2013 IRP. Developers have also requested studies through Avista's Large Generation Interconnection Request (LGIR) process. Table 5.1 states the projects and cost information for each of the IRP-related studies. The study results for each project, including cost and integration options, may be found in Appendix D. These studies are a high level view of the generation interconnect request similar to what would be performed as a feasibility study for a third party under the LGIR process.

Table 5.1: IRP Requested Transmission Upgrade Studies

Project	Size (MW)	Cost[1]
Nine Mile	60	No cost
Long Lake	68	$9.9 million
Monroe Street	80	No cost[2]
Upper Falls	40	No cost[3]
Post Falls	16	No cost
Cabinet Gorge	60	No cost
Thornton	200	$4 million
Benewah to Boulder	300	$7-$15 million
Rathdrum	300	$7-$30+ million

[1] Cost estimates are in 2013 dollars and use engineering judgment with a 50 percent margin for error.
[2] An upgrade to the College & Walnut substation may require upgrades.
[3] Ibid.

Large Generation Interconnection Requests

Third-party generation companies or independent power producers may make requests for transmission studies to understand the cost and timelines for integrating potential new generation projects. These types of projects follow a strict FERC process and include three study steps to estimate the feasibility, system impact, and facility requirement costs for project integration. Each of these studies provides the requester with a different level of project costs, and the studies are typically complete over at least a one-year period. After this process is completed a contract can be offered to integrate the project and negotiations can begin to enter into a transmission agreement if necessary. Each of the proposed projects are made public to some degree (customer names remain anonymous). Below Table 5.2 lists the current projects remaining in Avista's transmission queue.

Table 5.2: Third-Party Large Generation Interconnection Requests

Project #	Size (MW)	Type	Interconnection
#33	400	Wind	Lind 115 kV Substation
#35	200	CT	Thornton 230 kV Switching Station
#36	105	Wind	Thornton 230 kV Switching Station

Distribution System Efficiencies

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 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.

The system efficiencies team evaluated several efficiency programs to improve both urban and rural distribution feeders. The programs consisted of the following system enhancements:

- Conductor losses;
- Distribution transformers;
- Secondary districts; and
- Volt-ampere reactive compensation.

The energy losses, capital investments, and reductions in operations and maintenance (O&M) costs resulting from the individual efficiency programs under consideration were combined on a per feeder basis. This approach provided a means to rank and compare the energy savings and net resource costs for each feeder.

Feeder Upgrade Program

Avista's distribution system consists of approximately 330 feeders covering 30,000 square miles, ranging 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 Feeder Upgrade Program’s charter criterion has grown to include a more holistic approach to the way Avista addresses each project. This vital program integrates work performed under various operational initiatives in Avista including the Wood Pole Management Program, the Transformer Change-out Program, the Vegetation Management Program and the Feeder Automation Program. The work of the Feeder Upgrade Program includes the replacement of undersized and deteriorating conductors, replacement of failed and end-of-life infrastructure materials including wood poles, cross arms, fuses and insulators. Inaccessible pole alignment, right-away, undergrounding and clear zone compliance issues are addressed for each feeder section as well as regular maintenance work such as leaning poles, guy anchors, unauthorized attachments and joint-use management. This systematic overview enables Avista to cost-effectively deliver a modernized and robust electric distribution system that is more efficient, easier to maintain and more reliable for our customers.

Figure 5.2 illustrates the reliability advantages and reasons for the program. Prior to the 2009 feeder rebuild pilot program, outages were increasing at up to 13 outages per year. After the project, outages declined significantly. In the past two years, only one outage was recorded. The program is in its second year of regular funding and its intended purpose of capturing energy savings through reduced losses, increased reliability and decreased O&M costs is being realized. The feeders addressed through this program to date are shown in Table 5.3. The total energy savings, from both re-conductor and transformer efficiencies for all of these feeders, is approximately 4,869 MWh annually.

Table 5.3: Completed Feeder Rebuilds

Feeder	Area	Year Complete	Annual Energy Savings (MWh)
9CE12F4	Spokane, WA (9th & Central)	2009	601
BEA12F1	Spokane, WA (Beacon)	2012	972
F&C12F2	Spokane, WA (Francis & Cedar)	2012	570
BEA12F5	Spokane, WA (Beacon)	2013	885
WIL12F2	Wilbur, WA	2013	1,403
CDA121	Coeur d’Alene, ID	2013	438
		Total	**4,869**

The additional benefits ascertained through the work performed through the Feeder Upgrade Program are just now coming to fruition and will require a multi-year study to verify all of the planned benefits. Table 5.4 includes the working plan for feeder rebuilds over the next several years. The additional energy savings is anticipated to reach 1,626 MWh per year.

Figure 5.2: Spokane's 9th and Central Feeder (9CE12F4) Outage History

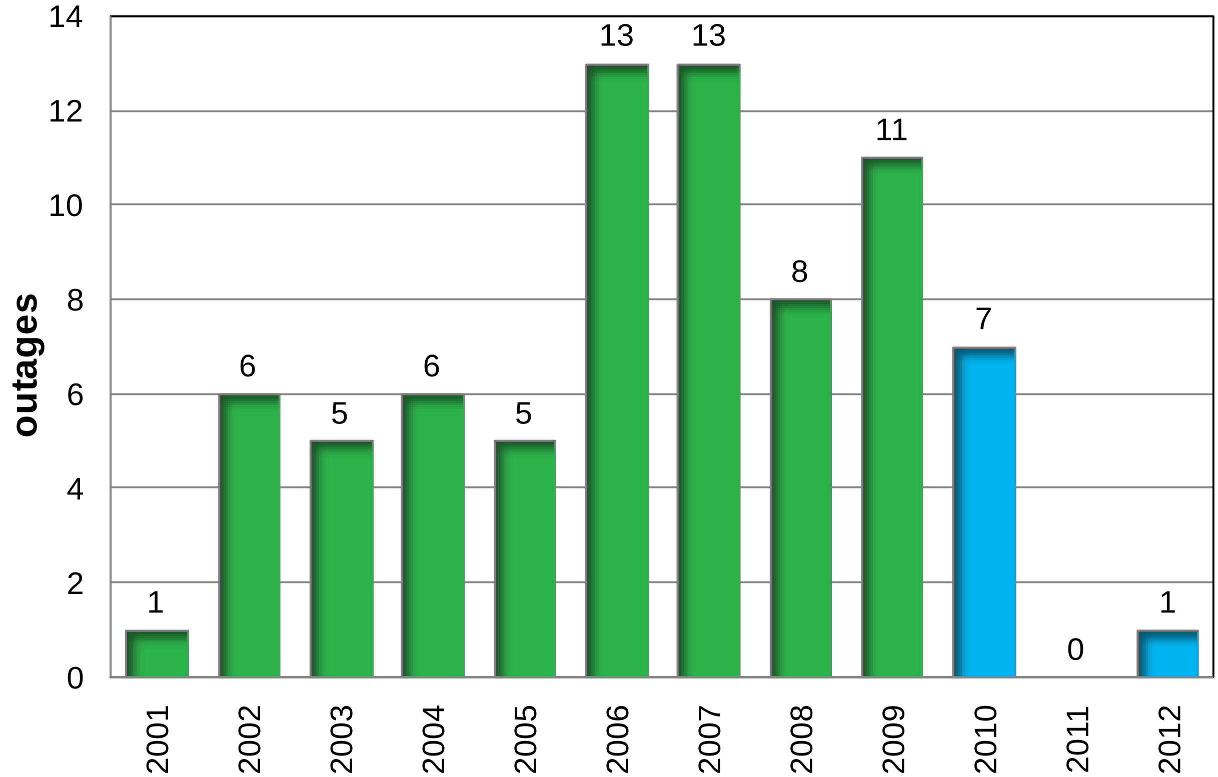


Table 5.4: Planned Feeder Rebuilds

Feeder	Area	Planned Year	Annual Energy Savings (MWh)
NE12F3	Spokane, WA	2014	115
RAT231	Rathdrum, ID	2014	91
OTH502	Othello, WA	2014	21
M23621	Moscow, ID	2014	151
DVP12F2	Davenport, WA	2014	35
HAR4F1	Harrington, WA	2014	69
BEA12F3	Spokane, WA	2015	167
FWT12F3	Spokane, WA	2015	121
TEN1255	Lewiston, ID/Clarkston, WA	2015	249
ROS12F1	Spokane, WA	2016	267
SPI12F1	Northport, WA	2016	162
TUR112	Pullman, WA	2016	101
TUR113	Pullman, WA	2017-2018	76
		Total	**1,626**

6. Generation Resource Options

Introduction

Several generating resource options are available to meet future load growth. Avista can upgrade existing resources, build new facilities, or contract with other energy companies for future delivery. This section describes resources Avista considered in the 2013 IRP to meet future 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 options to meet future resource needs.
- Wind, solar and hydro upgrades represent renewable options available to Avista; future requests for proposals (RFPs) might identify competing renewable technologies.
- Renewable resource costs assume no extensions of state and federal incentives.
- This IRP models battery storage technology as a resource option for the first time in an Avista IRP.
- Upgrades to Avista's Spokane and Clark Fork River facilities are included as resource options.

Assumptions

For the PRS analyses, Avista only considers commercially available resources with well-known costs, availability and generation profiles. These resources include gas-fired combined cycle combustion turbines (CCCT), simple cycle combustion turbines (SCCT), large-scale wind, storage, hydro upgrades, and certain solar technologies proven on a large-scale commercial basis. Several other resource options described later in the chapter were not included in the PRS analysis, but their costs were estimated for comparative analysis. Potential contractual arrangements with other energy companies are not an option for this plan, but are an option when Avista seeks new resources through a RFP.

Levelized costs referred to throughout this section are at the generation busbar. The nominal discount rate used in the analyses is 6.67 percent based on Avista's weighted average cost of capital approved by the states of Idaho and Washington. Nominal levelized costs result from discounting nominal cash flows at the rate of general inflation. All costs in this section are in 2014 nominal dollars unless otherwise noted.

Certain renewable resources receive federal and state tax incentives today and into the near future. Solar tax benefits fall by two-thirds after 2016 and all other renewable benefits end in 2013[1]. These incentives are included in IRP modeling.

Levelized resource costs presented in this chapter use the maximum available energy for each year, not expected generation. For example, wind generation assumes 34 percent availability, CCCT generation assumes 90 percent availability, and SCCT generation assumes 91 percent availability. Wind resources typically operate at or near assumed availability because the fuel is free, but CCCT or SCCT plants operate at levels well below their availability factors because their output will be displaced when lower-cost wholesale market power is available. Costs are levelized for the first 20 years of the project life using longer useful-life depreciation schedules. The following are definitions for the levelized cost components used in this chapter:

- *Capital Recovery and Taxes*: Depreciation, return of and on capital, federal and state income taxes, property taxes, insurance, and miscellaneous charges such as uncollectible accounts and state taxes for each of these items pertaining to a generation asset investment.
- *Allowance for Funds Used During Construction (AFUDC):* The cost of money associated with construction payments made on a generation asset during construction.
- *Federal Tax Incentives:* The estimated federal tax incentive (per MWh) in the form of a PTC, a cash grant, or an ITC, attributable to qualified generation options.
- *Fuel Costs*: The average cost of fuel such as natural gas, coal, or wood, per MWh of generation. Additional fuel prices details are included in the Market Analysis section.
- *Fuel Transport*: The cost to transport fuel to the plant, including pipeline capacity charges.
- *Fixed Operations and Maintenance (O&M):* Costs related to operating the plant such as labor, parts, and other maintenance services that are not based on generation levels.
- *Variable O&M:* Costs per MWh related to incremental generation.
- *Transmission*: 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 and/or third party transmission charges.
- *Other Overheads:* Includes miscellaneous charges for non-capital expenses such as uncollectibles, excise taxes and commission fees.

The tables at the end of this section show incremental capacity, heat rates, generation capital costs, fixed O&M, variable costs, and peak credits for each resource option.[2]

[1] After completion of the modeling for this IRP, the PTC for wind was expanded to allow any project under construction by the end of 2013 might qualify upon its completion.

Figure 6.2 compares the levelized costs of different resource types. Avista relies on a variety of sources including the NPCC, press releases, regulatory filings, internal analysis, and Avista's experiences with certain technologies for its resource assumptions.

Gas-Fired Combined Cycle Combustion Turbine

Gas-fired CCCT plants provide a reliable source of both capacity and energy for a relatively modest capital investment. The main disadvantage is generation cost volatility due to reliance on natural gas, unless the fuel price is hedged. CCCTs in this IRP are "one-on-one" (1x1) configurations, using air-cooling technology. 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. The plants have nameplate ratings between 250 MW and 330 MW each depending on configuration and location. A 2x1 CCCT plant configuration is possible with two turbines and one HRSG, generating up to 600 MW. Avista would need to share the plant with one or more utilities to take advantage of the modest economies of scale and efficiency of a 2x1 plant configuration due to its large size relative to our needs.

Water cooling technology could be an option for CCCT development, depending on the plant location; however, this IRP assumes air-cooled technology because of the difficulties in obtaining new water rights. Where water-cooling technology is available, the plant may require a lower capital investment and have a better heat rate relative to air-cooled technology.

The most likely CCCT configuration for Avista is a 270-300 MW air-cooled plant located in the Idaho portion of Avista's service territory, mainly due to Idaho's lack of an excise tax on natural gas consumed for power generation, a lower sales tax rate relative to Washington, and no fees on carbon dioxide emissions.[3] Potential combined cycle plant sites 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 in Idaho is access to low-cost natural gas on the GTN pipeline.

Cost and operational estimates for CCCTs modeled in the IRP use data from Avista's internal engineering analyses. The heat rate modeled for an air-cooled CCCT resource is 6,832 Btu/kWh in 2014. The projected CCCT heat rate falls by 0.5 percent annually to reflect anticipated technological improvements. The plants include duct firing for 7 percent of rated capacity at a heat rate of 8,910 Btu/kWh. If Avista were able to site a water-cooled plant, the heat rate would likely be 2 percent lower and net plant output might increase by five MW.

The IRP includes a 6 percent forced outage rate for CCCTs, and 14 days of annual plant maintenance. The plants are capable of backing down to 50 percent of nameplate

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

[3] Washington state applies an excise tax on all fuel consumed for wholesale power generation, the same as it does for retail natural gas service, at approximately 3.875 percent. Washington also has higher sales taxes and has carbon dioxide mitigation fees.

capacity, and ramping from zero to full load in four hours. Carbon dioxide emissions are 117 pounds per dekatherm of fuel burned. The maximum capability of each plant is highly dependent on ambient temperature and plant elevation.

The anticipated capital cost for an air-cooled CCCT located in Idaho on Avista's transmission system, with AFUDC, is $1,279 per kW in 2014; $345 million for a 270 MW plant. Table 6.1 shows the overnight costs for an air-cooled CCCT resource in nominal dollars; Table 6.2 shows levelized costs. The costs include firm natural gas transportation. At this time, excess pipeline capacity exists on the major pipelines near all potential siting locations to supply firm natural gas service.

Natural Gas-Fired Peakers

Natural gas-fired CTs and reciprocating engines, or peaking resources, provide low-cost capacity and are capable of providing energy as needed. Technological advances allow the plants to start and ramp quickly, providing regulation services and reserves for load following and to integrate variable resources such as wind and solar.

The IRP models four peaking resource options: Frame (GE 7EA), hybrid aero-derivative or intercooled (GE LMS 100), reciprocating engines (Wartsila 18V34), and aero-derivative (Pratt FT8). The different peaking technologies range in their abilities to follow load, costs, generating capabilities, and energy-conversion efficiencies. Table 6.1 shows cost and operational estimates based on Avista's internal engineering estimates. All peaking plants assume 0.5 percent annual real dollar cost decrease and forced outage and maintenance rates. The levelized cost for each of the technologies is in Table 6.2.

Firm fuel transportation has become an electric reliability issue with FERC, and is being discussed at several regional and extra-regional forums. For this IRP, Avista continues to assume it will not procure firm natural gas transportation for its peaking resources. Firm transportation could be necessary where pipeline capacity becomes scarce during utility peak hours; however, pipelines near potential sites being modeled by Avista in the IRP are not currently subscribed or expected to be subscribed in the near future to levels high enough to warrant the additional costs of having firm supply. Avista continues to monitor natural gas transportation options for its portfolio. Where non-firm natural gas transportation options become inadequate for system reliability, three options exist: contracting for firm natural gas transportation rights, or on-site oil or natural gas storage.

The lowest-cost peaking resource, as measured by production cost in Table 6.2, is hybrid technology. However, this comparison is misleading, as a peaking resource does not operate at its theoretical maximum operating levels. Peaking resources generally operate only a small number of hours in the year. Therefore, lower capacity-cost resources may be more cost-effective for the portfolio in relation to hybrid technology when considering the number of expected operating hours in the broader IRP modeling process.

Table 6.1: Natural Gas Fired Plant Cost and Operational Characteristics

Item	Air Cooled CCCT	Frame	Hybrid	Recip. Engines	Aero-Derivative
Capital Cost with AFUDC ($/kW)	$1,279	$910	$1,199	$1,141	$1,185
Fixed O&M ($/kW- yr)	$22.70	$11.48	$16.07	$18.78	$13.56
Heat Rate (Btu/kWh)	6,832	11,286	8,712	8,712	9,802
Variable O&M ($/MWh)	$1.77	$3.13	$5.22	$6.26	$4.17
Units Assumed at Site	1	2	1	6	2
Unit Size (MW)	270	83	92	19	50
Total Project Size (MW)	270	166	92	114	100
Total Cost for Segment Size (millions)	$345	$151	$110	$128	$119

Table 6.2: Natural Gas-Fired Plant Levelized Costs per MWh

Item	Air Cooled CCCT	Frame	Hybrid	Recip. Engines	Aero-Derivative
Capital Recovery & Taxes	18.69	13.79	18.17	16.83	17.96
AFUDC	2.02	0.58	0.76	0.70	0.75
Fuel Costs[4]	41.43	59.68	46.07	46.07	51.83
Fixed O&M	3.72	1.83	2.57	2.92	2.17
Variable O&M	2.25	3.97	6.62	7.94	5.29
Transmission	1.07	0.40	0.72	0.58	0.67
Other Overheads	1.44	1.96	1.67	1.71	1.78
Total Cost	**70.62**	**82.21**	**76.57**	**76.75**	**80.45**

Wind Generation

Concerns over the environmental impact of carbon-based generation technologies have increased demand for wind generation. Governments are promoting wind generation with tax credits, renewable portfolio standards, carbon emission restrictions, and stricter controls on existing non-renewable resources. The 2013 “Fiscal Cliff” deal in the U.S. Congress extended the PTC for wind through December 31, 2013, with provisions allowing projects to qualify after 2013 so long as construction begins in 2013. This IRP does not assume the PTC extends beyond this term, but does assume the preferential 5-year tax depreciation remains.

The IRP considers two wind generation resources located both on- and off-system. Both resources assume similar capital costs and wind patterns. On-system projects pay only transmission interconnection costs, whereas off-system projects must pay both interconnection and third-party wheeling costs.

[4] The Air-Cooled CCCT technologies fuel cost includes a charge for fuel transport to reserve capacity on a major pipeline. The levelized cost of the charge is estimated to be $5.04 per MWh.

Wind resources benefit from having no emissions profile or fuel costs, but they are not dispatchable, and have high capital and labor costs on a per-MWh basis when compared to most other resource options. Wind capital costs in 2014, including AFUDC and transmission interconnection, are $2,340 per kW, with annual fixed O&M costs of $46 per kW-yr. Fixed O&M includes indirect charges to account for the inherent variation in wind generation, oftentimes referred to as “wind integration.” The cost of wind integration depends on the penetration of wind in Avista’s portfolio, and the market price of power; for this IRP, wind integration is $4 per kW-year in 2014. These estimates come from Avista’s experience in the wind market at the time of the IRP, and results from Avista’s Wind Integration Study.

The wind capacity factors in the Northwest vary depending on project location, with capacity factors roughly ranging between 25 and 40 percent. This plan assumes Northwest wind has a 33 percent average capacity factor; on-system wind projects have a 34 percent capacity factor. 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). The expected capacity factor can have a dramatic impact on the levelized cost of a wind project. For example, a 30 percent capacity factor site could be $30 per MWh higher than a 40 percent capacity factor site holding all other assumptions equal.

Levelized costs, using these expected capacity factors, capital, and operating costs, are in Table 6.4. Actual wind resource costs vary depending on a project’s capacity factor, interconnection point, and the amount of tax related subsidies available. Further, this plan assumes wind resources selected in the PRS include the 20 percent REC apprenticeship adder for Washington state renewable portfolio standard eligible renewable resources. This adder applies only for Washington state compliance with the EIA, requiring 15 percent of the construction labor to be from apprentices through a state-certified apprenticeship program to qualify.

Table 6.3: Northwest Wind Project Levelized Costs per MWh

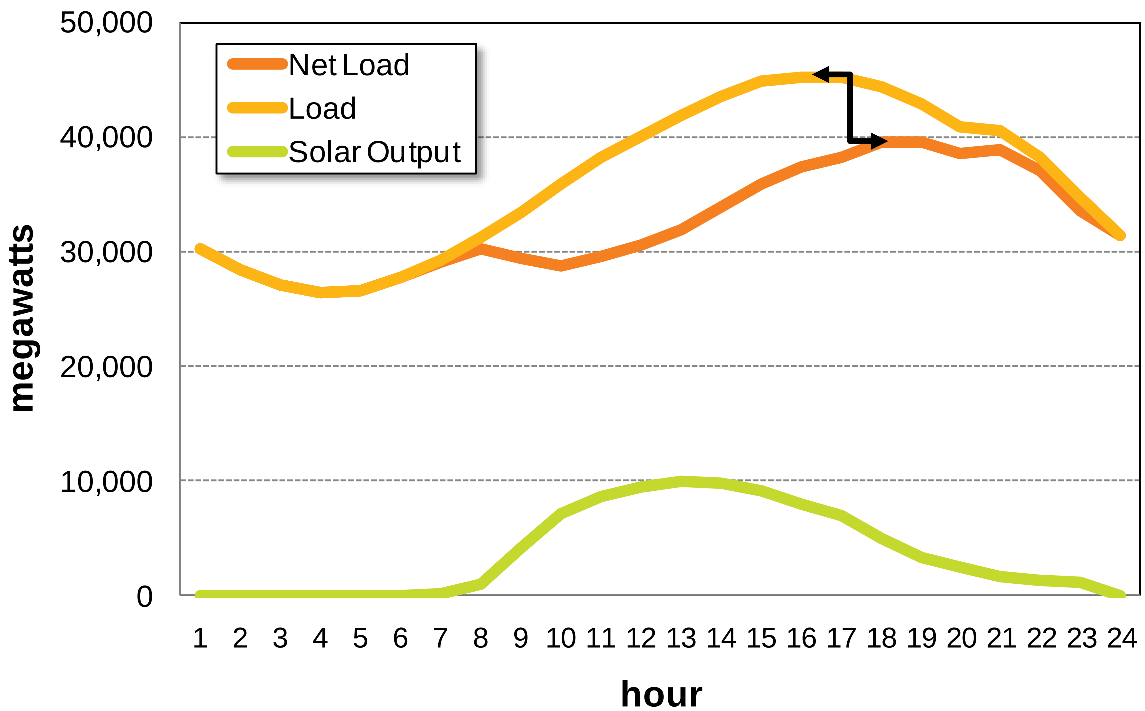
Item	On-System	Off-System
Capital Recovery & Taxes	80.68	83.12
AFUDC	4.73	4.87
Fuel Costs	0.00	0.00
Fixed O&M	19.81	20.41
Variable O&M	2.65	2.65
Transmission	1.77	9.99
Other Overheads	0.72	0.98
Total Cost	**110.36**	**122.02**

Solar Photovoltaic

Solar photovoltaic generation technology costs have fallen substantially in the last several years partly due to low-cost imports, and from renewable portfolio standards and government tax incentives, both inside and outside of the United States. Even with these large cost reductions, Avista’s analysis shows that solar still is uneconomic for winter-peaking utilities in the Northwest when compared to other generation resource options, both renewable and non-renewable. This is due to solar's low capacity factor, its lack of on-peak output during cold winter peak periods, and relatively high capital cost. Solar does provide predictable daytime generation complementing the loads of summer-peaking utilities, though fixed panels typically do not produce full output at system peak.

In the Northwest solar provides no wintertime on-peak capability. If a substantial amount of solar is added to a summer peaking utility (e.g., in the desert Southwest), the peak hour recorded prior to the solar installation will be reduced, but the peak will simply be shifted toward sundown when the solar facility witnesses a substantial output reduction. Figure 6.1 presents an example based on California Independent System Operator Daily Renewables output data for August 14, 2012. To better illustrate solar generation's impact, the figure shows a ten-fold increase to actual solar output. Assuming 10,000 MW of alternating current (AC) nameplate solar lowers the peak by 5,662 MW from the actual peak of 45,227, and shifts the overall system peak by two hours.[5] The example shows a net 56 percent peak credit for solar because solar's output falls off drastically in the later hours of the day.

Figure 6.1: Solar's Effect on California Load



Utility-scale photovoltaic generation can be optimally located for the best solar radiation, albeit at the expense of lower overall generation levels. Solar thermal technologies can

[5] Solar output generally is quoted on a direct current (DC) basis; however, for an alternating current system output is reduced by approximately 15-23 percent to account for DC-AC conversion and other on-site losses. The actual capacity of the solar generation profile is unknown, it is likely between 1,000 and 1,500 MW.

produce higher capacity factors than photovoltaic solar projects by as much as 30 percent, and can store energy for several hours for later use in reducing peak loads. Utility-scale solar capital costs in the IRP, including AFUDC, are $3,403 per kW for photovoltaic and $6,587 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 18 percent; the IRP uses a 15 percent capacity factor. Only utility-scale photovoltaic was included as an option for the PRS. Avista does not believe solar-thermal is an economically viable option in Avista's service territory given our modest solar resource and the relatively higher capital costs when compared to photovoltaic projects.

Table 6.4 shows the levelized costs of solar resources, including federal incentives. Even with declining prices, solar will continue to struggle as a cost-competitive resource in the Northwest because of its high installation costs and because the technology cannot meet winter peak system requirements. One advantage given to solar in the state of Washington is if the total plant is less than five megawatts it counts as two RECs towards Washington's EIA. Washington state also offers substantial financial incentives for consumer-owned solar. This IRP does not explicitly consider consumer-owned solar, as the overall incentives are not available to utilities and would otherwise be capped at a level that would not affect this plan. Consumer-owned solar continues to be accounted for through reductions in Avista's retail load forecast.

Table 6.4: Solar Nominal Levelized Cost ($/MWh)

Item	Photovoltaic Solar
Capital Recovery &Taxes	293.32
AFUDC	9.56
Fuel Costs	0.00
Fixed O&M	48.32
Variable O&M	0.00
Transmission	21.61
Other Overheads	2.08
Total Cost (without federal tax incentive)	**374.89**
Total Cost (with federal tax incentive)	**283.58**

Coal Generation

The coal generation industry is at a crossroads. In many states, like Washington, new coal-fired plants are unlikely due to emission performance standards. Coal remains a viable option in other parts of the country, but the risks associated with future carbon legislation make investments in this technology challenging. The EPA has proposed a greenhouse gas emission performance standard average of 1,000 lbs per MWh (averaged over a 30-year period). This proposed rule effectively eliminates new coal-fired generation without carbon sequestration, as non-sequestered coal options generate between 1,760 and 1,825 lbs of carbon dioxide per MWh.

Avista does not plan to build or participate in any new coal-fired generation resources in the future due to the risk of future national carbon mitigation legislation and the effective prohibition contained 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. Though 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 CO_2 emissions. 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 6.5: Coal Capital Costs

Item	Super-Critical	IGCC	IGCC w/ Sequestration
Capital Costs ($/kW includes AFUDC)	$3,683	$4,895	$7,342
Typical Size	600	600	550
Cost per Unit (Millions)	$2,210	$2,937	$4,038
Heat Rate (Btu/kWh)	8,910	8,594	10,652
CO_2 (lbs per MWh)	1,827	1,762	218

Table 6.6: Coal Project Levelized Cost per MWh

Item	Super-Critical	IGCC	IGCC w/ Sequestration
Capital Recovery & Taxes	54.90	72.26	108.38
AFUDC	8.25	13.35	20.02
Fuel Costs	14.52	14.00	17.36
Fixed O&M	7.24	11.07	11.07
Variable O&M	3.64	8.34	11.25
Transmission	9.47	9.62	4.38
Other Overheads	1.04	1.28	1.31
Total Cost	**99.06**	**129.92**	**173.77**

Energy Storage

Increasing amounts of solar and wind generation on the electric grid makes energy storage technologies attractive from an operational perspective. The technologies could be an ideal way to smooth out renewable generation variability and assist in load following and regulation needs. The technology also could meet peak demand, provide voltage support, relieve transmission congestion, take power during over supply events, and supply other non-energy needs for the system. Over time, storage may become an important part of the nation's grid. Several storage technologies currently exist, including; pumped hydro, traditional and chemical batteries, flywheels, and compressed air.

There are many challenges with storage technology. First, existing technologies consume a significant amount of electricity relative to their output through conversion losses. Second, the cost of storage is high, at near $4,000 per kW. This cost is nearly four times the initial cost of a natural gas-fired peaking plant that can provide many, but not all, of the same capabilities without the electricity consumption characteristics of storage. Storage costs are forecast to decline over time, and Avista continues to monitor the technologies as part of the IRP process. Third, the current scale of most storage projects is small, limiting their applicability to utility-scale deployment. Fourth, early adoption of technology can be risky, with many industry examples of battery fires and bankruptcy.

The Northwest might be slower in adopting storage technology relative to other regions in the country. The Northwest hydro system already contains a significant amount of storage relative to the rest of the country. However, as more capacity consuming renewables are added to the grid, new storage technologies might play a significant role in meeting the need for additional operational flexibility where upfront capital costs and operational losses fall.

One of the biggest obstacles to energy storage is quantifying and properly valuing its benefits. At a minimum, the value of storage is the spread or difference between the value of energy in on versus off-peak hours (load factoring), minus the losses. Since the technology can meet regulation, load following, and operating reserves, there is value beyond load factoring. Valuing these benefits requires new system modeling tools. Presently there are no adequate tools available in the marketplace. Avista is developing a tool it believes will enable detailed valuations of storage (and other) technologies within our existing mix of flexible hydro and thermal system. The results of these studies are not available for this plan, but should be available in the next IRP.

Other Generation Resource Options

A thorough IRP considers generation resources not readily available in large quantities or commercially or economically ready for utility-scale development. Today a number of emerging technologies, like energy storage, are attractive from an operational or environmental perspective, but are significantly higher-cost than other technologies providing substantially similar capabilities at lower cost. Avista analyzed several of these technologies for the IRP using estimates from the NPCC's Sixth Power Plan, publically available data, and Avista internal engineering analysis. The resources include biomass, geothermal, co-generation, nuclear, landfill gas, and anaerobic digesters. Table 6.7 shows the expected cost of these options. Their costs vary depending on site-specific conditions. All prices shown are utility-scale estimates with no federal tax incentives. However, given the lack of utility-scale development, cost could be substantially higher than shown.

Failure to be included in the PRS is not the last opportunity for technologies to be in Avista's portfolio. The resources will compete with those included in the PRS through Avista's RFP processes. RFP processes identify competitive technologies that might displace resources otherwise included in the IRP strategy. Another possibility is acquisition through federal PURPA law mandates. PURPA provides non-utility developers the ability to sell qualifying power to Avista at guaranteed prices and terms.[6] Since the 2011 IRP, Avista has acquired three renewable energy projects under PURPA.

Woody Biomass Generation

Woody biomass generation projects use waste wood from lumber or forest restoration process. The generation process is similar to a coal plant: a turbine converts boiler-created steam into electricity. A substantial amount of wood fuel is required for utility-scale generation. Avista's 50 MW Kettle Falls Generation Station consumes over 350,000 tons of wood waste annually, or 48 semi-truck loads of wood chips per day. It typically takes 1.5 tons of wood to make one MWh of electricity; the ratio varies seasonally with the moisture content of the fuel. The viability of another Avista biomass projects depends significantly on the availability and cost of the fuel supply. Many announced biomass projects fail due to lack of a long-term fuel source. If an RFP identifies a potential project, Avista will consider it for a future acquisition. A 25 MW utility scale biomass plant would cost approximately $111 million in initial capital expenditure ($4,436 per kW), with fuel and O&M costs increasing the total cost to an amount approaching $160 per MWh.

Geothermal Generation

Northwest utilities have shown increased interest in geothermal energy over the past several years. It provides predictable electrical capacity and energy with minimal carbon dioxide emissions (zero to 200 pounds per MWh). The technology typically involves injecting water into deep wells; hot earth temperatures heat water and spin turbines for power generation. In recent years, a few projects were built in the Northwest. Due to the geologic conditions of Avista's service territory, no geothermal projects are likely to be developed. For Avista to add this technology to its portfolio, it would require a third-party transmission wheel and be acquired through an RFP process.

Geothermal energy struggles to compete due to high development costs stemming from having to drill several holes thousands of feet below the earth's crust; each hole can cost over $3 million. Ongoing geothermal costs are low, but the capital required to locate and prove a viable site is significant. Costs shown in this section do not account

[6] Rates, terms, and conditions are at www.avistautilities.com under Schedule 62.

for dry-hole risk associated with sites that do not prove to be viable after drilling has taken place. Recent construction estimates for a 15 MW facility are $71.5 million ($4,767 per kW). The levelized cost of geothermal power is $104 per MWh.

Landfill Gas Generation

Landfill gas projects generally use reciprocating engines to burn methane gas collected at landfills. The Northwest has successfully developed many landfill gas resources. The costs of a landfill gas project will depend greatly on the site specifics of a landfill. The Spokane area had a project on one of its landfills, but it was retired after the fuel source depleted to an unsustainable level. The Spokane area no longer landfills its waste and instead uses its Municipal Waste Incinerator. Nearby in Kootenai County, Idaho, the Kootenai Electric Cooperative has developed a 3.2 MW Fighting Creek Project. It is currently under a PURPA contract with Avista. Using publically available costs and the NPCC estimates, landfill gas resources are economically promising, but are limited in their size, quantity, and location. Cost estimates in Table 6.7 assume a 3.2 MW unit with a capital cost of $8.5 million ($2,654 per kW including AFUDC). At an 88 percent capacity factor, a landfill gas project could cost up to $106 per MWh.

Anaerobic Digesters (Manure/Wastewater Treatment)

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 generators. These facilities tend to be significantly smaller than utility-scale generation projects (less than five MW). Most facilities are located in large dairies or feedlots. A survey of Avista's service territory found no large-scale livestock operations capable of implementing this technology.

Wastewater treatment facilities can also host anaerobic digesting technology. Digesters installed when a facility is initially 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. Avista currently has a 260 kW waste water system under a PURPA contract with a Spokane County facility.

Typical digester projects are 200 kW to five MW. Current estimates are $4,775 per kW for utility development, or $24 million in capital for a five MW project. The actual cost of the technology depends on the fuel source, site specifics, and subsidies available for the project. For example, many digesters qualify for agricultural loans and/or grants. Fuel costs vary based on feedstock prices and transportation costs to move fuel to the digester. The cost of the technology is $110 per MWh without fuel charges.

Small Cogeneration

Avista has 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, and emissions costs, and credit toward Washington's EIA targets.

Another potentially promising option is natural gas pipeline cogeneration. This technology uses waste-heat from large natural gas pipeline compressor stations. In Avista's service territory few compressor stations exist, but the existing compressors in our service territory have potential for this generation technology. Avista has discussed adding cogeneration with pipeline owners.

A big challenge in developing any new cogeneration project is aligning the needs of the cogenerator and the utility's need for power. The optimal time to add cogeneration is when an industrial process is being retrofitted, but oftentimes the utility does not need the new capacity at this time. Another challenge to cogeneration within an IRP is estimating costs when host operations drive costs for a particular project.

Nuclear

Avista does not include nuclear plants as a resource option in the IRP given the uncertainty of their economics, the apparent lack of regional political support for the technology, U.S. nuclear waste handling policies, and Avista's modest needs relative to the size of modern nuclear plants. Nuclear resources could be in Avista's future only if other utilities in the Western Interconnect incorporate nuclear power in their resource mix and offer Avista an ownership share.

The viability of nuclear power could change as national policy priorities focus attention on de-carbonizing the nation's energy supply. The lack of newly completed nuclear facility construction experience in the United States makes estimating construction costs difficult. Cost projections in the IRP are from industry studies, recent nuclear plant license proposals, and a small number of projects currently under development. New smaller, and more modular, nuclear design could increase the potential for nuclear by shortening the permitting and construction phase (lower AFUDC costs), and make these traditionally large projects better fit the needs of smaller utilities.

Table 6.7's nuclear cost estimate is for a 1,100 MW facility. This assumes a capital cost of $9,125 per kW (including AFUDC). At this cost, a large facility could easily cost $10 billion to build and cost $173 per MWh over the first 20 years of project life.

Table 6.7: Other Resource Options Levelized Costs ($/MWh)

	Landfill Gas	Manure Digester	Wood Biomass	Geothermal	Nuclear
Capital Recovery & Taxes	36.35	65.43	60.09	57.12	114.25
AFUDC	1.01	1.03	4.43	8.78	29.93
Fuel Costs	33.60	33.60	56.40	0.00	10.83
Fixed O&M	4.45	7.70	31.84	29.43	15.41
Variable O&M	25.14	31.75	4.90	5.95	1.98
Transmission	4.67	4.13	1.41	4.08	4.13
Other Overheads	2.02	2.30	2.81	1.17	0.96
Total Cost	**107.24**	**145.95**	**161.88**	**106.53**	**177.50**

New Resources Cost Summary

Avista has several resource alternatives for this IRP. Each alternative provides different benefits, costs and risks. The IRP identifies the relevant characteristics and chooses a set of resources that are actionable, meet energy and capacity needs, balance renewable requirements, and minimize costs. Figure 6.2 shows comparative cost per MWh of each new resource alternative over the first 20 years of project life using nominal levelized costs. Tables 6.8 and 6.9 provide detailed assumptions for each type of resource. The ultimate resource selection goes beyond simple levelized cost analyses and considers the capacity contribution of each resource, among other items discussed in the IRP.

Figure 6.2: New Resource Levelized Costs (first 20 Years)

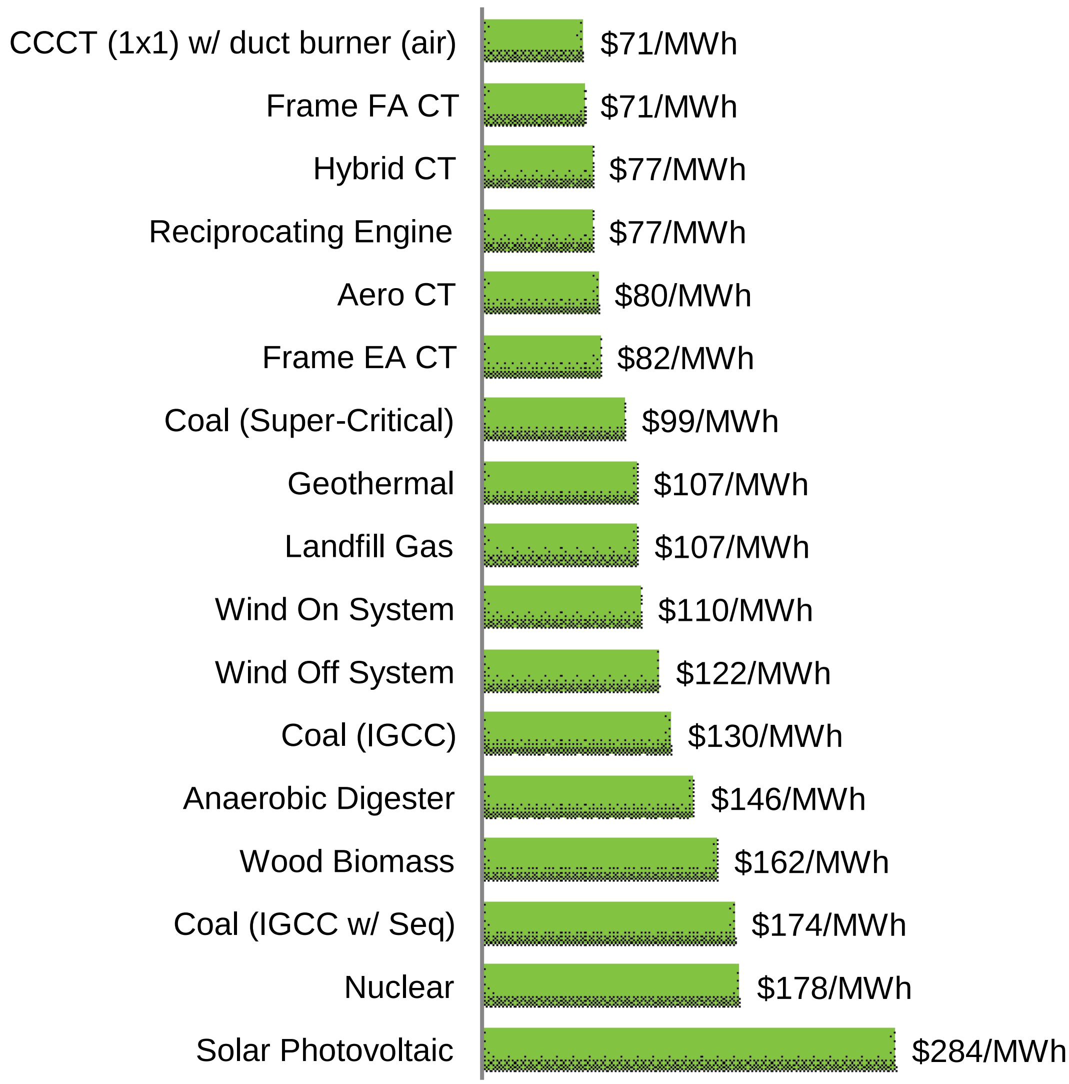


Table 6.8: New Resource Levelized Costs Considered in PRS Analysis

Resource	Size (MW)	Heat Rate (Btu/ kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Peak Credit (Winter/ Summer)
CCCT (air cooled)	270	6,832	1,279	22.7	1.77	104/94
Frame CT	83	11,286	910	11.5	3.13	104/94
Hybrid CT	92	8,712	1,199	16.1	5.22	104/94
Reciprocating Engines	114	8,712	1,141	18.8	6.26	100/100
Aero CT	100	9,802	1,185	13.6	4.17	104/94
Wind	100	n/a	2,340	53.0	2.09	0/0
Storage	5	n/a	3,889	52.2	0.00	100/100
Solar (photovoltaic)	5	n/a	3,403	53.0	0.00	0/62

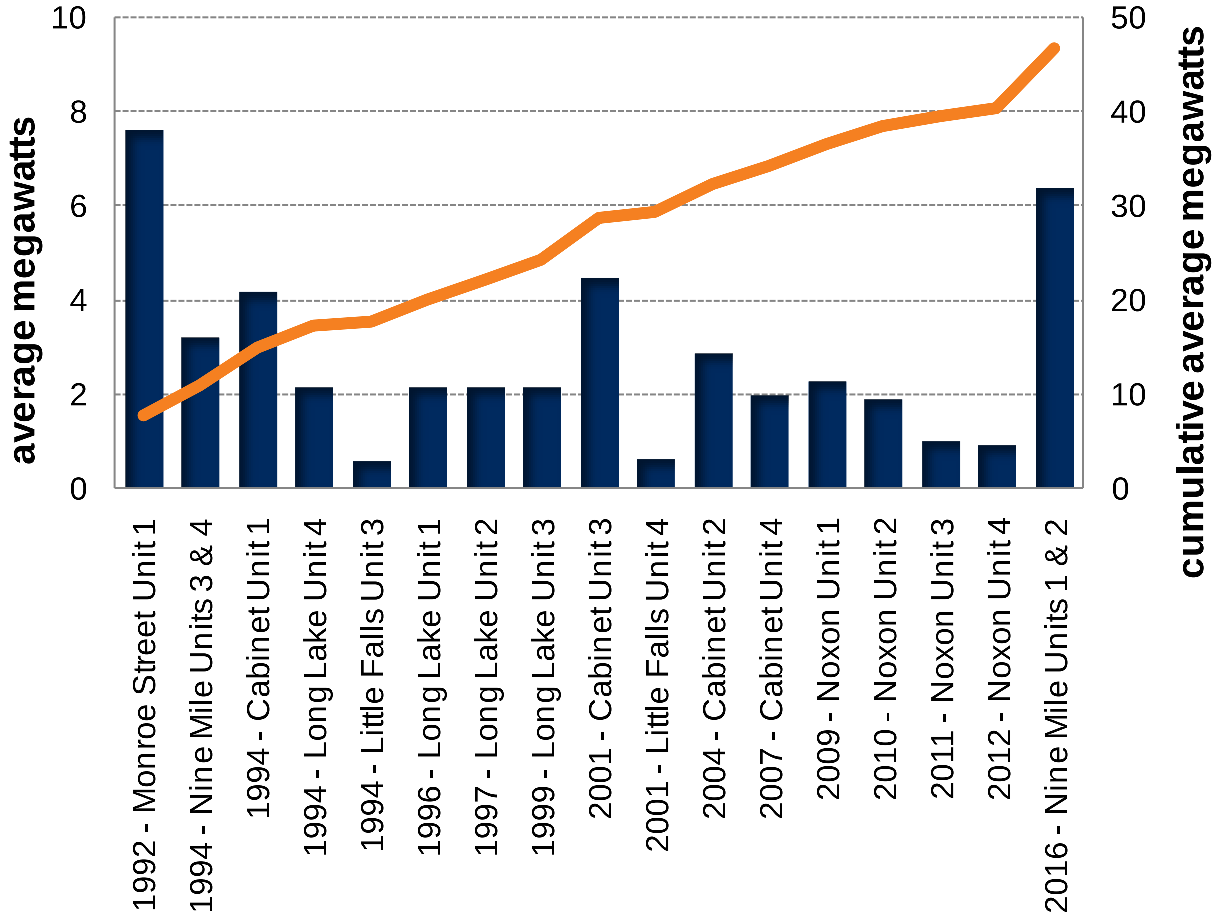
Table 6.9: New Resource Levelized Costs Not Considered in PRS Analysis

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	600	8,910	3,683	41.73	2.87	100/100
IGCC Coal	600	8,594	4,895	62.60	6.57	100/100
IGCC Coal w/ Seq.	550	10,652	7,342	62.60	8.87	100/100
Woody Biomass	25	13,500	4,436	187.80	3.86	100/100
Geothermal	15	n/a	4,767	182.59	4.70	100/100
Landfill Gas	3.2	10,500	2,654	27.13	19.82	100/100
Anaerobic Digester	1	10,500	4,721	46.95	25.04	100/100
Nuclear	1100	10,400	9,125	93.90	1.57	100/100

Hydroelectric Project Upgrades and Options

Avista continues to upgrade many of its hydroelectric facilities. The latest hydroelectric upgrade added nine megawatts to the Noxon Rapids Development in April 2012. Figure 6.3 shows the history of upgrades to Avista's hydroelectric system by year and cumulatively. Avista added 40.1 aMW of incremental hydroelectric energy between 1992 and 2012. Upgrades completed after 1999 qualify for the EIA, thereby reducing the need for additional higher-cost renewable energy options.

Figure 6.3: Historical and Planned Hydro Upgrades



Avista's next upgrade is at Nine Mile, replacing two of the four project units. Avista is currently removing the old equipment on units one and two, and replacing the 105-year old technology with new turbines, runners, generators, and other electrical equipment. The project is scheduled for completion in 2016.

The Spokane River developments were built in the late 1800s and early 1900s, when the priority was to meet then-current loads. They do not to capture a majority of the river flow. In 2012, Avista re-assessed its Spokane River developments. The goal was to develop a long-term strategy and prioritize potential facility upgrades. Avista evaluated five of the six Spokane River developments and estimated costs for generation upgrade options at each. Each upgrade option should qualify for the EIA, meeting the Washington state renewable energy goal. These studies were part of the 2011 IRP Action Plan and are discussed below. Each of these upgrades would be a major engineering project, taking several years to complete, and require major changes to the FERC licenses and project water rights.

Long Lake Second Powerhouse

Avista studied adding a second powerhouse at Long Lake over 20 years ago by using a small arch dam (Saddle Dam) located on the south end of the project site. This project would be a major undertaking and require several years to complete, including major changes to the Spokane River license and water rights. In addition to providing customers with a clean energy source, this project could help reduce total dissolved gas concerns by reducing spill at the project and provide incremental capacity to meet peak load growth.

The study focused on three alternatives. The first replaces the existing four-unit powerhouse with four larger units to total 120 MW, increasing capability by 32 MW. The other two alternatives develop a second powerhouse with a penstock beginning from a new intake near the existing saddle dam. One powerhouse option was a single 68 MW turbine project. The second was a two-unit 152 MW project. The best alternative in the study was the single 68 MW option. Table 6.10 shows upgrade costs and characteristics.

Post Falls Refurbishment

The Post Falls hydroelectric development is 108 years old. Three alternatives could increase the existing capacity from 18 MW up to 40 MW. The first option is a new two-unit 40 MW powerhouse on the south channel that removes the existing powerhouse. Alternative 2 retrofits the existing powerhouse with five 8.0 MW units (40 MW total). The last alternative retrofits the existing powerhouse with six 5.6-MW units (33.6 MW total). The cost differences between developing a new powerhouse in the south channel and the smaller plant refurbishment is small. Over the next decade, these alternatives will continue to be studied to address the aging infrastructure of the plant.

Monroe Street/Upper Falls Second Power House

Avista replaced the powerhouse at its Monroe Street project on the Spokane River in 1992. There are three options to increase its capability. Each would be a major undertaking requiring substantial cooperation with the City of Spokane to mitigate disruption in Riverfront Park and downtown Spokane during construction. The upgrade could increase capability by up to 80 MW. To minimize impacts on the downtown area and the park, a tunnel on the east side of Canada Island could be drilled, avoiding most above ground excavation of the south channel. A smaller option would be to add a second 40 MW Upper Falls powerhouse, but this option would require south channel excavation. The least cost option is an 80 MW upgrade adjacent to the existing Upper Falls facility.

Cabinet Gorge Second Powerhouse

Avista is exploring the addition of a second powerhouse at the Cabinet Gorge development site to mitigate total dissolved gas and produce additional electricity. A new powerhouse would benefit from an existing diversion tube around the dam and could range in size between 55 and 110 MW.

Table 6.10: Hydro Upgrade Option Costs and Benefits

Resource	Inc. Capacity (MW)	Inc. Energy (MWh)	Inc. Energy (aMW)	Peak Credit (Winter/ Summer)	Capital Cost ($ Mill)	Levelized Cost ($/MWh)
Post Falls	22	90,122	10.3	24/0	$110	158.60
Monroe St/Upper Falls	80	237,352	27.1	31/0	$153	87.50
Long Lake	68	202,592	23.1	100/100	$141	97.45
Cabinet Gorge	55	80,963	9.2	0/0	$116	192.56

Thermal Resource Upgrade Options

The 2011 IRP identified several thermal upgrade options for Avista's fleet. Since then Avista has negotiated with the turbine servicers to have some of the upgrades completed as part of an enhancement package during the 2013 maintenance cycle for Coyote Springs 2. The upgrades include Mark Vie controls, digital front end on the EX2100 gas turbine exciter, and model based controls with enhanced transient capability. These enhancements will improve reliability of the plant, reduce future O&M costs, improve our ability to maintain compliance with WECC reliability standards, and help prevent damage to the machine if electrical system disturbances occur. Installation of cold day controls and cooling optimization will occur after permitting is complete.

In addition to the upgrades at Coyote Springs 2, there are options at the Rathdrum CT site. Other Avista-owned project sites were reviewed, but based on economics none of the options were included for the 2013 IRP.

Rathdrum CT to CCCT Conversion

The Rathdrum CT has two GE 7EA units in simple cycle configuration built in 1995 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 80 MW of steam-turbine capacity (depending upon temperature), and increasing operating efficiency from a heat rate of 11,612 Btu/kWh, in its existing configuration, to a heat rate of about 8,000 Btu/kWh. A major issue with this conversion, besides overall cost, is noise. Residential development at the site since the plant's construction adds complexity to a project that would shift from occasional use during peak periods to more of a base-load configuration.

Rathdrum CT Water Demineralizer

Another identified upgrade at Rathdrum is the addition of a water demineralizer to allow summertime inlet fogging. Fogging increases peak output during hot summer load periods. The plant utilized a leased demineralizer in the past, but high leasing costs moved Avista to end the program.

7. Market Analysis

Introduction

This section describes the electricity and natural gas market environment developed for the 2013 IRP. It contains pricing risks Avista considers to meet customer demands at the lowest reasonable cost. The analytical foundation for the 2013 IRP is a fundamentals-based electricity model of the entire Western Interconnect. The market analysis evaluates 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 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 by 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 AURORA$^{\underline{XMP}}$, an electric market model that emulates the dispatch of resources to loads across the Western Interconnect 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.

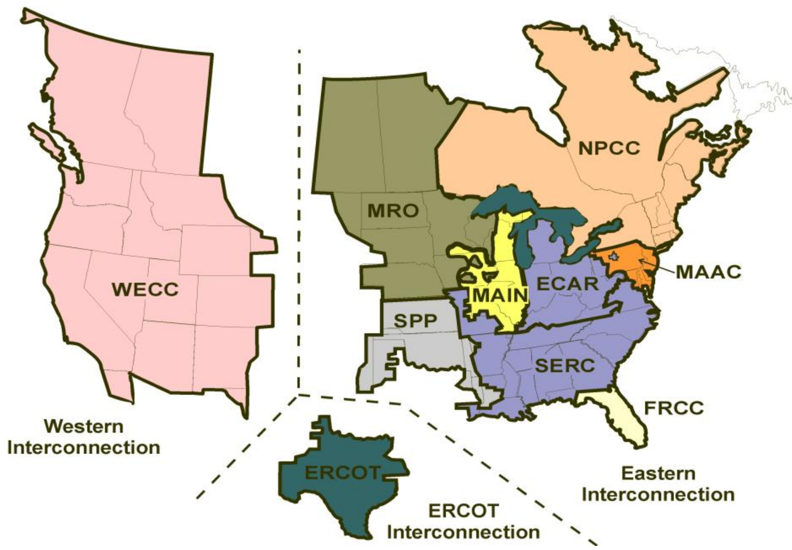
Section Highlights

- Natural gas and wind resources dominate new generation additions in the West.
- Shale gas continues to lower natural gas and electricity price forecasts.
- A growing Northwest wind fleet reduces springtime market prices below zero in many hours.
- Federal greenhouse gas policy remains uncertain, but new EPA policies point toward a regulatory model rather than a cap-and-trade system.
- Lower natural gas prices and lower loads have reduced greenhouse gas emissions from the U.S. power industry by 11 percent since 2007.
- The Expected Case forecasts a continuing reduction to Western Interconnect greenhouse gas emissions due to coal plant shut downs brought on by EPA regulations.
- Coal plant shut downs have similar carbon reduction results as a cap-and-trade market scheme, but have the advantage of not causing wholesale market price disruptions.

Marketplace

AURORA^{XMP} 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.

Figure 7.1: NERC Interconnection Map



The Western Interconnect is separated from the Eastern and ERCOT interconnects to the east by eight DC inverter stations. It follows operation and reliability guidelines administered by WECC. Avista modeled the electric system as 17 zones based on load concentrations and transmission constraints. After extensive study in prior IRPs, Avista now models the Northwest region as a single zone because this configuration dispatches resources in a manner more 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
COB- OR/CA Border	Wyoming
Eastern Montana	Southern California
Northern California	Arizona
Central California	New Mexico
Colorado	Alberta
British Columbia	South Nevada
North Nevada	Baja, Mexico
Utah	

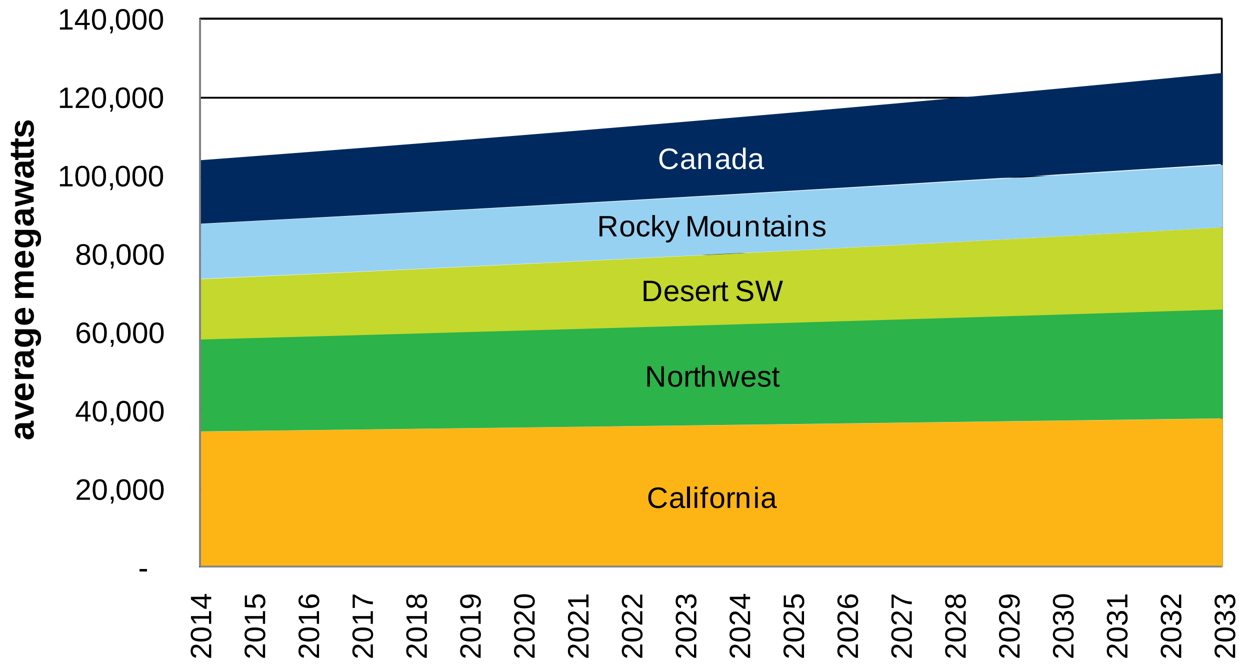
Western Interconnect Loads

The 2013 IRP relies on a load forecast for each zone of the Western Interconnect. Avista uses other utilities' resource plans to quantify load growth across the west. These estimates include energy efficiency and demand reduction caused by current and potential emissions legislation, and associated price increases also expected to reduce load growth rates from their present trajectory.

Regional load growth estimates are in Figure 7.2. Avista forecasts overall Western Interconnect loads will rise nearly 1 percent annually over the next 20 years. This is a significant reduction in expected energy growth from the 2011 IRP's 1.65 percent load growth assumption. Between 2008 and 2011, actual Western U.S. electricity demand declined by approximately 1 percent. However, loads did recover from their 2010 low of 2.6 percent below 2008 levels. The reduced energy growth projection is due to lower estimates of economic growth combined with energy efficiency gains that have reducing energy use. On a regional basis, the West Coast and Rocky Mountain states forecasts lower than 1 percent growth, while the desert Southwest region continues to expect growth in the 1 to 2 percent range. The strongest projected growth area in the region comes from Alberta at 2.5 percent.

From a system reliability perspective, Avista expects peak loads to grow at a slower pace than the last IRP. Northwest peak load growth rates average 0.93 percent annually. In California, demand response and high end-use solar penetration should reduce its system peak by 0.26 percent per year. Remaining regions should have growth rates similar to their energy forecast.

Figure 7.2: 20-Year Annual Average Western Interconnect Energy



Transmission

In past IRP's, expansion to the region's transmission system was expected to occur in the middle of the 20-year planning horizon. Due to changes in the marketplace, such as lower natural gas prices and the significant reduction in the cost of solar, many transmission projects expected in the 2011 IRP are on hold or cancelled. Remaining transmission projects are smaller or delayed. Table 7.2 shows the regional transmission upgrades included in this IRP. Only upgrades between modeled zones are shown, as transmission upgrades within AURORA[XMP] zones are not explicitly in the model; they do not affect power transactions between zones.

Table 7.2: Western Interconnect Transmission Upgrades Included in Analysis

Project	From	To	Year Available	Capacity MW
Eastern Nevada Intertie	North Nevada	South Nevada	2016	1,000
Gateway South	Wyoming	Utah	2015	3,000
Gateway Central	Idaho	Utah	2015	1,350
Gateway West	Wyoming	Idaho	2016	1,500
SunZia/Navajo Transmission	Arizona	New Mexico	2017	3,000
Wyoming – Colorado Intertie	Wyoming	Colorado	2014	900
Hemingway to Boardman	Idaho	Northwest	2020	1,400

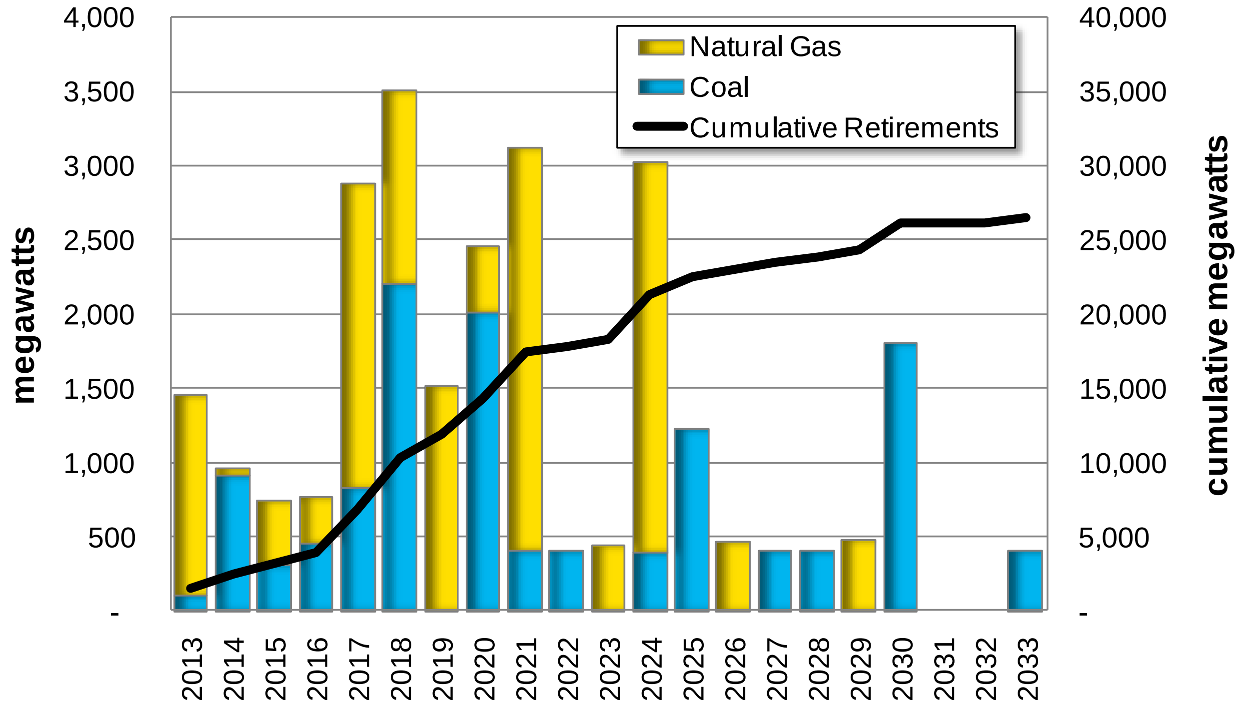
Resource Retirements

Since filing the 2011 IRP, new attention across western states is being directed to retire aging power plants, specifically plants with larger environmental impacts, such as once-through-cooling (OTC) in California and older coal technology throughout North America. Recently various states, encouraged by environmentally-focused groups, are developing rules to eliminate certain generation technologies. In California, all OTC facilities require retrofitting to eliminate OTC technology, or must retire. Over 14,200 MW of OTC natural gas-fired generators in California are forecast to be retired and replaced in the IRP timeframe. Remaining OTC natural gas-fired and nuclear facilities with more favorable fundamentals are expected to be retrofitted with other cooling technology. Many OTC plants have identified shutdown dates from their utility owners' IRPs, and company news releases. The remaining plants are assumed to shut down between 2017 and 2024; this retirement schedule is similar to WECC studies (see Figure 7.3 for the retirement schedule assumed in the 2013 IRP). Elimination of OTC plants in California will eliminate older technology presently used for reserves and high demand hours. While replacements will be expensive for California customers, they will be served by a more modern generation fleet.

Coal-fired facilities are also under increasing regulatory scrutiny. In the Northwest, the Centralia and Boardman coal plants are scheduled to retire in 2020 and 2025 respectively, a reduction of 1,961 megawatts. Other coal-fired plants throughout the Western Interconnect have announced plant closures, including Four Corners, Carbon, Arapahoe, San Juan, and Corette. Due to recent EPA standards, the IRP forecasts additional coal-fired facility retrofits or retirements.[1]

Plant retirements are based on Avista analyses, considering each plant's location, their unit sizes and fuel costs, and their current emission control technology. Based on these factors, Avista judges whether the plant is likely to face enough regulatory burdens to make the plant uneconomic. It is not the intent of the IRP to include a perfect coal retirement forecast, as this would be impossible. Instead, such analyses help Avista understand the potential effects a reduction in coal output in the West will have on pricing and the benefit of future resource investments by Avista. The analysis found that 12,300 MW of coal generation might shut down over the 20-year planning horizon. A graphical representation of the retirement is in Figure 7.3.

Figure 7.3: Resource Retirements (Nameplate Capacity)



New Resource Additions

New resource capacity is required to meet future load growth and replace retiring power plants over the next 20 years. To fill the gap, resources are added to each region to sustain a 5 percent Loss of Load Probability (LOLP), or in other words, all system demand must be met in 95 percent of simulated forecasts. The generation additions must meet capacity, energy, ancillary services, and renewable portfolio mandates. To meet future requirements, natural gas-fired CCCT or SCCT, solar, wind, coal IGCC with sequestration, and nuclear options were considered.[2] The IRP does not include new

[1] A recently passed Nevada law allows NV Energy to retire its coal plants.

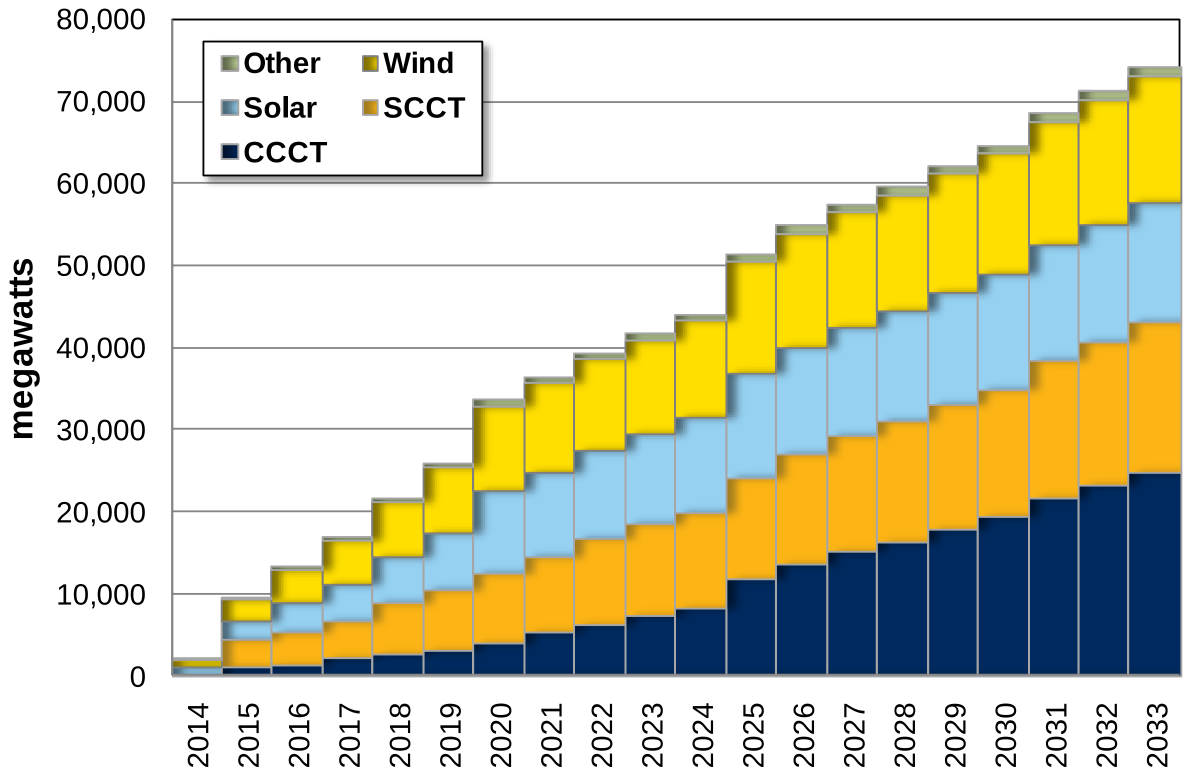
[2] Based on analysis in Chapter 6, Generation Resource Options, solar generation in the southern states receives a 56 percent capacity factor, while in the Northwest it would receive no peak credit. Wind

non-sequestered pulverized coal plants over the forecast horizon, consistent with recent EPA new source performance standard issued in late 2012.

Many states have RPS requirements promoting renewable generation to reduce greenhouse gas emissions, provide jobs, and diversify their energy mix. 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 RPS obligations differently. AURORA^{XMP} cannot model RPS levels explicitly. Instead, Avista inputs RPS requirements into the model at levels sufficient to satisfy state laws.

Figure 7.4 illustrates new capacity and RPS additions made in the modeling process. Wind and solar facilities meet most renewable energy requirements. Geothermal, biomass, and hydroelectric resources provide limited RPS contributions. Renewable resource choices differ depending on state laws and the local availability of renewable resources. 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 costs of these resources are the lowest. Rocky Mountain states will predominately meet RPS requirements with wind.

Figure 7.4: Cumulative Generation Resource Additions (Nameplate Capacity)



With lower load growth, and even with 26 GW in resource retirements, the forecast for new resource capacity additions is lower than prior IRPs. Compared to the 2011 IRP,

receives a 5 percent capacity credit on a regional basis, but receives no capacity credit for meeting Avista's balancing authority requirements.

future natural gas capacity is down 5 GW, wind is lower by 10 GW, other renewables are slightly lower, and solar maintains similar additions.

The Northwest market will need new capacity beginning in 2017 with the addition of combined- or simple-cycle CTs. Based on market simulation results, a 21 percent regional planning margin (including operating reserves) is necessary. The Northwest likely will continue to develop wind to meet RPS requirements, with small contributions from other renewable resources. Over the 20-year forecast, six gigawatts of new natural gas capacity is projected, along with over seven gigawatts of new wind capacity and one gigawatt of other renewable including solar, biomass, geothermal, and hydro.

Fuel Prices and Conditions

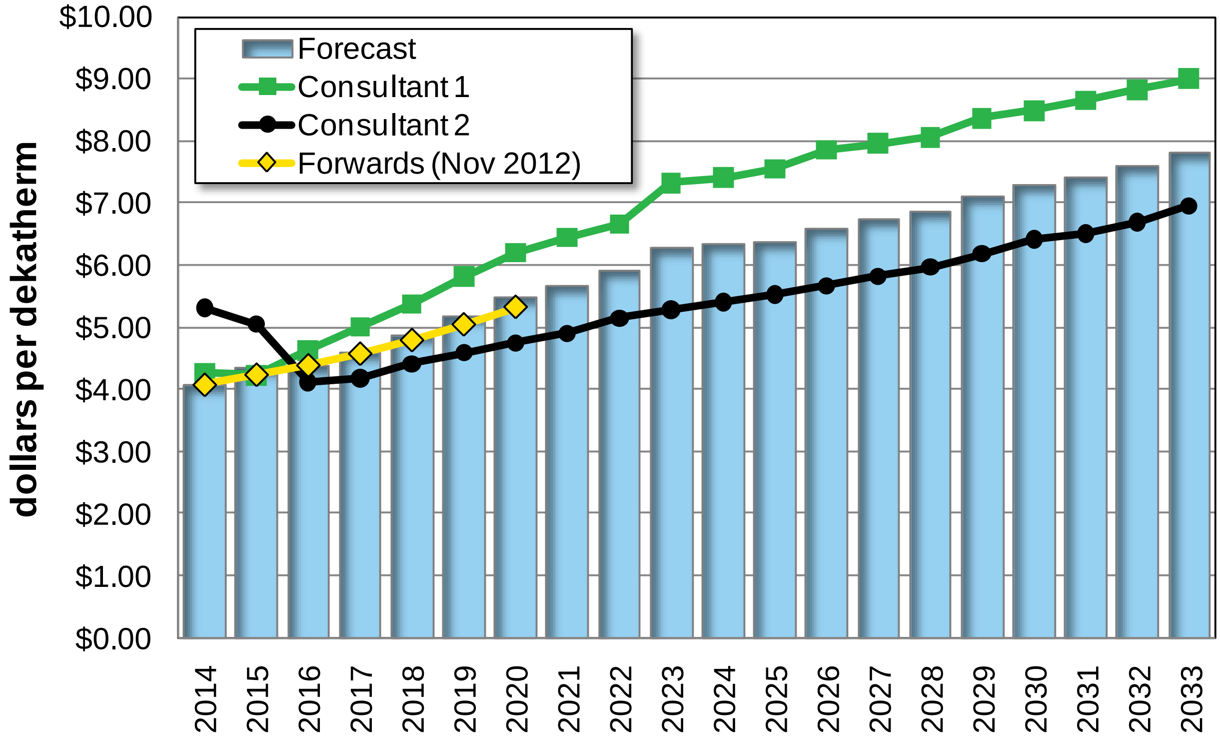
Fuel cost and availability are some of the most important drivers of the overall wholesale marketplace and resource values. Some resources, including geothermal and biomass, have limited fuel options or sources, while coal and natural gas have more potential. Hydro, wind, and solar benefit from free fuel, but are highly dependent on weather and limited siting opportunities.

Natural Gas

The fuel of choice for new base-load and peaking capability continues to be natural gas. Natural gas in past years was subject to significant price volatility. Unconventional sources have since reduced overall price levels and volatility, although it unknown how much volatility will exist in the future market as technology plays out against regulatory pressures and the potential for new demand created by falling prices. Avista uses forward market prices and a combination of two December 2012 forecasts from prominent energy industry consultants to develop its natural gas price forecast for this IRP. The levelized nominal price is $5.62 per dekatherm at Henry Hub (shown in Figure 7.5 as the gray bars). For the first year of the forecast, forward prices are used. After the first year, a 50/50 average of the consultant forecasts combines with the forward market to transition from a forward pricing methodology to a fundamental price forecast, as follows:

- 2015: 75 percent market, 25 percent consultant average;
- 2016: 50 percent market, 50 percent consultant average; and
- 2017-19: 25 percent market, 75 percent consultant average.

Figure 7.5: Henry Hub Natural Gas Price Forecast



Natural gas market transformation has brought consultant assumptions closer together. In previous forecasts, the Alaskan natural gas pipeline was included in many forecasts, but is no longer included in either forecast. Growth in the residential, commercial, and industrial markets is flat. Carbon legislation used to be included early and robust in both forecasts, but it is now delayed and less robust. The forecast from one consultant has muted demand growth through 2015. As domestic and global GDP growth rates improve, demand growth begins to materialize. This growth is led by natural gas utilized for power generation in support of renewable energy, and by coal plant retirements caused by new EPA regulations. Additionally, widespread adoption of natural gas for transportation and LNG exports increase demand in later years of the forecast. The forecast from one of the consultants has growth driven almost entirely by natural gas generation. LNG exports are also included in this forecast at a very modest level beginning in 2018.

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 natural gas supplies located in the Rocky Mountains. Table 7.3 presents western natural gas basin differentials from Henry Hub prices. Prices converge over the course of the study as new pipelines and sources of natural gas materialize. To illustrate the seasonality of natural gas prices, monthly Stanfield price shapes in Table 7.4 show selected forecast years.

Table 7.3: Natural Gas Price Basin Differentials from Henry Hub

Basin	2015	2020	2025	2030
Stanfield	101%	95%	94%	96%
Malin	102%	97%	95%	98%
Sumas	96%	94%	93%	95%
AECO	90%	87%	85%	87%
Rockies	100%	92%	86%	85%
Southern CA	106%	102%	103%	106%

Table 7.4: Monthly Price Differentials for Stanfield from Henry Hub

Month	2015	2020	2025	2030
Jan	103.3%	95.3%	93.3%	94.2%
Feb	102.6%	96.1%	93.1%	94.4%
Mar	103.1%	97.8%	96.7%	98.6%
Apr	101.7%	96.8%	93.4%	96.0%
May	98.8%	94.5%	91.9%	93.9%
Jun	98.6%	94.0%	92.0%	92.9%
Jul	98.6%	93.9%	91.8%	94.4%
Aug	98.3%	93.6%	92.9%	95.1%
Sep	97.7%	93.7%	92.7%	95.2%
Oct	99.1%	94.7%	93.6%	95.9%
Nov	103.2%	98.2%	97.3%	99.0%
Dec	102.5%	96.7%	94.6%	98.1%

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 can cost less than conventional natural gas production because of economies of scale, near elimination of exploration risks, standardization, and sophisticated production techniques that streamline costs and minimize the time from drilling to market delivery. Shale gas will continue to be a major factor in the natural gas marketplace, holding down both prices and volatility over the long run as production 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.

Shale gas is not without controversy. Concerns about water, air, noise, and seismic impacts arise 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 potential elevated seismic activity near drilling sites are also concerns. State and federal agencies are reviewing the environmental impacts of this production method. As a result, unconventional natural gas production has stopped in some areas. Increased environmental protections might change 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 and global LNG prices. Numerous planned re-gasification terminals are on hold or cancelled. Some facilities are seeking approvals to become LNG exporters rather than importers. These changes appear to affect natural 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, as British Columbia traditionally has provided significant natural gas supplies to the northwest United States.

Coal

This IRP models no new coal plants in the Western Interconnect, so coal price forecasts affect only existing facilities. The average annual price increase over the IRP timeframe is 2.9 percent based on Energy Information Administration estimates for Wyoming Coal Prices. For Colstrip Units 3 and 4, Avista used escalation rates based on expectations from existing contracts.

Hydroelectric

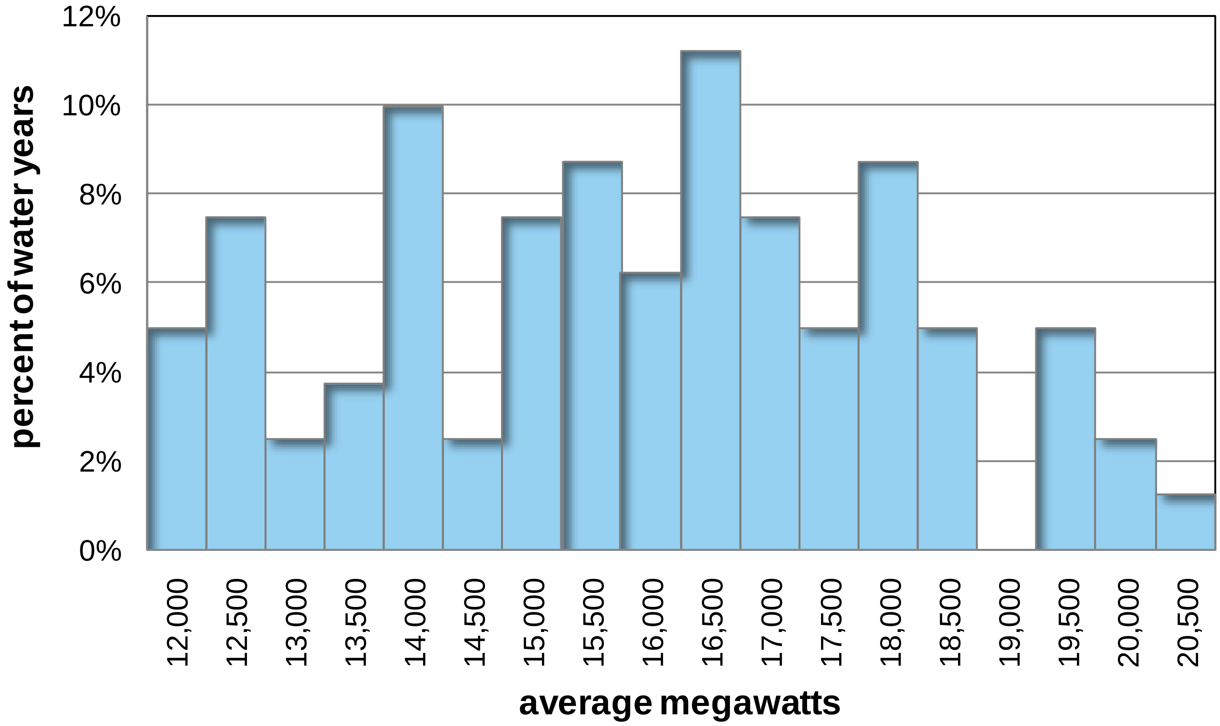
The Northwest U.S., British Columbia, and California have substantial hydroelectric generation capacity. A favorable characteristic of hydroelectric power is its ability to provide near-instantaneous generation up to and potentially beyond its nameplate rating. This characteristic is valuable for meeting peak load, following general intra-day load trends, shaping energy for sale during higher-valued hours, and integrating variable generation resources. The key drawback to hydroelectricity is its variable and limited fuel supply.

This IRP uses an 80-year hydro record from the 2014 BPA rate case. The study provides monthly energy levels for the region over an 80-year hydrological record spanning 1928 to 2009. This IRP also includes BPA hydro estimates for the 80-year record for British Columbia and California. The 80-year record is less than 1 percent lower than the 70-year record used in previous IRPs.

Many IRP analyses use an average of the 80-year hydroelectric record; whereas stochastic studies randomly draw from the 80-year record, as the historical distribution of hydroelectric generation is not normally distributed. Avista does both. Figure 7.6 shows the average hydroelectric energy of 15,706 aMW in Washington, Oregon, Idaho, and western Montana. The chart also shows the range in potential energy used in the stochastic study, with a 10th percentile water year of 12,370 aMW (-21 percent), and a 90th percentile water year of 18,475 aMW (+18 percent).

AURORA^{XMP} maps each hydroelectric plant to a load zone, creating a similar energy shape for all hydro projects in a load zone. For Avista hydroelectric plants, AURORA^{XMP} uses the output from proprietary software with a better representation of operating characteristics and capabilities. For modeling, AURORA[XMP] 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.

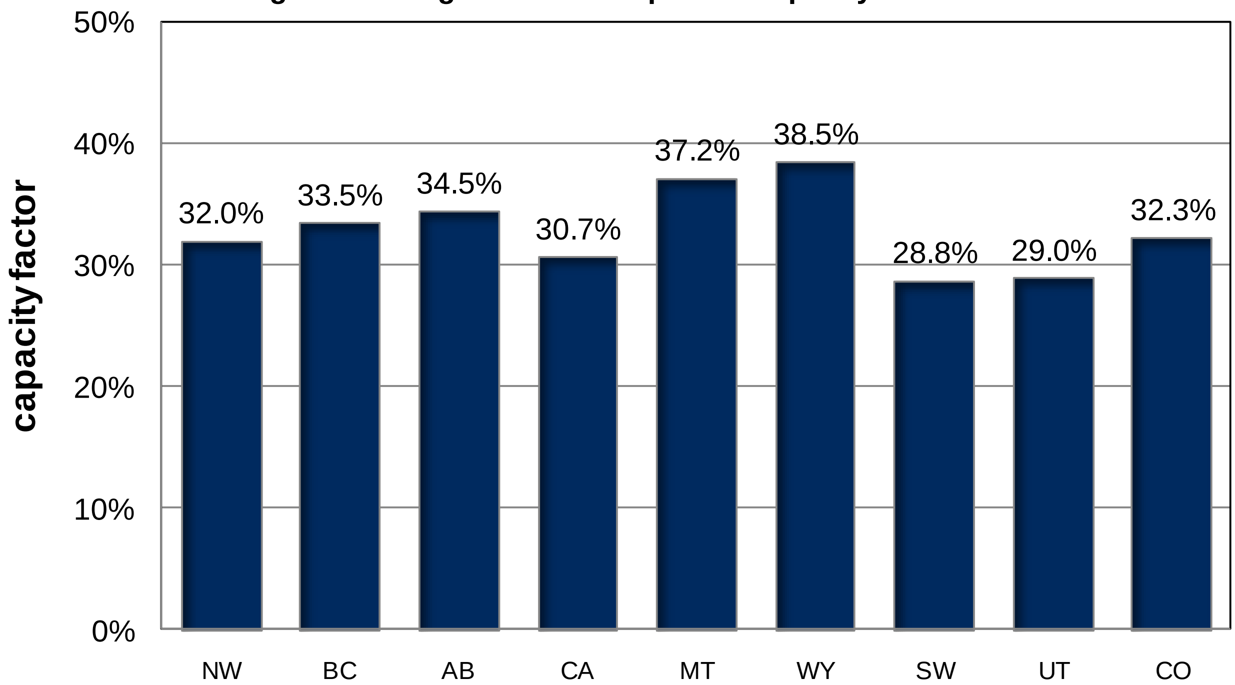
Figure 7.6: Northwest Expected Energy



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 BPA and the National Renewable Energy Laboratory (NREL) wind data.

Figure 7.7: Regional Wind Expected Capacity Factors



Greenhouse Gas Emissions

Greenhouse gas regulation is a significant risk for the electricity marketplace today because of the industry's heavy reliance on carbon-emitting thermal power generation. Reducing carbon emissions at existing power plants, and the construction of low- and non-carbon-emitting technologies, changes the resource mix over time. Since 2007, carbon emissions from electric generation have fallen from highs by nearly 11 percent due to reduced loads and lower coal generation levels.

Future carbon emissions could continue to fall due to fundamental market changes. To accelerate the reductions, national legislation would be required, but this plan assumes that no federal cap and trade regulations or carbon tax will constrain greenhouse emissions in the IRP timeframe. However, EPA regulations aimed at reducing air pollutants such as NO_X and SO_2 will have some marginal impacts on the generation fleet profile. In the interim, California and some Canadian provinces have greenhouse reduction goals and costs on greenhouse gas emissions. Within the Expected Case's market price forecast of this IRP, only existing greenhouse gas regulations and a forecast of expected plant closures based on current EPA regulations affect the market. No national cap and trade or carbon tax is included with the exception of a carbon-pricing scenario discussed later in this chapter. Environmental regulations decrease or maintain existing greenhouse gas emissions levels, instead of the cap and trade or tax mechanisms used in Avista's earlier IRPs.

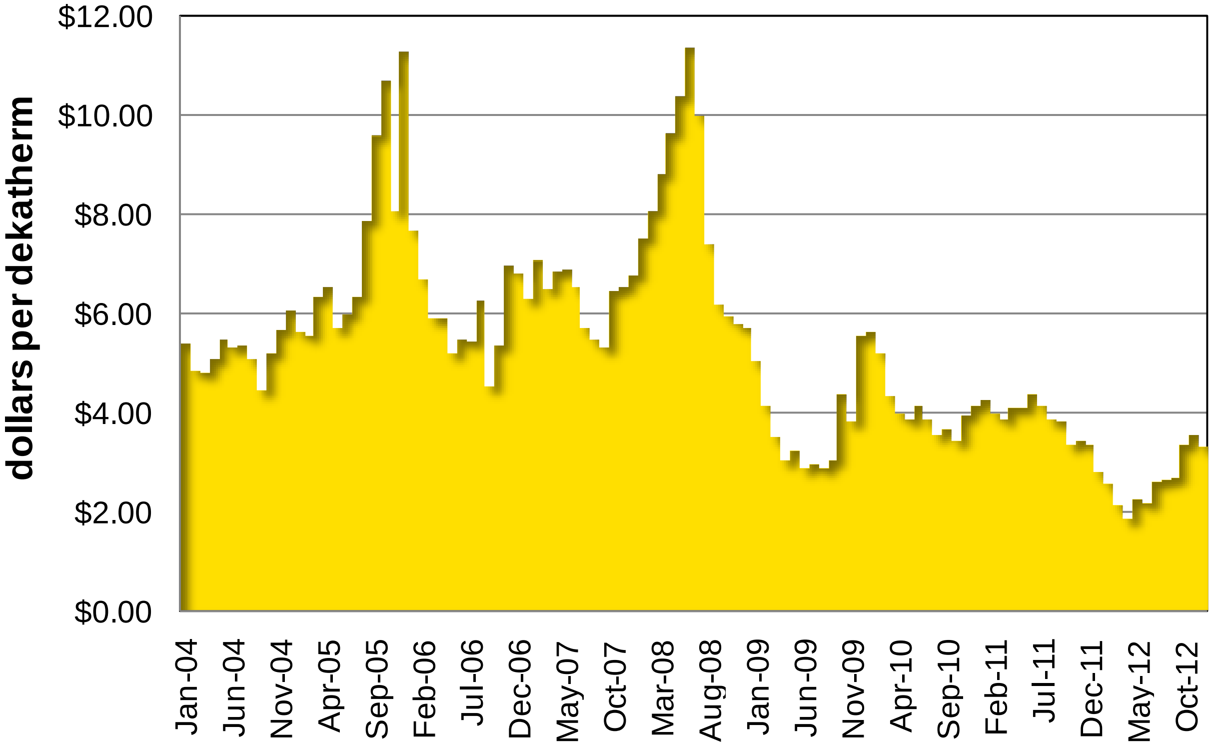
Risk Analysis

To account for future electricity price uncertainty, 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 instead of a point estimate, as point estimates are unlikely to forecast underlying assumptions perfectly. Stochastic price forecasts develop a more robust resource strategy by accounting for tail risk. This IRP developed 500 20-year market futures to provide a distribution of the marketplace and illustrate potential tail risk outcomes. The next several pages discuss the input variables driving market prices, and describe the methodology and the range in inputs used in the modeling process.

Natural Gas

Natural gas prices are among the most volatile of any traded commodity. Daily Stanfield prices ranged between $1.72 and $13.69 per dekatherm between 2004 and 2012. Average Stanfield monthly prices since January 2004 are in Figure 7.8. Prices retreated from 2008 highs to a monthly price of $1.87 per dekatherm in April 2012.

Figure 7.8: Historical Stanfield Natural Gas Prices (2004-2012)



There are several methods to stochastically model natural gas prices. This IRP retains the 2011 IRP method with the mean prices discussed in Figure 7.5 as the starting point. Prices vary using historical month-to-month volatility and a lognormal distribution.

Figure 7.9 shows Stanfield natural gas price duration curves for 2014, 2020, 2026 and 2032. The chart illustrates a larger price range in later years, reflecting a growing distribution. Shorter-term prices are more certain due to additional market information and the quantity of near term natural gas trading. Another view of the forecast is in Figure 7.10. The mean price in 2014 is $3.95 per dekatherm, represented by the horizontal bar; the median level is $3.89 per dekatherm. The bottom and top of the bars represent the 10th and 90th percentiles. The bar length indicates price uncertainty.

Figure 7.9: Stanfield Annual Average Natural Gas Price Distribution

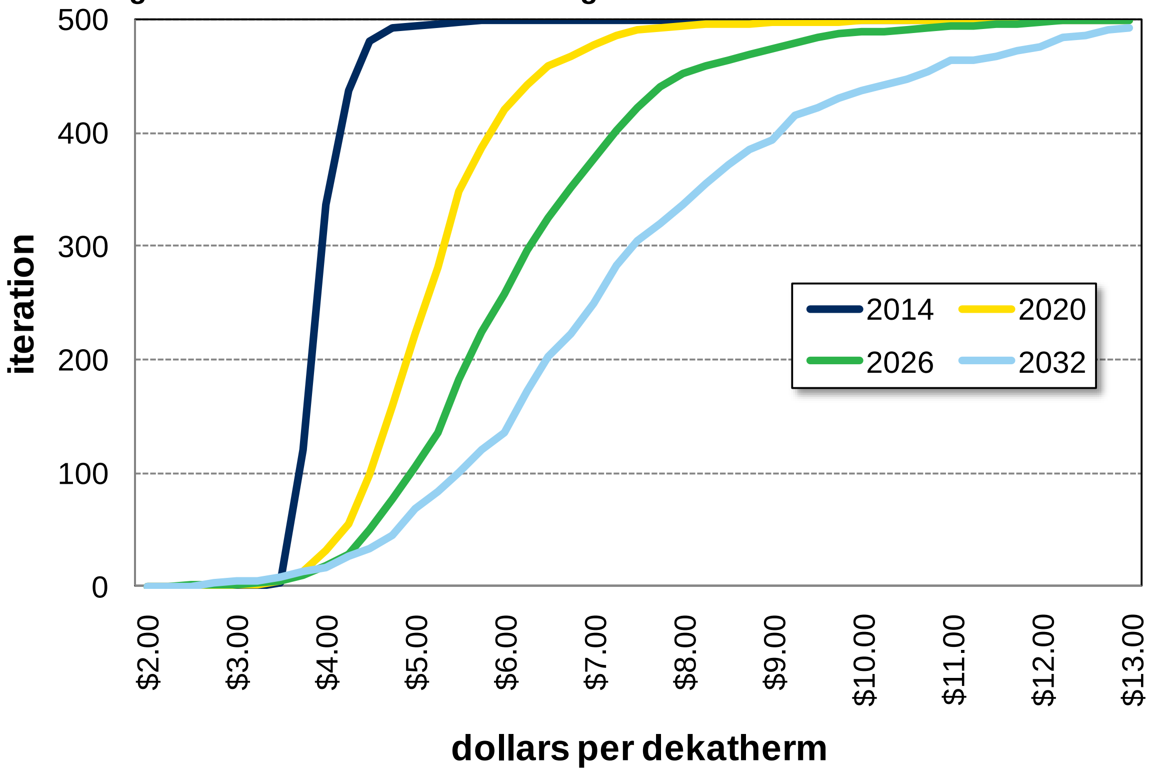
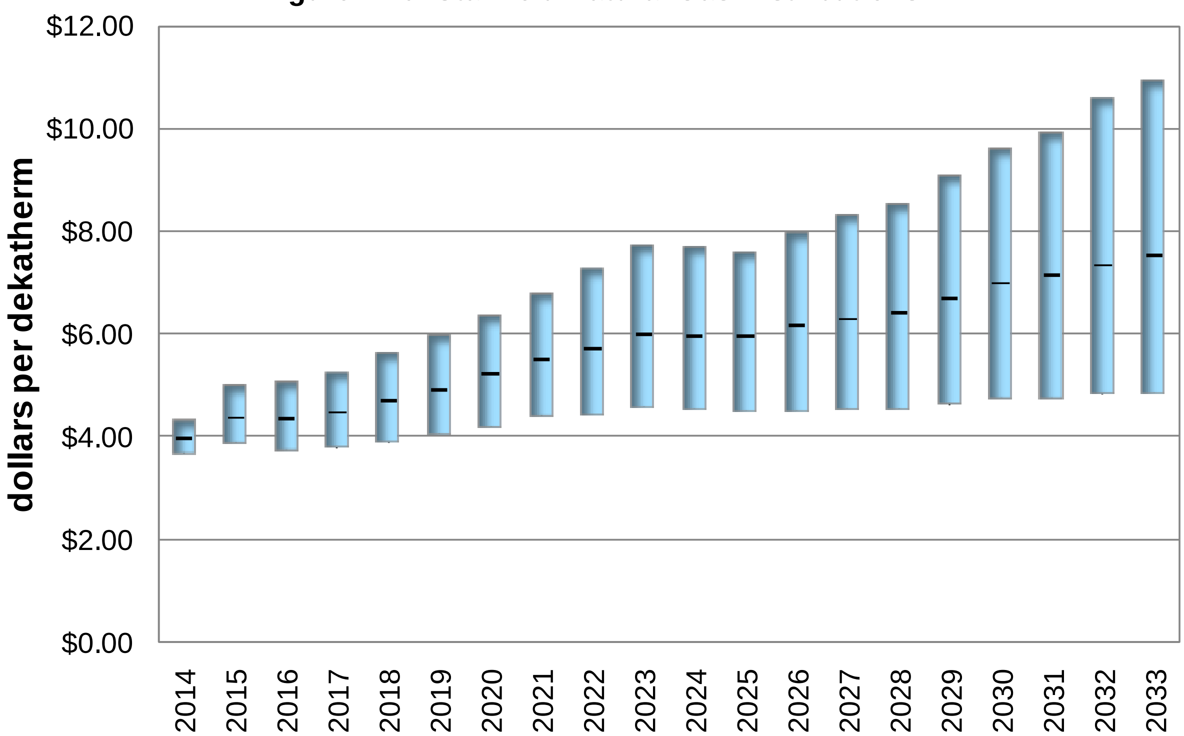


Figure 7.10: Stanfield Natural Gas Distributions



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

Avista continues to use a method it first adopted for its 2003 IRP to model weather variation. FERC Form 714 data for the years 2007 through 2011 for the Western Interconnect form the basis for the analysis. Correlations between the Northwest and other Western Interconnect load areas represent how loads change together across the larger system. This method avoids oversimplifying the Western Interconnect load picture. Absent the use of correlation, stochastic models will offset changes in one variable with changes in another, thereby virtually eliminating the possibility of modeling correlated excursions actually experienced by a system. Given the high degree of interdependency across the Western Interconnect created by significant intertie connections, the additional accuracy from modeling loads in this matter is crucial for understanding variation in wholesale electricity market prices. It is also crucial for understanding the value of peaking resources and heir use in meeting system variation.

Tables 7.5 and 7.6 present the load correlations used for the 2013 IRP. Statistics are relative to the Northwest load area (Oregon, Washington and 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 2007 to 2011 period. For regions and periods with NotSig and Mix results, no correlations are modeled. Tables 7.7 and 7.8 provide the coefficient of determination values for each zone.[3]

Table 7.5: January through June Load Area Correlations

Area	Jan	Feb	Mar	Apr	May	Jun
Alberta	Not Sig	17%	25%	8%	Mix	Mix
Arizona	8%	42%	Mix	Not Sig	Mix	Not Sig
Avista	89%	85%	84%	83%	47%	53%
British Columbia	91%	88%	71%	77%	52%	61%
California	Not Sig	Not Sig	Mix	Mix	17%	32%
CO-UT-WY	-7%	Mix	Mix	-20%	-3%	-17%
Montana	27%	30%	72%	63%	10%	18%
New Mexico	Not Sig	Not Sig	Mix	Not Sig	Mix	Mix
North Nevada	62%	27%	Not Sig	Not Sig	Mix	18%
South Idaho	84%	79%	68%	Not Sig	Not Sig	29%
South Nevada	17%	56%	Mix	Not Sig	Mix	Not Sig

[3] The coefficient of determination is the standard deviation divided by the average.

Table 7.6: July through December Load Area Correlations

Area	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	Not Sig	Mix	16%	Not Sig	50%	Not Sig
Arizona	Not Sig	Not Sig	Mix	Not Sig	Mix	Not Sig
Avista	66%	77%	68%	77%	93%	91%
British Columbia	70%	38%	19%	79%	90%	81%
California	10%	Not Sig	Not Sig	-11%	Mix	Not Sig
CO-UT-WY	-10%	-2%	-5%	Not Sig	22%	Mix
Montana	Mix	8%	8%	Not Sig	77%	73%
New Mexico	Mix	Mix	Mix	-9%	Not Sig	Not Sig
North Nevada	52%	44%	26%	Not Sig	77%	52%
South Idaho	51%	64%	Not Sig	Mix	86%	89%
South Nevada	Not Sig	25%	Mix	-8%	Mix	56%

Table 7.7: Area Load Coefficient of Determination (Standard Deviation/Mean)

Area	Jan	Feb	Mar	Apr	May	Jun
Alberta	2.9%	2.5%	3.1%	2.6%	2.7%	3.0%
Arizona	5.1%	5.0%	3.5%	5.8%	8.6%	10.3%
Avista	6.9%	5.4%	6.3%	5.9%	5.2%	5.7%
British Columbia	4.8%	4.4%	5.1%	5.3%	5.2%	3.9%
California	5.4%	5.1%	5.3%	5.9%	7.4%	8.1%
CO-UT-WY	4.6%	4.6%	4.4%	3.7%	4.8%	7.9%
Montana	5.5%	4.4%	4.2%	4.3%	3.7%	5.9%
New Mexico	4.5%	5.0%	4.3%	4.6%	6.9%	6.7%
Northern Nevada	2.8%	3.0%	3.2%	3.2%	4.3%	5.5%
Pacific Northwest	6.7%	6.0%	5.6%	5.8%	4.7%	4.3%
South Idaho	6.0%	5.6%	5.1%	6.1%	8.3%	14.7%
South Nevada	5.0%	4.1%	3.5%	6.5%	10.7%	12.7%
Baja Mexico	5.4%	5.1%	5.3%	5.9%	7.4%	8.1%

Table 7.8: Area Load Coefficient of Determination (Standard Deviation/Mean)

Area	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	3.1%	3.2%	2.7%	2.7%	2.9%	3.1%
Arizona	6.5%	6.7%	7.8%	9.2%	4.0%	5.0%
Avista	6.2%	7.2%	5.3%	5.4%	7.0%	6.8%
British Columbia	4.8%	4.4%	4.2%	5.0%	7.0%	5.8%
California	7.0%	7.6%	9.1%	6.7%	5.7%	5.4%
CO-UT-WY	6.7%	5.7%	5.7%	4.1%	4.6%	4.4%
Montana	5.0%	5.0%	3.6%	3.9%	5.1%	5.1%
New Mexico	5.9%	5.4%	6.0%	5.6%	4.6%	4.6%
Northern Nevada	4.7%	4.8%	4.6%	2.8%	3.7%	3.5%
Pacific Northwest	5.5%	5.6%	4.4%	5.1%	7.2%	8.0%
South Idaho	5.1%	7.0%	8.9%	5.7%	7.0%	6.1%
South Nevada	6.6%	7.2%	10.0%	8.7%	3.6%	4.2%
Baja Mexico	7.0%	7.6%	9.1%	6.7%	5.7%	5.4%

Hydroelectric Variation

Hydroelectric generation is the most commonly modeled stochastic variable in the Northwest because it has a large impact on regional electricity prices than other variables. The IRP uses an 80-year hydro record starting with the 1928/29 water year. Every iteration starts with a randomly drawn water year from the historical record, so each water year is selected approximately 125 times in the study (500 scenarios x 20 years / 80 water year records). There is some debate in the Northwest over whether the hydroelectric record has year-to-year correlation. Avista did not model year-to-year correlation after finding a modest 35 percent correlation over the 80-year record.

Wind Variation

Wind has the most volatile short-term generation profile of any large-scale resource presently available to utilities. Storage, apart from some integration with hydroelectric projects, is not a financially viable alternative at this time. This makes it necessary to capture wind volatility in the power supply model to determine its value in the wholesale power market. Accurately modeling wind resources requires hourly and intra-hour generation shapes. For regional market modeling, the representation is similar to how AURORA$^{\underline{XMP}}$ 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 an 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 wind resource options for Avista.

Ten potential 8,760-hour annual wind shapes represent each geographic region or facility. Each year contains a wind shape drawn from these 10 representations. 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 is auto-correlated.[4]
3. The average and standard deviation of each load area’s wind capacity factor is consistent with the expected amount of energy for a particular area in the year and month.
4. The relationship between on- and off-peak wind energy is consistent with historic wind conditions. For example, more energy in off-peak hours than on-peak hours where this has been experienced historically.

[4] Adjoining hours or groups of hours are correlated to each other.

5. Hourly capacity factors for a diversified wind region are never be greater than about 90 percent due to turbine outages and wind diversity within-area.

Absent meeting these conditions, it is unlikely any wind study provides a level of accuracy adequate for planning efforts. The methodology developed for the 2013 IRP attempts to adhere to the five requirements by first using a regression model based on historic data for each region. The independent variables used in the analysis were month, hour type (night or day), and 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 7.9. A Northwest region example of an 8,760-hour wind generation profile is in Figure 7.11. This example, shown in blue, has a 33 percent capacity factor. Figure 7.12 shows actual 2012 generation recorded by BPA Transmission; in 2012, the average wind fleet in BPA's balancing authority had a 26.2 percent capacity factor.

Table 7.9: Expected Capacity factor by Region

Region	Capacity Factor	Region	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 7.11: Wind Model Output for the Northwest Region

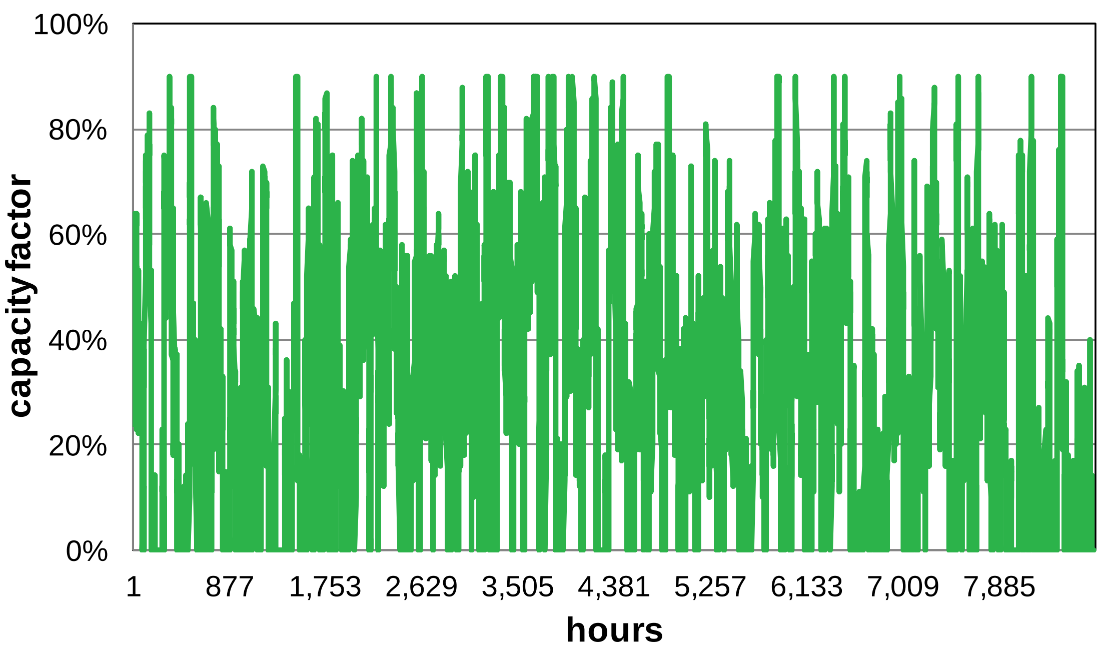
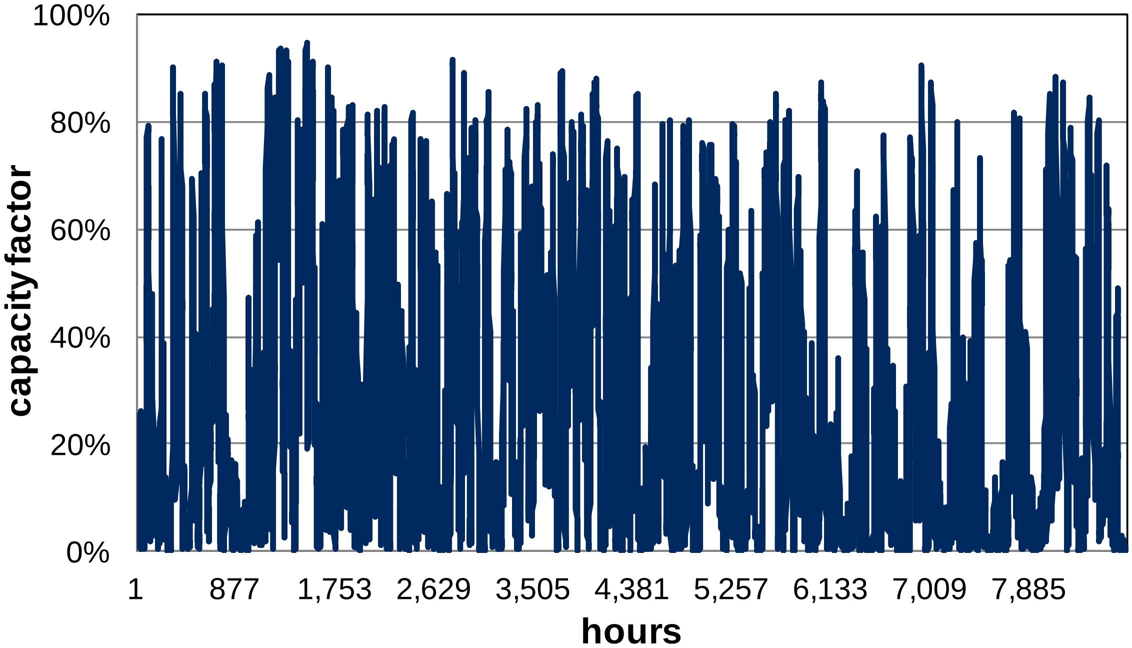


Figure 7.12: 2012 Actual Wind Output BPA Balancing Authority[5]



There is speculation that 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 wind data to test this hypothesis. Where correlation exists, it would be optimal to run the model 80 historical wind years with matching historical water years.

Forced Outages

Generator forced outages are represented by a simple average reduction to maximum capability in most deterministic market modeling studies. This over simplification generally represents expected values well; however, it is better to represent the system more accurately in stochastic modeling 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 natural gas-fired, coal, and nuclear plants with generating capacities in excess of 100 MW. Plants on forced outage smaller than 100 MW do not have a material impact on market prices and therefore are not modeled. Forced outage rates and mean time to repair data for the larger units in the WECC come from analyzing the North American Electric Reliability Corporation's Generating Availability Data System database.

Market Price Forecast

An optimal resource portfolio cannot ignore the extrinsic value inherent in its resource choices. The 2013 IRP simulation compares each resource's expected hourly output using forecasted Mid-Columbia hourly prices over 500 iterations of Monte Carlo-style scenario analysis.

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

Hourly zonal electricity prices are equal to either the operating cost of the marginal unit in the modeled zone, or the economic cost to generate and move power from one zone to another. 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 simply summing of the capacity needs of individual utilities in the region. This reflects the fact that Western regions can have resource surpluses even where individual utilities are deficit. This imbalance can be due in part to ownership of regional generation by independent power producers, and possible differences in planning methodologies used by utilities in the region.

AURORA^{XMP} assigns market values to each resource alternative available to the PRS, but the 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 analyses to help determine an optimal resource strategy. Risk analysis uses several market price forecasts with assumptions differing from the expected case, or changes the underlying statistics of a study. The modeling splits alternate cases 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, and wind generation shapes. The IRP includes two stochastic studies—an Expected Case and a case with greenhouse gas emissions pricing. All remaining studies were deterministic; modifying one or more key input assumptions and using average values for the remaining variables.

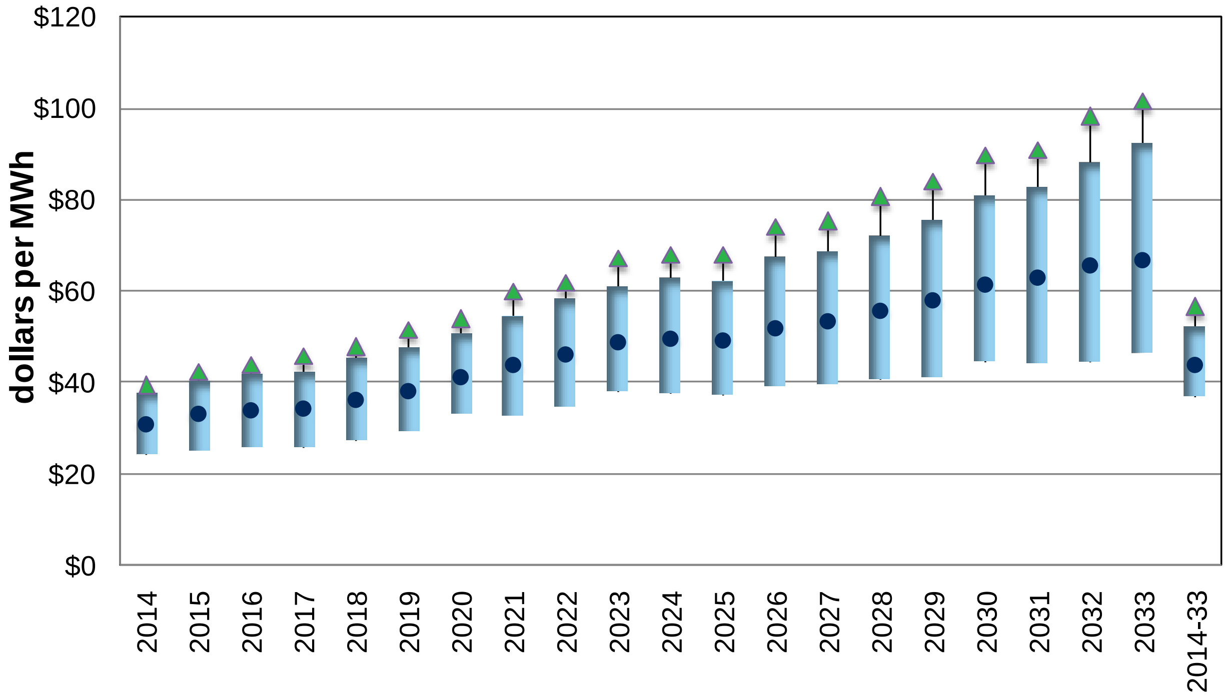
Mid-Columbia Price Forecast

The Mid-Columbia is Avista's primary electricity trading hub. The Western Interconnect also has trading hubs at the California/Oregon Border (COB), Four Corners (corner of northwestern New Mexico), Palo Verde (central Arizona), SP15 (southern California), NP15 (northern California) and Mead (southern Nevada). The Mid-Columbia market is usually the lowest cost because of the hubs dominant hydroelectric generation assets, though other markets can be less expensive when Rocky Mountain-area natural gas prices are low and natural gas-fired generation is setting marginal power prices.

Fundamentals-based market analysis is critical to understanding the power industry environment. 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 natural gas prices, load, wind generation, hydroelectric generation, forced outages, and others. Each study simulates the entire Western Interconnect hourly between 2014 and 2033. The analysis used 25 central processing units (CPUs) linked to a SQL server, creating over 45 GB of data in 3,000 CPU-hours.

The stochastic market average prices are similar to the results from the deterministic model. Figure 7.13 shows the stochastic market price results as horizontal bars represent the 10th to 90th percentile range for annual prices, the circle shows the average prices, while the triangle represents the 95th percentile. The 20-year nominal levelized price is $44.08 per MWh. The levelized deterministic price is $0.10 per MWh higher than the levelized stochastic price presented in Figure 7.14.

Figure 7.13: 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. Spreads between on- and off-peak prices average $9.76 per MWh over 20 years. The 2011 IRP annual average nominal price was $70.50 per MWh. The reduction in pricing is a result of lower natural gas prices, lower loads, higher percentages of new low-heat-rate natural gas plants, and the elimination of direct carbon pricing.

Table 7.10: Annual Average Mid-Columbia Electric Prices ($/MWh)

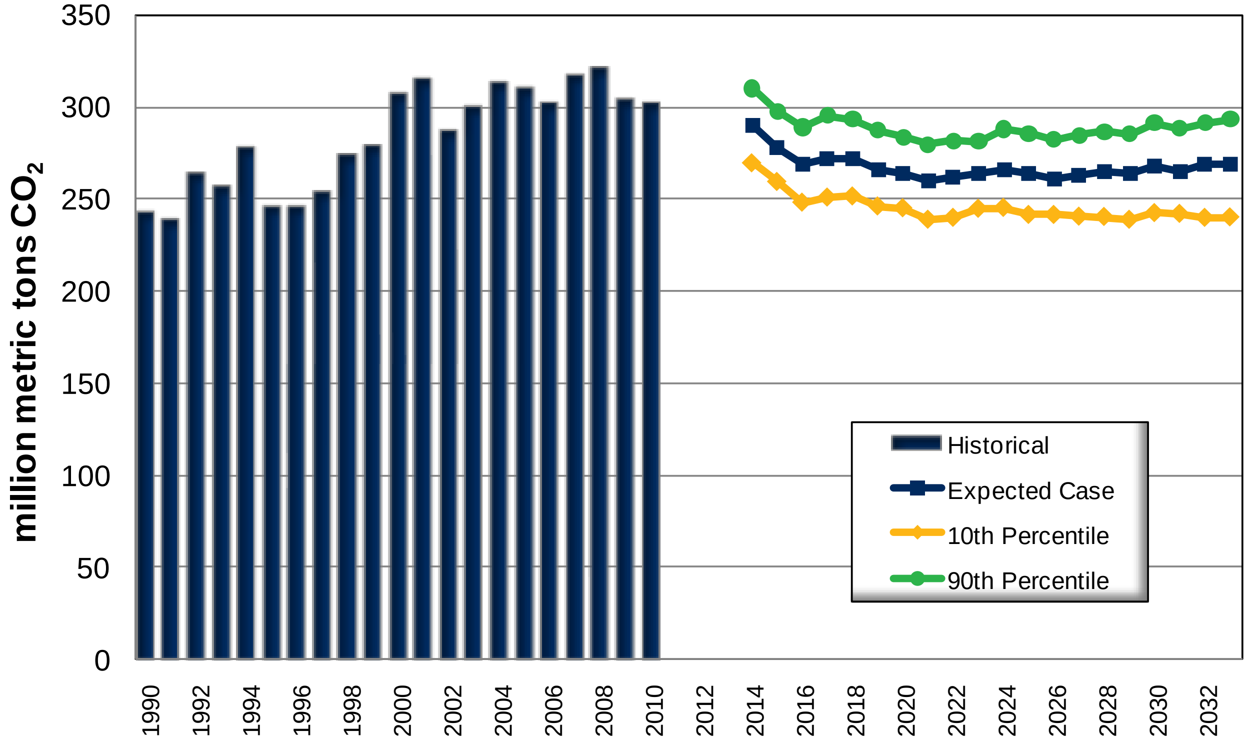
Year	Flat	Off-Peak	On-Peak
2014	31.02	25.63	35.18
2015	33.06	27.57	37.17
2016	33.91	28.52	37.93
2017	34.14	28.78	38.21
2018	36.18	30.90	40.16
2019	38.29	32.99	42.17
2020	41.34	36.15	45.06
2021	43.72	38.34	47.65
2022	46.06	40.49	50.04
2023	48.85	43.29	52.92
2024	49.52	43.78	53.64
2025	49.35	43.59	53.57
2026	52.04	46.31	56.16
2027	53.37	47.60	57.70
2028	55.65	49.77	59.79
2029	57.94	51.94	62.27
2030	61.39	55.12	66.06
2031	63.06	56.48	67.96
2032	65.65	59.02	70.57
2033	66.97	60.25	71.94
Levelized	**44.08**	**38.46**	**48.22**

Greenhouse Gas Emission Levels

Greenhouse gas levels could increase over the study period absent regulatory policies reversing the trend. This IRP does not include a legislative mandate to reduce greenhouse gases in the Expected Case, such as a cap and trade program or a carbon tax. Rather the forecast includes cap-and-trade pricing in California and power plant shut downs due to EPA and state regulations. This IRP models the California and Canadian carbon laws. Further discussion of carbon policy is in Chapter 4, Policy Considerations.

Figure 7.14 shows historic and expected greenhouse gas emissions for the Western Interconnect. Greenhouse gas emissions from electric generation decrease 10.8 percent between 2010 and 2033. The figure also includes the 10^{th} and 90^{th} percentile statistics from the 500-iteration dataset. The reduction drivers are a lower load forecast when compared to prior IRPs, lower natural gas prices, renewable portfolio standards, and forecasted coal-fired generation retirements.

Figure 7.14: Western States Greenhouse Gas Emissions

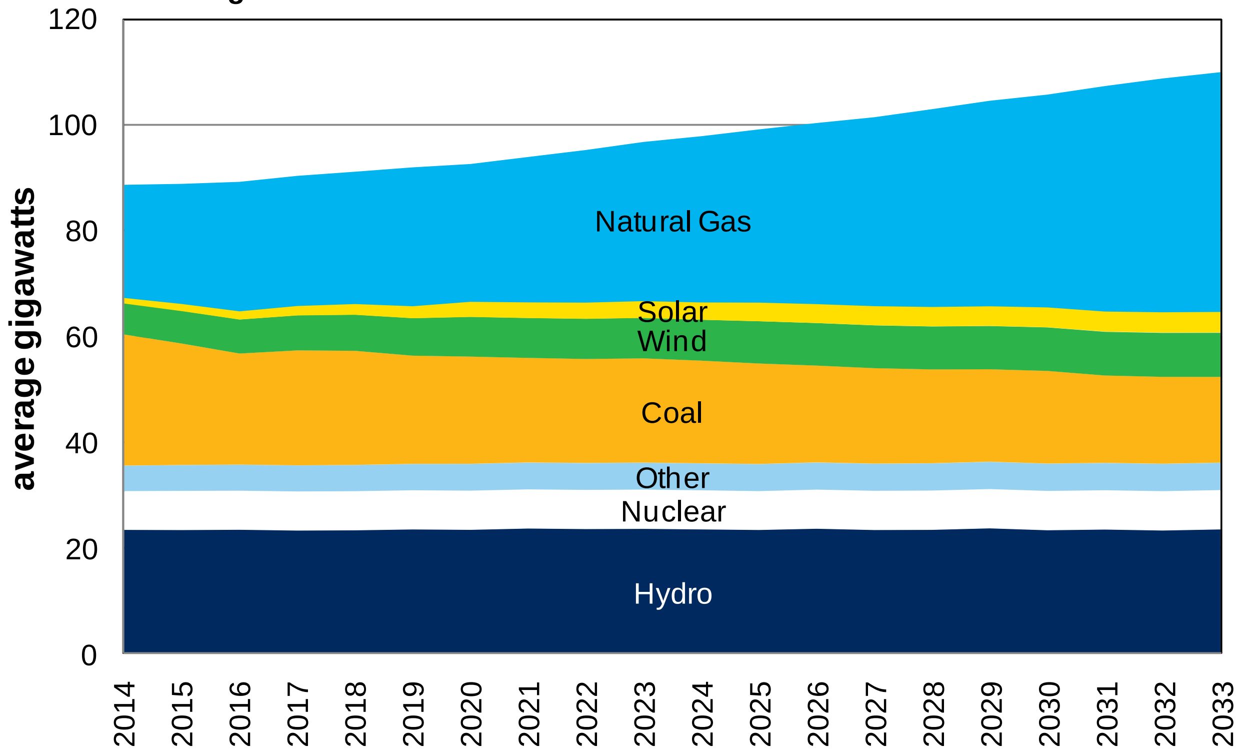


Resource Dispatch

State-level RPS goals and greenhouse gas legislation changes resource dispatch decisions and affect future power prices. The Northwest already is witnessing the market-changing effects of more than an 8,500 MW wind fleet. Figure 7.15 illustrates how natural gas will increase its contribution as a percentage of Western Interconnect generation, from 24 percent in 2014 to 41 percent 2033. The increase offsets coal-fired generation; coal drops from 28 percent in 2014 to 15 percent in 2034. Utility-owned solar and wind increase from 8 percent in 2014 to 11 percent by 2033. New renewable generation sources also reduce coal generation, but natural gas is the primary resource meeting load growth.

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

Figure 7.15: Base Case Western Interconnect Resource Mix



Scenario Analysis

Scenario analysis evaluates the impact of specific changes in underlying assumptions on the market, Avista's generation portfolio, and new generation resource options' values. In addition to the Expected Case, a stochastic greenhouse gas reduction case was studied: the Carbon Pricing Scenario. The case is similar to the 2011 IRP Expected Case. In addition to stochastic market scenarios, deterministic scenarios explain the impacts of lower and higher natural gas prices and higher state RPS. Prior IRPs 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 section is more limited in this IRP. Additional scenarios illustrate impacts potential future policies might have on the industry, and how Avista could respond.

No Coal Retirement Scenario

The Expected Case price forecast includes speculative coal plant retirements based on how Avista understands state and federal environmental policies, and the effect on power generation in the Western Interconnect. The No Coal Retirement scenario models the impact coal retirements might have on market prices, greenhouse gas emissions, and the costs to meet customer load growth. In the event coal plants are not retired, the impact on wholesale power prices is minimal. The levelized prices of power over the 20-year period is $1.25 per MWh lower than the Expected Case (see Figure 7.16), with the largest annual price difference being 4.4 percent.

Figure 7.16: Mid-Columbia Prices Comparison with and without Coal Plant Retirements

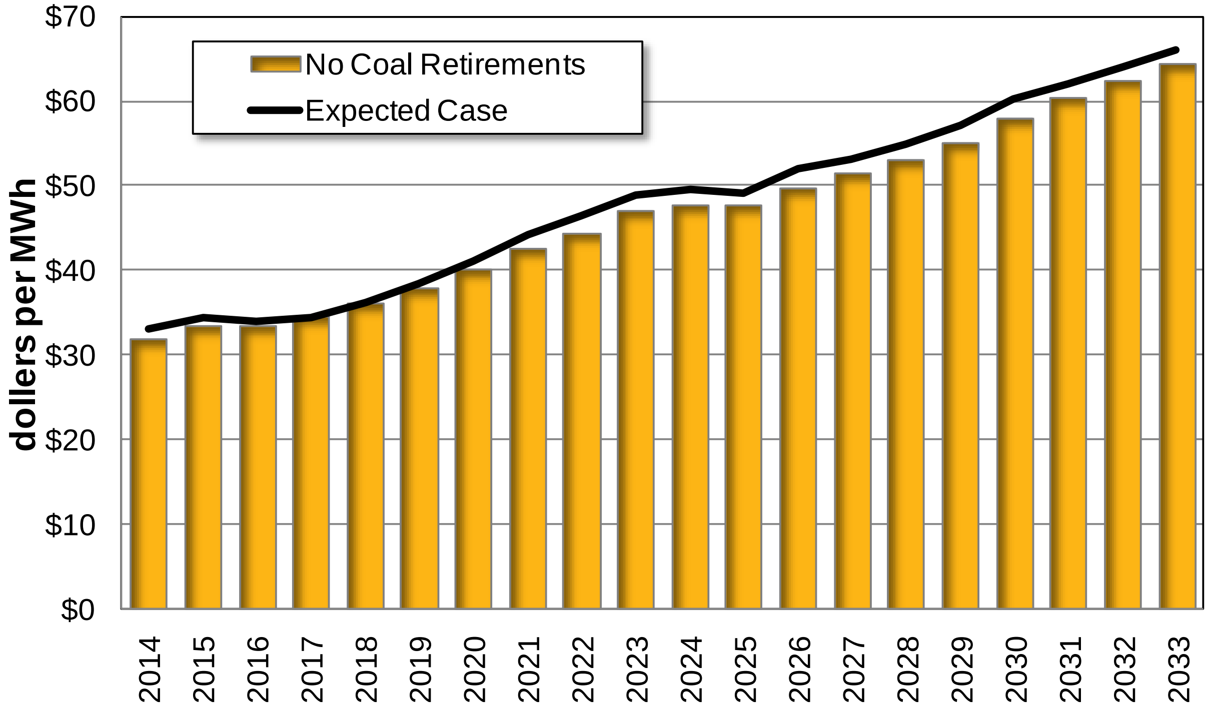
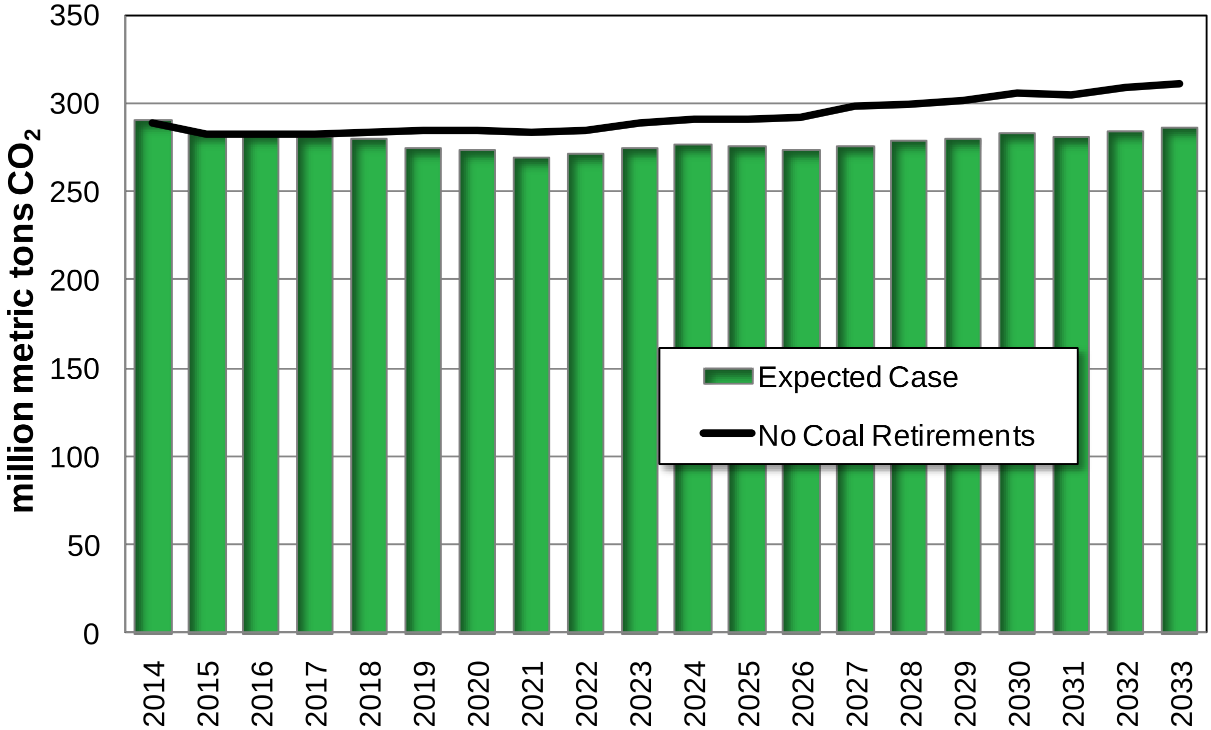


Figure 7.17 illustrates the difference between greenhouse gas emissions with and without the coal plant retirements. Based on the model results and assumptions, emissions would be nearly 9 percent higher in 2033 without the assumed coal plant retirements. The coal plant retirements due to regulations has a similar greenhouse gas reduction as a carbon tax or cap and trade scheme, but does not have a substantial impact on market prices. With forced earlier retirement, coal plant owners will face replacement costs up front rather the delayed until carbon prices make coal uneconomic. As regulations continue to force coal plants to improve their environmental footprint, lower compliance costs could take shape as engineers focus on solutions to meet stricter guidelines to reduce air emissions.

The No Coal Retirement scenario allows an estimate of the short-term (20-year) cost of greenhouse gas reduction. This estimate takes into account the changes to the Western Interconnect resources' fuel and variable O&M costs. The analysis also takes into account capital cost changes reflecting investments in new capacity and its associated fixed O&M costs. Based on cost changes and carbon emission reductions, the implied 2019-2033 levelized price paid to reduce carbon emissions is $95.33 per metric ton (2014$) for the Western Interconnect.

Figure 7.17: Western U.S. Carbon Emissions Comparison



Carbon Pricing Scenario

In Avista's recent IRPs, the Expected Case has included explicit costs for greenhouse gas emissions. The Expected Case in this IRP does not include these costs explicitly. The political climate in the last several IRPs was more amenable to national greenhouse gas policies. To understand the costs and ramifications of a national greenhouse gas reduction policy, this scenario quantifies the potential outcomes. It considers four potential carbon mitigation alternatives. Figure 7.18 shows each alternative modeled as a cap and trade mechanism. Figure 7.19 shows the levelized electric market price results of these alternatives compared to the Expected case. The levelized costs are not substantially higher than the Expected Case, as the levelization methodology discounts later periods where carbon policies are expected; therefore, levelization masks future higher market prices for utility customers. Figure 7.20 shows the annual expected greenhouse gas emissions levels for each of the policies. The four potential outcomes represent a range of futures under different forms of greenhouse gas emissions legislation. Over the last nine years of this study the weighted average levelized price is $22.36 per metric ton, the high case is $55.06 and the low case is $19.15 per metric ton.

Figure 7.18: Greenhouse Gas Pricing Scenarios

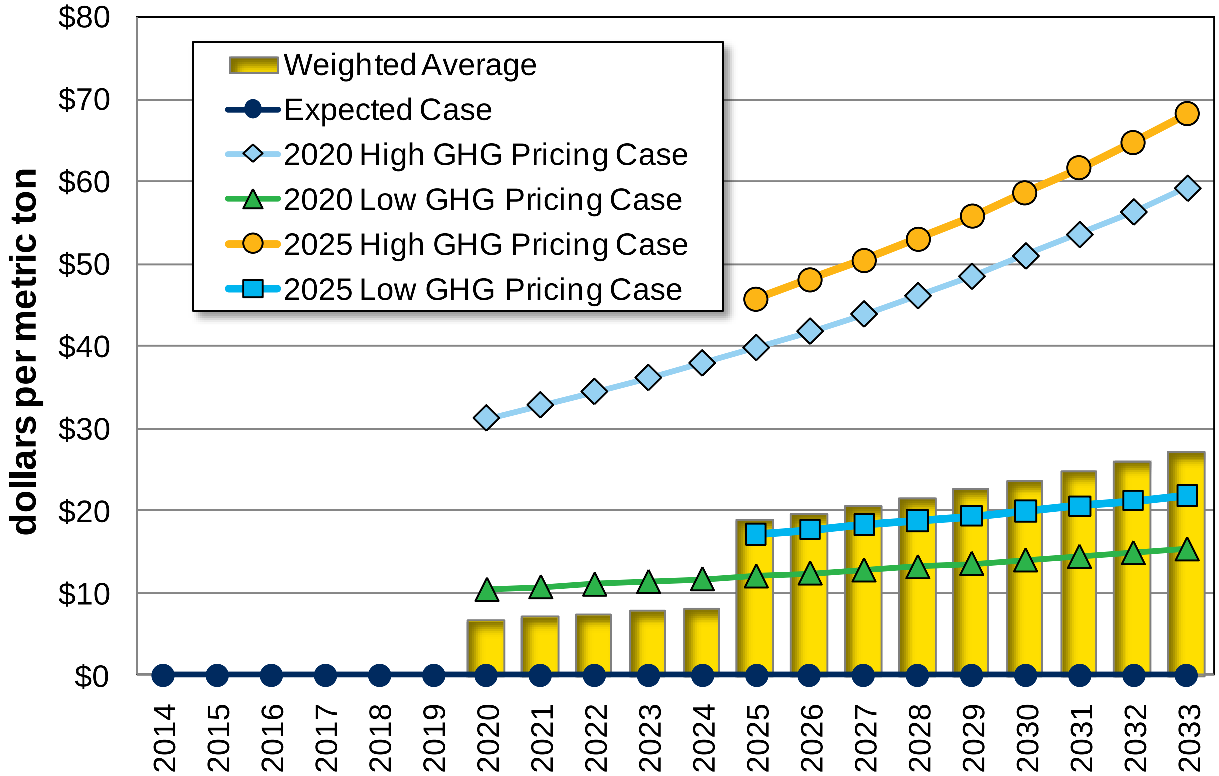


Figure 7.19: Nominal Mid-Columbia Prices for Alternative Greenhouse Gas Policies

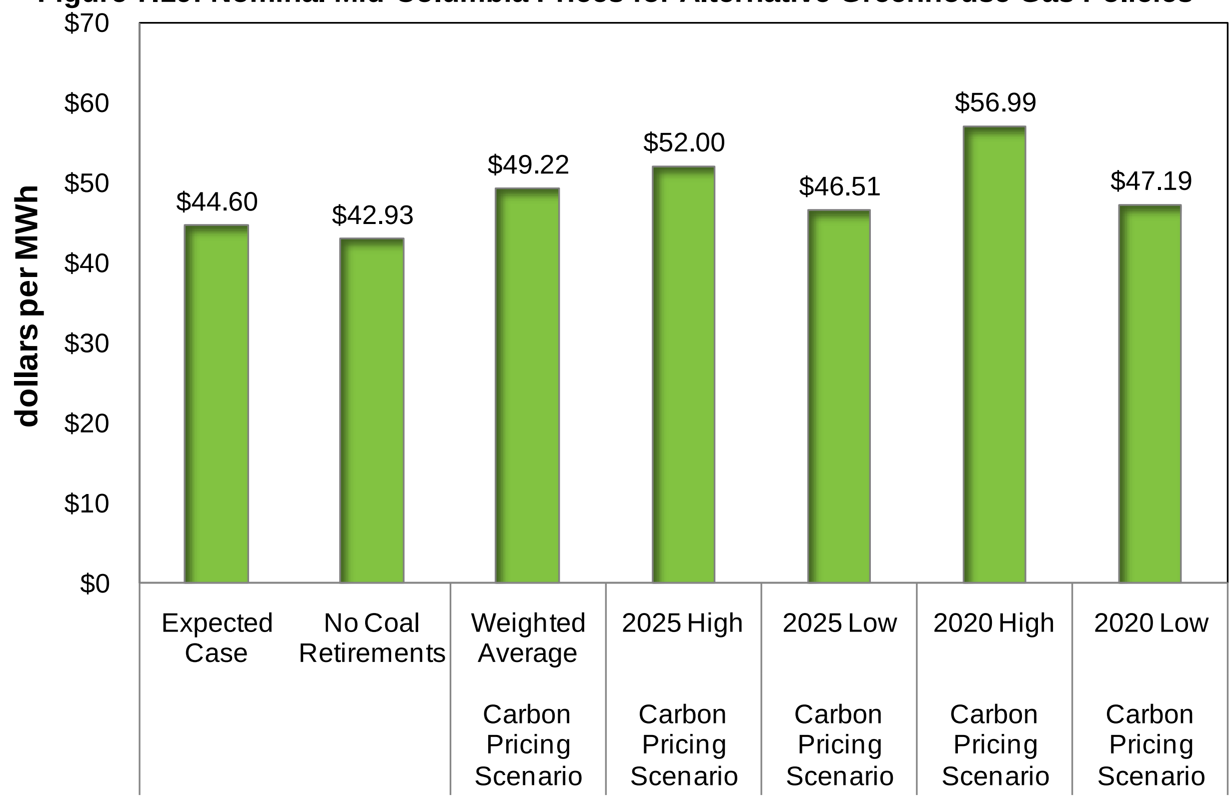
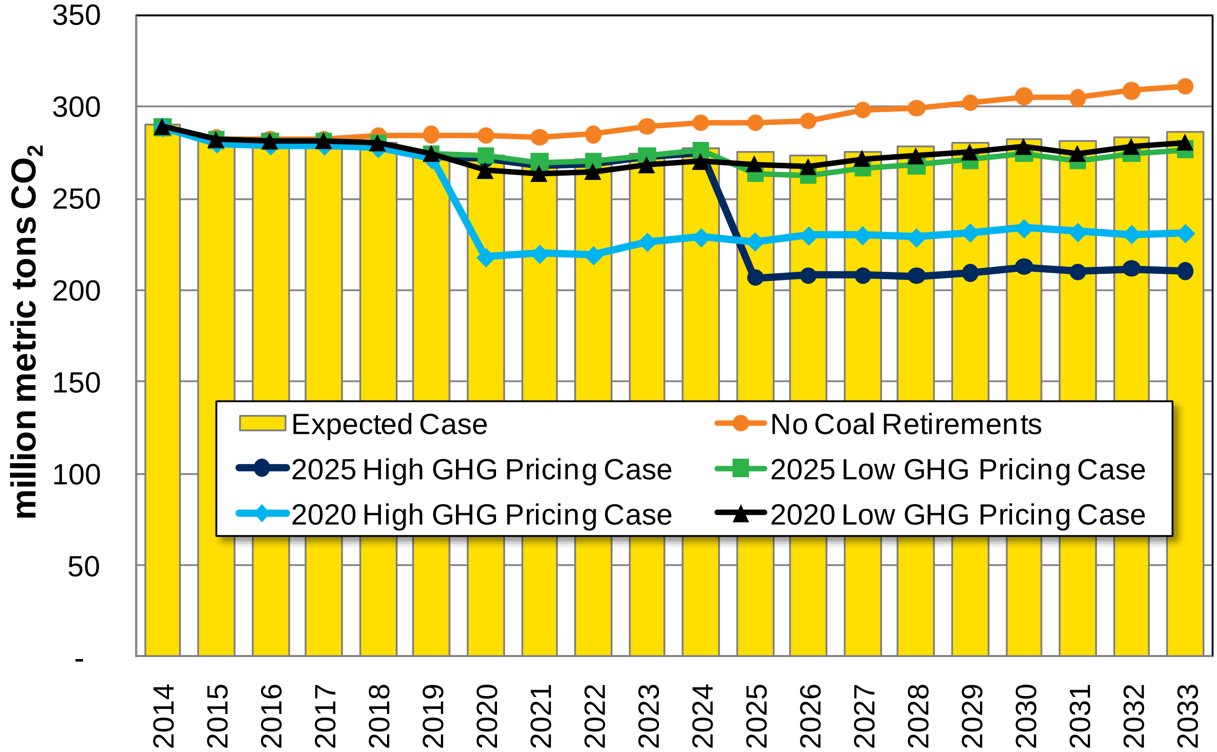


Figure 7.20: Annual Greenhouse Gas Emissions for Alternative Greenhouse Gas Policies



High and Low Natural Gas Price Scenarios

The high and low natural gas price scenarios provide important information about how a potential resource strategy might change if the natural gas prices vary substantially from the Expected Case. They also provide an overview of how the energy market behaves when natural gas prices vary. Over the past several years, as natural gas prices have fallen, certain resources, such as coal, are dispatching differently. For this IRP, Avista completed two natural gas pricing scenarios in addition to the stochastic cases. The stochastic cases' 500 natural gas scenarios are considered a better method to consider the risk of price changes, but these two scenarios are useful in understanding the fundamental market changes.

The high and low price scenarios assume prices either rise or decline up to 35 percent relative to the Expected Case over time. The Expected Case assumes a levelized price of $5.62 per dekatherm, while the high price scenario is $7.48. The low price scenario is $3.97 per dekatherm. Figure 7.21 shows the resultant annual prices. The electricity price forecast follows the general tendencies of the change in natural gas in Figure 7.22. Important to note, the implied market heat rate (IMHR) shown in Figure 7.23 changes significantly with natural gas prices. The IMHR divides natural gas prices by electric prices and is illustrative of the market point in which a heat rate of a natural gas facility is profitable. For example, the approximate heat rate of a CCCT is 7,000 Btu/kWh. Lower natural gas prices make operating gas plants more frequently a better option.

Figure 7.21: Annual Natural Gas Price Forecast Scenarios

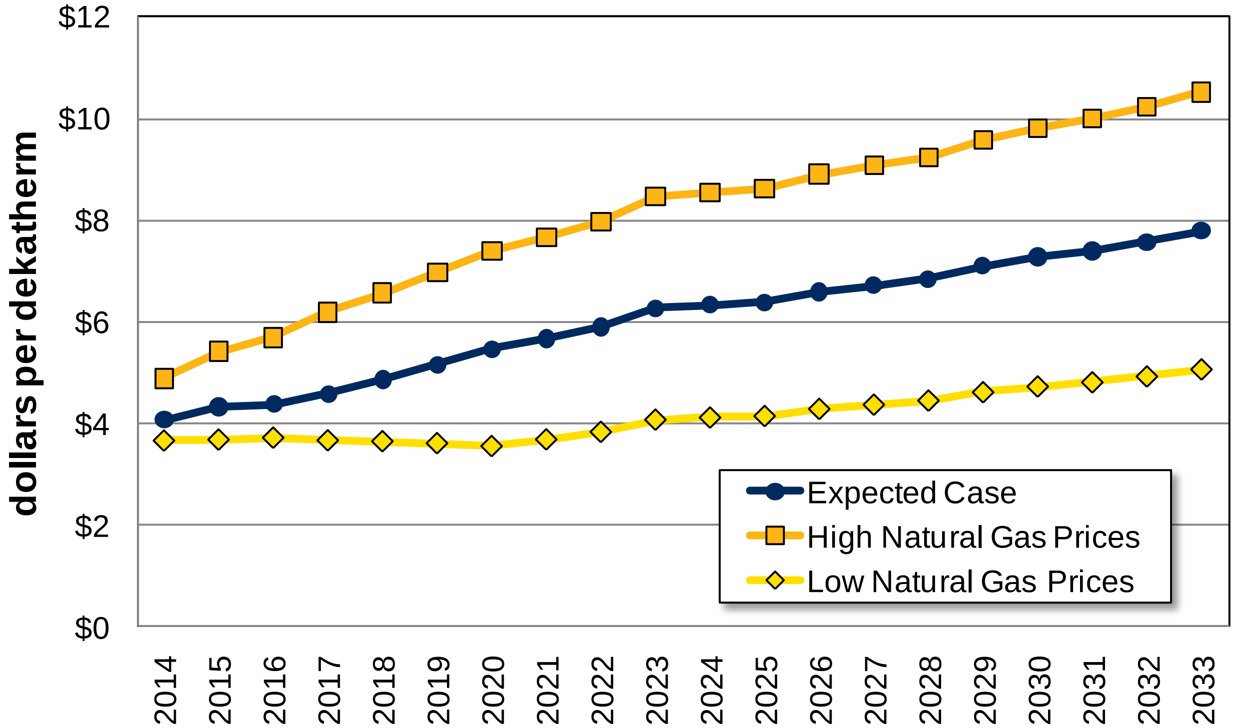


Figure 7.22: Natural Gas Price Scenario's Mid-Columbia Price Forecasts

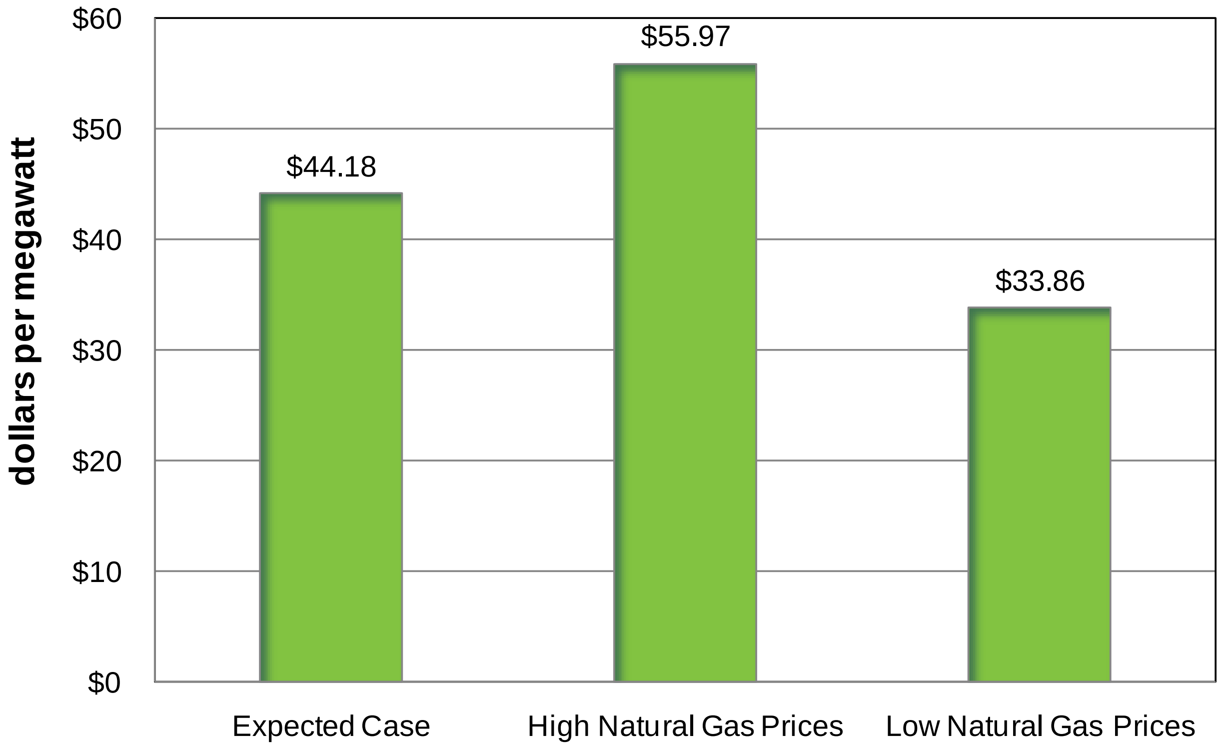
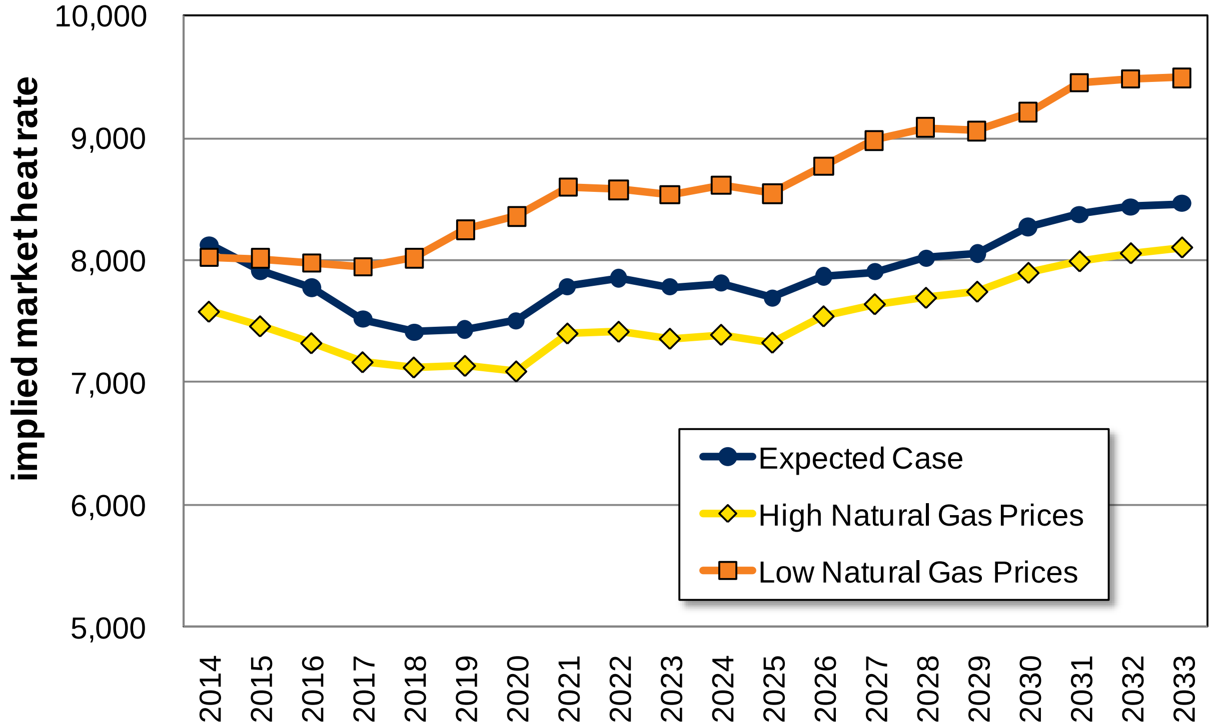


Figure 7.23: Implied Market Heat Rate Changes



Increased State Renewable Portfolio Standards

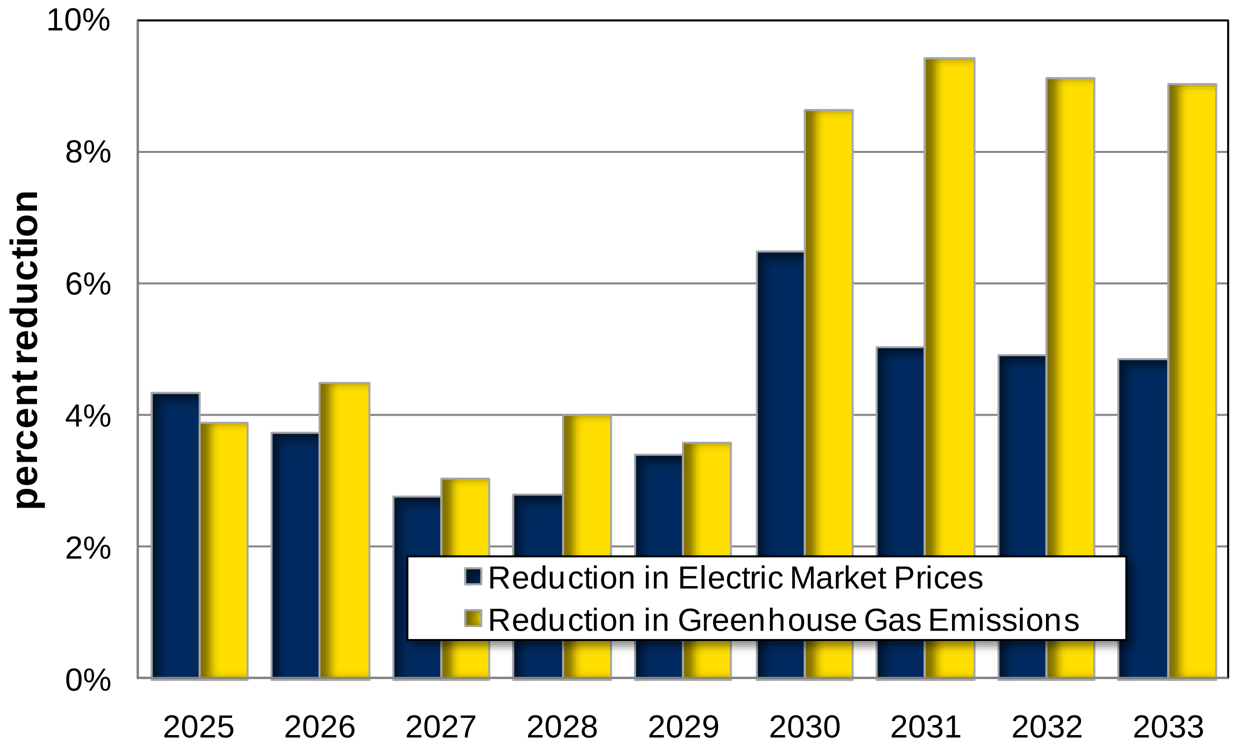
Many western states have RPS requirements. As utilities reach their mandated levels of renewables, some states have increased the goals for reasons of further reducing energy risk, creating green jobs, and lowering carbon emissions. This scenario attempts to address the impact of RPS legislation on the Northwest energy market. If the only goal of the RPS is to lower carbon emissions, this method can be costly. This IRP does not attempt to address these costs for the existing RPS rules, but rather discusses what the costs and benefits are from additional rules.

This scenario is speculative in many ways, such as from which states an increase in RPS levels will come from, and the type of technology used to meet the increased goals. For this analysis, the renewable requirement increases after 2025, and focuses on states where existing standards stop increasing in 2020. For example, this scenario assumes Washington state increases from 15 percent to 25 percent in 2025, and California's increases from 33 percent to 50 percent by 2030. Other states' increases include Colorado, Nevada, New Mexico, and Arizona. Solar will meet much of the need in states with increased requirements that have strong solar potential; additions beyond the current standard could strain existing transmission systems and produce low capacity factors. For this analysis, 7,000 MW of wind, 29,000 MW of solar and 1,000 MW of other renewable technology is added to meet the assumed higher standards of this scenario. The net added cost to the West for these assumed law changes is $120 billion (2012$). This compares to the estimated $17 billion spent on renewable energy investments in the Northwest to date.[6]

[6]This scenario assumes 8,500 MW of Northwest wind using an average cost of $2,000 per kW.

The market and greenhouse gas reduction benefits of the increased RPS scenario are shown in Figure 7.24 for the years 2025 to 2033. As more solar and wind generation are added to the system wholesale market prices are expected to decline; this scenario shows wholesale price reductions of 3 percent to 4 percent. Overall system costs of the Western Interconnect will not fall due to the large investment levels. The added renewables reduce greenhouse gas emissions from the Expected Case by up to 9 percent toward the end of the study. As with the forced coal plant retirements in the Expected Case, an assumption included in this RPS scenario as well, the higher RPS results in an implied price for carbon. The implied cost of reduced carbon emissions for this increased RPS scenario is $198 per metric ton. For further information on this calculation, refer to the Expected Case analysis described on page 7.27. While added renewables can reduce fuel costs, the incremental investments in new renewable generation greatly overwhelms the fuel cost savings.

Figure 7.24: Changes to Mid-Columbia Prices and Western US Greenhouse Gas Levels



8. Preferred Resource Strategy

Introduction

The PRS chapter describes potential costs and financial risks of various resource acquisition strategies. Further, the chapter details planning and resource decision methods and strategies, the impact of climate change policies, and provides an overview of alternative resource strategies.

The 2013 PRS describes a reasonable low-cost plan along the efficient frontier of potential resource portfolios accounting for fuel supply and price risks. Major changes from the 2011 plan include reduced energy efficiency, wind, and natural gas-fired fired resources and, for the first time, a modest contribution from demand response. The plan no longer calls for new renewable resources due to the recent acquisition of the 105 MW Palouse Wind Project and the recent law change allowing the Kettle Falls Generation Station to qualify for Washington's EIA beginning in 2016. The strategy's lower energy efficiency level is due to lower avoided costs, increased codes and standards supplanting the need for utility-sponsored acquisition, and rising implementation and verification costs associated with utility-sponsored energy efficiency programs. The reduction in natural gas-fired resources results primarily from a lower retail load forecast. Demand response is included because lower energy prices increase the value of resources providing on-peak capacity.

Section Highlights

- Avista's first anticipated resource acquisition is a natural gas-fired peaker by the end of 2019 to replace expiring contracts and growing loads.
- A combined cycle combustion turbine replaces the Lancaster Facility when its contract ends in 2026.
- The selection of natural gas-fired peaking units is due primarily to their smaller size better fitting Avista's resource deficits.
- The 2013 Preferred Resource Strategy includes demand response programs for the first time.
- Energy efficiency offsets projected load growth by 42 percent through the 20-year IRP timeframe.
- Colstrip Units 3 and 4 remain viable and cost-effective throughout the planning horizon, even under scenarios most adverse to the plant.

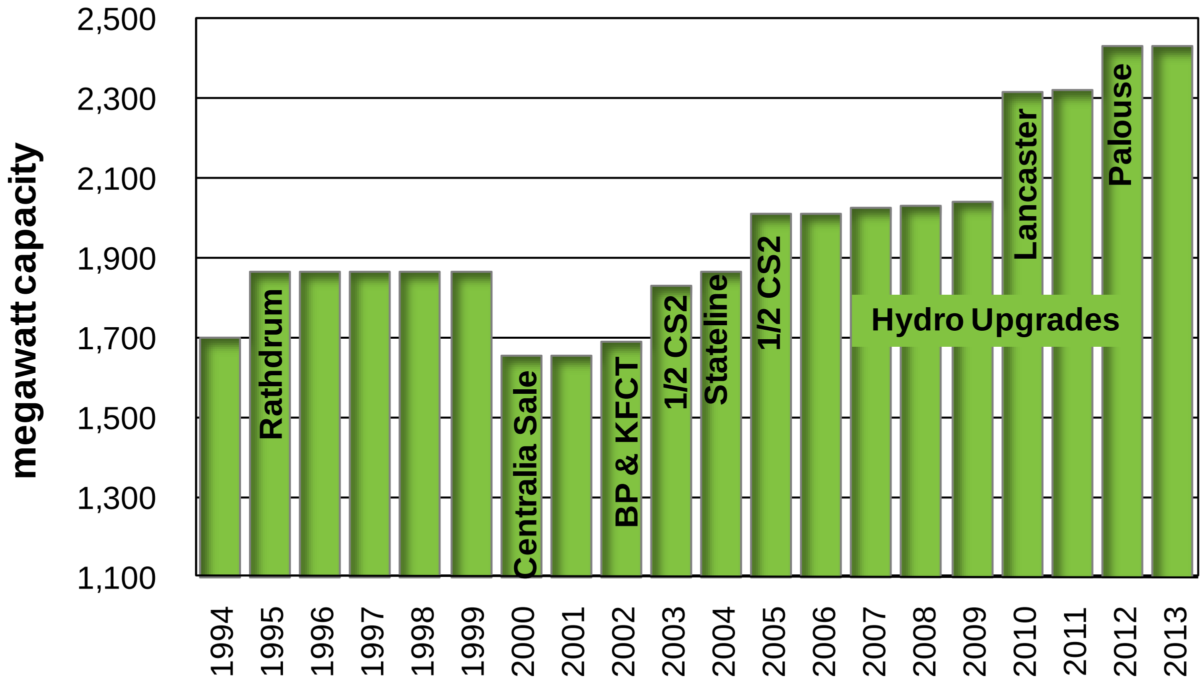
Supply-Side Resource Acquisitions

Avista began its shift away from coal-fired resources with the sale of its 210 MW share of the Centralia coal plant in 2000, and its replacement with natural gas-fired generation projects. See Figure 8.1. Since the Centralia sale, Avista has made several generation acquisitions and upgrades, including:

- 25 MW Boulder Park natural gas-fired reciprocating engines (2002);

- 7 MW Kettle Falls gas-fired CT (2002);
- 35 MW Stateline wind power purchase agreement (2004);
- 56 MW (total) hydroelectric upgrades (through 2012);
- 270 MW natural gas-fired Lancaster Generation Station power purchase agreement (2010); and
- 105 MW Palouse Wind power purchase agreement (2012).

Figure 8.1: Resource Acquisition History



Resource Selection Process

Avista uses several decision support systems to develop its resource strategy, including AURORA[XMP] and Avista's PRiSM model. The AURORA[XMP] model, discussed in detail in the Market Analysis chapter, calculates the operating margin (value) of every resource option considered in each of the 500 Monte Carlo simulations of the Expected Case, as well as Avista's existing portfolio of generation assets. The PRiSM model helps make resource decisions. Its objective is to meet resource deficits while accounting for overall cost, risk, capacity, energy, renewable energy requirements, and other constraints. PRiSM evaluates resource values by combining operating margins with capital and fixed operating costs. The model creates an efficient frontier of resources, or the least cost portfolios, given a certain level of risk and constraints. Avista's management selects a resource strategy using this efficient frontier to meet all capacity, energy, RPS, and other requirements.

PRiSM

Avista staff developed the first version of its PRiSM model in 2002 to support resource decision making. PRiSM 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
    - Greater of summer 1- or 18-hour capacity
    - Greater of winter 1- or 18-hour capacity
    - Annual energy
    - I-937 RPS requirements
2. Costs to serve future retail loads
3. Existing resource contributions
    - Operating margins
    - Fixed operating costs
4. Resource Options
    - Fixed operating costs
    - Return on capital
    - Interest expense
    - Taxes
    - Generation levels
    - Emission levels
5. Constraints
    - The level of Market reliance (surplus/deficit limits on energy, capacity and RPS)
    - Resources quantities available to meet future deficits

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

Equation 8.1: PRiSM Objective Function

Minimize: $(X_1 * NPV_{2014\text{-}2033}) + (X_2 * NPV_{2014\text{-}2063})$

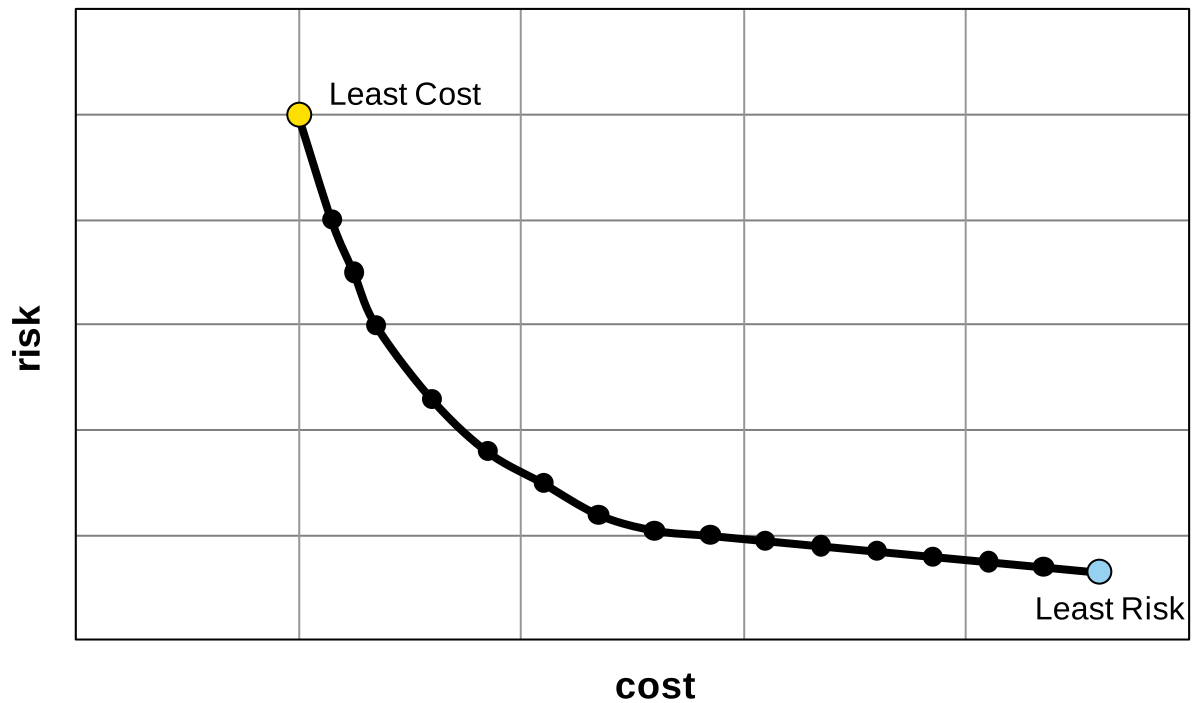
Where: X_1 = Weight of net costs over the first 20 years (95 percent)
X_2 = Weight of net costs over the next 50 years (5 percent)
NPV is the net present value of total system cost.[1]

An efficient frontier captures the optimal resource mix graphically given varying levels of cost and risk. Figure 8.2 illustrates the efficient frontier concept. As you attempt to lower risk, costs increase. The optimal point on the efficient frontier depends on the level of risk Avista and its customers are willing to accept. The best point on the curve could be

[1] Total system cost is the existing resource marginal costs, all future resource fixed and variable costs, and all future energy efficiency costs and the net short-term market sales/purchases.

where you can make small incremental cost additions for large reductions in risk. Portfolios to the left of the curve would be more optimal, but do not meet the planning requirements or resource constraints. Examples of these constraints are environmental legislation cost, regulation, and the availability of commercially viable technologies greatly limit utility-scale resource options. Further, portfolios to the right of the curve are less efficient as they have higher costs than a portfolio with the same level of risk. The model does not meet deficits with market purchases, or allow the construction of resources in any incremental size.[2] Instead, it uses market purchases to fill short-term gaps and "constructs" resources in block sizes equal to the project sizes Avista could build.

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 more 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 greenhouse gas emissions performance standard.

The PRiSM model selects from combined- and simple-cycle natural gas-fired combustion turbines, natural gas-fired reciprocating engines, wind, solar, storage batteries, carbon-sequestered coal, and upgrades to existing thermal and hydro resources. Energy efficiency is a fixed input derived from an iterative process of

[2] Market reliance, as identified in Section 2, is determined prior to PRiSM's optimization.

developing avoided costs using PRiSM. Further, scenarios illustrate energy efficiencies' impact on resource selections. Non-sequestered coal plants are not an option in this IRP because Washington's emissions performance standard bans them.[3]

Washington's EIA or RPS fundamentally changed how Avista meets future loads. Before the addition of an RPS obligation, the efficient frontier contained a least-cost strategy on one axis, the least-risk strategy on the other axis, and all of the points in between. Management used the efficient frontier to help determine where they wanted to be on the cost-risk continuum. The least cost strategy typically consisted of natural gas-fired peaking resources. Portfolios with less risk generally replaced some of the natural gas-fired peaking resources with wind generation, other renewables, combined cycle natural gas-fired plants, or coal-fired resources. Past IRPs identified resource strategies including all of these risk-reducing resources. Added environmental and legislative constraints reduce the ability of resource choices to positively impact future costs and/or risks, at least in the traditional sense, and the requirement to procure renewable generation resources previously were included only in lower-risk and higher-cost portfolios. Further, these laws increase customer costs by obligating the utility to pay for energy efficiency levels above their direct financial benefit.

Resource Deficiencies

Avista uses a single-hour and a three-day, 18-hour (6 hours each day), peak event methodology to measure resource adequacy. The three-day 18-hour, methodology assures our energy-limited hydro resources can meet a multiday extreme weather event.

Avista considers the regional power surpluses consistent with the NPCC's forecast, and does not plan to acquire long-term generation assets while the region is significantly surplus.

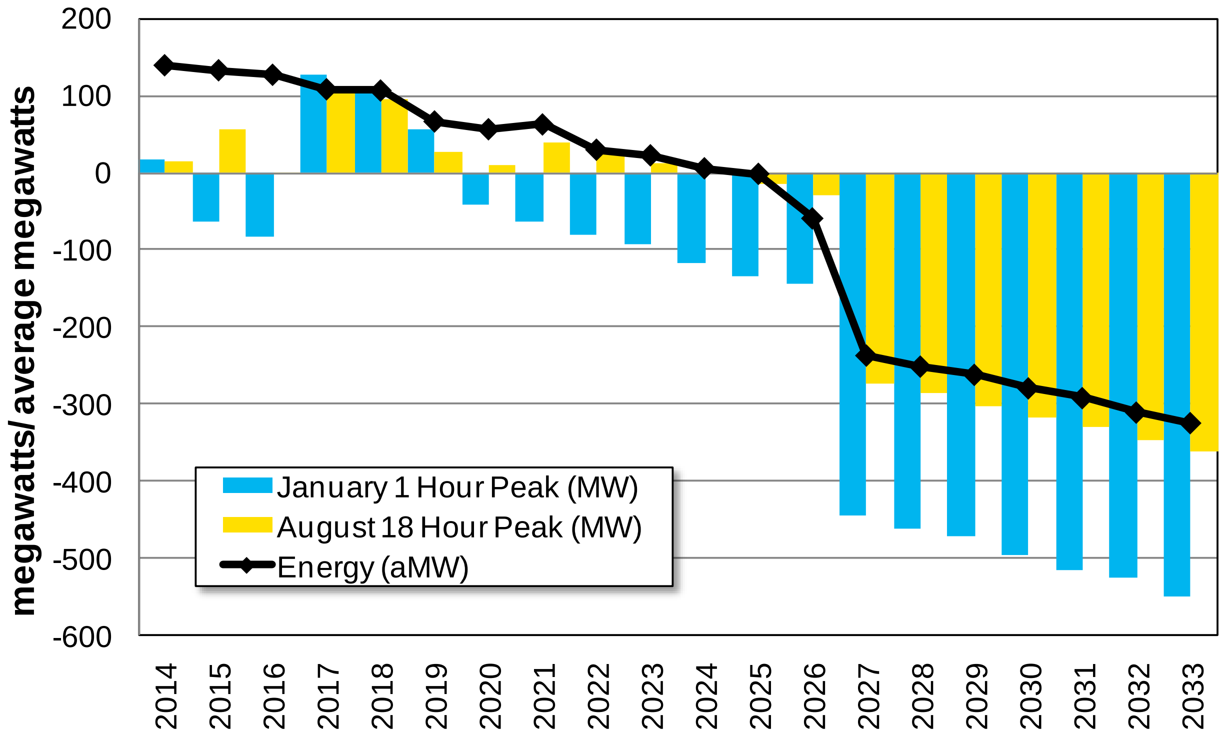
Avista's peak planning methodology includes operating reserves, regulation, load following, wind integration and a planning margin. Even with this planning methodology, Avista currently projects having adequate resources between owned and contractually controlled generation to meet physical energy and capacity needs until 2020.[4] See Figure 8.3 for Avista's physical resource positions for annual energy, summer capacity, and winter capacity. This figure accounts for the effects of new energy efficiency programs on the load forecast. Absent energy efficiency, Avista would be deficient earlier. Figure 8.3 illustrates short-term capacity needs in the winter of 2014/15 and 2015/16. This period is short-lived because a 150 MW capacity sale contract ends in 2016. Avista expects to address these short-term deficits with market purchases; therefore, the first long-term capacity deficit begins 2020. If Avista uses a similar planning margin in the summer as winter (14 percent plus reserves); Avista would be deficit in the summer of 2025. Given the region has a capacity surplus in the summer;

[3] See RCW 80.80.
[4] See Chapter 2 for further details on this peak planning methodology.

Avista will meet its ancillary service needs from its own portfolio, but rely on term purchases to meet other deficits.

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.

Figure 8.3: Physical Resource Positions (Includes Energy Efficiency)



Renewable Portfolio Standards

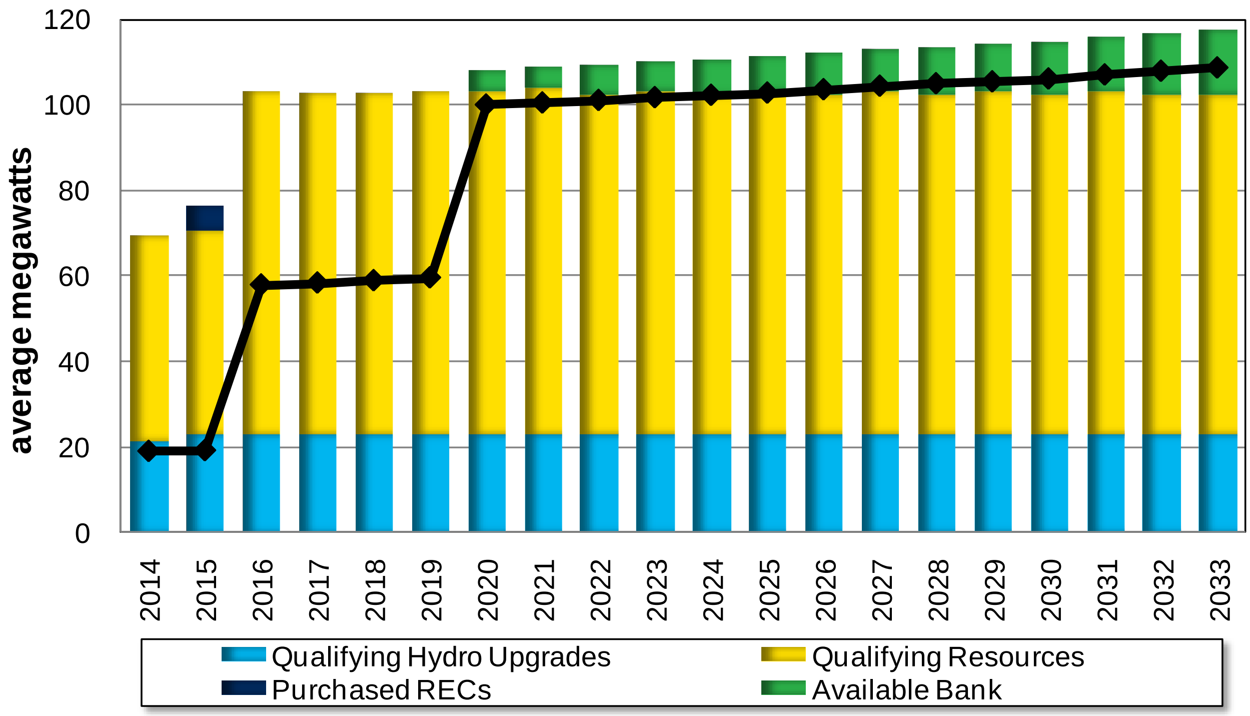
Washington voters approved the EIA in the November 2006 general election. The EIA requires utilities with over 25,000 customers to meet 3 percent of retail load from qualified renewable resources by 2012, 9 percent by 2016, and 15 percent by 2020. The initiative also requires utilities to acquire all cost-effective energy efficiency and energy efficiency. Avista participates in the UTC's Renewable Portfolio Standard Workgroup to help interpret application of this law.

Avista expects to meet or exceed its EIA requirements through the 20-year plan with a combination of qualifying hydroelectric upgrades, the Palouse Wind project, the Kettle Falls Generating Station and selective REC purchases. A list of the qualifying generation projects and the associated expected output is in Table 8.1 below. The forecast REC positions are in Figure 8.4. The flexibility included in the EIA to use RECs from the current year, from the previous year, or from the following year for compliance helps mitigate year-to-year variability in the output of qualifying renewable resources.

Table 8.1: Qualifying Washington EIA Resources

Resource	Resource Type	On-line Year	Nameplate Capacity	Expected MWh	Expected RECs	Average RECs
Kettle Falls GS[5]	Biomass	1983	47.0	374,824	281,118	32.1
Long Lake 3	Hydro	1999	4.5	14,197	14,197	1.6
Little Falls 4	Hydro	2001	4.5	4,862	4,862	0.6
Cabinet Gorge 3	Hydro	2001	17.0	45,808	45,808	5.2
Cabinet Gorge 2	Hydro	2004	17.0	29,008	29,008	3.3
Cabinet Gorge 4	Hydro	2007	9.0	20,517	20,517	2.3
Wanapum	Hydro	2008	0.0	22,206	22,206	2.5
Noxon Rapids 1	Hydro	2009	7.0	21,435	21,435	2.4
Noxon Rapids 2	Hydro	2010	7.0	7,709	7,709	0.9
Noxon Rapids 3	Hydro	2011	7.0	14,529	14,529	1.7
Noxon Rapids 4	Hydro	2012	7.0	12,024	12,024	1.4
Palouse Wind	Wind	2012	105.0	349,726	419,671	47.9
Nine Mile 1 & 2	Hydro	2016	4.0	11,826	11,826	1.4
Total			**236.0**	**928,671**	**904,910**	**103.3**

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



[5] The Kettle Falls Generation Station becomes EIA qualified beginning in 2016. Clarification is required to determine the amount of energy to qualify for the law (75 percent qualifying is currently assumed).

Preferred Resource Strategy

The 2013 PRS consists of existing thermal resource upgrades, energy efficiency, demand response, and natural gas-fired simple- and combined-cycle gas turbines. A list of forecast acquisitions is in Table 8.2. The first resource acquisition is 83 MW of natural gas-fired peaking technology by the end of 2019. This resource acquisition fills the capacity deficit created by the expiration of the WNP-3 contract with the BPA (82 MW), the expiration of the Douglas County PUD contract for a portion of the Wells hydroelectric facility (28 MW) and load growth. In this IRP evaluation, frame technology SCCTs are preferred. Given the relatively small cost differences between the evaluated natural gas-fired peaker technologies, the ultimate technology selection will be made in a future RFP. Further, technological changes in efficiency and flexibility may mean the Avista will need to revisit this resource choice closer to the actual need. Since the need is six years out, Avista will not release an RFP in the next two years, but will begin a process to evaluate technologies, and potential site locations prior, to a RFP release, likely following the 2015 IRP.

Table 8.2: 2013 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Simple Cycle CT	2019	83	76
Simple Cycle CT	2023	83	76
Combined Cycle CT	2026	270	248
Rathdrum CT Upgrade	2028	6	5
Simple Cycle CT	2032	50	46
Total		**492**	**453**
Efficiency Improvements	**Acquisition Range**	**Peak Reduction**	**Energy (aMW)**
Energy Efficiency	2014-2033	221	164
Demand Response	2022-2027	19	0
Distribution Efficiencies	2014-2017	<1	<1
Total		**240**	**164**

The next resource acquisition is another natural gas-fired peaking technology by the end of 2023. The 2019 acquisition could increase in size to accommodate the 2023 unit, or the 2019 site could be designed to add a second unit later. Given the length in time for this decision, more studies will occur in the next IRP.

The proposed 270 MW CCCT is to replace the Lancaster tolling agreement expiring in October 2026. Avista could renegotiate the current PPA or find other mutual terms to retain the plant for customers. If Avista is not able to retain Lancaster generation, Avista would need to build or procure a similar-sized natural gas-fired unit. The new plant size could meet future load growth needs and could delay or eliminate the need for later two additional resource acquisitions in this plan. Due to the uncertainty surrounding replacing Lancaster, this IRP assumes the replacement is a new facility of similar size. As 2026 approaches, more information and costs will be known and discussed in future IRPs.

The 2013 PRS is significantly different from the 2011 IRP resource strategy. The 2011 PRS is in Table 8.3. Since the prior plan, Avista's renewable and capacity needs have changed. First, the 2012 NW Wind need was met with the acquisition of the Palouse Wind PPA and its subsequent commercial operation date of December 2012. Changes in the EIA eliminated the 2019/2020 wind resource acquisition. The amendment under SB 5575 allows the Kettle Falls Generating Station and other legacy biomass resources to be counted as qualifying resources beginning in 2016. Previously, the EIA excluded Kettle Falls due to its age. Another significant change from the 2011 PRS is a lower load growth projection. Loads were expected to grow at 1.6 percent per year in the 2011 IRP. This IRP forecasts 1 percent growth (see Chapter 2, Loads and Resources). This change in load growth delays the first natural gas-fired resource acquisition by one year and eliminates the need for a CCCT in 2023.

Table 8.3: 2011 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
NW Wind	2012	120	35
Simple Cycle CT	2018	83	75
Existing Thermal Resource Upgrades	2019	4	3
NW Wind	2019-2020	120	35
Simple Cycle CT	2020	83	75
Combined Cycle CT	2023	270	237
Combined Cycle CT	2026	270	237
Simple Cycle CT	2029	46	42
Total		**996**	**739**
Efficiency Improvements	**Acquisition Range**	**Peak Reduction (MW)**	**Energy (aMW)**
Distribution Efficiencies	2012-2031	28	13
Energy Efficiency	2012-2031	419	310
Total		**447**	**323**

Energy Efficiency

Energy efficiency is an integral part of the IRP analytical process. It also is a critical component of the EIA, where the law requires utilities to obtain all cost effective energy efficiency at below 110 percent of generation alternatives. Avista developed avoided energy costs and compared those figures against a energy efficiency supply curve developed by EnerNOC. The 20-year forecast of energy efficiency acquisitions is in Figure 8.5. Avista plans to acquire 77 aMW of energy efficiency over the next 10 years and 164 aMW over 20 years.[6] These acquisitions will reduce system peak, shaving 104 MW from peak needs by 2023, and 221 MW by 2033. To illustrate the benefits of energy efficiency, the before and after load forecast is shown in Figure 8.6. Prior to energy efficiency, loads would increase at 1.7 percent per year; with energy efficiency loads growth at 1.07 percent per year. Energy efficiency reduces load growth by 43

[6] Includes savings with system losses; at the customer's meter savings are 154 aMW.

percent over the 20-year plan. Please refer to Chapter 3 for a more detailed discussion of energy efficiency resources.

Figure 8.5: Energy Efficiency Annual Expected Acquisition

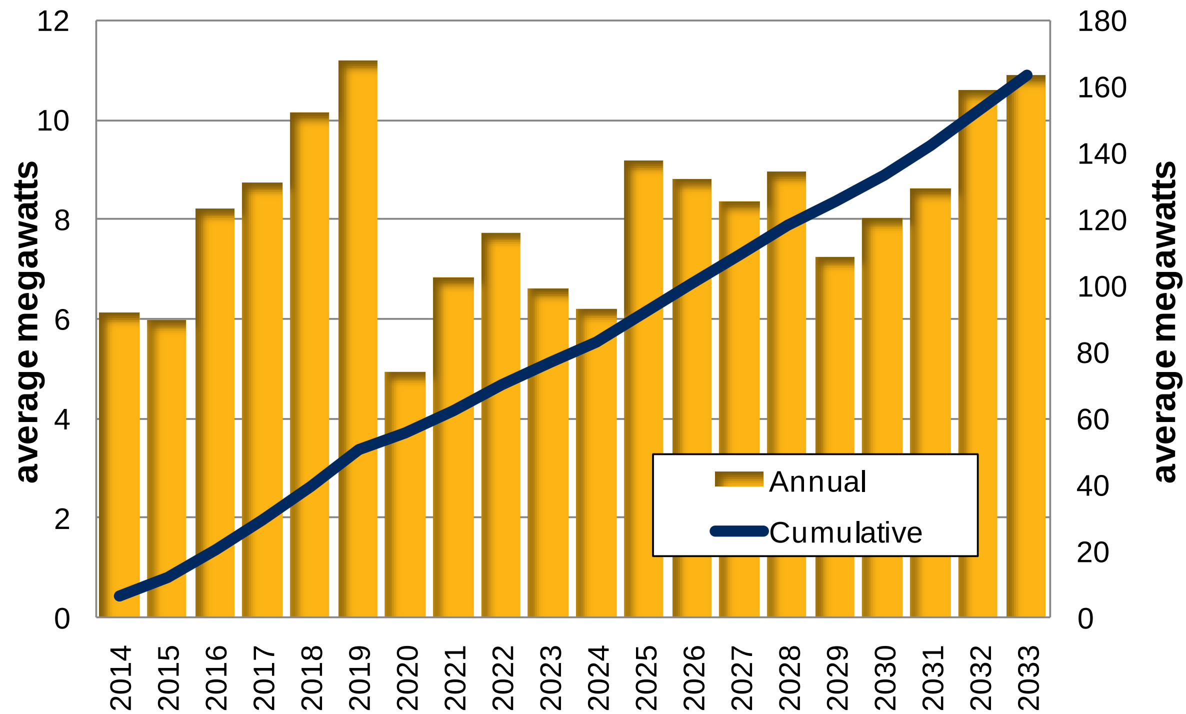
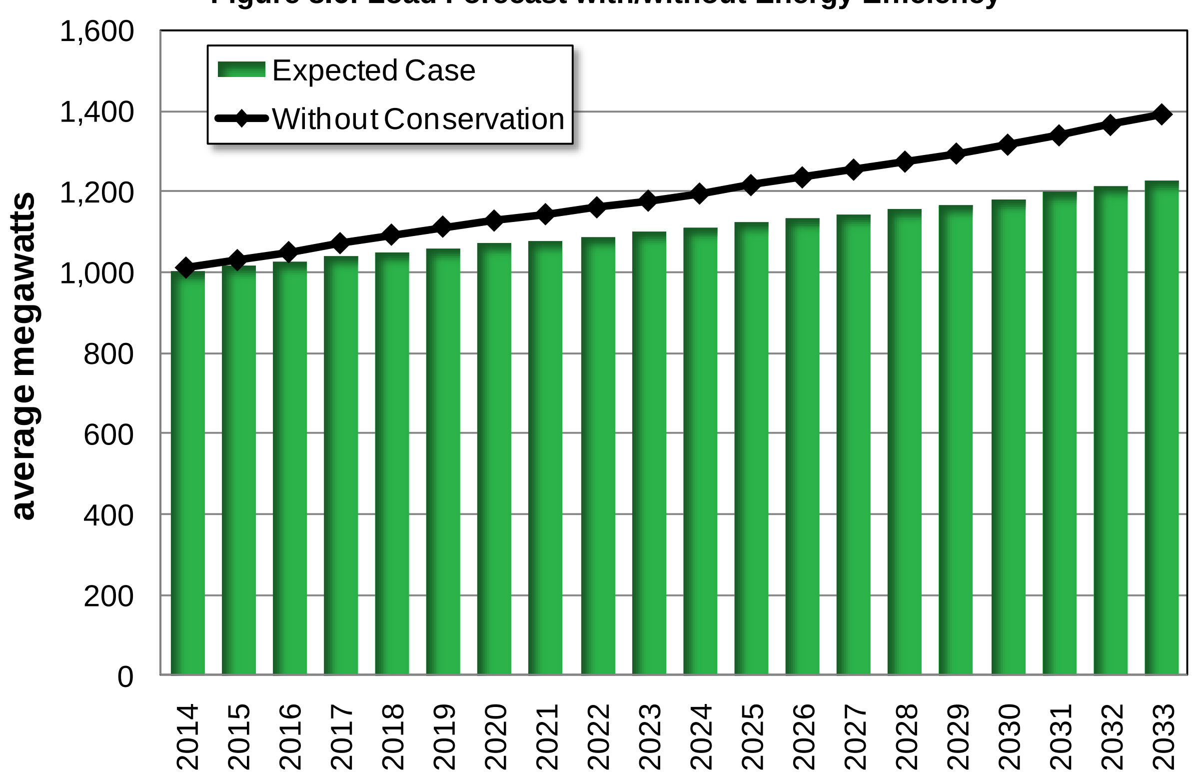


Figure 8.6: Load Forecast with/without Energy Efficiency



Demand Response

For the first time in an Avista IRP, demand response is a selected resource option in the PRS. Demand response is selected beginning in 2022 and continuing through 2027. Demand response could also offset part of the 2019 simple cycle resource, depending on its achievable potential and the actual costs incurred to procure it. Demand response will likely come from industrial and commercial customers with flexible processes; given Avista's limited experience with this resource, demand response research is included as an action item for the IRP.

Distribution Feeder Upgrades

Distribution feeder upgrades entered the PRS for the first time in the 2009 IRP. The upgrade process began with our Ninth and Central Streets feeder in Spokane. The decision to rebuild a feeder considers energy, operation and maintenance savings, the age of existing equipment, reliability indexes, and the number of customers on the feeder. The driver for pursuing a feeder rebuild generally is not energy savings, but rather system reliability. Since the 2011 IRP, several additional feeders were rebuilt. Avista plans to rebuild 13 feeders over the next four years. A broader discussion of our feeder rebuild program is in Chapter 5.

Simple Cycle Combustion Turbines

Avista plans to identify potential sites for new natural gas-fired generation capacity within its service territory ahead of an anticipated need. Avista's service territory has areas with different combinations of benefits and costs. Locations in Washington have higher generation costs because of natural gas fuel taxes and carbon mitigation fees. However, there are other potential benefits of a Washington location, including proximity to natural gas pipelines and Avista's transmission system, lower project elevations providing higher on-peak capacity contributions per investment dollar, and potential for water to cool the facility. In Idaho, lower taxes and fees decrease the cost of a potential facility, but fewer locations exist to site a facility near natural gas pipelines, fewer low cost transmission interconnection points are available, and fewer sites have available cooling water. The identification and procurement of a natural gas project site option will again be an action item for this IRP. Further siting factors for consideration include proximity to neighbors, environmental review, transmission access, pipeline access, elevation, and water availability.

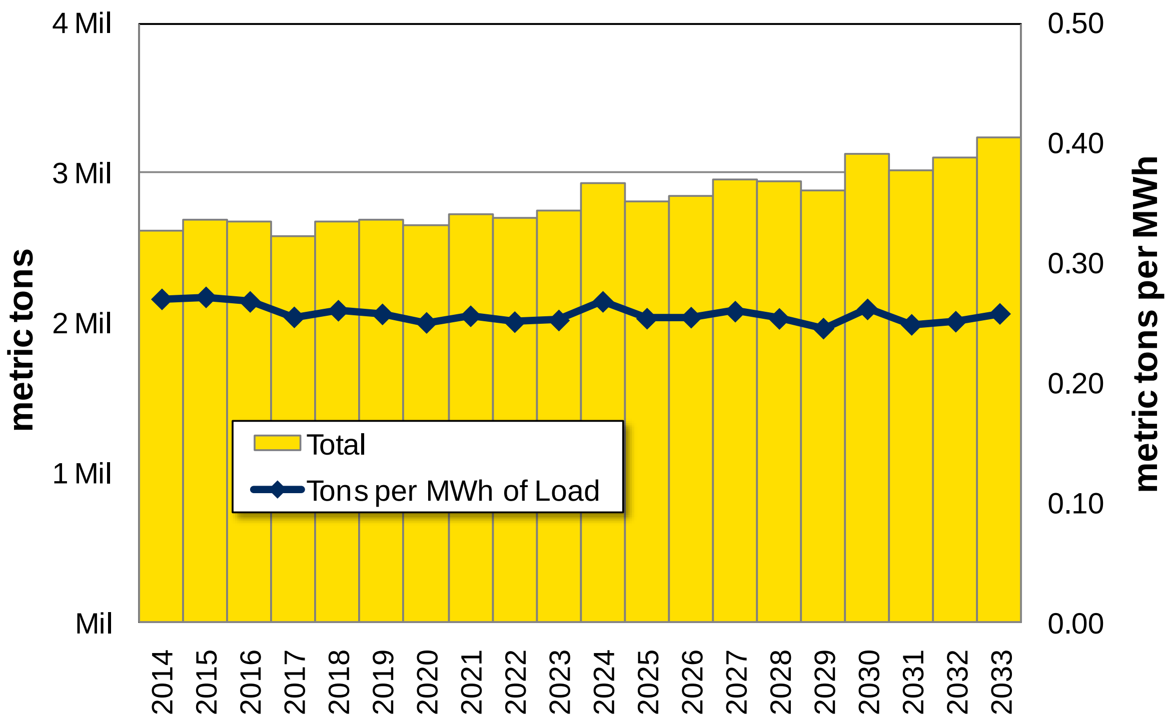
Avista is not specifying a preferred peaking technology until an RFP is completed. Given current assumptions, the resource strategy would select a Frame CT machine. Tradeoffs will occur between capital costs, operating efficiency and flexibility. Frame CT machines are a lower capital cost option, but have higher operating costs and less flexibility, while the hybrid technology has higher capital costs, lower operating costs, and more operational flexibility. Given the hours of operating, the lowest cost option is the less efficient and less flexible Frame CT. Increased flexibility requirements and greenhouse gas emissions costs could make a hybrid machine preferable. If Avista needs regulation or reserve capacity, a hybrid machine may be selected over the Frame CT if no other opportunities were available. If greenhouse gas reductions were identified as the only reason to choose hybrid technology, the emissions reductions would cost

$147 per reduced metric ton of greenhouse gas emissions. The emissions reductions will not be realized by the owning utility, but rather the power system as a whole. If Avista selected hybrid technology over a Frame CT, the unit would run substantially more hours than the Frame CT causing utility emissions to increase, but regional emissions to slightly decrease because of the higher efficiency of the hybrid machine. Avista plans to study the tradeoffs of peaking technology in the next IRP.

Greenhouse Gas Emissions

Chapter 7, Market Analysis, discusses how greenhouse gas emissions decrease due to coal plant closures because of EPA and state regulations. Avista's resource mix does not include any retirements due to current or proposed environmental regulations. The only significant lost resource with carbon emissions is the expiration of the Lancaster PPA in 2026, but it will be replaced to maintain system reliability and stabilize rates. Figure 8.7 presents Avista's expected greenhouse gas emissions (excluding Kettle Falls Generating Station) with the addition of PRS resources. Emissions should not change significantly prior to 2019 other than from year-to-year fluctuations resulting from periodic maintenance outages, market fluctuations, and regional hydroelectric generation levels. Beginning in 2019 additional emissions will occur from new peaking resources, but these resources will not affect overall emissions levels much due to low projected runtime hours. The estimates in Figure 8.6 do not include emissions from purchased power or a reduction in emissions for off-system sales. Avista expects its greenhouse gas emissions intensity from owned and controlled generation to fall from 0.35 short tons per MWh to 0.32 short tons per MWh with the current resource mix and the new generation identified in the PRS.

Figure 8.7: Avista Owned and Controlled Resource's Greenhouse Gas Emissions



Capital Spending Requirements

One of the major assumptions in this IRP is Avista will finance and own all new resources. Using this assumption, and the resources identified in the 2013 PRS, the first capital addition to rate base is in 2020 for the first natural gas-fired peaker. The development is likely to begin multiple years earlier but would likely enter rate base January 1, 2020. Avista may begin making major capital investments for the addition in 2017. The capital cash flows in Table 8.4 include AFUDC, transmission investments for generation, and account for tax incentives, and sales taxes. Over the 20-year IRP timeframe, a total of $782 million (nominal) in generation and related transmission expenditure is required to support the PRS. The capital investment projection does not include any capital to exercise the Palouse Wind PPA purchase option.

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

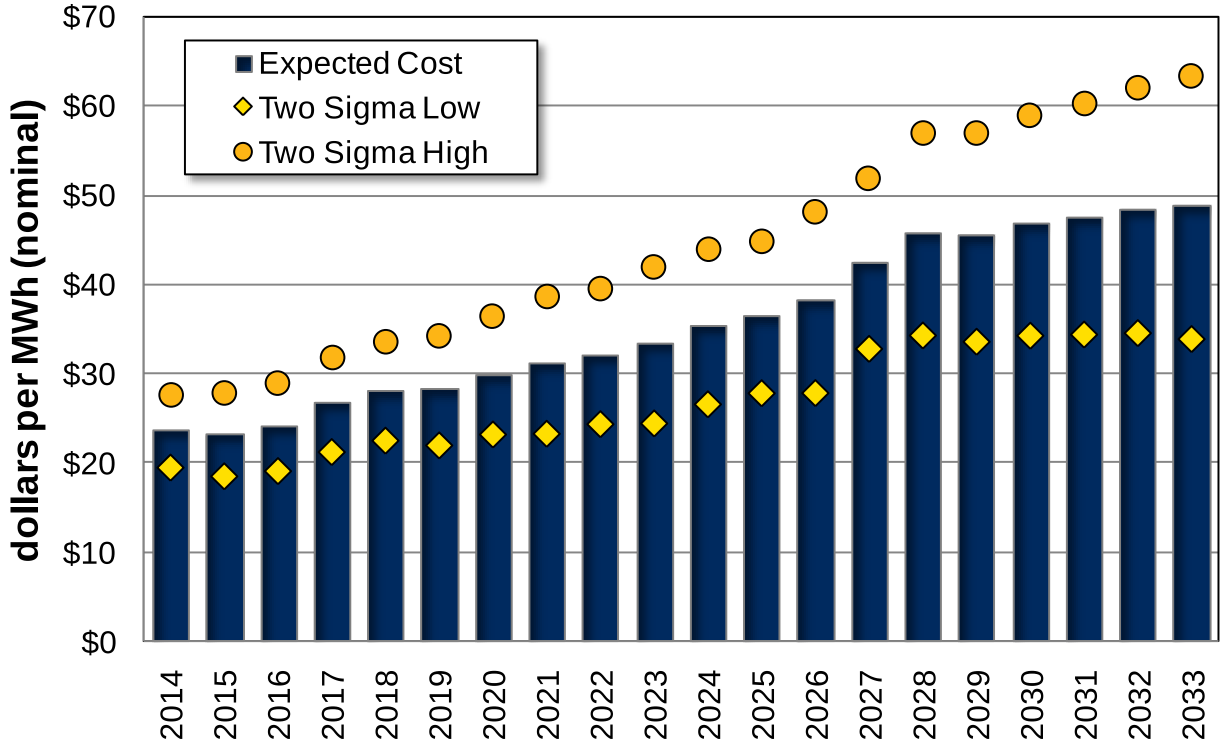
Year	Investment	Year	Investment
2014	0.0	2024	91.6
2015	0.0	2025	0.0
2016	0.0	2026	0.0
2017	0.0	2027	421.7
2018	0.0	2028	97.0
2019	0.0	2029	2.4
2020	85.8	2030	0.0
2021	0.0	2031	0.0
2022	0.0	2032	0.0
2023	0.0	2033	83.6
2014-23 Total	**85.8**	**2024-33 Totals**	**696.2**

Annual Power Supply Expenses and Volatility

PRS variance analysis tracks fuel, variable O&M, emissions, and market transaction costs for the existing resource portfolio for each of the 500 Monte Carlo 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 8.8 shows expected PRS costs through 2033 as the blue bar (nominal dollars). In 2014, costs are expected to be $24 per MWh. The chart shows costs with a range of two sigma. The lower range is represented by yellow diamonds ($19 per MWh in 2014) and the upper range is shown with orange dots ($28 per MWh in 2014). The main driver increasing power supply costs and volatility in future years is natural gas prices and weather (hydro and load variability), Avista increases the volatility assumption of natural gas prices in the future as the commodity price has many unknown future risks and has a history of volatility.

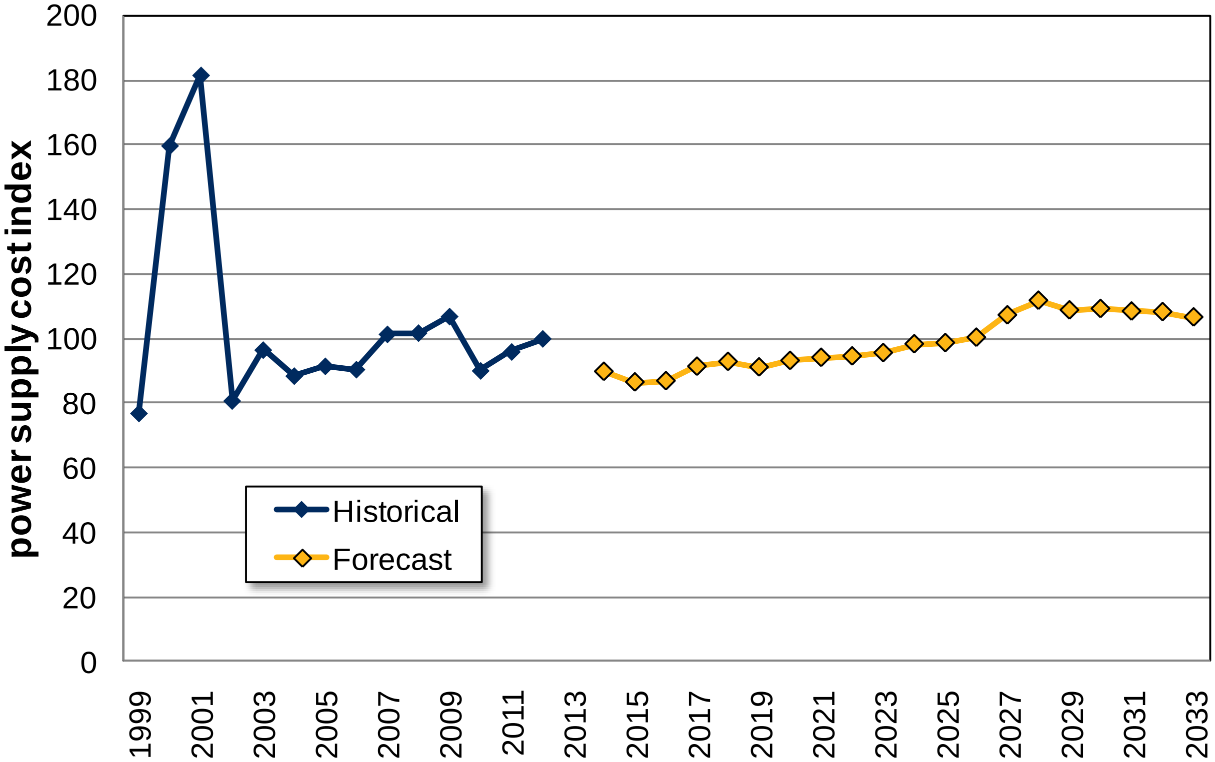
A common IRP question is what will be the change to power supply costs over the time horizon of the plan. Figure 8.9 shows total portfolio costs, but does not account for future load growth that would offset much of the increase as viewed from a customer bill perspective. Figure 8.9 illustrates expected PRS power supply cost changes compared to historical power supply costs, and provides a representation more correlated to future customer bills. Power supply costs, on a per-MWh basis, have increased 2.3 percent per year over inflation between 2002 and 2012. In the next 10 years power supply costs are forecast to fall from 2012 levels if expected energy prices come to fruition along with cost reductions from increased renewable energy credit sales, reduced energy efficiency costs, and consideration of 23 months of increased revenues from a power sale contract with Portland General Electric.[7]

Figure 8.8: Power Supply Expense Range



[7] Since 1998, the capacity payments paid by Portland General Electric to Avista were monetized. Beginning February 2014, the capacity payments will be paid to Avista and reduce power supply costs.

Figure 8.9: Real Power Supply Expected Rate Growth Index $/MWh (2012 = 100)



Near Term Load and Resource Balance

Under Washington regulation (WAC 480-107-15), utilities having supply deficits within three years of an IRP filing must file a RFP with the WUTC. The RFP is due to the WUTC no later than 135 days after the IRP filing. After WUTC approval, bids to meet the anticipated capacity shortfall must be solicited within 30 days.

Tables 8.16 and 8.17, shown later in this section, detail Avista's capacity position over the IRP timeframe. With a portion of loads met by Avista's share of the regional capacity surplus, Avista does not require winter capacity until 2019. Simplified summaries for the near-term are displayed below in Tables 8.5 and 8.6. They show short-term capacity deficits met by market transactions in 2015 and 2016. Avista's short positions are short lived as a 150 MW capacity sale to Portland General Electric expires at the end of 2016. As part of the IRP Action Items, Avista will develop a short-term capacity position report to monitor capacity requirements.

Table 8.5: Avista Medium-Term Winter Peak Hour Capacity Tabulation

	2014	2015	2016	2017
Load Obligations	1,665	1,683	1,700	1,713
Other Firm Requirements	211	158	158	8
Reserves Planning	359	366	369	362
Total Obligations	**2,235**	**2,206**	**2,227**	**2,084**
Firm Power Purchases	117	117	117	117
Owned & Contracted Hydro	998	888	889	955
Thermal Resources	1,137	1,137	1,137	1,137
Wind (at Peak)	0	0	0	0
Total Resources	**2,252**	**2,143**	**2,143**	**2,210**
Net Position	**17**	**-64**	**-84**	**126**
Short Term Market Purchase	0	75	100	0
Net Position	**17**	**11**	**16**	**126**

Table 8.6: Avista Medium-Term Summer 18-Hour Sustained Peak Capacity Tabulation

	2014	2015	2016	2017
Load Obligations	1,465	1,482	1,498	1,510
Other Firm Requirements	212	159	159	9
Reserves Planning[8]	0	0	0	0
Total Obligations	**1,677**	**1,641**	**1,657**	**1,519**
Firm Power Purchases	29	29	29	29
Owned & Contracted Hydro	701	707	663	631
Thermal Resources	961	961	961	961
Wind (at Peak)	0	0	0	0
Total Resources	**1,691**	**1,698**	**1,653**	**1,621**
Net Position	**14**	**57**	**-3**	**102**
Short Term Market Purchase	0	0	25	0
Net Position	**14**	**57**	**22**	**102**

Efficient Frontier Analysis

Efficient frontier analysis is the backbone of the PRS. The PRiSM model develops the efficient frontier by simulating the costs and risks of resource portfolios using a mixed-integer linear program. PRiSM finds an optimized least cost portfolio for a full range of risk levels. The PRS analyses examined the following portfolios.

[8] Due to the sustained peak planning methodology, hydroelectric capacity exceeding sustained maximum capability is used for operating and control area reserves.

- **Market Only**: Meets all resource deficits with spot market purchases. The portfolio is least cost from a long-term financial perspective, but has the highest level of risk. The strategy fails to meet capacity, energy, and RPS requirements with Avista-controlled assets.
- **Least Cost**: Meets all capacity, energy and RPS requirements with the least-cost resource options. This portfolio ignores power supply expense volatility in favor of lowest-cost resources.
- **Least Risk**: Meets all capacity, energy and RPS requirements with the least-risk mix of resources. This portfolio ignores the overall cost of the selected portfolio in favor of minimizing portfolio volatility (risk).
- **Efficient Frontier:** Meets all capacity, energy and RPS requirements met with sets of intermediate portfolios between the least risk and least cost options. Given the resource assumptions, no resource portfolio can be at a better cost and risk combination than these portfolios.
- **Preferred Resource Strategy**: Meets all capacity, energy and RPS requirements while recognizing both the overall cost and risk inherent in the portfolio. Avista's management chose this portfolio as the most reasonable path to follow given current information.

Figure 8.10 presents the Efficient Frontier. The x-axis is the levelized nominal cost per year for the power supply portfolio, including capital recovery, operating costs, and fuel expense; the y-axis displays the standard deviation of power supply costs in 2028. The year 2028 is far enough out to account for the risk tradeoffs of several resource decisions. If a near term year was selected to measure risk, there would be too few new resource decisions available to distinguish between portfolios. It is necessary to move far enough into the future so load growth provides PRiSM the opportunity to make new resource decisions. By choosing a year later in the planning horizon, relevant resource decisions can be studied.

Avista is not choosing to pursue the least cost strategy, as it relies exclusively on natural gas-fired peaking facilities. This strategy would include more market risk than exists in the portfolio today because the portfolio would trade the Lancaster (CCCT plant) for a SCCT. The PRS instead diversifies Avista's resource mix with peaking and combined-cycle natural gas-fired plants. Further, based on an analysis of the efficient frontier, the additional cost of this strategy is near zero (0.1 percent) on an NPV basis and reduces market risk by 11 percent. Table 8.7 shows a sampling of portfolios along the efficient frontier with the costs, risks, and carbon emissions described.

Figure 8.10: Expected Case Efficient Frontier

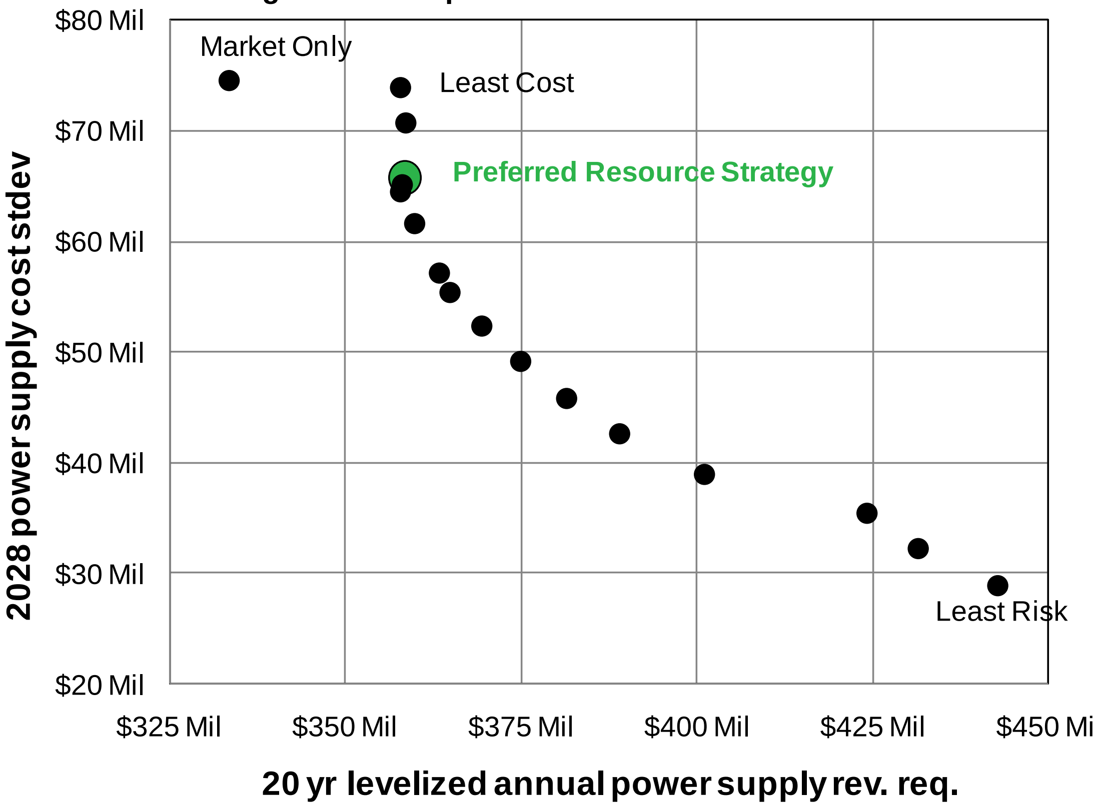


Table 8.7: Efficient Frontier Sample Resource Mixes

Nameplate (MW)	PRS	Low Cost	Medium High Risk	Medium Risk	Medium Low Risk	Low Risk
Combined Cycle CT	270	-	270	270	540	540
Natural Gas-Fired Peaker	299	566	296	216	100	68
Wind	-	-	-	30	50	350
Solar	-	-	-	-	-	-
Biomass	-	-	-	-	-	50
Coal (sequestered)	-	-	-	-	-	-
Hydro Upgrade	-	-	-	-	-	-
Thermal Upgrade	6	6	6	85	85	80
Demand Response	19	20	20	8	12	17
Total (excluded efficiency)	**594**	**592**	**592**	**609**	**788**	**1,104**
Power Supply Revenue Requirement Cost Metrics (Millions)						
20-yr Levelized Cost	$358.4	$357.9	$357.9	$362.3	$367.0	$396.0
2028 Power Supply Std Dev	$65.7	$74.0	$64.4	$60.5	$54.1	$40.2
2033 GHG Emissions (millions of metric tons)	3.2	2.9	3.4	3.4	3.9	3.8

Determining the Avoided Costs of Energy Efficiency

The efficient frontier methodology determines the avoided cost of the new resource additions included in the PRS. There are two avoided cost calculations for this IRP: one for energy efficiency and one for new generation resources. The energy efficiency avoided cost is higher because it includes various benefits beyond generation resource value, as detailed in Table 8.8.

Avoided Cost of Energy Efficiency

Three portfolios are required to derive the supply-side cost components of the avoided cost for energy efficiency calculations. The differences between each portfolio sum to the avoided cost of energy efficiency:

- **Commodity Energy (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. These prices used are determined from the long-term energy price forecast discussed in Chapter 7.
- **Capacity:** This resource portfolio builds a least-cost strategy to meet peak demand. The difference between the Commodity Energy and Capacity 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, but it assumes Avista does no further energy efficiency.

The avoided cost of energy efficiency includes the various components of avoided cost only in those periods where Avista is deficit. For example, the avoided costs of energy efficiency programs only include a capacity value in the years where Avista has capacity needs. Further, the commodity component applies to each energy efficiency program depending on the expected timing of its energy delivery. For example, an air conditioning program receives an energy value based on expected savings in the summer months when actual energy savings occur.

The EIA requires avoided costs used for energy efficiency to be increased by 10 percent to incent energy efficiency acquisition in the IRP. Additionally, reduced transmission and distribution losses, and operations and maintenance are credited in the avoided cost of energy efficiency. The following formula details the avoided cost for energy efficiency measures.

Equation 8.2: Energy Efficiency Avoided Costs

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

Where:

E = Market energy price. The price calculated with AURORA$^{\underline{XMP}}$ is $44.08 per MWh.

PC = New resource capacity savings. This value is calculated using PRiSM and is estimated to be $11.74 per MWh.

R = Risk premium to account for RPS and rate volatility reductions. This PRiSM-calculated value is $1.89 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 $1.35 per MWh.

Table 8.8 estimates the levelized avoided cost for a theoretical energy efficiency program reducing load by one megawatt each hour of the year:

Table 8.8: Nominal Levelized Avoided Costs of the PRS ($/MWh)

	2014-2033
Energy Forecast	44.08
Capacity Value	11.74
Risk Premium	1.89
Transmission & Distribution Losses	2.69
Distribution Capacity Savings	1.35
Power Act Premium	6.17
Total	**67.92**

Determining the Avoided Cost of New Generation Options

Avoided costs change as new information becomes available, including changes to market prices, loads, and resources. Therefore, the estimates in Table 8.9 must be updated at the time a new resource is evaluated. Table 8.9 shows the avoided costs derived from the Preferred Resource Strategy. These prices represent the value of energy from a project making equal deliveries over the year in all hours. In this case, a new resource (such as PURPA qualifying project) would not qualify for capacity payments until 2020, because Avista does not need capacity resources until then.

Table 8.9: Updated Annual Avoided Costs ($/MWh)

Year	Energy	Capacity	Risk	Total
2014	31.02	0.00	0.00	31.02
2015	33.06	0.00	0.00	33.06
2016	33.91	0.00	0.00	33.91
2017	34.14	0.00	0.00	34.14
2018	36.18	0.00	0.00	36.18
2019	38.29	0.00	0.00	38.29
2020	41.34	15.15	0.56	57.06
2021	43.72	15.77	0.59	60.08
2022	46.06	16.41	0.61	63.09
2023	48.85	17.08	0.64	66.57
2024	49.52	17.78	0.66	67.96
2025	49.35	18.50	0.69	68.54
2026	52.04	19.26	0.72	72.01
2027	53.37	20.04	0.75	74.16
2028	55.65	20.86	0.78	77.29
2029	57.94	21.71	0.81	80.46
2030	61.39	22.59	0.84	84.82
2031	63.06	23.51	0.87	87.44
2032	65.65	24.47	0.91	91.03
2033	66.97	25.47	0.95	93.38

Efficient Frontier Comparison of Greenhouse Gas Policies

In addition to the stochastic Expected Case, Avista evaluated a National Climate Change policy scenario. Several hypothetical climate change policies are included in the 500 Monte Carlo market futures to capture the range of policy alternatives (see Chapter 7, Market Analysis for further detail). Given the higher market prices resulting from climate legislation, 20.5 aMW of additional energy efficiency would be acquired over the IRP period, a 12.5 percent increase. The cost of this incremental energy efficiency is 37 percent higher than in the Expected Case.

Except for increased energy efficiency, the PRS under the National Climate Change policy remains similar to the Expected Case's strategy. Somewhat surprisingly, this scenario increases the total resource build, but natural gas-fired frame peaking resources are replaced with hybrid CTs. This change reflects the increasing margin of lower heat rate machines. A detail of the Least Cost strategy, and the likely PRS, under a National Climate Change policy is in Table 8.10.

Table 8.10: Alternative PRS with National Climate Change Legislation

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Simple Cycle CT	2019	92	85
Simple Cycle CT	2024	92	85
Combined Cycle CT	2026	270	248
Rathdrum CT Upgrade	2024	6	5
Simple Cycle CT	2032	92	85
Total		**552**	**508**
Efficiency Improvements	**By the End of Year**	**Peak Reduction**	**Energy (aMW)**
Energy Efficiency	2014-2033	249	185
Demand Response	2022-2027	5	0
Distribution Efficiencies	2014-2017	<1	<1
Total		**254**	**185**

Figure 8.11 illustrates the efficient frontier in the Expected Case and a case with National Climate Change legislation. With climate change legislation, the cost curve moves to the right, showing increased customer costs. The curve also shows lower risk, because higher risk resources, such as frame CTs, are no longer the least cost resource. The most cost effective resource shifts from frame CTs to hybrid CTs. A carbon-pricing regime would also increase the amount of energy efficiency pursued by Avista. Figure 8.11 shows this efficient frontier in orange. The higher avoided cost of the national climate change policy increases the amount of energy efficiency, thereby reducing risk through lower loads, but with increased costs.

The lesson learned from this scenario is the utility's cost and financial risk increases. If climate policies were enacted, Avista likely would acquire more energy efficiency. This additional energy efficiency would reduce risk, but at overall higher costs. In reality, if this legislation is passed, a new portfolio would be developed to select resources better suited to a carbon-restricted environment; in this case, Frame CT's are traded for hybrid CTs, lowering risk and lowering cost. Table 8.11 summarizes these cost and risk changes. Since Avista's resource need is at the end of the decade, Avista is able to postpone its technology decision until closer to the time of need.

Figure 8.11: Efficient Frontier Comparison

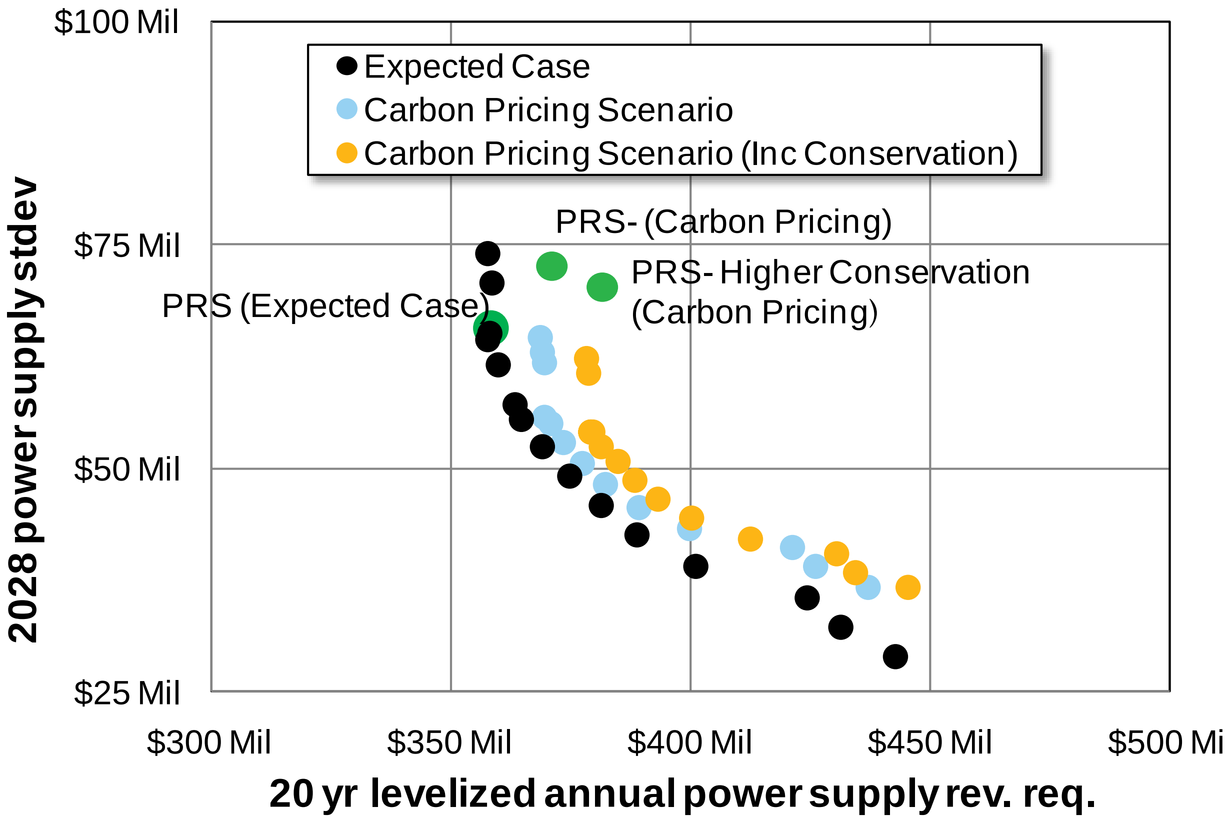


Table 8.11: Preferred Portfolio Cost and Risk Comparison (Millions $)

Portfolio	20-Yr Power Supply Levelized Cost	
	Expected Case	Carbon Pricing Scenario
PRS	358.4	367.3
PRS w/ Higher Efficiency	365.0	377.8
Climate Scenario- PRS	364.7	374.5
Portfolio	**2028 Power Supply Cost Standard Deviation**	
	Expected Case	**Carbon Pricing Scenario**
PRS	65.7	72.6
PRS w/ Higher Efficiency	63.9	70.3
Climate Scenario- PRS	61.0	63.6

Energy Efficiency Scenarios

Due to the complexities introduced by EIA, energy efficiency is not directly modeled in PRiSM. Instead, it is separately modeled using the avoided costs discussed above. Avista has found this method of determining energy efficiency investments is robust.

Refer to Figure 8.12 for an illustration of this point. This figure demonstrates the changes in risk and cost from the point of view of the PRS and the efficient frontier.

Under current Washington rules, Avista must acquire all cost effective energy efficiency up to 110 percent of the avoided cost. Energy efficiency resources are oversubscribed compared to alternative generating resource options. To illustrate this concept, a portfolio acquiring energy efficiency up to 100 percent of avoided costs is shown as a "light blue dot". This portfolio adds 154 aMW of energy efficiency (rather than the 168 aMW from the PRS shown as the "green diamond"). This portfolio illustrates power supply costs would be 2.7 percent lower and risk would be 0.3 percent higher if the utility could select this portfolio. This portfolio does not appear on the efficient frontier and is considered more optimal than any portfolio on the efficient frontier as it is to the left of the valid portfolio options, but is an invalid option due to the EIA requirement to over-invest in energy efficiency. A scenario acquiring energy efficiency to a level more consistent with its true contribution to the portfolio likely would lower costs.

If Avista did not acquire any energy efficiency, total power supply costs and risks would increase. This portfolio, shown as a dark orange dot, is 8.6 percent more expensive than the PRS and has 20 percent more risk. This confirms energy efficiency is an effective tool to lower costs and risks, but must be properly balanced to achieve optimal benefits for customers.

Three additional studies illustrating the effect of acquiring energy efficiency beyond 110 percent of cost effectiveness. These portfolios are shown as an orange dot for 125 percent of avoided costs and as a light orange dot for 150 percent of avoided cost in Figure 8.12. These options add 3.6 percent and 8.6 percent to the power supply costs and reduce volatility by 2.9 percent and 5.0 percent respectively. The light blue dot shows the 100 percent of avoided costs case. The efficient frontier illustrates these risk reductions are achievable at lower cost by acquiring generation instead of energy efficiency resources. Further information on the energy efficiency analysis is in Chapter 3, Energy Efficiency. Table 8.12 captures the resource selection of each of these portfolios, the costs, risks and carbon emissions.

Figure 8.12: Efficient Frontier Comparison

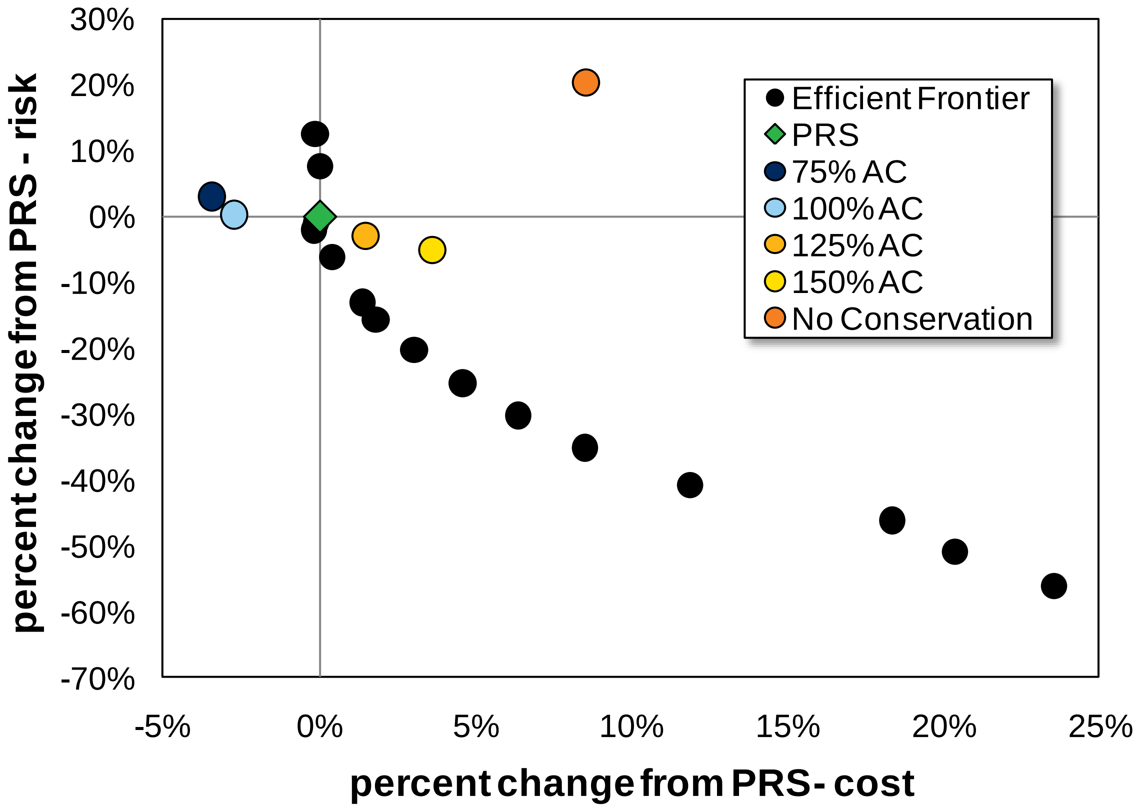


Table 8.12: Preferred Portfolio Cost and Risk Comparison for Avoided Cost Studies

Nameplate (MW)	75%	100%	PRS	125%	150%	0%
Combined Cycle CT	270	270	270	270	270	270
Natural Gas-Fired Peaker	313	316	299	271	228	481
Wind	-	-	-	-	-	-
Solar	-	-	-	-	-	-
Biomass	-	-	-	-	-	-
Coal (sequestered)	-	-	-	-	-	-
Hydro Upgrade	-	-	-	-	-	68
Thermal Upgrade	6	-	6	6	6	-
Energy Efficiency (aMW)	139	154	164	185	201	-
Demand Response	20	19	19	20	20	20
Total	748	748	758	752	725	839
20-year Levelized Cost (millions)	$346.1	$349.5	$354.8	$363.7	$371.3	$389.1
2028 Power Supply Stdev (millions)	$67.7	$66.0	$65.7	$63.8	$62.4	$79.2
2033 Greenhouse Gas Emissions (millions of metric tons)	3.2	3.2	3.3	3.2	3.1	3.2

Colstrip

Coal-fired generation has been the target of increased regulatory and legal attention. Colstrip is a four unit coal-fired plant jointly owned by Avista, NorthWestern Energy, PacifiCorp, PPL- Montana, Portland General Electric, and Puget Sound Energy. Avista's share of the plant is 15 percent of Units 3 and 4, or 222 MW. Units 3 and 4 are newer and larger technology than Units 1 and 2. Avista has no ownership interest in Units 1 or 2 at Colstrip.

As part of the 2011 IRP acknowledgement, the UTC requested that Avista study two Colstrip scenarios. The first scenario is a cost and utility impact if Colstrip is not part of Avista's resource portfolio. The second case examines the costs and utility impacts on Colstrip (Units 3 and 4) from additional environmental controls to meet potential new rules from the EPA. These portfolio scenarios are studied in the Expected Case and the Carbon Pricing scenarios.

No Colstrip Resource Strategy Scenario

In the scenario where Colstrip Units 3 and 4 are no longer resources for Avista customers, Colstrip exits the portfolio at the end of 2017. This case focuses on the costs and risk to replace its capacity and energy, not the revenues from a sale of the asset or the cost of reclamation. Table 8.13 shows an alternative PRS excluding Colstrip Units 3 and 4. The major difference between a portfolio with and without Colstrip is the addition of a CCCT to replace Colstrip Units 3 and 4 in 2017; the remaining portfolio is very similar to the Expected Case PRS.

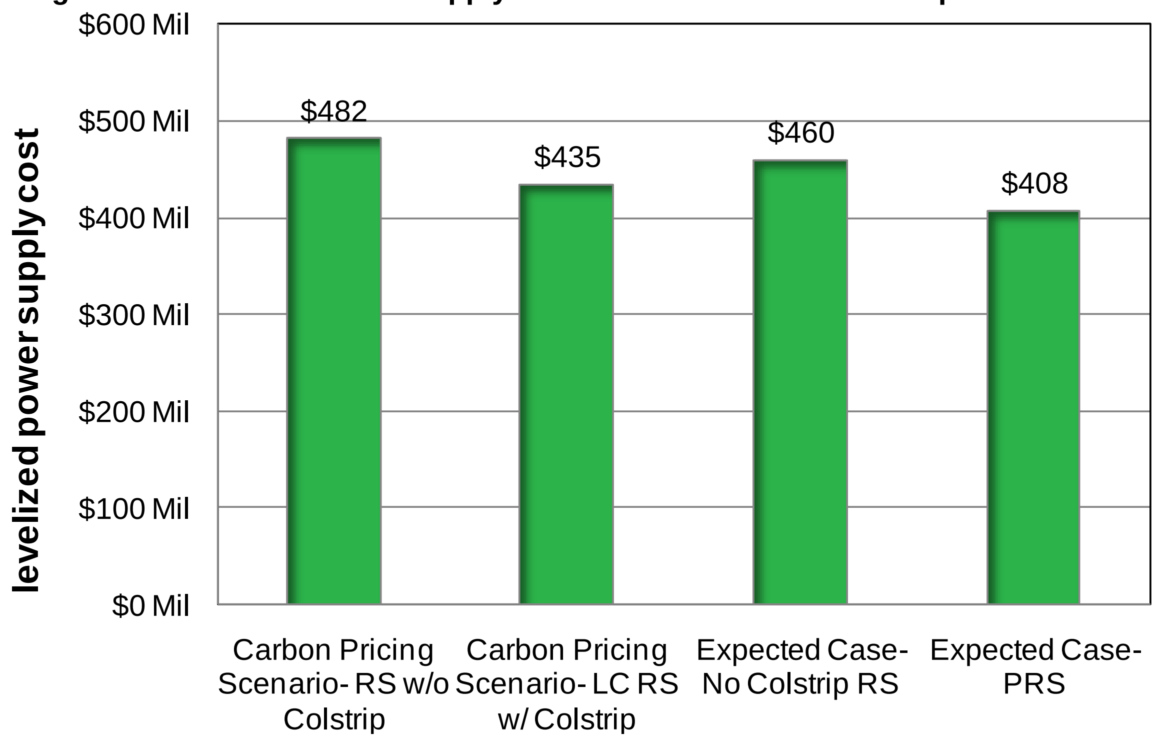
Table 8.13: No Colstrip Resource Strategy Scenario

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Combined Cycle CT	2017	270	248
Simple Cycle CT	2020	50	46
Simple Cycle CT	2023	50	46
Combined Cycle CT	2026	270	248
Simple Cycle CT	2026	51	47
Simple Cycle CT	2029	55	51
Simple Cycle CT	2032	50	46
Total		**797**	**733**
Efficiency Improvements	**By the End of Year**	**Peak Reduction (MW)**	**Energy (aMW)**
Energy Efficiency	2014-2033	221	164
Demand Response	2022-2027	20	0
Distribution Efficiencies	2014-2017	<1	<1
Total		**241**	**164**

Removing Colstrip Units 3 and 4 from Avista's resource portfolio has a large impact on portfolio costs. Figure 8.13 illustrates the cost impact. In the Expected Case, the present value of added cost is $505 million or $52.4 million per year levelized. This is 12.8 percent higher than the PRS (includes Avista's Colstrip generation). Greenhouse gases decrease by 1.2 million short tons in 2018 and one million tons on average over the 16 years of the study, as shown in Figure 8.14.[9] The average greenhouse gas reduction cost Avista customers is $45 per metric ton (levelized).

Using the carbon-pricing scenario, levelized costs increase by $47.2 million or 10.9 percent per year. In any case evaluated, removing Colstrip Units 3 and 4 from Avista's resource portfolio creates significantly higher customer costs. To understand the annual impact to power supply expense and risk, Figure 8.15 shows the Expected Case cost difference without Colstrip, and two-sigma tail risk. In the first year, Power Supply Costs are expected to be over $60 million higher than with the plant, and slowly fall as the substitute plant is depreciated. Another way to look at the increased costs without Colstrip Units 3 and 4 is in Figure 8.16. This figure shows the power supply cost index from earlier in this chapter and includes the no-Colstrip scenario.

Figure 8.13: 2018-33 Power Supply Costs with and without Colstrip Units 3 and 4



[9] This figure does not include the carbon neutral emissions from Kettle Falls.

Figure 8.14: Greenhouse Gas Emissions without Colstrip Units 3 and 4

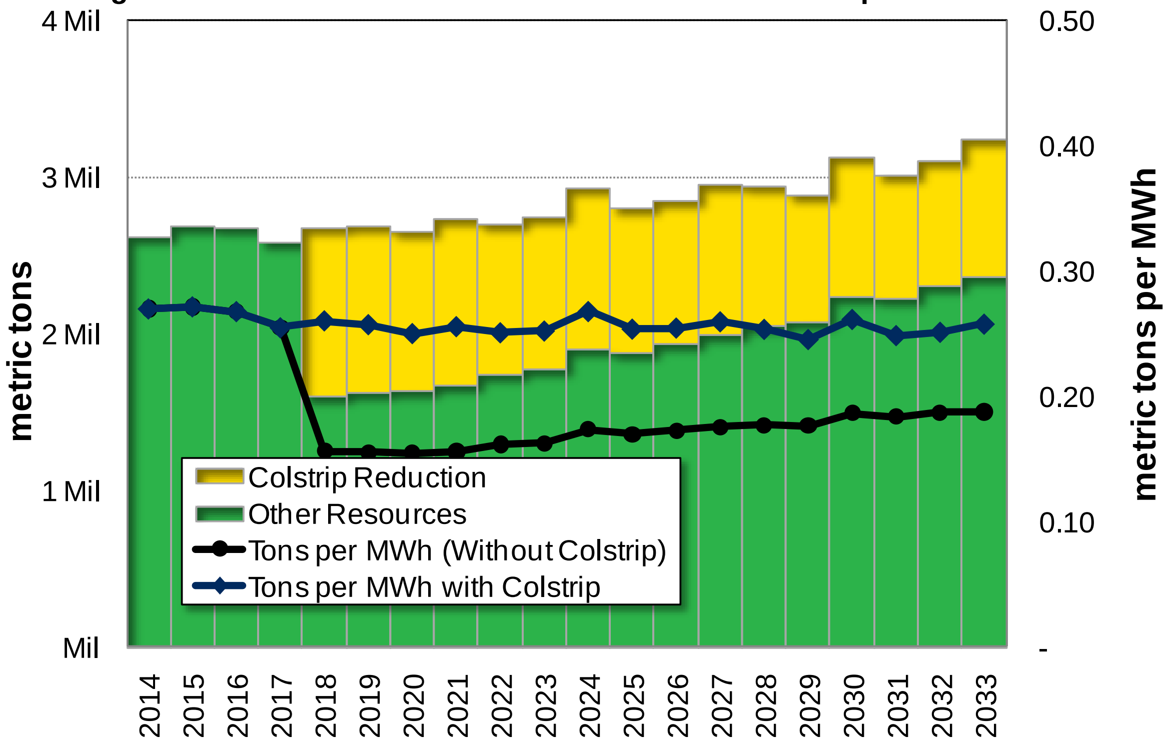


Figure 8.15: Change to Power Supply Cost without Colstrip

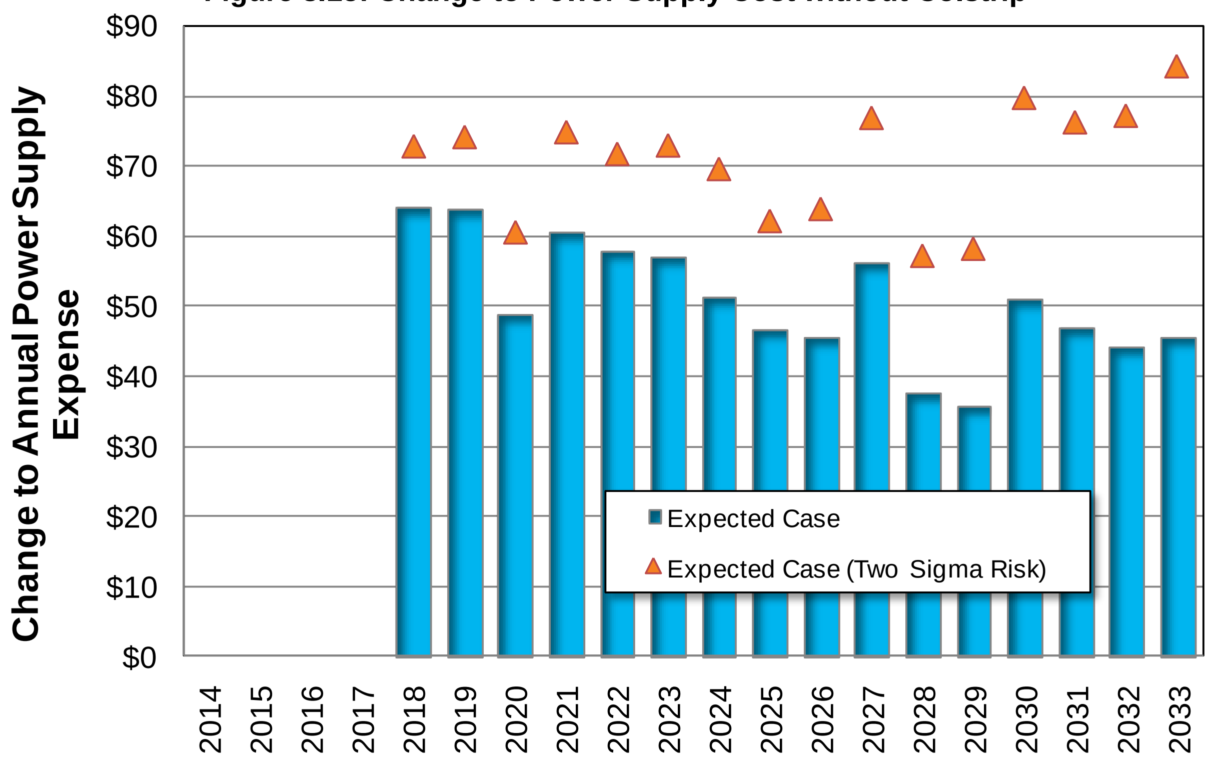
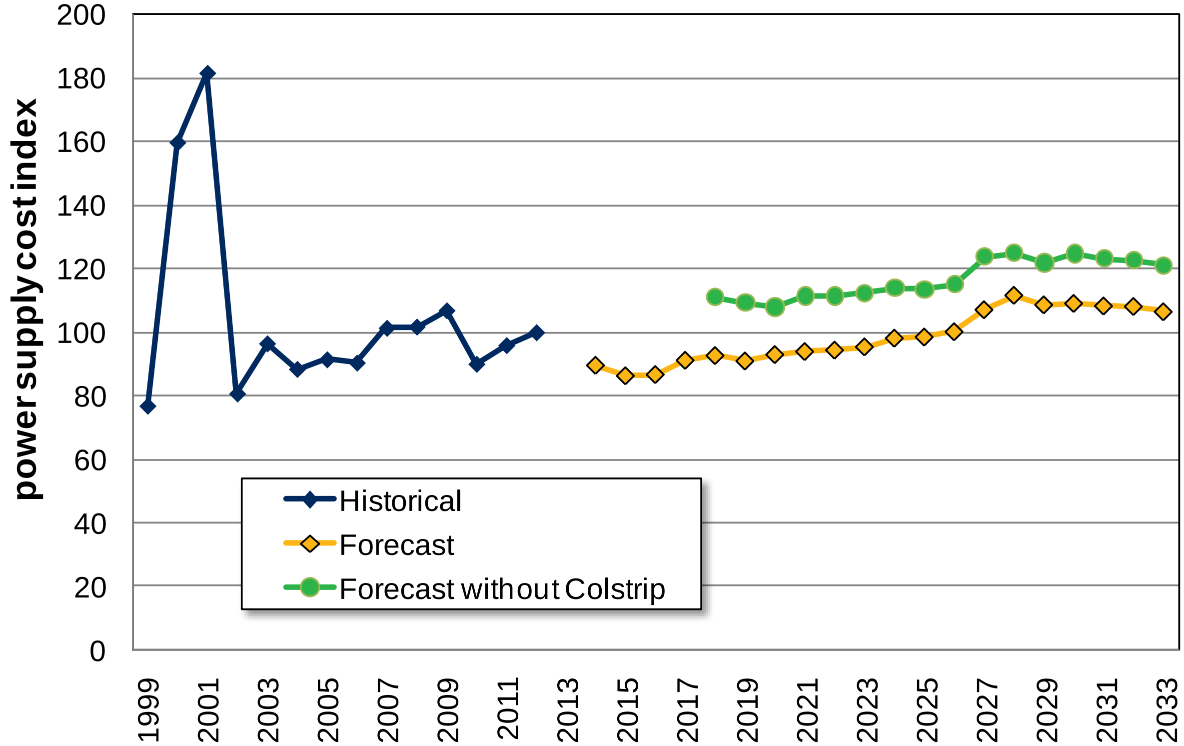


Figure 8.16: Change to Power Supply Cost without Colstrip



Environmental Control Review

There are potential costly regulations Colstrip Units 3 and 4 could face over the next 20 years of this resource plan if state or federal agencies promulgate new coal-fired generation environmental regulations. This section identifies anticipated regulations the EPA could establish over the time horizon of this plan based on information available during the development of this plan. The President's Climate Action Plan was released after the analysis for this IRP was completed, but details about the plan are in Chapter 4, Policy Considerations. Avista will monitor and review implications of the plan as they develop. This discussion is speculative unless otherwise noted and only pertain to Colstrip Units 3 and 4. The following section discusses four main areas of possible new environmental regulations.

Hazardous Air Pollutants

MATS is for the coal and oil-fired source category. For Colstrip Units 3 and 4, existing emission control systems should be sufficient to meet MATS limitations.

Coal Ash Management/Disposal

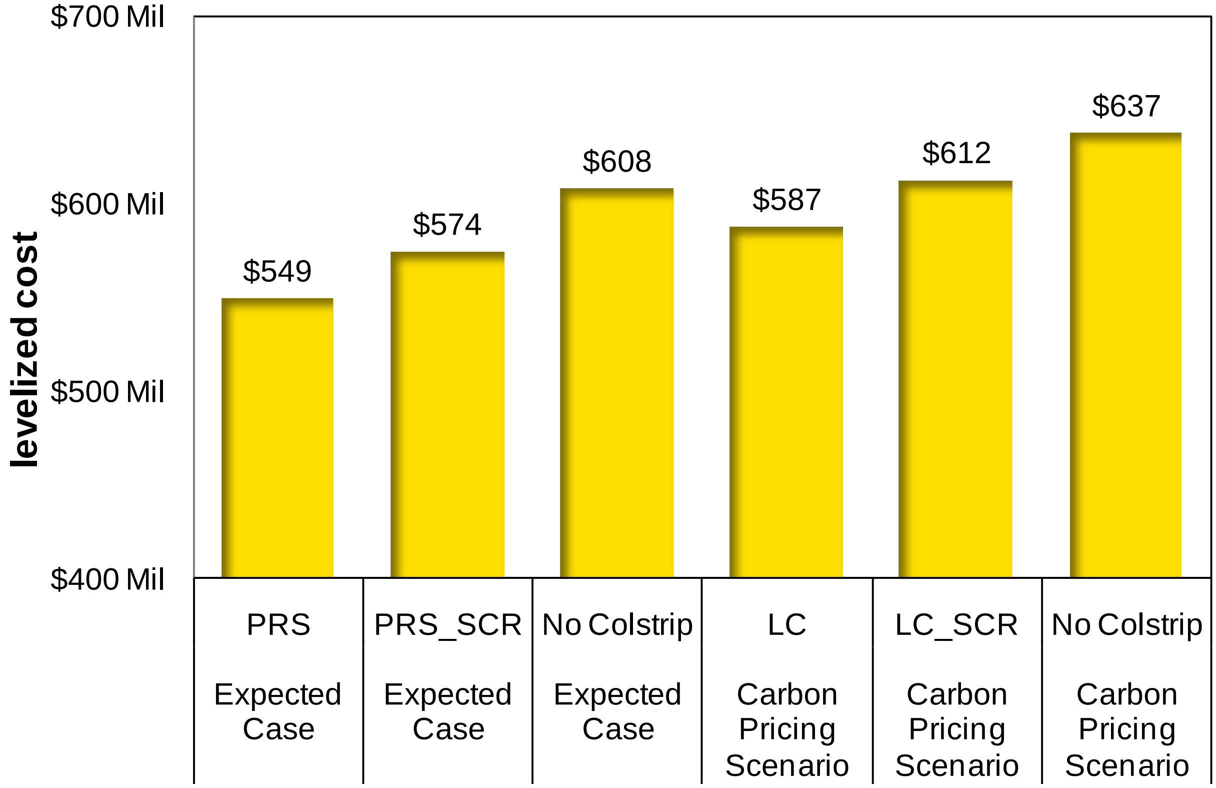
Avista does not anticipate a significant change in operation at Colstrip Units 3 and 4 due to coal ash management or disposal issues at this time.

Effluent Discharge Guidelines
Avista does not anticipate a significant change in operation at Colstrip Units 3 and 4 due to coal ash management or disposal issues at this time because it is a zero discharge facility managing wastewater onsite.

Regional Haze Program
Colstrip Units 3 and 4 will be evaluated for reasonable progress on approximately 10-year intervals going forward. Avista anticipates Nitrous Oxides (NO_X) emission controls could be required in 2027. The cost to comply with this potential regulation is unknown due to technology changes potentially on the horizon to reduce NO_X emissions. In order to understand this regulation if imposed on Colstrip Units 3 and 4 using existing technology, a study was completed and submitted to EPA in 2010.

This study evaluates whether or not the cost of installing this existing technology would have an impact on the ongoing operations of the Colstrip Units 3 and 4. The study estimated the cost of a SCR NO_X control to be $280 million per unit (2011 dollars); Avista chose to increase these estimates by 25 percent to account for potential retrofit costs. Further, Avista believes these control costs are on the high end of the cost range. In this case, Avista's share of this cost for both units would be $105 million in capital, and about $560,000 in annual O&M (2014$). Over the life of this technology, the levelized cost of the controls is $8.39 per MWh (2014 dollars nominal). Further analysis is in Figure 8.17. This chart illustrates three scenarios for the two market price forecasts (Expected Case and Carbon Pricing Scenario). The results shown in the Expected Case's removal of Colstrip Units 3 and 4 from the portfolio adds $34 million or (6.1 percent) to power supply costs compared to installing the SCR controls scenario. In the Carbon Pricing Scenario, $25 million per year is added or 4.3 percent per year without Colstrip Units 3 and 4 compared to installing the SCR. Based on this study using high cost to comply with potential regional haze regulation costs, Colstrip Units 3 and 4 remain a viable and cost-effective resource for Avista's customers.

Figure 8.17: Annual Levelized Cost (2027-33) of Colstrip Scenarios



Other Portfolio Scenarios

Avista examined a number of possible policy outcomes affecting future resource selection. These scenarios review how Avista's resource strategy might change in response to new policies

Higher Washington RPS

Avista's current resource mix fully meets the EIA, but it is possible new legislation or a citizen's initiative could increase the renewable goals further. This scenario contemplates this change to understand the resulting cost, risk, and emissions impacts. The scenario assumes an additional step in the renewable goal of 25 percent of Washington retail sales to be from qualified renewables. Such a goal would require Avista to add 77 aMW of qualified renewables beyond the present plan. The PRiSM model found the most cost-effective method to meet this requirement, with a similar risk profile to the PRS would be Spokane River hydroelectric upgrades. Both Long Lake (68 MW) and Monroe Street (55 MW) second powerhouse additions would meet the renewable requirement if they were certified as EIA-qualifying resources. The addition of these upgrades would prevent the final natural gas peaking resource from being required in the PRS. While the 20-year levelized cost is slightly higher than the PRS, the costs between 2025 and 2033 are $18 million levelized higher, or 3.5 percent.

National RPS

Over the past several years, several bills have proposed national RPS legislation. This legislation has not been enacted, but is a potential future scenario to understand. Differences in the proposals have ranged from the type of resources qualifying for the RPS, percentages and timing of renewables required, and hydroelectric netting.[10] For the National RPS scenario, Avista assumes a 20 percent renewable standard with hydroelectric generation (existing or new) netted from load. Given these assumptions, 78 aMW of renewables would be required by the end of this plan. The hydro netting provision would have an impact on how Avista would meet this potential law. As shown in the higher Washington RPS scenario hydro upgrades were selected in the national RPS scenario. If the hydro netting provision counted hydro upgrades as a load reduction rather than a qualifying renewable resource, the hydro upgrades would need to be replaced by new wind generation.

Higher Capacity Planning Margins

This IRP uses a 14 percent planning margin (plus operating reserves) above the winter peak load forecast. Planning margins are not necessarily a precise target and there is no universally accepted standard. To increase reliability, and to protect Avista's customers from the potential of regional power shortages, a higher planning margin standard could be implemented. This scenario increases the planning margin to 20 percent, or an additional 117 MW by the end of plan. In addition to requiring more capacity on the planning horizon, Avista's first-year deficit would occur earlier in 2016.

2011 IRP Preferred Resource Strategy

This scenario illustrates the impacts of changes since the 2011 IRP. Since then, load growth has fallen from 1.6 percent to 1.0 percent per year, reducing Avista's need for new capacity. In addition to load growth changes, the Washington RPS was amended to include Kettle Falls and other legacy biomass projects as a qualifying renewable resource beginning in 2016. These changes eliminate the need for new resources following Avista's recent acquisition of output from the Palouse Wind project.

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[10] Hydroelectric netting subtracts a utility's hydroelectric generation from the amount of load that the utility would have their RPS based on. For example, a utility with 1,000,000 MWh of load and 300,000 MWh of hydroelectric generation would only have an RPS requirement based on 700,000 MWh of load.

Table 8.14: Policy Portfolio Scenarios

Nameplate (MW)	PRS	Higher WA St. RPS	National RPS	Higher Capacity Margins	2011 PRS
CCCT	270	270	270	270	540
Natural Gas-Fired Peaker	299	249	296	435	187
Wind	-	-	203	-	120
Solar	-	-	-	-	-
Biomass	-	-	-	-	-
Coal (sequestered)	-	-	-	-	-
Hydro Upgrade	-	148	-	-	-
Thermal Upgrade	6	6	6	6	-
Demand Response	19	10	20	8	-
Total	594	683	795	718	847
20-year Levelized Cost (millions)	$354.8	$360.3	$365.3	$364.2	$373.9
2028 Power Supply Stdev (millions)	$65.7	$64.8	$63.6	$65.8	$54.0
2033 Greenhouse Gas Emissions (millions of metric tons)	3.2	3.2	3.3	3.4	3.7

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 exercise by focusing on how the portfolio might change if key assumptions changed. This section identifies assumptions that could alter the PRS, such as changes to load growth, varying resource capital costs, 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

For the past several years, photovoltaic solar generation costs have decreased and more solar generation installed. Solar has benefited from the federal 30 percent ITC, accelerated depreciation, and lucrative state incentives. Solar price decreases have allowed the technology (with government subsidies) to be cost effective compared with retail utility rates in some parts of the western US. After a review of solar potential in the Northwest, and the needs of our system, solar is not a good fit. As discussed throughout this document, Avista and the Northwest require new capacity for winter peak periods. Avista (and the region) experience winter peaks between 6:00 am and 8:00 am or between 5:00 pm and 6:00 pm. In December and January, the months most likely for a peak to occur, these hours have very little or no sunlight. Adding solar to Avista’s resource mix will not delay or remove the need for other resource options. Solar costs would have to fall by a further 88 percent to be cost effective compared to other options.

Nuclear Capital Cost Sensitivity

Nuclear power has made a small resurgence on the U.S. energy-planning horizon, with several large East Coast utilities planning construction of the multi-billion dollar projects. Nuclear’s resurgence is driven by a search for low greenhouse gas emitting base-load power. Avista is not large enough, nor does Avista have the load requirements, to construct a large-scale nuclear plant. It is possible that a group of utilities could co-develop a large project, but the failure of the past regional attempt in the 1980s makes that option unlikely. New research has begun on smaller scale nuclear facilities to make the technology more readily available to smaller utilities. This sensitivity study reduces nuclear capital costs until it was picked as a resource in the PRiSM model. Selection by PRiSM indicates lower cost than other options. The model selected nuclear when its capital costs decreased by 70 percent.

IGCC Coal with Sequestration Capital Cost Sensitivity

Like nuclear facilities, much attention has been given to coal gasification along with the sequestration of CO_2 emissions. Also like nuclear power, this technology is expensive, has long lead times, and requires large project scale. The plant is beyond Avista's needs, but a group of utilities could jointly develop a sequestered coal plant. In order to be selected by the PRiSM model, and compete economically with other options, sequestered IGCC capital costs would need to decrease 87 percent from present estimates. Like nuclear plants, the technology has high O&M costs. The O&M costs are nearly as much as the total cost of natural gas CTs including fuel.

Load Forecast Alternatives

An important test in an IRP is to understand how the plan should change with alternative load growth sensitivities. Since Avista's first new resource need is not until the end of 2019, Avista has time to change its resource needs if loads grow faster or slower than predicted. In order to be nimble Avista must have resource options available to quickly add capacity. Three different resource positions based on varying load growth scenarios, along with the Expected Case, are shown below in Figure 8.18. Chapter 2 discusses the economic drivers of these forecasts. The Low Load Growth scenario changes Avista's first deficit year, but the High caseload Growth scenario increases the need from 42 MW to 88 MW. The Low Load Growth and the Medium Load Growth cases push the need to 2024 or 2022 respectively. Toward the end of the plan, the range in resource need is 267 MW between the High and Low Load Growth cases.

Table 8.15 shows the generation resource strategies meeting the load growth alternatives. These strategies are designed to have similar resource portfolios and risk levels as the PRS. Energy efficiency levels also change, reflecting the expected achievable cost effective levels given the changes to new construction assumed in the load forecast scenarios. Energy efficiency levels will differ depending on the amount of existing structures versus new structures, because new structures are built with more efficient building codes. Energy efficiency for existing structures should remain relatively unchanged, but as economic activity changes, the amount of energy efficiency from new construction will vary. Since 87 percent of energy efficiency is from existing structures, the levels of energy efficiency in the Low Load to High Load Growth forecasts do not materially change.

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

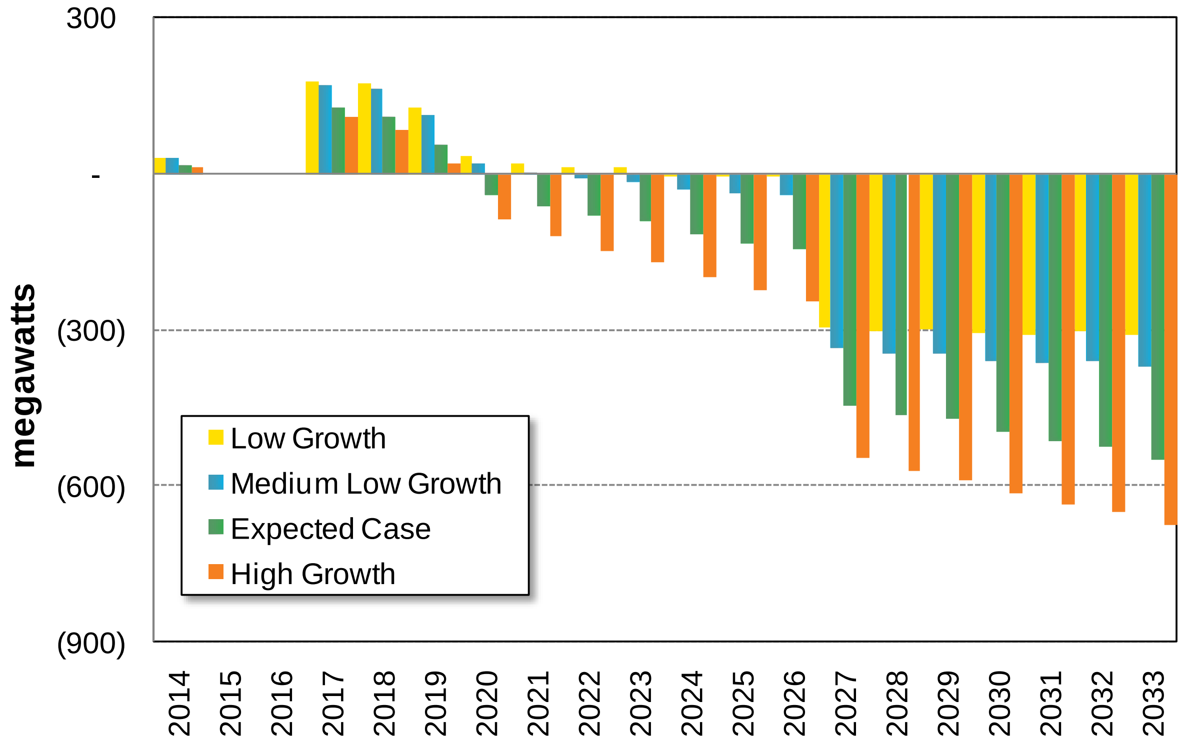

Table 8.15: Load Growth Sensitivities

Year	PRS	Low Load Growth	Medium Low Load Growth	High Load Growth
2019	83 MW SCCT			150 MW SCCT
2020				
2021				
2022			6 MW Upgrade	92 MW SCCT
2023	83 MW SCCT		90 MW SCCT	
2024				
2025				
2026	270 MW CCCT	270 MW CCCT	270 MW CCCT	270 MW CCCT
2027		50 MW SCCT		92 MW SCCT
2028				6 MW Upgrade
2029	6 MW Upgrade			50 MW SCCT
2030				
2031				
2032				
2033	50 MW SCCT			50 MW SCCT
Demand Res. (MW)	19	1	20	20
Efficiency (aMW)	164	142	147	175

Resource-Specific Scenarios

As part of an IRP, resource specific scenarios are helpful to gain understanding of specific resource decisions. This section covers four resource specific scenarios. This exercise illustrates the changes in cost and risk with selective resource decision making. The scenarios evaluate different resource decision such as more renewables, or switching from CTs to CCCTs. Figure 8.19 shows the results of the four scenarios outlined below

- **200 MW Wind and CTs:** 200 MW of new wind is added to the portfolio, 100 MW in 2020 and another 100 MW in 2025. This scenario meets capacity needs with Frame CT's and Demand Response. In the case, costs are 5.5 percent higher and risk 5 percent higher than the PRS. Further, this portfolio lays to the right of the efficient frontier indicating there are more optimal portfolios to meet capacity objectives.
- **200 MW Solar and CTs:** 10 MW of solar is added each year totaling 200 MW over the 20-year planning horizon. Since solar does not provide any capacity benefit to Avista in the winter, Frame CT's are added along with a demand response to meet capacity needs. This scenario results in power supply costs 8 percent higher and risk is 8.5 percent higher
- **Hydro Upgrades and CTs:** The Spokane River hydro upgrades (Post Falls, Monroe Street 2, and Long Lake 2) and Cabinet Gorge upgrades are included in this scenario beginning in 2024 and adding an upgrade each year through 2027. This scenario also fills in remaining capacity needs with CT's, in this portfolio costs and risks are also increased as compared to the PRS. Costs are 5 percent higher and risk is 13 percent higher.
- **Two CCCTs:** The first capacity need in 2019 replaces the SCCT with a CCCT, creating a short-term resource surplus. This scenario then uses another CCCT in 2027 to replace Lancaster (similar to the PRS). The portfolio is on the efficient frontier and reduces power supply volatility. This case lowers risk by 13 percent, but costs increase 2 percent. An RFP would evaluate this portfolio option prior to selecting a new resource in 2020.

The risk is higher in all renewable scenarios, compared to the PRS, because of increased dependence on the energy market. The PRS includes a combination of CCCT and CT plants. CCCT plants reduce market risk as hedges against short-term market shortages. Figure 8.19 shows that the combination of CTs and renewable resources do not outperform the PRS from a risk measure, this illustrates the CCCT plan reduces market risk more than renewables. Renewables help lower risk, this is shown by comparing the portfolio point to the upper most black dot (CT only portfolio). Renewables do not significantly reduce risk because all of the energy is excess to load needs and the energy is sold on the market, where as the CCCT plant is used to meet capacity and energy needs.

Figure 8.19: Resource Specific Scenarios

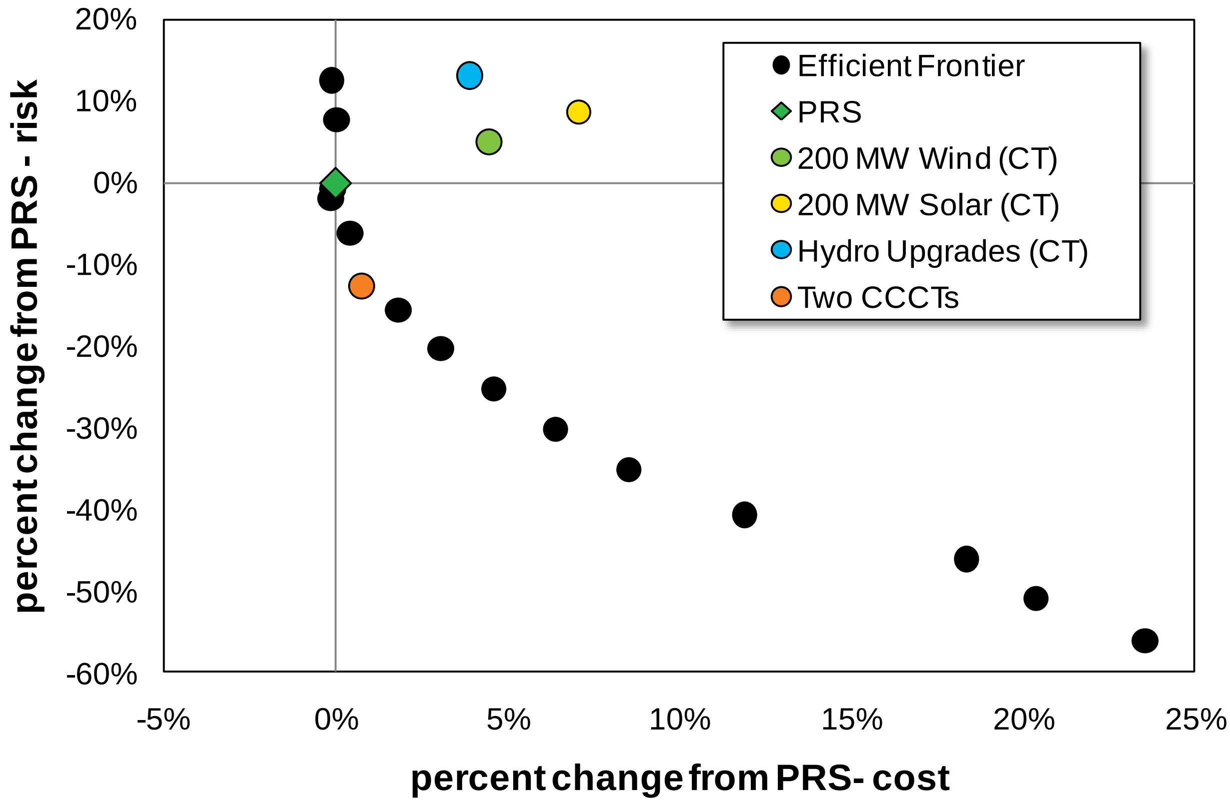

Table 8.16: Winter 1 Hour Capacity Position (MW) with New Resources

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
TOTAL LOAD OBLIGATIONS																				
Native Load Forecast	1,673	1,699	1,727	1,753	1,780	1,809	1,830	1,853	1,878	1,901	1,924	1,951	1,978	2,004	2,031	2,056	2,082	2,109	2,139	2,170
Conservation Forecast	8	16	27	39	53	68	75	84	95	104	112	124	136	148	160	170	180	192	206	221
Net Native Load Forecast	**1,665**	**1,683**	**1,700**	**1,713**	**1,727**	**1,741**	**1,755**	**1,769**	**1,783**	**1,798**	**1,812**	**1,827**	**1,842**	**1,856**	**1,871**	**1,887**	**1,902**	**1,917**	**1,933**	**1,948**
Firm Power Sales	211	158	158	8	8	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total Requirements	**1,875**	**1,841**	**1,857**	**1,721**	**1,735**	**1,747**	**1,761**	**1,775**	**1,789**	**1,804**	**1,818**	**1,833**	**1,848**	**1,863**	**1,878**	**1,893**	**1,908**	**1,923**	**1,939**	**1,954**
RESOURCES																				
Firm Power Purchases	117	117	117	117	117	116	34	34	33	33	33	33	33	33	33	33	33	33	33	33
Hydro Resources	998	888	889	955	955	919	924	920	920	928	920	920	928	920	920	928	920	920	928	920
Base Load Thermals	895	895	895	895	895	895	895	895	895	895	895	895	895	617	617	617	617	617	617	617
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	**2,252**	**2,143**	**2,143**	**2,210**	**2,210**	**2,172**	**2,095**	**2,091**	**2,091**	**2,098**	**2,090**	**2,090**	**2,098**	**1,811**	**1,811**	**1,819**	**1,811**	**1,811**	**1,819**	**1,811**
Peak Position Before Reserve Planning	**377**	**302**	**286**	**489**	**475**	**425**	**334**	**316**	**301**	**294**	**272**	**257**	**250**	**-51**	**-66**	**-74**	**-97**	**-112**	**-120**	**-143**
RESERVE PLANNING																				
Planning Margin	-233	-236	-238	-240	-242	-244	-246	-248	-250	-252	-254	-256	-258	-260	-262	-264	-266	-268	-271	-273
Total Ancillary Services Required	-139	-136	-137	-128	-129	-131	-136	-137	-138	-139	-141	-142	-143	-139	-139	-140	-140	-140	-140	-140
Reserve & Contingency Availability met by Hydro	13	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Reserve Planning	**-359**	**-366**	**-369**	**-362**	**-366**	**-369**	**-376**	**-379**	**-382**	**-386**	**-389**	**-392**	**-395**	**-393**	**-396**	**-398**	**-400**	**-403**	**-406**	**-408**
Peak Position w/ Contingency	**17**	**-64**	**-84**	**126**	**110**	**56**	**-42**	**-64**	**-81**	**-92**	**-117**	**-135**	**-145**	**-445**	**-462**	**-472**	**-497**	**-515**	**-525**	**-551**
Planning Margin	**20%**	**16%**	**15%**	**28%**	**27%**	**24%**	**19%**	**18%**	**17%**	**16%**	**15%**	**14%**	**14%**	**-3%**	**-4%**	**-4%**	**-5%**	**-6%**	**-6%**	**-7%**
NEW RESOURCES																				
Short-Term Market Purchase	0	75	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New NG Fired Peakers	0	0	0	0	0	0	80	80	80	80	160	160	160	160	240	240	240	240	240	288
New Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	260	260	260	260	260	260	260
Thermal Resource Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2
Demand Response	0	0	0	0	0	0	0	0	1	6	6	10	15	20	20	20	20	20	20	20
Total New Resources	**0**	**75**	**100**	**0**	**0**	**0**	**80**	**80**	**81**	**86**	**166**	**169**	**175**	**440**	**520**	**522**	**522**	**522**	**522**	**570**
Peak Position with New Resources	**17**	**11**	**16**	**126**	**110**	**56**	**38**	**16**	**0**	**-5**	**49**	**34**	**30**	**-5**	**58**	**50**	**25**	**7**	**-4**	**19**
Planning Margin with New Resources	**20%**	**20%**	**21%**	**28%**	**27%**	**24%**	**23%**	**22%**	**21%**	**21%**	**24%**	**23%**	**23%**	**21%**	**24%**	**24%**	**22%**	**21%**	**21%**	**22%**

Table 8.17: Summer 18-Hour Capacity Position (MW) with New Resources

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
TOTAL LOAD OBLIGATIONS																				
Native Load Forecast	1,474	1,500	1,527	1,553	1,581	1,611	1,631	1,655	1,679	1,703	1,726	1,753	1,780	1,806	1,834	1,859	1,885	1,912	1,943	1,974
Conservation Forecast	9	18	30	43	58	74	82	92	103	113	122	135	148	161	174	185	196	209	225	241
Net Native Load Forecast	**1,465**	**1,482**	**1,498**	**1,510**	**1,523**	**1,536**	**1,550**	**1,563**	**1,576**	**1,590**	**1,604**	**1,618**	**1,631**	**1,646**	**1,660**	**1,674**	**1,689**	**1,703**	**1,718**	**1,733**
Firm Power Sales	212	159	159	9	9	8	8	7	7	7	7	7	7	7	7	7	7	7	7	7
Total Requirements	**1,677**	**1,641**	**1,657**	**1,519**	**1,532**	**1,544**	**1,557**	**1,570**	**1,584**	**1,597**	**1,611**	**1,625**	**1,639**	**1,653**	**1,667**	**1,681**	**1,696**	**1,710**	**1,725**	**1,740**
RESOURCES																				
Firm Power Purchases	29	29	29	29	29	26	26	26	26	25	25	25	25	25	25	25	25	25	25	25
Hydro Resources	701	707	663	631	638	583	580	622	624	622	622	624	622	622	624	622	622	624	622	622
Base Load Thermals	785	785	785	785	785	785	785	785	785	785	785	785	785	556	556	556	556	556	556	556
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	**1,691**	**1,698**	**1,653**	**1,621**	**1,628**	**1,571**	**1,568**	**1,609**	**1,611**	**1,609**	**1,609**	**1,611**	**1,609**	**1,379**	**1,381**	**1,379**	**1,379**	**1,381**	**1,379**	**1,379**
Peak Position Before Reserve Planning	**14**	**57**	**-3**	**102**	**96**	**27**	**11**	**39**	**27**	**11**	**-2**	**-14**	**-30**	**-274**	**-286**	**-302**	**-317**	**-330**	**-346**	**-361**
RESERVE PLANNING																				
Planning Margin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Ancillary Services Required	-177	-176	-177	-170	-172	-173	-175	-176	-177	-179	-180	-181	-182	-166	-167	-167	-168	-169	-169	-170
Reserve & Contingency Availability met by Hydro	177	176	177	170	172	173	175	176	177	179	180	181	182	166	167	167	168	169	169	170
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Reserve Planning	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Peak Position w/ Contingency	**14**	**57**	**-3**	**102**	**96**	**27**	**11**	**39**	**27**	**11**	**-2**	**-14**	**-30**	**-274**	**-286**	**-302**	**-317**	**-330**	**-346**	**-361**
Planning Margin	**1%**	**3%**	**0%**	**7%**	**6%**	**2%**	**1%**	**2%**	**2%**	**1%**	**0%**	**-1%**	**-2%**	**-17%**	**-17%**	**-18%**	**-19%**	**-19%**	**-20%**	**-21%**
NEW RESOURCES																				
Short-Term Market Purchase	0	0	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New NG Fired Peakers	0	0	0	0	0	0	72	72	72	72	144	144	144	144	217	217	217	217	217	260
New Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	235	235	235	235	235	235	235
Thermal Resource Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	5	5	5
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total New Resources	**0**	**0**	**25**	**0**	**0**	**0**	**72**	**72**	**72**	**72**	**144**	**144**	**144**	**379**	**451**	**457**	**457**	**457**	**457**	**500**
Peak Position with New Resources	**14**	**57**	**22**	**102**	**96**	**27**	**83**	**111**	**99**	**84**	**142**	**130**	**114**	**105**	**165**	**154**	**140**	**127**	**111**	**139**
Planning Margin with New Resources	**1%**	**3%**	**1%**	**7%**	**6%**	**2%**	**5%**	**7%**	**6%**	**5%**	**9%**	**8%**	**7%**	**6%**	**10%**	**9%**	**8%**	**7%**	**6%**	**8%**

Table 8.18: Average Annual Energy Position (aMW) With New Resources

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
TOTAL LOAD OBLIGATIONS																				
Native Load Forecast	1,060	1,079	1,100	1,123	1,144	1,165	1,181	1,197	1,215	1,232	1,250	1,272	1,291	1,311	1,331	1,351	1,373	1,396	1,422	1,449
Conservation Forecast	6	12	20	29	39	51	55	62	70	77	83	92	101	109	118	126	134	142	153	164
Net Native Load Forecast	**1,054**	**1,067**	**1,079**	**1,093**	**1,105**	**1,114**	**1,125**	**1,135**	**1,145**	**1,155**	**1,167**	**1,180**	**1,190**	**1,201**	**1,212**	**1,225**	**1,239**	**1,254**	**1,270**	**1,285**
Firm Power Sales	109	58	58	6	6	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total Requirements	**1,163**	**1,125**	**1,137**	**1,099**	**1,111**	**1,119**	**1,130**	**1,140**	**1,150**	**1,160**	**1,172**	**1,185**	**1,195**	**1,206**	**1,217**	**1,230**	**1,244**	**1,259**	**1,274**	**1,290**
RESOURCES																				
Firm Power Purchases	128	129	128	76	76	56	31	30	30	29	29	29	29	29	29	29	29	29	29	29
Hydro Resources	527	495	495	495	490	481	481	481	481	481	481	481	481	481	481	481	481	481	481	481
Base Load Thermals	723	725	718	715	732	711	724	736	713	717	714	719	673	506	504	506	504	506	504	506
Wind Resources	42	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Peaking Units	153	139	154	153	153	153	147	151	152	153	152	153	152	153	152	153	152	153	152	153
Total Resources	**1,573**	**1,528**	**1,535**	**1,479**	**1,490**	**1,440**	**1,422**	**1,438**	**1,416**	**1,420**	**1,415**	**1,421**	**1,374**	**1,208**	**1,206**	**1,208**	**1,206**	**1,208**	**1,206**	**1,208**
Energy Position Before Reserve Planning	**410**	**404**	**398**	**380**	**379**	**321**	**292**	**299**	**266**	**259**	**243**	**237**	**179**	**2**	**-12**	**-22**	**-39**	**-51**	**-69**	**-82**
RESERVE PLANNING																				
Contingency	-228	-231	-231	-232	-232	-214	-195	-196	-196	-197	-197	-198	-198	-199	-199	-200	-200	-201	-202	-202
Energy Position w/ Contingency	**182**	**173**	**167**	**148**	**147**	**106**	**96**	**103**	**70**	**63**	**46**	**39**	**-19**	**-197**	**-211**	**-221**	**-239**	**-252**	**-270**	**-284**
NEW RESOURCES																				
Short-Term Market Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New NG Fired Peakers	0	0	0	0	0	0	68	68	68	68	135	135	135	135	204	204	204	204	204	249
New Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	245	245	245	245	245	245	245
Thermal Resource Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	5	5	5
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total New Resources	**0**	**0**	**0**	**0**	**0**	**0**	**68**	**68**	**68**	**68**	**135**	**135**	**135**	**380**	**449**	**454**	**454**	**454**	**454**	**500**
Energy Position with New Resources	**182**	**173**	**167**	**148**	**147**	**106**	**164**	**170**	**137**	**130**	**181**	**174**	**116**	**184**	**238**	**233**	**215**	**203**	**184**	**216**

9. Action Items

The 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 to document ongoing improvements to the modeling and forecasting procedures and tools, as well as enhance the process with new research as the planning environment changes. This section provides an overview of the progress made on the 2011 IRP Action Plan and provides the 2013 Action Plan.

Summary of the 2011 IRP Action Plan

The 2011 Action Plan included five separate categories: resource additions and analysis, energy efficiency, environmental policies, modeling and forecasting enhancements, and transmission planning.

2011 Action Plan and Progress Report – Resource Additions and Analysis

- Continue to explore and follow potential new resource opportunities.
    - Over the past two years, Avista began investigating sites for future peaking-capable generation. This process consisted of interconnection feasibility studies, site visits, and permitting and environmental evaluation. Avista will continue this effort over the next several years prior to releasing an RFP for new peaking capacity.
    - Avista is ending studies on wind resource development with the passage of SB 5575 in Washington and the subsequent lack of need for renewables in this IRP. This includes ceasing development at the Reardan Wind site.

- Continue studies on the costs, energy, capacity and environmental benefits of hydro upgrades at both Spokane and Clark Fork River projects.
    - During 2012, Avista studied upgrade options to the Spokane River Project. The assessment included an engineering screening of several upgrade options for the five upper Spokane River developments and concluded with a recommendation to rehabilitate the Nine Mile Falls project rather building or rebuilding the powerhouse. The assessment provided perspectives on the river system's potential for meeting future load requirements, and options to add renewable energy at a price competitive with other renewables. Details on Spokane River upgrade opportunities are in Chapter 6, Generation Resource Options.
    - Avista completed high-level studies for the Cabinet Gorge hydroelectric development. The review evaluated options to add a fifth unit in the original bypass tunnel for additional capacity and to reduce total dissolved gases. This alternative was uneconomic compared to other utility alternatives.
- Study potential locations for the natural gas-fired resource identified to be online by the end of 2018.

  - Avista has begun its efforts to identify a site for a new natural gas-fired peaker. A small cross-function team is investigating potential sites within the service territory. Site selection considers proximity to natural gas pipelines, transmission, and distance away from population centers or locations with potential environmental liabilities. Avista has initiated transmission studies for potential areas discussed in Chapter 5.

- Continue participation in regional IRP processes and, where agreeable, find opportunities to meet resource requirements on a collaborative basis with other utilities.
  - Avista monitors and attends when appropriate other northwest utility's IRP processes. With Avista's needs toward the beginning of the next decade, and for smaller unit sizes, the potential for resource collaboration is unlikely. Collaboration works best on developing large projects where economies of scale benefits smaller off-takers. Given the PRS's first identified resource is for a small peaker, collaborating on a project would be unlikely.
  - Avista's staff continues to participate in regional processes including the development of the Seventh Power Plan, PNUCC studies, and work done by the Western Governors Association.

- Provide an update on the Little Falls and Nine Mile hydroelectric project upgrades.
  - The Nine Mile hydro facility is undergoing rehabilitation. Units 1 and 2 have been removed and engineering work is complete. A status update will be included in the next IRP; the project is scheduled for completion in 2016.
  - At Little Falls, new electrical equipment and generator excitation systems are installed. Avista is replacing station service, updating the powerhouse crane, and developing new control systems on each of the units.

- Study potential for demand response projects with industrial customers.
  - Avista has begun preliminary investigation into demand response from industrial and commercial customers. For this IRP Avista identified 20 MW of commercial demand response. Avista intends to conduct a market assessment study during the next IRP process, and begin preliminary discussion with large industrial customers.

- Continue to monitor regional surplus capacity and Avista's reliance on this surplus for near- and medium-term needs.
  - Avista participates in the NPCC Resource Adequacy Forum. On January 23, 2013, the NPCC released a resource adequacy study. The study found that the Northwest has sufficient resources until a small regional deficit (350 MW) begins in 2017.
  - Avista has short-term winter peaking needs in 2015 and 2016; thereafter a 150 MW return of the PGE capacity sale will provide sufficient capacity through 2019. The Resource Adequacy forum studies provide evidence

that Avista can rely on for market capacity during this period. Further, the report identifies the regional summer peak periods to be surplus into the future, and that Avista can lower its planning margin requirements during summer months.

2011 Action Plan and Progress Report – Energy Efficiency

- Study and quantify transmission and distribution efficiency projects as they apply to the Washington RPS goals.
    - Avista continues to update its transmission and distribution system since the 2011 IRP; it has completed several distribution feeder upgrades and installed smart grid technology in Pullman and Spokane. In the 2010/2011 conservation target report Avista reported 3,512 MWh of savings. In the upcoming 2012/2013 report Avista plans on filing 32,387 MWh of savings.

- Update processes and protocols for conservation, measurement, evaluation and verification.
    - Avista is continuing to work through the process of updating and documenting its processes and procedures for the conservation programs offered through the utility. For evaluation, measurement and verification, Avista is guided by its framework and is committed to revisiting with stakeholders as necessary with the intent of updating and editing it as circumstances warrant.

- Continue to determine the potential impacts and costs of load management options.
    - Avista is participating in the Northwest Regional Smart Grid Demonstration Project to help understand the costs and benefits of load management programs. In the past, Avista has sponsored a pilot in Idaho as a way to understand how these programs could work and understand the costs and benefits. In the future, Avista will focus more on commercial and industrial opportunities by studying the potential and costs of such a programs.

2011 Action Plan and Progress Report – Environmental Policy

- Continue studies of state and federal climate change policies.
    - Avista actively engages in reviewing and participating in state and federal discussions about climate change policies related to electric generation and natural gas distribution. Details about the issues covered are in Chapter 4, Policy Considerations.

- Continue and report on the work of Avista's Climate Policy Council.
    - Avista's Climate Policy 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 the applicable laws and regulations. Avista has quantified its greenhouse gas emissions using the World Resources Initiative–World Business Council for Sustainable

Development inventory protocol in anticipation of state and federal greenhouse gas reporting mandates. Details about Climate Policy Council efforts are in Chapter 4, Policy Considerations.

2011 Action Plan and Progress Report – Modeling and Forecasting

- Continue following regional reliability processes and develop Avista-centric modeling for possible inclusion in the 2013 IRP.
    - Avista has developed, with support from NPCC staff, an Avista view of the northwest load and resource balance (see Chapter 2). Given today's assumptions, the region has enough capacity to meet Northwest winter needs to 2017, and summer capacity needs indefinitely where the larger winter capacity needs are met.
    - Since the 2011, IRP Avista updated and added logic and reporting enhancements to Avista's LOLP model per NPCC staff recommendations. The results of this discussion and analysis led Avista to rely on the mixture of new resources and market purchases to meet a 5 percent LOLP reliability target. See Chapter 2, Loads & Resources, for a discussion of this study.

- Continue studying the impacts of climate change on retail loads.
    - The load forecast includes changes in Spokane temperatures away from the 30-year normal to include fewer heating degree days and more cooling degree days per a 2008 University of Washington study. The study anticipates there will not be a large effect on retail loads from potential climate change activities. Avista investigated studies regarding changing water conditions from climate change and found there is no evidence of changing annual average conditions, but rather higher flows earlier in the year. The higher flows indirectly benefit customers as increased flow periods coincide with higher 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.
    - Quality regional wind output data is available from the BPA website only back to 2007. Given this short term dataset, correlating to load and hydro data will provide statistically insignificant results. The best way to estimate these correlations is to fund a long-term weather consultant study; the NPCC's Seventh Power Plan would benefit from such a study. Avista will be participating in this planning process and will recommend a study based on long-term data.

2011 Action Plan and Progress Report – Transmission and Distribution Planning

- Work to maintain Avista's existing transmission rights, under applicable FERC policies, for transmission service to bundled retail native load.
    - Avista has maintained its existing transmission rights to meet native customer load.

- Continue to participate in BPA transmission processes and rate proceedings to minimize the costs of integrating existing resources outside of Avista's service area.
  - Avista is actively participating in the BPA transmission rate proceedings.

- 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.
  - Avista staff participate in and lead many regional transmission efforts including Columbia Grid and the Transmission Coordination Work Group (TCWG).

- Evaluate costs to integrate new resources across Avista's service territory and from regions outside of the Northwest.
  - Avista's Transmission group performed seven studies of potential generation upgrades and new facilities, these studies are in Appendix D and Chapter 5.

- Study and implement distribution feeder rebuilds to reduce system losses.
  - Since the 2011 IRP, Avista has completed two feeder rebuilds. These rebuilds reduce losses by 1,542 MWh, improve reliability, and decrease future operation and maintenance costs.

- Continue to study other potential areas to implement Smart Grid projects to other areas of the service territory.
  - With the completion of the Spokane and Pullman Smart Grid projects, Avista put all such future projects on hold. Additional projects will be evaluated on a case-by-case basis for cost effectiveness and increased reliability.

- Study transmission reconfigurations that economically reduce system losses.
  - Avista's transmission department continues to review potential projects to increase reliability and reduce system losses. Chapter 5, Transmission & distribution, discusses projects meeting this objective.

2013 IRP Action Plan

Avista's 2013 PRS provides direction and guidance for the type, timing and size of future resource acquisitions. The 2013 IRP Action Plan highlights the activities planned for possible inclusion in the 2015 IRP. Progress and results for the 2013 Action Plan items are reported to the TAC and the results will be included in Avista's 2015 IRP. The 2013 Action Plan includes input from Commission Staff, Avista's management team, and the TAC.

Generation Resource Related Analysis

- Consider Spokane and Clark Fork River hydro upgrade options in the next IRP as potential resource options to meet energy, capacity and environmental requirements.

- Continue to evaluate potential locations for the natural gas-fired resource identified to be online by the end of 2019, including environmental reviews, transmission studies, and potential land acquisition.
- Continue participation in regional IRP and regional planning processes and monitor regional surplus capacity and continue to participate in regional capacity planning processes.
- Commission a demand response potential and cost assessment of commercial and industrial customers per its inclusion in the middle of the PRS action plan.
- Continue monitoring state and federal climate change policies and report work from Avista's Climate Change Council.
- Review and update the energy forecast methodology to better integrate economic, regional, and weather drivers of energy use.
- Evaluate the benefits of a short-term (up to 24-months) capacity position report.
- Evaluate options to integrate intermittent resources.

Energy Efficiency

- Work with NPCC, the UTC, and others to resolve adjusted market baseline issues for setting energy efficiency target setting and acquisition claims in Washington.
- Study and quantify transmission and distribution efficiency projects as they apply to EIA goals.
- Update processes and protocols for conservation measurement, evaluation and verification.
- Assess energy efficiency potential on Avista's generation facilities.

Transmission and Distribution Planning

- Work to maintain Avista'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.

Production Credits

Primary Avista 2013 Electric IRP Team

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