BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-12________

EXHIBIT NO._____(RJL-6)

ROBERT J. LAFFERTY

REPRESENTING AVISTA CORPORATION

2009 Electric Integrated Resource Plan

August 31, 2009

AVISTA®

SPECIAL THANKS TO OUR TALENTED VENDORS FROM THE SPOKANE AREA WHO PRODUCED THIS IRP:

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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 our reports filed with the Securities and Exchange Commission which are available on our website at www.avistacorp.com. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events.

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LIST OF ACRONYMS AND KEY TERMS

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

2009 IRP INTRODUCTION

Avista has a long tradition of innovation as a provider of clean, renewable energy. The 2009 Integrated Resource Plan (IRP) continues that tradition as it looks into the future needs of our customers. The IRP analyzes and outlines a strategy to meet projected demand through energy efficiency and a careful mix of new renewables and traditional resources.

The plan includes economic growth forecasts for the Avista service territory. Electricity sales growth is expected to occur at a rate of 1.7 percent over the next two decades. Avista projects that it will have sufficient resources to meet growth until 2018 when new energy supplies will need to be brought online.

Avista expects to add increasing amounts of new renewables to its generation portfolio in the coming years. This is partly due to active and pending state and federal regulations. Regardless of legislation, Avista believes that renewables represent viable energy sources that reduce the need for fossil fuels and diversify our resource mix.

New renewable energy sources like wind and solar power currently are more expensive to build than traditional energy resources. An added challenge is they are intermittent resources, meaning that the wind doesn't always blow and the sun doesn't always shine. Customers except high reliability so utilities will still need energy resources like natural gas and hydropower to keep the lights on. This presents a challenge to resource planners who must consider realiabilty as well as rate and environmental impacts.

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 input from interested community stakeholders.

Each IRP is a thoroughly researched and data driven document to guide responsible resource planning for the company. The plan's Preferred Resource Strategy (PRS) section covers our projected resource acquisitions over the next 20 years.

Some highlights of the PRS include:

- 150 MW of wind power by 2012 to take advantage of renewable energy tax incentives, diversify our fuel mix, and meet renewable portfolio standards.
- An additional 200 MW of wind power over the IRP timeframe.
- 26 percent of future load growth is met by new conservation.
- Construction of 750 MW of clean-burning natural gas-fired generation facilities.
- Avista does not plan to add any coal-fired generation to its resource mix.
- Aggressive energy efficiency measures are expected to save 226 aMW of cumulative energy over the next 20 years.
- 5 MW of hydro upgrades are planned for the Little Falls and Upper Falls hydro projects.
- Large hydro upgrades will be studied as alternative new renewable resources for the 2011 IRP.
- Transmission upgrades will be needed to add new generation and 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 2011 IRP in early 2010. 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's 2009 Integrated Resource Plan (IRP) guides the utility's resource acquisition strategy over the next two years and the overall direction of resource procurements for the remainder of the 20-year planning horizon. The IRP provides a snapshot of the Company's resources and loads, and provides guidance regarding resource needs and acquisitions. The Preferred Resource Strategy (PRS) is a mix of renewable resources, conservation, upgrades at existing facilities, and new gas-fired generation.

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

Noxon Rapids Upgrade Crew

Resource Needs

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

Table 1: Net Position Forecast

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

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

Figure 1: Load Resource Balance—Winter Capacity

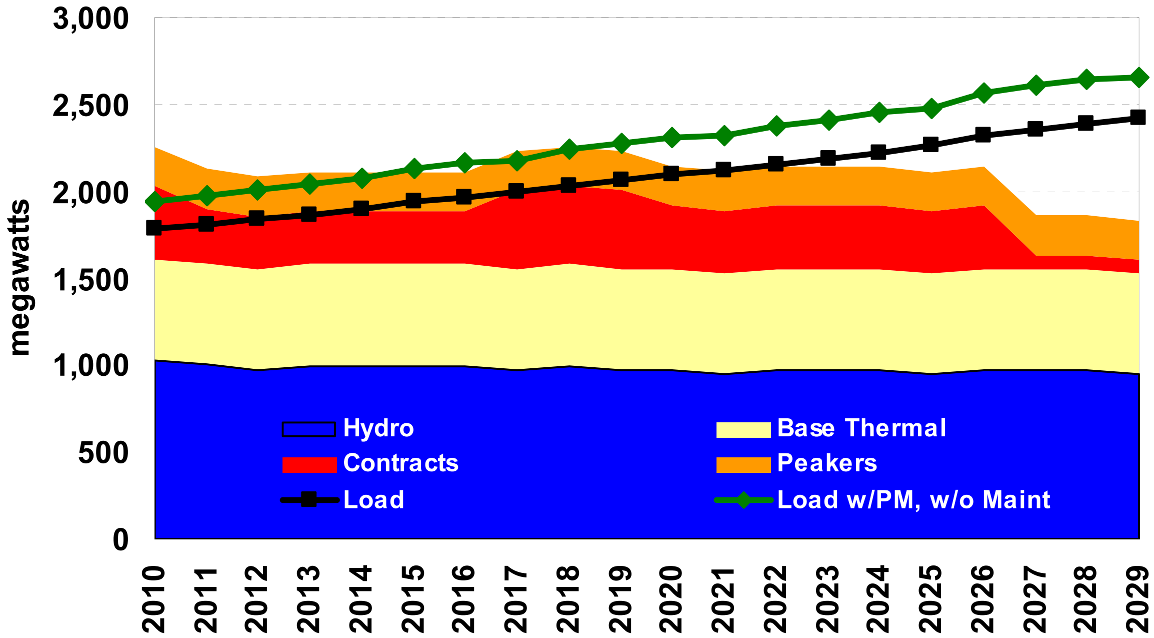
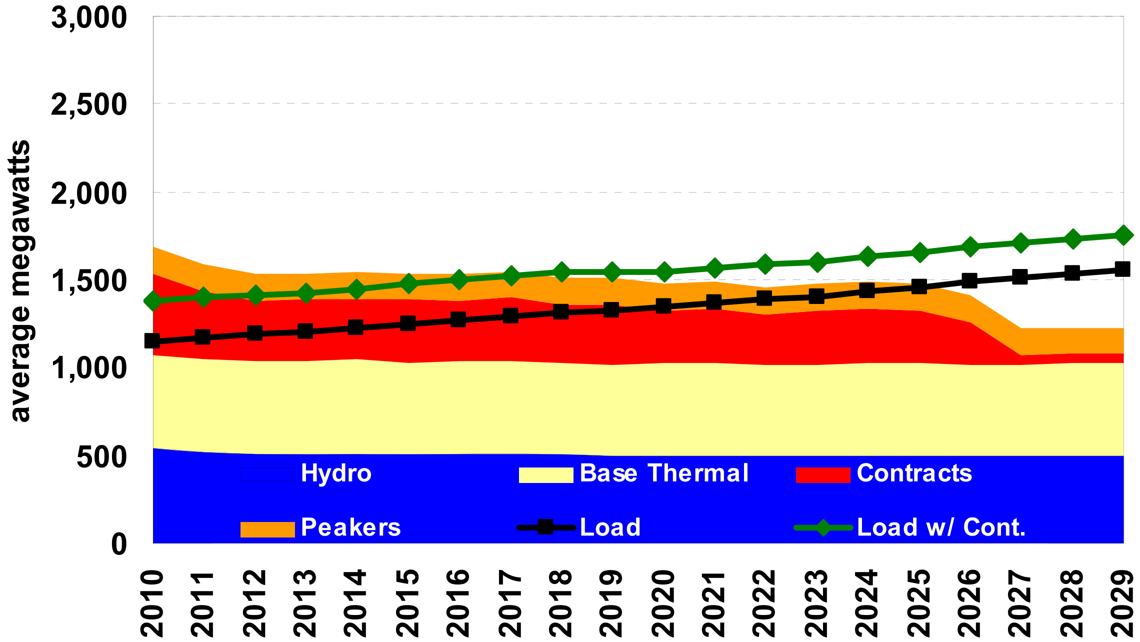


Figure 2: Load Resource Balance—Energy



Modeling and Results

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

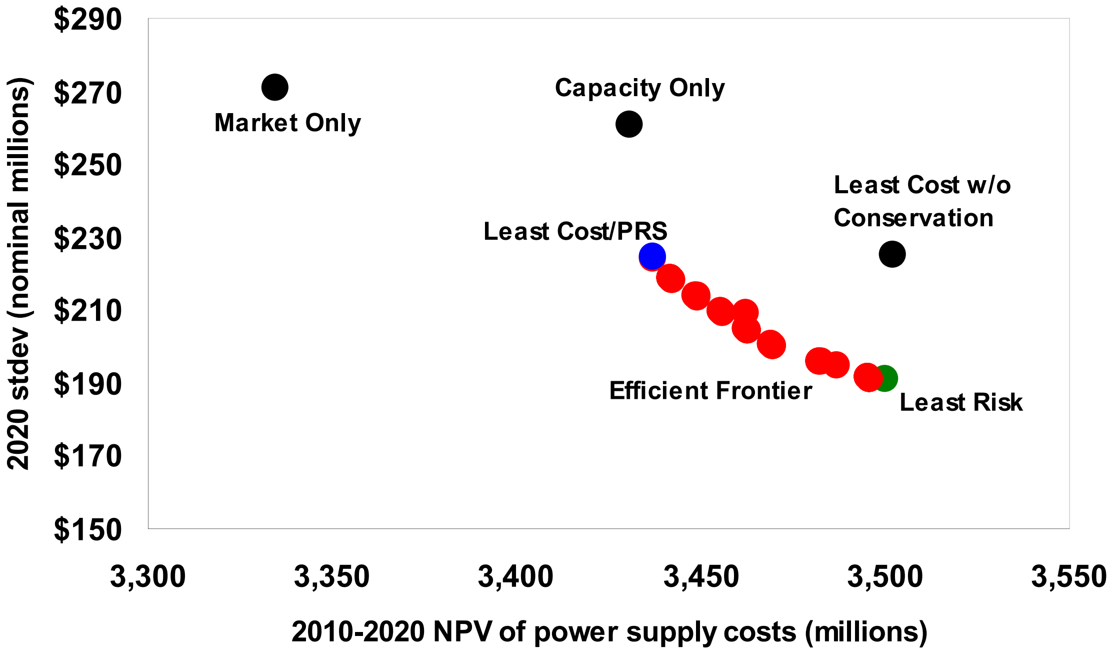
Cost-effective new resources and transmission were added as necessary to meet growing loads. Monte Carlo-style analysis varied hydro, wind, load, forced outages, greenhouse gas emissions, and gas price data over 250 iterations of potential future conditions. The simulation results were used to estimate the Mid-Columbia electric market, and the iterations collectively formed the Base Case for this IRP.

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

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

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

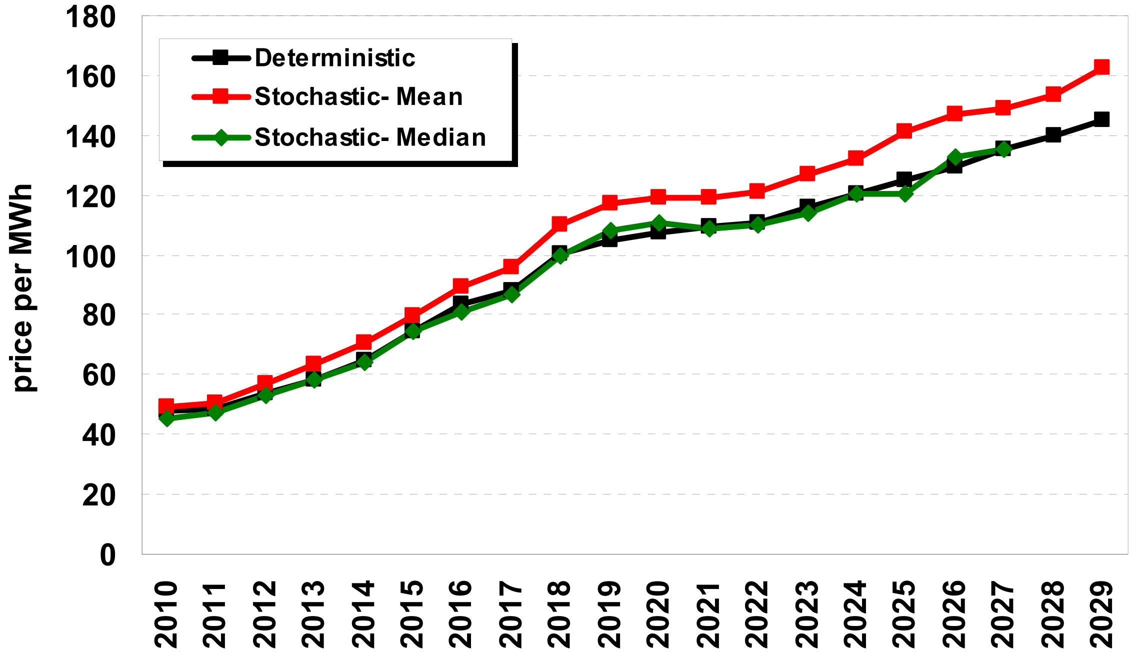
Figure 3: Efficient Frontier



Electricity and Natural Gas Market Price Forecasts

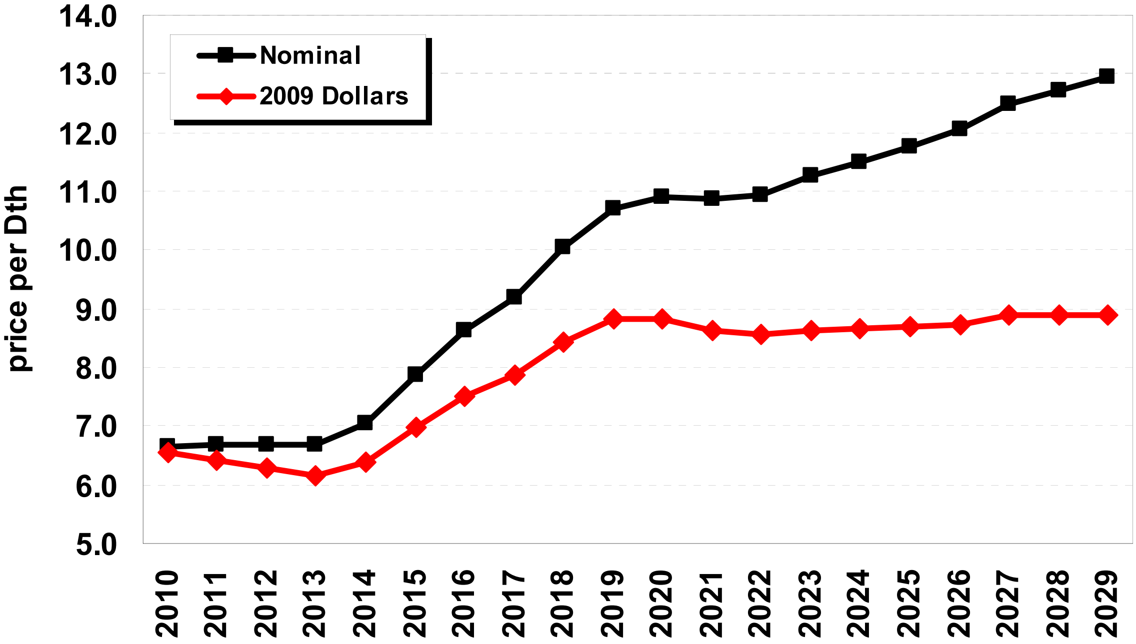
Figure 4 shows the Company's electricity price forecast developed for the 2009 IRP. The Mid-Columbia market price is expected to average $79.56 per MWh in 2009 dollars over the next 20 years; the average nominal price is $93.74 per MWh. Spreads between on- and off-peak prices are $14.34 per MWh in 2010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

Figure 4: Annual Flat Mid-Columbia Prices



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

Figure 5: Annual Average Henry Hub Natural Gas Price

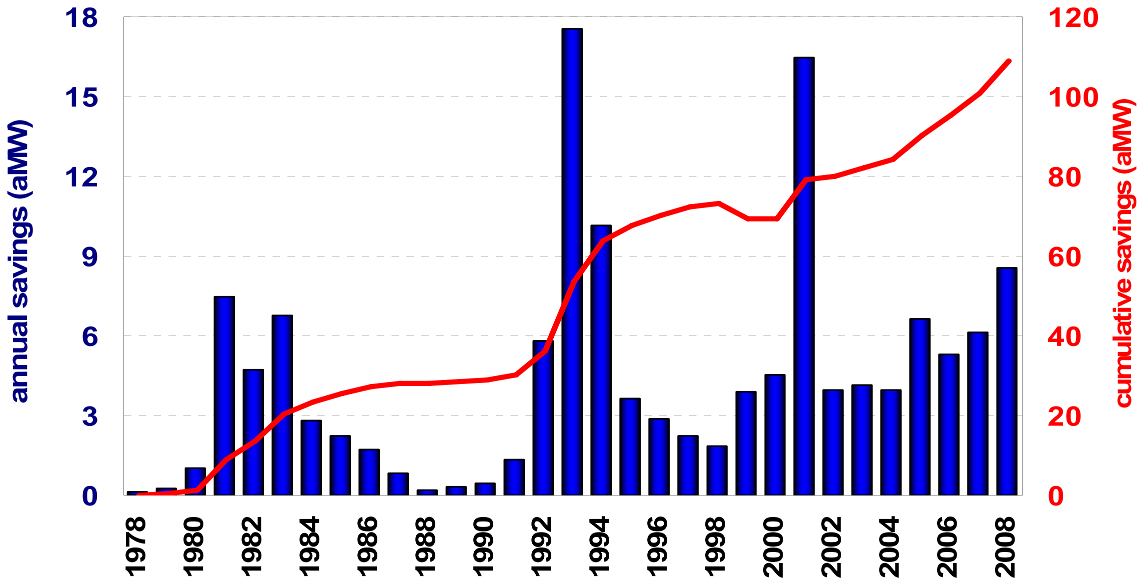


Energy Efficiency

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

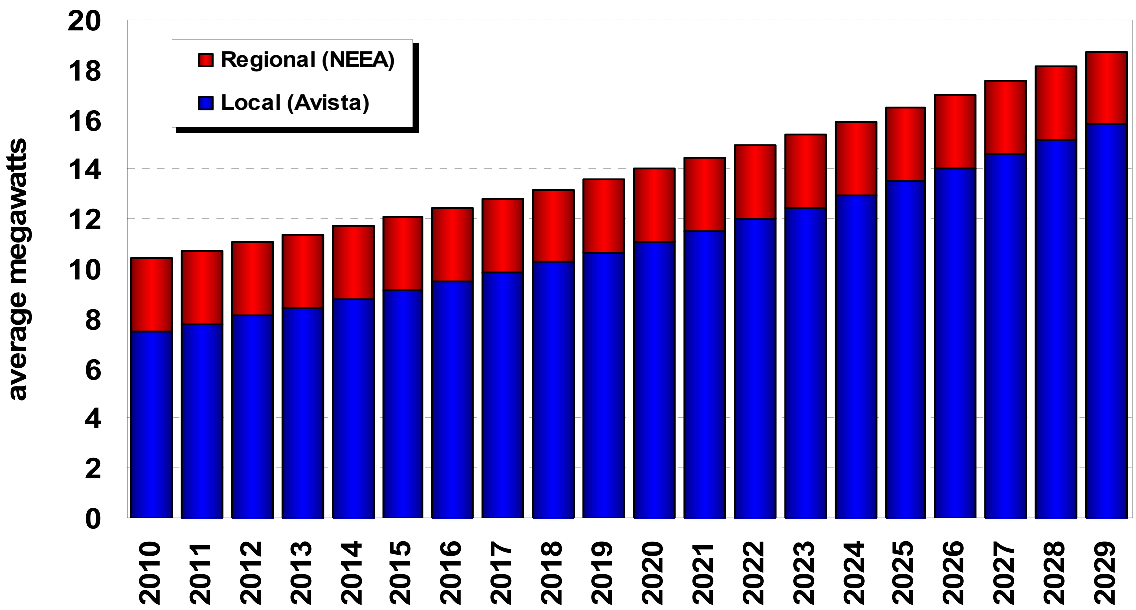
Figure 6 shows how conservation has decreased the Company's energy requirements by 138.5 aMW since programs began in the late 1970s. 109 aMW of efficiency projects acquired over the past 18 years are still online.

Figure 6: Cumulative Conservation Acquisitions



Approximately 3,000 efficiency measures were evaluated for the 2009 IRP. The PRS includes 10.4 aMW (7.5 aMW local and 2.9 aMW regional) of conservation are expected to be obtained in 2010. Figure 7 shows the projected levels of local and regional conservation over the next 20 years.

Figure 7: Forecast of Conservation Acquisition



Preferred Resource Strategy

The PRS is developed after careful consideration of information gathered over the IRP process. The PRS is reviewed and critiqued by management and the TAC. The 2009 plan relies on a combination of conservation, distribution system upgrades, wind, hydro upgrades, and gas-fired combined-cycle combustion turbines. It also identifies transmission projects to improve system reliability and to access generation resources necessary to comply with renewable portfolio standards. Figure 8 illustrates the Company's PRS.

Figure 8: Preferred Resource Strategy

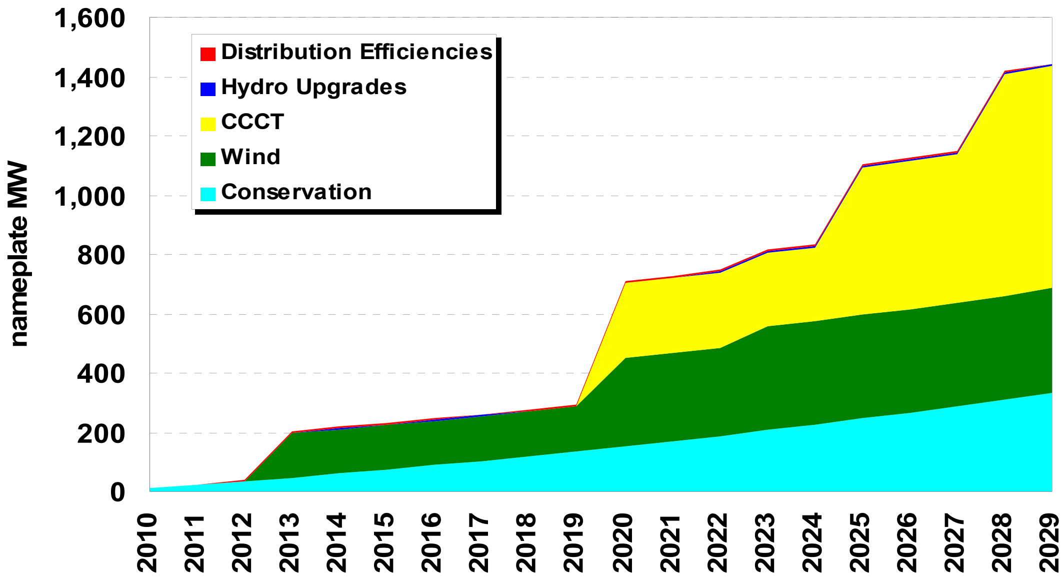


Table 2: 2009 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
NW Wind	2012	150.0	48.0
Distribution Efficiencies	2010-2015	5.0	2.7
Little Falls Unit Upgrades	2013-2016	3.0	0.9
NW Wind	2019	150.0	50.0
CCCT	2019	250.0	225.0
Upper Falls	2020	2.0	1.0
NW Wind	2022	50.0	17.0
CCCT	2024	250.0	225.0
CCCT	2027	250.0	225.0
Conservation	All Years	339.0	226.0
Total		**1,449.0**	**1,020.6**

The PRS resources, shown in nameplate capability, are shown in tabular format in Table 2 for the 2009 PRS and Table 3 for the 2007 PRS.

Table 3: 2007 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Non-Wind Renewable	2011	20.0	18.0
Non-Wind Renewable	2012	10.0	9.0
NW Wind	2013	100.0	33.0
Non-Wind Renewable	2013	5.0	4.5
Share of CCCT	2014	75.0	67.5
NW Wind	2015	100.0	33.0
NW Wind	2016	100.0	33.0
Non-Wind Renewable	2019	10.0	9.0
Non-Wind Renewable	2020	10.0	9.0
Non-Wind Renewable	2021	5.0	4.5
Share of CCCT[1]	2019	297.0	267.3
Share of CCCT	2027	305.0	274.5
Conservation	All Years	331.5	221.0
Total		**1,368.5**	**983.3**

The 2009 IRP requires just over $1.0 billion in net present value of new capital investments over the next 20 years.

Carbon Emissions

Carbon emission costs have been included in the Base Case since the 2007 IRP. Carbon, or CO_2, cost estimates are from a national market study by Wood Mackenzie. Figure 8 shows projected CO_2 emissions prices. Figure 9 shows the projected carbon emissions for existing and new generation assets. These estimates do not include emissions from market and contract purchases, and CO_2 emissions are not reduced for wholesale sales. The white area of Figure 10 indicates estimated emission levels without legislative action.

Figure 9: Estimated Price of CO_2 Credits for 2009 IRP

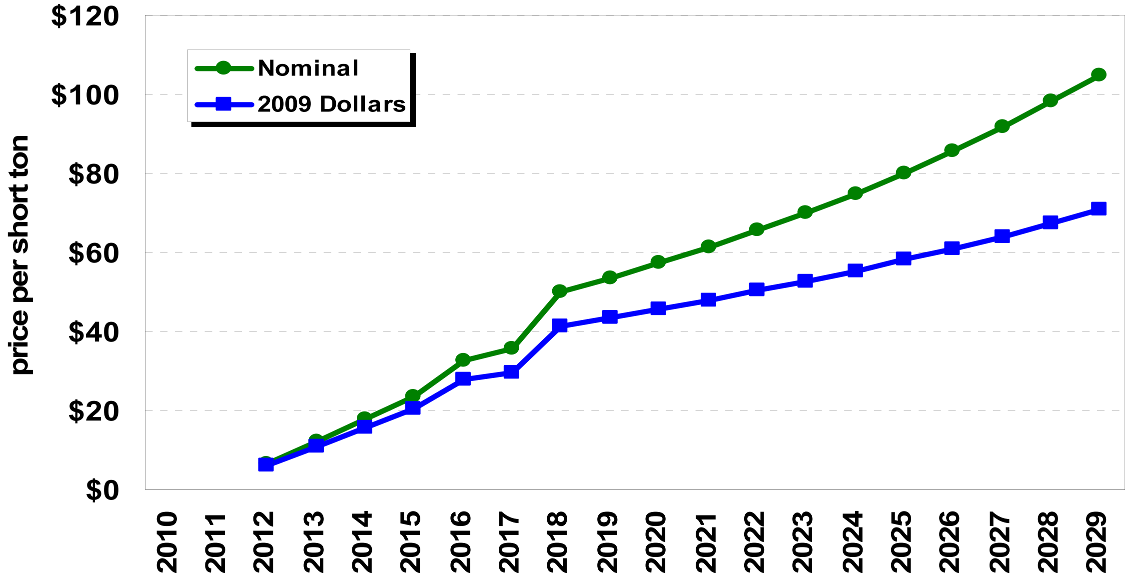
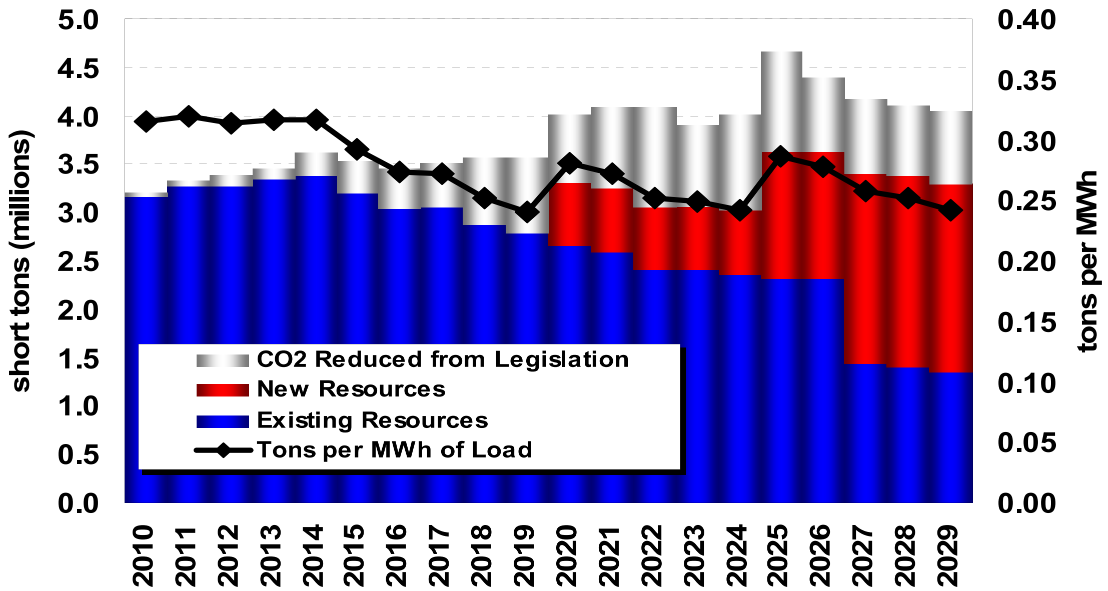


Figure 10: Avista Owned and Controlled Resource's Greenhouse Gas Emissions



Action Items

The Company's 2009 Action Plan outlines activities and studies to be developed and presented in the 2011 Integrated Resource Plan. The Action Plan was developed using input from the Company'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.

1. Introduction and Stakeholder Involvement

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

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

IRP Process

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

Stakeholder Participation

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

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

Public Process

The 2009 IRP is developed and written with the aid of a public process. All of the 2009 TAC presentations are available for review at the Company's website. The entire 2009 IRP, its appendices, and previous IRPs are available at Avista's web site.

Technical Advisory Committee

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

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

Table 1.1: TAC Participants

Participant	Organization
Andy Ford	Washington State University
Robin Toth	Greater Spokane Inc.
Dave Van Hersett	Resource Development Associates
Mike Connelly	Idaho Forest Group
John Daquisto	Gonzaga University
Lea Daeschel	Washington Attorney General's Office
Deborah Reynolds	Washington Utility and Transportation Commission
Steve Johnson	Washington Utility and Transportation Commission
David Nightingale	Washington Utility and Transportation Commission
Vanda Novak	Washington Utility and Transportation Commission
Carrie Dolwick	Northwest Energy Coalition
Kirsten Wilson	Washington State General Administration
Rick Sterling	Idaho Public Utilities Commission
Chuck Murray	Community Trade and Economic Development
Tom Noll	Idaho Power
Maury Galbraith	Northwest Power and Conservation Council
Villamour Gamponia	Puget Sound Energy
Mike Kersh	Inland Empire Paper

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

Table 1.2: TAC Meeting Dates and Agenda Items

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

Issue Specific Public Involvement Activities

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

External Energy Efficiency ("Triple E") Board

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

FERC Hydro Relicensing – Clark Fork River Projects

Over 50 stakeholder groups participated in the Clark Fork hydro-relicensing process beginning in 1993. This led to the first all-party settlement filed with a Federal Energy Regulatory Commission (FERC) relicensing application, and eventual issuance of a 45-year FERC operating license effective March 1, 2001. The nationally recognized Living License concept was a result of this process. This collaborative process continues in the implementation phase of the Living License with stakeholders participating in various protection, mitigation and enhancement measures.

FERC Hydro Relicensing – Spokane River Projects

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

Low Income Rate Assistance Program (LIRAP)

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

Regional Planning

The Pacific Northwest's generation and transmission system is operated in a coordinated fashion. Avista participates in many organization's planning processes. Information from this participation is used to supplement the Company's IRP process. Some organizations 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
- Seams Steering Group – Western Interconnection
- North American Electric Reliability Council

Future Public Involvement

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

2009 IRP Outline

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

Executive Summary

This chapter summarizes results and highlights of the 2009 IRP.

Chapter 1: Introduction and Stakeholder Involvement

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

Chapter 2: Loads and Resources

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

Chapter 3: Energy Efficiency

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

Chapter 4: Environmental Policy

This chapter focuses on modeling efforts and issues surrounding greenhouse gas emissions and state and federal environmental regulations.

Chapter 5: Transmission and Distribution Planning

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

Chapter 6: Generation Resource Options

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

Chapter 7: Market Analysis

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

Chapter 8: Preferred Resource Strategy

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

Chapter 9: Action Items

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

Regulatory Requirements

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

Table 1.3 Washington IRP Rules and Requirements

Rule and Requirement	Plan Citation
WAC 480-100-238(4) – Work plan filed no later than 12 months before next IRP due date. Work plan outlines content of IRP. Work plan outlines method for assessing potential resources.	Work plan submitted to the WUTC on August 29, 2008, See Appendix B
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- Environmental Policy Chapter 7- Market Analysis Chapter 8- Preferred Resource Strategy
WAC 480-100-238 (2)(b) – LRC analysis considers demand side uncertainties.	Chapter 3- Energy Efficiency
WAC 480-100-238(2)(b) – LRC analysis considers resource dispatchability.	Chapter 6- Generation Resource Options Chapter 7- Market Analysis
WAC 480-100-238(2)(b) – LRC analysis considers resource effect on system operation.	Chapter 7- Market Analysis Chapter 8- Preferred Resource Strategy

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

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

2. Loads and Resources

Introduction and Highlights

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

Section Highlights

- Weak economic growth is expected through 2011 in Avista's service territory.
- Historic conservation acquisitions are included in the load forecast; higher acquisition levels anticipated in this IRP reduce the load forecast further.
- Annual electricity sales growth from 2010-2020 averages 1.7 percent over the next decade (199 aMW) and 1.7 percent over the entire 20-year forecast.
- Peak loads are expected to grow at a 1.7 percent annual rate over the next 10 years (312 MW) and 1.7 percent over the 20-year forecast.
- Energy deficits begin in 2018; absent conservation deficits would begin in 2016.
- Renewable portfolio standard deficiencies are the driver of near-term resource need.

Economic Conditions in the Electric Service Territory

Avista's Plug-In Hybrid Sun Car

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

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

Figure 2.1: Avista's Service Territory

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

Population often is more stable than employment during times of economic change; however, population contracts during severe economic downturns as people leave in search of employment opportunities. Over the past 25 years, 1987 was the only year the region experienced a net loss in population. Figure 2.2 details actual and projected annual population changes in Bonner, Kootenai, and Spokane counties from 1990 to 2030. Figure 2.3 shows total population in these three counties for the same period.

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

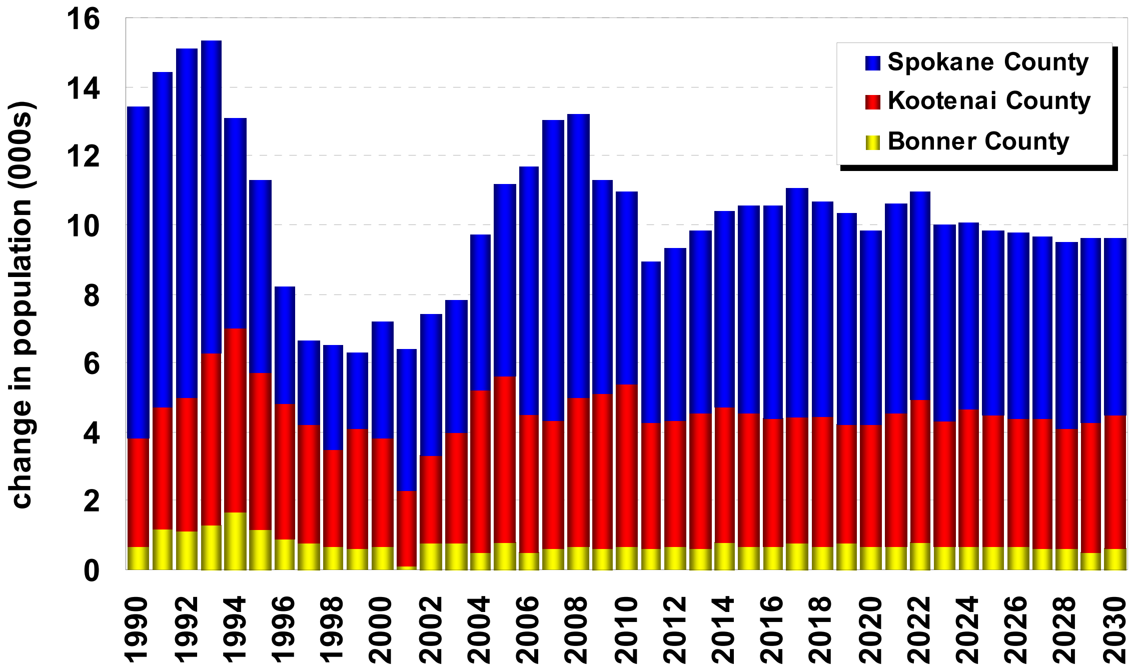
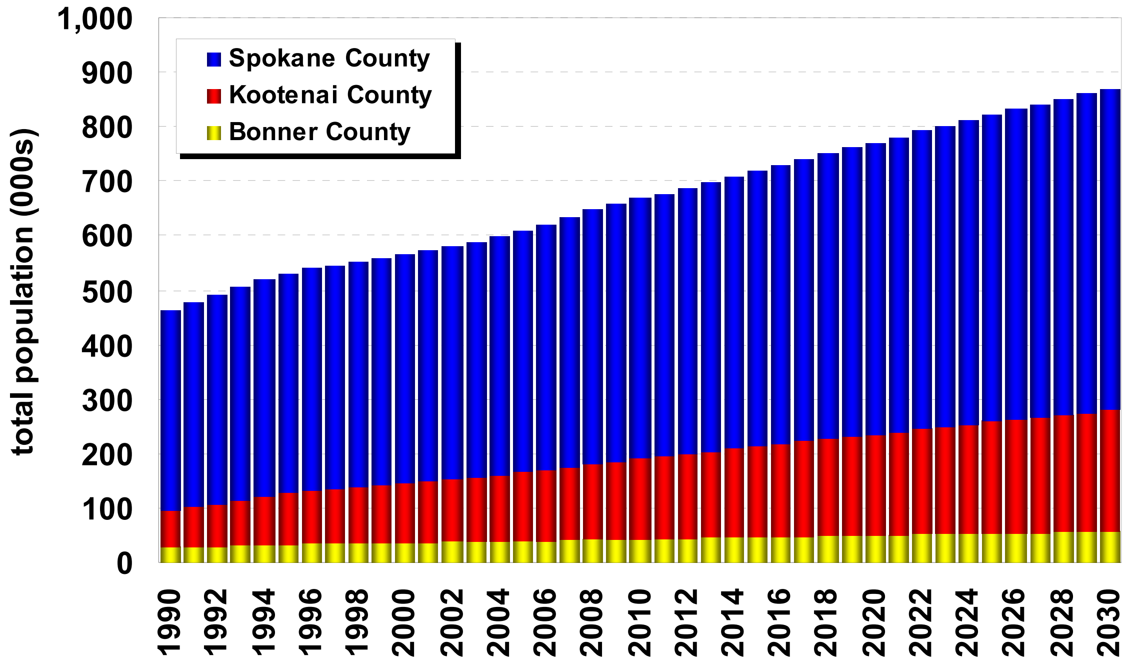


Figure 2.3: Total Population for Spokane, Kootenai and Bonner Counties



People, Jobs and Customers

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

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

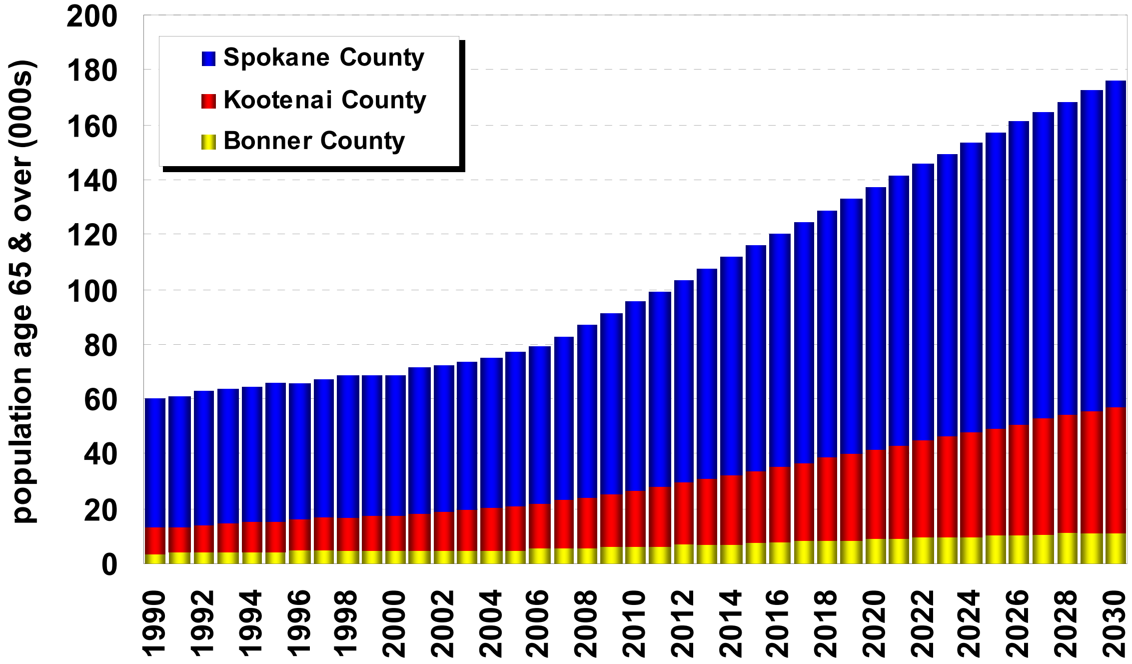
Table 2.1: Global Insight National Long Range Forecast Assumptions

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

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

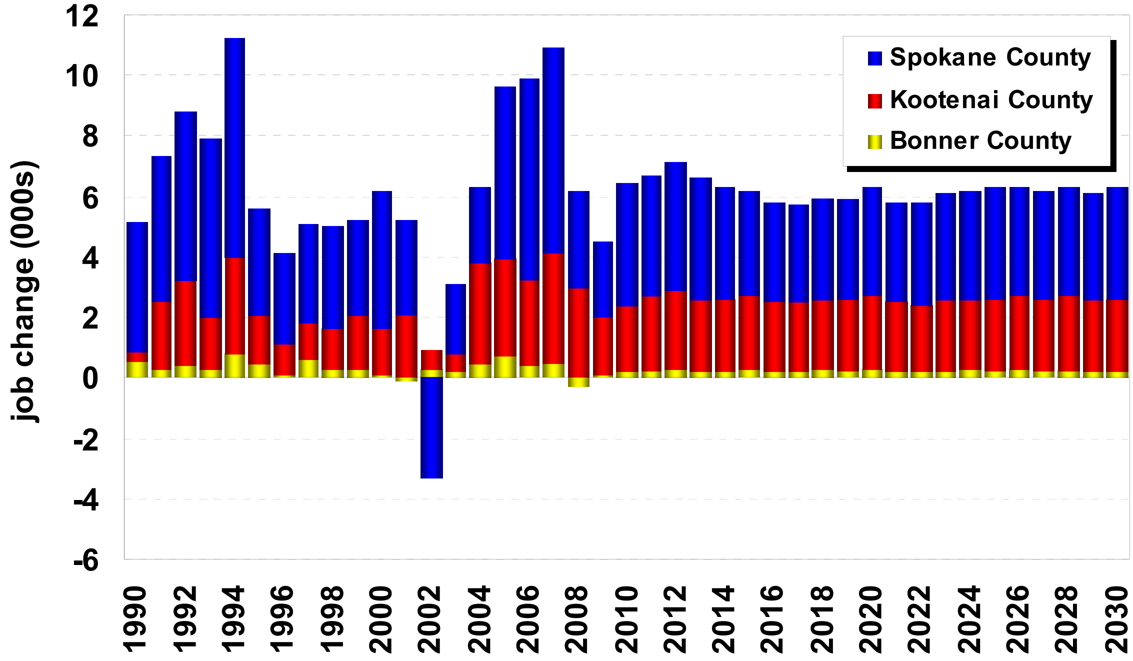
Regional population growth is supported by retiree immigration, representing between 10 and 20 percent of overall population growth. Figure 2.4 presents the population history and forecast for individuals 65 years and over in the three-county area. Between 1990 and 2010 this segment averages a compound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

Figure 2.4: Three-County Population Age 65 and Over



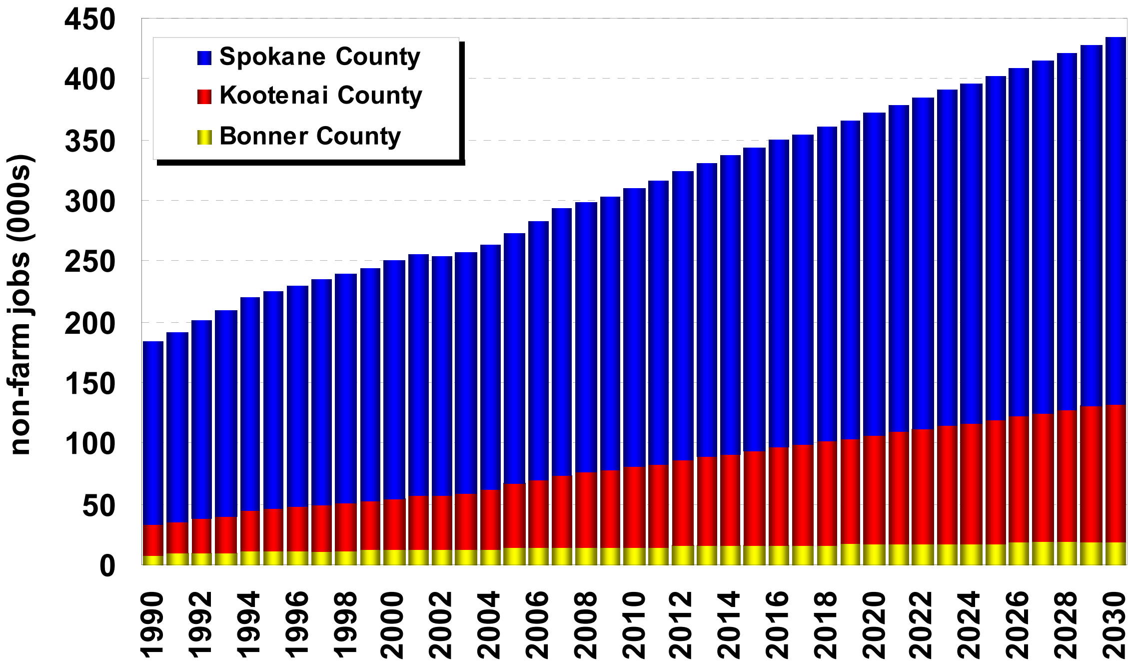
Employment growth often drives population growth. Figure 2.5 shows historical employment trends from 1990 and anticipated growth through 2030.

Figure 2.5: Three-County Job Change



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

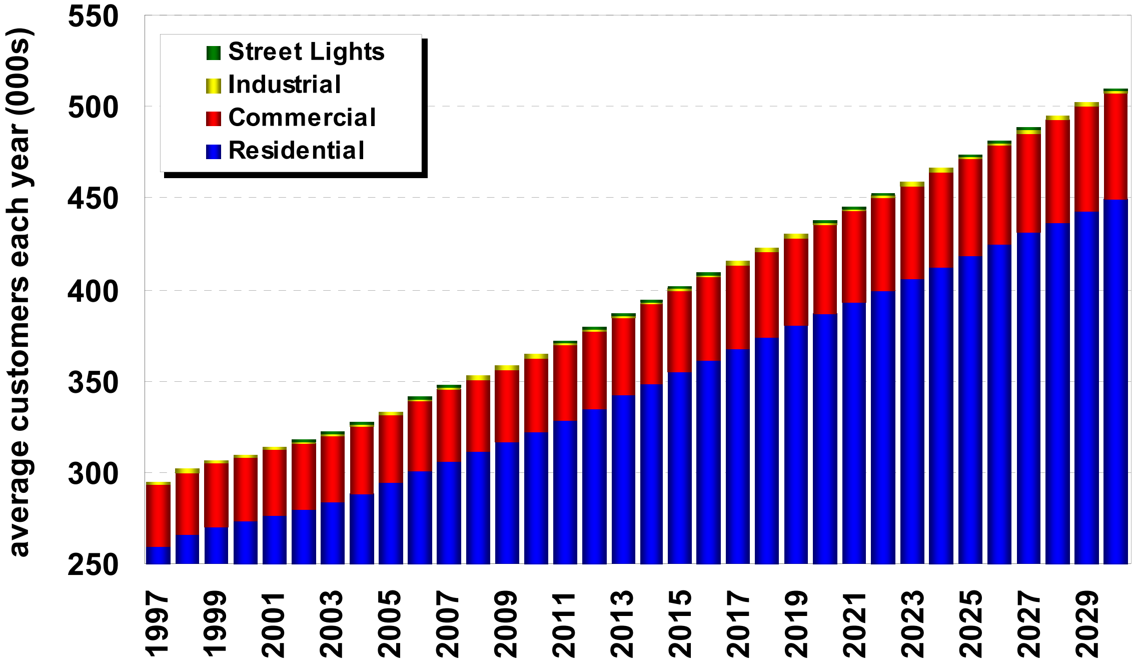
Figure 2.6: Three-County Non-Farm Jobs



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

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

Figure 2.7: Avista Annual Average Customer Forecast



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

Weather Forecasts

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

In response to questions from the TAC, the Company has implemented estimates of the impacts of climate change in its retail load forecast. Ample evidence of cooling and warming trends exists in the 115-year record. The recent trend has been a warming climate compared to the 30-year normal. Trends in heating and cooling degree days for Spokane are roughly equal to the scientific community's predictions for this geographic area, implying a one degree warming every 25 years. Incorporating the warming trend finds that in 20 years summer load would be approximately 26 aMW higher than the 30 year average weather case. In the winter, loads would be approximately 40 aMW lower in 2029, for a net impact of a 14 aMW load decrease. The Company will continue to study these data trends in its two year Action Plan and report findings in the 2011 IRP.

Price Elasticity

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

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

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

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

Retail Price Forecast

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

Conservation

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

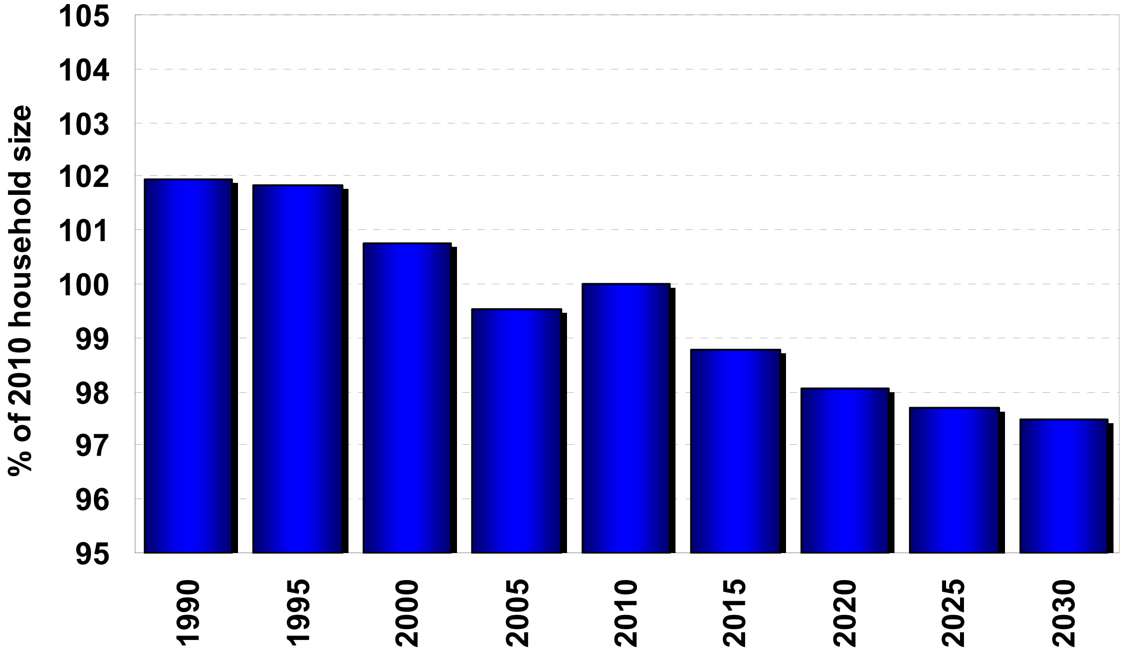
Use Per Customer Projections

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

The Company included a forecast of personal residential electric vehicles in the Base Case. These vehicles are a combination of plug-in hybrids and electric-only and represent a proportional share from the Northwest Power and Conservation Council's estimates available in mid-2008. Avista's share by 2030 is expected to be 85,000 plug-in hybrid cars, increasing residential load about 1.3% from 2010 to 2030.

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

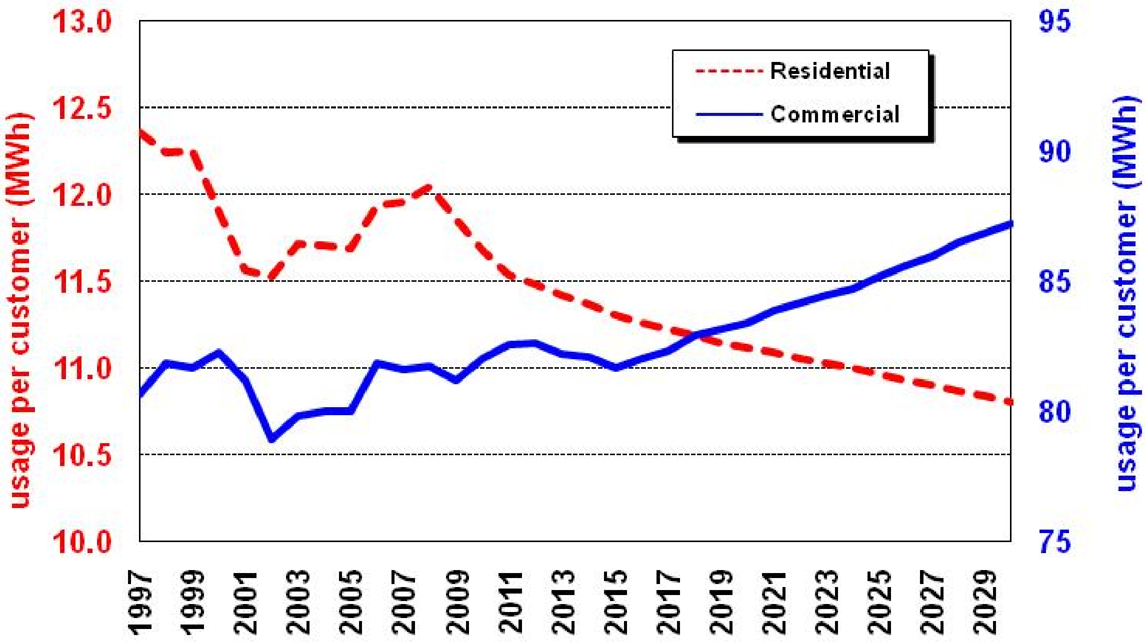
Figure 2.8: Household Size Index



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

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

Figure 2.9: Annual Use per Customer



Retail Electricity Sales Forecast

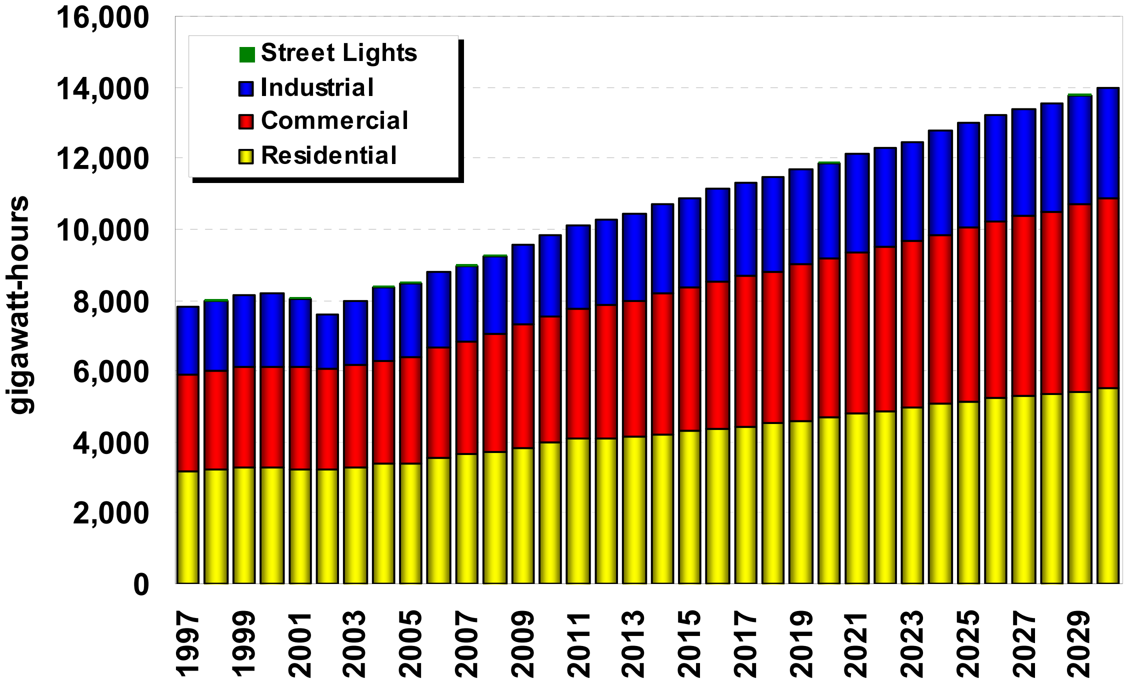
Between 1997 and 2008 the region was affected by major economic changes, not the least of which was a marked increase in wholesale and retail electricity prices. The energy crisis of 2000-01 included the implementation of widespread, permanent conservation efforts by our customers. In 2004, rising retail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

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

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

Actual, not weather corrected, retail electricity sales to Avista customers in 2008 were 8.93 billion kWh. Heating degree days in 2008 were 103 percent of normal, almost completely offset in terms of energy use by 121 percent of normal cooling degree days. The forecast for 2030 is 12.85 billion kWh, representing a 1.7 percent compounded increase in retail sales. See Figure 2.10. Degree days in 2030 are forecast to be 87 percent of the 1971-2000 thirty year normal for heating and 149 percent for cooling.

Figure 2.10: Avista's Retail Sales Forecast

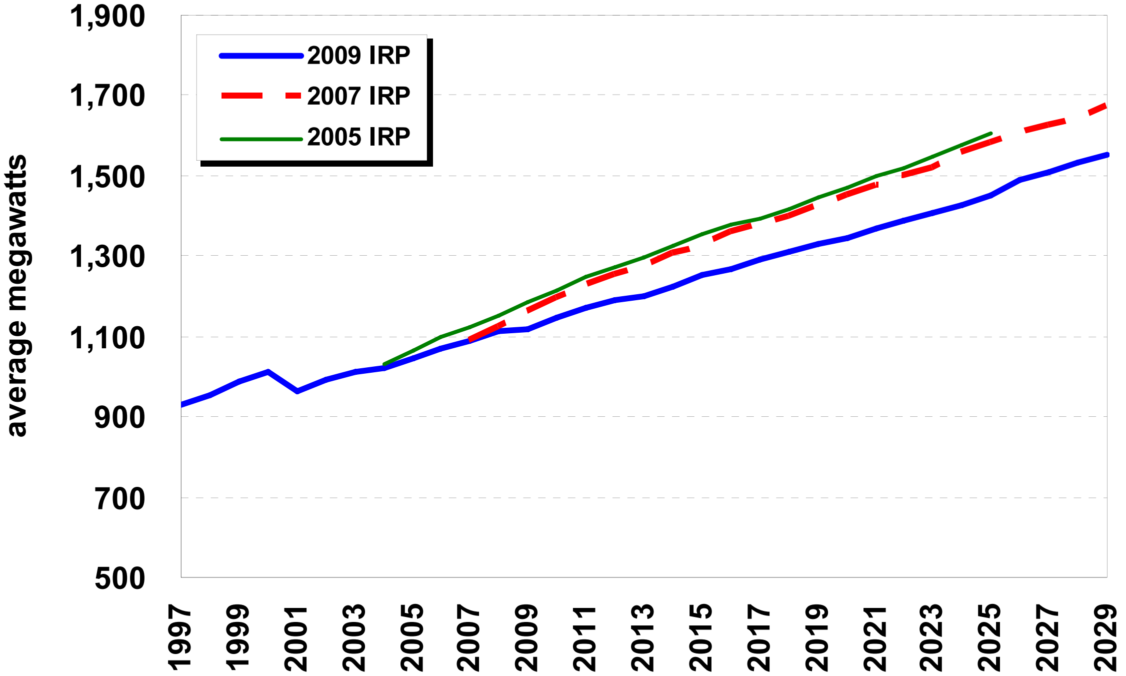


Load Forecast

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

Native load growth is shown in Figure 2.11. Note the significant drop in 2001 during the energy crisis. Loads from 1997 to 2008 are not weather normalized. Annual growth is expected to be 1.7 percent over the next twenty years. The 2005 and 2007 IRP load forecasts are presented for comparison purposes. Loads are moderately lower in the 2009 IRP compared with the 2007 IRP due to the cumulative impact of additional conservation measures from the 2007 IRP being incorporated in this forecast.

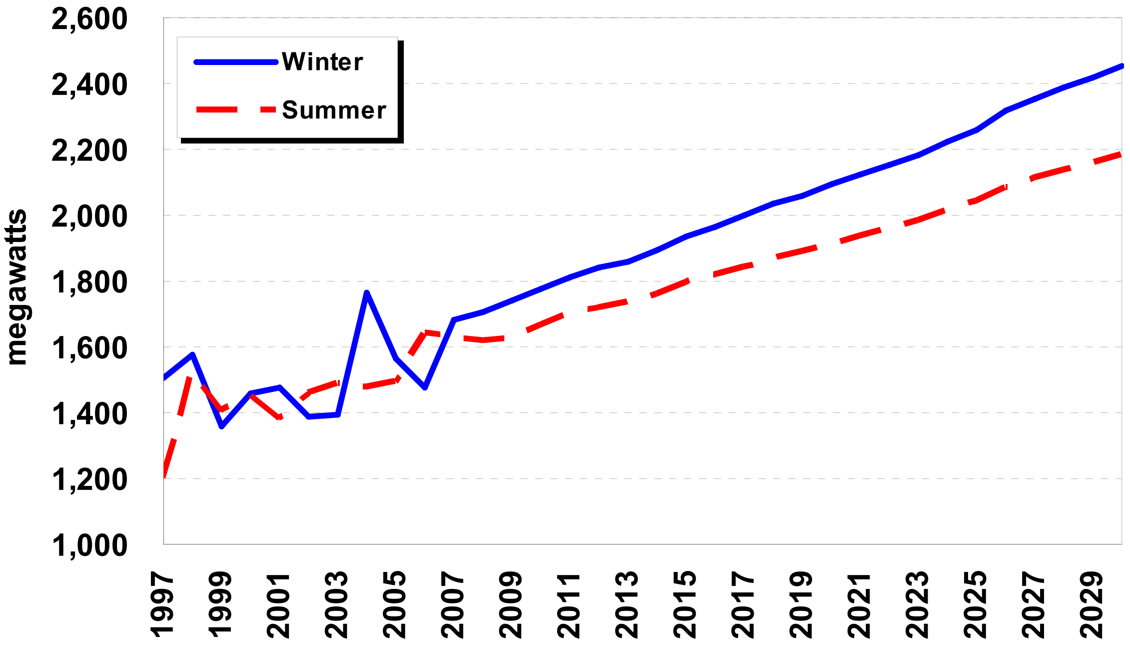
Figure 2.11: Annual Net Native Load



Peak Demand Forecast

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

Figure 2.12: Calendar Year Peak Demand

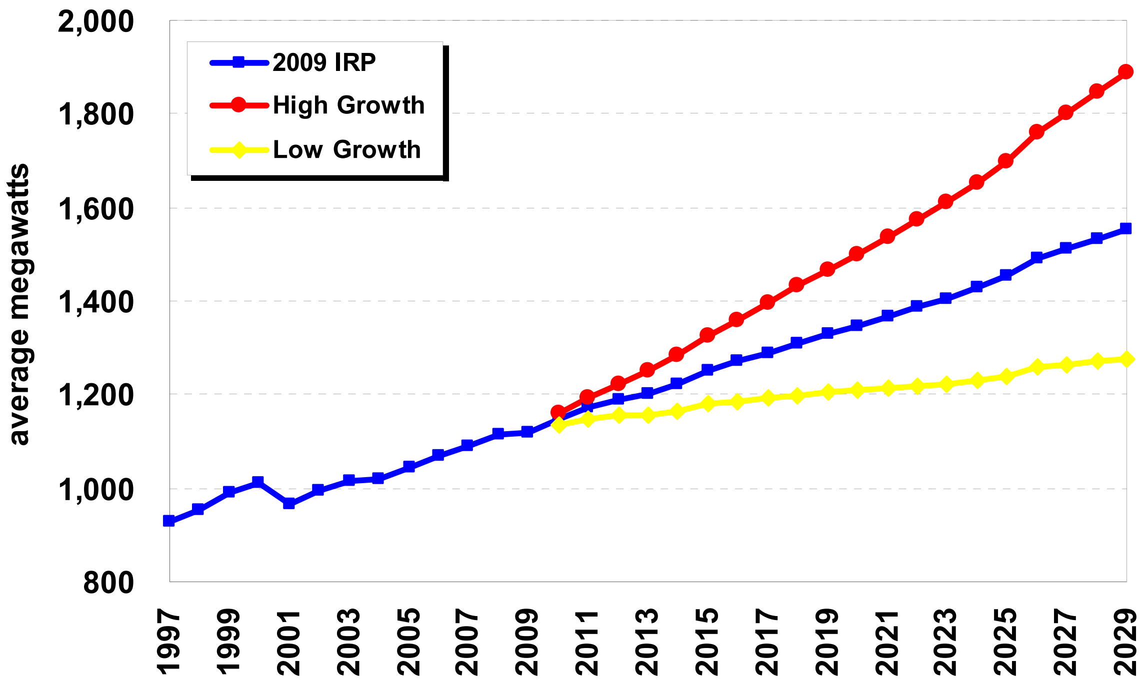


Historical data are influenced by extreme weather events. The comparatively low 1999 peak demand figure was the result of a warmer-than-average winter peak day; the peak in 2006 was the result of a below-average winter peak day. The 1999 and 2006 peak demand values illustrate why relying on compound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

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

Figure 2.13 shows the high and low load growth scenarios compared to the base load forecast. The high load growth scenario projects 2.6 percent load growth over the 20 year forecast. The low load forecast assumes 0.6 percent load growth over the next 20 years.

Figure 2.13: Electric Load Forecast Scenarios



Avista Resources and Contracts

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

Spokane River Hydroelectric Projects

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

Post Falls

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

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

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

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

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

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

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

Clark Fork River Hydroelectric Project

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

Cabinet Gorge

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

Noxon Rapids

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

Total Hydroelectric Generation

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

Table 2.2: Company-Owned Hydro Resources

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

Thermal Resources

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

Colstrip

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

Rathdrum

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

Northeast

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

Boulder Park

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

Coyote Springs 2

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

Kettle Falls and Kettle Falls CT

The Kettle Falls biomass facility was completed in 1983 near Kettle Falls, Washington and is one of the largest biomass plants in North America. The open-loop biomass steam plant is fueled by waste wood products from area mills and forest slash, but can

Kettle Falls Generation Station

also run on natural gas. A gas-fired CT was added to the facility in 2002. The CT burns natural gas and sends exhaust heat to the wood facilities boiler to increase wood fuel efficiency.

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

Table 2.3: Company-Owned Thermal Resources

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

Power Purchase and Sale Contracts

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

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

Bonneville Power Administration – WNP-3 Settlement

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

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

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

Mid-Columbia Hydroelectric Contracts

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

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

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

Lancaster

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

Table 2.4: Large Contractual Rights and Obligations

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

Reserve Margins

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

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

Avista Planning Margin

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

Planning reserves are set at a level equal to 15 percent planning reserve margin during the Company's peak load hour.

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

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

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

Other Planning Methods

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

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

LOLP has only recently gained attention in the Northwest. The industry standard is a 5.0 percent acceptable loss of load. Avista has created a tool to evaluate LOLP, but there is still significant uncertainty surrounding how much energy from the wholesale market would be available to Avista at a time of regional peak loads. At the first TAC meeting, an early analysis was shown for 2009 and included many scenarios. The results of this study indicated for the 2009 planning year the LOLP is 2.1 percent in the winter and 3.8 percent in the summer, but this includes a market availability of 300 MW. If only 200 MW of on-peak market is available, the LOLP increases to 7.4 percent in the winter and 12.1 percent in the summer. Additional studies are required for this analysis. The goal for the LOLP tool is to ensure the Preferred Resource Strategy adds resources adequate to meet reliability criteria, but the critical assumption is the amount of energy available from the market. The Northwest Power and Conservation Council is studying this problem, and Avista will use the results from that process.

Washington State Renewable Portfolio Standard

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

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

Resource Requirements

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

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

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

Figure 2.15: Winter Capacity Position

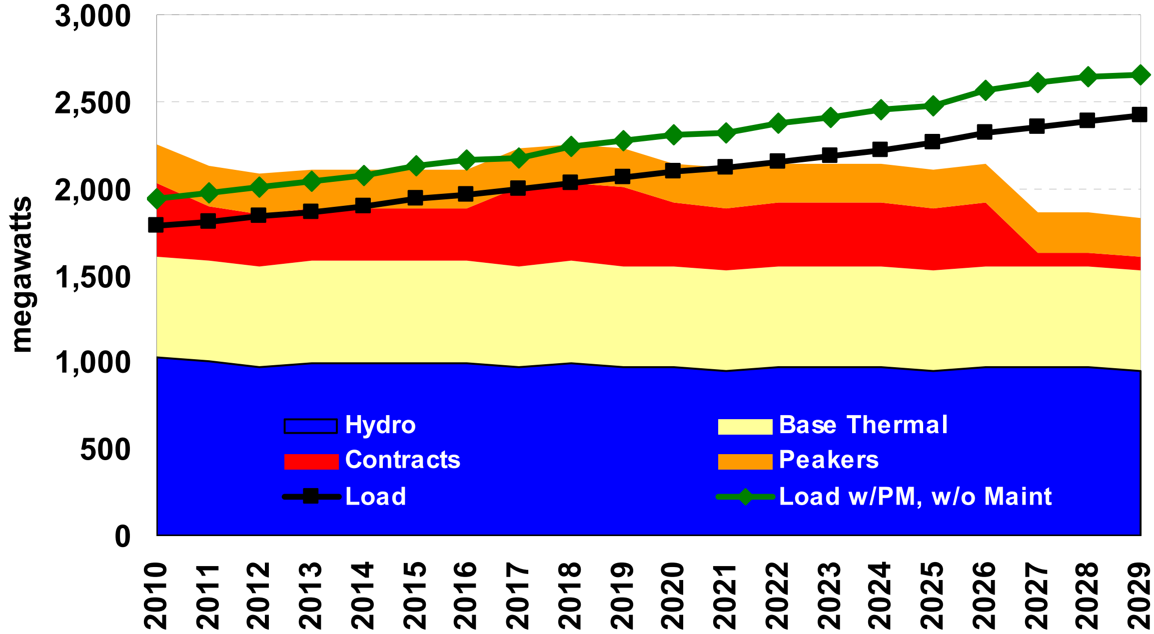


Figure 2.16: Summer Capacity Position

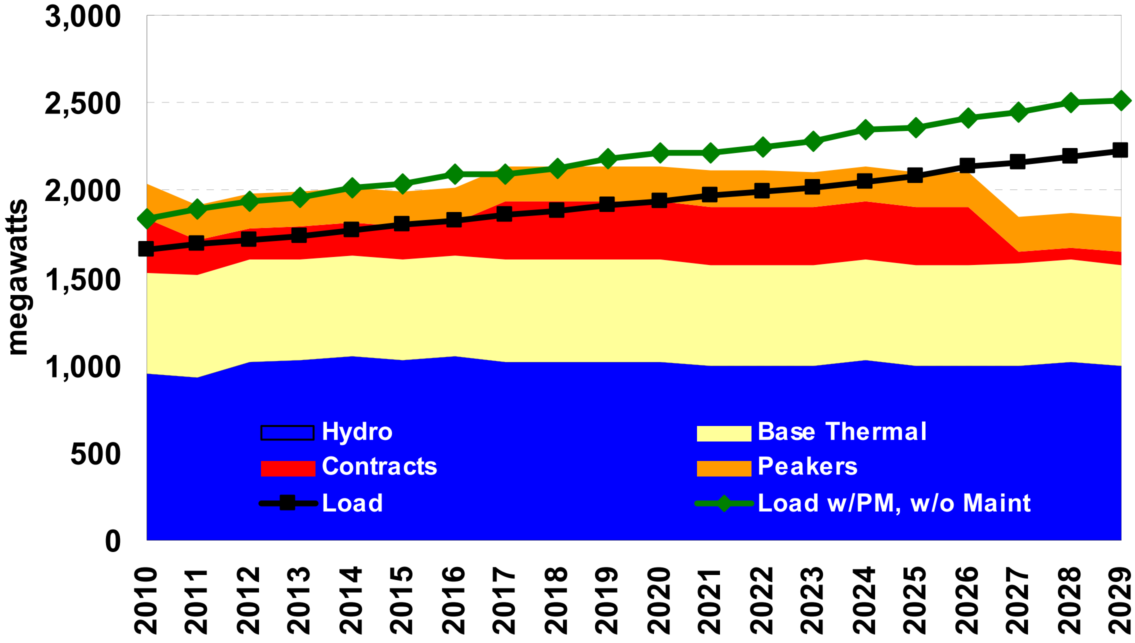


Figure 2.17: Annual Average Position

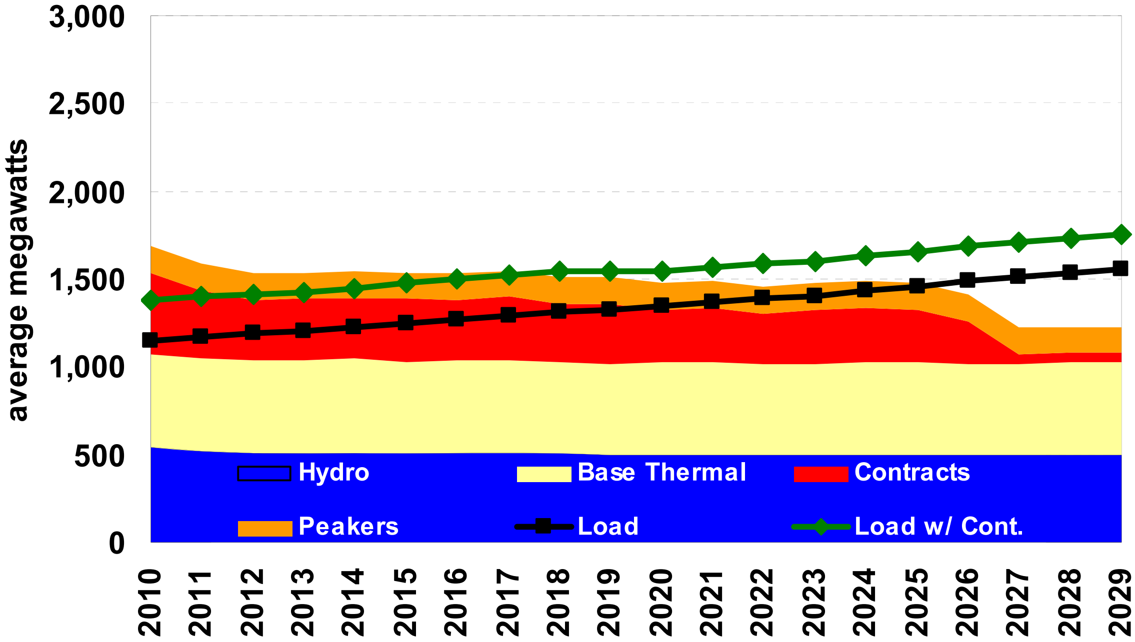


Table 2.5: Washington State RPS Detail (aMW)

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

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

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

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

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

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

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

3. Energy Efficiency

Introduction

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

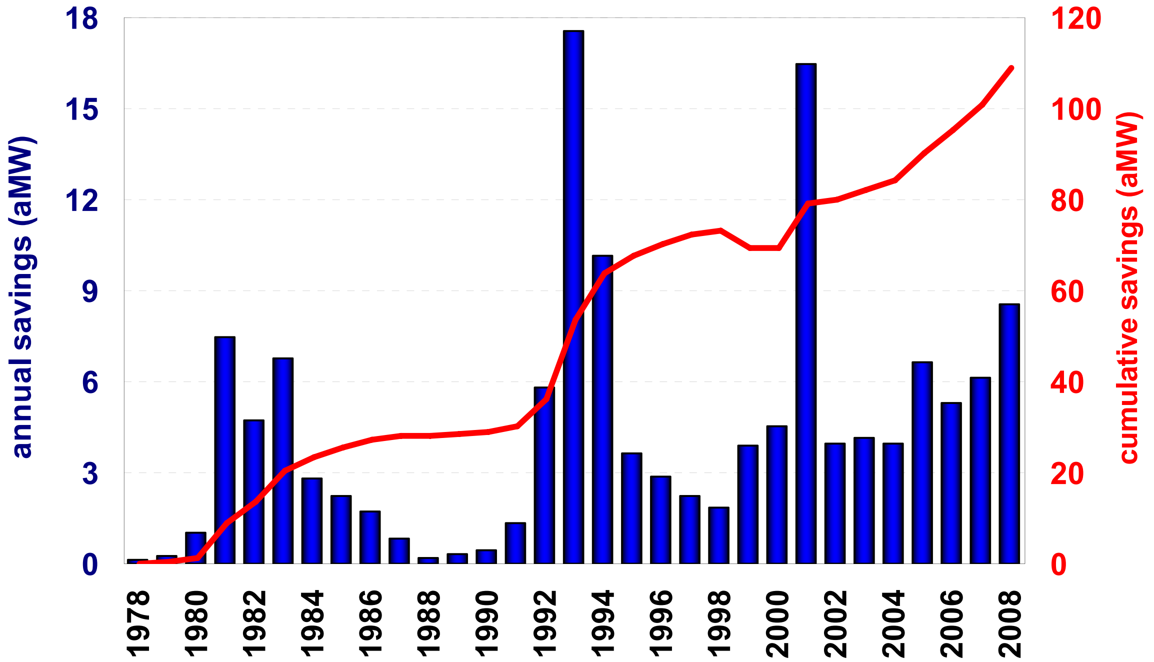
Energy efficient window replacement at Avista's headquarters in Spokane, Washington

Chapter Highlights

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

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

Figure 3.1: Historical Conservation Acquisition



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

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

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

Cooperative Regional Market Transformation Programs

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

Past NEEA funding has been $20 million shared throughout the region. Avista's four percent annual portion of NEEA funding has been $800,000. The Northwest funding utilities have been discussing increasing this amount by 50 percent or more and reapportioning member shares to reflect current retail load. Avista's share would be increased from 4.0 percent to 5.41 percent. This increase in our regional funding share would increase our savings acquisition by 30% or more. NEEA has proven to be a cost-effective component of regional resource acquisition. Avista has and continues to leverage NEEA ventures when cost-effective enhancements can be achieved.

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

Program Funding

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

The aggregate tariff rider balances were returned to a zero balance in 2005 from a $12.4 million deficit in the aftermath of the 2001 Western energy crisis. Recent demand for conservation services has exceeded tariff rider revenues. The most recent projection forecasts a $3.6 million negative balance in the Washington electric DSM tariff rider by the end of 2009. The Idaho electric tariff balance is projected to be just below $4.0 million with schedule 91 increases effective August 1, 2009.

Energy Independence Act

Washington's Energy Indpendence Act, established under Initiative 937 (I-937), and codified under RCW 19.285, requires utilities with over 25,000 customers to obtain a fixed percentage of their electricity from qualifying renewable resources. The mandates are three percent of retail load in Washington by 2012, nine percent by 2016 and 15 percent by 2020. As experience has shown in other jurisdictions, these requirements could be changed by the state legislature in the future. In addition to its RPS, I-937 also requires utilities with over 25,000 customers to acquire all cost-effective and achievable energy conservation. The methodology for identifying the conservation target must be consistent with the methods used by the Northwest Power and Conservation Council (NPCC) in its power plans. Avista's methodology for identifying its conservation target is consistent with the NPCC Sixth Power Plan methodology to the extent possible given the timing of the two processes (this IRP was completed prior to the completion of the Sixth Power Plan). The conservation inputs for this IRP process leveraged the NPCC work. To the extent that significant changes are incorporated into the Sixth Power Plan after the completion of this IRP, it is Avista's intent to reserve the opportunity to substitute our share of the regional conservation potential ultimately defined by the Sixth Power Plan, on a year-by-year basis, for the conservation targets identified in this IRP.

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

American Recovery and Reinvestment Act of 2009

Portions of the American Recovery and Reinvestment Act of 2009 (ARRA) provide economic stimulus funding for energy conservation, including residential audits, weatherization and smart grid development. Avista is working with local governments to field residential audits funded by a combination of our energy efficiency tariff rider, local government Energy Efficiency Conservation Block Grant (EECBG) funds, State Energy Program funds and the customer. The most recent iteration of these analyses calls for a "mid-level" audit that includes the installation of low-cost measures such as CFL's, door sweeps, water tank blankets, low-flow showerheads, furnace filter replacements, refrigerator and coil cleaning and several infiltration reduction measures. The audit is a $325 direct investment including about $160 in low-cost direct-install measures and $165 in auditor labor cost. The Company anticipates some program administrative labor needs on the back-end and estimates this to be the equivalent of about 2.9 full-time employees.

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

The ARRA economic stimulus funding low income weatherization will be allocated directly to regional community action agencies, as they already have the infrastructure necessary to distribute these funds to low income customers. Therefore, Avista will not be involved in administering programs funded under this portion of the ARRA. Low income populations served by the economic stimulus funding will not be counted towards our conservation goals since the Company is not contributing to the acquisition process.

Avista may participate in a regional smart grid demonstration project. The project scope would include distribution automation, distributed generation, energy storage, advanced metering infrastructure (AMI), software and support and demand response. The application deadline for this project is August 26, 2009.

Electricity Efficiency in the 2009 IRP

Avista has reviewed its efficiency options to ensure it is evaluating all alternatives in an effort to delay building additional generation industry infrastructure. The Heritage Project began during the 2007 IRP evaluation and “roadmaps” for several key areas were developed and followed. The roadmaps included: energy efficiency, demand response, transmission and distribution, and analytics.

Energy Efficiency

The Company has completed a comprehensive assessment of industry best practices in energy efficiency and enhanced its program offerings. As a result of this process, the Company launched rebate programs for residential fireplace dampers, non-residential prescriptive side-stream filtration, prescriptive energy/heat recovery ventilation, prescriptive demand control ventilation, prescriptive steam trap maintenance, retro-commissioning, as well as offering CFL coupons and community outreach and education on low cost and no cost ways to save energy. In addition, the Company has an on-going Facilities Model Program focusing on energy efficiency while maintaining and upgrading our facilities. Several projects at Avista’s facilities, such as HVAC control upgrades, variable frequency drives (VFDs) on fan motors, and upgrades to the economizer cooling were estimated to save the Company 270,000 kWh and nearly 20,000 therms per year. The Company continues to assess the implementation of cost-effective energy efficiency upgrades where appropriate.

Load Management

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

Analytics

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

Transmission and Distribution

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

Consistency between the IRP Evaluation and Conservation Operations

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

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

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

Evaluation of Efficiency Technology Opportunities

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

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

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

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

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

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

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

Evaluation of TRC Cost-Effectiveness for Finalist Concepts

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

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

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

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

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

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

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

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

Evaluation of Comprehensive Program Elements

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

The Company's limited income portfolio is all-inclusive for qualifying efficiency measures. The portfolio is implemented in cooperation with community action agencies that are given wide latitude in their approach to distributing program funds. No changes were expected in the ability of agency infrastructure to deliver these programs, and there were not any known market or technology changes that would cause a significant change in the ability to obtain efficiency resources from this segment. It was determined that a historical baseline would be the most appropriate starting point for estimating future throughput. The economic stimulus funding from the ARRA for low income weatherization was unknown at the time this analysis was completed. There may be material increases in the low income population served by the economic stimulus funding. Analysis funding impacts will be treated as an Action Item for reporting in the 2011 IRP. This historical baseline was modified for load growth and retail price elasticity based upon assumptions consistent with the forecasts available at the time. This resulted in a forecast of limited income acquisition for incorporation into the final conservation forecast.

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

Technical Potential

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

The Sixth Power Plan is currently being drafted and will not be completed until after submission of the 2009 IRP, however, the Council's most recent draft plan estimates Avista's portion of the regional target to be 329 aMW for the twenty year period. This is an early estimate but should be within 10 to 15 percent of the final regional technical potential per the Council's Sixth Power Plan.

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

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

Compilation of the Final DSM Resource Estimates

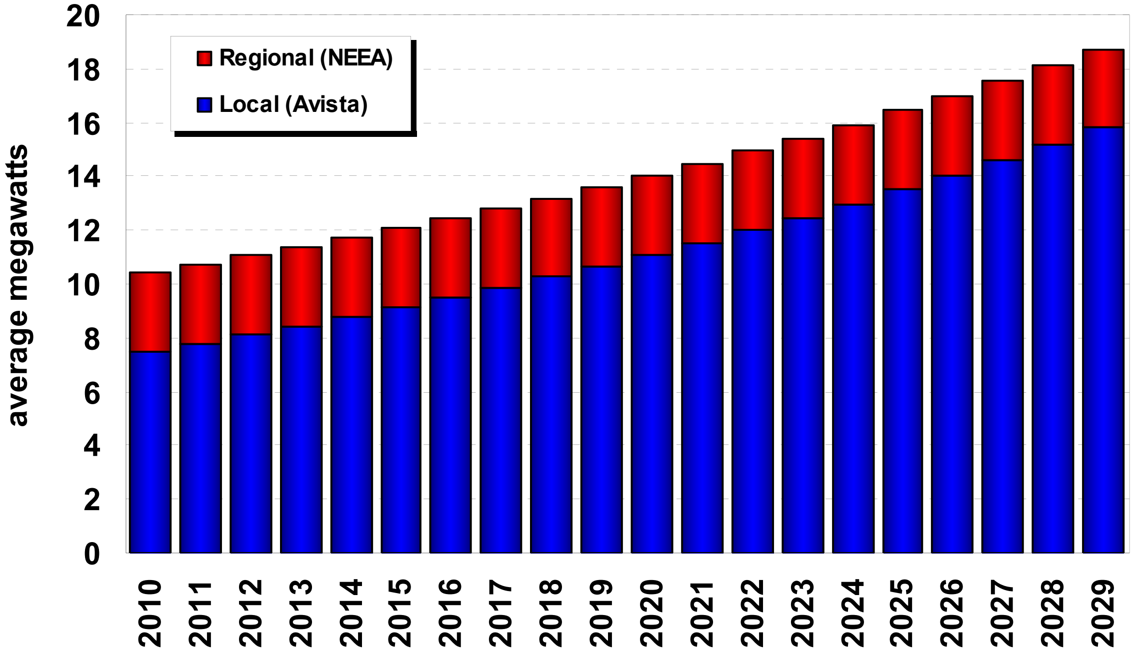
The following conservation targets were developed by summing individually evaluated concepts and the evaluated programs over a 20-year period. The first two years of the targets are detailed in Table 3.1. Transmission and Distribution efficiency improvements are covered in Chapter 5.

Table 3.1: Current Avista Energy Efficiency Programs

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

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

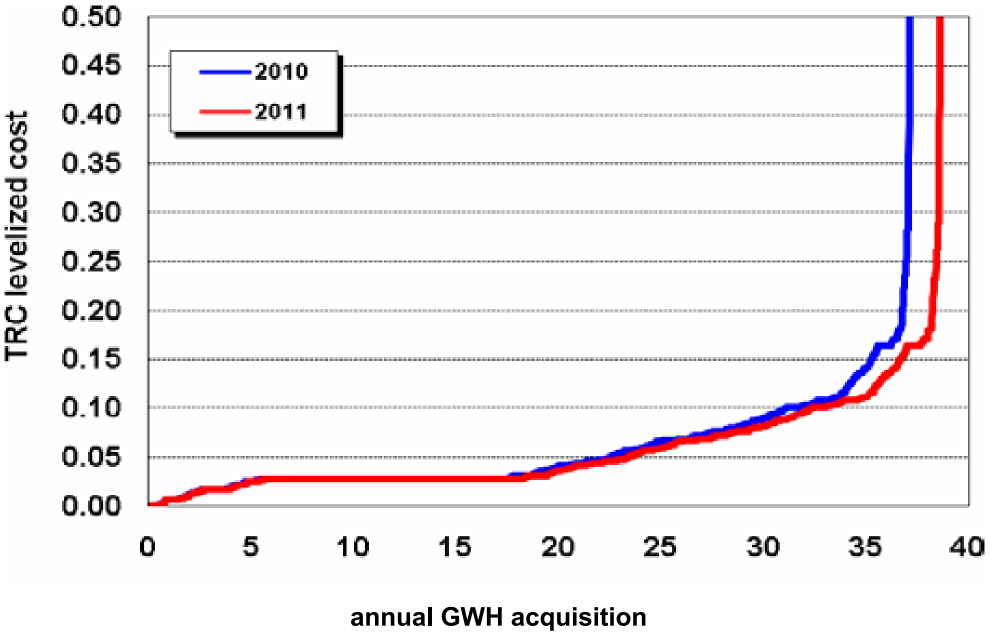
Figure 3.2: Forecast of Conservation Acquisition



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

Since there is a gap in the cost of energy efficiency measures, the measures with a very high total resource cost cause a rapid sloping of the supply curve. Therefore, measures with a total resource cost in excess of $0.50 per kwh have not been included in Figure 3.3

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



Integrating IRP Results into the Business Planning Process

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

Residential Portfolio

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

Limited Income Residential Portfolio

Avista is committed to maintaining stable funding and maintaining program flexibility for limited income conservation programs. There are six local community action partner (CAP) agencies the Company funds to deliver limited income weatherization and energy efficiency programs. Five of the funded agencies offer electric efficiency measures. CAP agency funding is currently set at $1,972,000 million per year ($490,000 to Idaho and

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

Non-Residential Portfolio

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

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

Demand Response

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

Summary

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

4. Environmental Policy

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

Environmental Concerns

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

Chapter Highlights

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

Newly installed solar panels at Avista's headquarters in Spokane, Washington

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

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

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

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

Climate Change Policy Efforts

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

- Anticipates and evaluates strategic needs and opportunities relating to climate change;
- Analyzes the company-wide implications of various trends and proposals;
- Develops recommendations on positions and action plans; and
- Facilitates internal and external communications regarding climate change issues.

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

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

Avista's Position on Climate Change Legislation

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

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

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

Greenhouse Gas Concerns for Resource Planning

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

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

- Increasing efficiency of existing fossil-fueled generation resources;
- Reducing emissions from existing fossil-fueled generation through fuel displacement including co-firing with biomass or biofuels;
- Permanently decreasing output from existing fossil-fueled resources and substituting them with lower emitting resources;
- Decommissioning or divesting fossil-fueled generation and substituting lower emitting resources;
- Reducing exposure to market purchases of fossil-fueled generation, particularly during periods of diminished hydropower production, by establishing larger reserves based on lower emitting technologies; and
- Increasing investments in energy efficiency measures.

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

Emissions Legislation

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

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

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

Federal Emissions and Renewables Legislation

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

- RPS goals start at six percent in 2012 and increase to 20 percent by 2020.
- Recognizes hydroelectric efficiency upgrades and additions effectuated since January 1, 1992 as qualifying against the renewable energy standard.

- Removes existing hydroelectric power generation, excluding upgrades made after January 1, 1992, from the load base against which the renewable energy standard is applied.
- Allows electric utilities to make $25 per MWh alternative compliance payments, adjusted for inflation starting in 2010, in lieu of acquiring new renewable resources or renewable energy certificates (REC).
- Permits REC trading, and banking of RECs for three years.
- Greenhouse gas reduction goals of 3 percent below 2005 levels by 2012, 17 percent by 2020, 42 percent by 2030 and 83 percent by 2005.
- Proposes to administratively allocate allowances to electric utilities from 2011 through 2028, with 50 percent of them being allocated on the basis of a utility's share of emissions associated with retail sales and 50 percent being allocated based on a utility's annual average electricity deliveries.
- Calculates a utility's average annual emissions based upon data from 2006 through 2008, or any three consecutive calendar years between 1999 and 2008, as may be selected by the utility.
- Allows banking and borrowing of emission allowances.
- Allows for some forms of carbon offsets.
- Establishes mechanisms for containing costs and for regulating allowance and derivative markets.

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

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

State Level Emissions Legislation

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

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

The Western Regional Climate Action Initiative, otherwise known as the Western Climate Initiative (WCI), began with a February 26, 2007 agreement to reduce greenhouse gas emissions through a regional reduction goal and market-based trading system. This group includes Arizona, British Columbia, California, Manitoba, Montana, New Mexico, Oregon, Utah, Quebec and Washington. In September 2008, the WCI released a set of Final Design recommendations for a regional cap and trade regulatory system to cover 90 percent of the societal greenhouse gas emissions within the region by 2015. The WCI is presently proceeding to finish its Work Plan, which completes details necessary to implement its proposed cap and trade system. The WCI has also recently initiated a process to identify and evaluate complementary policies that can be adopted region-wide to further ensure that greenhouse gas reduction goals are met. In addition, the WCI has formally submitted comments to Congress regarding the content of the Waxman-Markey bill. There have also been a number of regional municipalities participating in the U.S. Mayors Climate Protection Agreement to reduce GHG emissions to seven percent below 1990 levels by 2012.

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

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

Idaho Emissions Legislation

Idaho is not a member of WCI and does not regulate greenhouse gases or have an RPS. However, the state is actively trying to promote the development of local renewable energy.

Montana Emissions Legislation

The Montana Global Warming Solutions Act (House Bill 753) was submitted in late 2006 to establish greenhouse gas reductions goals to be achieved by 2020. This legislation did not leave committee. Montana now has a non-statutory goal of reducing greenhouse gas emissions to 1990 levels by 2020. In 2007, the Legislature passed House Bill 25, requiring new coal-fired facilities built in the state to sequester 50 percent of their emissions. Montana's renewable portfolio standard law, which was enacted through Senate Bill 415 in 2005, does not apply to Avista because the Company does not serve retail load in Montana. While involved in the Western Climate Initiative, Montana did not consider any legislation during the 2009 Legislative Session to authorize its participation in and implementation of the regional cap and trade system designed by the WCI.

Oregon Emissions Legislation

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

Washington Emissions Legislation

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

Senate Bill 5840 was brought forward in 2009 to update I-937, qualify existing biomass generation (e.g., Kettle Falls) as an eligible renewable resource, and adjust the renewable energy standards, but it failed to obtain the needed votes after emerging from Conference Committee in the closing days of the Legislative Session. The renewable requirement begins in 2012.

Avista is projected to meet or exceed its renewable requirements between 2012 and 2015 through a combination of hydro upgrades and REC purchases. The Company could bank RECs acquired from the Stateline Wind contract in 2011 for 2012, but these RECs are allocated for its Buck-a-Block program. The 2009 IRP has been developed so that the I-937 RPS goals will be achieved by the Company.

In 2007 the Legislature passed Senate Bill 6001. It prohibits electric utilities from entering into financial commitments beyond five years for fossil-fueled generation where CO_2 emissions exceed 1,100 pounds per MWh. In 2013 the emissions performance standard will be lowered every five years to reflect the emissions profile of the latest commercially available CCCT. The emissions performance standard effectively prevents utilities from developing new coal-fired generation or 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 commitments where more than 12 percent of the total power supplied under the contract comes from unspecified sources.

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

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

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

Washington Renewable Portfolio Standard (I-937)

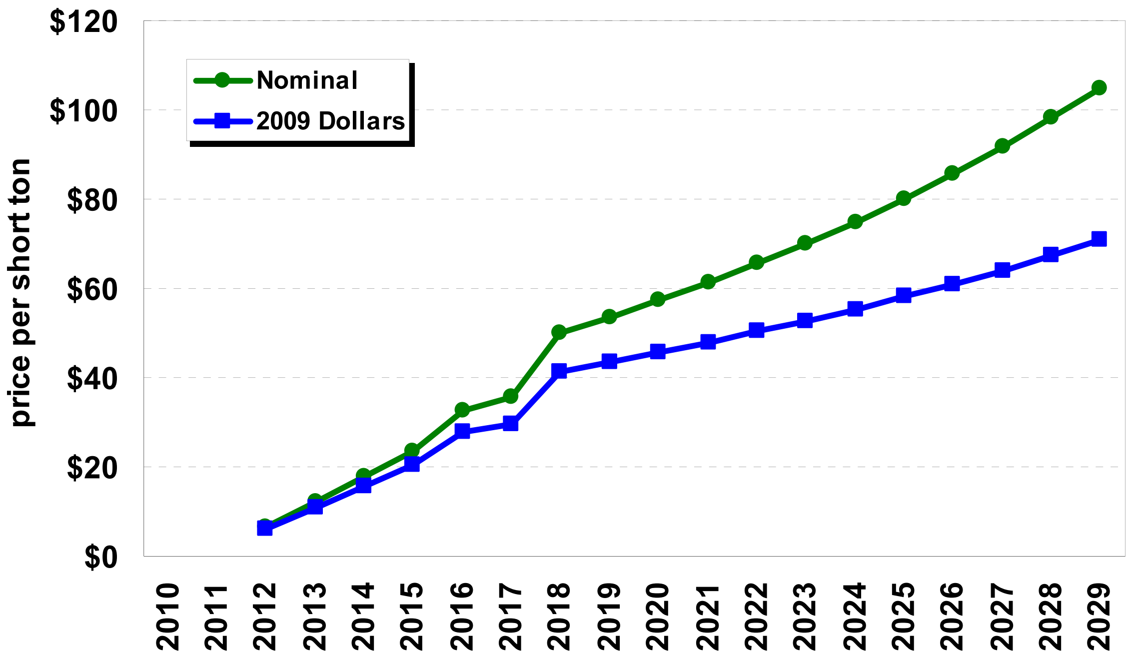
National RPS legislation is being developed through Waxman and Markey’s American Clean Energy Security Act of 2009 (HR 2454) and Senator Bingaman’s draft RPS bill. The proposed federal RPS level ranges between 10 and 25 percent with several target years. Federal legislation is expected to include a hydro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

Emissions Measurement and Modeling

Greenhouse gas tracking is an important part of the IRP modeling process because emissions legislation is one of the greatest fundamental risks facing the electricity marketplace today. Reducing CO_2 emissions from power plants will fundamentally alter the resource mix as society moves towards a carbon constrained future. Though there are no federal laws regulating carbon emissions presently, carbon costs still need to be projected for planning purposes because expectations for carbon regulation can change resource decisions.

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

Figure 4.1: Price of Carbon Dioxide Credits



5. Transmission and Distribution

Introduction

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

Transmission upgrade work

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

Chapter Highlights

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

Avista's Transmission System

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

- Bonneville Power Administration (BPA)
- Chelan County PUD
- Grant County PUD
- Idaho Power Company
- NorthWestern Energy
- PacifiCorp
- Pend Oreille County PUD

Figure 5.1: Avista transmission system

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

Transmission Changes since the 2007 IRP

Avista has completed a multi-year $130 million transmission upgrade project. Much of this construction was completed prior to 2007 and was documented in the 2007 IRP. Since the 2007 IRP the Company completed 60 miles of new 230 kV transmission between its Benewah and Shawnee substations to increase capacity between the north and south portions of its system. The project provides a second 230 kV transmission line between Avista's northern and southern load service areas, significantly improving reliability. Energized in December, 2007, Avista installed a new 200 megavolt- ampere-reactive (MVAR) 230 kV capacitor bank at the Benewah station in October of 2008, and installed a new 125 MVA 230/115 kV transformer in November of 2008. This work, known as the West of Hatwai reinforcement, was part of a joint transmission project between Avista and BPA.

Future Upgrades and Interconnections

Station Upgrades

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

South Spokane 230 kV Reinforcement

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

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

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

Canada to California Transmission Project and Devils Gap Interconnection

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

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

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

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

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

Regional Transmission System

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

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

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

FERC Planning Requirements and Processes

FERC provides guidance to regional and local area transmission planning. The following section describes several requirements and processes important to Avista's transmission planning function.

Attachment K

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

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

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

Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) coordinates and promotes electric system reliability in the Western Interconnection. WECC also supports efficient and competitive power markets, assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access or capacity ownership disputes, and provides an environment for coordinating operating and planning activities as set forth in WECC Bylaws. Avista participates in WECC's Planning, Operations, and Market Interface committees, as well as various sub groups and other processes such as the TCWG.

Northwest Power Pool

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

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

ColumbiaGrid

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

Transmission Coordination Work Group

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

Avista Transmission Reliability and Operations

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

Transmission Construction Costs

An essential part of the IRP is estimating transmission costs to integrate new generation resources. Construction-quality estimates were only made for three projects proposed in the IRP. The other options identified in this IRP are based on engineering judgment.

There is an inverse relationship between transmission project size and the certainty of the estimates. A 50 MW resource can be integrated in many places on the Company's system for a moderate cost compared to its overall installation cost. There are fewer options available for locating a 500 MW plant on Avista's system. Larger (750 and 1,000 MW) plants have even fewer location options. Each would require participation in FERC's Generation Interconnection Process as well as coordination through the regional processes described above. These processes would be completed to determine impacts on Avista and other systems' transmission grid before a final plant placement decision.

Estimating Transmission and Integration Costs

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

Integration of Resources External to the Avista System

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

Eastern Montana Resources

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

Integration of Resources on the Avista Transmission System

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

Reardan, Washington

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

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

Grangeville, Idaho

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

Garfield County, Washington

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

Lancaster Integration

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

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

Other Potential Resources

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

CCCT with Duct Burner

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

Small Cogeneration (<5 MW)

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

Hybrid SCCT (LMS 100)

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

Coal

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

Geothermal

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

Nuclear

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

Hydro Upgrades

Spokane River Upgrades

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

Clark Fork Hydro Upgrades

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

Distribution Efficiencies

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

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

System Efficiencies Team

Avista's System Efficiencies Team of operational, engineering and planning staff developed a plan to evaluate potential energy savings from transmission and distribution (T&D) system upgrades. The first phase summarized energy savings from distribution feeder upgrades. The second phase, beginning in the summer of 2009, combines transmission system topologies with "right sizing" distribution feeders to reduce system losses, improve system reliability and meet future load growth.

Distribution Feeders

The System Efficiencies Team evaluated energy losses across Avista's distribution system. Avista's distribution system consists of approximately 330 feeders covering 30,000 square miles. The distribution feeders range in length from 3 to 73 miles.

The System Efficiencies Team evaluated several efficiency programs across urban and rural distribution feeders. The programs consisted of the following system enhancements:

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

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

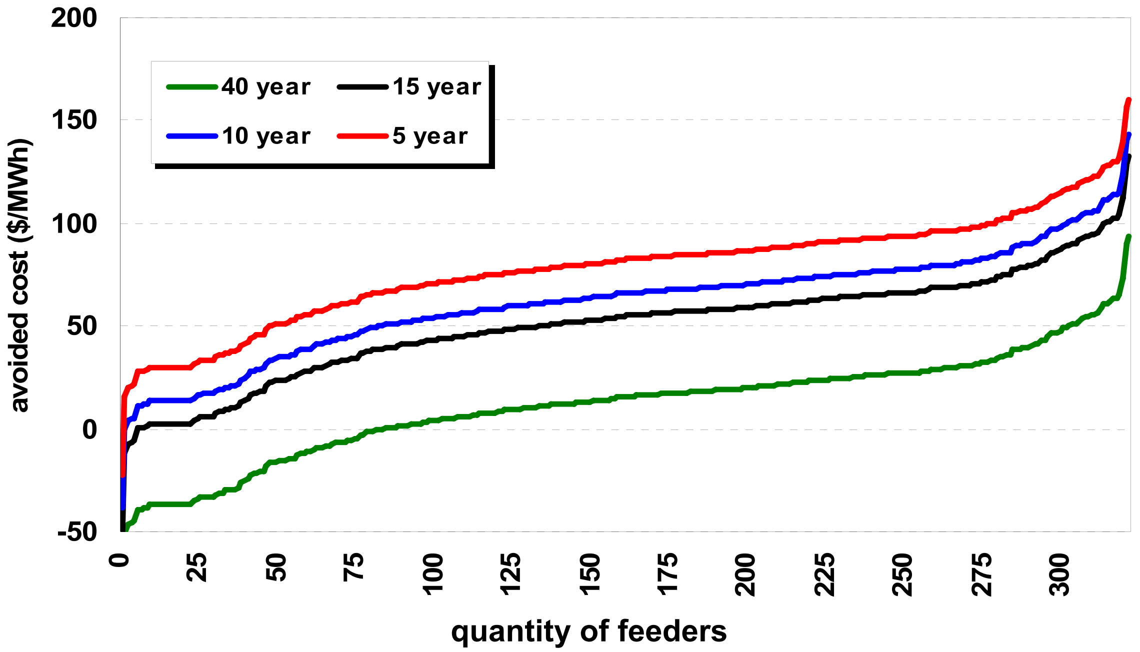
Economic Analysis

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

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

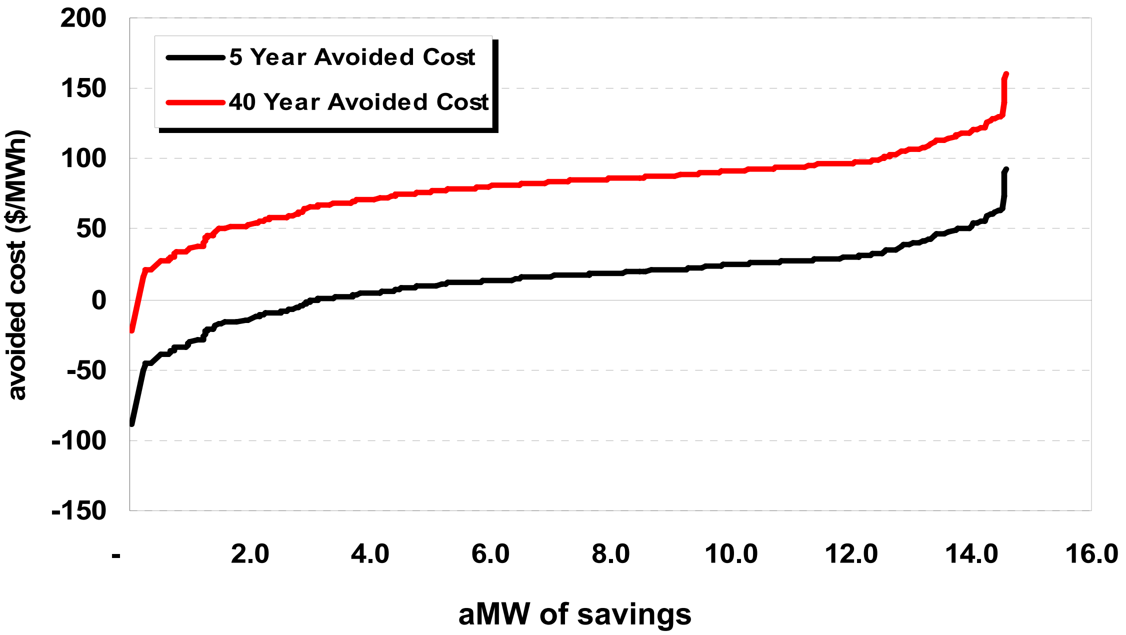
A sensitivity analysis determined the variability of net resource values of different projected O&M time horizons, since O&M avoided costs are based on expected outcomes. Figure 5.2 illustrates the levelized cost of feeder upgrades.

Figure 5.2: Levelized Cost of Feeder Upgrades



Distribution feeders with the highest potential for efficiency gains were included in the IRP analysis. The five selected feeders are estimated to reduce system losses by 2.7 aMW. Figure 5.3 shows the projected feeder upgrade supply curve of potential for loss reduction. If all feeders under $100 per MWh using the 40 year levelized cost method were upgraded, nearly 13 aMW could be saved and between 20 and 25 MW of peak savings could be realized.

Figure 5.3: Estimated Feeder Supply Curve



Operational Considerations

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

Transmission Topologies and Distribution Feeder Sizing

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

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

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

Summary

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

6. Generation Resource Options

Introduction

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

Chapter Highlights

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

Assumptions

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

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

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

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

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

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

Noxon Rapids turbine upgrade

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

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

Gas-Fired Combined Cycle Combustion Turbine (CCCT)

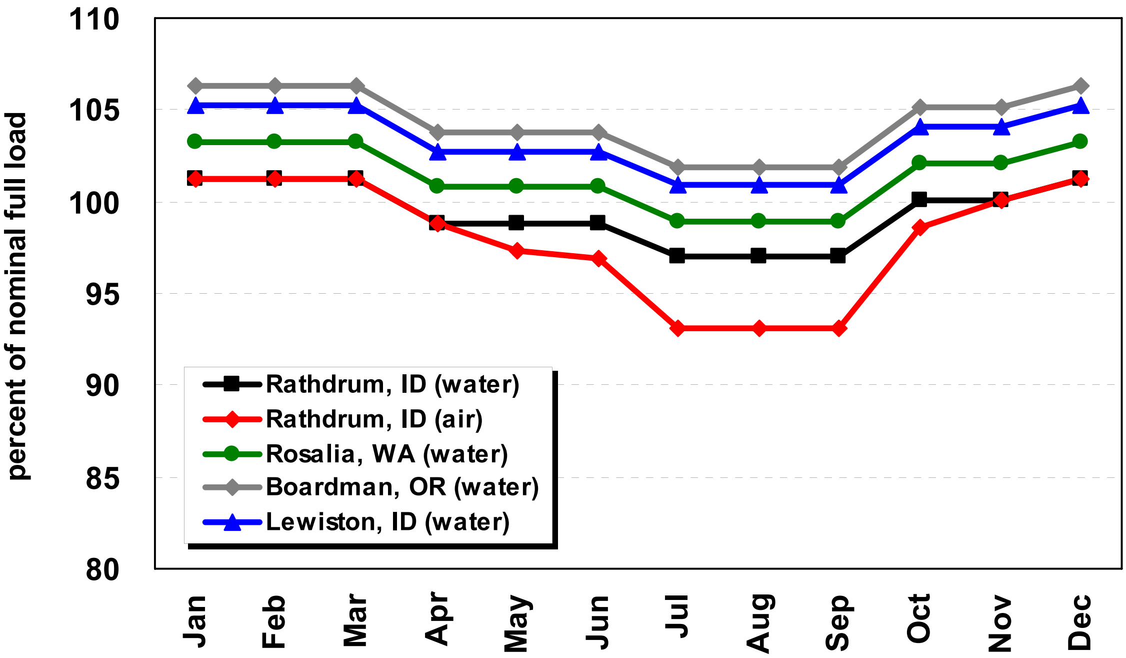
The gas-fired CCCT plants were the Northwest resource of choice earlier this decade. The technology provides a reliable source of both capacity and energy for a relatively inexpensive upfront investment. The main disadvantage is generation cost volatility due to reliance on natural gas. The Company's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

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

The heat rate modeled for a water-cooled CCCT resource is 6,750 Btu/kWh in 2009. The CCCT heat rate falls by 0.5 percent annually to reflect anticipated technological improvements. The plants include seven percent of rated capacity as duct firing at a heat rate of 8,500 Btu/kWh. Forced outage rates are estimated at 5.0 percent per year and 18 days of maintenance are assumed. Cold startup costs are $35/MWh plus 6.6 Dth per MW per start.

CCCT plants are modeled to back down to 55 percent of nameplate capacity and ramp from zero to full load in five hours. Carbon emissions are 117 pounds per Dth of fuel. The maximum capability of each plant is highly dependent on ambient temperature and plant elevation. Figure 6.1 illustrates the average capacity by month for a water-cooled CCCT located in Rathdrum, Idaho, compared to the same technology at other locations. The air-cooled technology is shown for illustrative purposes and would be an alternative configuration if an adequate water supply is unavailable. Air-cooled technologies provide less capacity during warmer periods of the year. The figure illustrates how combined cycle capacity is greatly affected by site elevation. (Rosalia-2,238 feet, Rathdrum-2,211 feet, Lewiston-745 feet and Boardman-298 feet).

Figure 6.1: CCCT Output Per 100 MW of Nameplate Capacity



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

Table 6.1: CCCT (Water Cooled) Levelized Costs per MWh

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

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

Table 6.2: CCCT with Carbon Sequestration Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	43.70	32.38
Interconnection capital recovery	0.57	0.48
AFUDC	7.51	6.37
Variable O&M	5.69	4.83
Fixed O&M	5.86	4.97
CO_2 emissions adder	1.98	1.68
NOx & SO_2 emission adder	0.00	0.00
Fuel costs	75.51	64.20
Excise taxes and other overheads	3.86	3.28
Total Cost	**144.68**	**118.18**

Gas-Fired Simple Cycle Combustion Turbine (SCCT)

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

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

Heat rates for SCCT plants are 8,400 Btu/kWh (LMS100) and 10,200 Btu/kWh (7EA) in 2009, decreasing by 0.5 percent per year (real) to reflect anticipated technological improvements. Forced outage rates are estimated at five percent per year, with no maintenance outages (approximately 10 days per year) because it is assumed to occur in months when these plants do not typically operate. Cold startup costs are $15 per MW per start for the frame machine and one Dth per MW for the LMS 100. The maximum capabilities of these plants are highly dependent on ambient temperature, and use the same monthly capacity shape as CCCT plants.

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

Table 6.3: Frame SCCT Levelized Costs per MWh

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

Table 6.4: LMS 100 Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	19.31	14.31
Interconnection capital recovery	0.74	0.63
AFUDC	0.89	0.75
Variable O&M	6.49	5.50
Fixed O&M	0.58	0.49
CO_2 emissions adder	18.97	16.10
NOx & SO_2 emission adder	0.19	0.16
Fuel costs	74.19	62.92
Excise taxes and other overheads	4.35	3.69
Total Cost	**125.71**	**104.55**

Wind

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

Several wind resource locations were studied for this IRP:

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

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

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

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

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

Table 6.5: Wind Capital and Fixed O&M Costs

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

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

Table 6.6: Columbia Basin Wind Project Levelized Costs per MWh

Item	Nominal $	Real 2009$
Capital recovery and taxes	56.63	48.01
Interconnection capital recovery	4.40	3.73
AFUDC	4.60	3.90
Variable O&M	3.54	3.00
Fixed O&M	20.79	17.63
CO_2 emissions adder	0.00	0.00
NO_x & SO_2 emissions adder	0.00	0.00
Fuel costs	0.00	0.00
Integration	4.05	3.50
Excise taxes and other overheads	1.05	0.89
Total Cost	**95.06**	**80.66**

Table 6.7: Small Scale Project Levelized Costs per MWh

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

Table 6.8: Offshore Wind Project Levelized Costs per MWh

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

Coal

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

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

The Washington State legislature passed Senate Bill 6001 in 2007, effectively prohibiting local electric utilities from developing coal-fired facilities that do not sequester emissions. A coal facility could legally be constructed to serve Idaho loads, where no emissions performance standard exists, but Avista is not considering a pulverized coal facility for the 2009 IRP and believes such a facility is unlikely to be approved. IGCC facilities were modeled in 200 MW increments in the PRS analysis beginning in 2022 for IGCC plants without sequestration and 2025 for an IGCC plants with sequestration.

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

Table 6.9: Coal Capital Costs (2009$)

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

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

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

Table 6.11: IGCC Coal Project Levelized Cost per MWh

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

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

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

Hydroelectric Project Upgrades

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

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

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

Table 6.13: Hydro Upgrade Project Characteristics

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

Table 6.14: Hydro Upgrade Nominal Levelized Costs per MWh

Project	Generation Capital Recovery & Taxes	Transmission Capital Recovery & Taxes	AFUDC	Fixed O&M	Total Cost
Little Falls Unit 1	81.07	0.00	5.82	0.00	**86.89**
Little Falls Unit 2	56.13	0.00	4.03	0.00	**60.16**
Little Falls Unit 3	99.78	0.00	7.16	0.00	**106.94**
Little Falls Unit 4	40.54	0.00	2.91	0.00	**43.45**
Post Falls Unit 6	155.91	0.00	11.19	0.00	**167.10**
Upper Falls	71.27	0.00	7.54	0.00	**78.81**
Long Lake Unit 5	63.58	14.38	10.93	0.40	**89.29**
Long Lake 2nd Powerhouse	66.52	6.51	10.56	0.90	**84.49**
Cabinet Gorge Unit 5	83.15	0.00	14.29	1.58	**99.02**

Table 6.15: Hydro Upgrade 2009$ Levelized Costs per MWh

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

Other Resource Options

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

Solar

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

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

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

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

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

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

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

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

Item	Utility Scale Photovoltaic	Solar Thermal	Roof-Top Solar
Capital recovery and taxes	264.93	110.90	376.79
Interconnection capital recovery	0.00	4.11	0.00
AFUDC	9.38	10.88	13.34
Variable O&M	0.00	0.00	0.00
Fixed O&M	16.60	25.21	20.76
CO_2 emissions adder	0.00	0.00	0.00
NO_x and SO_2 emissions adder	0.00	0.00	0.00
Fuel costs	0.00	0.00	0.00
Excise taxes and other overheads	0.72	1.09	0.90
Total Cost	**291.63**	**152.20**	**411.78**

Biomass and Wood Generation

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

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

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

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

Table 6.18: Biomass Capital Costs

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

Table 6.19: Biomass Nominal Levelized Costs per MWh

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

Table 6.20: Biomass 2009 Dollar Levelized Cost per MWh

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

Geothermal

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

Table 6.21: Geothermal Levelized Costs per MWh

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

Tidal and Wave

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

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

Table 6.22: Tidal/Wave Levelized Costs per MWh

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

Small Cogeneration

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

Table 6.23: Small Cogeneration Levelized Costs per MWh

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

Nuclear

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

Table 6.24: Nuclear Levelized costs per MWh

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

Hydrokinetics

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

Table 6.25: Hydrokinetics Levelized costs per MWh

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

Pumped Storage

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

Table 6.26: Pumped Storage Levelized costs per MWh

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

Large Scale Hydro

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

Table 6.27: Large Scale Hydro Levelized costs per MWh

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

Summary

Avista has several resource alternatives to select from for this IRP. Each provides different benefits, costs and risks. This IRP identifies relevant characteristics and chooses a set of resources that are actionable, meet customer's energy and capacity needs, balances renewable requirements and keeps customer costs minimized. Table 6.28 is a summary of resource costs and plant characteristics used in the PRS analyses. All other resources are shown in Table 6.29. The PRS chapter discusses resource choices and provides "tipping-point" analyses to explain how resource costs would need to change to be included in the PRS. [Note: capital costs do not include AFUDC.]

Table 6.28: Resource Analysis Summary for Preferred Resource Strategy Analysis

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

Table 6.29: Resource Analysis Summary for Other Resources Options

Resource	Increment Resource Size (MW)	Heat Rate (btu /kWh)	Capital Cost ($2009/ kW)	Trans. Capital Cost ($2009/k W)	Fixed O&M ($2009/k W/yr)	Variable O&M ($2009/ MWh)	Peak Credit (Winter/ Summer)	Nominal Levelized Costs ($MWh)	Real Levelized Costs (2009$/ MWh)
Biomass Open-Loop	5	10,500	5,000	18	85	3	100/100	68.91	58.48
Geothermal	5	n/a	5,000	18	75	5	110/90	75.97	64.41
Long Lake 2nd Powerhouse	60	n/a	2,000	0	2	0	100/90	84.49	71.65
Long Lake Unit 5	24	n/a	2,167	0	1	0	100/90	89.29	75.71
Cabinet Gorge Unit 5	60	n/a	1,417	0	2	0	100/100	99.02	84.00
Small Co-Gen	2.5	5,700	2,000	0	5	5	105/95	102.94	84.29
Wood Gasifer Combined Cycle	5	10,300	3,300	18	85	7.7	110/90	99.41	84.30
KFCT Wood Gasifier	7	10,300	4,370	0	85	7.7	100/0	110.24	93.47
Ultra Critical Pulverized Coal	200	8,825	3,000	36	38	1.3	100/100	117.34	94.32
Biomass Closed-Loop	5	10,500	8,000	18	150	10	100/100	118.74	100.66
CCCT Wood Boiler	10	10,500	2,500	0	121	6	100/100	141.63	120.12
Hydrokinetics	0.1	n/a	4,000	0	3	0	100/100	147.87	125.35
Nuclear	250	10,400	5,500	36	97	0.55	100/100	148.17	125.61
Wind: Off Shore	75	n/a	5,000	36	95	5	0/0	156.58	132.81
Post Falls Unit 6	0.2	n/a	5,000	0	0	0	100/90	167.10	141.65
Wind: Small Scale	0.1	n/a	3,000	100	50	3	0/0	174.82	148.27
Solar Thermal	2	n/a	4,200	100	3	0	5/100	179.54	152.20
Pumped Storage	5	n/a	3,500	100	5	0	100/100	208.31	188.35
Large Scale Hydro	100	n/a	4,500	36	2	0	100/100	275.24	238.54
Utility Scale Photovoltaic	0.5	n/a	7,500	0	1	0	5/60	344.00	291.63
Roof-Top Solar	0.5	n/a	8,000	0	0.5	0	5/60	485.73	411.78
Tidal (wave)	0.1	n/a	10,000	0	1000	0	0/0	785.63	666.12

7. Market Analysis

Introduction

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

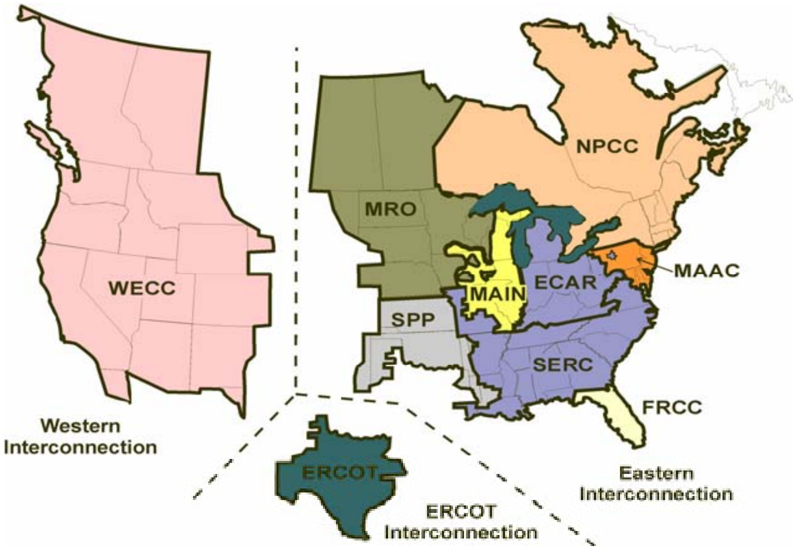
Chapter Highlights

- Mid-Columbia electricity and Malin natural gas prices are 27 and 20 percent higher than the 2007 IRP, primarily due to carbon legislation impacts.
- Mid-Columbia electricity prices are expected to average $79.56 per megawatt-hour (levelized) over the next 20 years.
- Mid-Columbia electricity prices are forecast to be one-third higher, than they otherwise would be, due to projected carbon legislation.
- Average Malin natural gas prices are expected to be $7.36 per decatherm (levelized) over the next 20 years.
- Gas-fired resources continue to serve most new loads and take the place of coal generation to reduce greenhouse gas emissions
- Society's mandates to acquire new renewable resources help reduce carbon emmisions, but force utilities to invest in twice as much generation infrastructure.
- New environment-driven investment, combined with higher market prices will lead to higher retail rates, absent federal initiatives to limit rate increases.
- Carbon legislation is expected to increase 20-year cost (NPV, 2009 dollars) for electricity generation by $25.7 billion (10 percent) in the Western Interconnect.

Marketplace

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

Figure 7.1: NERC Interconnection Map



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

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

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

Table 7.1: AURORA^{XMP} Zones

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

Western Interconnect Loads

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

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

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

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

Transmission

Several regional transmission projects have been announced in the last two years. Many of these projects will move renewable resources to load centers for renewable portfolio standards (RPS) obligations. The AURORAxmp model was updated to reflect the 26,600 MW of transmission upgrades shown in Table 7.3. The transmission expansion represents the most likely upgrades at the time the price forecast was developed (Dec 2008). Transmission upgrades within AURORAxmp zones were not included in the model, as they do not impact power transactions between zones.

Table 7.3: Western Interconnect Transmission Upgrades Included in Analysis

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

Regional Renewable Portfolio Standards

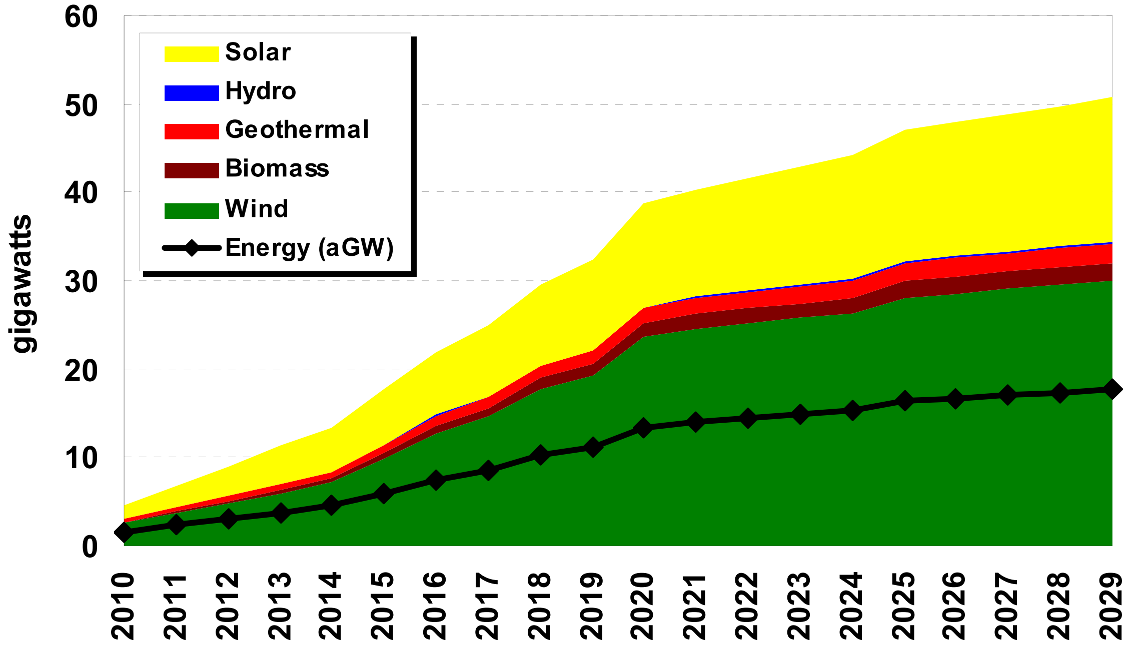
In an effort to curb greenhouse gas emissions and diversify energy sources, many states have created RPS requirements. RPS legislation requires utilities to meet a portion of their load with qualified renewable resources. Each state defines RPS obligations differently. AURORAxmp does not have the ability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

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

AURORAxmp could have added additional renewable resources where they were found to be economical as part of its optimization routine, but it did not.

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

Figure 7.2: Renewable Resource Additions to Meet RPS

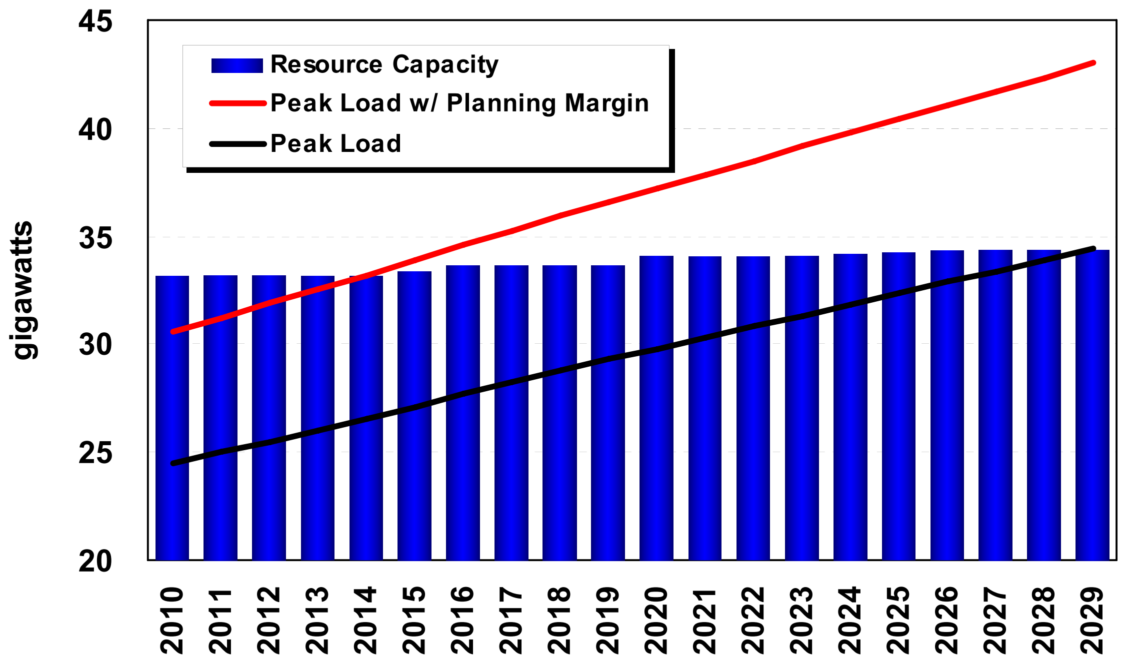


Resource Deficits

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

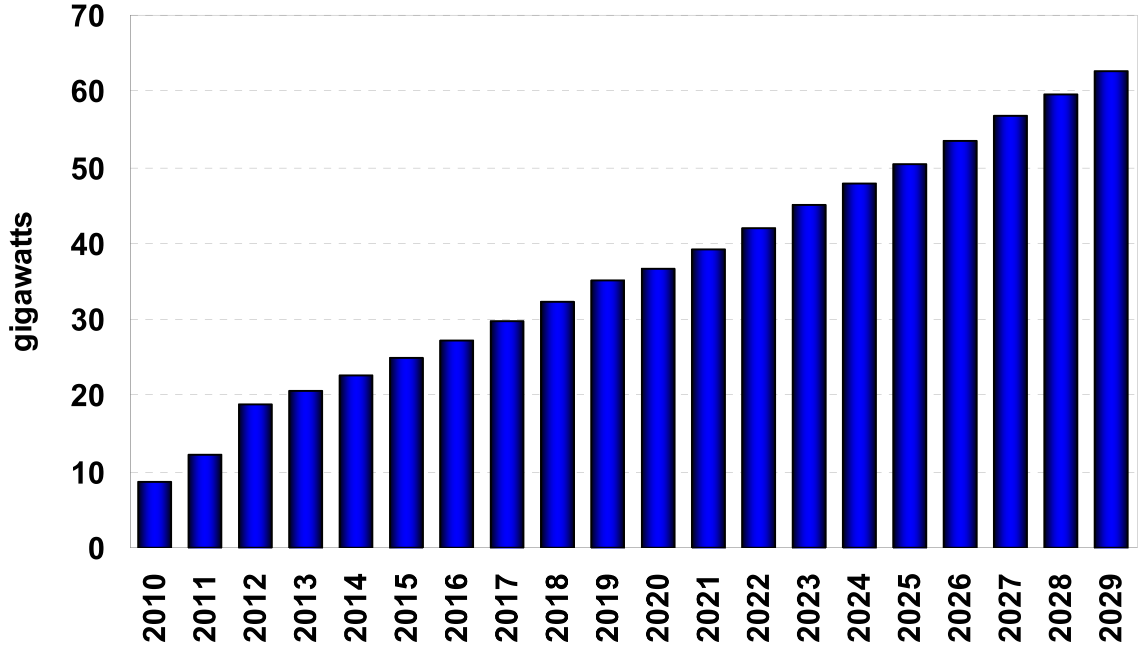
The Northwest historically has depended on hydro system flexibility to meet peak demand, but new wind regulation obligations and increased fisheries obligations have constrained the system. The hydro system can flex for a few hours during a cold day, but may not have the energy to meet a cold or hot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

Figure 7.3: Northwest Peak Load/Resource Balance



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

Figure 7.4: Total Western Interconnect Capacity Deficits



New Resource Options

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

Table 7.4: New Resources Available to Meet Resource Deficits

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

Fuel Prices and Conditions

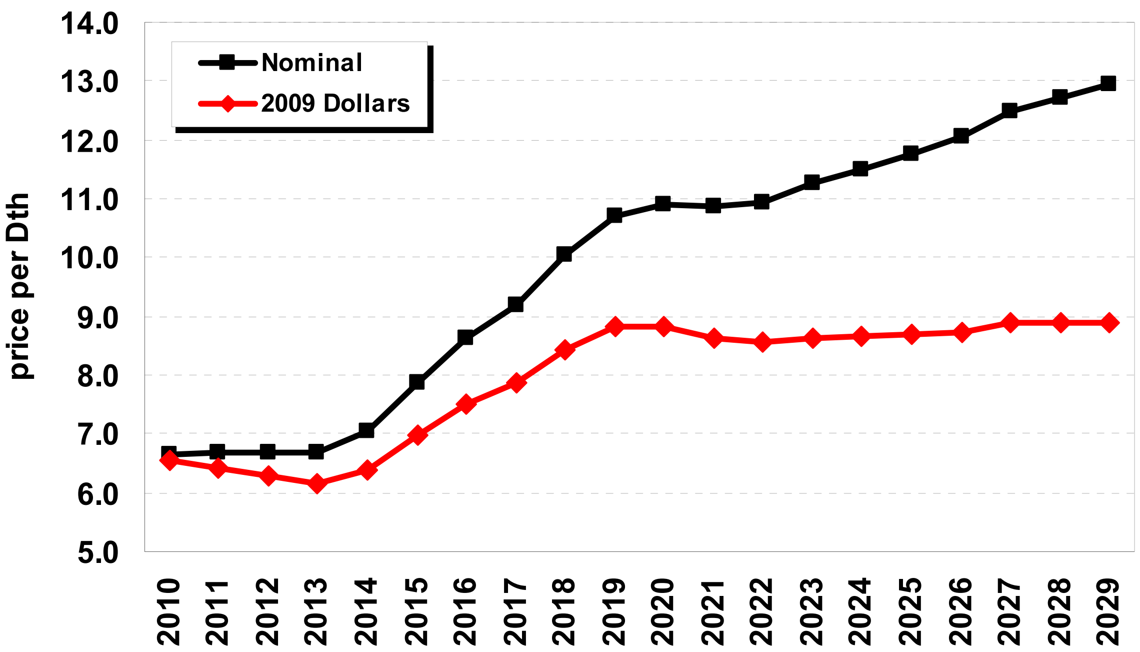
Some of the most important drivers of resource costs and values are fuel and availability. Some resources, including geothermal and biomass, have limited fuel options or sources, while coal and natural gas have more fuel sources. Hydro and wind use free fuel sources, but are highly dependent on weather.

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

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

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

Figure 7.5: Henry Hub Natural Gas Price Forecast



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

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

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

Table 7.6: Monthly Price Differentials for Malin

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

Coal

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

Table 7.7: Western Interconnect Coal Prices (2009$)

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

Wood/Hog Fuel

Avista has operated the Kettle Falls wood-fired generator for 25 years. When Kettle Falls was constructed, hog fuel was a waste product from area sawmills at low or no cost. The future price and availability of hog fuel are critical to understanding the viability of new wood-fired facilities. Hog fuel costs for new plants are forecasted for two locations. The first is fuel in Avista's service territory, forecast at $30 per ton or $3.30 per MMBtu in real 2009 dollars. The second fuel forecast is for the Boardman, Oregon area for a Coyote Spring 2 wood addition, where the price is estimated to be $60 per ton or $6.60 per MMBtu (2009$). Hog fuel availability is highly dependent on lumber demand. The Kettle Falls plant had surplus fuel in the mid-2000s, but the plant has struggled to find enough economically priced fuel over the past two years.

Hydro

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

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

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

Table 7.8: Northwest Hydro Capacity Factors

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

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

Wind and Solar

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

Table 7.9: Western Interconnect Wind Capacity Factors

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

Greenhouse Gas Emissions

Greenhouse gas or CO_2 legislation is one the greatest fundamental risks facing the electricity marketplace today. Reducing CO_2 emissions from power plants will change the resource mix over time as society moves away from traditional resources and shifts to an increased reliance on renewable resources. There is currently no federal regulation of carbon emissions, but national legislation is expected to pass in the next few years. In the interim, several western states and provinces are promoting the Western Climate Initiative to develop a multi-jurisdictional greenhouse gas reduction program. Whether or not a federal system will ultimately supersede these efforts is not known.

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

Wood Mackenzie based its carbon price forecast on November 2008 legislation sponsored by Representatives Dingell and Boucher. Their macro-economic models were balanced by identifying a carbon price forecast adequate to meet federal emission goals. The analysis included new nuclear and carbon sequestration resources to meet future load growth in the 2020's. Figure 7.6 shows the carbon price forecast. The IRP assumes carbon will have a cost starting in 2012. The price trajectory increases greatly in 2018 as the next major step in carbon reduction goals begins. The 20-year levelized cost of carbon is $46.14 (nominal) and $33.37 (2009 dollars). When natural gas prices rise or fall, the cost of carbon is expected to change to balance the relative competitiveness of gas and coal.

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

Figure 7.6: Price of Carbon Credits

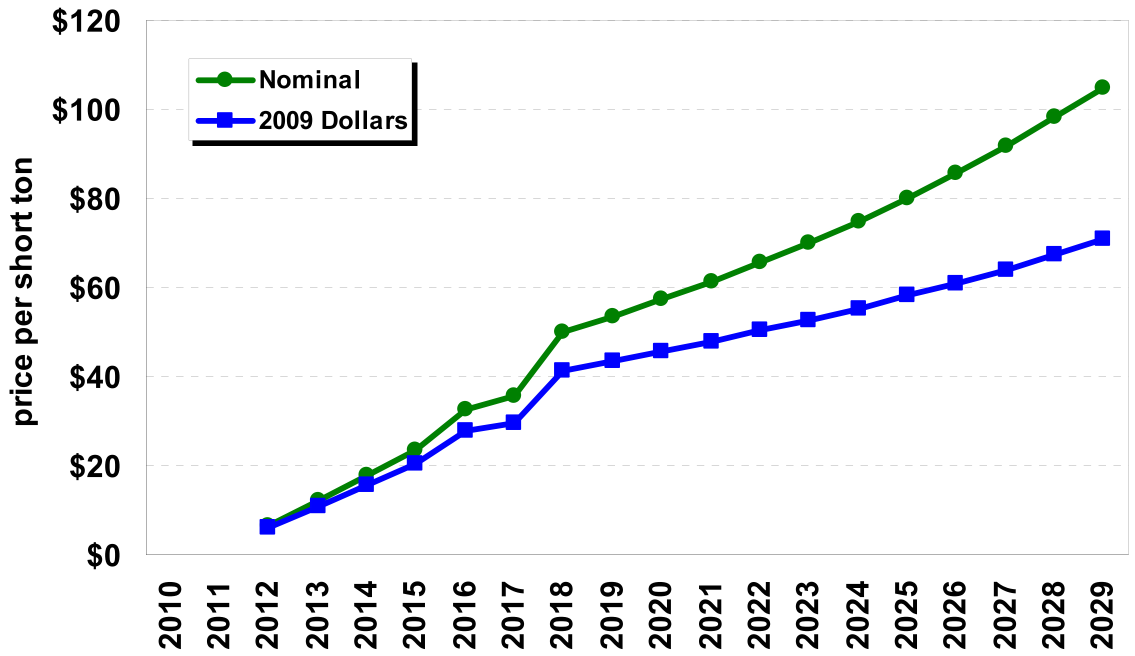
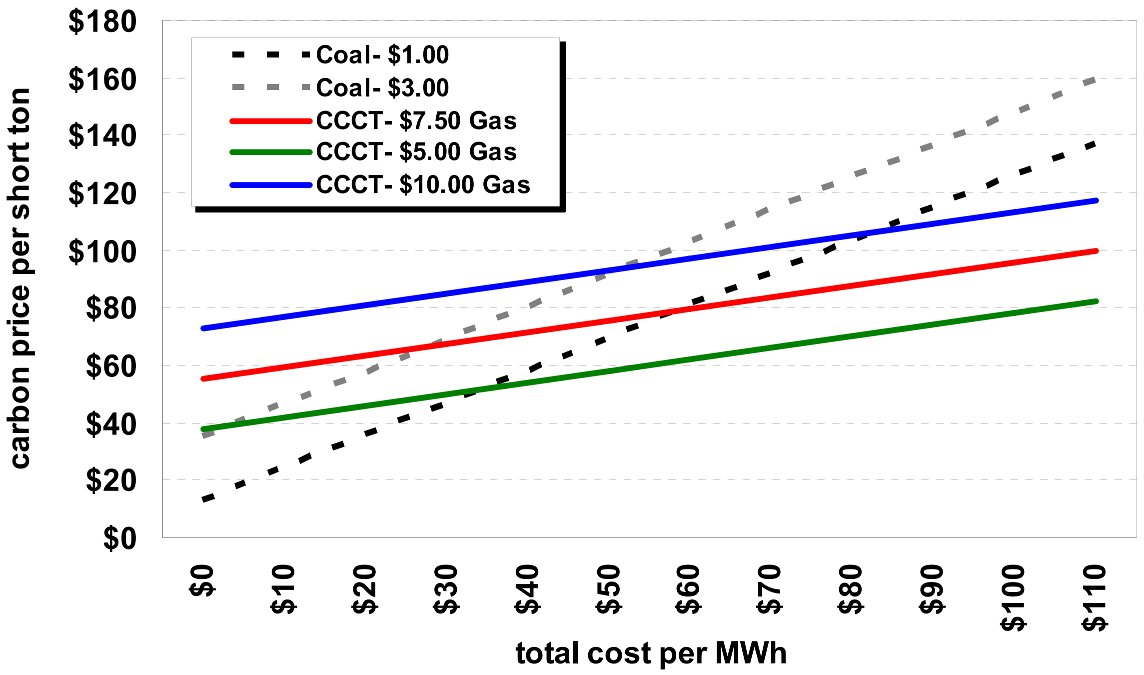


Figure 7.7: Cost of Carbon Credits



Risk Analysis

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

Table 7.10: Stochastic Study Correlation Matrix

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

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

Greenhouse (GHG) Prices

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

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

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

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

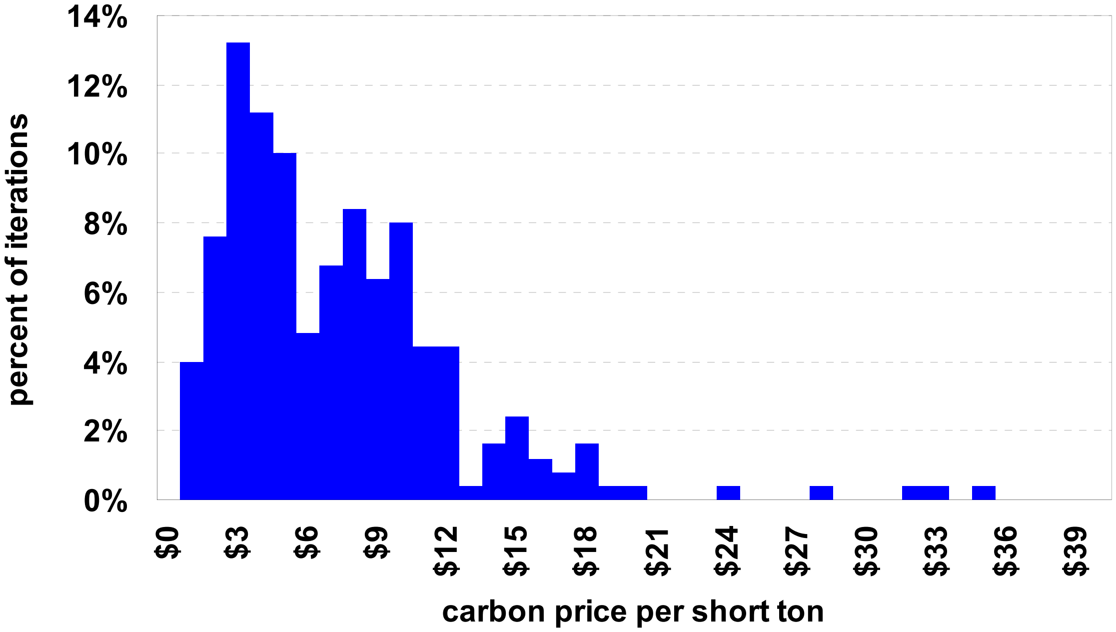
Table 7.12: Ten Cost Scenarios Based on Wood Mackenzie and EPA Studies (Nominal Price per Short Ton)

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

The carbon price is determined in a two-step process. The first step draws the carbon price regime; the second step adjusts natural gas prices and other variables. The adjustment keeps prices correlated so the market effect is consistent. See Figure 7.8 for the carbon price distribution for the 250 iterations in 2012. Carbon prices range from $1 to $35 per short ton, with an average of $6.55 per short ton. The standard deviations of carbon prices in 2012, 2014, 2016 and beyond are 50 percent, 25 percent and ten percent respectively.

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

Figure 7.8: Distribution of Annual Average Carbon Prices for 2012



Natural Gas

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

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

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

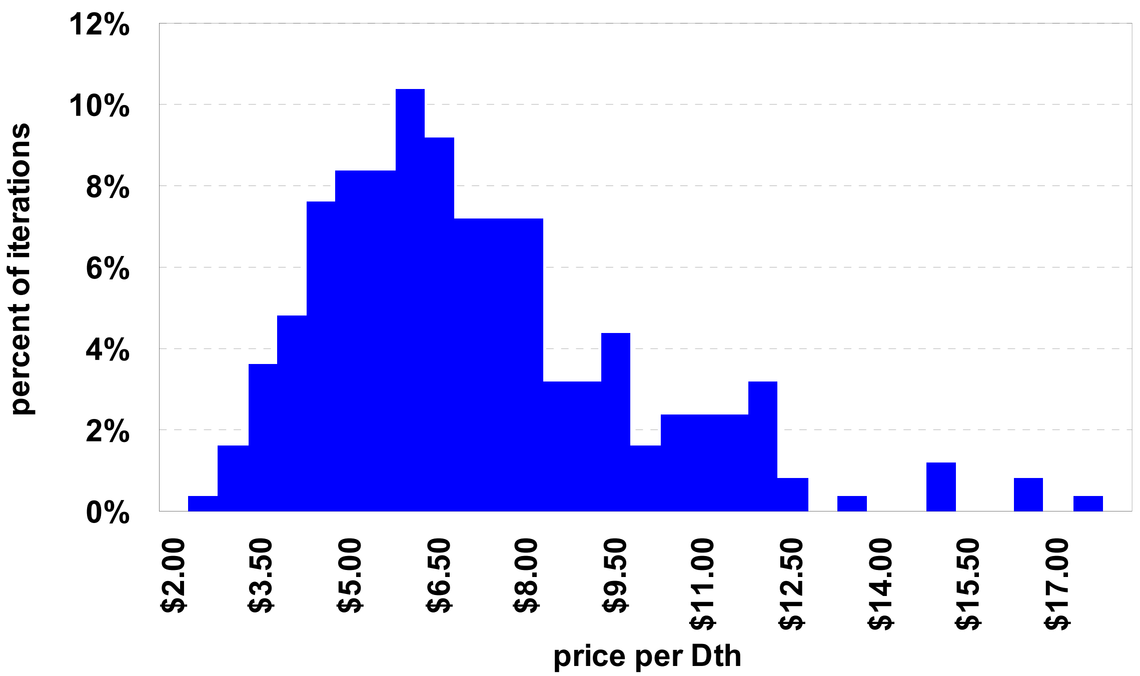
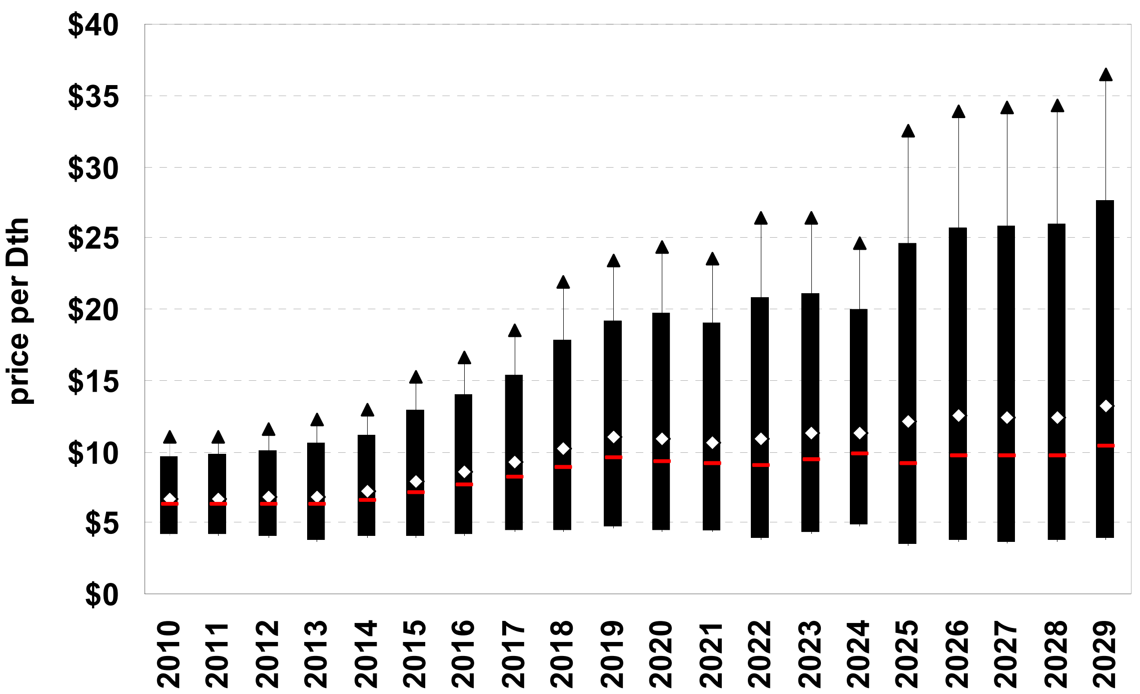
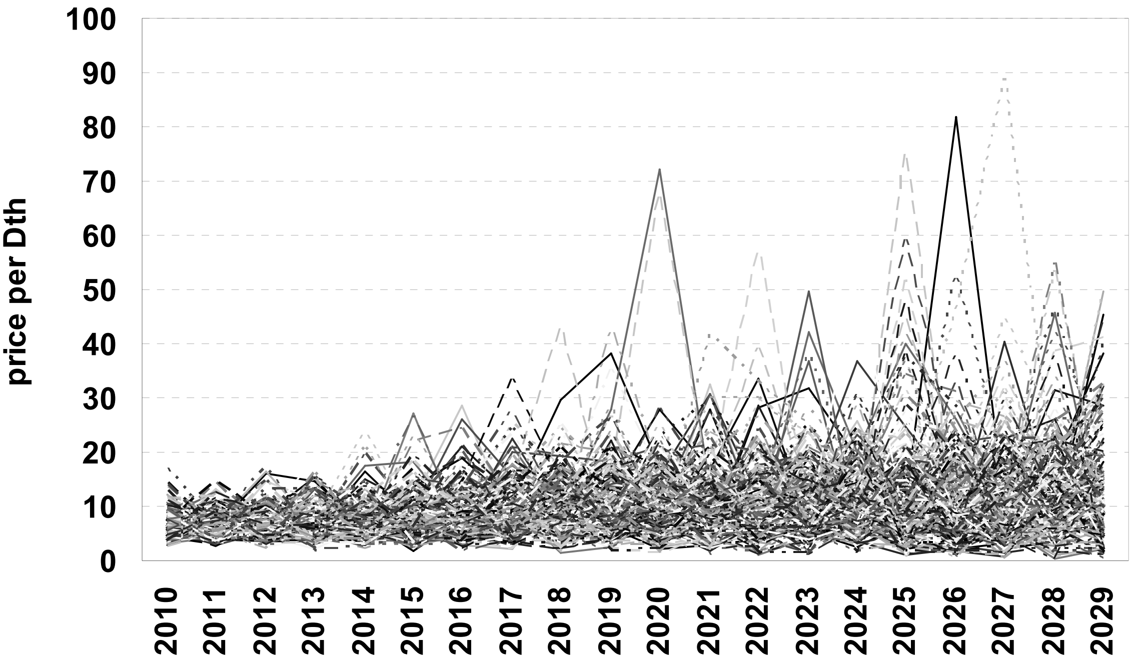


Figure 7.10: Henry Hub Natural Gas Distributions



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

Figure 7.11: Random Draws from the Henry Hub Price Distribution

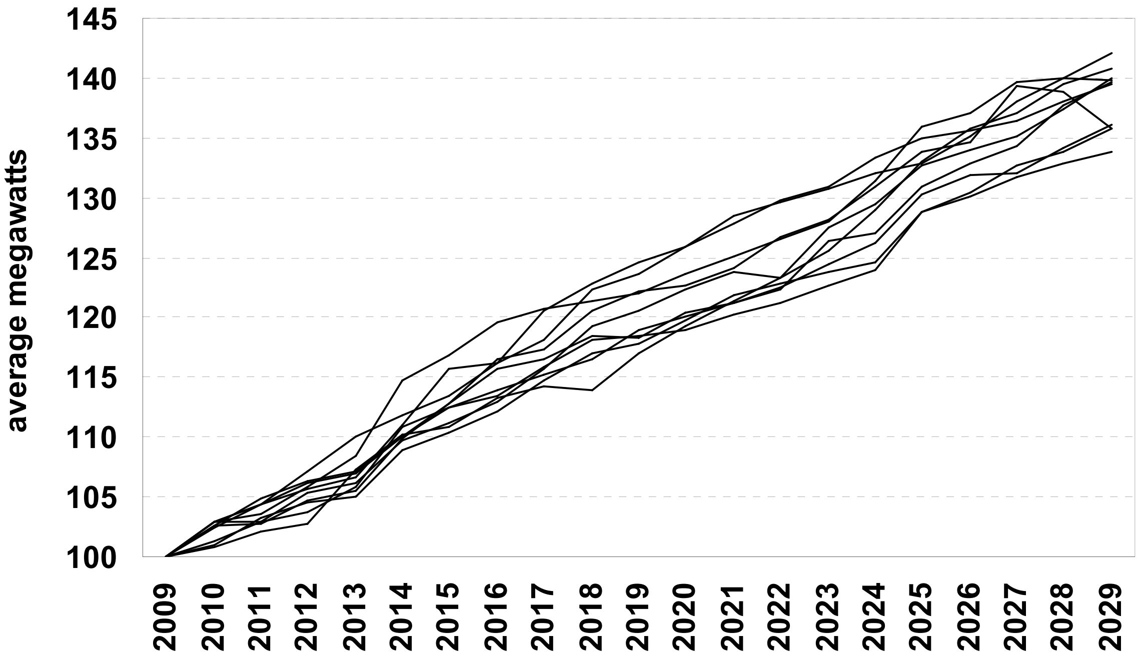


Load

Load variability is driven by several factors. The largest driver is weather because extreme weather variations can move loads up or down compared to overall expected levels. The recent economic downturn has decreased electric demand relative to the long-term average, while earlier economic expansions increased loads. Loads are modeled to increase at the levels discussed earlier in the chapter, but the risk analysis varied economic and weather conditions. The economic adjustments are inversely correlated to natural gas and carbon prices using a lag function. This means that if carbon prices were high in the previous year, then the probability of lower loads is likely the following year (25 percent probability) due to price elasticity responses.

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

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



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

The method Avista adopted for its 2003 IRP continues to be used to reflect weather patterns across the Western Interconnect. FERC Form 714 data was collected for 2002 to 2007. Correlations between Northwest and other Western Interconnect load areas were calculated and represented as stochastic weather adjustments to the load model. Correlating area loads avoids oversimplifying the Western Interconnect load picture. Absent correlations, stochastic models would offset load changes in one zone with load changes in another, thereby virtually eliminating the possibility of modeling the West-wide load excursions we witness in today's marketplace. Given the high degree of interdependency across the Western Interconnect (e.g., the Northwest and California), this additional accuracy is crucial for understanding variation in wholesale electricity market prices and the value of resources used to meet such variation (i.e., peaking generation). For example, without regional correlation the volatility would be measured, but would not adequately represent heat waves and cold snaps occurring across the Western Interconnect.

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

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

Table 7.13: January through June Area Correlations

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

Table 7.14: July through December Area Correlations

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

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

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

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

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

Coal Prices

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

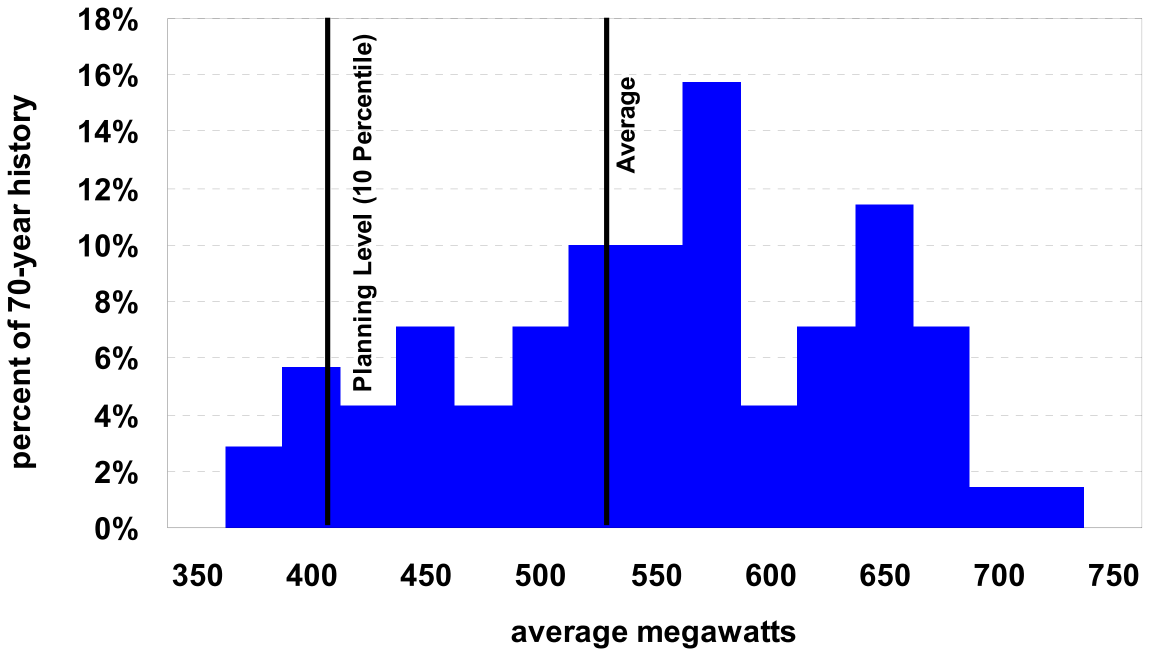
Wood/Hog Fuel

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

Hydro

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

Figure 7.13: Distribution of Avista's Hydro Generation



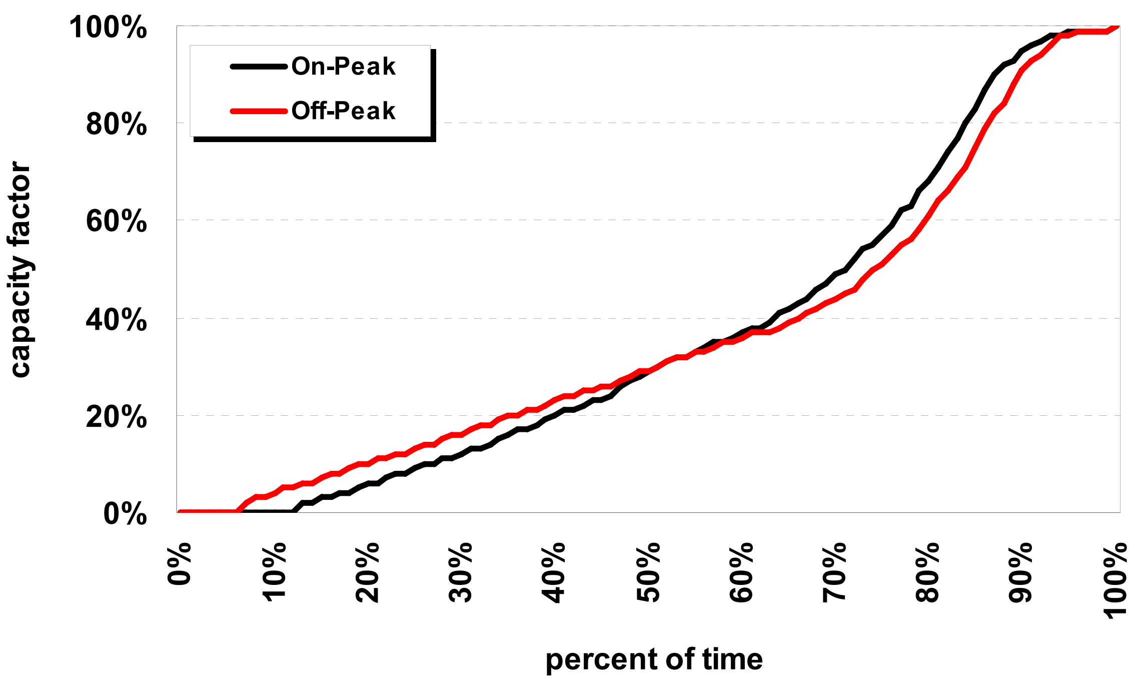
Wind

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

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

The first step in developing the wind randomization model was to create a distribution of hourly output. Figure 7.14 shows the distribution for a Northwest wind site. In this example, generation is zero for 13 percent of the on-peak hours and zero for 6 percent of the off-peak hours. The resource is near full output only 5 percent of the time. The second step links next-hour generation to present generation levels. The next hour has a 95 percent probability of being within two percent of the last hour's generation level. The model also correlates wind locations: Reardan is 75 percent correlated to Northwest resources and Montana is 25 percent correlated to Northwest wind resources.

Figure 7.14: Wind Output Distribution



Forced Outages

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

Market Forecast

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

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

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

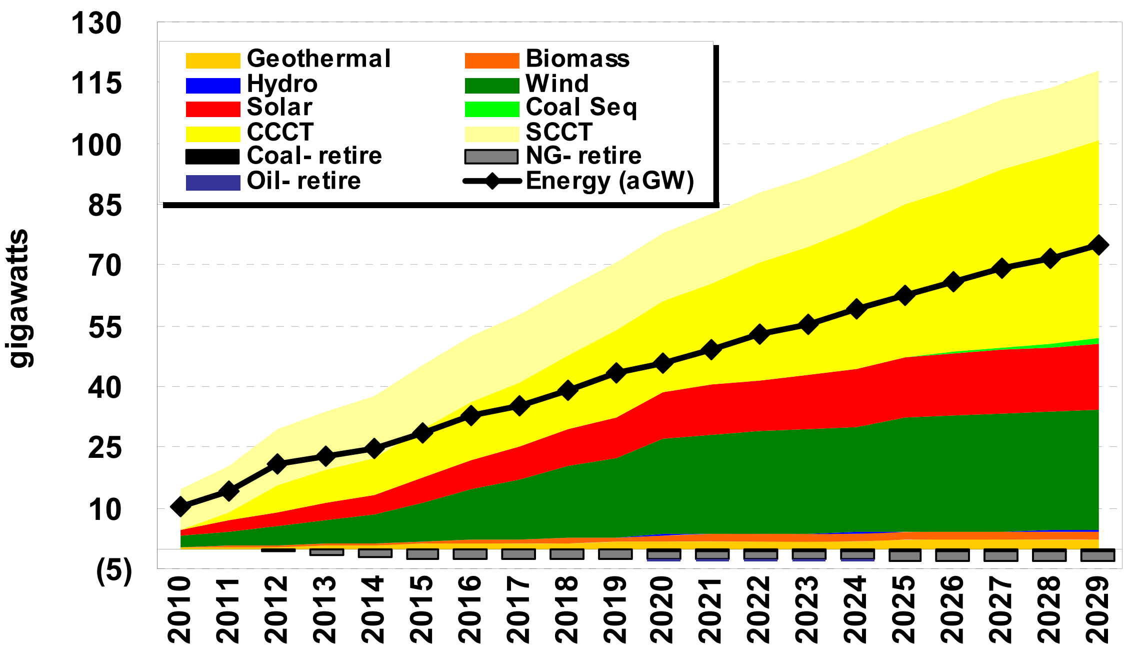
A stochastic study uses Monte Carlo analysis to quantify variability in future market prices. These analyses include 250 iterations of varying gas prices, loads, hydro, thermal outages, wind shapes and emissions prices. Two stochastic studies were developed for this IRP, one with and one without carbon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

Resource Selection

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

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

Figure 7.15: Base Case New Resource Selection



Mid-Columbia Price Forecast

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

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

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

Figure 7.16: Annual Flat Mid-Columbia Electric Prices

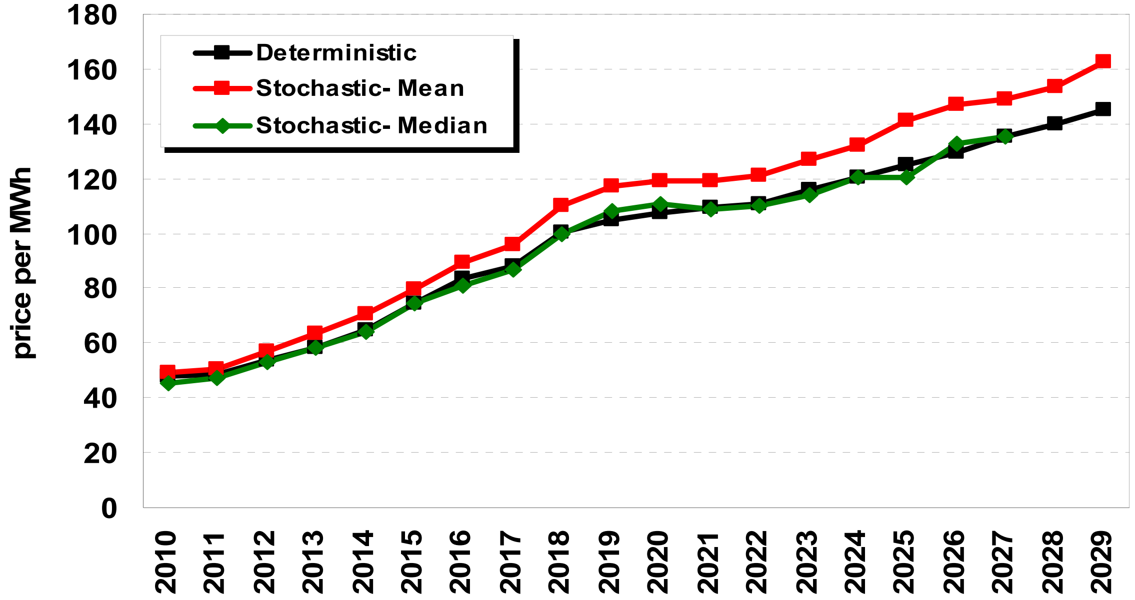
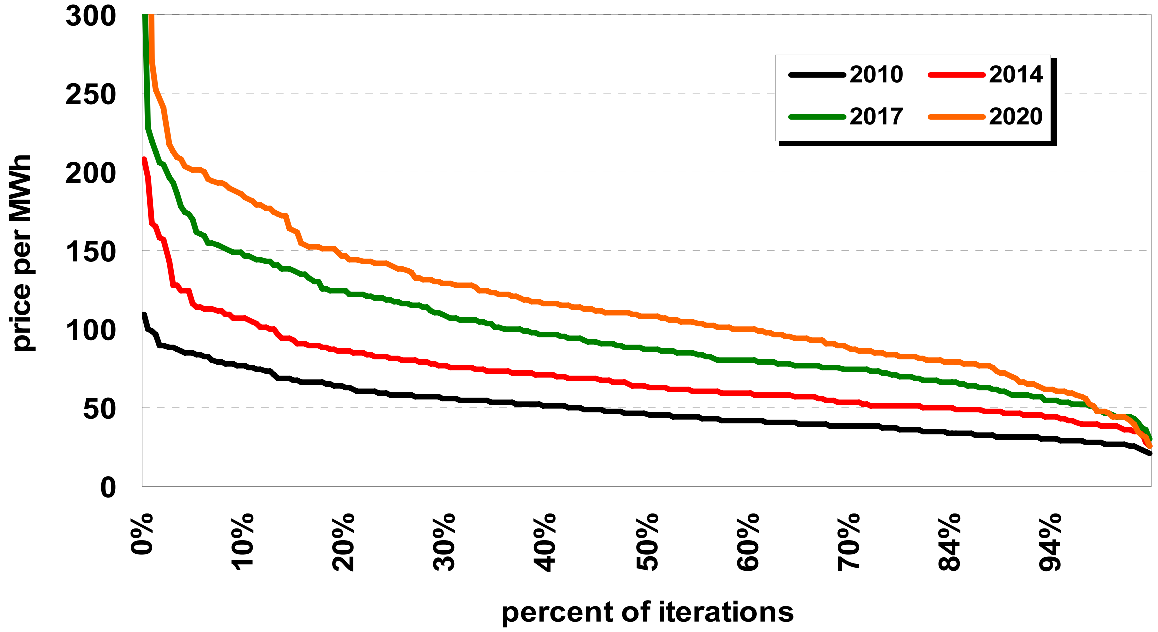


Figure 7.17: Selected Mid-Columbia Annual Flat Price Duration Curves



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

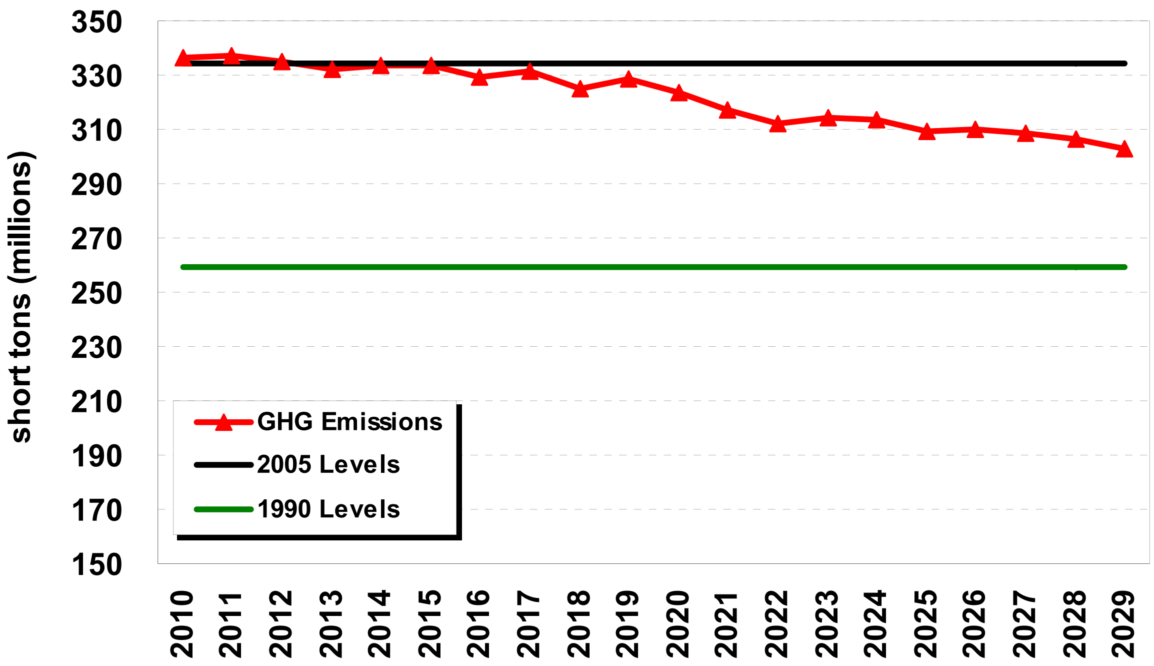
Table 7.17: Annual Mid-Columbia Electric Prices ($/MWh)

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

Greenhouse Gas Emissions Levels

Greenhouse gas levels are expected to increase over the study period where no carbon legislation is enacted that would affect the Western Interconnect. The carbon costs discussed earlier in this chapter provide price signals to encourage greenhouse gas emission reductions following proposed legislation at the end of 2008. The prices were based on a Wood Mackenzie study including the entire U.S. electrical system. Figure 7.18 shows emissions across the Western Interconnect. Emissions are expected to quickly fall to 2005 levels, and then more toward 1990 levels by the end of the study. The Wood Mackenzie study assumed carbon offsets would help meet Western Interconnect carbon reduction goals. Carbon prices would need to be significantly higher to reduce the Western Interconnect to 1990 emissions levels without the offset assumptions. The Wood Mackenzie study found that the Eastern Interconnect will lower emissions at twice the level as the West, but that the West would reduce it emissions by a higher percentage.

Figure 7.18: Western States Greenhouse Gas Emissions

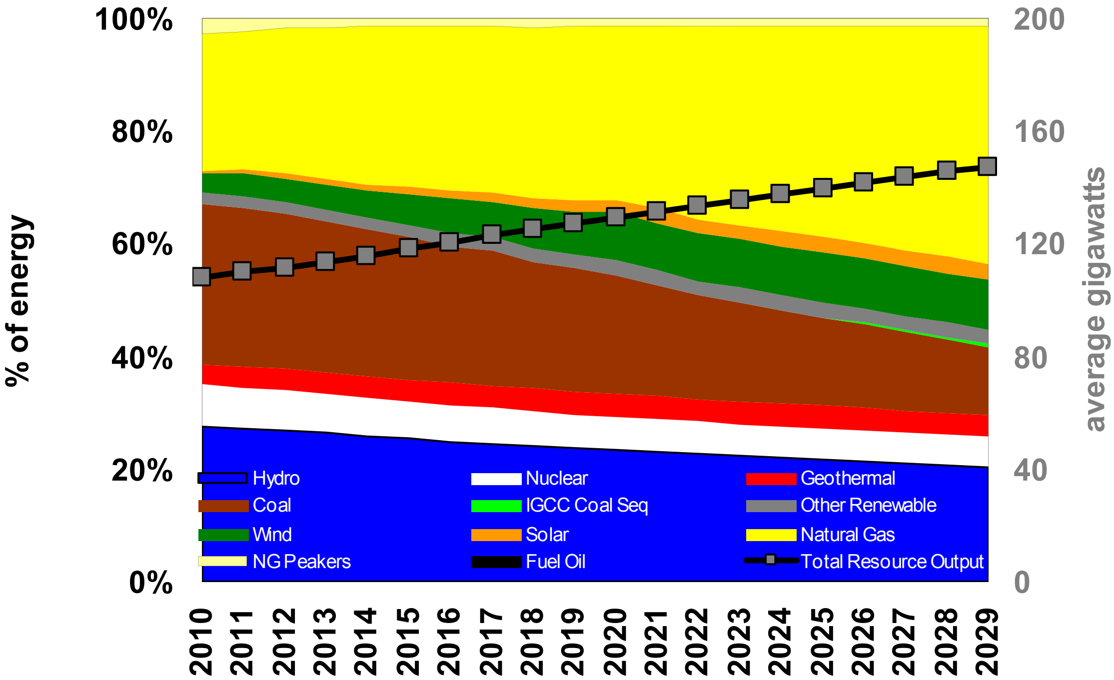


Resource Dispatch

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

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

Figure 7.19: Base Case Western Interconnect Resource Energy



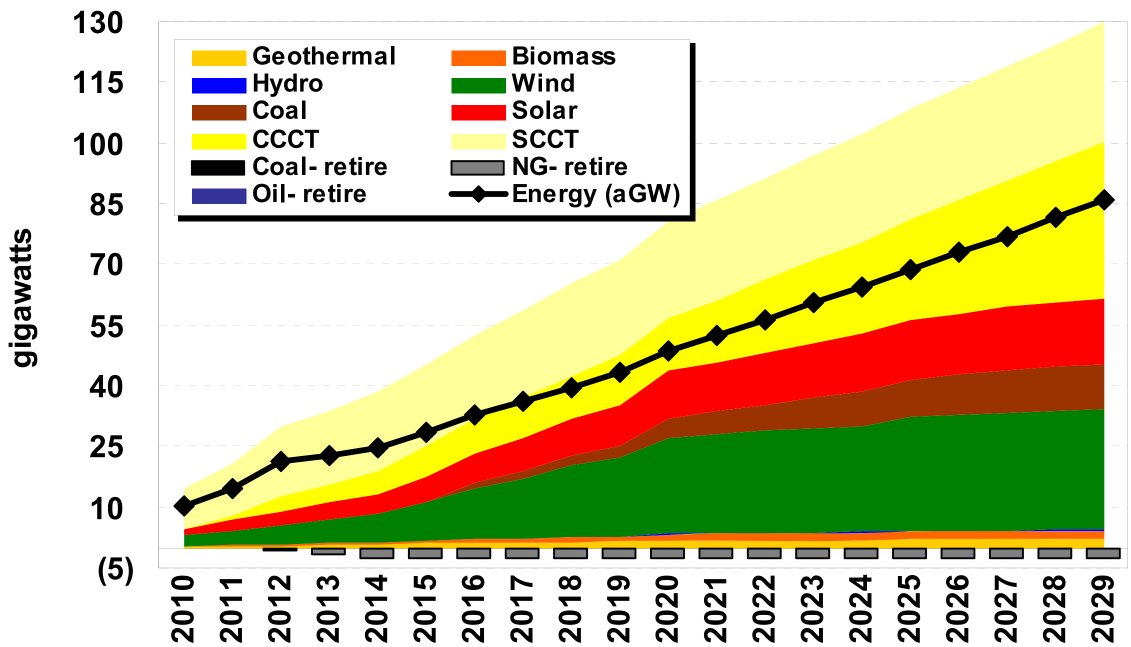
Scenario Analysis

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

Unconstrained Carbon Emissions

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

Figure 7.20: Unconstrained Carbon Emissions Resource Selection



Mid-Columbia market prices would be lower absent carbon legislation. The deterministic analysis found prices would be $22.43 per MWh lower on a nominal levelized basis over the forecast horizon; the stochastic analysis found prices would be $25.52 per MWh (32 percent) lower. Prices are lower without carbon penalties because fuel and dispatch costs for natural gas-fired plants are lower. A comparison of the two forecasts is shown in Figure 7.21.

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

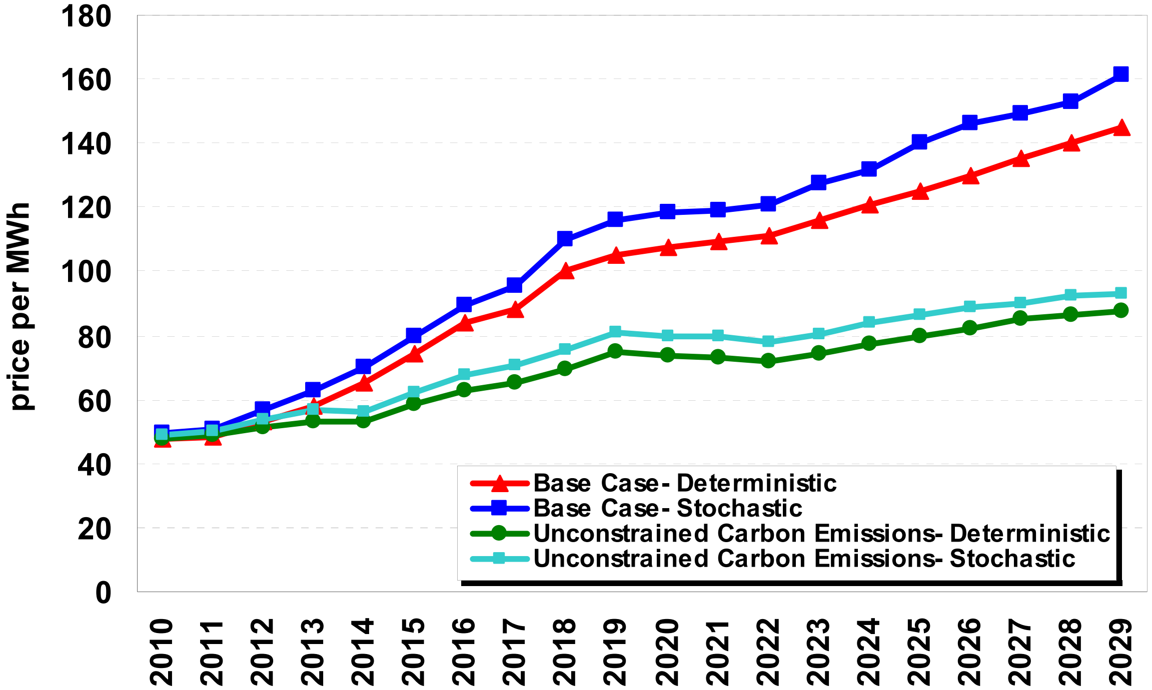


Figure 7.22 illustrates the difference between carbon emissions with and without the carbon adder included in the Base Case. Carbon emissions would be 11 percent higher in 2020 and 40 percent higher in 2029 without the Base Case carbon adder. The increased emissions are caused by higher dispatch levels for coal-fired resources (Figure 7.23) relative to the Base Case. Carbon emission impacts on coal plants could increase overall fuel costs across the Western Interconnect by 16.3 percent or $42.5 billion in present value terms (2009 dollars). Annual cost increases are shown in Figure 7.24. Carbon legislation adds $328 million in present value term (2009 dollars) over the study period for operations, but reduces capital and other non-O&M costs by $17.1 billion. In total, carbon legislation on a 20 year net present value calculation will increase costs by $25.7 billion (10 percent).

Figure 7.22: Western U.S. Carbon Emissions Comparison

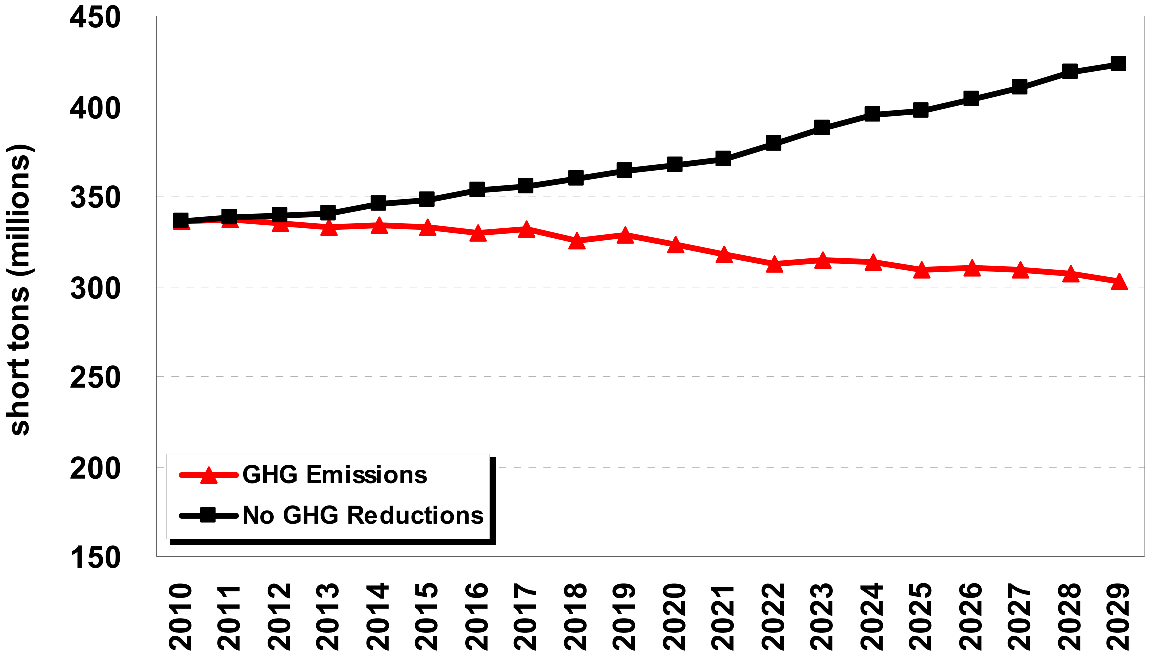


Figure 7.23: Unconstrained Carbon Scenrio Resource Dispatch

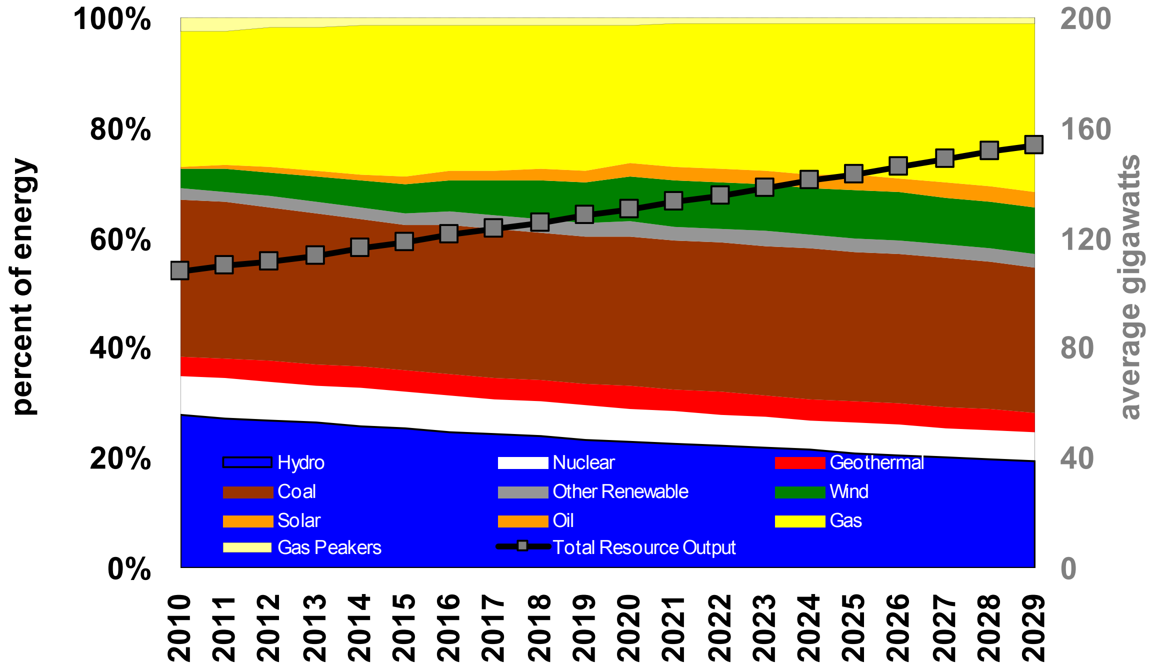
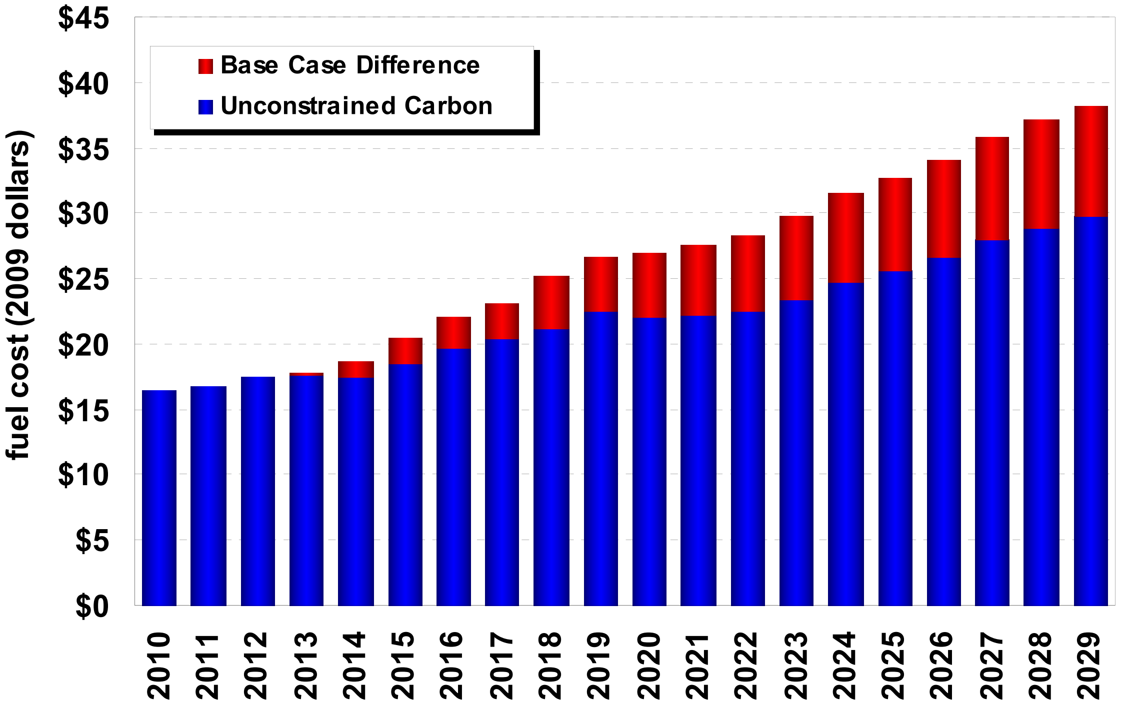


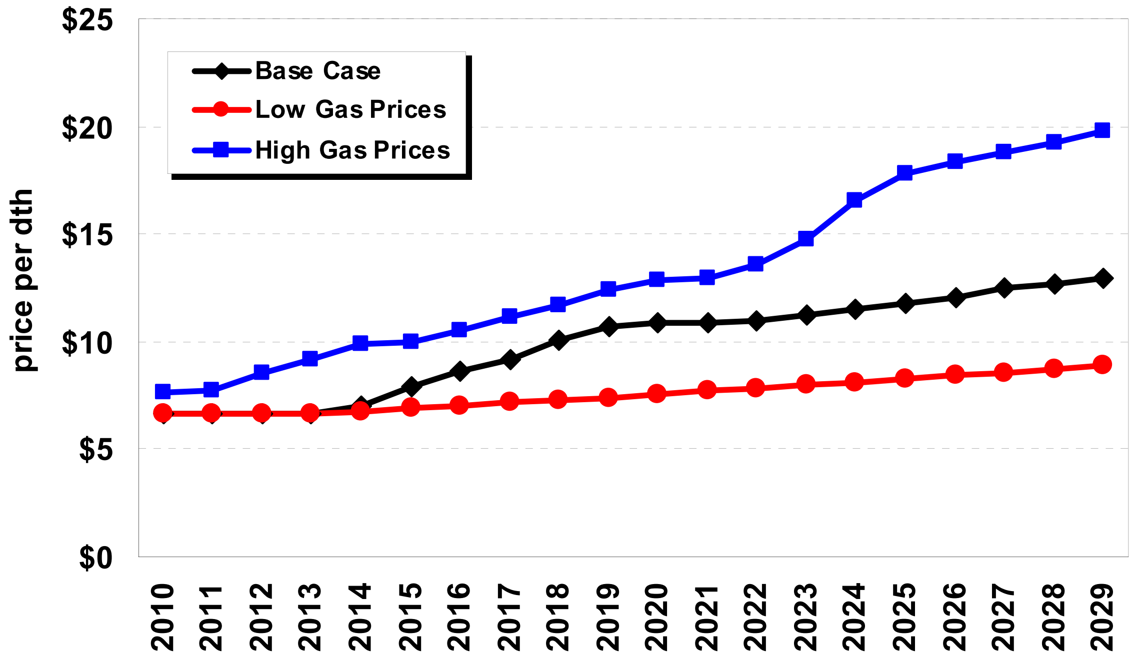
Figure 7.24: Western Interconnect Fuel Cost Comparison



High and Low Natural Gas Prices

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

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



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

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

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

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

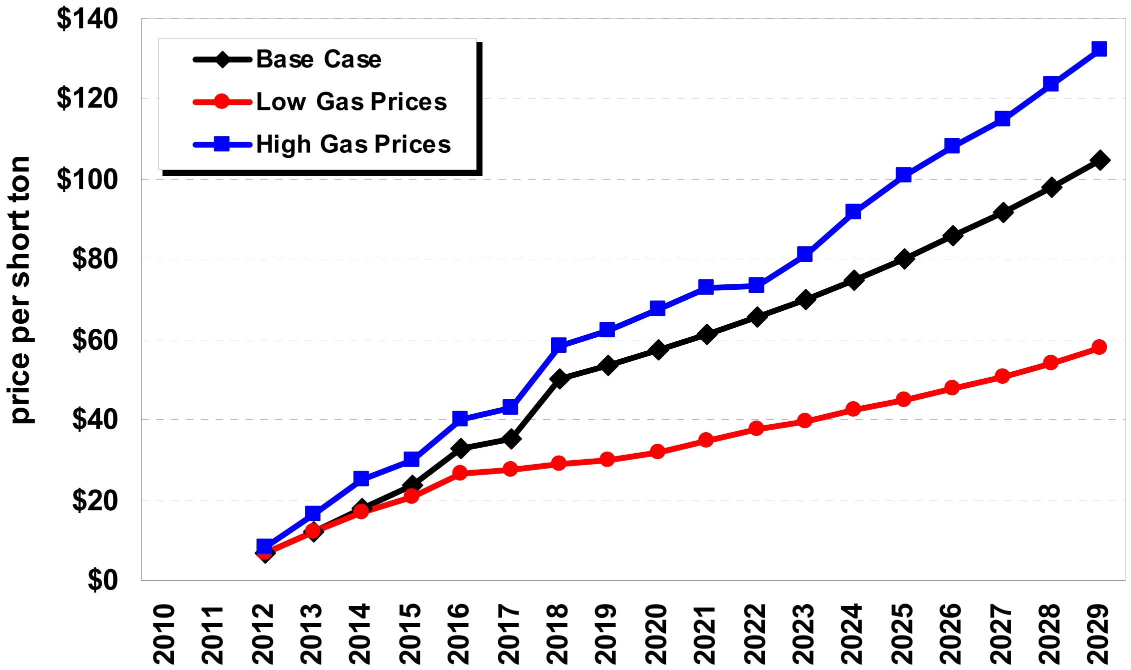


Figure 7.27: High Natural Gas Prices Scenario Resource Selection

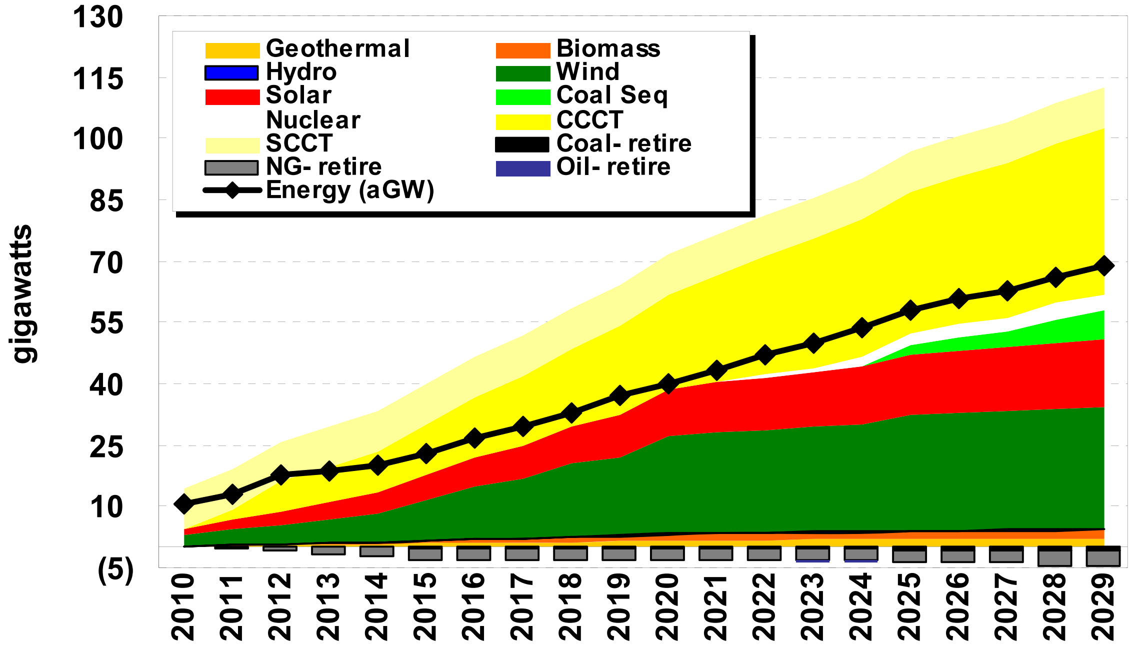
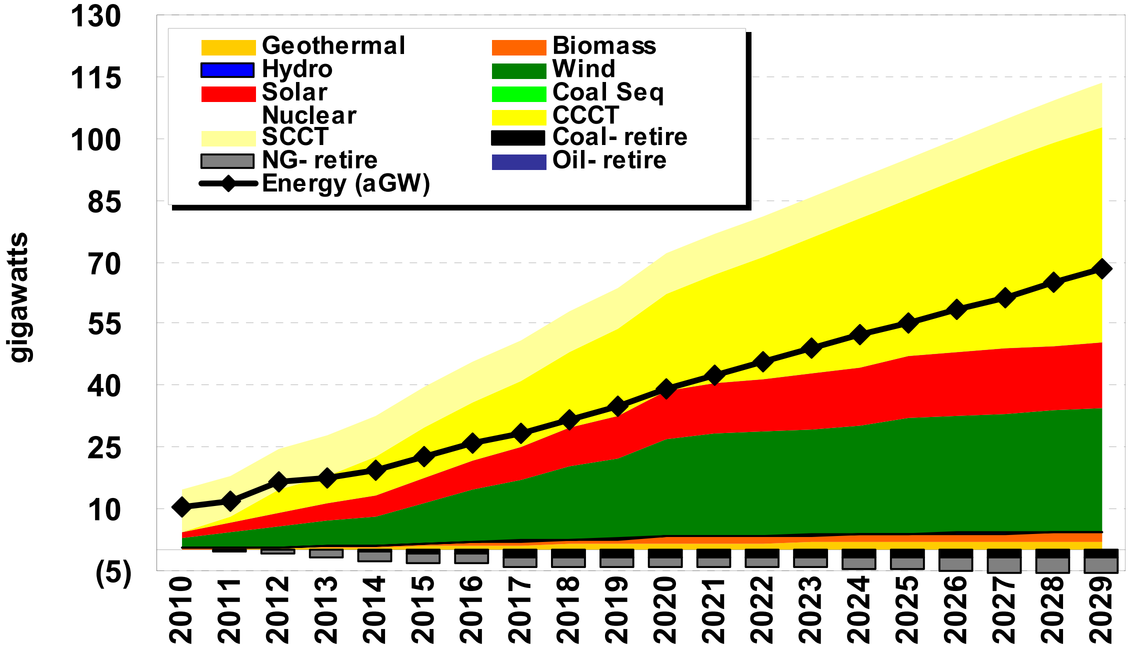


Figure 7.28: Low Natural Gas Prices Scenario Resource Selection



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

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

Figure 7.29: Mid-Columbia Electric Price Forecast

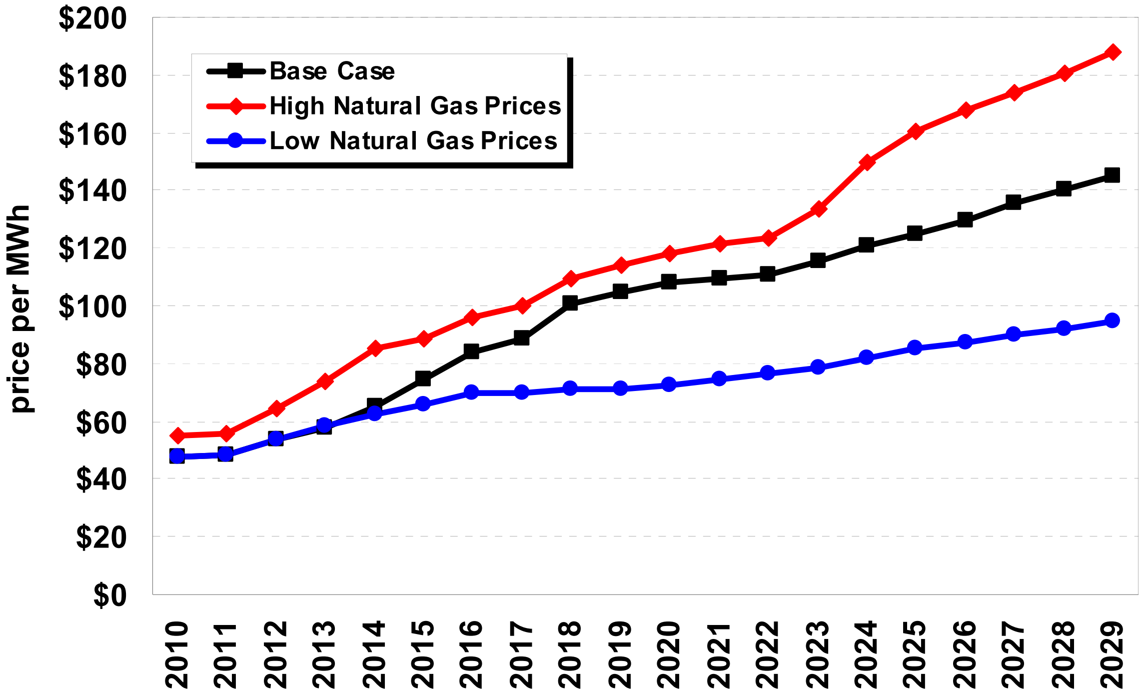


Figure 7.30: Resource Dispatch- High Gas Price Scenario

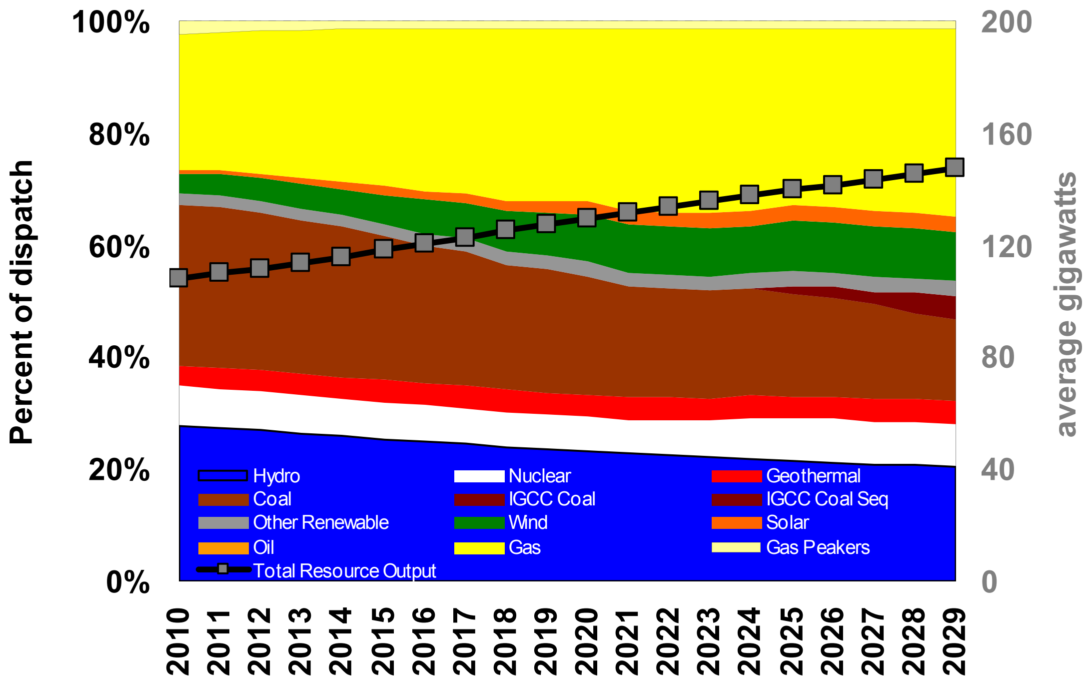
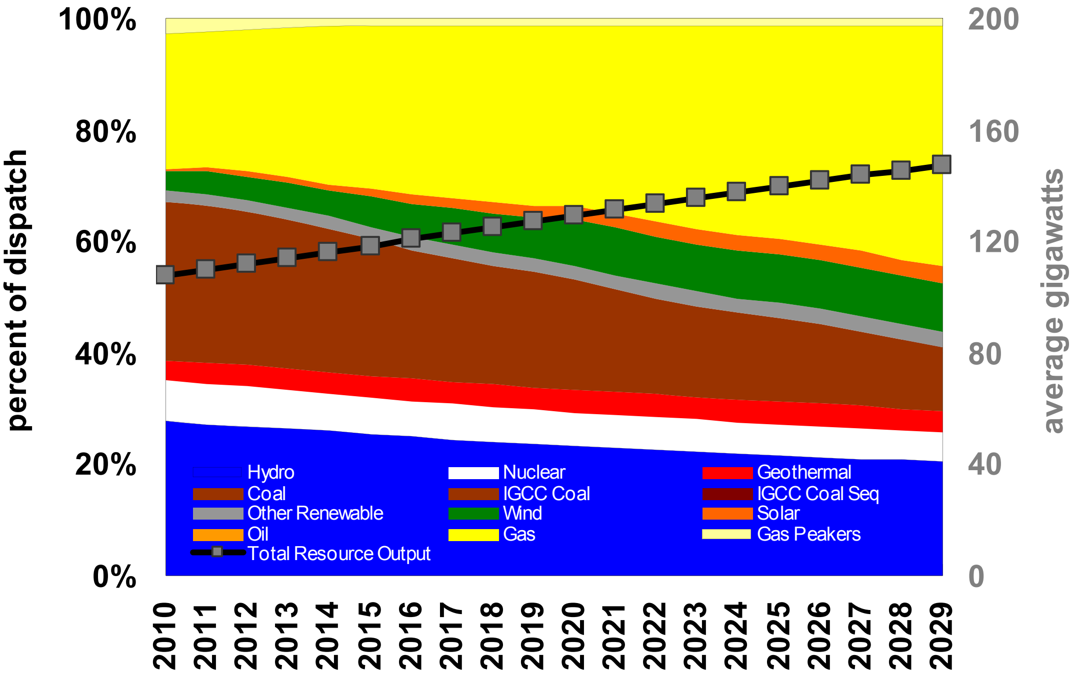


Figure 7.31: Resource Dispatch- Low Gas Price Scenario

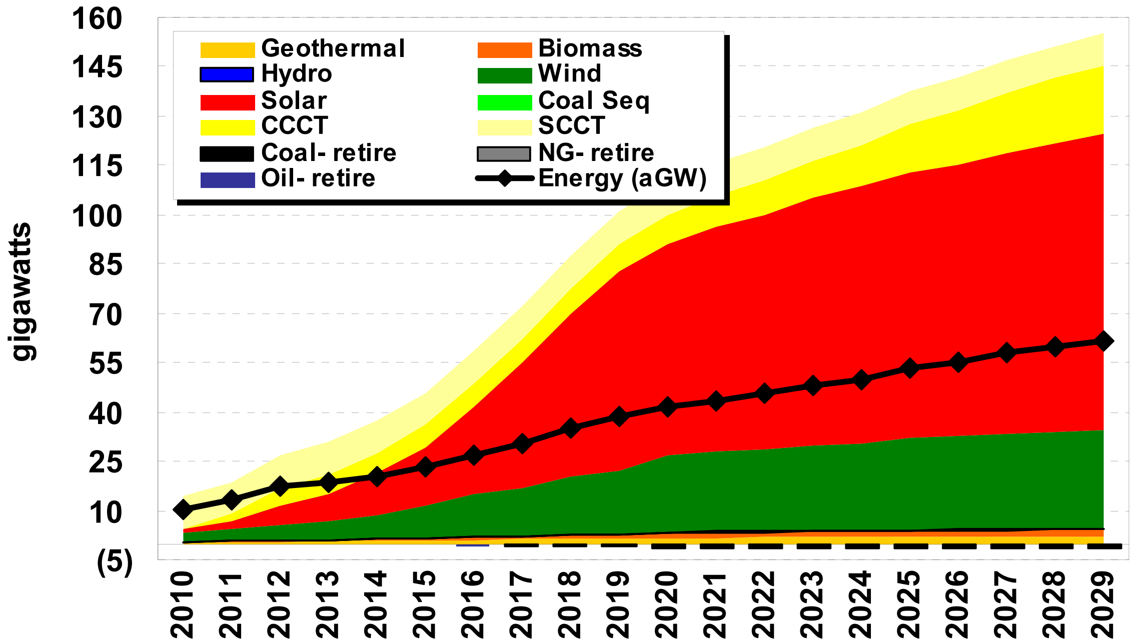


Solar Saturation

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

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

Figure 7.32: Solar Saturation Scenario Resource Selection



Adding 75 GW of solar did not have a significant impact on Mid-Columbia market prices. There was only a reduction of $3.50 per MWh (4 percent) levelized (nominal), though second and third quarters (high solar months in the Northwest) had lower on-peak power prices than in the Base Case. Prices did not change because the marginal cost of power was still set by gas-fired resources and because solar does not produce power at night. More solar would need to be added and a low-cost storage technology identified to effectively lower market prices. Greenhouse gas emissions were reduced by 10 percent from the Base Case (see Figure 7.33) in this scenario.

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

Figure 7.33: Western Interconnect Carbon Emissions Comparison

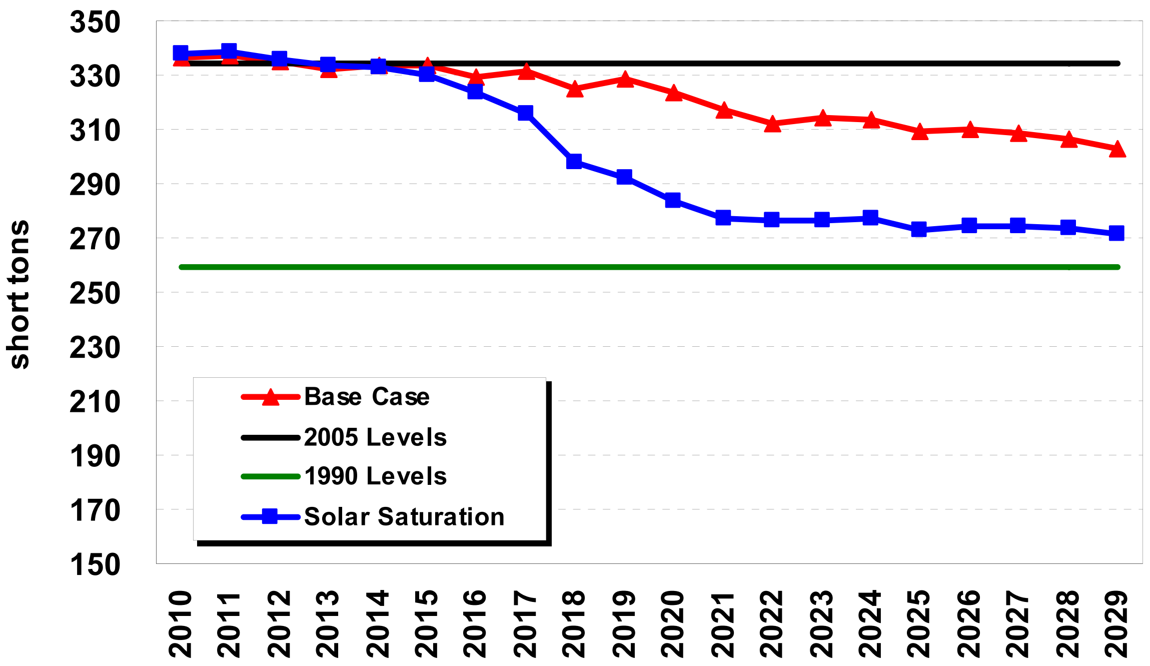
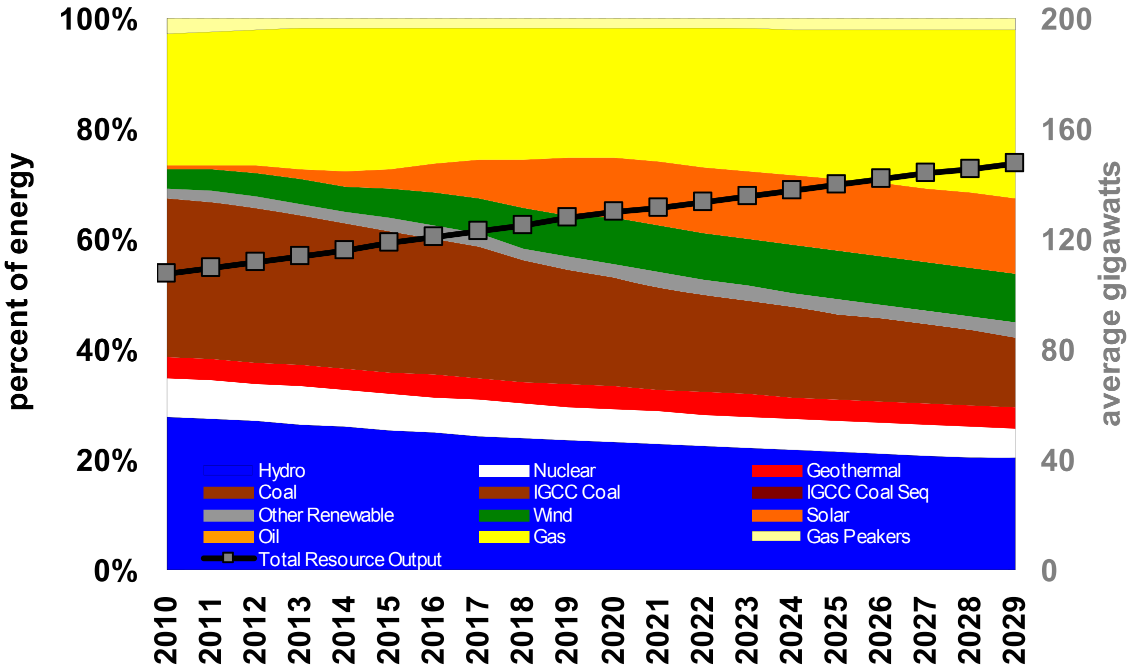


Figure 7.34: Resource Dispatch- Solar Saturation Scenario



Market Analysis Summary

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

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

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

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

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

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

8. Preferred Resource Strategy

Introduction

This chapter summarizes the 2009 Integrated Resources Plan's (IRP) Preferred Resource Strategy (PRS), along with its potential cost and risks. It details the planning and resource decision methodologies; describes the strategy, climate change ramifications and how the PRS might evolve if base forecasts of future conditions are incorrect.

Site of the Proposed Reardan Wind Project

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

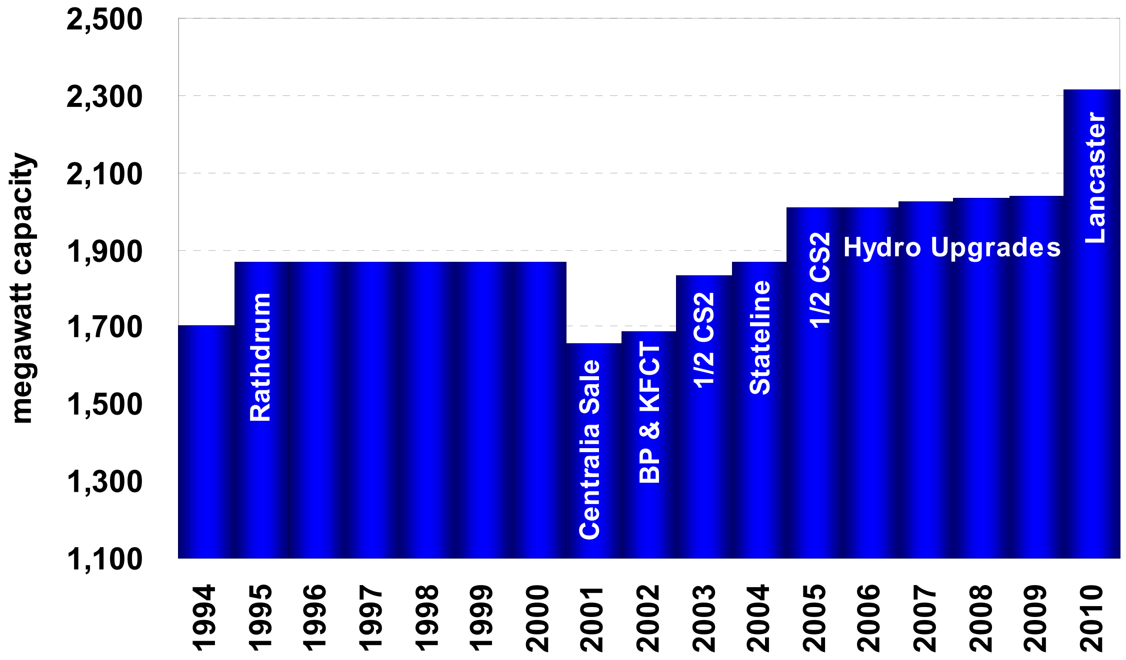
Chapter Highlights

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

Supply-Side Resource Acquisition History

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

Figure 8.1: Resource Acquisition History



Resource Selection Process

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

PRiSM

Avista staff developed the PRiSM model in 2002 to help select the PRS. The PRiSM model uses a linear programming routine to support complex decision making with single or multiple objectives. Linear programs provide optimal values for variables using given system constraints.

Overview of the PRiSM Model

PRiSM has six basic inputs:

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

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

PRiSM Objective Function

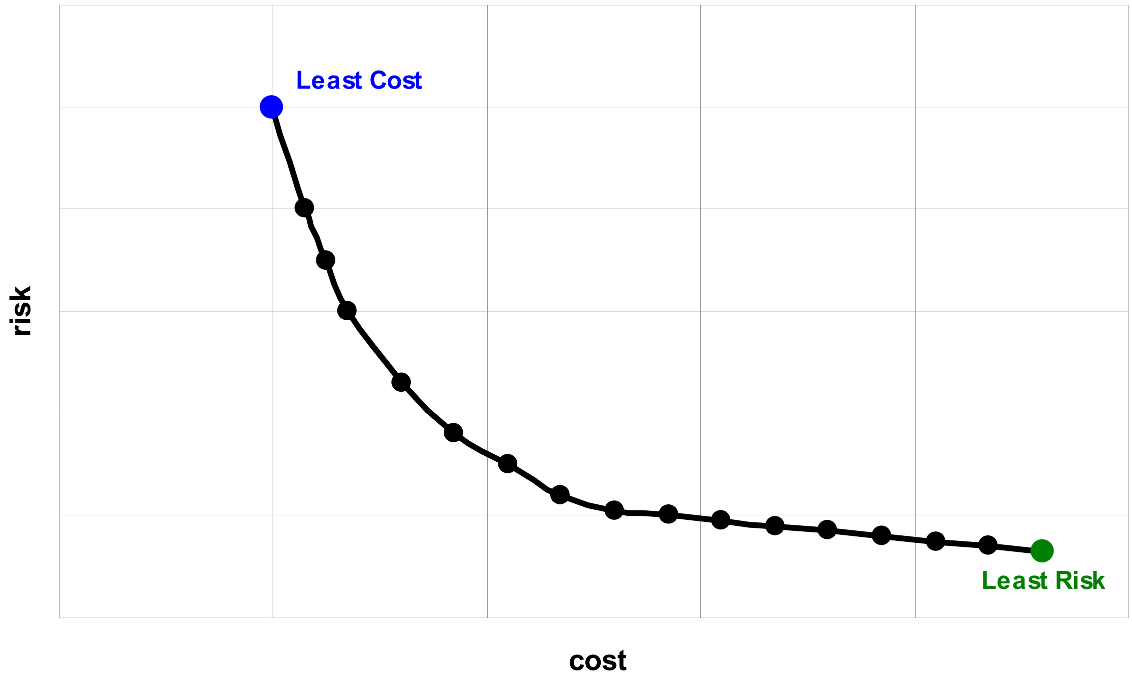
Minimize: $(X_1 * NPV_{2010\text{-}2019}) + (X_2 * NPV_{2010\text{-}2029}) + (X_3 * NPV_{2010\text{-}2059})$

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

Subject to: Capacity needs;
Energy needs;
Washington RPS;
Resource limitations;
Resource availability; and
Risk tolerance

The hypothetical resource set is used to develop an Efficient Frontier. The 2009 IRP Efficient Frontier captures the optimal resource selection, given constraints at each level of cost and risk. Figure 8.2 illustrates the Efficient Frontier. The optimal point on the curve depends on the level of risk Avista and its customers can accept. As discussed in the 2007 IRP, utility-scale resource options are limited because of environmental legislation. Two portfolio planning assumptions from the 2007 IRP are not continued for this plan: RPS requirements can no longer be met entirely with utility purchases of renewable energy certificates (RECs), and long-term fixed-price natural gas is not available to the portfolio. The loss of these options further limits resource choices compared with the 2007 IRP. Avista does not expect it will be able to acquire sufficient RECs at a reasonable price to meet the RPS, and REC purchases expose the Company to potential volatility that asset ownership would not. For resource planning purposes, REC purchases are an option, but not in excess of 45,000 per year. Work since the 2007 IRP have found that long-term fixed-price natural gas contracts consume inordinate amounts of Company capital.

Figure 8.2: Efficient Frontier Curve



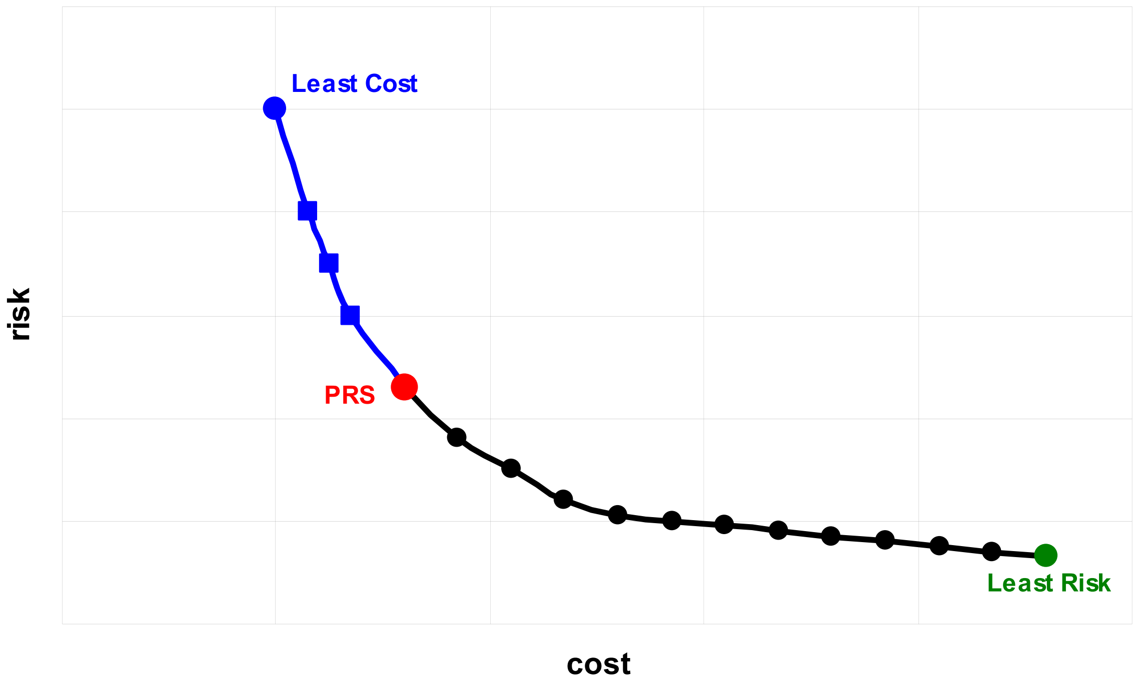
Constraints

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

The PRiSM model is limited by resource type and size. It can select from combined- and simple-cycle natural gas-fired combustion turbines, wind and small hydro upgrades. Sequestered coal plants are available beginning in 2023. A new enhancement to PRiSM for the 2009 IRP cycle ensures it selects resources in minimum block sizes rather than mathematically optimal increments. This change better reflects how Avista actually acquires resources. It also emulates how the Company manages lumpy resource additions and that resource positions are not perfectly balanced with load each year. PRiSM is allowed to model Avista's portfolio to be as much as 50 MW short or 200 MW long in any given planning year.

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

Figure 8.3: Efficient Frontier in a Constrained Environment



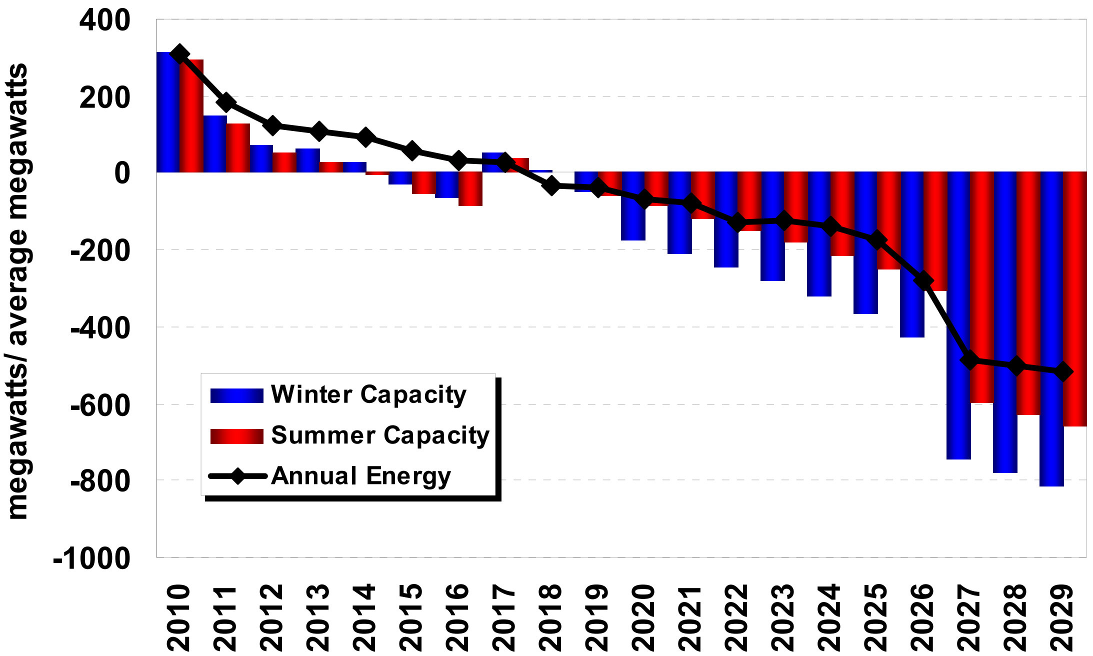
Resource Shortages

Avista has adequate resources to meet annual physical energy and capacity needs until 2015. See Figure 8.4. The graphic accounts for energy efficiency and conservation program impacts on the portfolio. Absent these efficiency gains, our position would be deficit sooner. The first capacity deficit is short-lived because a 150 MW exchange contract ends in 2016. Avista plans to address the 2015-2016 capacity deficit with market purchases as 2015 approaches.

The Company's resource portfolio has 226 MW of natural gas-fired peaking plants available to serve winter loads. For long-term planning these resources are assumed to generate energy at their full capabilities. Operationally, the resources often will be displaced with less expensive purchases from the wholesale marketplace. On an annual average basis our loads and resources fall out of balance in 2018 for energy; the first quarterly energy deficit is in the fourth quarter of 2014.

PRiSM selects new resources to fill capacity and energy deficits, although the model might over- or under-build for economic reasons. Because of its greater capacity need, and the fact that wind acquisitions do not provide capacity commensurate with their energy production, Avista will retain large energy surpluses.

Figure 8.4: Physical Resource Positions



Planning Criteria

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

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

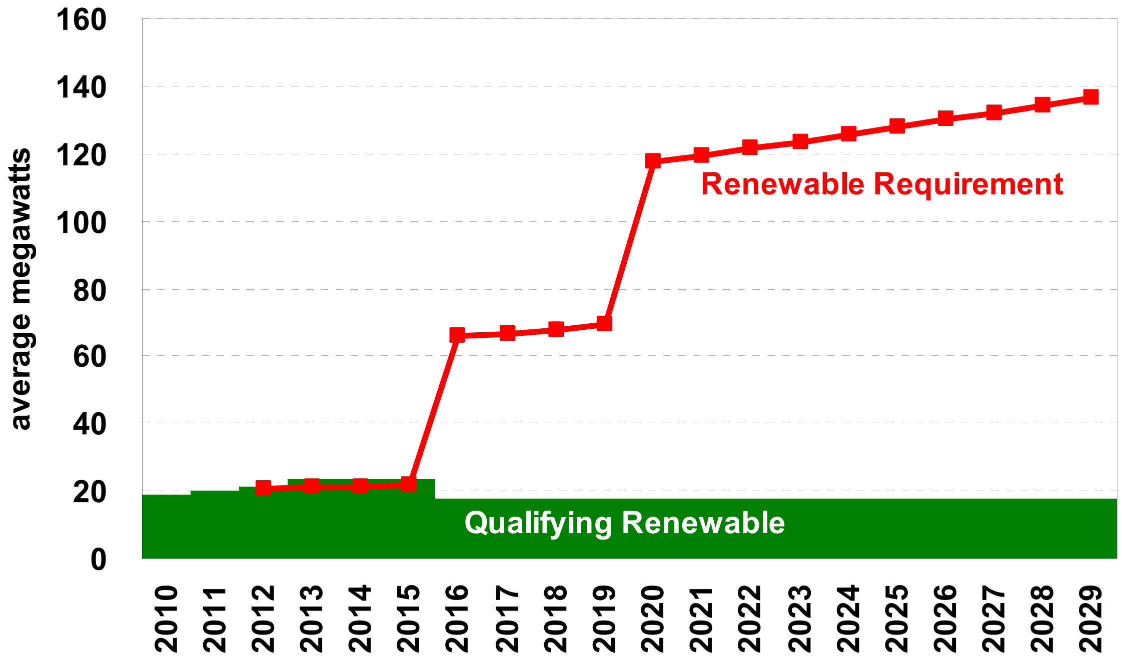
Renewable Portfolio Standards (I-937)

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

Avista projects it will meet or exceed its renewable requirements between 2012 and 2015 through hydro upgrades and a REC purchase made in 2009, as shown in green in Figure 8.5. Avista has the ability to bank RECs acquired from the Stateline Wind contract in 2011 for 2012, but these RECs are sold to customers as part of the Buck-a-Block program. As part of the REC analysis, Avista included a 10 percent margin so Avista is not forced to make REC purchases in a strained market when hydroelectric generation or load varies from its expectation and the Company would potentially be required to pay a penalty.

The Company will need its next block of qualifying resources prior to 2016 and another block will be required prior to 2020. Assuming Avista meets RPS requirements with wind, as illustrated later in this section, it will require 150 MW of nameplate capacity by 2016 and a similar amount by 2020. After 2020, Avista will continue to acquire renewable resources to meet load growth as specified in I-937.

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



Preferred Resource Strategy

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

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

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

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

Table 8.1: 2009 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
NW Wind	2012	150.0	48.0
Distribution Efficiencies	2010-2015	5.0	2.7
Little Falls Unit Upgrades	2013-2016	3.0	0.9
NW Wind	2019	150.0	50.0
CCCT	2019	250.0	225.0
Upper Falls	2020	2.0	1.0
NW Wind	2022	50.0	17.0
CCCT	2024	250.0	225.0
CCCT	2027	250.0	225.0
Conservation	All Years	339.0	226.0
Total		**1,449.0**	**1,020.6**

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

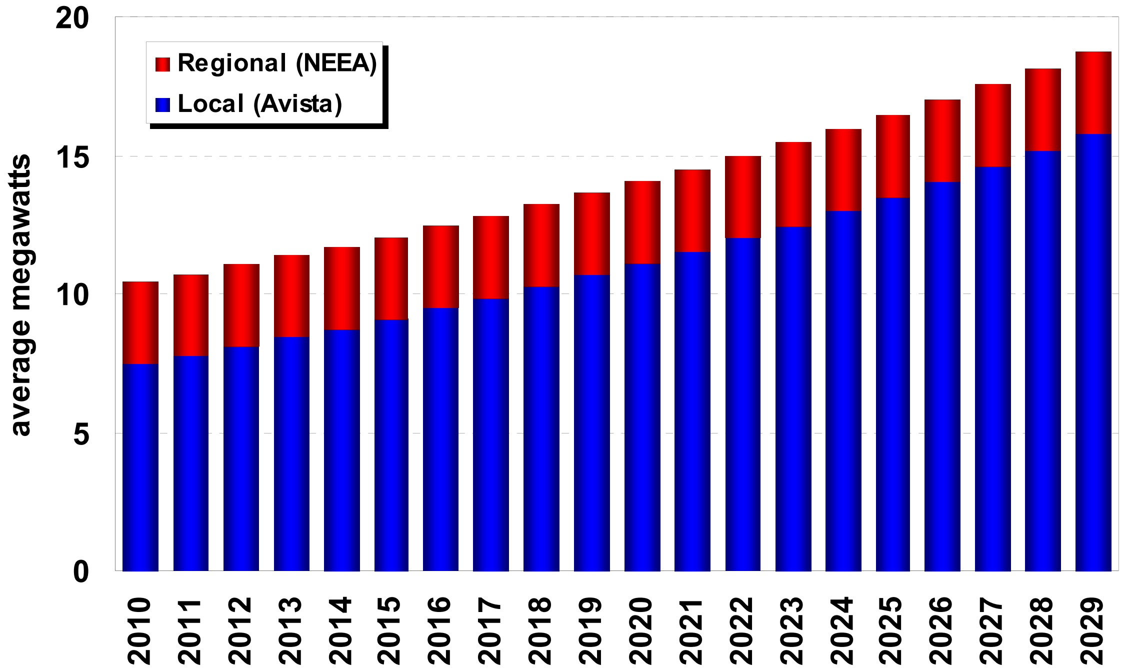
Table 8.2: 2007 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
Non-Wind Renewable	2011	20.0	18.0
Non-Wind Renewable	2012	10.0	9.0
NW Wind	2013	100.0	33.0
Non-Wind Renewable	2013	5.0	4.5
Share of CCCT	2014	75.0	67.5
NW Wind	2015	100.0	33.0
NW Wind	2016	100.0	33.0
Non-Wind Renewable	2019	10.0	9.0
Non-Wind Renewable	2020	10.0	9.0
Non-Wind Renewable	2021	5.0	4.5
Share of CCCT[1]	2019	297.0	267.3
Share of CCCT	2027	305.0	274.5
Conservation	All Years	331.5	221.0
Total		**1,368.5**	**983.3**

Energy Efficiency and Conservation

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

Figure 8.6: Energy Efficiency Annual Expected Acquisition



Reardan

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

Additional Northwest Wind

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

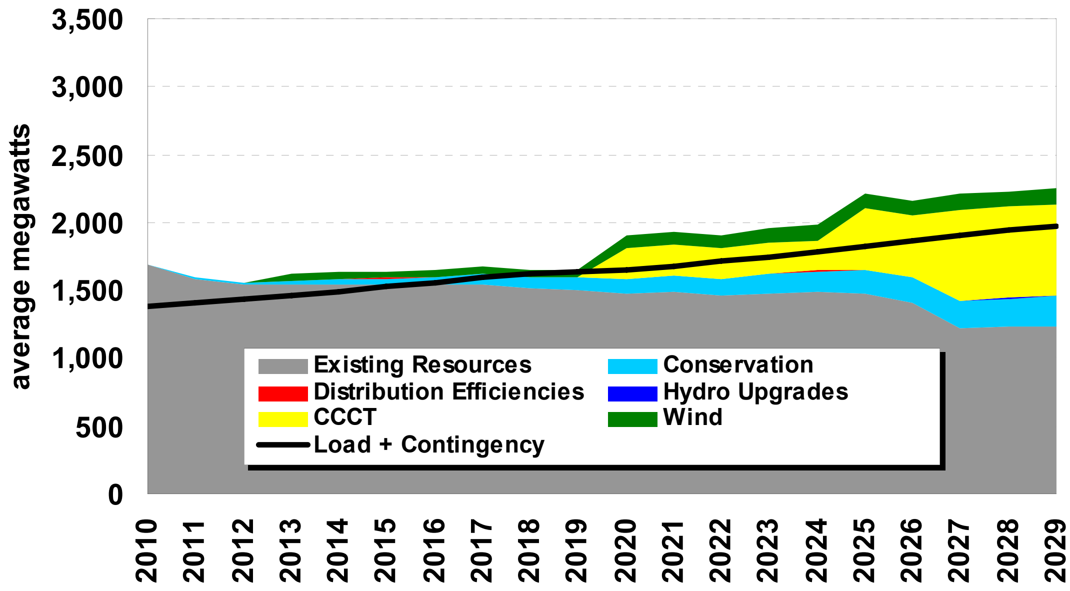
Hydro Upgrades

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

Loads and Resource Balances

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

Figure 8.7: Annual Average Load and Resource Balance



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

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

Figure 8.8: Winter Peak Load and Resource Balance

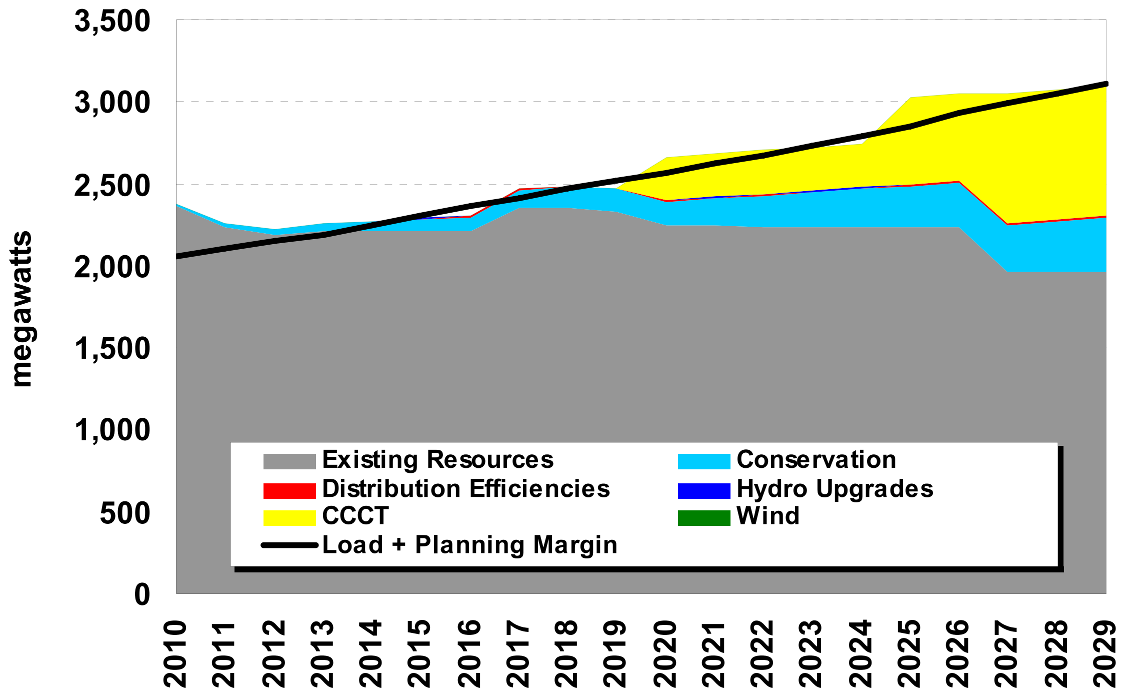
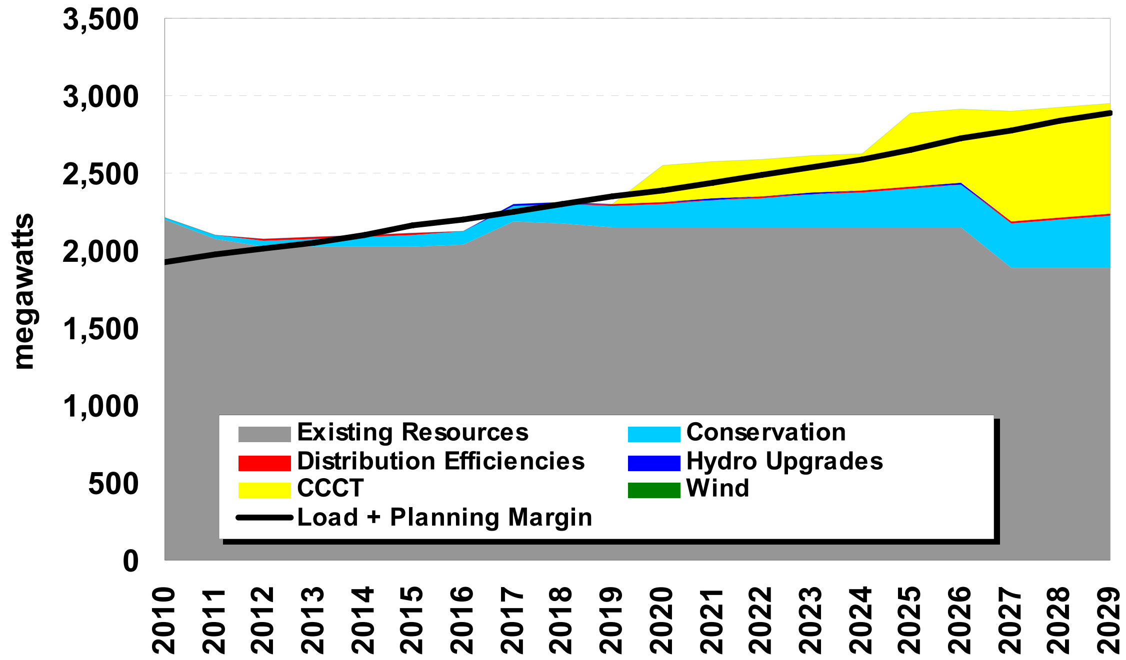


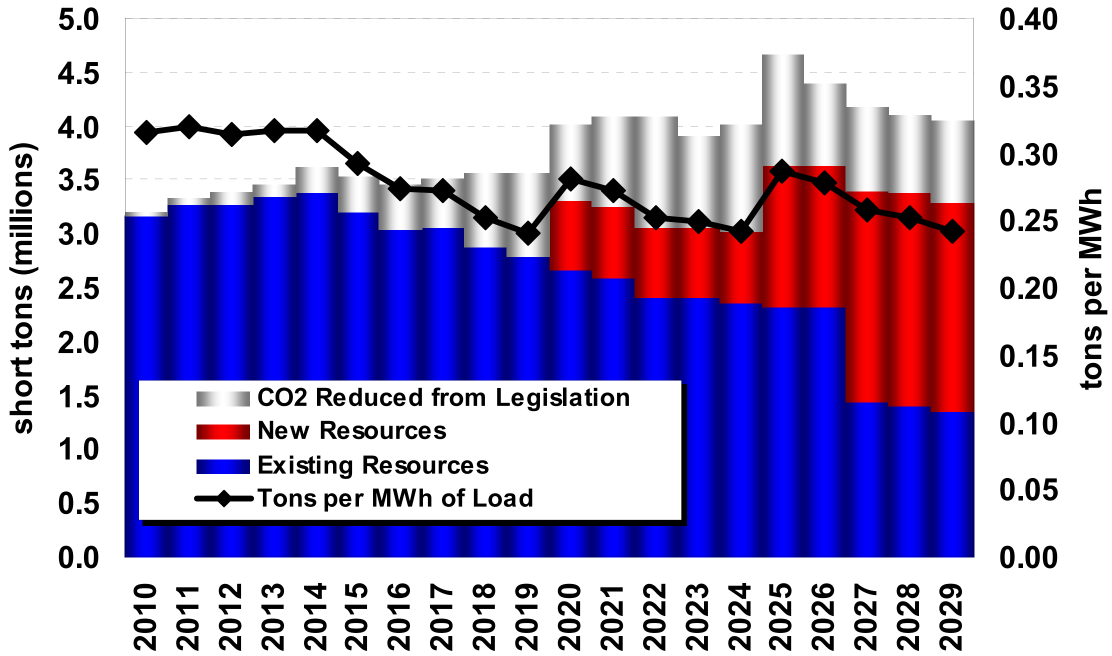
Figure 8.9: Summer Peak Load and Resource Balance



Greenhouse Gas Emissions

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

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



Efficient Frontier Analysis

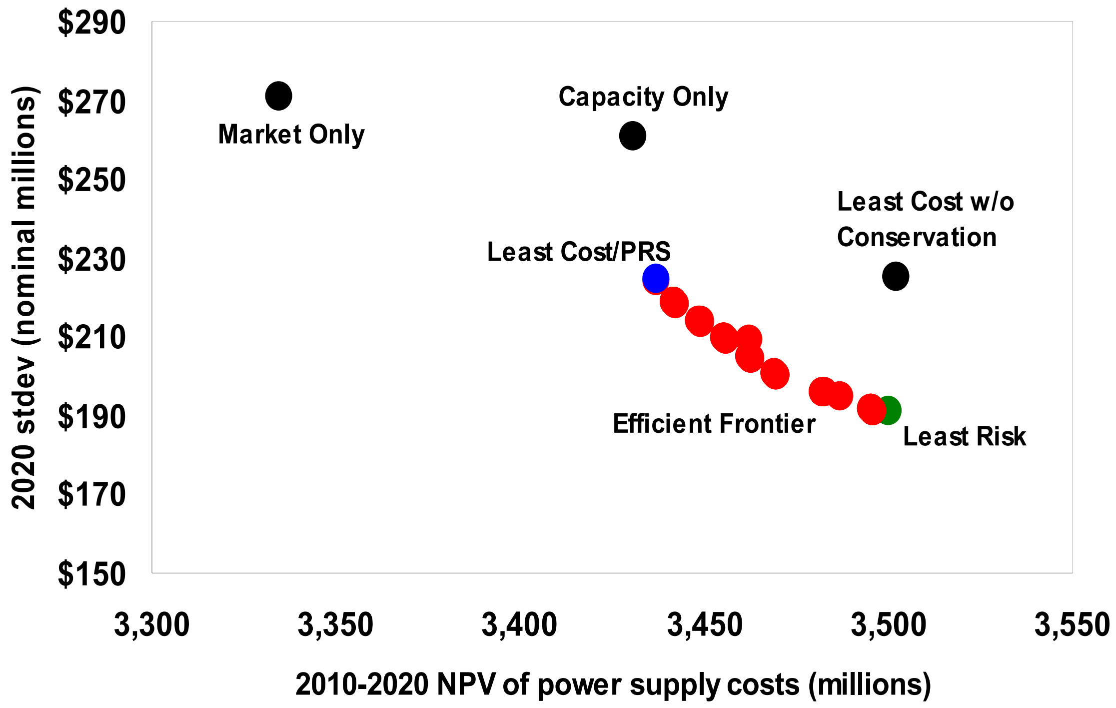
The backbone of the PRS is the Efficient Frontier analysis. This analysis illustrates the relative performance of potential portfolios to each other on a cost and risk basis. The curve created in the analysis represents the least-cost strategy at each level of risk. The PRS analyses examined the following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

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

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

The Capacity Only strategy meets reliability needs with CT plant additions, that are mostly displaced by wholesale market purchases. This strategy does not meet RPS requirements or relieve volatility, except for tail risk. The Least Cost without Conservation strategy reduces risks with wind resource additions and selects CCCT resources rather than CTs; this portfolio meets RPS and capacity requirements.

Figure 8.11: Base Case Efficient Frontier



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

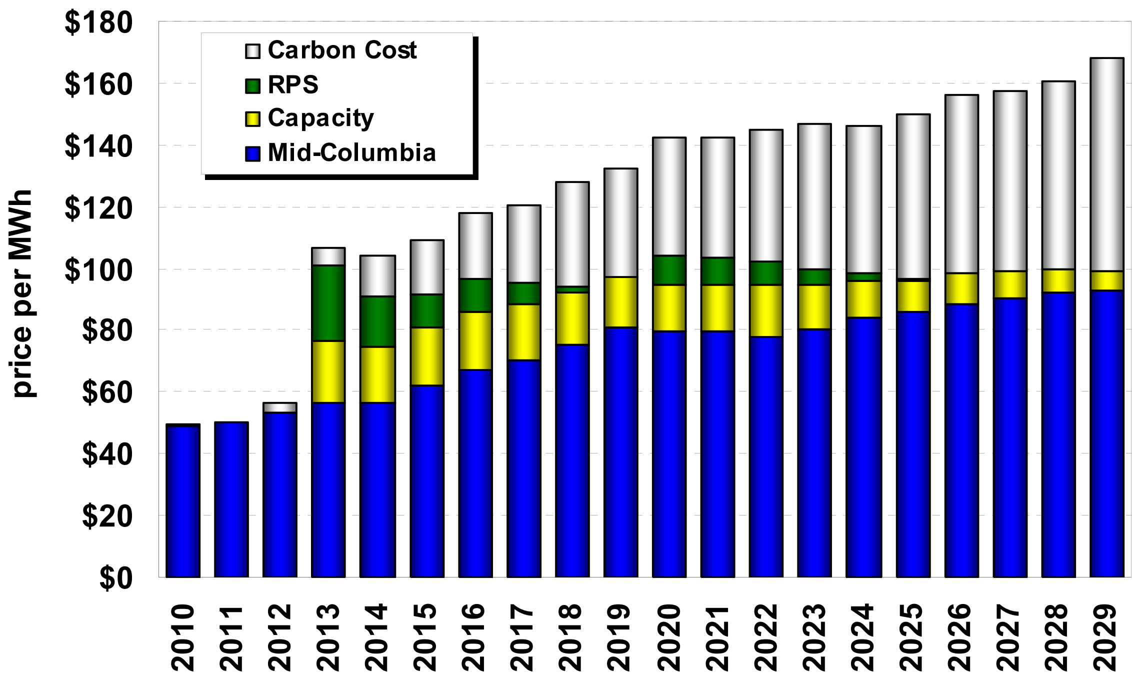
- Market costs: Market Only portfolio.
- Capacity costs: difference between the Market Only and Capacity Only strategies.
- RPS and risk reduction costs: difference between the Capacity Only and Least Cost without Conservation strategies.
- Carbon costs: difference between market prices in the Base Case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

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

Table 8.3: Levelized Avoided Costs ($/MWh)

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

Figure 8.12: Avoided Costs for Conservation

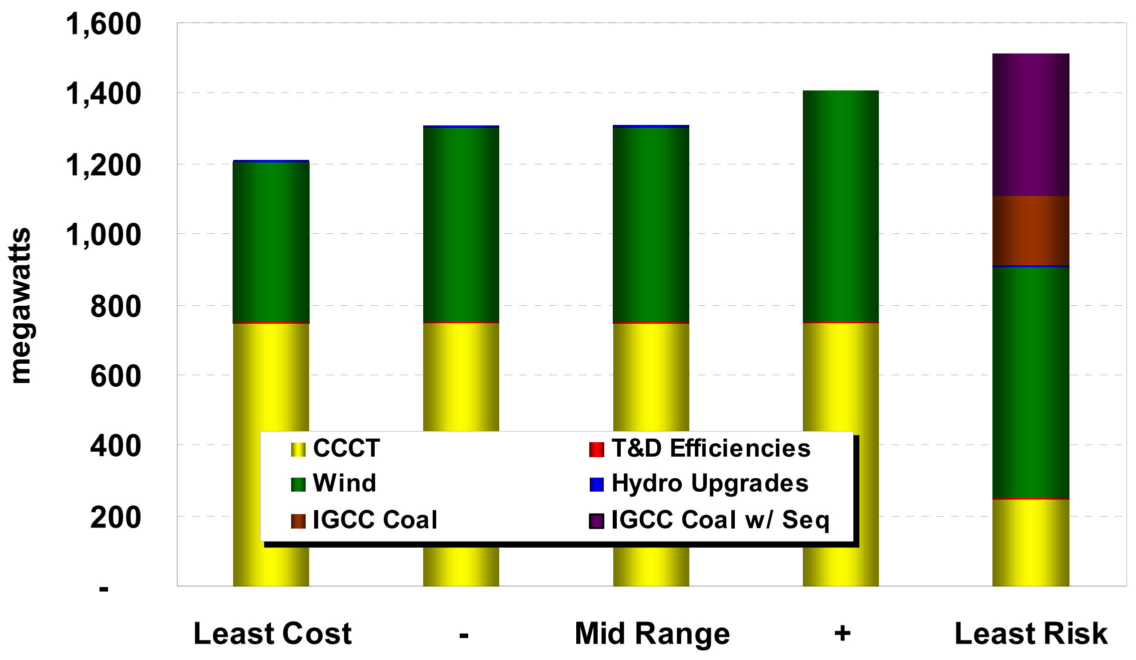


A $111.15 per MWh levelized avoided cost added enough conservation to lower costs by $65 million from the least-cost strategy absent this resource; risk is reduced by 14 percent. The Efficient Frontier portfolios decrease risk but increase costs. These portfolios add wind resources beyond RPS levels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

Efficient Frontier Portfolios

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

Figure 8.13: Efficient Frontier Portfolios 2029 New Resources



Expected Costs

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

Capital

The PRS first requires capital in 2010 for distribution feeder upgrades, followed by needs for wind development. The capital cash flows in Table 8.4 include AFUDC costs and account for various tax incentives including federal investment tax credits. Costs are shown for years where capital would be placed in rate base, rather than when capital is actually expended. The present value of the $2.2 billion required investment is just over $1 billion. Avista may not have to supply all of the capital that has been identified where it chooses to procure resources through power purchase agreements.

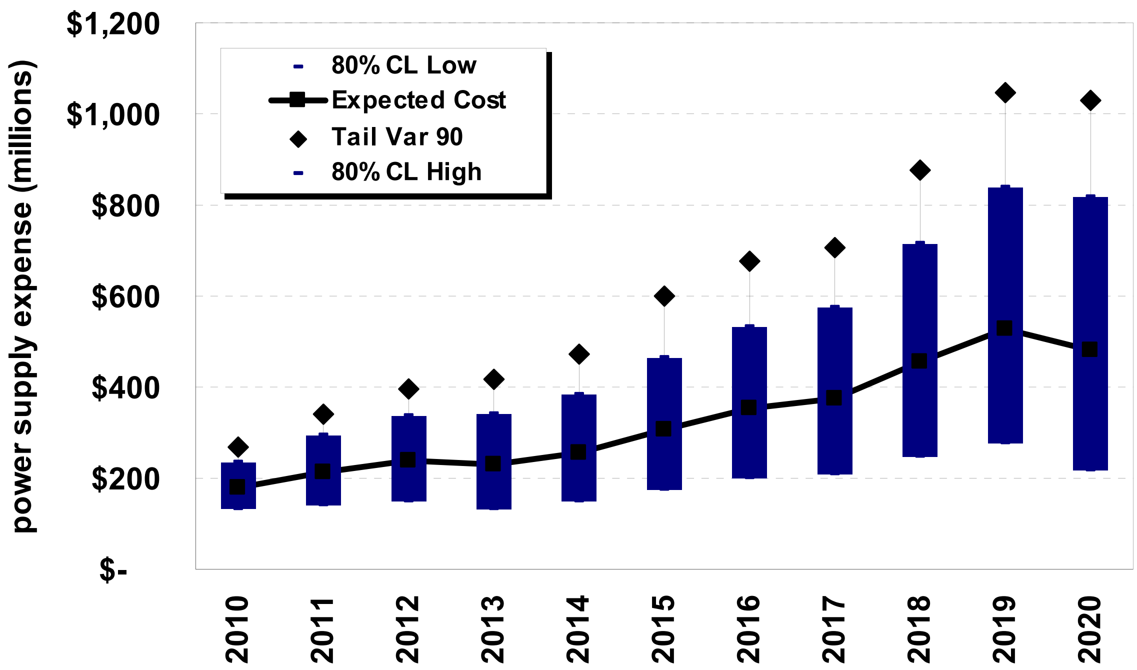
Table 8.4: PRS Rate Base Additions for Capital Expenditures (Millions of Dollars)

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

Annual Power Supply Expenses and Volatility

The PRS analyses track fuel, variable O&M, emissions and market transaction costs for the existing resource portfolio. These costs are captured for each of the 250 iterations of the Base Case risk analysis. In addition to existing portfolio costs, new resource capital, fuel, O&M, emissions and other costs are tracked to provide a range in potential costs to serve future loads. Figure 8.14 shows expected PRS costs modeled through 2020 as the black line. Costs are expected to be $180 million in 2010. The 80 percent confidence interval, shown in blue, ranges between $130 and $233 million. The black diamonds represent the TailVar 90 risk level, or the top 10 percent of the worst outcomes; this 2010 cost is $270 million, 50 percent higher than the expected value. As natural gas and greenhouse gas prices increase, power supply costs also increase. Price uncertainty increases with time and the confidence interval band expands. The 2020 reduction in variability is created by the addition of wind and CCCT resources to Avista's portfolio.

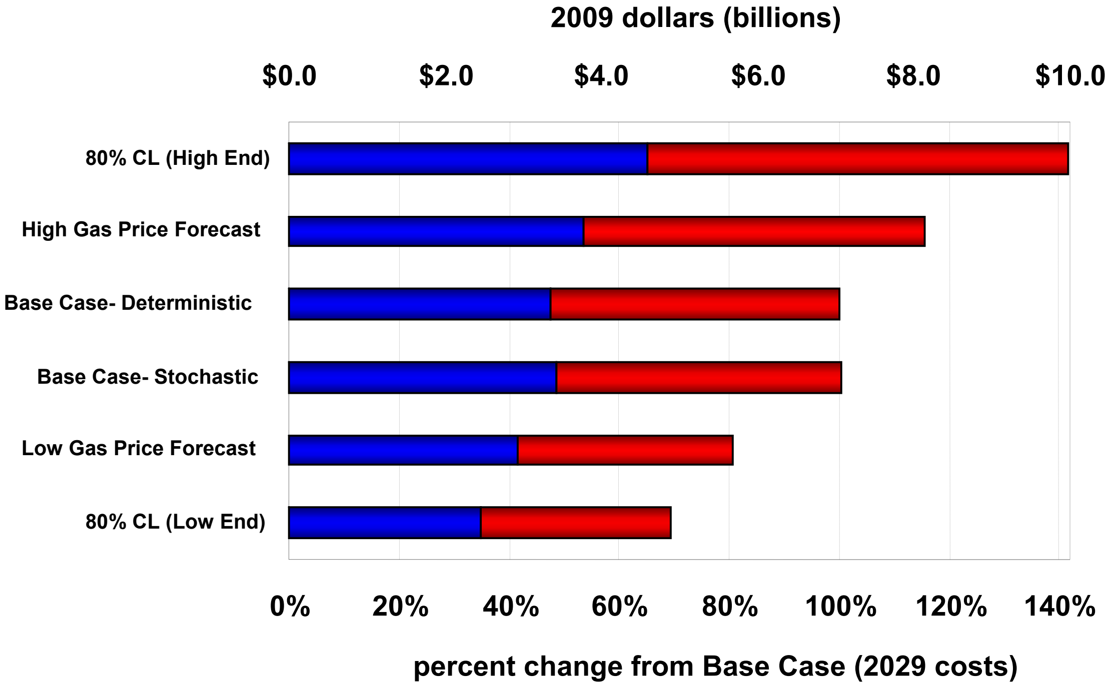
Figure 8.14: Power Supply Expense



Natural Gas Price Risk

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

Figure 8.15: Power Supply Cost Sensitivities

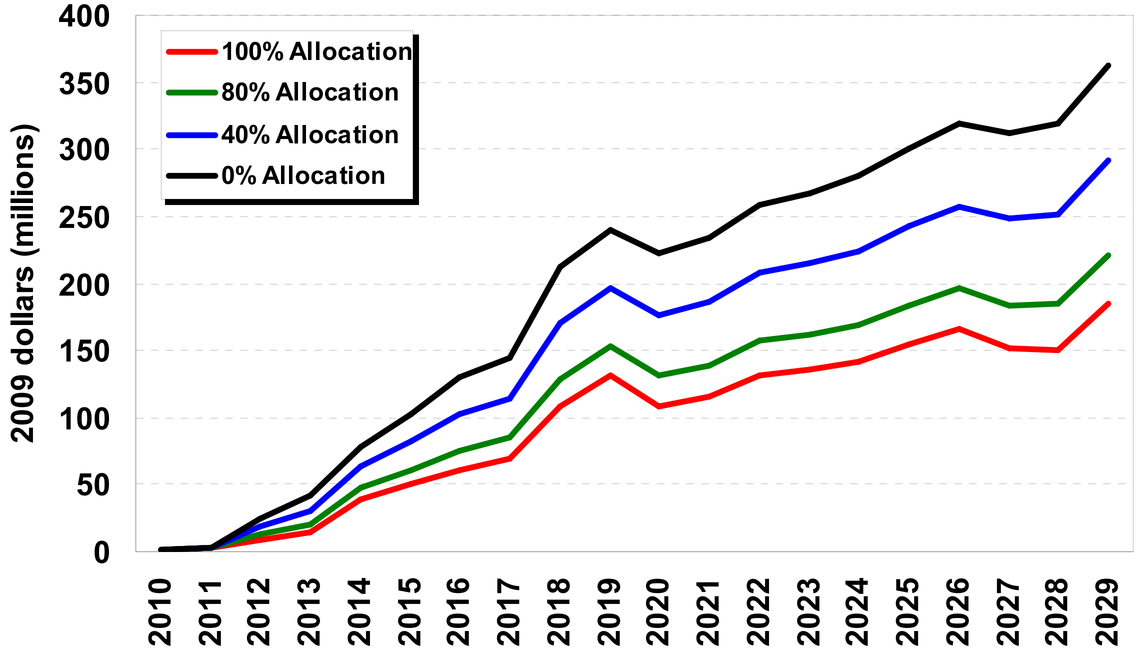


Greenhouse Gas Costs

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

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

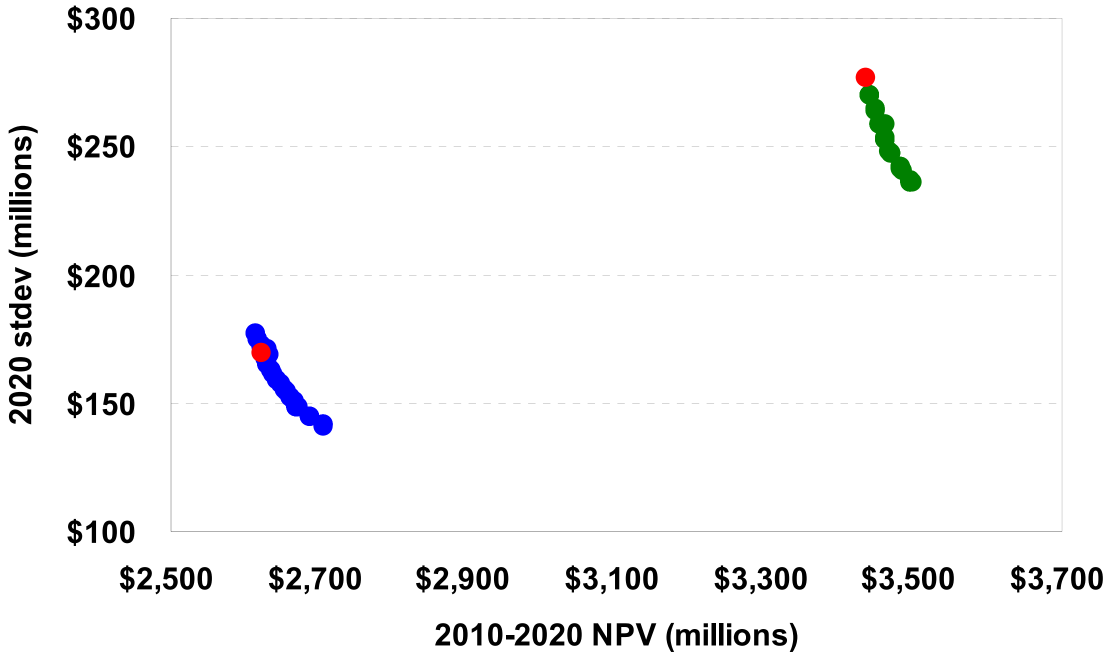
Figure 8.16: Carbon Related Power Supply Expense



Carbon Legislation Impact

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

Figure 8.17: Efficient Frontier Comparison



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

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

Table 8.5: Unconstrained Carbon Scenario- Least Cost Portfolio

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

Table 8.6: Portfolio Cost and Risk Comparison

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

Portfolio Scenarios

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

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

Wind Capital Costs Sensitivity

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

CCCT Capital Cost Sensitivity

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

CCCT in 2015

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

Load Forecast Alternatives

Loads will probably differ from the current forecast because of the recession and the greater Spokane area could grow faster with future development activity after the economy recovers. This sensitivity analysis studies the impact to the PRS if loads grow faster or slower than the Base Case estimate. Faster load growth will increase the need for capital and slower load growth will slow the need for increased capital. This analysis focuses on understanding the changes in timing of resource decisions. The Base Case forecast is for a 1.7 percent growth rate. The Low Load scenario cuts the growth rate by one percentage point to 0.7 percent and the High Growth case increases by one percentage point to 2.7 percent. Table 8.7 shows the resource strategy adjusted for lower growth rates. The lower load growth projection would not change near-term resource acquisitions, but would eliminate the need for some wind and gas-fired resources, as shown in the Modification to Strategy column. Table 8.8 shows the resource strategy with higher growth rates. The amount of near-term wind would increase by 50 MW and additional peaking resources would be acquired by 2011 to compensate for higher growth rates. In later years of the study, additional gas-fired and wind resources would be needed to meet peak load growth and RPS requirements. This analysis indicates that lower load growth would not change near-term resource decisions.

Table 8.7: Low Load Growth Resource Strategy Changes to PRS

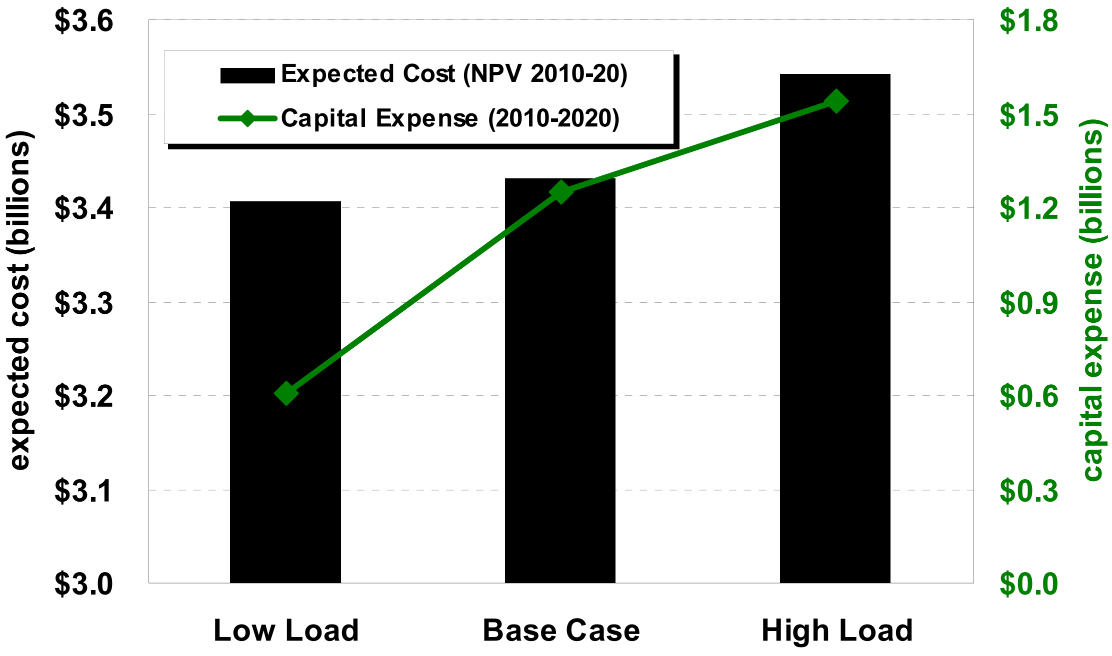
Resource	By the End of Year	Nameplate (MW)	Energy (aMW)	Modification to Strategy
NW Wind	2012	100.0	48.0	No Change
Distribution Efficiencies	2010-2015	5.0	2.7	No Change
Little Falls Unit Upgrades	2013-2016	3.0	0.9	No Change
NW Wind	2019	100.0	33.0	Reduced from 150 MW
CCCT				Removed 250 MW
Upper Falls	2020	2.0	1.0	Delayed to 2028
NW Wind				Removed 50 MW
CCCT	2024	250.0	225.0	Delayed to 2025
CCCT				Removed 250 MW
SCCT	2027	100.0	92.3	Added 100 MW
Total		**560.0**	**402.9**	

Table 8.8: High Load Growth Resource Strategy Changes to PRS

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

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

Figure 8.18: High & Low Load Growth Cost Comparison



Large Hydro Facility Scenarios

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

Table 8.9: Large Hydro Upgrade Resource Strategy Modifications

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)	Modification to Strategy
NW Wind	2012	100.0	48.0	No Change
Distribution Efficiencies	2010-2015	5.0	2.7	No Change
Little Falls Unit Upgrades	2013-2016	3.0	0.9	No Change
Cabinet Gorge 5	2014	60.0	10.2	60 MW Added
Long Lake 2 Powerhouse	2019	60.0	18.0	60 MW Added
NW Wind	2019	100.0	33.0	Reduced from 150 MW
CCCT	2019	250.0	225.0	No Change
NW Wind	2022	50.0	17.0	No Change
CCCT	2026	400.0	360.0	Delayed from 2024 and upgraded from 250 MW
CCCT				Removed 250 MW
Upper Falls	2029	2.0	1.0	Delayed from 2020
Totals		**1,030.0**	**715.8**	

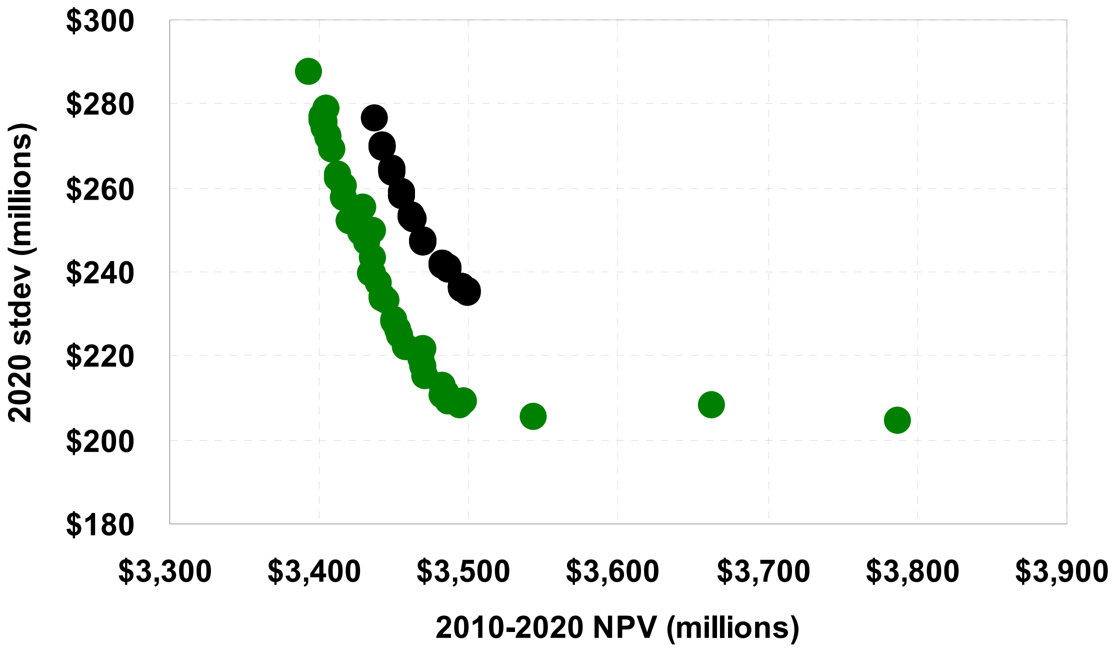
Capital cost sensitivities were performed to determine capital cost limits needed to select large hydro upgrades for the PRS. The analysis found that although higher in cost, a second power house at Long Lake is more favorable than a new Unit 5 at the plant because of the higher capacity value of that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

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

Small Renewable Resources Scenario

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

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



Where Avista is able to acquire non-wind renewables, its resource portfolio strategy will emit fewer greenhouse gases (see Table 8.10). The PRS changes under the small renewable resource scenario are shown in Table 8.11. The strategy reduces wind capacity by 100 MW and trades 100 MW of CCCT for SCCT (the cause for increased risk).

Table 8.10: Portfolio Cost and Risk Comparison

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

Table 8.11: Other Renewables Available- Changes to PRS

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)	Modification to Strategy
Biomass/Geothermal	2011	10.0	9.1	10 MW Added
Reardan Wind	2012	50.0	15.0	No Change
NW Wind	2012	50.0	17.0	Reduced from 100 MW
Biomass/Geothermal	2012	5.0	4.5	5 MW Added
Biomass/Geothermal	2013	5.0	4.5	5 MW Added
Distribution Efficiencies	2010-2015	5.0	2.7	No Change
Little Falls Unit Upgrades	2013-2016	3.0	0.9	No Change
Wood Biomass	2017	5.0	4.5	5 MW Added
KFCT Wood Conversion	2019	7.0	0.0	Capacity/Energy Neutral RECs Added
NW Wind	2019	100.0	33.0	Reduced by 50 MW
Simple Cycle CT	2019	100.0	92.3	100 MW Added
CCCT	2020	250.0	225.0	Delayed from 2019
Upper Falls	2020	2.0	1.0	No Change
NW Wind	2023	50.0	17.0	Delayed from 2022
CCCT	2026	400.0	360.0	Delayed from 2024 and changed to 400 MW
CCCT				250 MW in 2027 Removed
Total		**1,042.0**	**786.5**	

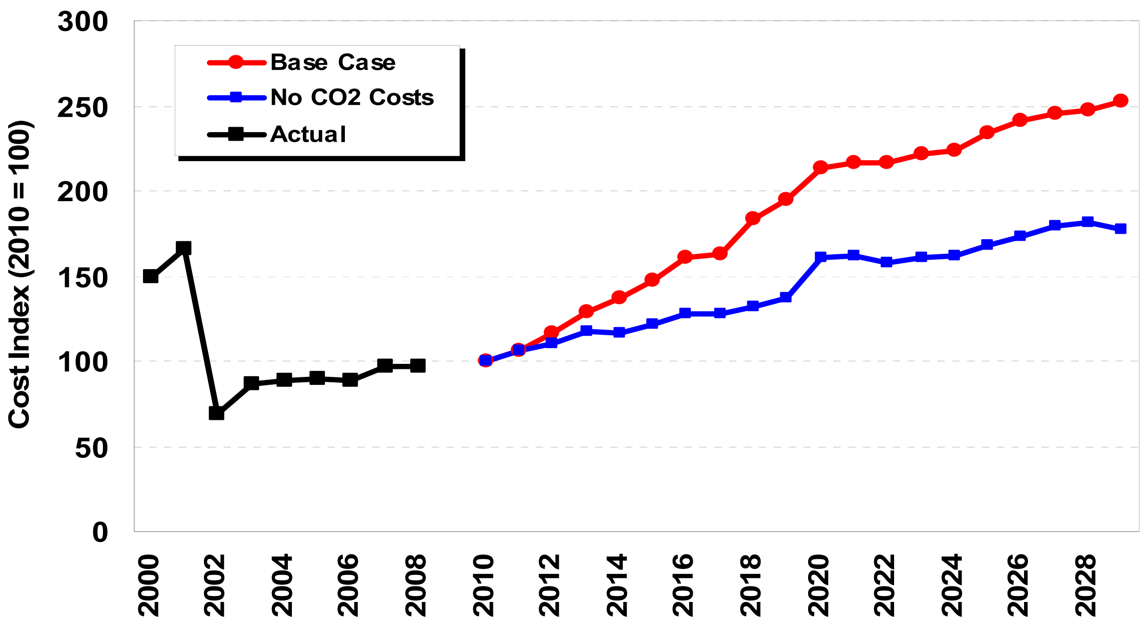
Nuclear

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

Summary

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

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



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

Table 8.12: Annual Load & Resources (aMW)

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

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

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

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

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

9. Action Items

The Integrated Resource Plan (IRP) is an ongoing and iterative process balancing regular publication with pursuing the best long-term resource strategy. The biennial publication date provides opportunities for ongoing improvements to modeling and forecasting procedures and tools, as well as additional research into changing market variables and technologies. This section provides an overview of the progress made on the 2007 IRP Action Plan, while the 2009 Action Plan provides details about issues and improvements developed or raised during this planning cycle, but deferred for treatment in the 2011 IRP.

Summary of the 2007 IRP Action Plan

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

Renewable Energy

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

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

Preliminary work concerning a Montana wind study was done. Transmission limitations for power coming west and the potential for such projects to not qualify toward the Washington RPS made continued work on Montana wind projects less attractive than previously thought. Montana wind will be reevaluated as RPS laws change, and as transmission upgrades are made.

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

Demand Side Management

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

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

Emissions

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

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

Modeling and Forecasting Enhancements

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

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

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

There have been several improvements to the Efficient Frontier and PRiSM modeling approaches, including solving for minimum acquirable resource sizes, and including emissions accounting. Projected impacts from climate change and electric car market penetration have been included in the Company's load forecast, as discussed in the Loads and Resources chapter. Details about changes to relevant load conditions are also included in the Loads and Resources chapter.

Transmission Planning

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

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

2009 IRP Action Plan

The Company's 2009 Preferred Resource Strategy provides direction and guidance for the type, timing and size of future resource acquisitions. The 2009 IRP Action Plan provides an overview of activities planned for inclusion in the 2011 IRP. Progress and results for each of the Action Plan items will be monitored and reported to the Technical Advisory Committee and in Avista's 2011 IRP. The Action Plan was developed using input from Commission Staff, the Company's management team and the Technical Advisory Committee.

Resource Additions and Analysis

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

Energy Efficiency

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

Environmental Policy

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

Modeling and Forecasting Enhancements

- Refine cost driver relationships in the stochastic model.
- Continue to refine PRiSM by developing a resource retirement capability, adding the ability to solve for other risk measurements and by adding more resource options.
- Continue developing Loss of Load Probability and Sustained Peaking analysis for inclusion in the IRP process, and confirm appropriateness of the 15 percent capacity planning margin assumed for this IRP.
- Continue studying the impacts of climate change on the load forecast.
- Stay load growth trends and their correlation to weather patterns.

Transmission Planning

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

Production Credits

Primary 2009 IRP Team

Individual	Contribution	Contact
Clint Kalich, Manager of Resource Planning & Analysis	Project Manager	clint.kalich@avistacorp.com
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Other Contributors

Jon Powell, Partnership Solutions Manager	Bob Lafferty, Director of Power Supply
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Kelly Irvine, Natural Gas Analyst	Tracy Rolstad, Senior Planning Engineer II
Thomas Dempsey, Manager of Generation Joint Projects	Steve Silkworth, Manager of Wholesale Marketing and Contracts

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Appendix

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2009

Electric
Integrated Resource Plan

Appendix A – Technical Advisory Committee Meeting Presentations

August 31, 2009

2009 Integrated Resource Plan

Technical Advisory Committee Meeting No. 1 Agenda
May 14, 2008

	Topic	Time	Staff
1.	Introduction	10:30	Vermillion
2.	Load & Resource Balance Update	10:35	Gall
3.	Climate Change Update	11:15	Lyons
4.	Lunch	12:15	
	Special Guest - Steve Silkworth- update on renewable acquisitions		
5.	Loss of Load Probability Analysis	1:15	Gall
6.	2009 IRP Topic Discussions • Work Plan • Analytical Process Changes • Other	2:00	Kalich
7.	Adjourn	3:30	

Load and Resource Balance Forecast

James Gall

2007 IRP L&R Review

- Capacity & Energy short beginning 2011
- Load is expected to grow at 2.3% over the next 10 years, and 2.0% over the next twenty years
- Lancaster will be added to the utility's portfolio beginning in 2010, pushing our deficit out to 2015 for capacity and 2017 for energy

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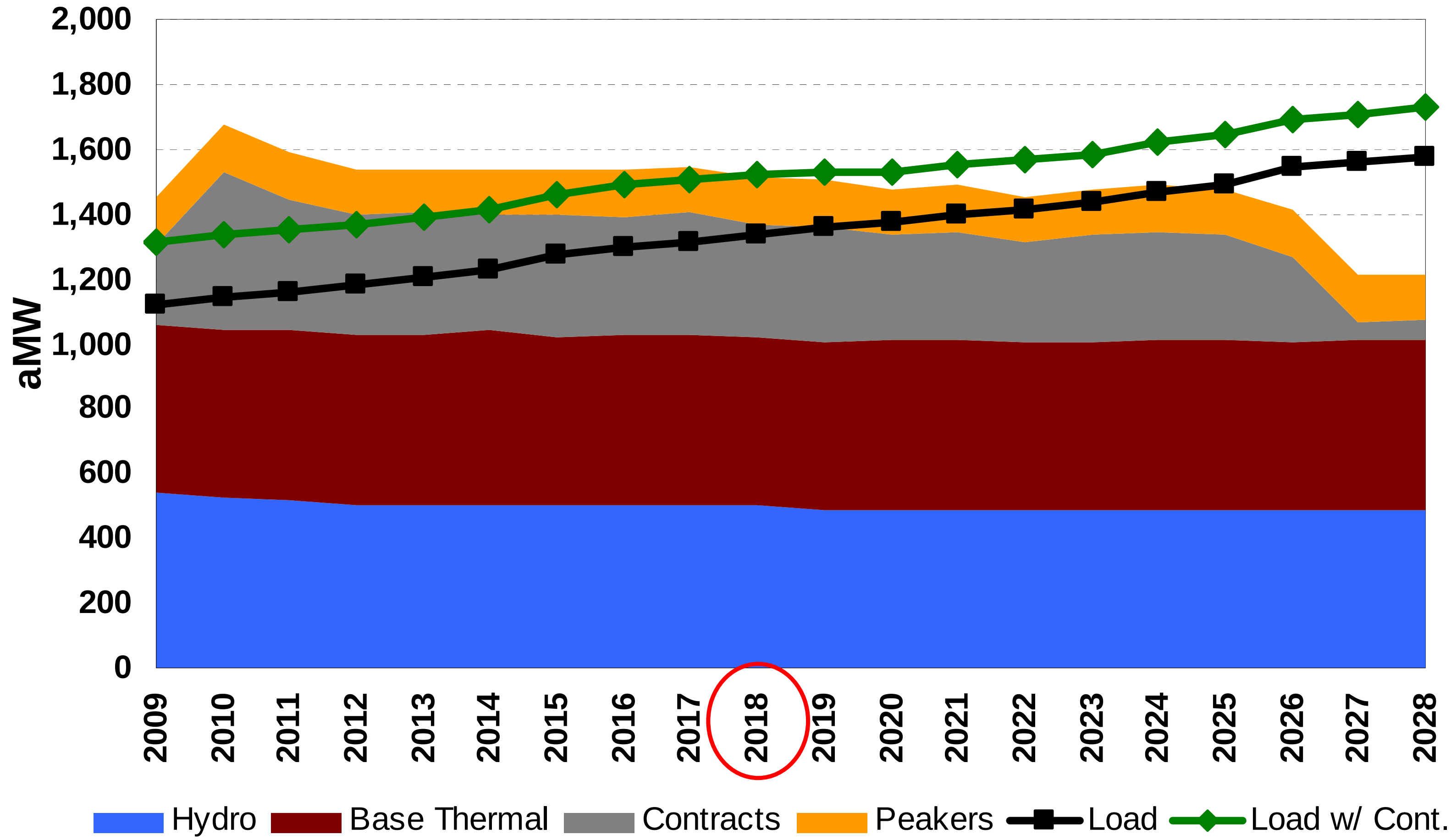
Current L&R

What's Changed:

- **Lancaster**- 270 MW CCCT in Rathdrum, ID will be available Jan 1, 2010
- **Load**- 10 year growth rate 1.9%, 20 year growth rate 1.8% for Peak and Energy. The 2010 forecast is 52 aMW lower than previous forecast or 4.4% lower, due to slow down in growth and implementation of conservation programs.
- **Hydro**- Uses 2006/07 Northwest Power Pool Headwater benefits study, mean energy is used versus median energy [-8 aMW]
- **Misc**- Updates to contracts, most from WNP-3 expected availability [+22 aMW]

Annual Average Energy Position



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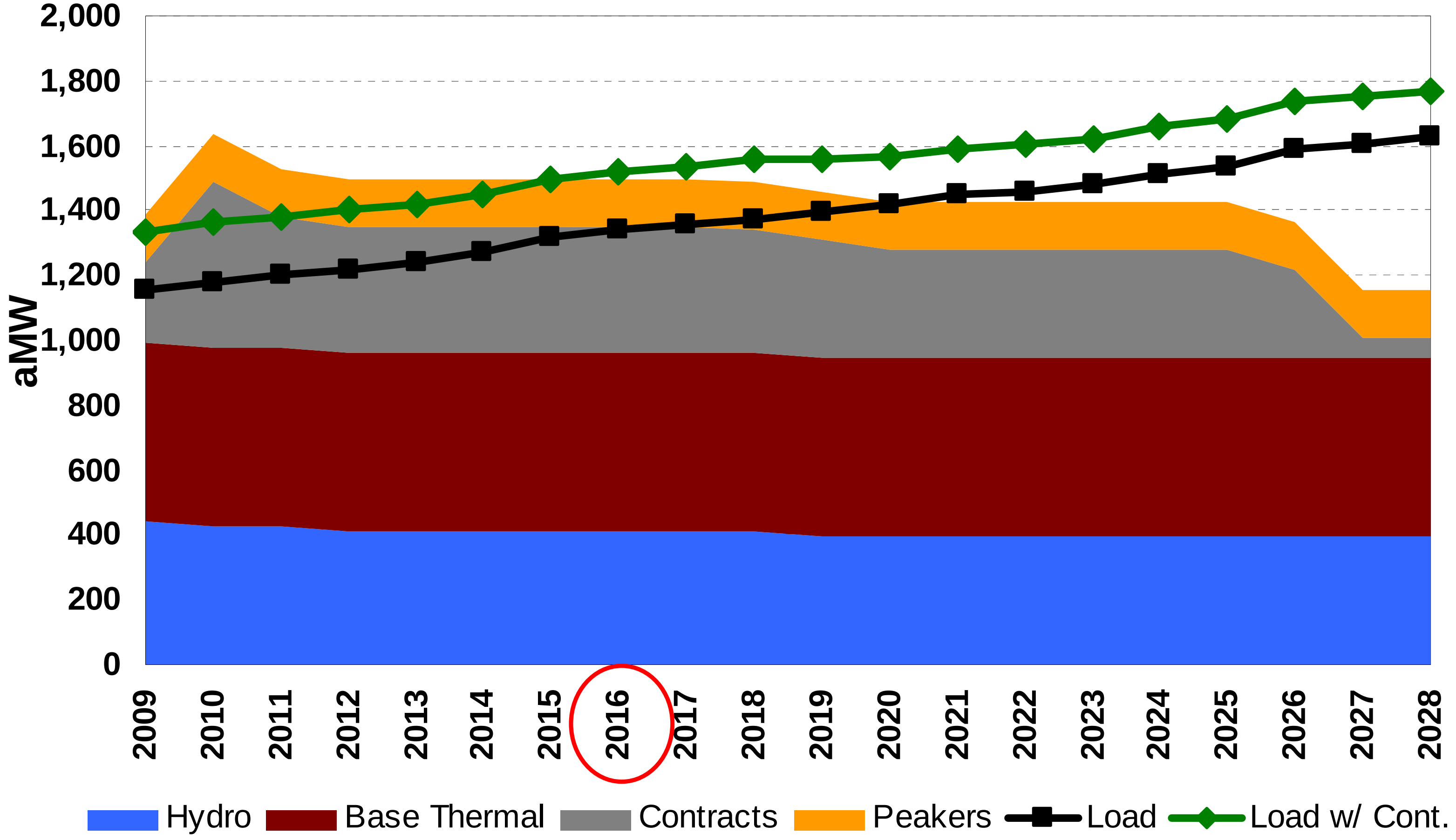
Annual Average Energy Position (exclude Q2)



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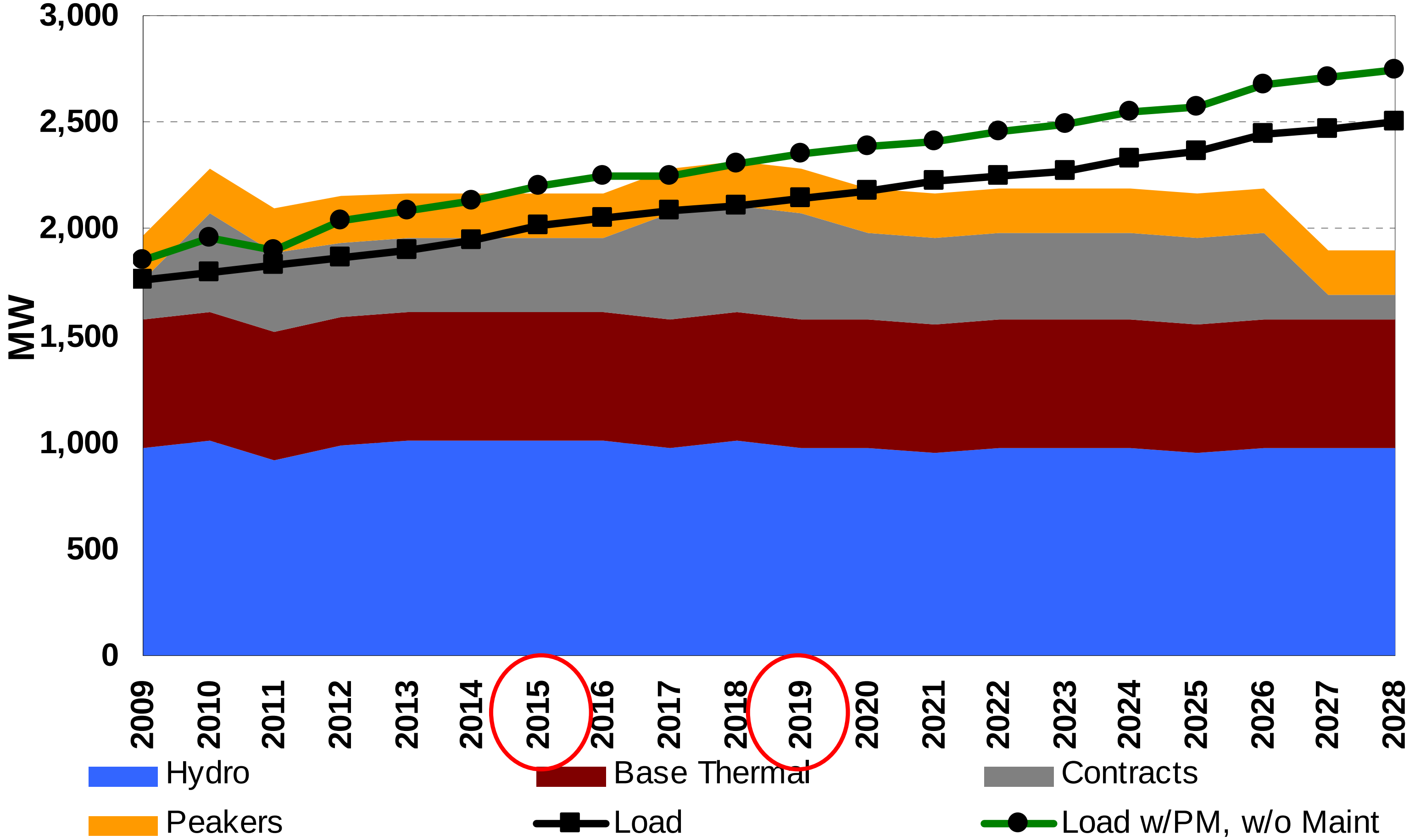
Annual Position at System Peak



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Washington State RPS (aMW)

	On-line Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Native Load (Excludes Potlatch)		1,012	1,034	1,053	1,074	1,094	1,121	1,153	1,177	1,194	1,211	1,233	1,253
WA State Load		659	674	686	700	713	730	751	767	778	789	803	816
Load 10% Change of Exceedance		28	29	29	30	30	31	32	33	33	34	34	35
Planning RPS Load		687	702	715	729	743	761	783	799	811	822	837	851
RPS %		0%	0%	0%	3%	3%	3%	3%	9%	9%	9%	9%	15%
Required Renewable Energy		**0.0**	**0.0**	**0.0**	**21.3**	**21.7**	**22.1**	**22.6**	**69.5**	**71.2**	**72.5**	**73.5**	**124.5**
Current Qualifying Resources													
Stateline	1999	7.6	7.6	7.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Long Lake 3	1999	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Little Falls 4	2001	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Cabinet 2	2004	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Cabinet 3	2001	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Cabinet 4	2007	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Apprentice Credits		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Hydro 10% Chance of Exceedance		(4.1)	(4.1)	(4.1)	(4.1)	(4.1)	(4.1)	(4.1)	(4.1)	(4.1)	(4.1)	(4.1)	(4.1)
Total Qualifying Resources		***16.1***	***16.1***	***16.1***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***	***8.5***
Net Requirement Need (Completed)		**0.0**	**0.0**	**0.0**	**12.8**	**13.2**	**13.6**	**14.1**	**61.0**	**62.7**	**64.0**	**65.0**	**116.0**
Budgeted Hydro Upgrades													
Noxon 1	2009	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 2	2010	0.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Noxon 3	2011	0.0	0.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Noxon 4	2012	0.0	0.0	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Little Falls 1	2015	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.6
Little Falls 2	2016	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6
Apprentice Credits		0.5	0.7	0.9	1.2	1.2	1.2	1.3	1.4	1.4	1.4	1.4	1.4
Hydro 10% Chance of Exceedance		(1.0)	(1.4)	(1.9)	(2.4)	(2.4)	(2.4)	(2.6)	(2.8)	(2.8)	(2.8)	(2.8)	(2.8)
Total Budgeted Hydro Upgrades		***1.8***	***2.6***	***3.6***	***4.5***	***4.5***	***4.5***	***5.1***	***5.6***	***5.6***	***5.6***	***5.6***	***5.6***
Net Requirement Need (Budgeted)		**0.0**	**0.0**	**0.0**	**8.2**	**8.6**	**9.1**	**9.0**	**55.3**	**57.1**	**58.3**	**59.4**	**110.4**

Climate Change Update

John Lyons, Ph.D.

Climate Change Update

- Federal GHG legislation – Overview of Lieberman-Warner Bill
- EPA Analysis of Lieberman-Warner
- EIA Analysis of Lieberman-Warner
- Washington Greenhouse Gas Legislation
- Regional Greenhouse Gas Initiative

Lieberman-Warner Climate Security Act of 2007

- Covers emissions of 10,000 mtco2 or greater
- GHG Emissions Reduction Goals:

2012 – 2005 levels (5,775 mmtco2)

2020 – 15% below 2005 levels (4,924 mmtco2)

2030 – 35% below 2005 levels (3,860 mmtco2)

2040 – 50% below 2005 levels (2,796 mmtco2)

2050 – 70% below 2005 levels (1,732 mmtco2)

2007 total U.S. GHG emissions were about 6,000 mmtco2

Lieberman-Warner Climate Security Act of 2007

- 73.5% of allowances distributed for free in 2012 to 14 different groups, free allocations decrease over time
- Allows unlimited banking and trading of allowance
- Borrowing is from EPA is allowed with interest for up to 15% of obligations
- 30% of reductions can be offsets (15% domestic and 15% international)
- Establishes a Carbon Market Efficiency Board to monitor and intervene in the carbon market

EPA Analysis of Lieberman-Warner

- Reference Case
- S. 2191 Scenario
- S. 2191 Scenario with Low International Actions
- S. 2191 Scenario Allowing Unlimited Offsets
- S. 2191 Scenario with No Offsets
- S. 2191 Constrained Nuclear and Biomass
- S. 2191 Constrained Nuclear, Biomass, and CCS
- S. 2191 Constrained Nuclear, Biomass, and CCS + Beyond Kyoto + Natural Gas Cartel
- Alternative Reference Scenario
- S. 2191 Alternative Reference Scenario

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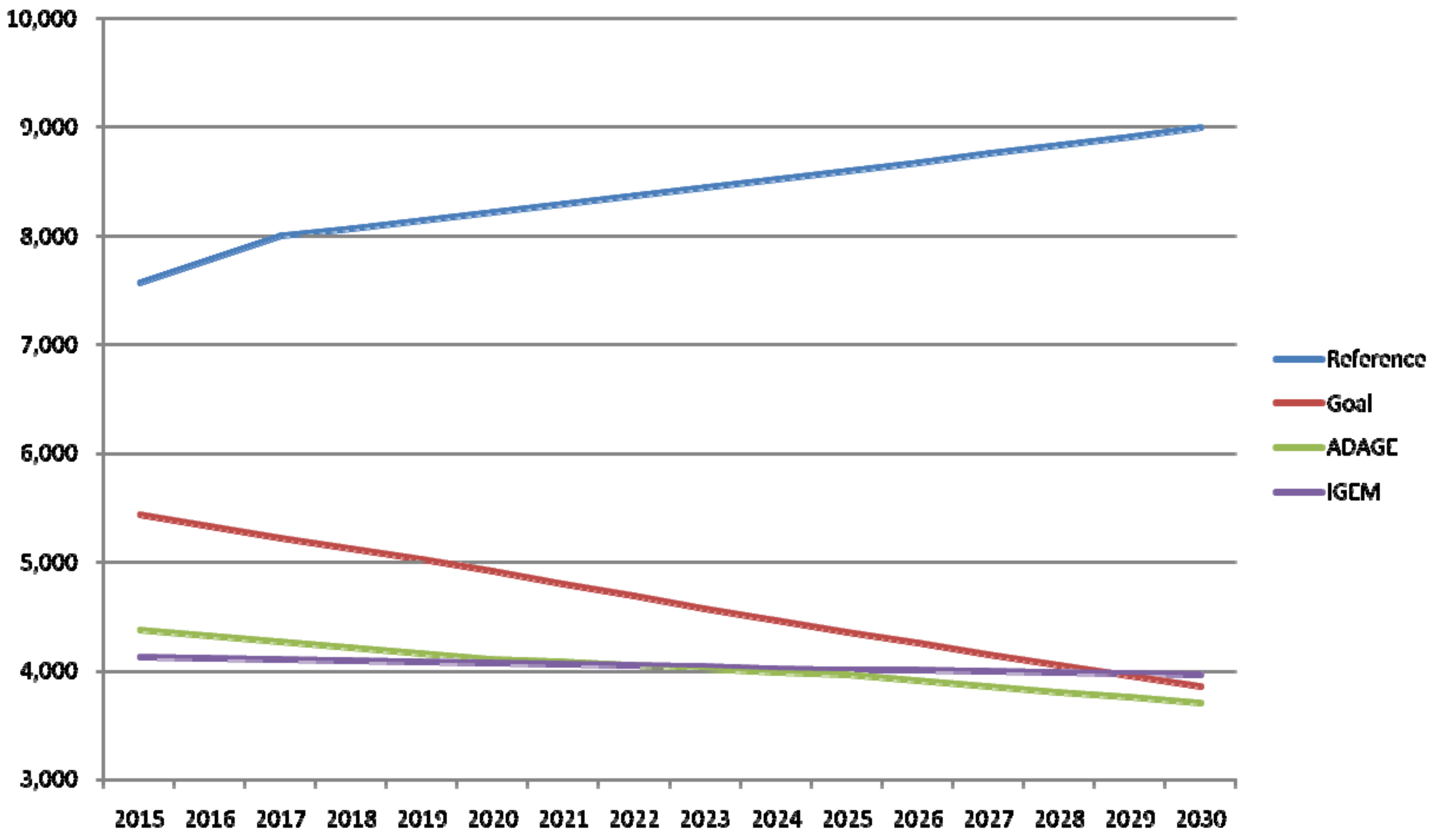
U.S. Carbon Footprint Projections 2015 – 2030



Federal Spending of Auctioned Credits

	ADAGE		IGEM	
Category	**2015**	**2030**	**2015**	**2030**
Administration of S. 2191 (assumed to be 1% of auction revenues)	1.6	2.3	2.2	3.2
Zero or Low-Carbon Energy Technologies Deployment	7.8	23.7	10.9	32.7
Advanced Coal and Sequestration Technologies Program	6.1	18.5	8.5	25.6
Fuel from Cellulosic Biomass Program	1.5	4.4	2.0	6.1
Advanced Technology Vehicles Manufacturing Program	2.9	8.9	4.1	12.3
Sustainable Energy Program	6.1	18.5	8.5	25.6
Energy Consumers	8.5	25.6	11.7	35.4
Climate Change Worker Training Program	2.4	7.1	3.3	9.8
Adaptation for Natural Resources in the U.S. and Territories	8.5	25.6	11.7	35.4
International Climate Change Adaptation and National Security Program	2.4	7.1	3.3	9.8
Emergency Firefighting Program	1.2	1.2	1.2	1.2
Energy Independence Acceleration Fund	0.9	2.8	1.3	3.9
Total	**49.9**	**145.7**	**68.7**	**201.0**

ADAGE (Applied Dynamic Analysis of the Global Economy - Ross 2007)

IGEM (Intertemporal General Equilibrium Model - Jorgenson 2007)

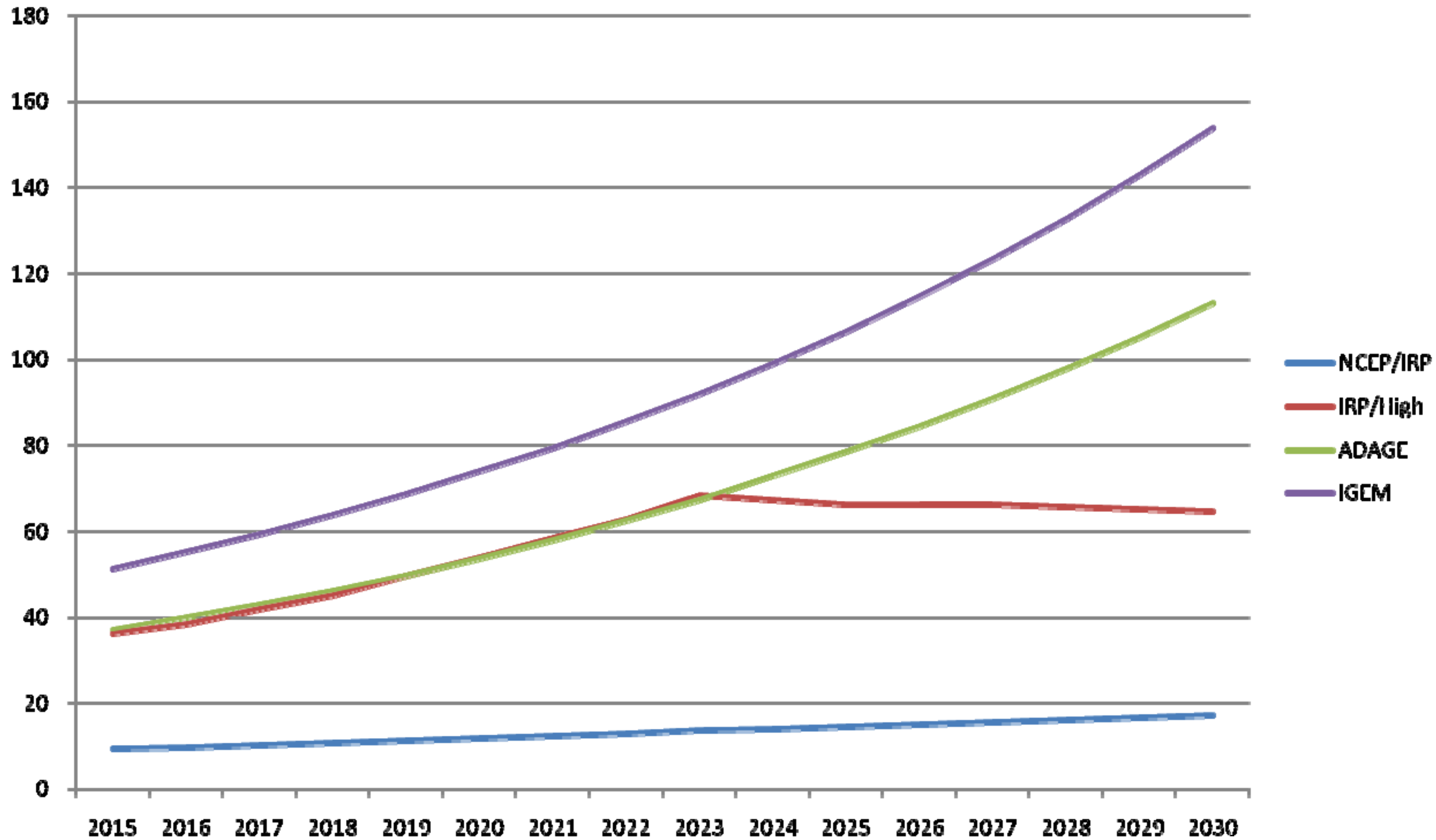
Value of Auctioned & Allocated Allowances

Category	ADAGE 2015	ADAGE 2030	IGEM 2015	IGEM 2030
Subtitile A - Auctions (pre-spent by Feds)	47.0	147.0	64.0	201.0
Subtitle B - Early Action	3.0	0.0	4.0	0.0
Subtitle C - States	18.0	26.0	24.0	35.0
Subtitle D - Electricity Consumers	14.0	21.0	20.0	29.0
Subtitle E - Natural Gas Consumers	3.0	5.0	4.0	6.0
Subtitle F - Bonus Allowances for CCS	6.0	9.0	9.0	13.0
Subtitle G - Domestic Ag/Forestry	8.0	12.0	11.0	16.0
Subtitle H - International Forest Protection	4.0	6.0	5.0	8.0
Subtitle I - Transition Assistance	54.0	6.0	74.0	9.0
Subtitle J - Landfill / Coal Mine CH4 Allowance Set - Asides	2.0	2.0	2.0	3.0
Total	**159.0**	**234.0**	**217.0**	**320.0**
net of customer "refunds"	142.0	208.0	193.0	285.0
customer refund %	11%	11%	11%	11%

ADAGE (Applied Dynamic Analysis of the Global Economy - Ross 2007)

IGEM (Intertemporal General Equilibrium Model - Jorgenson 2007)

EPA Analysis of U.S. Carbon Emission Cost
($/Metric Ton)



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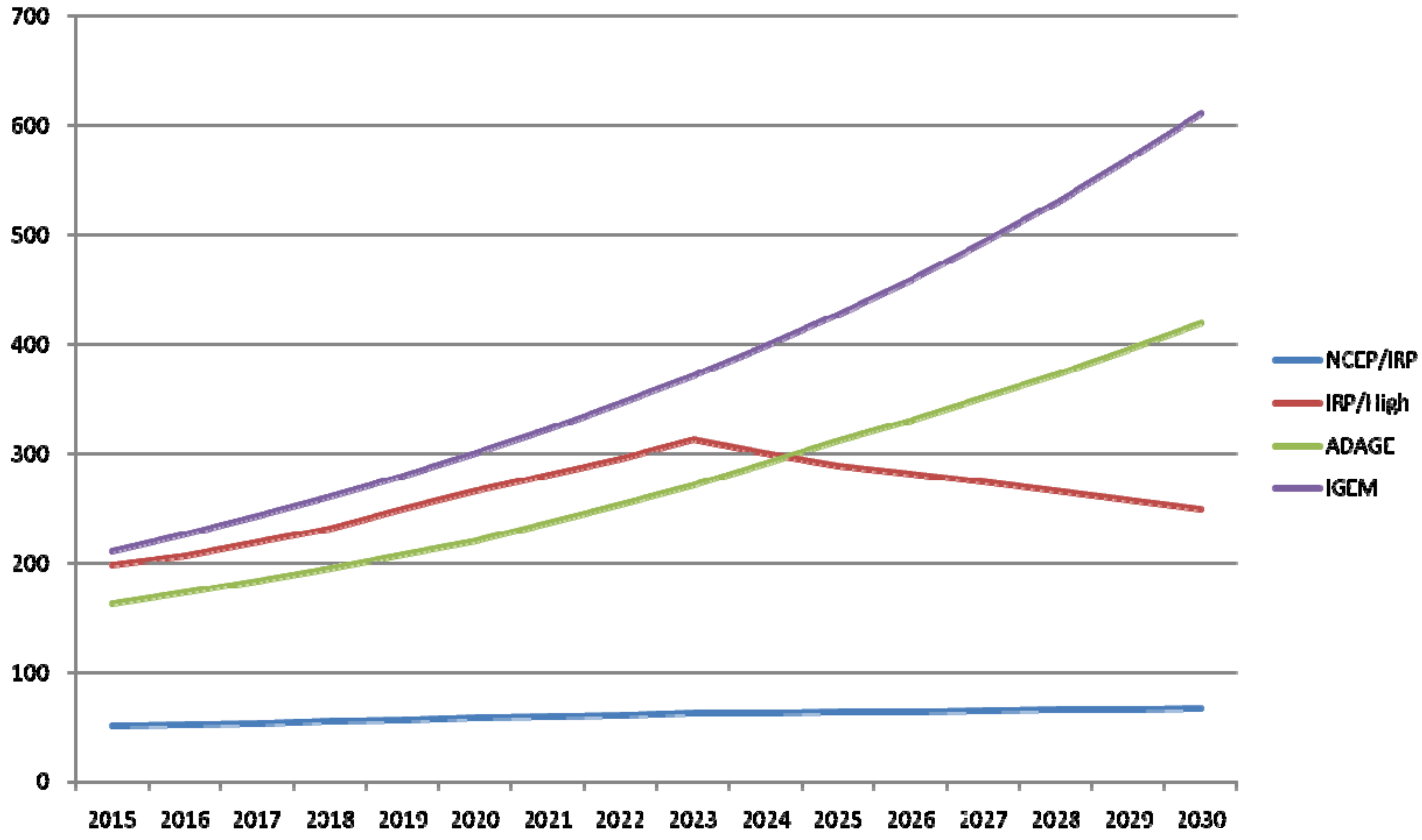
EPA Analysis Total U.S. Carbon Emission Cost
($billions)



EIA Analysis of Lieberman-Warner

- Analysis included 7 cases
- Reference Case
- S. 2191 Core
- No International Offsets Case
- S. 2191 High Cost (CCS, Nuclear and biomass costs 50% higher than in the base case)
- S. 2191 Limited Alternatives
- S. 2191 Limited Alternatives / No International Offsets
- S. 1766 Update (Low Carbon Economy Act of 2007)

EIA Analysis Results

- As expected, impacts directly related to the availability and cost of low-carbon technologies such as CCS and nuclear, as well as the availability of international offsets
- Results are also dependent upon the assessment of the current high commodity prices being permanent or temporary
- Most reductions before 2030 are electricity-related
- GDP reductions in the S. 2191 cases
  - 2020: 0.3% to 0.9%
  - 2030: 0.3% to 0.8%
  - Higher manufacturing impacts

EIA Analysis Results

- Significant increases in new capacity because of early retirement of coal plants through 2030
- There are limited opportunities in the electric power industry after 2030 because the most GHG-intensive plants will have been retired, but population growth will require new generation
- Delivered coal prices increase 405% to 804% in 2030 (2006$)
- Natural gas prices increase 34% to 107% in 2030 (2006$)
- Retail gasoline prices increase $0.41 to $1.01 in 2030

Washington State GHG legislation

Washington state has three different laws that directly impact GHG emissions and electric resource planning:

- Washington Energy Independence Act (I-937): 15% of new generation must be renewable by 2020
- SB 6001: Limits new base load generation to 1,100 pounds of CO_2 per MWh
- HB 2815: Sets GHG reductions goals for the state as part of the Western Climate Initiative

Washington HB 2815

Goals are set to meet Washington's share of the Western Climate Initiative

- 2020 – Below 1990 levels
- 2035 – 25% below 1990 levels
- 2050 – 50% below 1990 levels

- May 2008: Guidelines are expected to be released by Department of Ecology

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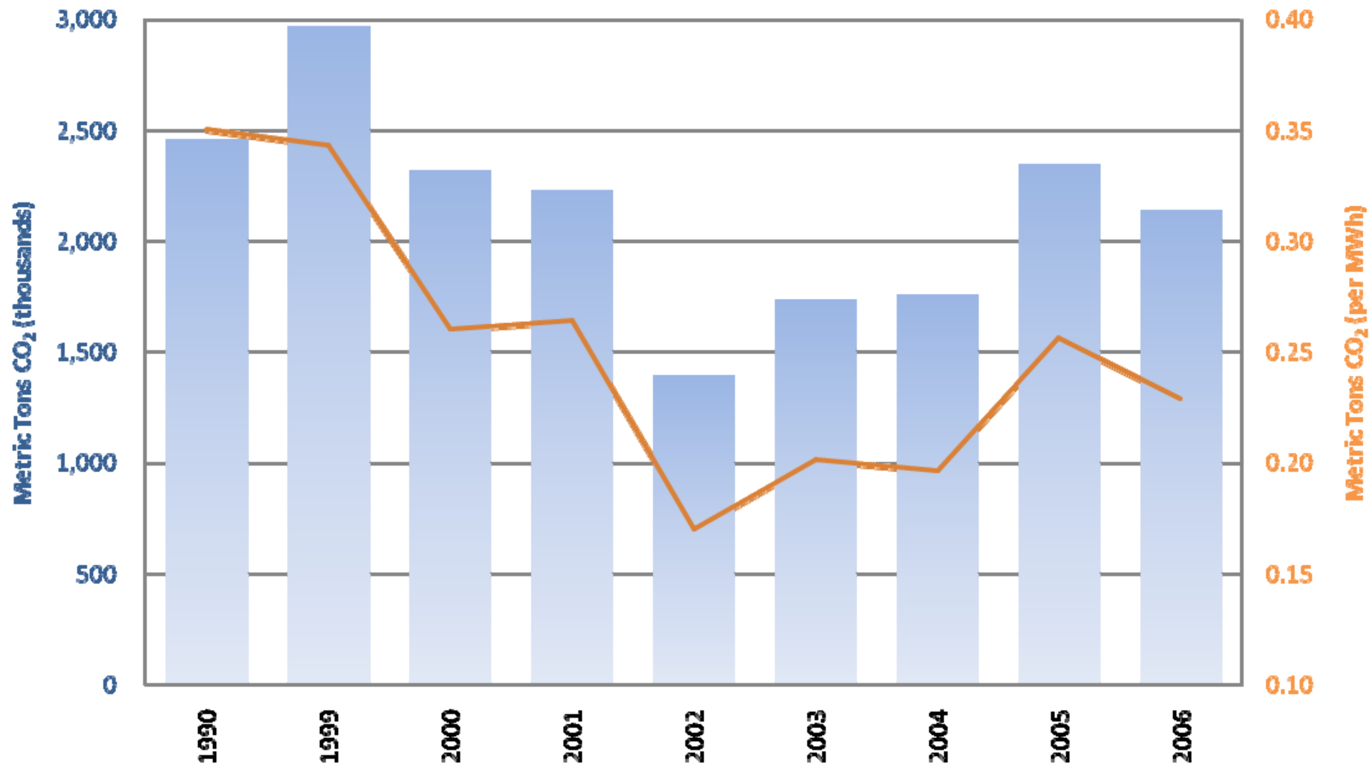
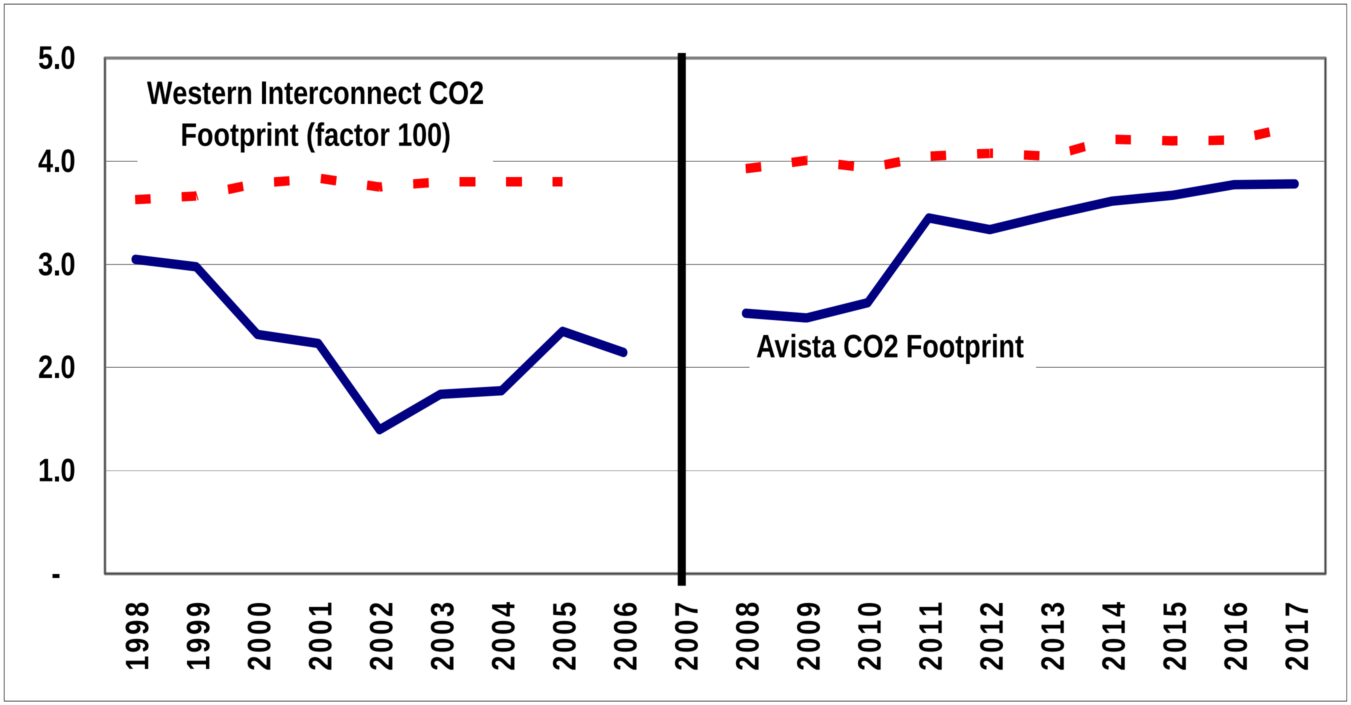
Avista Generation Carbon Footprint
(WRI-WBCSD Protocols, Selected Years 1990-2006)



Avista/WI Generation Carbon Footprint
(millions of tons)



Regional Greenhouse Gas Initiative (RGGI)

- Begins January 1, 2009
- Memorandum of understanding signed in 2005 and includes 10 northeastern states
- Caps CO_2 emissions from all power plants greater than 25 MW
- Emissions capped at 121 million short tons per year from 2009 through 2014
- 2015 – 2019 emissions cap reduced by 10%
- 25% of allowances must be strategic or customer oriented in nature
- Some offsets allowed – amount tied to allowance price
- Quarterly auctions beginning in September 2008 with most states having 100% auctions

Loss of Load Probability

James Gall

What is Loss of Load Probability?

A measure of the probability that a system demand will exceed capacity during a given period; often expressed as the estimated number of days over a long period, frequently 10 years or the life of the system.

- *U.S. Department of Energy*

Our study is measured as # of draws where there was a loss of load, for example 1 in 20 draws, is 5%.

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LOLP Model Overview

What is it?

- Estimates the probability that not all of load will be served in a given simulation
- Uses available capacity for a given week in January and August
- Simulates major random events, such as wind, hydro, load, and forced outages
- Used to validate planning margin in IRP forecast period

What it is <u>not</u>?

- Energy dispatch model
- Financial costs are not considered
- No estimates for localized transmission/distribution outages
- Does not take into account natural disaster/terrorism related outages

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How It Works

Runs for 168 continuous hours (7 days) in January & August

1) Load is estimated (-)
2) Available capacity from thermal resources (+)
3) Run of river hydro (+)
4) Wind shape calculated (+)
5) Contracts are netted (+/-)
6) Available storage hydro is shaped to high load hours (+) [LP]
7) Market energy purchased up to an assumed limit (+) [LP]
8) Federal hydro release from upstream storage (+) [LP]
9) If load is not served in one or more hours, loss of load occurs

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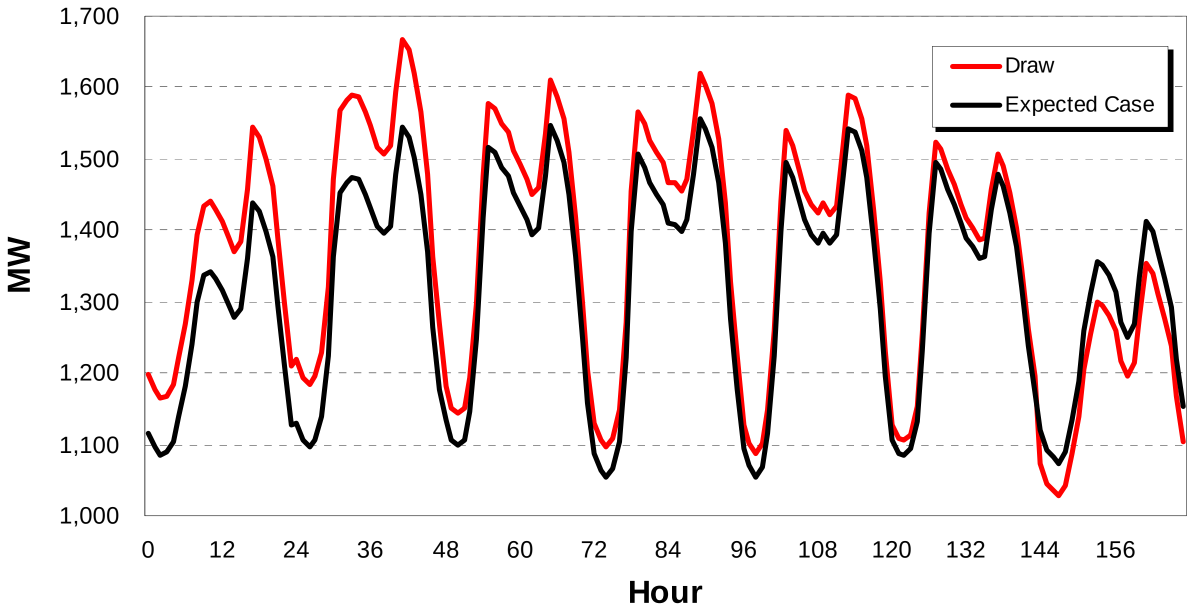
Load

- Uses actual 2007 hourly load shapes for January and August
- Each day an amount of energy is drawn,
  - Correlated to previous day to simulate cold and hot snaps,
  - Based on historic weekly energy shape, and
  - Normal distributions are assumed



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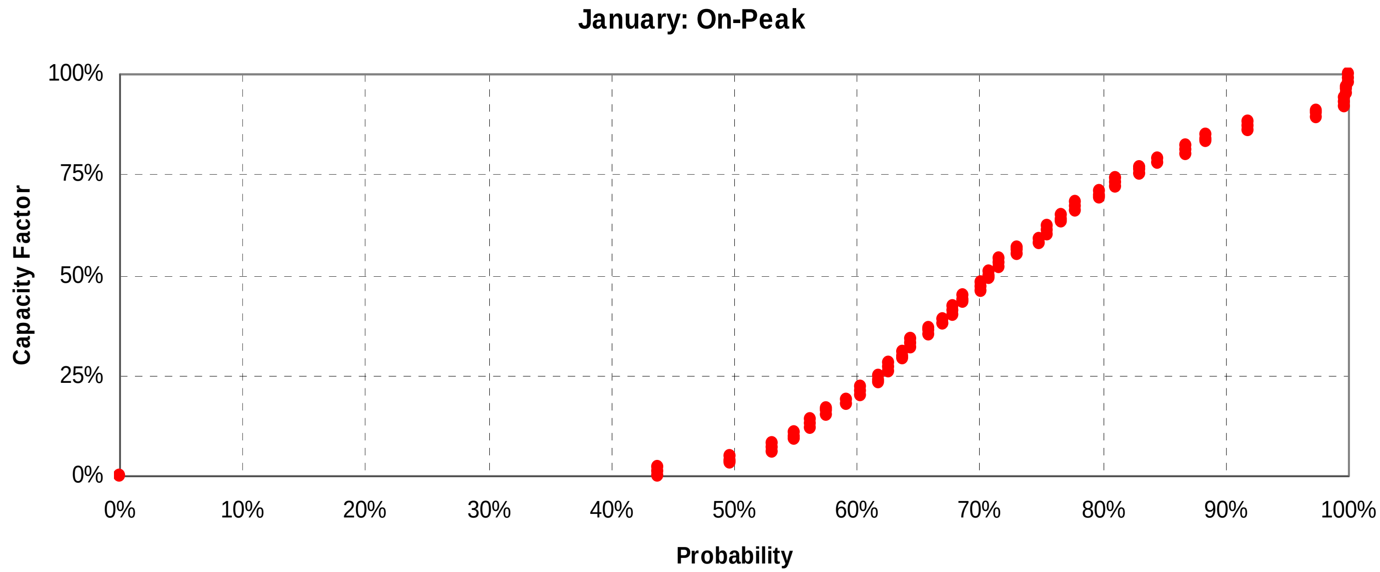
Hydro

- Available energy is a random draw from 70 year historical record from the Northwest Power Pool
- Run-of-River projects use this energy shaped to historical flow
- Storage projects use a Linear Program (LP) to move hydro energy to more valuable hours subject to storage constraints and minimum and maximum capacity.
- Plants can spill energy, and draft reservoirs to minimum level
- Scenarios can be studied with/without federal hydro release from upstream storage to prevent load loss

Wind

- Hourly shape based on expected mean energy and frequency distribution for on/off peak hours by month
- Hour to hour correlation
- Future enhancement will have projects correlated



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Forced Outages

- For each plant:
  - *Forced Outage Rate (FOR)*
  - *Mean Time To Repair (MTTR)*
  - *Ramp Rate*
- For each hour a unit has a probability of an outage, calculated as:

  Outage Probability = FOR x 8760 / MTTR / 52

  e.g. 0.10 x 8760 / 24 / 52 = 70% chance of outage in the week or 0.42% in a given hour

- If an outage is drawn, another probability is calculated if the unit is to return to service, calculated as:

  Return to Service if: Rnd# > 1 / MTTR, than "on", otherwise "off"

- If a unit has a ramp rate, such as 10 hours, the units available generation will increase linearly over 10 hours until it reaches maximum capability

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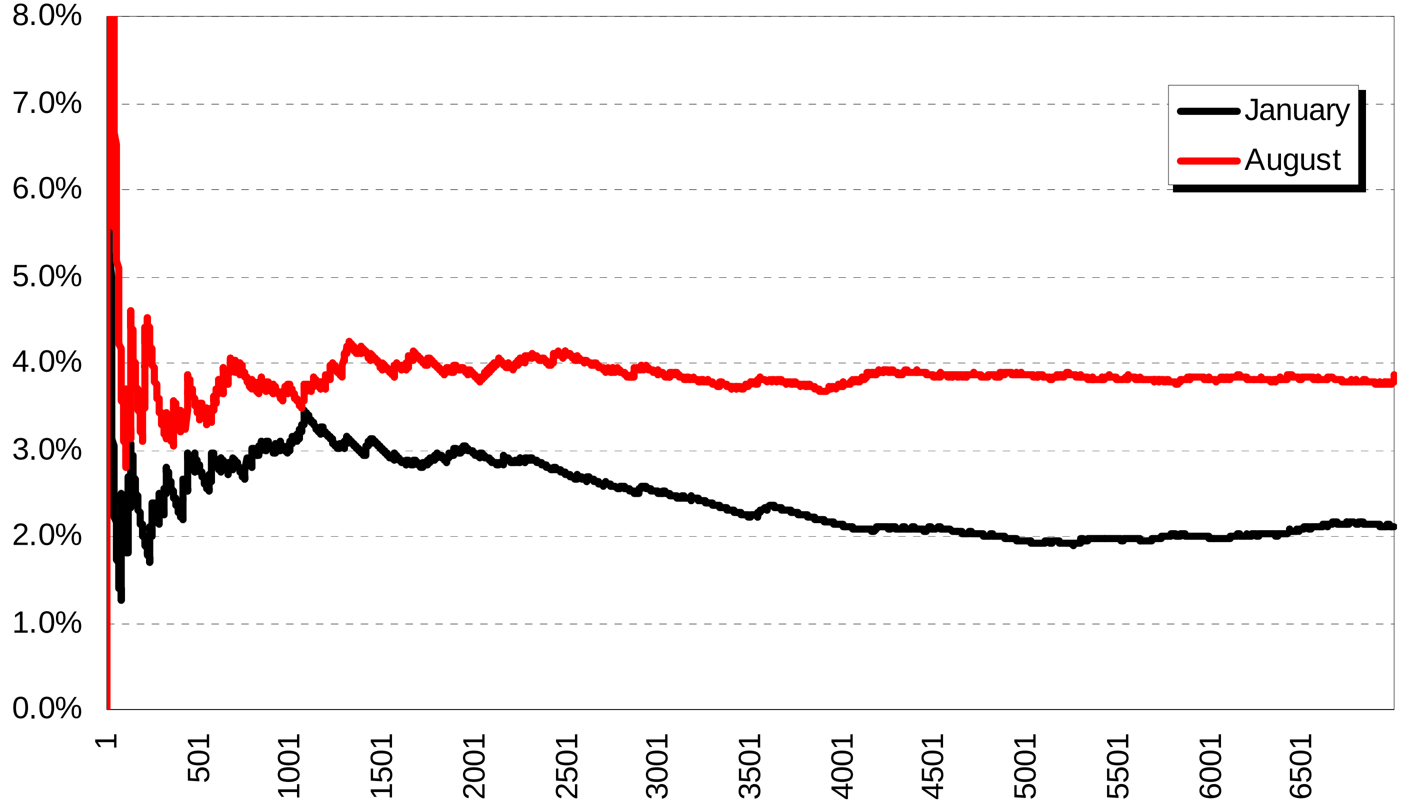
2009 Results- Base Case

	January	August
Loss of Load	2.1%	3.8%
Market Reliance	47.6%	55.6%
Peak Load	2,023	2,005
Average Peak Load	1,656	1,492
Average Load	1,319	1,081
Available Market (MW)	300	300
Federal Hydro	0	0

How Many Iterations Do You Need?



2009 Results- Scenario 1, Less Market Opportunity
200 MW (on-peak), 300 MW (off-peak)

	January	August
Loss of Load	7.4%	12.1%
Market Reliance	47.3%	56.1%
Peak Load	2,053	1,841
Average Peak Load	1,656	1,494
Average Load	1,319	1,081
Available Market (MW)	200	200
Federal Hydro	0	0

2009 Results- Scenario 2, Increase Market Opportunity
400 MW of Market

	January	August
Loss of Load	0.4%	0.9%
Market Reliance	47.3%	56.1%
Peak Load	2,026	1,762
Average Peak Load	1,656	1,494
Average Load	1,319	1,081
Available Market (MW)	400	400
Federal Hydro	0	0

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2020 Results- Scenario 3, Potential Future

	January	August
Loss of Load	3.3%	0.8%
Market Reliance	41.7%	19.6%
Peak Load	2,494	2,279
Average Peak Load	2,048	1,849
Average Load	1,631	1,338
Available Market (MW)	300	300
Federal Hydro	0	0

Adds: Lancaster (270 MW), Reardan (50 MW), CCCT (200 MW), Wind (200 MW)

2020 Results- Scenario 4, All Wind Future

	January	August
Loss of Load	9.8%	3.2%
Market Reliance	73.5%	51.8%
Peak Load	2,515	2,198
Average Peak Load	2,048	1,848
Average Load	1,629	1,138
Available Market (MW)	300	300
Federal Hydro	0	0

Adds: Lancaster (270 MW), Reardan (50 MW), CCCT (0 MW), Wind (400 MW)

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2020 Results- Scenario 5, Flat Wind Future

	January	August
Loss of Load	6.0%	1.8%
Market Reliance	65.7%	39.0%
Peak Load	2,662	2,238
Average Peak Load	2,047	1,851
Average Load	1,630	1,339
Available Market (MW)	300	300
Federal Hydro	0	0

Adds: Lancaster (270 MW), Reardan (50 MW), CCCT (0 MW), Wind (400 MW)

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2009 Results- Scenario 6, 5% LOLP Case

	January	August
Loss of Load	4.9%	5.1%
Market Reliance	47.5%	54.8%
Peak Load	1,992	1,780
Average Peak Load	1,657	1,493
Average Load	1,319	1,080
Available Market (MW)	235	270
Federal Hydro	0	0

What it takes to stay at 5% LOLP for 2009 if remove 100MW of market availability

- Remove 100MW of Market: 15.1%/15.9%
- Add 100MW of CCCT: 5.0%/5.4%
- Add 300MW of Wind: 7.9%/11.1%
- Add 600MW of Wind: 6.0%/8.3%

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2009 Results- Scenario 7, Federal Hydro 16 hrs

	January	August
Loss of Load	0.1%	0.0%
Market Reliance	47.6%	55.8%
Peak Load	2,025	1,785
Average Peak Load	1,657	1,493
Average Load	1,320	1,080
Available Market (MW)	300	300
Federal Hydro	16 hrs	16 hrs

2009 IRP Topic Discussions

Clint Kalich

Work Plan – Proposed TAC Meeting Schedule

May 14, 2008 – Kickoff Meeting

August 2008 – TBD

October 2008 – TBD

January 2009 – Review of final modeling and assumptions

March 2009 – Review of scenarios and futures, resource, and transmission costs

April 2009 – Review of final PRS

June 2009 – Review of report

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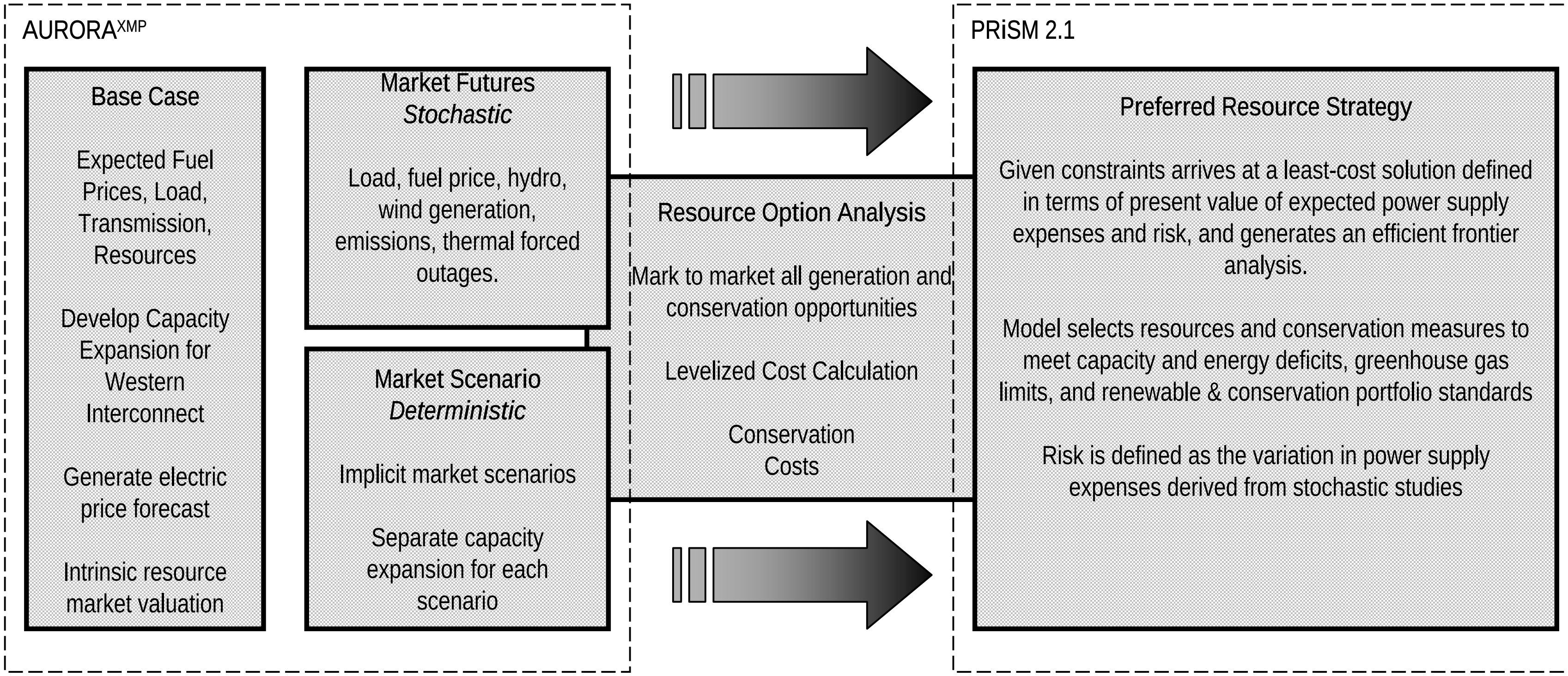
Work Plan – Flow Diagram



Work Plan – Timeline on IRP Development

Preferred Resource Strategy	
Identify Regional resource options for electric market price forecast	8/15/2008
Identify Avista's resource options	8/31/2008
Develop PRiSM 2.1 model & implement	9/15/2008
Update AURORA^{xmp} database for electric market price forecast	9/30/2008
Select natural gas price forecast	10/10/2008
Finalize deterministic Base Case	10/17/2008
Create datasets/statistics variables for risk studies	10/31/2008
Base case risk study complete	11/30/2008
Develop Efficient Frontier & PRS	1/30/2009
Simulation of risk studies "futures" complete	1/30/2009
Simulate market scenarios in AURORA^{xmp}	2/27/2009
Evaluate resource strategies against market futures & scenarios	3/20/2009
Present to TAC preliminary study and PRS	3/31/2009

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Work Plan – Timeline on IRP Development

Writing Tasks

File 2009 Integrated Resource Planning Work Plan	8/30/2008
Prepare Report and Appendix Outline	9/15/2008
Prepare text drafts	4/15/2009
Prepare charts and tables	4/15/2009
Internal draft released	5/1/2009
External draft released	6/15/2009
Final editing and printing	8/1/2009
Report distribution	8/30/2009

Analytical Process Changes

DSM Fully Integrated Into PRiSM

- Valuation, risk, selection

PRiSM Improvements

- "Lumpiness" added
- Portfolio carbon limits
- Additional resource options
- Plant retirement
- New efficient frontier method (balancing risk and cost)
- End effects more accurately modeled
- Added AFUDC
- Market and green tag purchases risk

Resource dispatch & valuation

- Evaluating options to AURORA (e.g., LP Model)

Planning Futures/Scenarios

- More carbon looks
- Solar cost collapse
- Sustained high gas prices
- Lots of nuclear (government support/promotion)
- 25% RPS nationwide
- Back to the Future
  - Determine cost of renewable energy & carbon legislation
- Other Ideas from TAC??

2009 Integrated Resource Plan
Technical Advisory Committee Meeting No. 2 Agenda
August 27, 2008

	Topic	Time	Staff
1.	Introduction	10:30	Vermillion
2.	Risk Assumptions/PRiSM	10:35	Gall
3.	Resource Assumptions	11:30	Lyons
4.	Lunch	12:15	
5.	Scenarios and Futures	1:15	Lyons
6.	Demand Side Management	2:00	Powell
7.	Adjourn	3:30	

Stochastic Analysis & Resource Portfolio Selection Modeling

James Gall

Presentation Overview

Risk

- Discuss methods and risk assumptions, expected (mean) values will be discussed at later TAC meetings
- Variable correlations are difficult to quantify, recommendations are placeholders until better information is available or the TAC agrees the assumption is acceptable for modeling purposes
- Risk analysis is modeled in AURORA- impacts electric markets prices and the cost of new resource options
- Feedback and suggestions are needed

PRiSM

- Overview of the model and enhancements
- Feedback and suggestions are welcome

Stochastic Analysis Methods & Assumptions

Long-Term Correlation Matrix

	Gas Prices	CO_2 Prices	NO_X Prices	SO_2 Prices	New Coal Prices	Hog Fuel Prices	Load Growth
Gas Prices	1.00						
CO_2 Prices	0.50	1.00					
NO_X Prices		0.75	1.00				
SO_2 Prices		0.75	1.00	1.00			
New Coal Prices		-0.25	-0.25	-0.25	1.00		
Hog Fuel Prices		0.50				1.00	
Load Growth	-0.25	-0.25					1.00

Carbon Dioxide Credit Prices (CO_2, GHG)

- Similar method to 2007 IRP
- For each iteration, a potential carbon cost scenario is selected, based on a weighting of 10 EPA studies.
- After the scenario is selected, the cost is treated as an expected value and a lognormal distribution is applied to each year.
- Further, natural gas and other market price drivers are correlated to the CO_2 prices
- The intent of this method is model the unknown nature of climate change legislation, it potential for year-to-year price volatility, and its affect on other major market price drivers.

Carbon Dioxide Credit Prices (nominal)

%	Nominal $/ Short Ton	2010	2011	2012	2016	2020	2025	2029
10%	EPA S. 2191 ADAGE	-	-	28.60	39.08	50.89	72.40	94.74
3%	EPA S. 2191 IGEM	-	-	40.50	53.13	70.15	98.04	122.32
15%	EPA S. 2191 ADAGE - Low Intl Action	-	-	26.20	36.53	48.14	66.36	88.25
10%	EPA S. 2191 IGEM Unlimited Offsets	-	-	8.70	16.09	20.63	28.66	47.69
2%	EPA S. 2191 IGEM with No Offsets	-	-	80.80	100.39	134.79	190.04	221.27
3%	EPA S. 2191 ADAGE Scenario 6	-	-	39.70	51.85	67.39	95.02	119.07
2%	EPA S. 2191 ADAGE Scenario 7	-	-	57.20	72.29	94.90	132.73	159.63
35%	EPA S. 2191 Alt. Ref. ADAGE	-	-	21.00	30.14	38.51	54.30	75.27
5%	EPA S. 2191 Alt. Ref. IGEM	-	-	35.00	46.75	61.89	85.97	109.34
15%	EPA S. 1766 ADAGE	-	-	10.20	17.37	20.63	28.66	47.69
100%	**Expected Value**	**-**	**-**	**23.46**	**33.09**	**42.76**	**59.91**	**81.31**

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Carbon Dioxide Credit Prices (Cont.)

- Randomly draws price strips for each AURORA iteration
- Each year has lognormal distribution (draw is the mean), market become less volatile over time as market matures
  - 2012-2014 prices use 50% sigma
  - 2015-2016 prices use 25% sigma
  - 2017-2029 prices use 10% sigma

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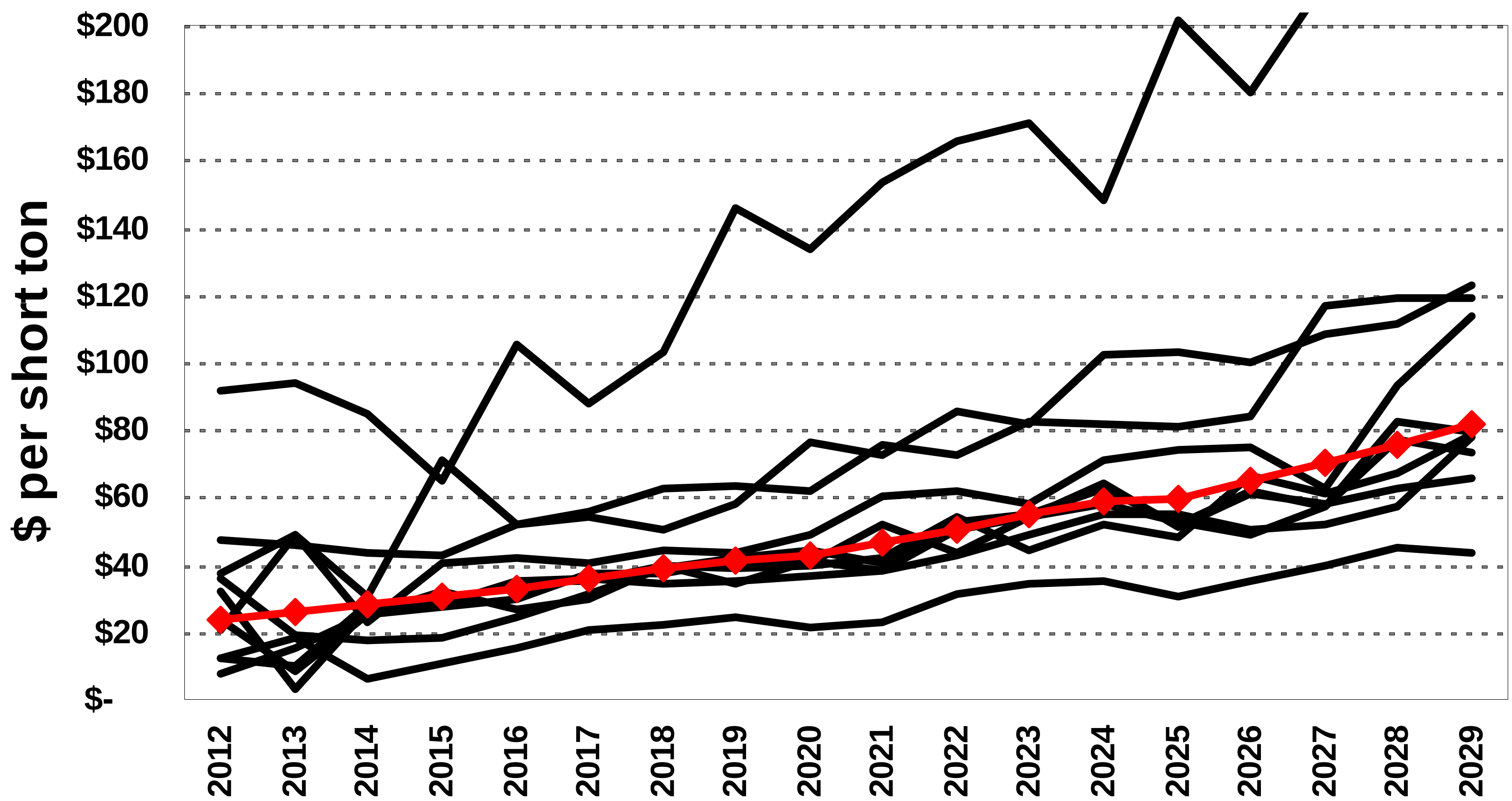
CO_2 Price Trends (10 Simulations)



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Natural Gas Prices

- Lognormal distribution
- Correlated to CO_2 credit prices (50% as placeholder),
  - *Wood Mackenzie will help identify this assumption by studies that model gas prices by changes in gas demand from CO_2 legislation*
- Assumes 35% sigma before CO_2 volatility is applied, than ~58-70%
- Monthly prices may be correlated to load in the winter
- No direct annual serial correlation
- Load growth is negatively correlated at 25%

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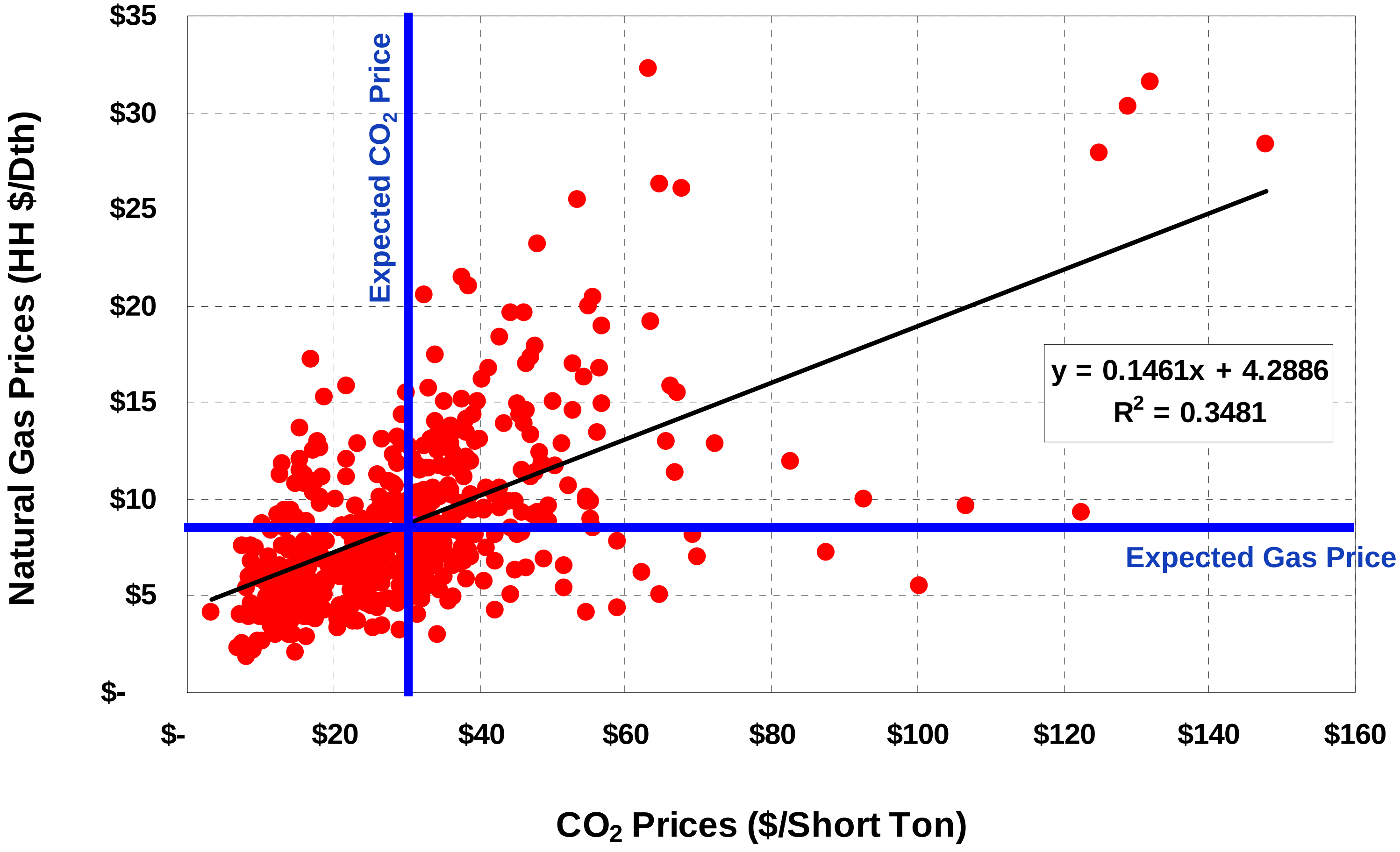
Modeled Natural Gas & CO_2 Price Relationship

Year 2015, Correlation 59%, 500 draws



Load Growth

- Normal distribution
- Standard deviation is equal to expected value, represents potential volatility due economic activity *(perhaps too volatile)*
- Energy load growth negatively correlated to gas (-25%), CO_2 (-25%),
- Peak load variance modeled as weather variance
- Western Interconnect regional correlation between zones, similar to the 2007 IRP
- Potential correlation between natural gas prices in winter

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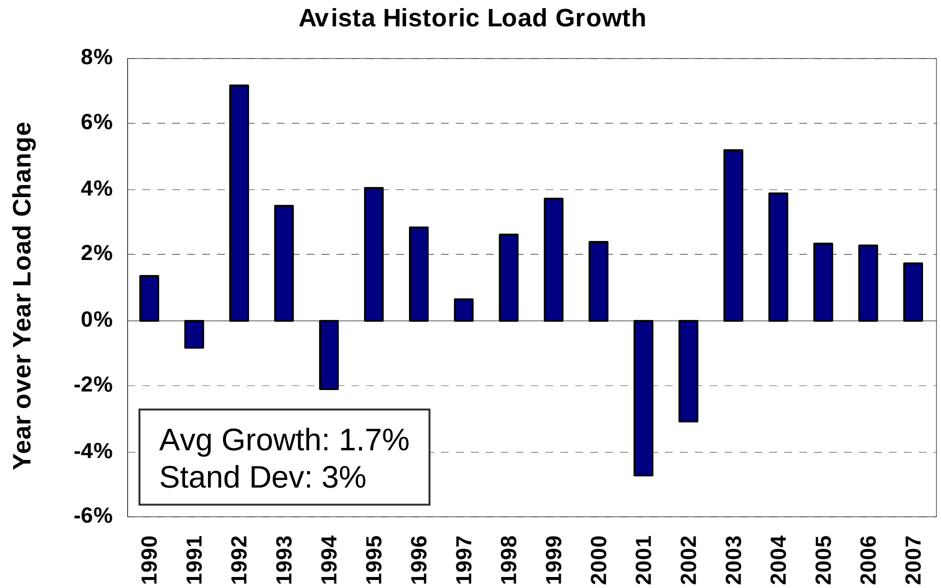
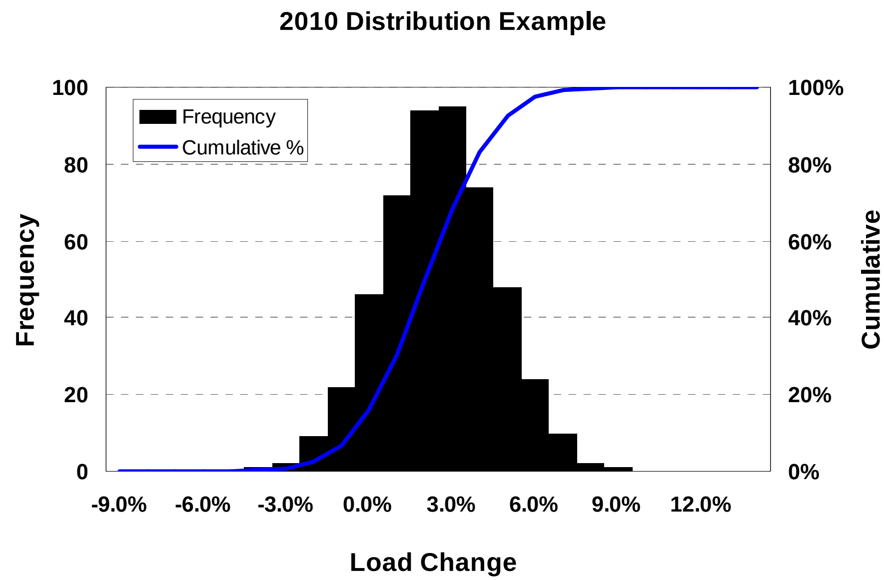
Avista Load Growth Example





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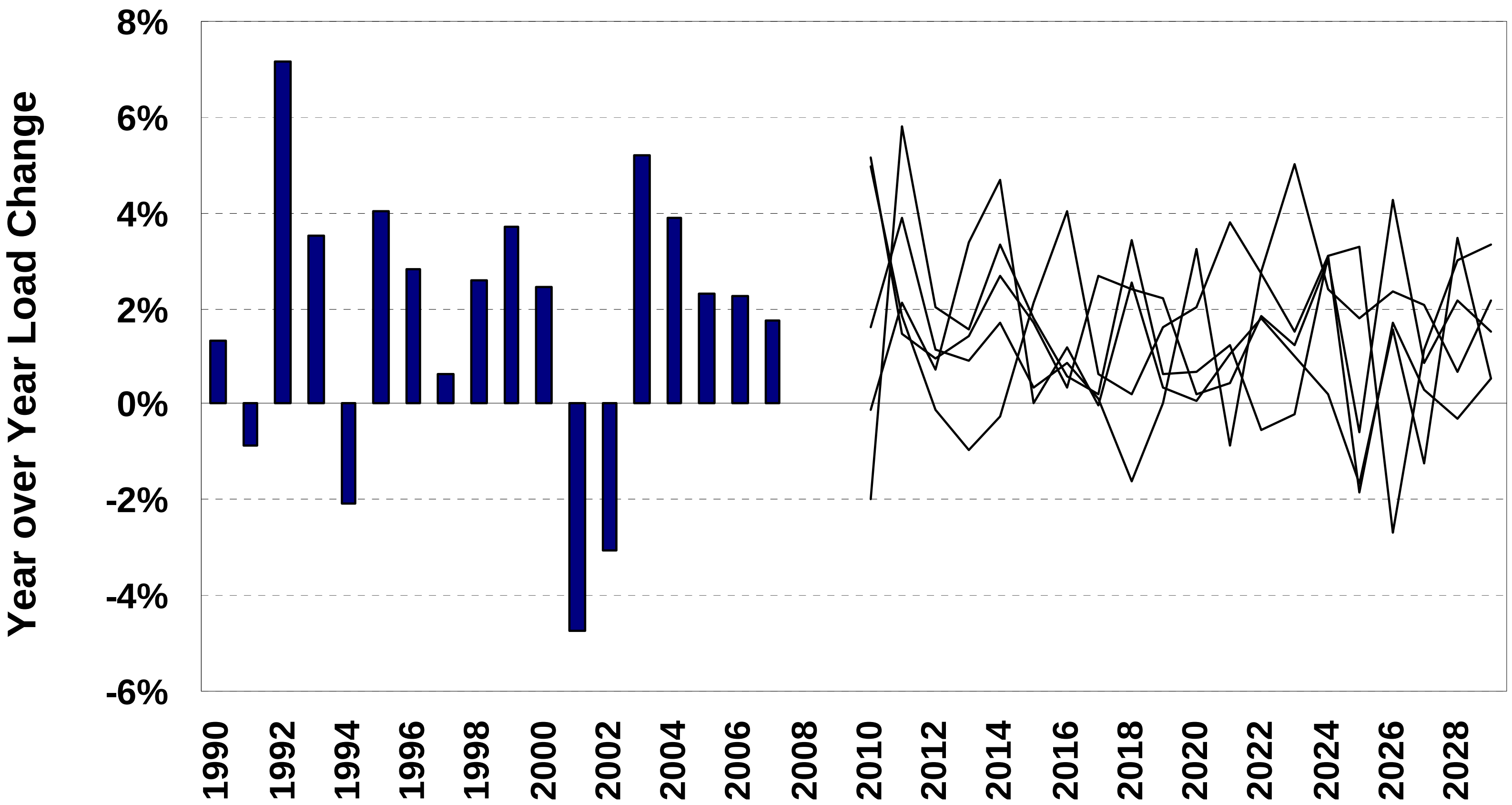
Load Growth Example (Forecast- 5 draws)



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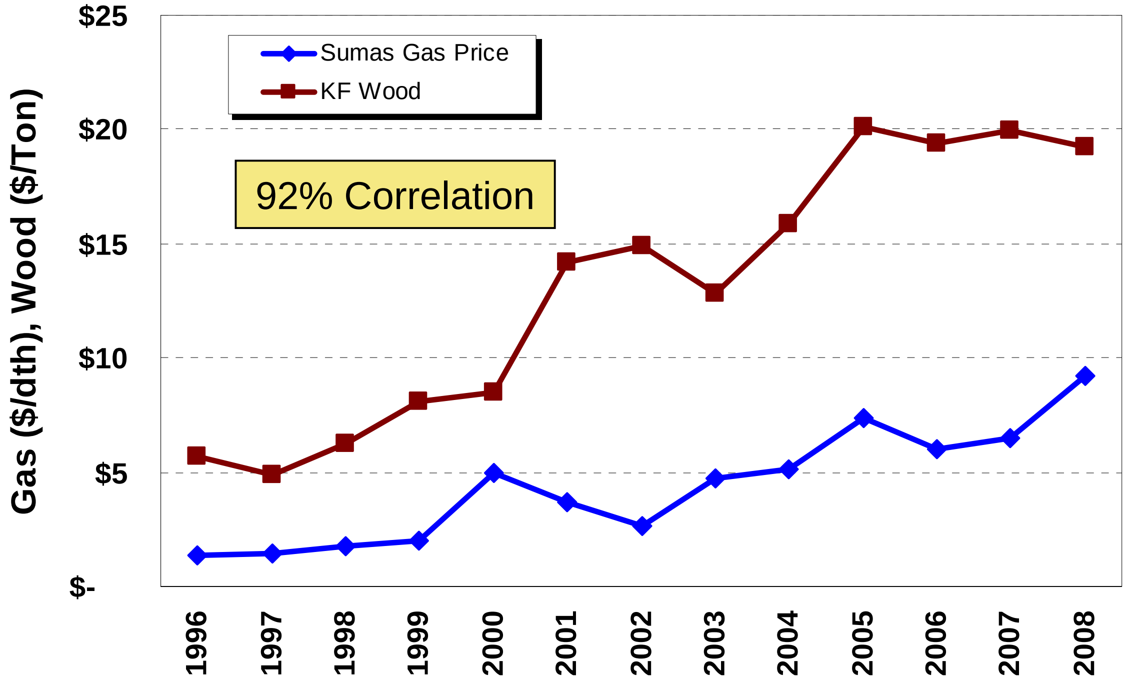
Hog Fuel (Wood Waste) Prices

- Normal distribution
- Standard deviation: 10% of expected value
- Positively correlated CO_2 (50%) prices,
  - *A higher CO_2 price could add demand to Wood Prices to offset CO_2*
- Potential correlation to load growth, but more likely correlated to on economic growth, while loads tend to have additional drivers
- What about correlating to natural gas prices

Kettle Falls Prices Compared to Sumas Gas Prices



A multiple regression including inflation & natural gas prices were tested to see if inflation was actually the cause for the correlation.

The results indicated that Sumas gas prices was not a significant predictor of wood prices. **Therefore natural gas will not be correlated to wood prices for this IRP.**

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Mine Mouth Coal Price

- Normal distribution
- Standard deviation: 10% of expected value
- Negatively correlated to CO_2 (-25%), and other emissions (-25%)
  - *As policy changes decreasing domestic coal demand, prices could potentially lower as coal mines remain open for international demand*
- Basis for short and long-haul coal prices for new coal options- *this should not affect market prices to any extent*
- No change to existing coal prices for existing plants

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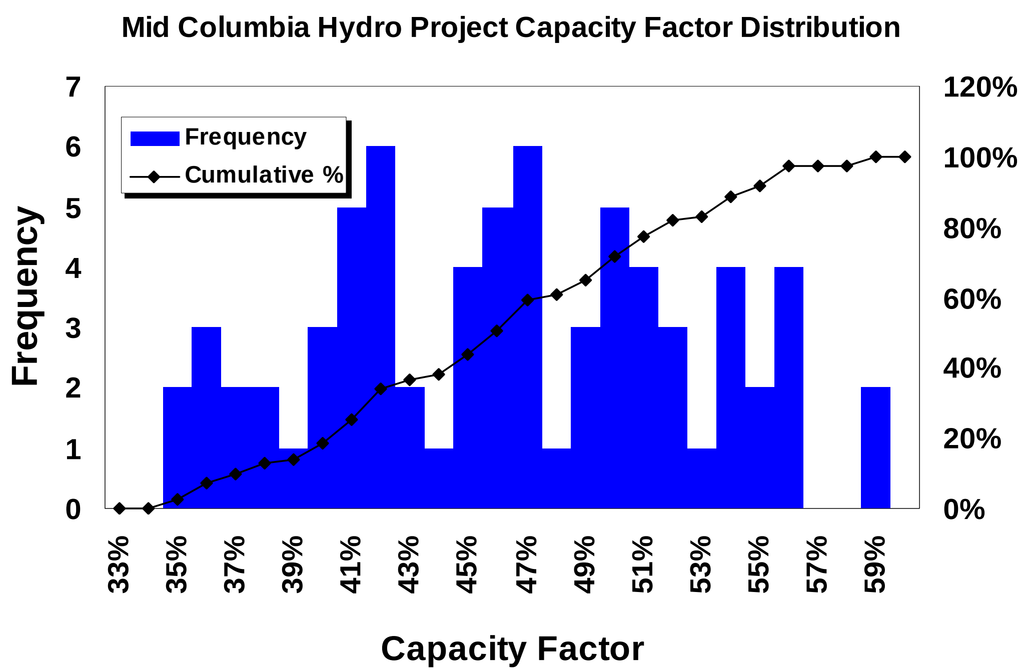
NO_X and SO_2 Credit Prices

- Lognormal distribution
- Standard Deviation: 10% of expected values
- Expected values will be based on July 2008 Wood-Mackenzie study
- Positively correlated to CO_2 prices (75%)
  - *Stricter CO_2 policy will likely lead to stricter air emissions policy and additional gas fired generation- requiring the needs for credits*
- Negatively correlated to new coal prices (-25%)
- No mercury prices will be modeled in this IRP, rather controls will be assumed to be installed on required plants.

Hydro

- Each year of each iteration will randomly draw of historical 70 year history (1929-1998)
- No historical evidence of normality



Wind

- Generic wind for existing projects will use fixed shape with distribution of energy- this is only used for market analysis.
- For potential Avista wind resources, each hour will be randomly drawn based on its probability of occurrence in a given month and time of day with correlation to previous hour.
  - Statistics are available for potential projects on the Columbia River, Reardan, and Montana.
- Similar method was used in the 2007 IRP.
- Potential correlation to winter hydro conditions and will be evaluated

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Forced Outages

- Use AURORA logic for random forced outages
- Only Coal, Nuclear, and CCCT plants will be modeled with F/O logic
- Mean Repair Times:
  - Nuclear: 84 hours
  - Coal: 72 hours
  - CCCT: 24 hours

PRiSM

Preferred Resource Strategy Model

Overview & Enhancements

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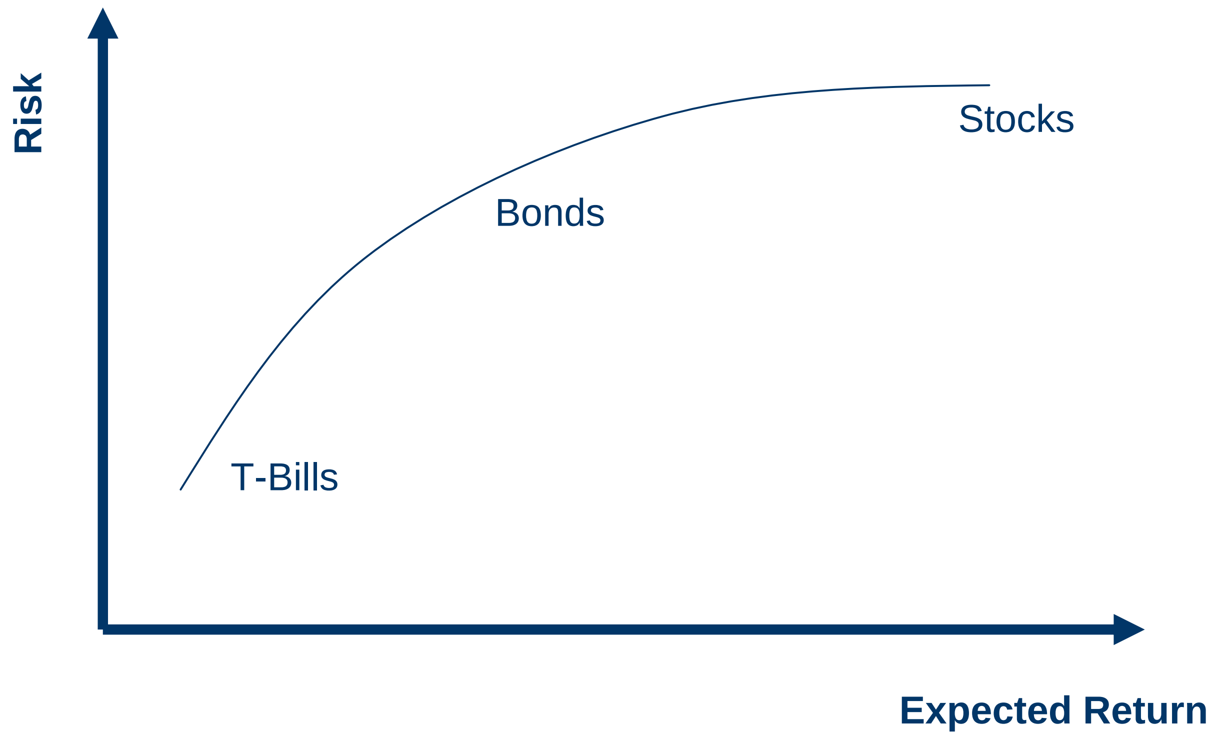
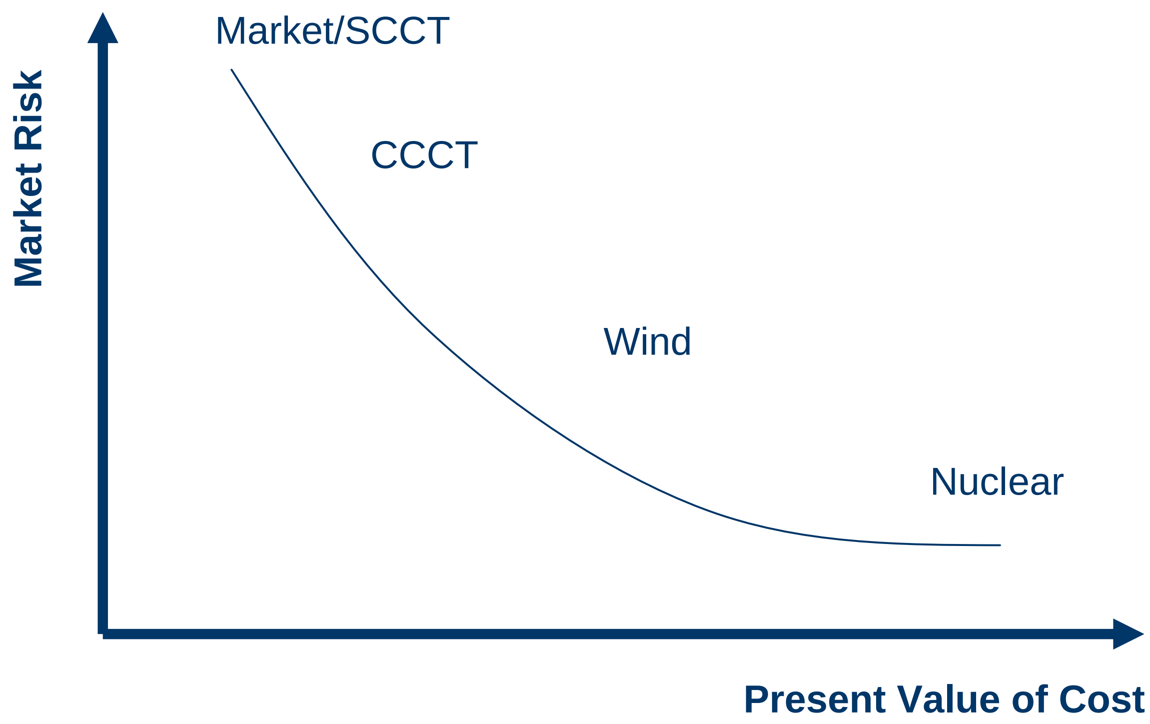
What is PRiSM?

- Preferred Resource Strategy Model
  - *Selects resource & conservation opportunities on an optimal cost and risk basis using a linear program (What's Best!)*
  - *What's Best is a linear programming tool added to MS Excel*
- Objective function is to either select resource strategies to meet our energy/capacity/market/RPS/CO_2 requirements on a least cost or least risk basis
- Cost is measured by the present value of incremental fuel & O&M expenses and new capital investment
- Risk is measured by the variation in fuel & variable O&M expenses in years 2019 & 2029 (possible PV of 20 years)

Efficient Frontier- Introduction



Efficient Frontier- Introduction



New Enhancements

- Conservation measures are selected in model rather than an input (only measures that are between $xx/MWh & $xxx/MWh)
- Resources are now added in increments rather than any amount
- Use more precise method to estimate frontier curve
- Meets both summer & winter capacity requirements
- Ability to retire resources
- Ability to account for greenhouse gas caps
- More accurate ability to take into account post IRP time period

2009 IRP Resource Assumptions

John Lyons

Supply Side Resource Data Sources

- Resource lists developed internally
  - Trade journals
  - Press releases
  - Engineering studies and models (ThermoFlow)
  - Announcements from state commissions
  - International projects
  - Proposals from developers
- Power Council
- Consulting firms/reports: Wood Mackenzie, Goldman Sachs, Black & Veatch
- State and federal resource studies
- These data sources are used to develop generic resource types

Resource Differences from 2007 IRP

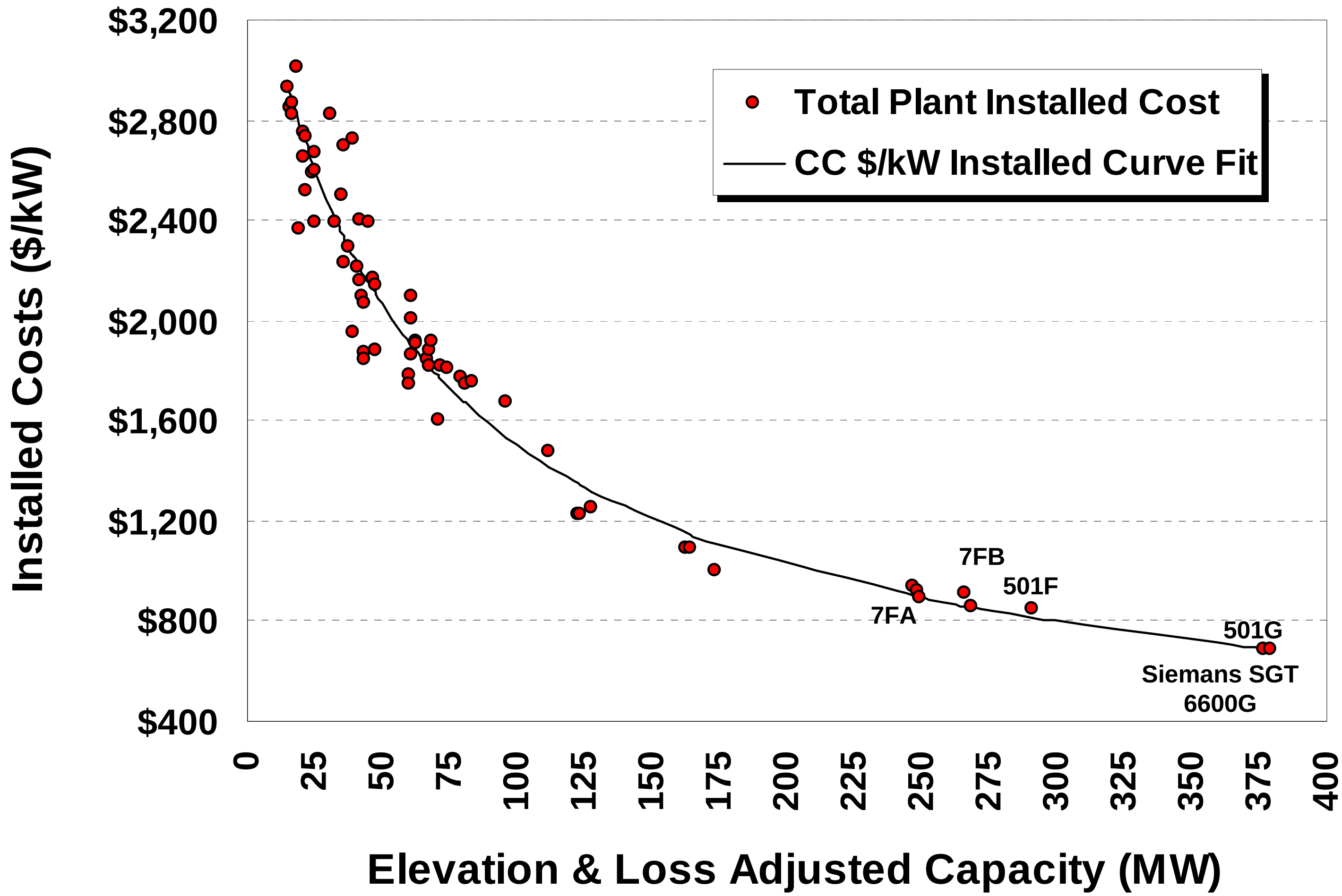
- Fewer types of coal resources are included – only ultra critical and IGCC plants are being modeled
- Alberta oil sands are not included as a resource option
- Solar and hydro are being included as resource options for the preferred resource strategy
- Adding more specifics for the Other Renewable Resources category – geothermal, biomass, and solar resources are being modeled separately

Non-Renewable Supply Side Resources

- Natural Gas Combined Cycle (CCCT)
  - 2 x 1 and 1 x 1 with duct burner water cooled (1x1 for PRS)
  - 2 x 1 and 1 x 1 with duct burner air cooled
  - 600 MW with sequestration
- Natural Gas-Fired Simple Cycle – Aero, Frame, and Hybrid
- Small co-generation (< 5 MW)
- Pipeline co-generation
- Coal – ultra critical, IGCC, and IGCC with sequestration
- Nuclear

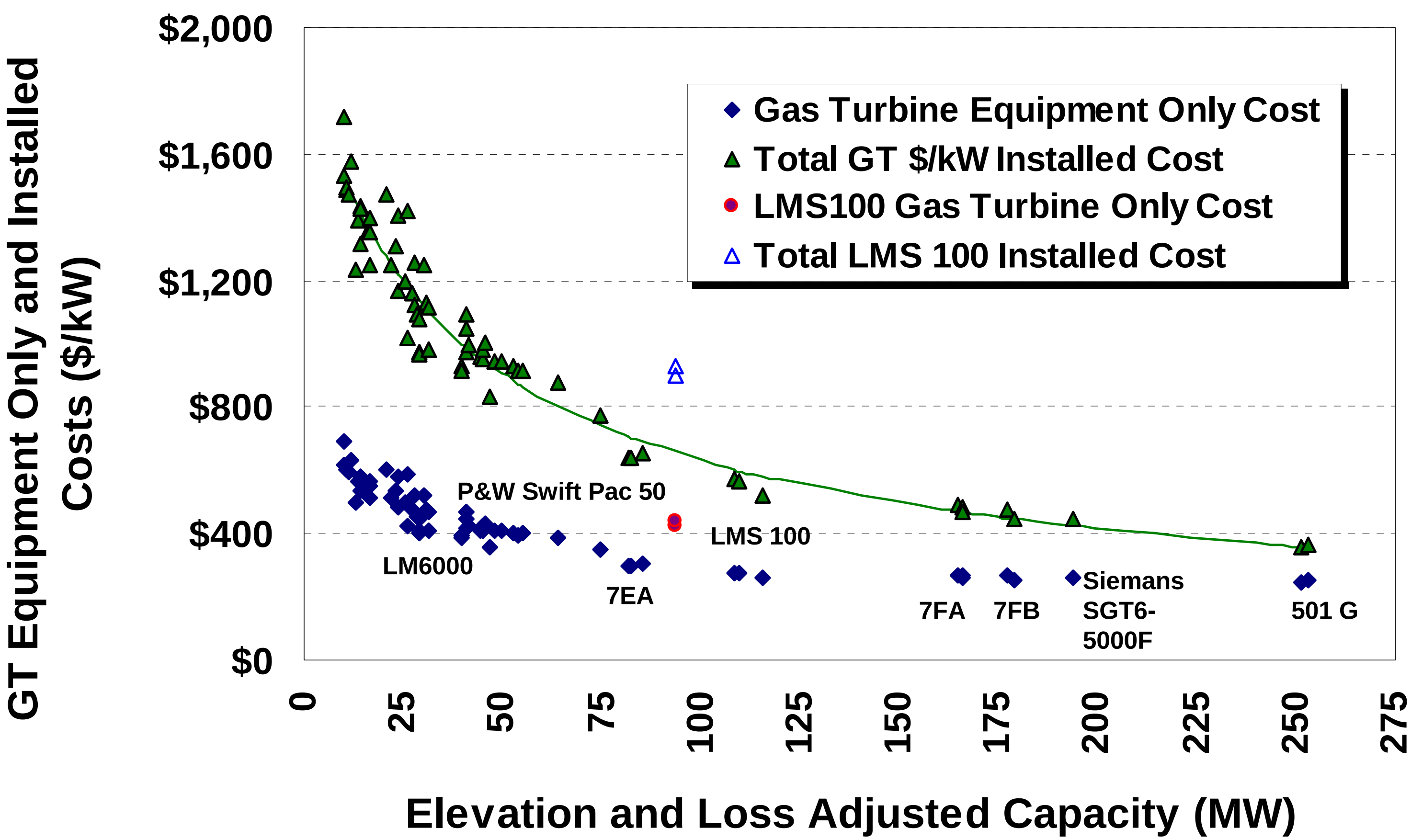
2008 Combined Cycle Total Installed Cost Estimate

2,000 Feet Elevation



2008 Simple Cycle Total Installed Cost Estimate

2,000 Feet Elevation



Renewable Supply Side Resources

- Geothermal
- Wind – 100 MW, < 5 MW, and offshore
- CCCT Wood Boiler
- Wood Gasification Conversion
- Open Loop Biomass – landfill gas, wood, waste, etc.
- Closed Loop Biomass
- Solar Photovoltaic
- Solar Thermal
- Roof Top Solar
- Tidal Power
- Hydrokinetics
- Run of River Hydro
- Pumped Storage

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Avista Resource Upgrades

- Little Falls Unit #1 – 4 Upgrades
- Post Falls Unit #6 Upgrade
- Upper Falls Upgrade
- Long Lake new unit and new powerhouse
- Cabinet Gorge #5
- Scheduled upgrades and acquisitions are included in the L&R
  - Noxon Rapids Units #1 – 4 scheduled for 2009 – 2012
  - Lancaster Generation Facility – 2010
  - Reardan – preliminarily scheduled for 2011

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Avista 2009 IRP Resource Assumptions

Draft as of 8/27/08
2009 Dollars

Resource (not locational specific)	First Year Available	Availability (MW)	Capital Cost- Exclude AFUDC (2009$/kW)	Transmission Interconnect ($/kW)	Construction (Yrs)	Fixed O&M ($/kW/Yr)	Net HHV Heat Rate(s) (Btu/kWh)	Variable Costs ($/MWh)	Gas Transport ($/Dth/Mn)	Fuel Charge (%)	Winter Capacity Credit (%)	Summer Capacity Credit (%)	Availability (%)	Forced Outage (%)	Annual Avg Maintenance (days)	Min Dispatch (%)	Start up Cost ($/MW/Start)	Start up Fuel (Dth/MW/Start)	Ramp Rate (%/hr)	CO2 (lbs/mmbtu)	SO2 (lbs/mmbtu	NOX (lbs/mmbtu)	Federal Incentives	Sources/Notes
CCCT (2x1) w/ duct burner (wet)	2011	N/A			3		6,750/ 8,500	3.29	0.27	1.0	105	95	90.1	5	18	55	35	6.6	20	117	0.0006	0.02	No	
CCCT (2x1) w/ duct burner (dry)	2011	N/A			3		6,900/ 8,700	3.29	0.27	1.0	105	95	90.1	5	18	55	35	6.6	20	117	0.0006	0.02	No	
CCCT (1x1) w/ duct burner (wet)	2011	N/A	900		3	11.0	6,750/ 8,500	3.29	0.27	1.0	105	95	90.1	5	18	55	35	6.6	20	117	0.0006	0.02	No	O&M: '08 CS2 Budget (LTSA/Major Maint is in VOM calculation), emissions based on CS2, Eng. Est.
CCCT (1x1) w/ duct burner (dry)	2011	N/A	928		3	11.0	6,900/ 8,700	3.29	0.27	1.0	105	95	90.1	5	18	55	35	6.6	20	117	0.0006	0.02	No	Capital Cost Est from Thermoflex and HR based on
CCCT (600MW, w/ Seq)	2025	N/A							0.27	1.0	105	95	90.1	5	18					11.7	0	0	No	
Small Co-Gen (<5MW)	2011	15	2,000		1.5	5.0	5,700	5.00	0.27	1.0	105	95	92.3	5	10	n/a	n/a	n/a	n/a	117	0.0006	0.02	No	
Pipeline Co-Gen	2010								n/a	n/a						n/a	n/a	n/a	n/a	n/a	n/a	n/a	No	
Frame SCCT	2010	N/A	480		1.5		10,200	5.00	0	3.4	105	95	92.3	5	10		15	3.7	100	117	0.0006	0.02	No	Thermoflex, NPCC
Hybrid SCCT (LMS 100)	2010	N/A	900		1.5		8,400	5.00	0	3.4	105	95	92.3	5	10				100	117	0.0006	0.02	No	Thermoflex, NPCC
Wind (100MW)	2010	500	2,400		2	50.0	n/a	3.00	n/a	n/a	TBD	TBD	28-33	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FULL PTC- 10 Yrs (end 2011)	Recent press, O&M from Uwe's latest O & M Presentation
Wind (<5MW)	2010	10	3,000		2		n/a	3.00	n/a	n/a	TBD	TBD	20.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FULL PTC- 10 Yrs (end 2011)	
Wind (Offshore)	2018	100	5,000			95.0	n/a		n/a	n/a	TBD	TBD	45.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FULL PTC- 10 Yrs (end 2011)	PSE Assumption from Wind Developer
Coal (Ultra Critical)	2019	N/A	3,000		8	38.0	8,825	1.30	n/a	n/a	100	100	89.2	7	14	50	n/a	n/a	8	205	0.12	0.07	No	Black & Veatch (O&M), VOM Goldman Sachs, maint based on Colstrip
Coal (IGCC)	2022	N/A	3,600		8	41.0	8,130	4.00	n/a	n/a	105	95	89.2	7	14	75	n/a	n/a	4	205	0.03	0.15	No	Black & Veatch (O&M), VOM Goldman Sachs, assumes extra gasifier
Coal (IGCC w/ Seq)	2025	N/A	5,040		8	50.0	9,595	4.40	n/a	n/a	100	100	88.3	7	17	75	n/a	n/a	4	20.5	0.003	0.015	No	Escalated rates from IGCC based on NPCC for O&M, capital 40% higher than IGCC
Geothermal	2012		4,250		3	75.0		5.00	n/a	n/a	110	90	93.4	5	6	n/a	n/a	n/a	n/a	10	n/a	n/a	FULL PTC- 5 Yrs (End 2011)	Capital Costs per Avg of Kitz & Public Renewable Partners, O&M per GS Study
CCCT Wood Boiler	2012	20	2,500		3	121.0	10,500	6.00	n/a	n/a	100	100	90.1	5	18	0	n/a	n/a	n/a	202	0.025	0.17	HALF PTC- 5 Yrs (End 2011)	Emissions data per Kettle Falls & TD analysis
Wood Gasification Conv. for CCCT DB		25							n/a	n/a			100.0				n/a	n/a	n/a	202			HALF PTC- 5 Yrs (End 2011)	
Wood Gasification Conversion (KFCT)		7							n/a	n/a			100.0				n/a	n/a	n/a	202			HALF PTC- 5 Yrs (End 2011)	
Biomass Open Loop (landfill,wood,waste,etc)	2011		5,000		2				n/a	n/a	100	100	92.3	5	10	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 5 Yrs (End 2011)	Black & Veatch (Capital)
Biomass Closed Loop	2017				2				n/a	n/a	100	100	92.3	5	10	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FULL PTC- 10 Yrs (end 2011)	
Solar Photovoltaic	2010	50	7,500		1	32.0	n/a	0.00	n/a	n/a		100	20.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	30% ITC (End 2011)	Black & Veatch (Capital), O&M per Goldman Sachs Study
Solar Thermal	2010	50	4,200		3	65.0	n/a	0.00	n/a	n/a		100	30.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	30% ITC (End 2011)	Black & Veatch (Capital) O&M per Goldman Sachs Study
Roof Top Solar	2010	50	8,000		0.5	30.0	n/a	0.00	n/a	n/a		100	15.5	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	30% ITC (End 2011)	Kyocera Website, O&M per Goldman Sachs Study
Nuclear	2022	500	5,500		10	97.0	10,400	0.55	n/a	n/a	100	100	87.1	8	18		n/a	n/a		n/a	n/a	n/a	FULL PTC- 10 Yrs (end 2011)	Reports/Huron Consulting (Capex), Black & Veatch (O&M)
Tidal Power	2018	2	10,000		1.5	1000.0	n/a	0.00	n/a	n/a	0	0	30.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FULL PTC- 10 Yrs (end 2011)	Tidal Power Conference and CC fabricated based on range from conference
Little Falls 1 Upgrade	2014	1.0	2,600		2	0.0	n/a	0.00	n/a	n/a	100	100	61.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 10 Yrs (end 2011)	Avista Engineering Preliminary Estimate
Little Falls 2 Upgrade	2015	1.0	1,800		2	0.0	n/a	0.00	n/a	n/a	100	100	61.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 10 Yrs (end 2011)	Avista Engineering Preliminary Estimate
Little Falls 3 Upgrade	2016	1.0	3,200		2	0.0	n/a	0.00	n/a	n/a	100	100	61.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 10 Yrs (end 2011)	Avista Engineering Preliminary Estimate
Little Falls 4 Upgrade	2017	1.0	1,300		2	0.0	n/a	0.00	n/a	n/a	100	100	61.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 10 Yrs (end 2011)	Avista Engineering Preliminary Estimate
Post Falls 6 Upgrade	2018	0.2	5,000		2	0.0	n/a	0.00	n/a	n/a	100	100	50.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 10 Yrs (end 2011)	Avista Engineering Preliminary Estimate
Upper Falls Upgrade	2019	2.0	3,500		3	0.0	n/a	0.00	n/a	n/a	100	100	90.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 10 Yrs (end 2011)	Avista Engineering Preliminary Estimate
Long Lake 5 Addition	2020	24.0	2,167		5	1.0	n/a	0.00	n/a	n/a	100	100	30.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 10 Yrs (end 2011)	Avista Engineering Preliminary Estimate
Long Lake 2nd Powerhouse	2020	60.0	2,000		6	2.0	n/a	0.00	n/a	n/a	100	100	2.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 10 Yrs (end 2011)	Avista Engineering Preliminary Estimate
Cabinet Gorge Unit 5	2016	60.0	1,417		5	2.0	n/a	0.00	n/a	n/a	100	100	12.5	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 10 Yrs (end 2011)	Avista Engineering Preliminary Estimate
Pumped Storage	2020	25	5,000		8	5.0	n/a	Off-Peak Market	n/a	n/a	100	100	50.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	No	Avista Engineering Preliminary Estimate
Hydrokinetics	2014	5	4,000		3	3.0	n/a	0.00	n/a	n/a			75.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 10 Yrs (end 2011)	Avista Engineering Preliminary Estimate
Run of River Hydro	2020	N/A	4,500		5	2.0	n/a	0.00	n/a	n/a	100	100	30.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	HALF PTC- 10 Yrs (end 2011)	Avista Engineering Preliminary Estimate

Scenarios and Futures

John Lyons

Uses of Scenarios and Futures

Provide details about impacts and size of impacts of different assumptions

- Avista's current load and resource portfolio
- Preferred Resource Strategy
- Wholesale electric market
- Different resource options

Market Scenarios

- Starts with the Base Case assuming expected conditions
  - Hydro
  - Load
  - Gas prices
  - Wind
  - Emissions prices
  - Forced outages
- Scenarios study the effects of fundamental changes to a driving force in the forecast
- Scenarios have quicker solution times and provide more understandable results due to the limited change in variables
- Used to test portfolio sensitivities

Market Futures

- A future is a stochastic or random study using Monte Carlo style analysis for risk quantification
- Multiple iterations provide a shape and boundaries to potential costs
- Avista’s modeling process looks 21 years into the future with several hundred draws of hydro, load, wind, fuel prices, emissions costs, and thermal forced outage values
- Futures can quantitatively assess market risk
- Use a large amount of computational power for each future
- Results are sometimes difficult to understand because of the sheer number of variables

2009 IRP Market Futures

- **Base Case:** uses expected hydro, wind, load, fuel costs, and emissions costs
- **Unconstrained Carbon:** quantifies CO_2 emissions costs
- **High CO_2 Costs:** higher expected value of CO_2 emissions costs
- **Volatile Fuel:** increase natural gas price volatility

2009 IRP Market Scenarios

- **High and Low Gas Prices:** 50% higher and 50% lower prices
- **CO_2 and Natural Gas:** different levels of linkage between CO_2 and natural gas prices
- **High and Low Load Growth**
- **Electric Car:** high penetration of electric cars
- **Constant Gas Growth:** No downward trend in near term gas prices
- **Unconstrained Carbon Costs:** zero carbon costs
- **High Carbon Costs:** significantly higher than the Base Case
- **Nuclear:** significant new nuclear in the Western Interconnect
- **Buck-a-Watt Solar:** drastic decrease in photovoltaic solar costs

2009 IRP Portfolio Options

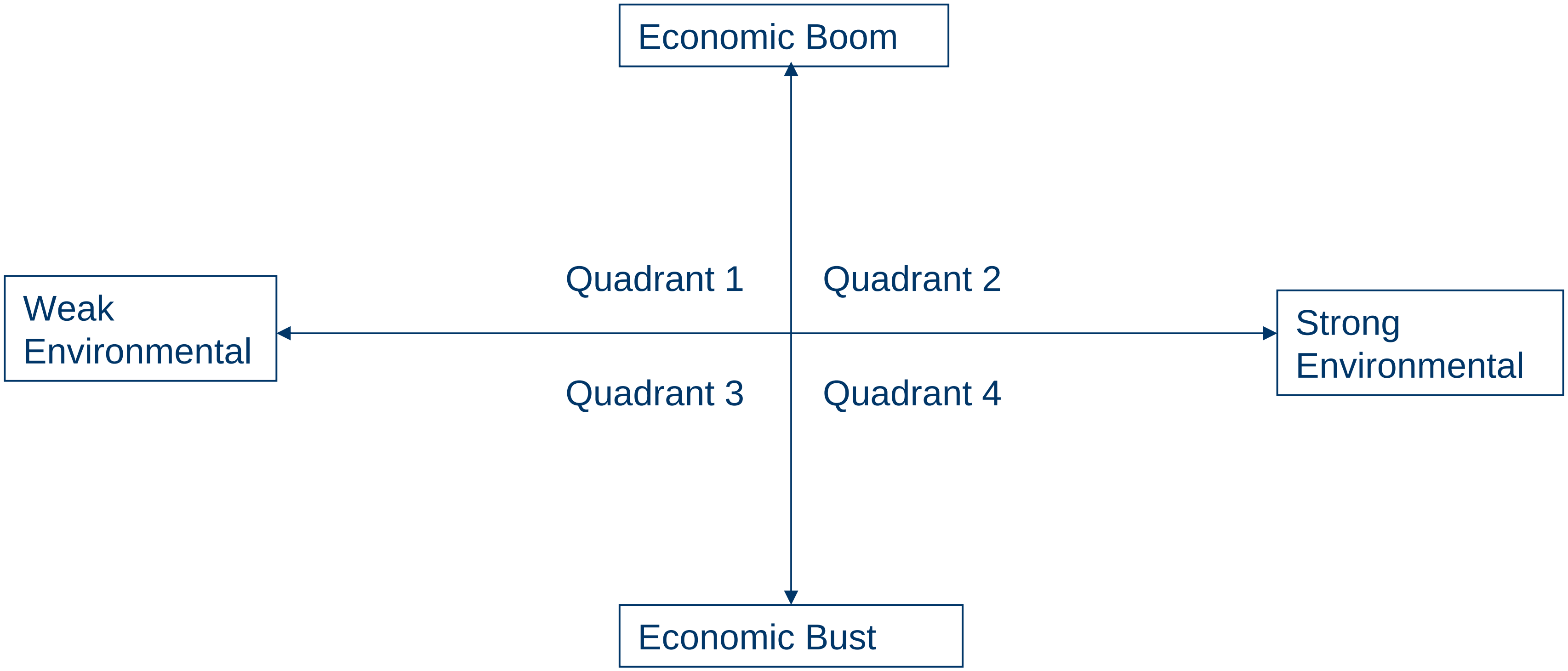
- **Efficient frontier**
- **No Resource Additions –** market reliance
- **All CT –** with and without green tags
- **All CCCT –** with and without green tags
- **Fixed Gas –** with and without
- **All Renewables**
- **Wind and CT**
- **Nuclear –** available in 2020
- **Coal –** available in 2018
- **2007 IRP**
- **Others?**

New Scenario Approach

- Previous slides show Avista's past approach to scenarios and futures
- This approach is difficult to use to adjust our resource strategy
- Moving towards a smaller number of scenarios, where each scenario represents a fundamentally different future with its own assumptions
- Scenario matrix with the economy and environmental concerns

1. **Base Case –** center of the matrix
2. **Quadrant 1 –** Economic Boom and Weak Environmental
3. **Quadrant 2 –** Economic Boom and Strong Environmental
4. **Quadrant 3 –** Economic Bust and Weak Environmental
5. **Quadrant 4 –** Economic Bust and Strong Environmental

Scenario Matrix – Environmental Regulation and Economics



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Potential Scenario Drivers

- **Economic –** inflation, load, commodities, and market developments
- **Environmental –** carbon costs, RPS, and competition for renewables
- **Political –** structure of carbon market
- **Social –** views of environmental issues and response of customers to rate pressure
- **Technological –** help or hindrance, new technologies, and electric cars
- **Organizational –** business as usual, new ways of doing things

Demand-Side Management in the 2009 Electric IRP

Jon Powell

DSM / IRP Objectives

Opportunity to perform a comprehensive overview of electric resource opportunities and strategy on a level playing field

DSM Challenges in the IRP

- IRP results must be actionable to be meaningful
- The IRP must provide the basis for continual evaluation of DSM opportunities between IRP cycles
- "Normal" technical challenges of assessing DSM resources within the IRP

How Avista Addresses Challenges

- The biennial high-level IRP process is augmented with an annual detailed DSM business plan
- Our tariffs are reasonably flexible in the short-term; even more flexible in the long-term
- The IRP avoided cost stream forms the basis for intra-IRP DSM resource analysis and cost-effectiveness

Annual DSM Business Plan

- Establishes a corporate budget
- Allows for the detailed review of DSM opportunities
- Considers the packaging of measures
- Establishes a high-level program plan for promising measures:
  - Infrastructure requirements (labor and non-labor)
  - Outreach requirements (brochures, paid and free media, etc)
  - Establishes critical trade allies relationships (including potential regional cooperative efforts)
- Program trigger points are established
- Plan for the M&E necessary for program management and external reporting
- Calculate prospective cost-effectiveness (program and portfolio)

DSM Tariffs and Operations

- Tariffs can, and have, changed to meet resource acquisition needs
- DSM operations governed by Schedule 90 and funded by Schedule 91
- Tariffs allow for the inclusion of any measure into the DSM portfolio
- Four basic portfolio's within Avista's DSM operations

1. Non-Residential – mix of "site-specific" and prescriptive programs
2. Residential – exclusively prescriptive programs
3. Residential Limited Income – any measure cooperating with CAP agencies
4. Regional – NEEA's market transformation portfolio

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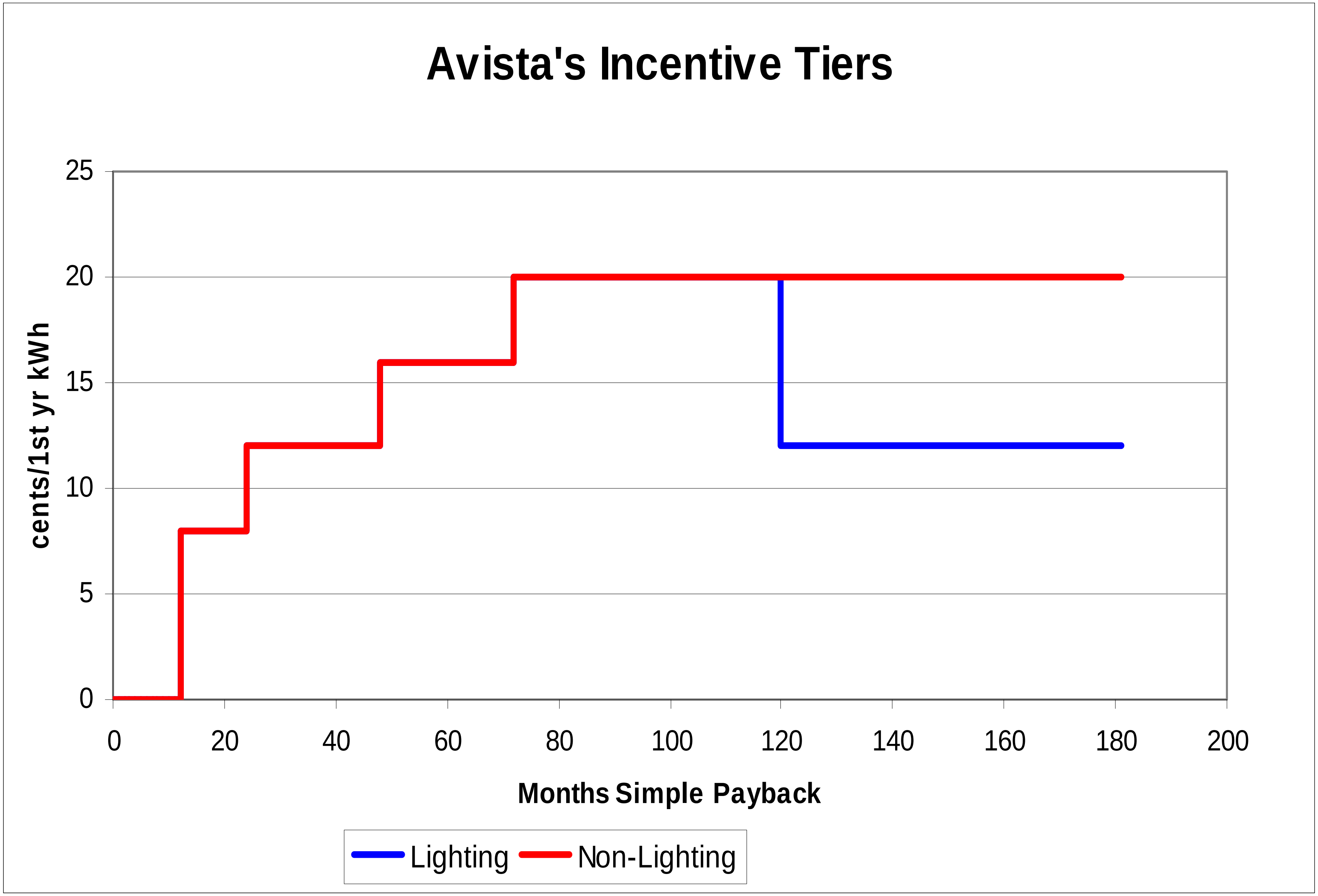

Avista's Incentive Tiers
25
20
15
10
5
0
cents/1st yr kWh
0
20
40
60
80
100
120
140
160
180
200
Months Simple Payback
Lighting
Non-Lighting

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Electric Avoided Costs

- Price is an efficient means of signaling resource scarcity
- Avoided cost composed of:
  - Commodity avoided cost ($/kWh)
  - Distribution losses ($/kWh)
  - Carbon cost ($/kWh)
  - Value of risk reduction ($/kWh)
  - Generation capacity ($/kW)
  - T&D capacity ($/kW)

Demand-Side Management in the 2009 Electric IRP

Lori Hermanson

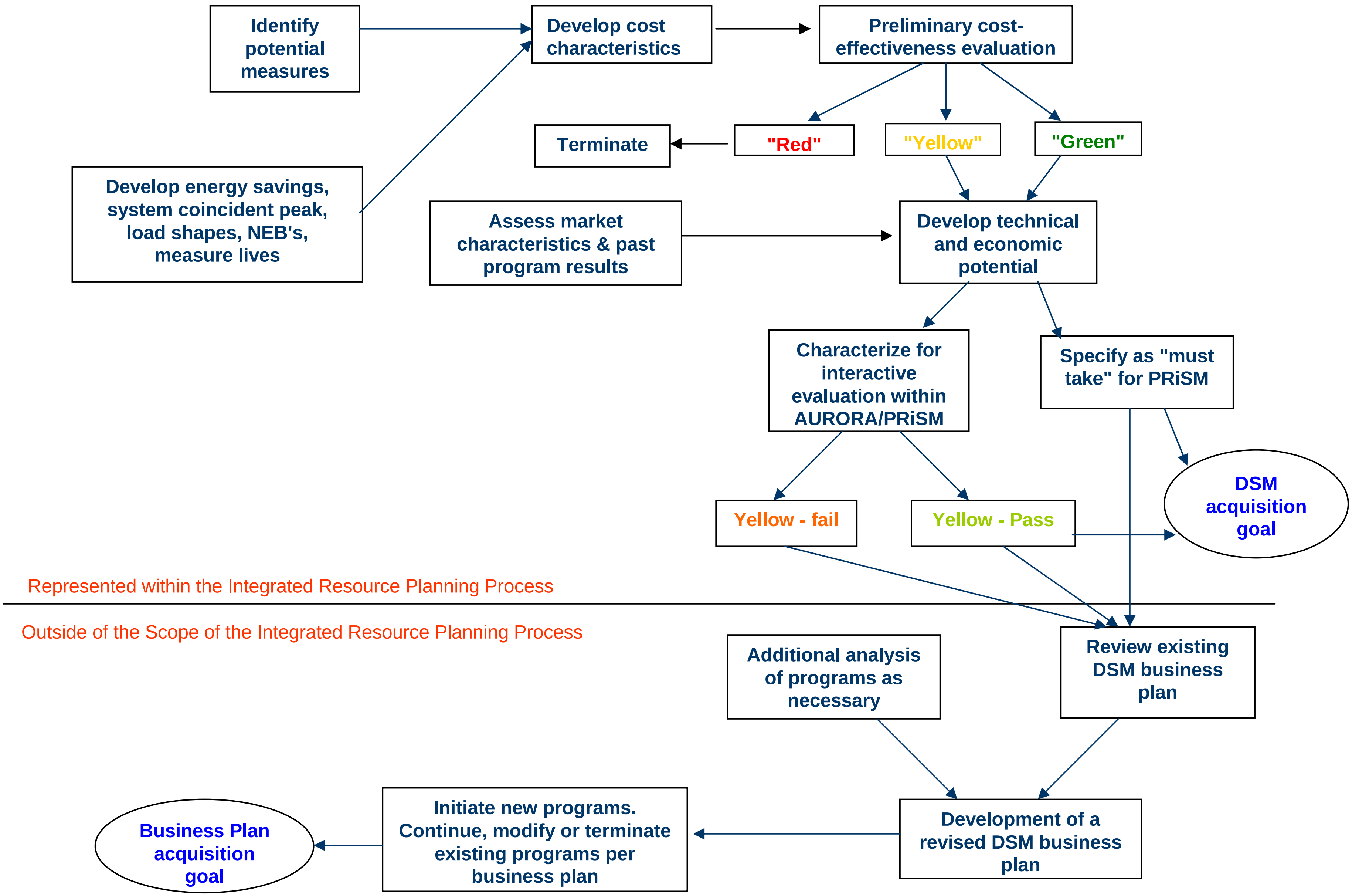
Integration of DSM into the 2009 IRP

Interactive process that meets regulatory requirements and produces results for the business planning process.

- Identify commercially available non-residential technologies and applications
  - "Acceptance" or "rejection" within the IRP will not remove any technology or application from potentially being included in our non-residential portfolio
  - Almost 2,500 measures being evaluated for the 2009 IRP
- Re-evaluate existing residential measures and evaluate the inclusion of additional measures
  - May change the menu of qualifying residential measures.
  - Nearly 800 measures being evaluated for 2009

Integration of DSM into the 2009 IRP

- Inclusion of Limited Income and Non-Residential Site Specific programs are done by modifying the historical baseline
  - Not necessarily limited to modifying baseline for price elasticity and load growth
- Improvements in estimating Site Specific programs
  - Identified the largest portion of Site Specific programs and are trying to make them more generic in nature
  - Can process more Non-Residential programs through the entire IRP process as opposed to modifying a historical base


Identify potential measures
Develop cost characteristics
Preliminary cost-effectiveness evaluation
Terminate
"Red"
"Yellow"
"Green"
Develop energy savings, system coincident peak, load shapes, NEB's, measure lives
Assess market characteristics & past program results
Develop technical and economic potential
Characterize for interactive evaluation within AURORA/PRiSM
Specify as "must take" for PRiSM
DSM acquisition goal
Yellow - fail
Yellow - Pass
Represented within the Integrated Resource Planning Process
Outside of the Scope of the Integrated Resource Planning Process
Additional analysis of programs as necessary
Review existing DSM business plan
Business Plan acquisition goal
Initiate new programs. Continue, modify or terminate existing programs per business plan
Development of a revised DSM business plan

Categories of Savings and Benefits

- Obtain savings, system coincident peak savings, incremental customer cost, non-energy benefits and life of each measure
  - Used to calculate a levelized sub-TRC cost
  - Sorted based on results into “reds,” “yellows” and “greens”
  - Band of “yellow” energy only measures to be tested in AURORA is projected to be $70-150/MWh
  - PRiSM automatically selects “greens”
  - Remainder of need is selected from passing “yellows”
  - Establishes the 2009 DSM acquisition goal

Integration of DSM into the 2009 IRP

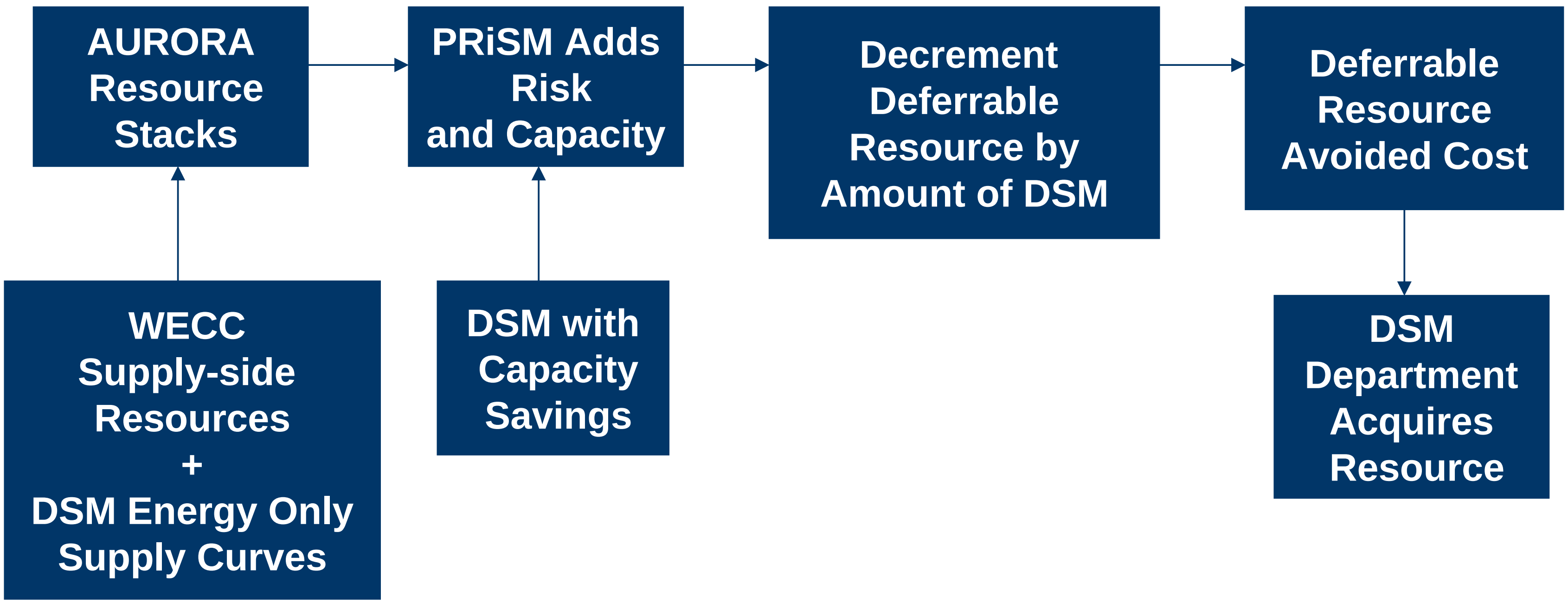
- Last year was the first focus on deferring summer space cooling-driven load
  - Load profiles were assigned to each measure
  - Measures categorized by impact to cooling load
    - Zero impact – measures received no additional value regardless of their load profile
    - Non-Drivers – measures unrelated to space cooling but contribute to system load during a cooling-driven peak receive a capacity value based upon the average demand of their specific load profile during peak periods

Space Cooling

- Drivers – measures that drive a space cooling peak received a capacity valuation based upon the maximum hourly demand for that load profile
- Improving method of addressing the space cooling driven peak
  - Using the Council's system coincident peak estimates
  - Measures with capacity savings will be tested in PRiSM against the avoided costs inclusive of risk and capacity
  - PRiSM will select measures and they will be incorporated into the final DSM acquisition goal

Incorporating DSM in the 2009 IRP

Integration by Price Signal



What Works – What Doesn't

- DSM is acquired in small annual amounts relative to the overall load requirement
  - "Snowballing" effect over time
- Historically Avista's DSM has been non-dispatchable
  - Demand Response pilot
  - When enough data is available, modifications to this existing process may need to be made to accommodate demand response technologies and applications
- Allows continuous modification and testing of new opportunities between IRPs in a consistent manner

Avista's 2009 Electric Integrated Resource Plan
Technical Advisory Committee Meeting No. 3 Agenda
October 22, 2008

	Topic	Time	Staff
1.	Introduction	10:30	Vermillion
2.	Load Forecast	10:35	Barcus
3.	Lunch	11:45	
4.	Natural Gas Price Forecast	12:30	Rahn
5.	Electric Price Forecast	1:30	Gall
6.	Legislative Update	2:30	Sprague
7.	Adjourn	3:30	

F2009 Sales and Load Forecast

July 21, 2008 Operations Council Meeting

Randy Barcus

Edited for 2009 Electric Integrated Resource Plan

Third Technical Advisory Committee Meeting

October 22, 2008

Summary of Results

Electricity Sales Forecast

- 2009 Forecast 9,138 million kWh
- 2009 in F2008 9,134 million kWh
- 5 Year Growth Rate 2009-2014 +1.8%
- 10 Year Growth Rate 2009-2019 +1.7%
- 20 Year Growth Rate 2009-2029 +1.7%
- Last Year 20 Yr. GR 2009-2029 +1.8%

Natural Gas Firm Sales Forecast

- 2009 Firm Forecast 338.5 million therms
- 2009 in F2008 352.0 million therms
- 5 Year Growth Rate 2009-2014
  - Washington -0.2%
  - Idaho +1.0%
  - Oregon +0.8%
  - System +0.3%
- 10 Year GR System +0.9%
- 20 Year GR System +1.3%
- 20 Year Customer GR +2.5%

Significant Assumptions

Economy—slower growth in near term, returns to trend

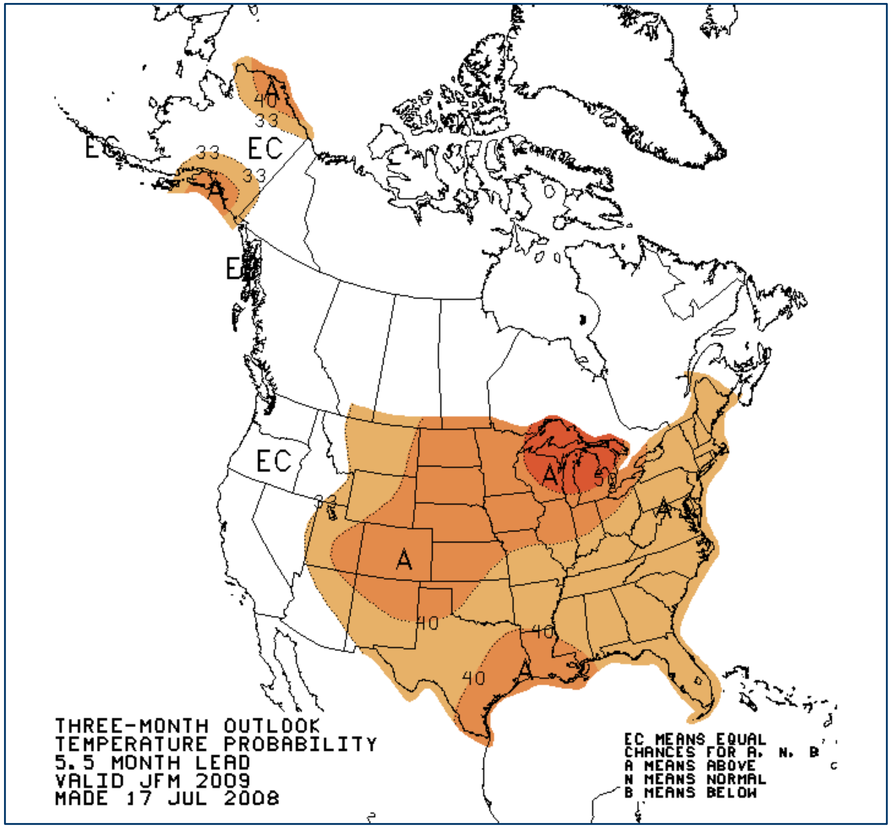
- Tight credit, housing bubble, but strong commodity prices for agriculture and metals
- Regional economy returns to long term trend in 2012

Avista Retail Prices

- Electric prices increase 10% in 2009 and thereafter until 2015, and at inflation plus real income growth thereafter
- Natural gas prices increase 20% in 2009 and 10% thereafter until 2015, and at inflation plus real income growth thereafter
- Carbon taxes are included in the 2012-2015 price increases

Global Warming Degree Days

- 2009 Heating and Cooling at NOAA Normal (1971-2000 avg.)
- 2010-2019 ramps to trend, 2020-2029 on trend



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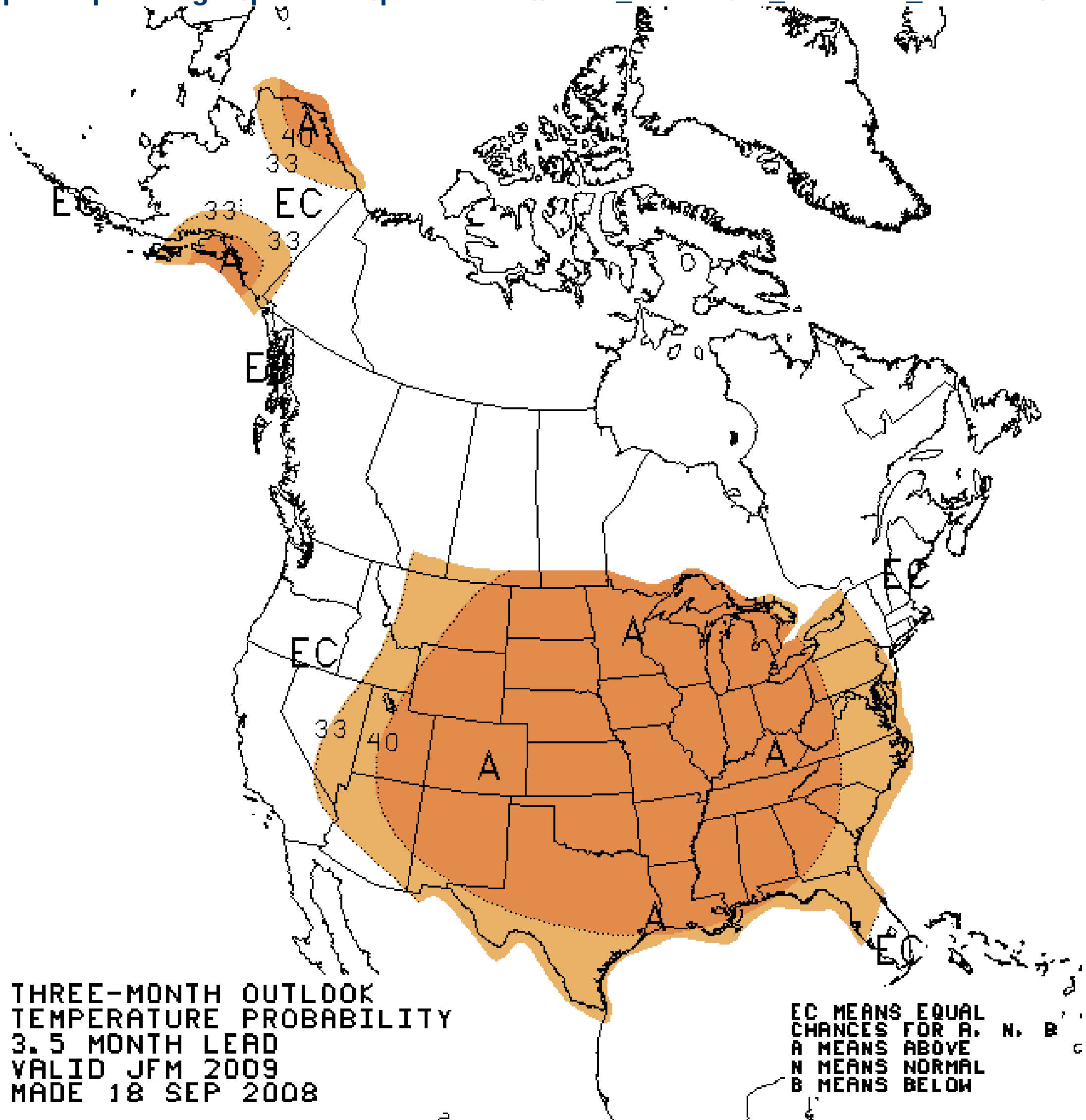
http://www.cpc.ncep.noaa.gov/products/predictions//multi_season/13_seasonal_outlooks/color/churchill.php



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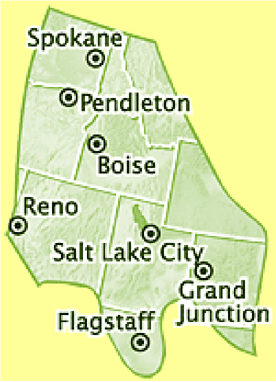
The OLD FARMER'S ALMANAC



Intermountain
Annual Weather Summary
November 2008 to October 2009

Winter will be much colder and drier than normal, on average, with snowfall above normal in the north and below normal in the south. The coldest temperatures will occur in late December; early, mid-, and late January; and early February. The snowiest periods will be in mid-November, early and mid-December, mid- and late January, and late February.

April and May will be cooler than normal, with slightly above-normal precipitation.

Summer will be cooler than normal, with slightly above-normal rainfall. The hottest periods will be in mid- and late June and early and mid- to late July.

September and October will be warmer and drier than normal.

http://www.almanac.com/weatherforecast/us/13

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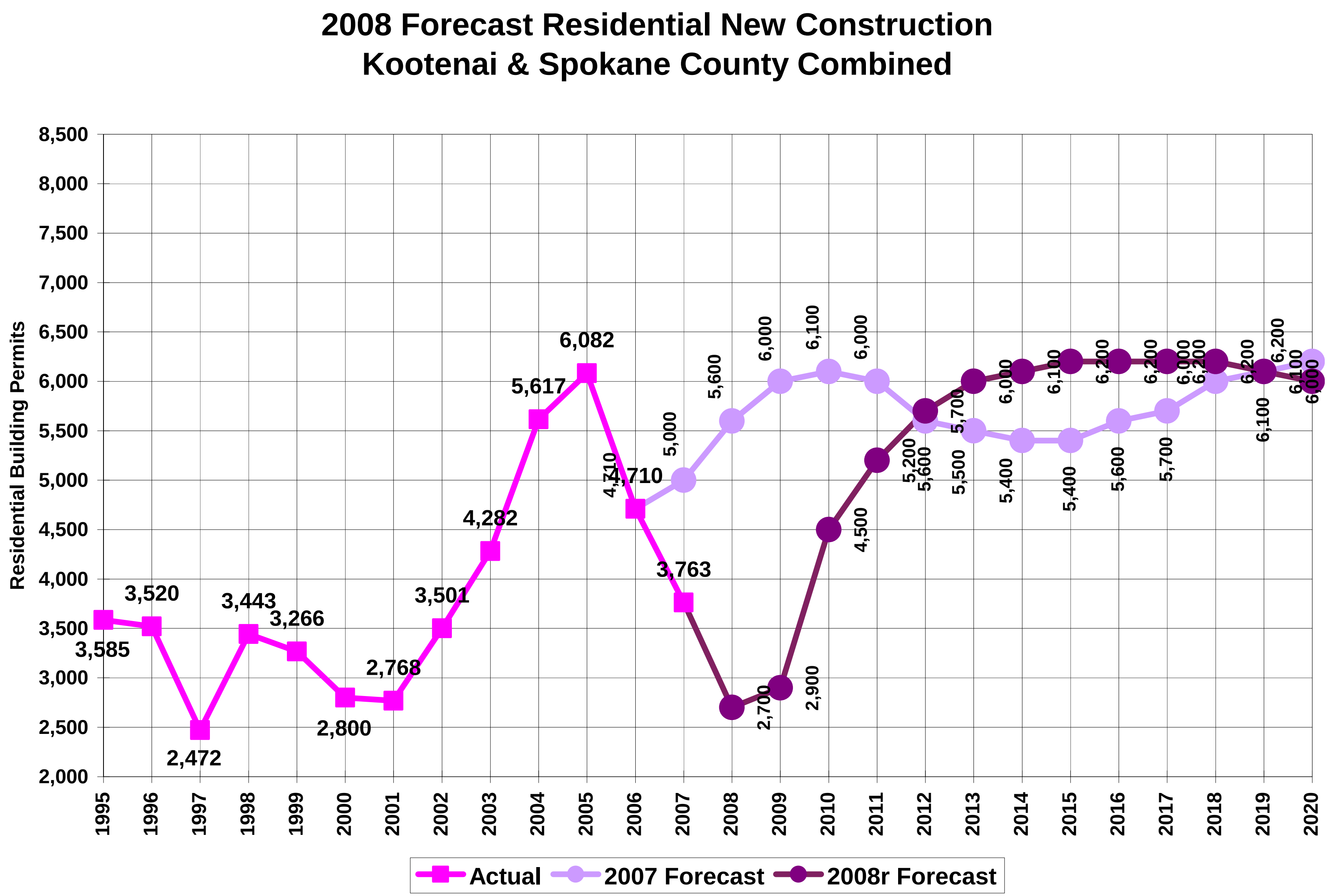
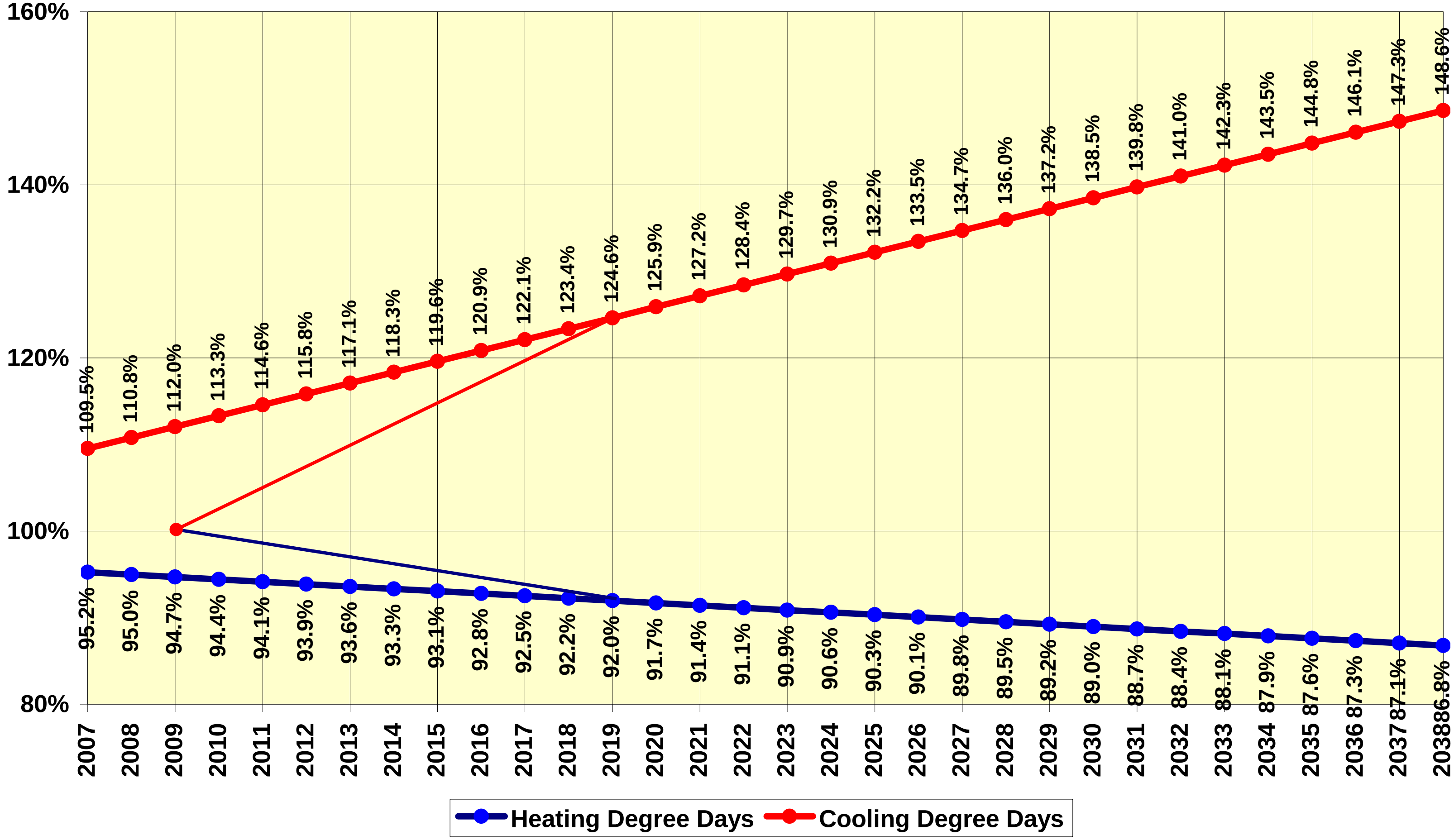
Other Assumptions

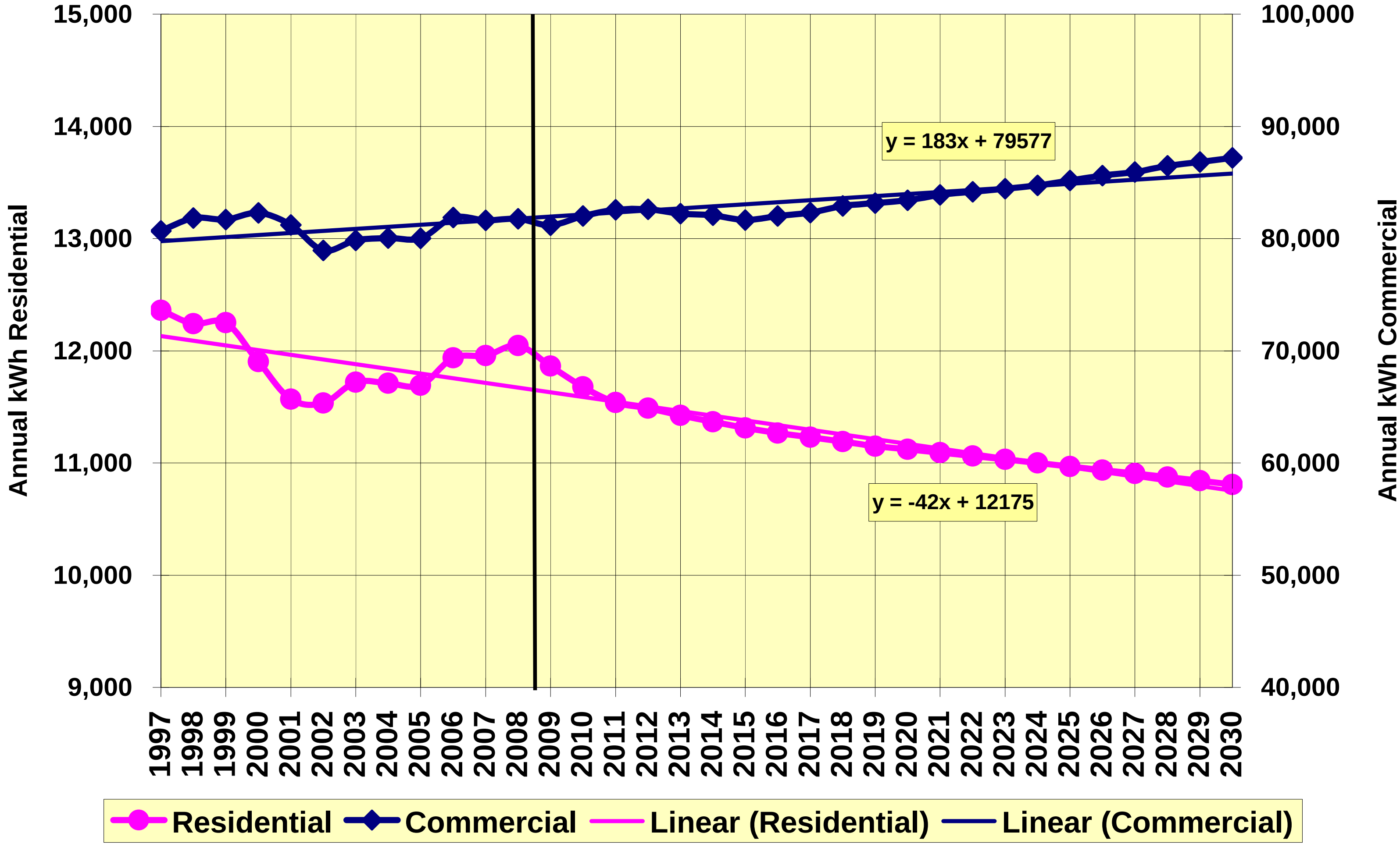
- **DSM and Conservation—included in forecast at new levels**
- **Multi-Family Natural Gas—assuming successful penetration**
- **Inland Empire Paper—12 average MW added load in 2010**
- **Mining Loads—continued high silver prices lead to modest growth**
- **Lumber Loads—low levels through 2009, some bounce in 2010**
- **Plug-In Hybrid Cars—included in forecast**
- **Other implicit assumptions**
  - Housing mix 40% single family, 30% condo/townhome, 30% multifamily rental
  - Average new construction size is 30% larger than present average
  - Growing plug loads (largely digital TV's) offset Energy Star savings
  - The Energy Independence and Security Act of 2007 contains provisions that significantly impact electricity use, particularly residential lighting usage, over the next 5 to 10 years. The key lighting-related provisions that related to energy forecasters are:
    - Incandescent Light Bulb Standard. Requires roughly 25 percent greater efficiency for light bulbs, phased in from 2012 through 2014. This effectively bans the sale of most current incandescent light bulbs. The initial targets will be met by advanced incandescent lamps, which the major manufacturers are just introducing to the market, using halogen capsules with infrared reflective coatings. The longer-term targets will likely be met by compact fluorescent lamps and other advanced technologies, such as light emitting diodes and very advanced incandescent lamps now in development.
    - Lighting Efficiency Standard. Requires a minimum 45 lumens/watt efficiency standard for general service lamps by 2020.
    - Federal Building Lighting Standard. Requires that all lighting in Federal buildings use Energy Star products.
  - The Energy Information Administration's 2008 Annual Energy Outlook (AEO) forecast provides insight into the impact that these provisions will have on residential lighting use. The 2008 Residential AEO forecast projects that lighting's share of total residential electricity usage will drop from 14.4% in 2011, the year before the incandescent light bulb standard takes place, to 10.7% in 2016. Over this five year period, lighting's share of electricity usage is projected to drop by approximately 25%.
  - The long-run effect of the lighting standards on residential electricity usage is to decrease residential lighting share of usage to 8.3% by 2030, a reduction of over 40% from its 2011 level of 14.4%.


2008 Forecast Residential New Construction
Kootenai & Spokane County Combined
Residential Building Permits
8,500
8,000
7,500
7,000
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
3,585
3,520
2,472
3,443
3,266
2,800
2,768
3,501
4,282
5,617
6,082
4,710
3,763
5,000
5,600
6,000
6,100
6,000
5,600
5,500
5,400
5,400
5,600
5,700
6,000
6,100
6,200
2,700
2,900
4,500
5,200
5,700
6,000
6,100
6,200
6,200
6,200
6,200
6,100
6,000
Actual
2007 Forecast
2008r Forecast

Spokane NWS Global Warming Degree Day Trends 2007-2038



Electric Average Use per Average Customer



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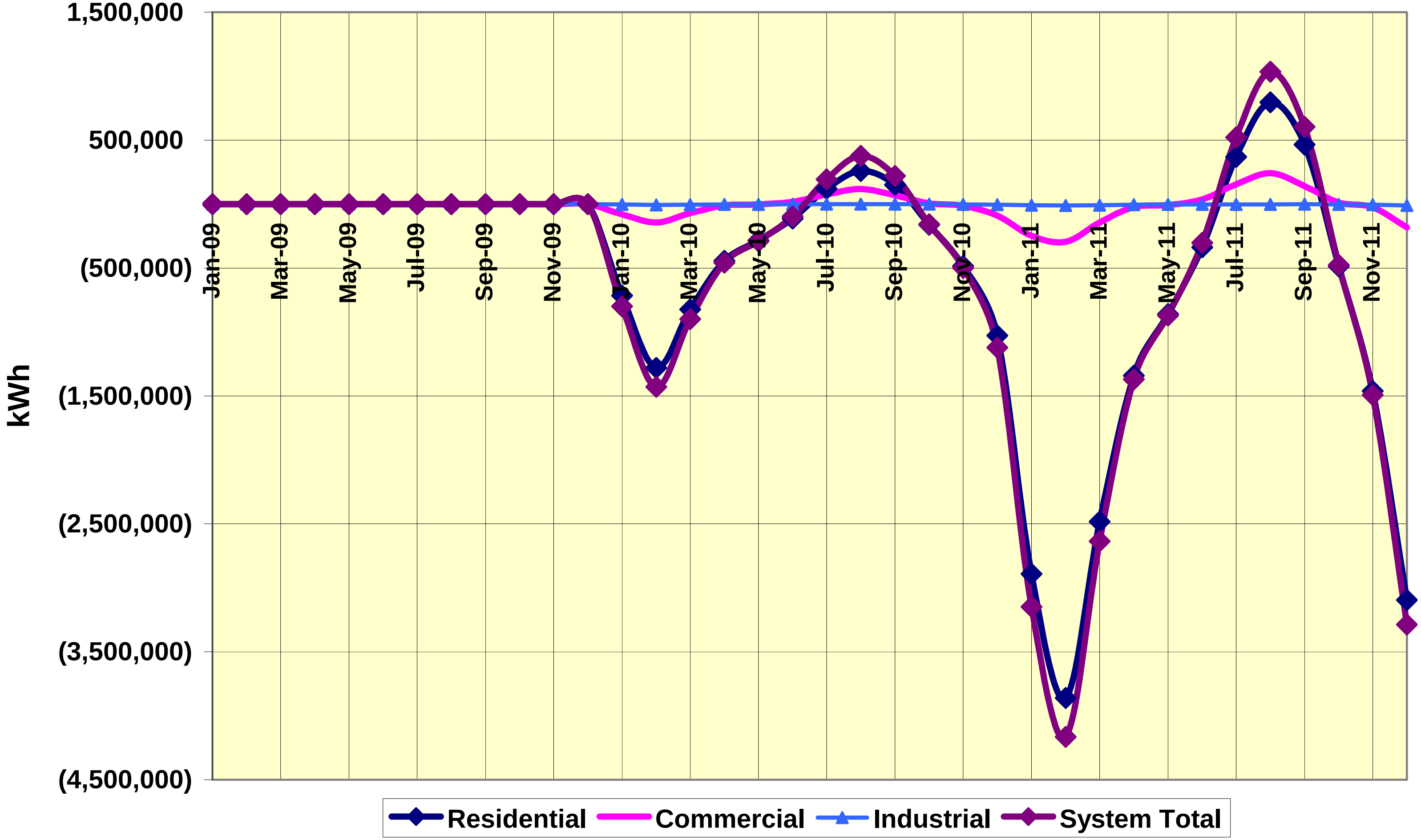
Global Warming Impact

Normal minus Warming HDD and CDD



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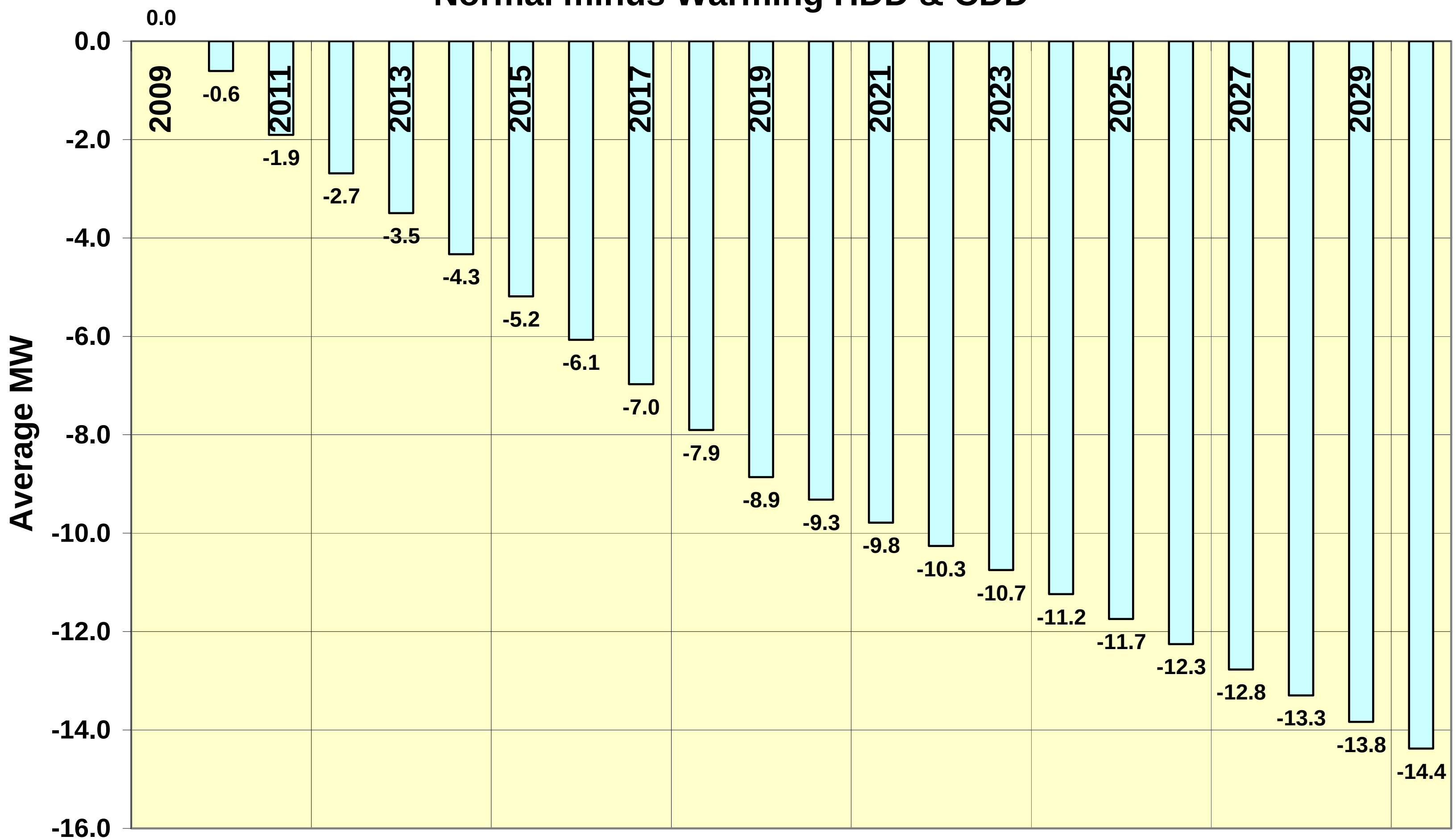
MW Difference

Normal minus Warming HDD & CDD



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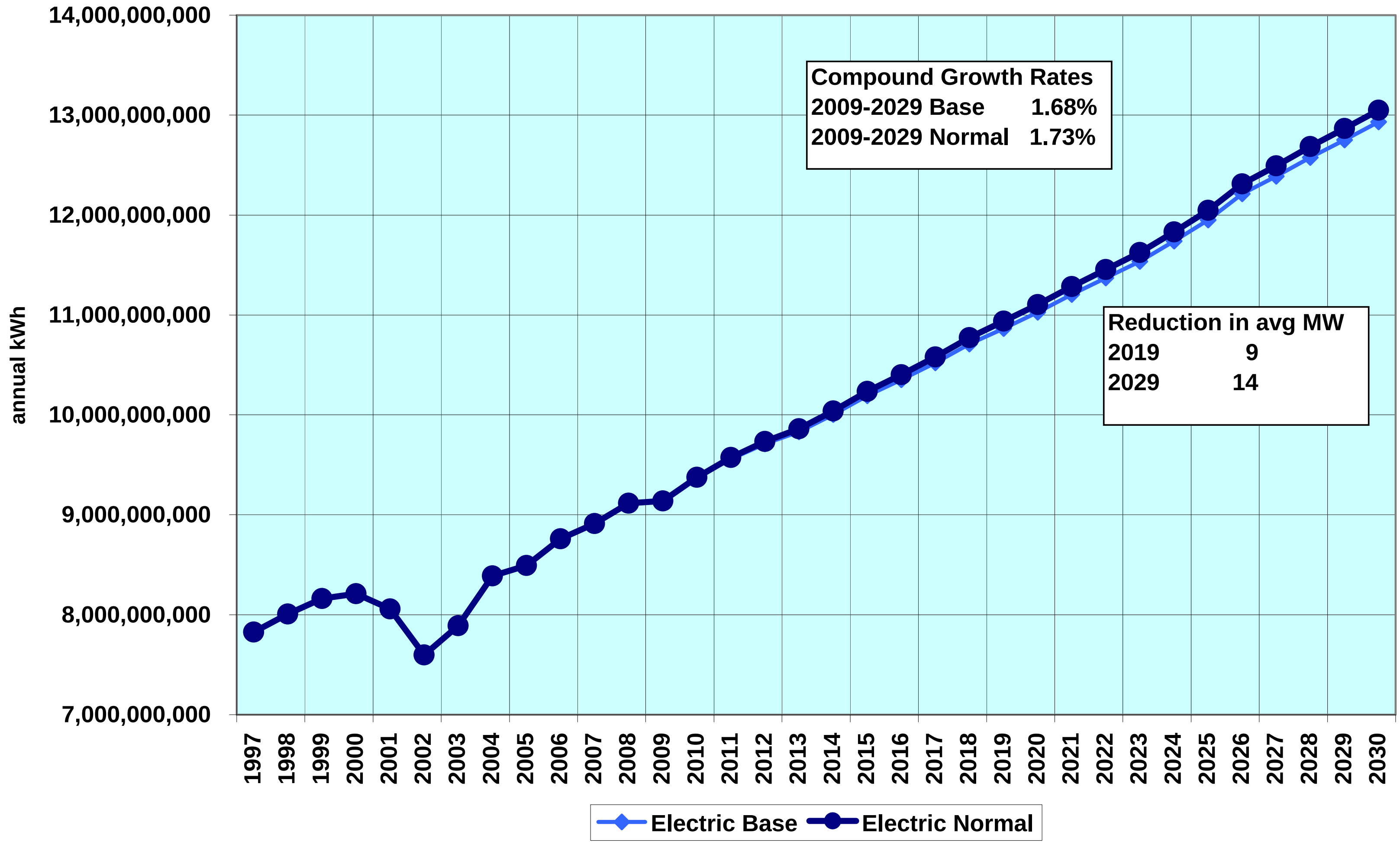
Electric Sales Forecast Base w/ GW vs. Normal Weather



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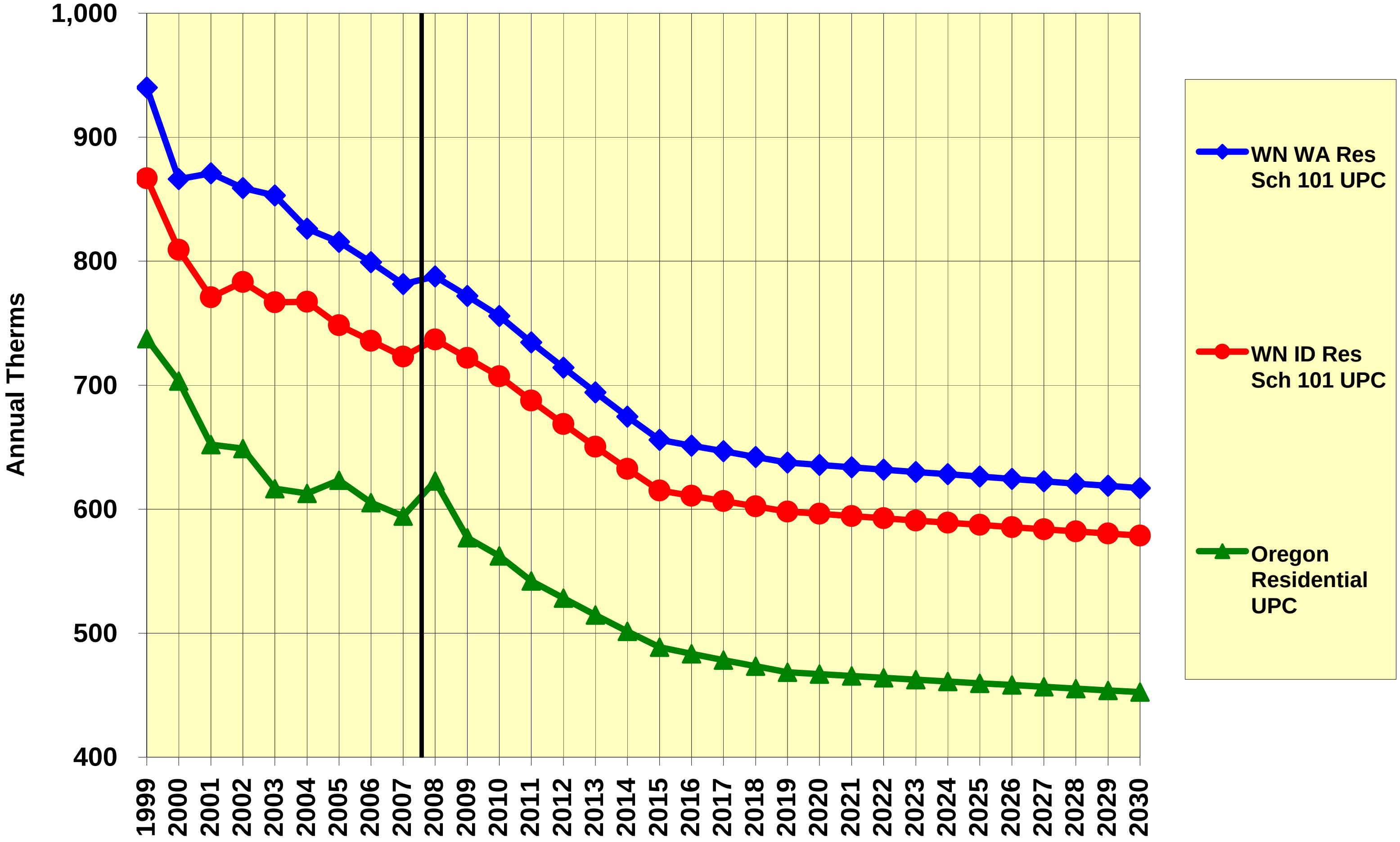
Avista Residential by Schedule

Therm Use Per Customer



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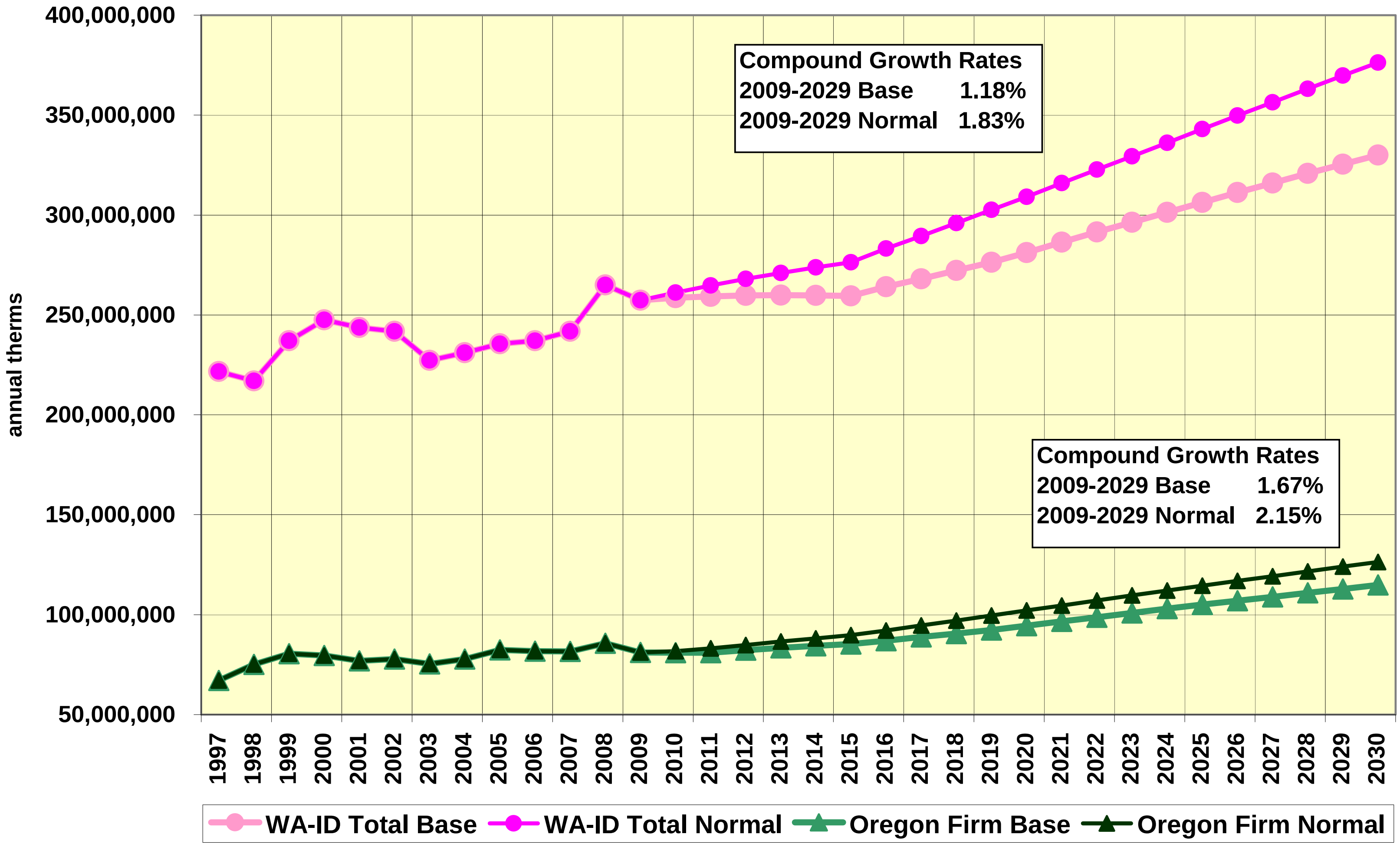
WA-ID & Oregon Natural Gas Base w/GW vs. Normal Weather



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Avista Electric Service Area Plug-In Hybrid Car Sales Forecast

	Market Share	Hybrid Vehicles Served	Incremental Sales of Hybrid Vehicles	kWh Energy Consumption	Average MW	Base Case Residential Sales Forecast	Cumulative Percent Boost to Residential	Residential Sales with Hybrid Vehicles
2010	3.5%	1,000	1,000	2,500,000	0.3	3,761,638,997	0.1%	3,764,138,997
2011	6.0%	2,000	1,000	5,000,000	0.6	3,788,118,462	0.1%	3,793,118,462
2012	8.5%	3,500	1,500	8,750,000	1.0	3,842,900,187	0.2%	3,851,650,187
2013	11.0%	5,500	2,000	13,750,000	1.6	3,893,034,524	0.4%	3,906,784,524
2014	14.0%	8,000	2,500	20,000,000	2.3	3,941,757,508	0.5%	3,961,757,508
2015	18.0%	11,000	3,000	27,500,000	3.1	3,988,061,420	0.7%	4,015,561,420
2016	24.0%	15,000	4,000	37,500,000	4.3	4,034,409,825	0.9%	4,071,909,825
2017	26.0%	20,000	5,000	50,000,000	5.7	4,079,468,146	1.2%	4,129,468,146
2018	26.0%	25,000	5,000	62,500,000	7.1	4,123,323,408	1.5%	4,185,823,408
2019	26.0%	30,000	5,000	75,000,000	8.6	4,167,601,524	1.8%	4,242,601,524
2020	26.0%	35,000	5,000	87,500,000	10.0	4,215,588,573	2.1%	4,303,088,573
2021	26.0%	40,000	5,000	100,000,000	11.4	4,261,378,267	2.3%	4,361,378,267
2022	26.0%	45,000	5,000	112,500,000	12.8	4,306,622,849	2.6%	4,419,122,849
2023	26.0%	50,000	5,000	125,000,000	14.3	4,351,888,063	2.9%	4,476,888,063
2024	26.0%	55,000	5,000	137,500,000	15.7	4,396,064,205	3.1%	4,533,564,205
2025	26.0%	60,000	5,000	150,000,000	17.1	4,439,711,711	3.4%	4,589,711,711
2026	26.0%	65,000	5,000	162,500,000	18.6	4,481,771,729	3.6%	4,644,271,729
2027	26.0%	70,000	5,000	175,000,000	20.0	4,523,907,789	3.9%	4,698,907,789
2028	26.0%	75,000	5,000	187,500,000	21.4	4,564,967,067	4.1%	4,752,467,067
2029	26.0%	80,000	5,000	200,000,000	22.8	4,605,531,184	4.3%	4,805,531,184
2030	26.0%	85,000	5,000	212,500,000	24.3	4,645,605,390	4.6%	4,858,105,390
2,500 kWh per car		80% WA	20% ID		2010-2030 CGR	1.06%		1.28%

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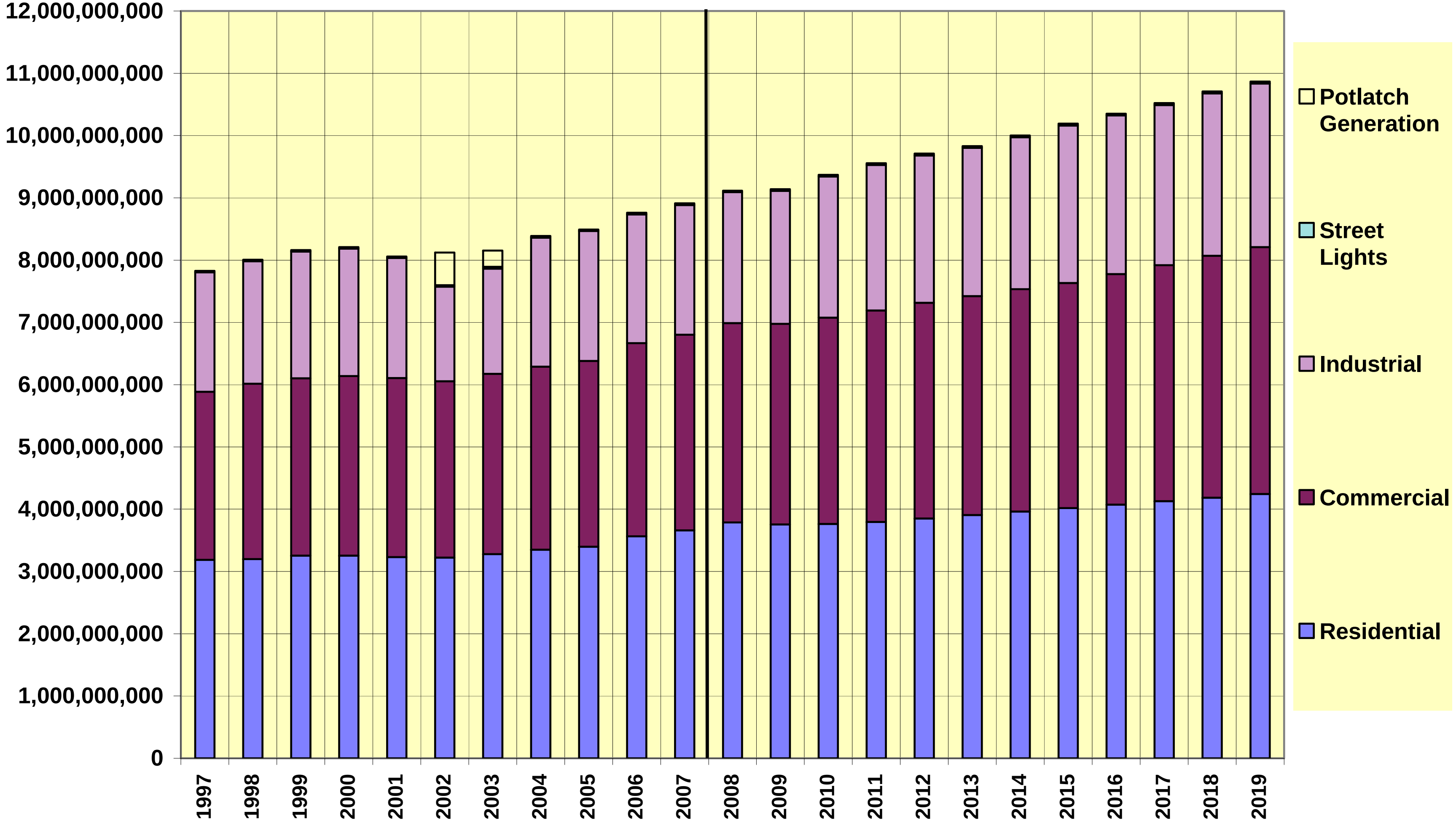
2009 ELECTRIC RETAIL SALES FORECAST



2009-2019 growth rate = 1.75%, 2009-2029 growth rate =1.68%

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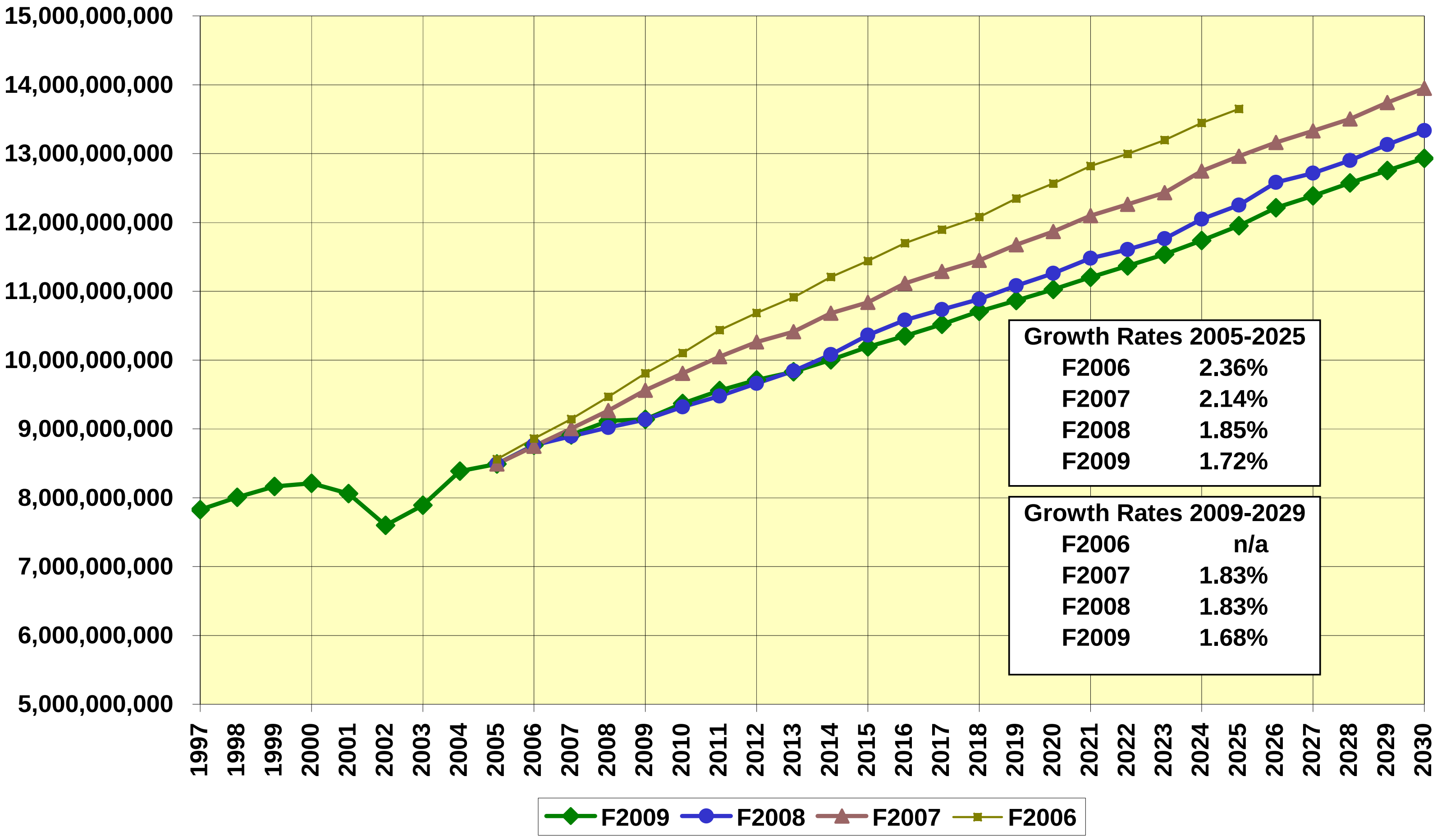
Load Growth Comparisons

(plug-in hybrid car consumption is included)



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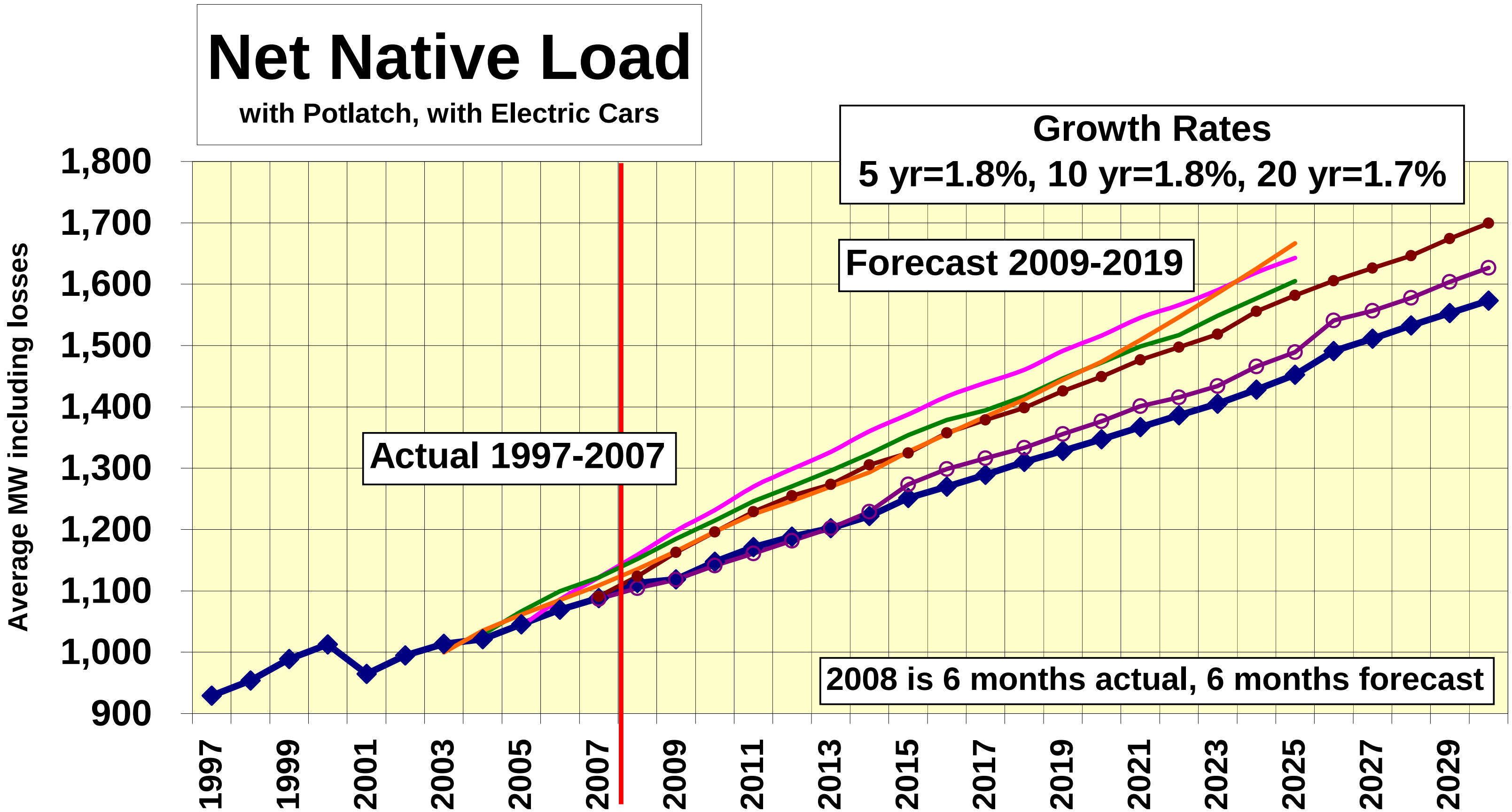

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
F2009	929	954	989	1,013	965	995	1,013	1,021	1,046	1,069	1,088	1,113	1,119	1,148	1,171	1,188	1,202
F2008											1,087	1,104	1,118	1,141	1,161	1,182	1,202
F2007IRP											1,091	1,124	1,163	1,196	1,229	1,255	1,274
F2006									1,043	1,086	1,122	1,159	1,198	1,232	1,270	1,299	1,327
F2005								1,029	1,067	1,099	1,122	1,152	1,185	1,215	1,246	1,270	1,296
F2004							1,000	1,035	1,061	1,085	1,109	1,135	1,164	1,196	1,225	1,247	1,270

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
F2009	1,222	1,252	1,270	1,289	1,311	1,329	1,347	1,367	1,386	1,405	1,428	1,452	1,491	1,511	1,533	1,553	1,573
F2008	1,229	1,274	1,299	1,316	1,333	1,356	1,376	1,401	1,416	1,434	1,466	1,489	1,541	1,556	1,577	1,604	1,627
F2007IRP	1,306	1,325	1,358	1,379	1,399	1,426	1,449	1,477	1,497	1,518	1,556	1,582	1,606	1,626	1,646	1,674	1,699
F2006	1,360	1,388	1,417	1,440	1,461	1,491	1,516	1,545	1,566	1,590	1,619	1,643					
F2005	1,323	1,354	1,379	1,395	1,417	1,447	1,472	1,499	1,517	1,549	1,577	1,605					
F2004	1,293	1,327	1,356	1,384	1,412	1,444	1,474	1,509	1,546	1,585	1,625	1,667					

F2009 F2008 F2007IRP F2006 F2005 F2004

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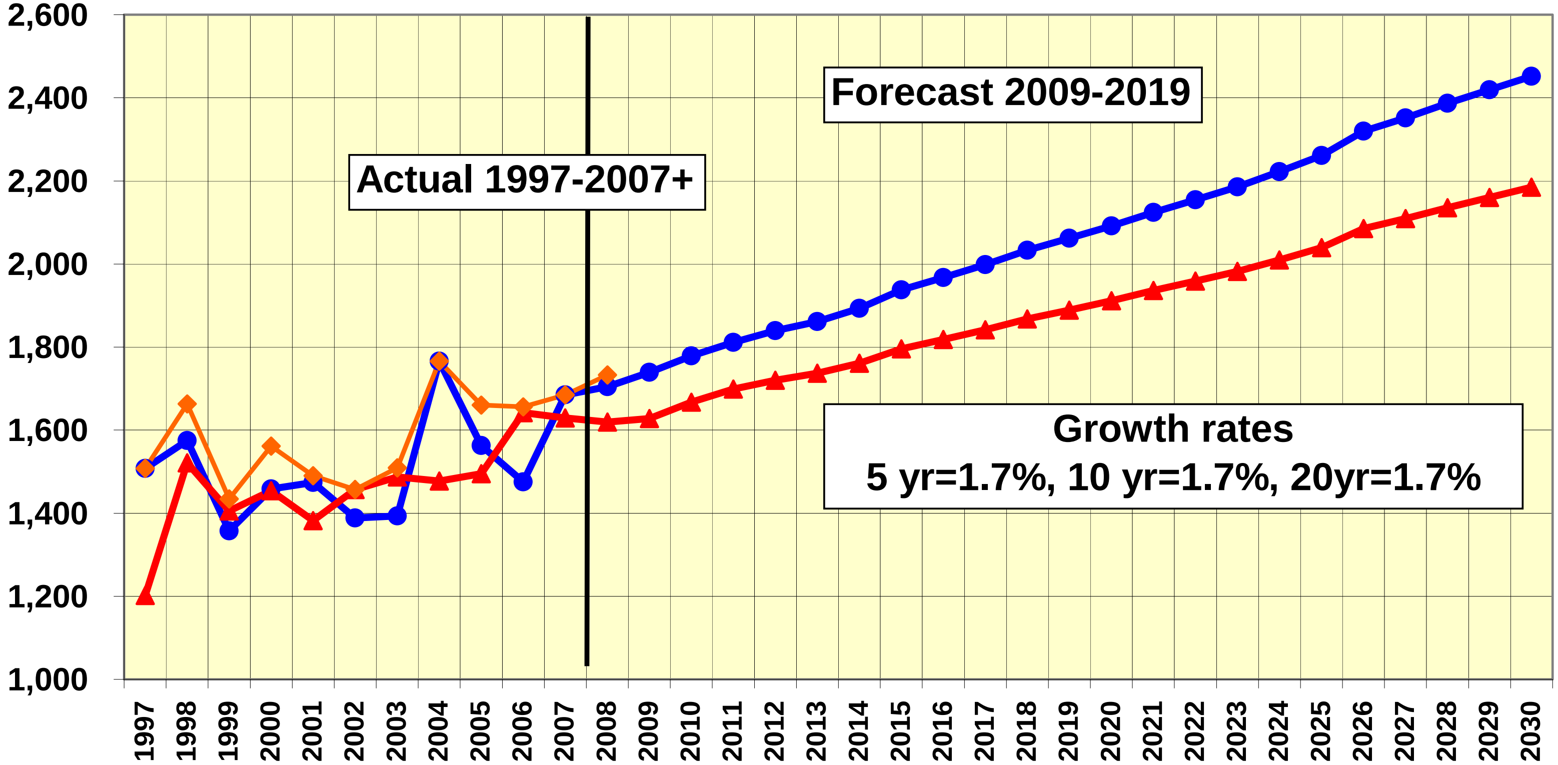
Calendar Year, January & July Peak Demands

Megawatts



	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Jan	1,508	1,575	1,357	1,458	1,474	1,388	1,393	1,766	1,563	1,475	1,685	1,705	1,739	1,779	1,812	1,839	1,862
Jul	1,202	1,521	1,405	1,454	1,382	1,457	1,487	1,477	1,495	1,642	1,629	1,619	1,628	1,667	1,699	1,720	1,737
Calendar	1,508	1,663	1,434	1,561	1,490	1,457	1,509	1,766	1,660	1,656	1,685	1,733					

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Jan	1,893	1,937	1,967	1,998	2,033	2,062	2,091	2,124	2,154	2,185	2,222	2,261	2,320	2,352	2,387	2,419	2,452
Jul	1,761	1,796	1,818	1,842	1,867	1,889	1,912	1,936	1,959	1,982	2,010	2,039	2,085	2,109	2,135	2,160	2,185
Calendar																	

Peak Load Planning

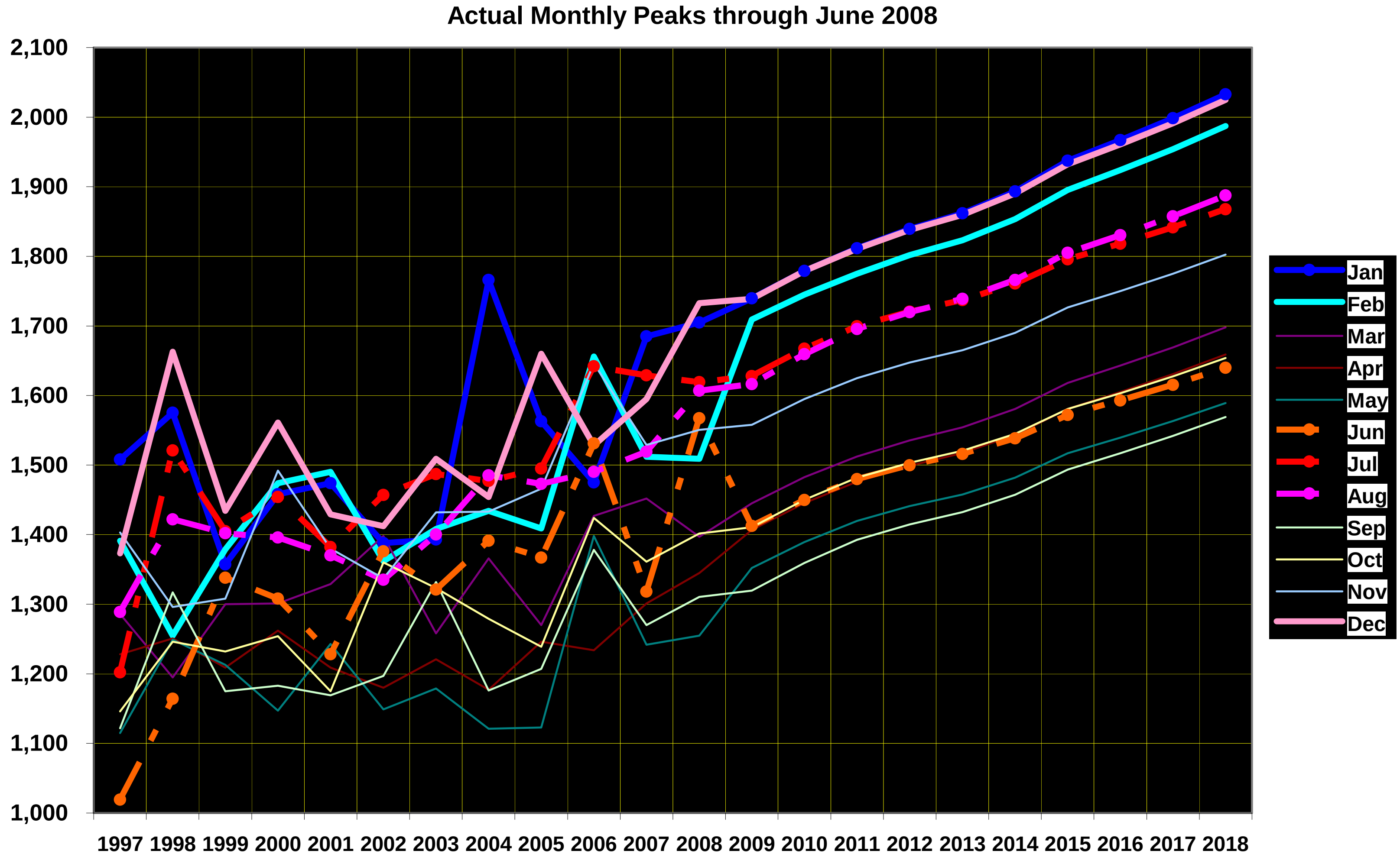
•Winter based on average coldest day

Data from 1890 to 2007			Temp	HDD
Average Coldest Day (December & January)			11.7	53.3
Standard Deviation		10.2		
5% chance of exceedance	1.645	16.779	-5.1	70.1
1% chance of exceedance	2.330	23.766	-12.1	77.1
0.25% chance of exceedance	2.814	28.7	-17.0	82.0

•Summer based on average hottest day

Data from 1890 to 2007			Temp	CDD
Average Hottest Day (July & August)			80.0	15.0
Standard Deviation		3.405		
5% chance of exceedance	1.645	5.601	85.6	20.6
1% chance of exceedance	2.330	7.933	87.9	22.9
0.16% chance of exceedance	2.950	10.0	90.0	25.0

Peak Demand Trends



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Questions & Answers

Natural Gas Price Forecast

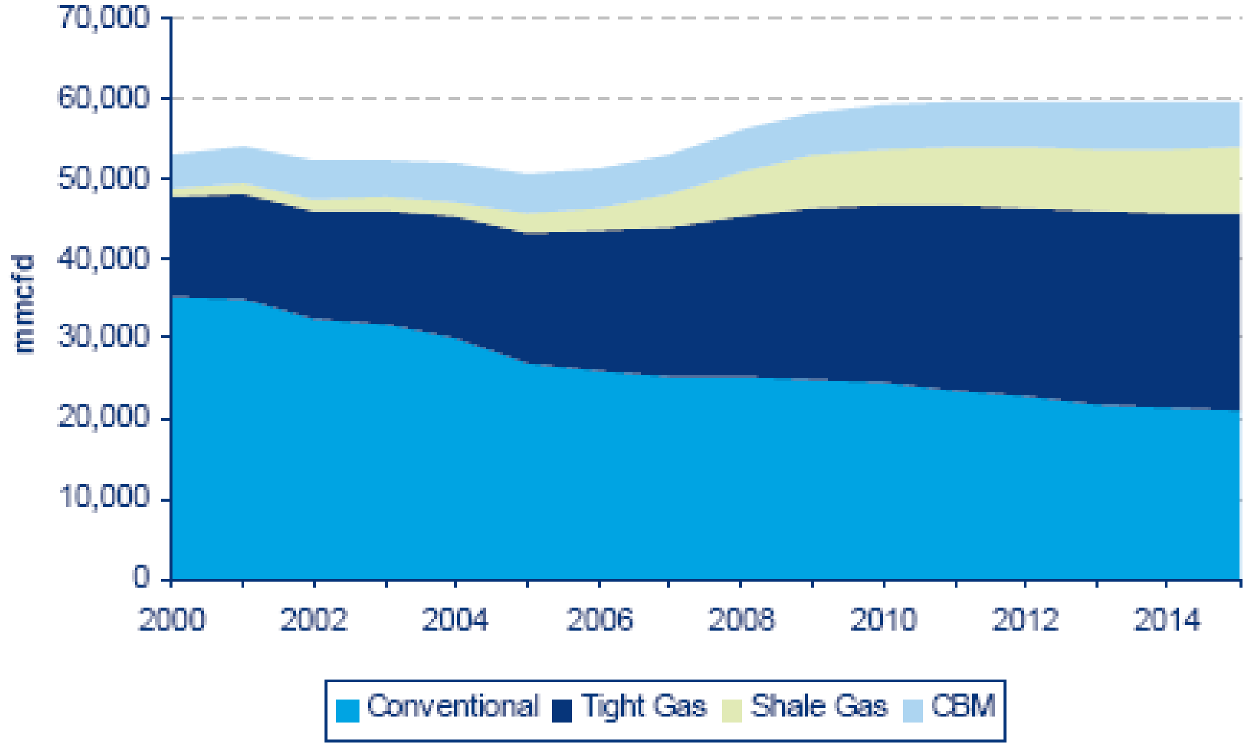
Greg Rahn, Manager Natural Gas Planning
James Gall, Senior Power Supply Analyst

2009 Electric Integrated Resource Plan

Third Technical Advisory Committee Meeting

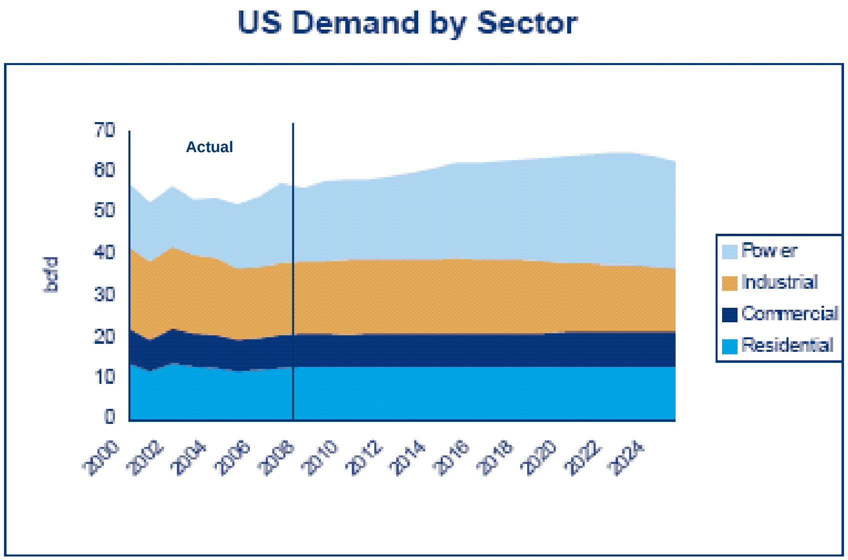
October 22, 2008

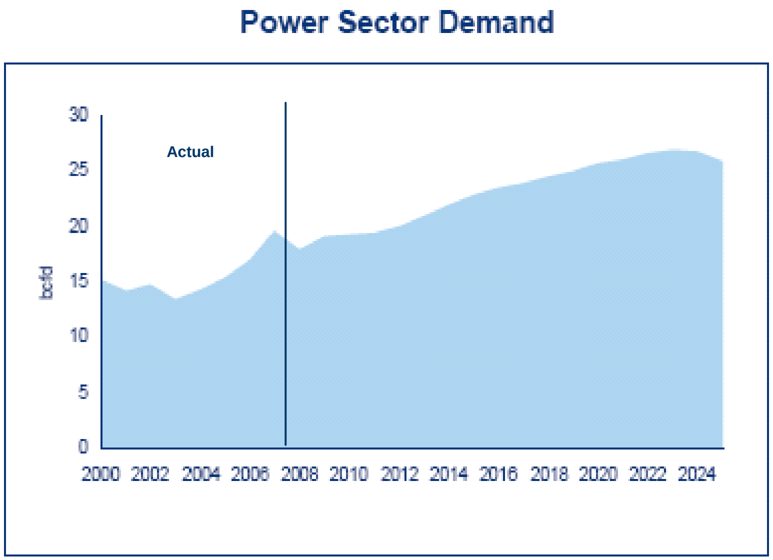
US Supply Growth Forecast through 2015



Source: Wood Mackenzie

Generation Forecasted to Lead National Demand for Natural Gas





Source: Wood Mackenzie

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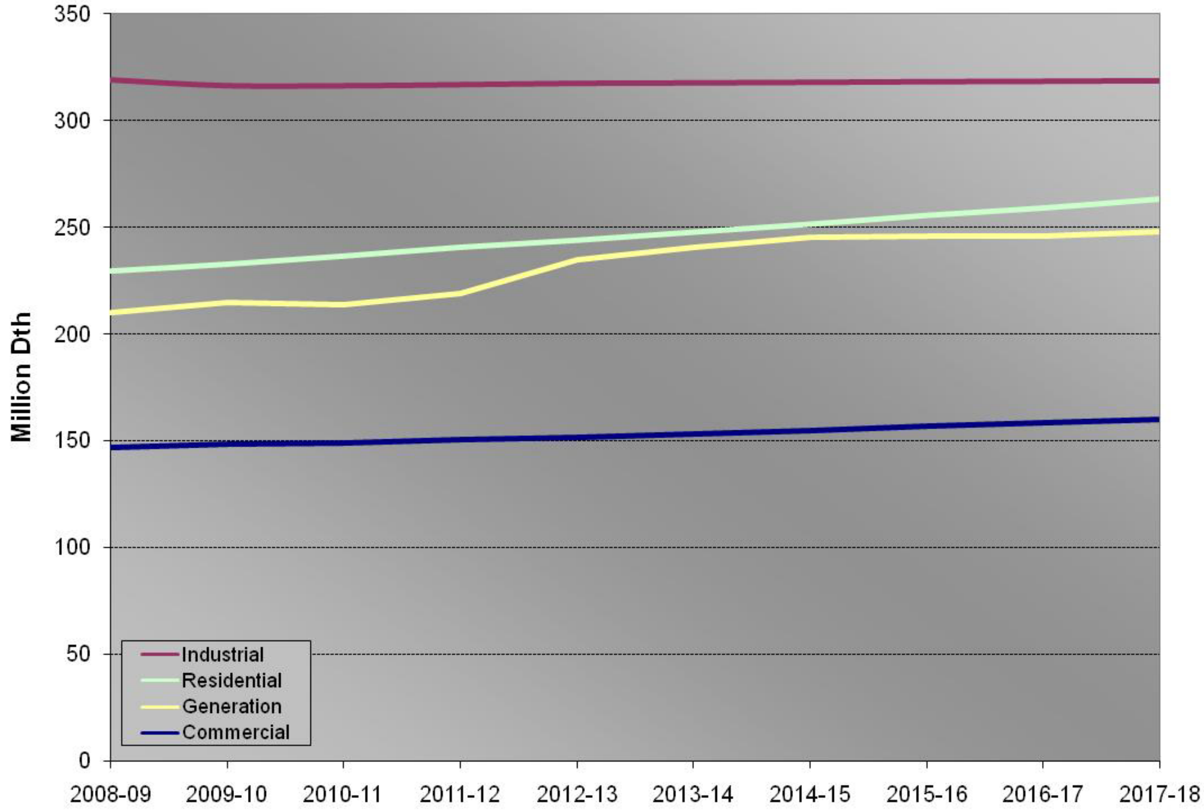
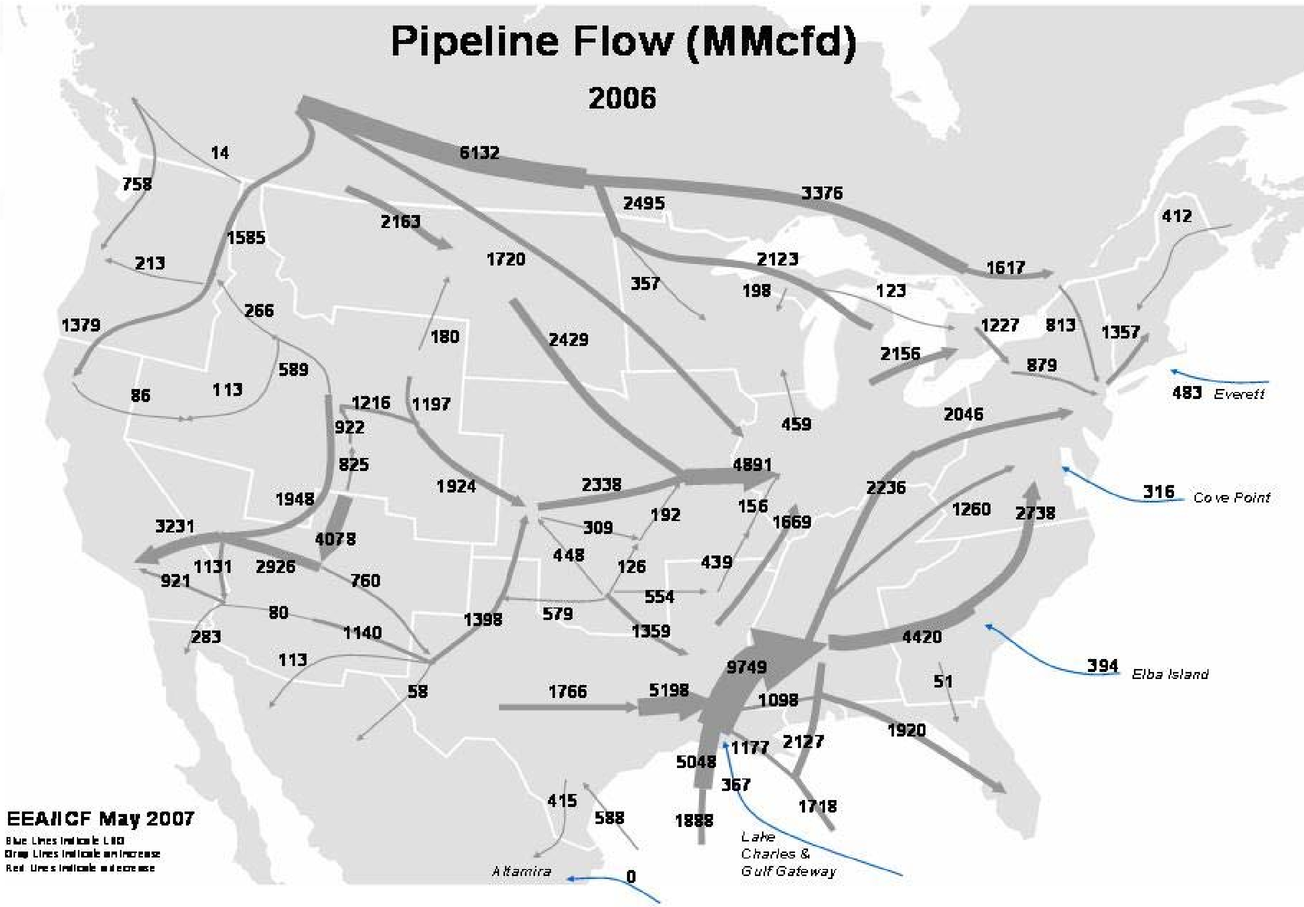
Regional Natural Gas Demand Forecast



Source: Northwest Gas Association

Interstate Pipeline Flow



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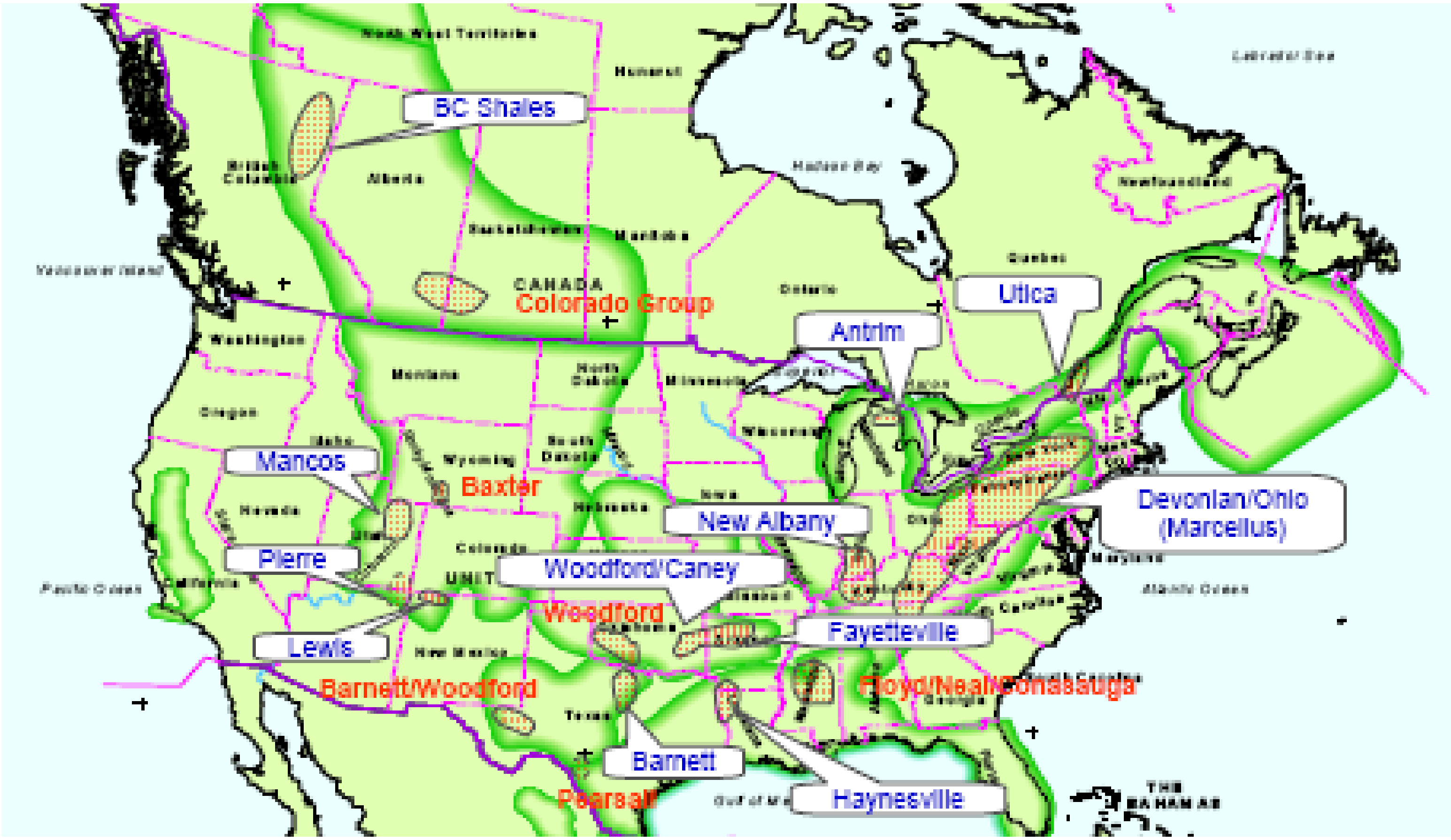
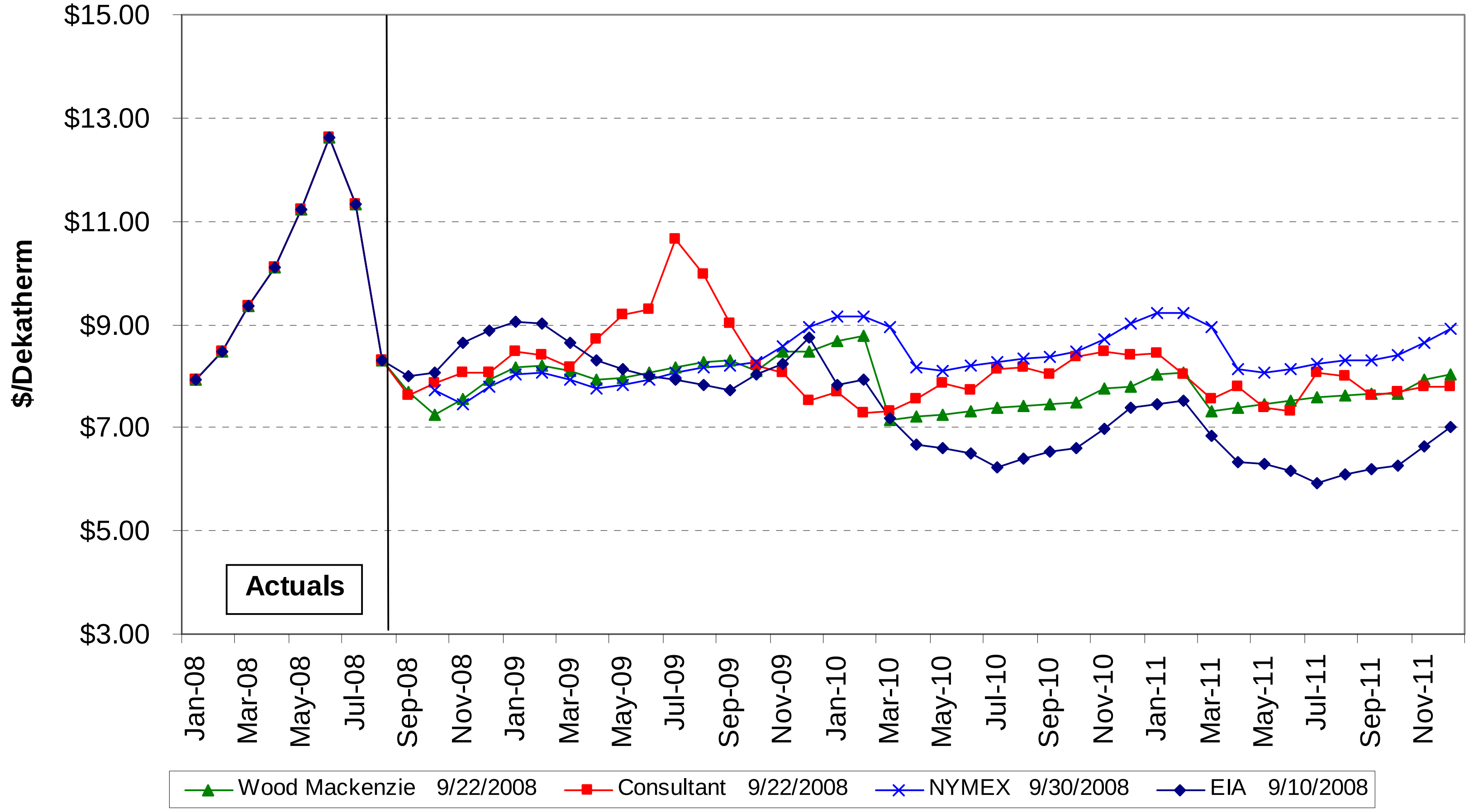
Shale Gas Plays



Source: Wood Mackenzie

Henry Hub Short Term Price Forecasts



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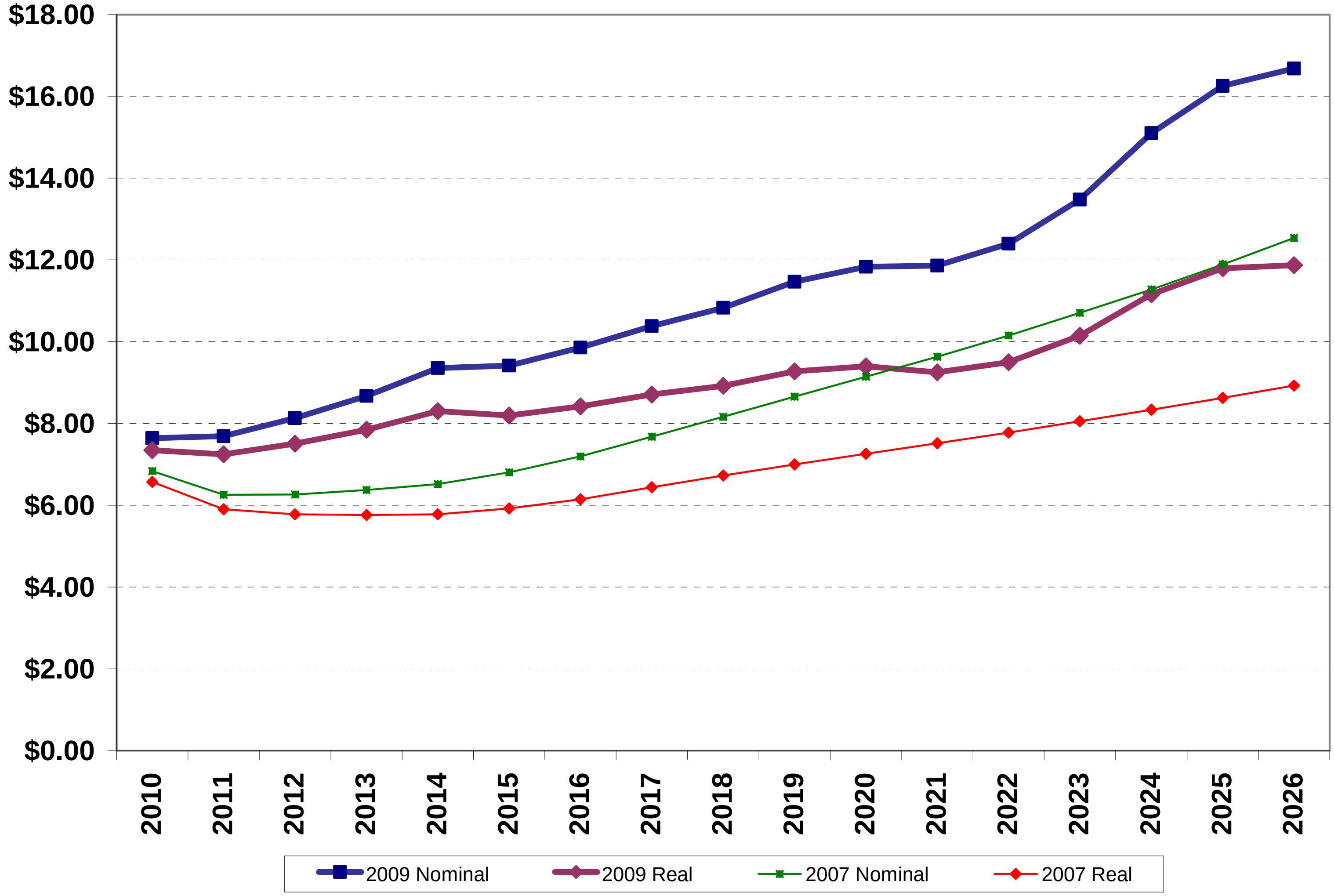
Forecast Assumptions

	2009	2015	2020
US Economic Growth (% GDP)	2.55%	2.84%	2.73%
US Gas Demand (bcf/d)	64.85	68.44	70.67
EG Demand (bcf\d)	19.33	22.88	26.41
WTI Oil Price (2008$)	$ 72.25	$ 60.40	$ 68.17
US Gas Prod. (bcf\d)	56.82	57.36	55.21
LNG Imports (bcf\d)	1.28	8.40	12.20
Alaska Pipeline			2021

Source: Wood Mackenzie

Annual Gas Price Forecast (Henry Hub)



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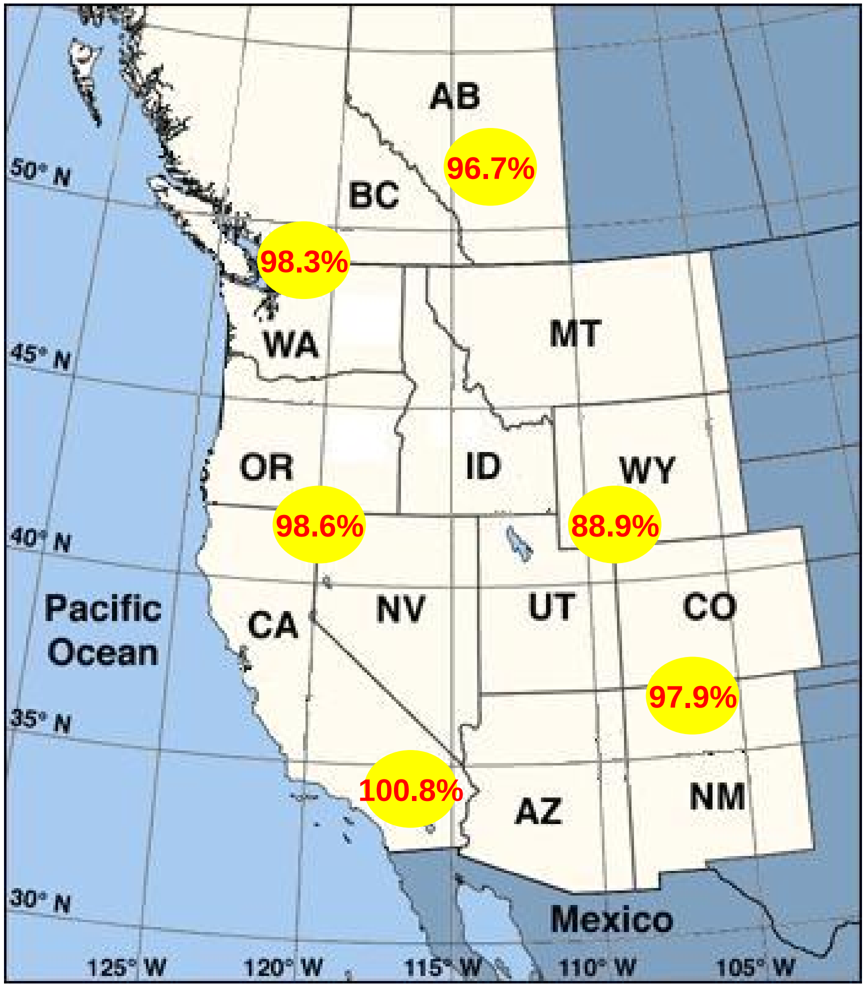
Basin Differentials as a % of Henry Hub*



Location	%
Henry Hub	100.0%
AECO	96.7%
Sumas	98.3%
Malin	98.6%
Opal	88.9%
San Juan	97.9%
So Cal	100.8%

* Based on forecasted 20 year levelized nominal prices

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Monthly Gas Shape*

Month	% of Annual	Month	% of Annual
Jan	103%	Jul	98%
Feb	104%	Aug	99%
Mar	97%	Sep	99%
Apr	96%	Oct	100%
May	97%	Nov	104%
Jun	98%	Dec	105%

* Based on 5 year average of monthly differentials to annual average (AECO)

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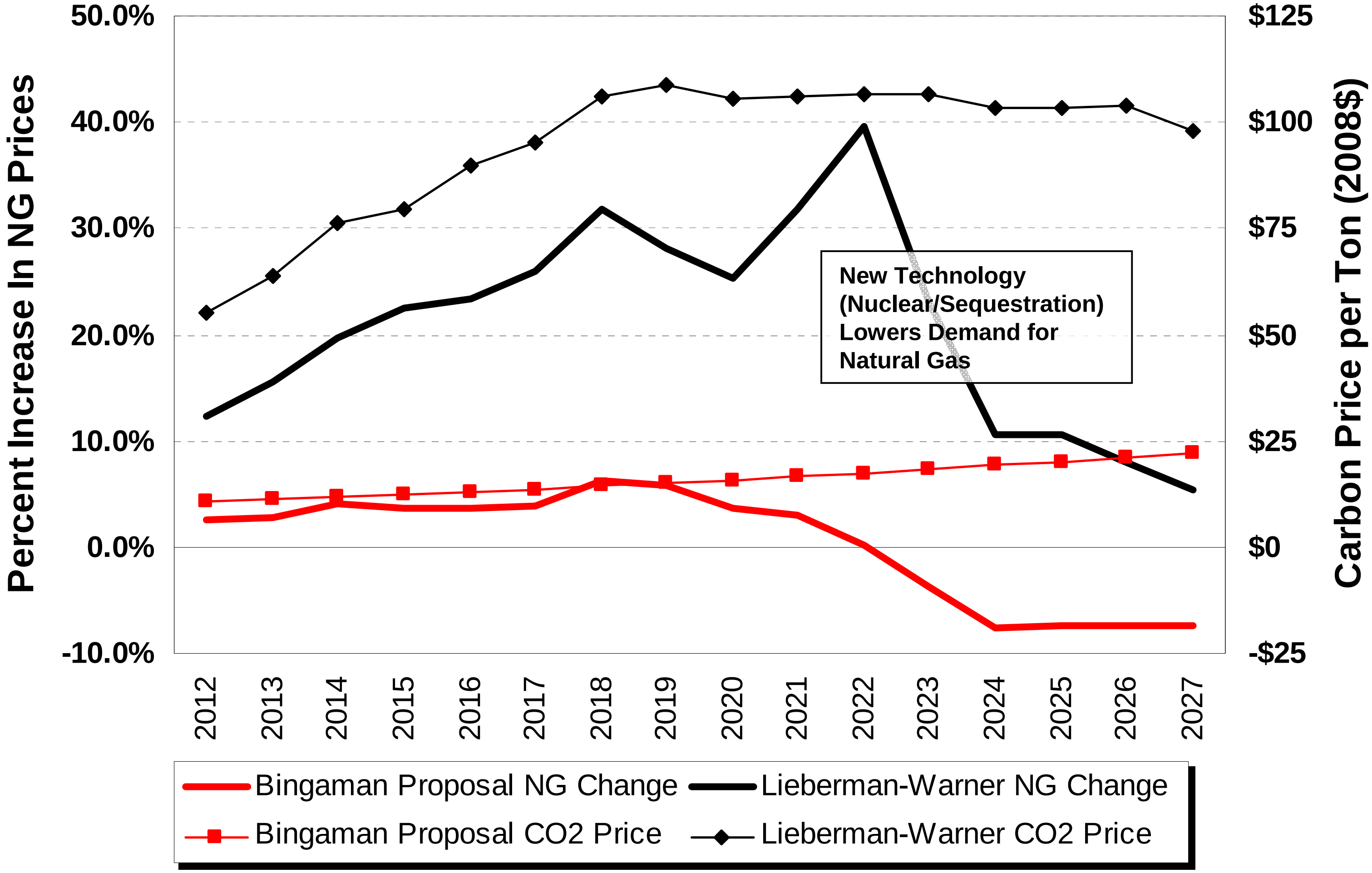
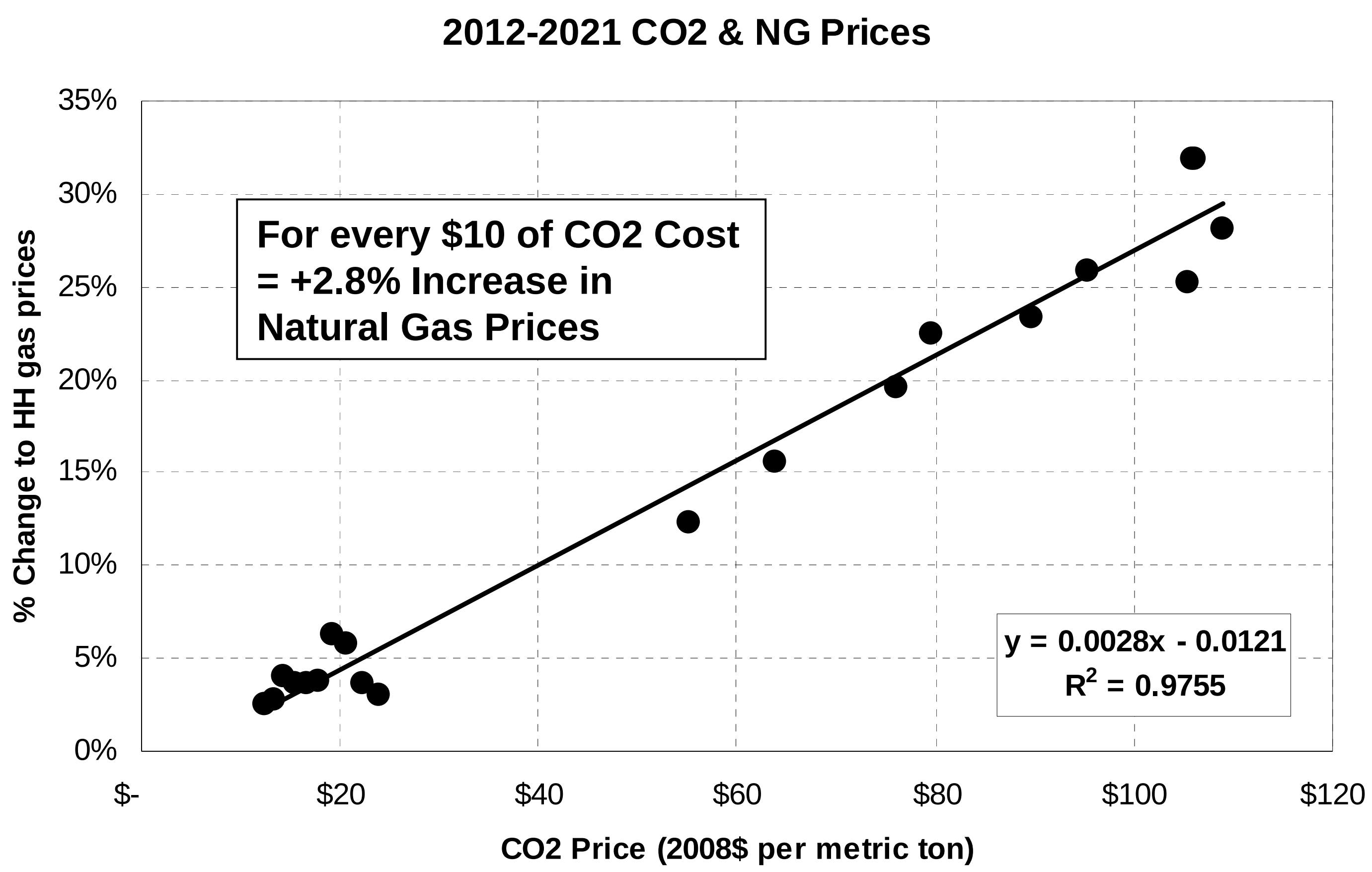
Wood Mackenzie Green House Gas Scenarios



Carbon Cost & LT Natural Gas Prices Relationship



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Carbon Impact to Natural Gas Conclusion

- Carbon Legislation will increase natural gas demand and price.
- To meet a national 1990 Carbon Emissions levels; gas prices could be 30% higher than without Carbon Legislation, unless new technology (Nuclear or Carbon Sequestration) is available in high supply.
- ’09 IRP will use the discussed relationship to develop the Base Case natural gas price forecast, until 2025 (first year sequestration is available to the market), post 2025 prices differentials will flatten.
- Increases to natural gas prices will allow existing coal resources to compete with natural gas at higher Carbon cost levels (see Price Forecast Presentation)

Levelized Natural Gas Costs ($/Dth)*

Location	Nominal		Real (2008$)	
	WM	w/CO_2	WM	w/CO_2
Henry Hub	$10.94	$11.71	$9.11	$9.75
AECO	$10.58	$11.35	$8.81	$9.45
Sumas	$10.76	$11.53	$8.96	$9.60
Malin	$10.79	$11.56	$8.98	$9.62
Opal	$9.72	$10.49	$8.10	$8.74
San Juan	$10.71	$11.48	$8.92	$9.56
Southern Cal	$11.02	$11.80	$9.18	$9.82

* Levelized 20 Years (2010-2029)

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Mid-Columbia Electric Market Forecast

James Gall

2009 Electric Integrated Resource Plan

Third Technical Advisory Committee Meeting

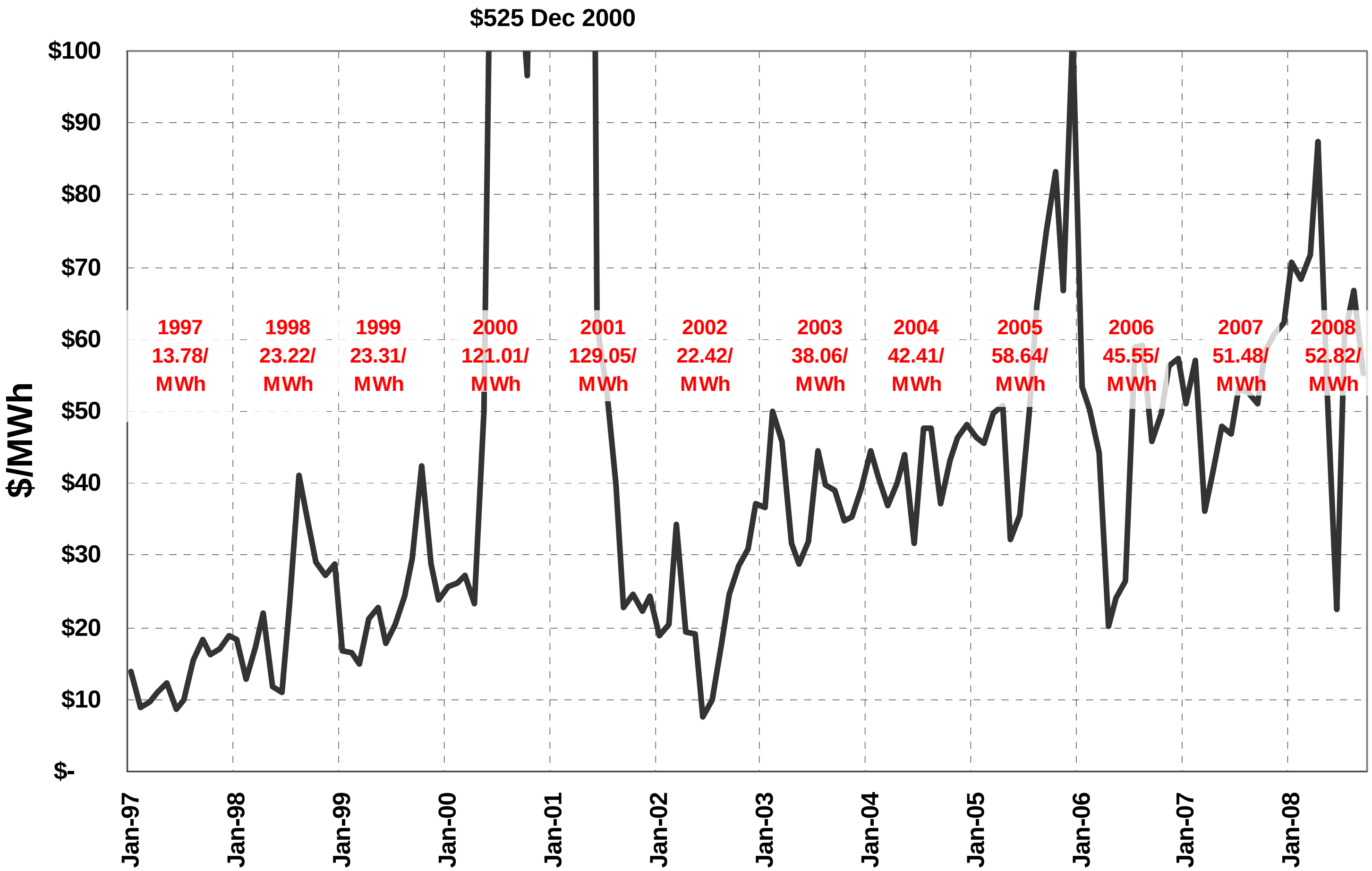
October 22, 2008

AVISTA®

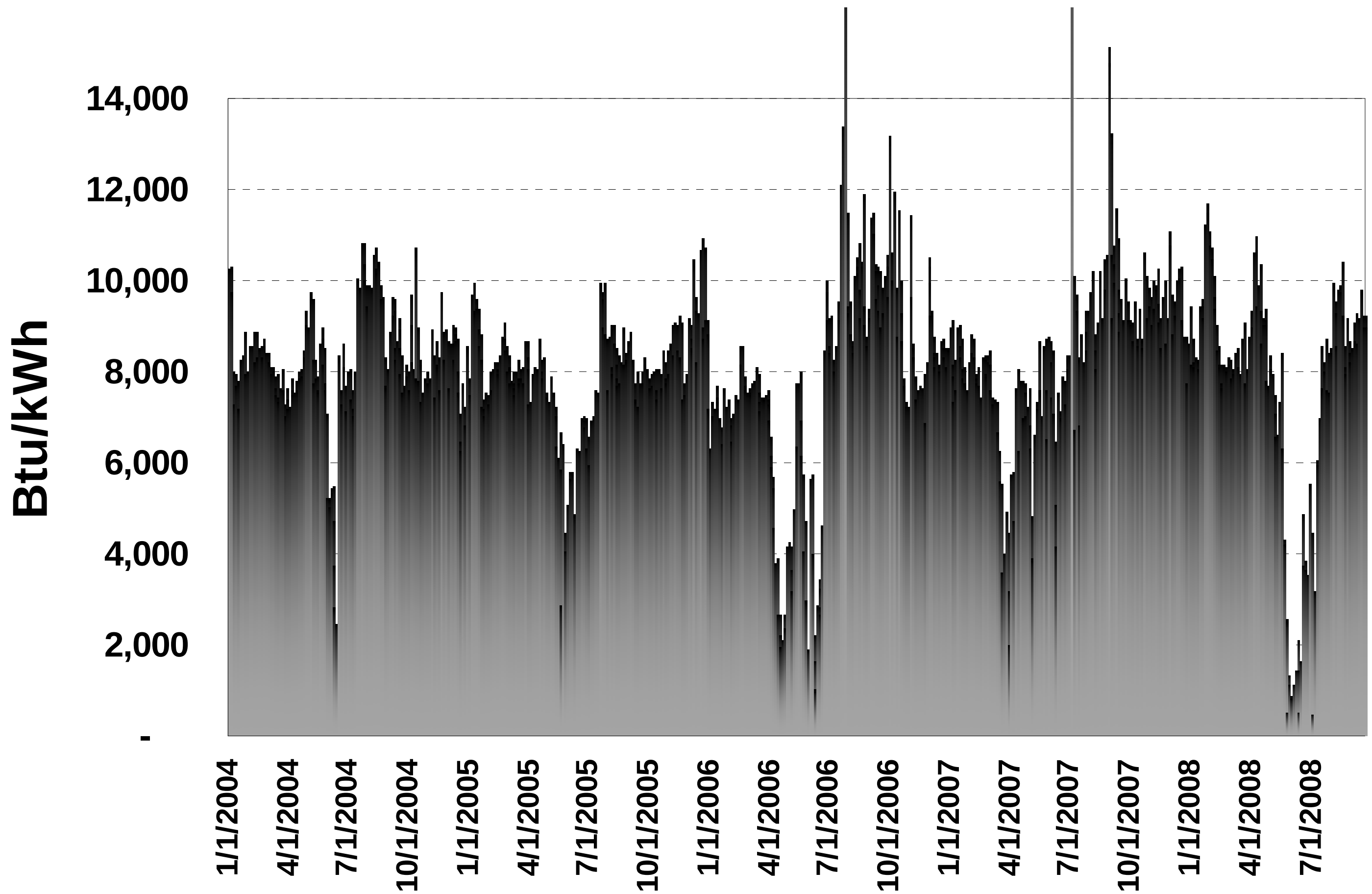
Why Is This Forecast Relevant?

- Used to value future energy costs
- Used to determine resources financial value given different market conditions
- Forecasts when and under what conditions a resource is likely to dispatch
- Test regional market conditions and policies
- Time for changes- recommendations are welcome!

Historical Mid-Columbia Market Prices



Historical Market Implied Heat Rate



Mid C Daily Firm/Stanfield Prices x 1000

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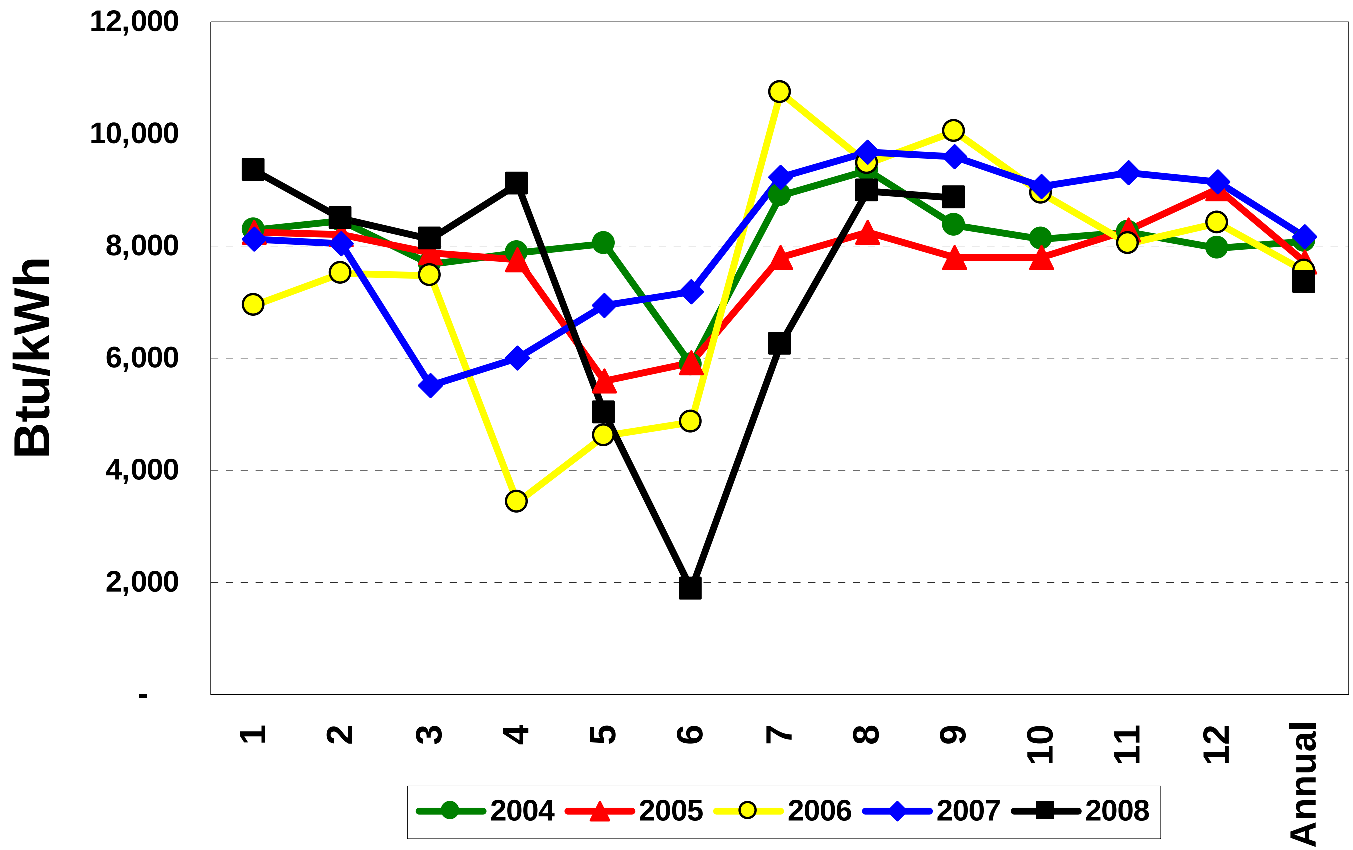
Historical Market Implied Heat Rate



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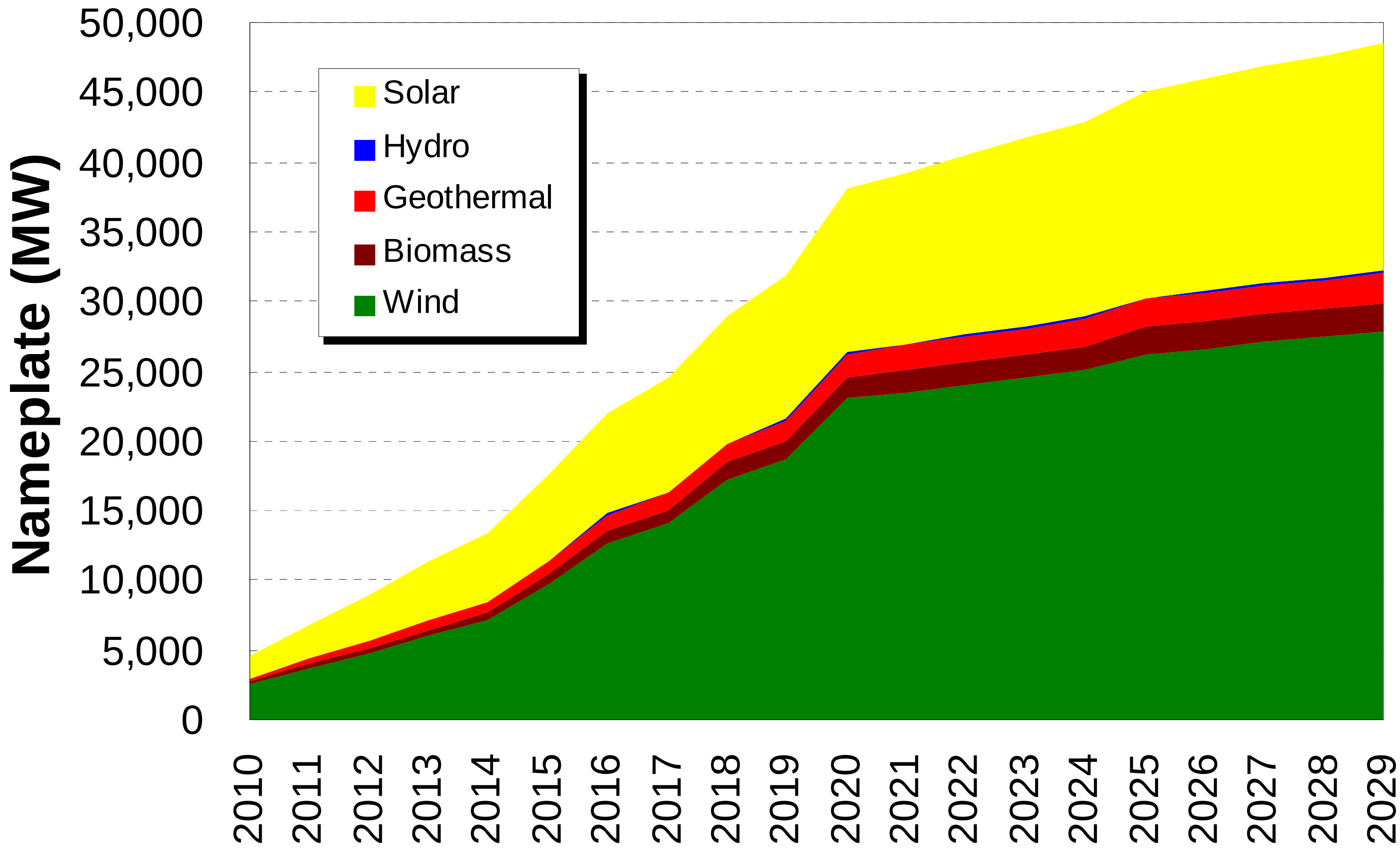
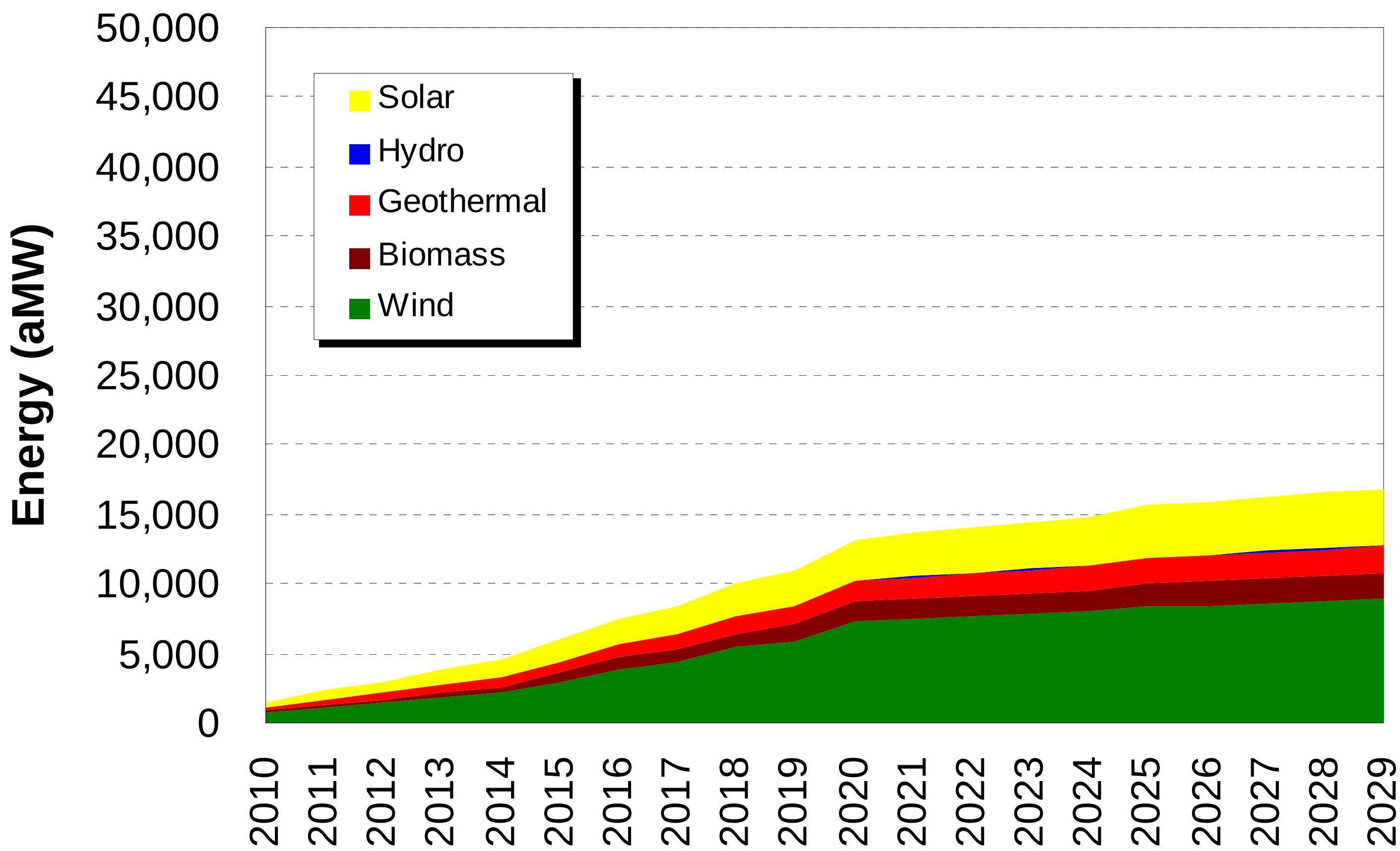
Regional Demand (20 Year AAGR)

- Source: Wood Mackenzie
  - NW- 0.84%
  - DSW- 2.09%
  - CA- 1.61%
  - RM- 1.78%
  - UT- 2.19% (PAC IRP)
- Will evaluate using NPCC after GRAC meeting
- Evaluate NW IRP Forecasts

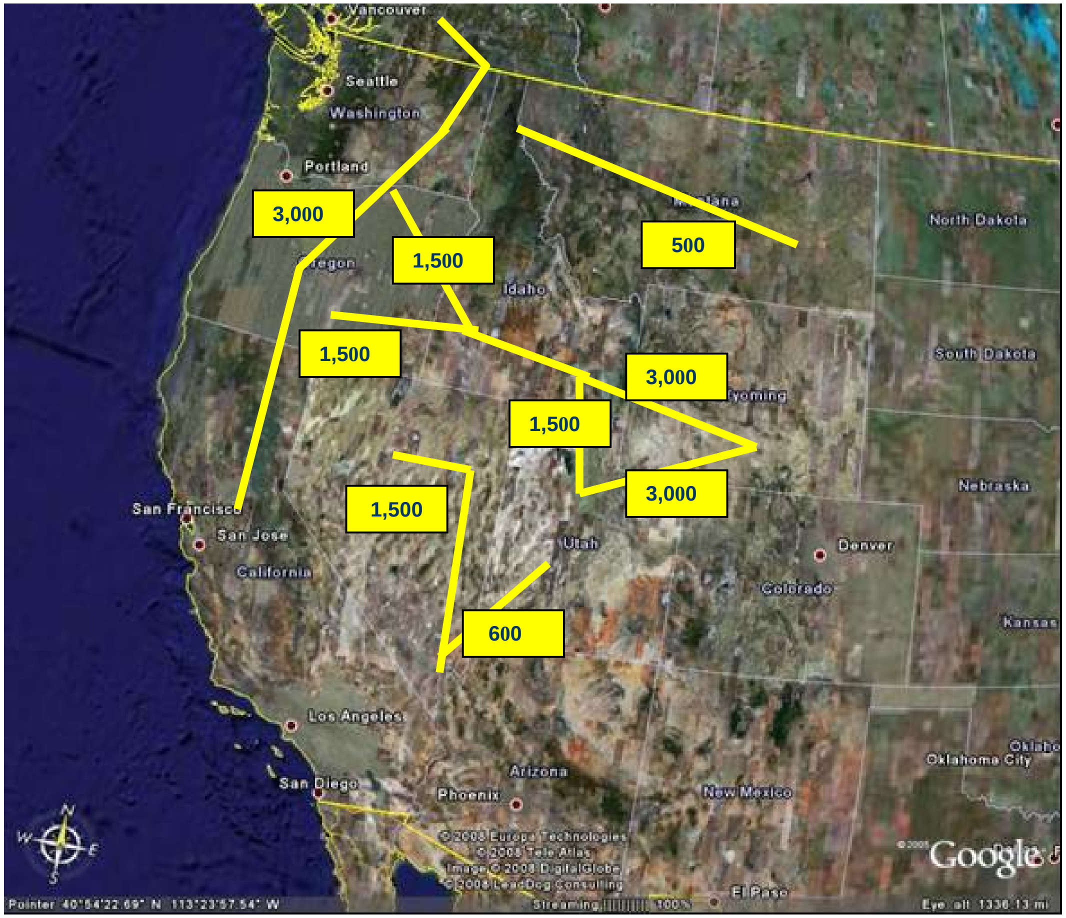
RPS Assumptions (Nameplate Capacity)



RPS Assumptions (Energy)



New Transmission Assumptions



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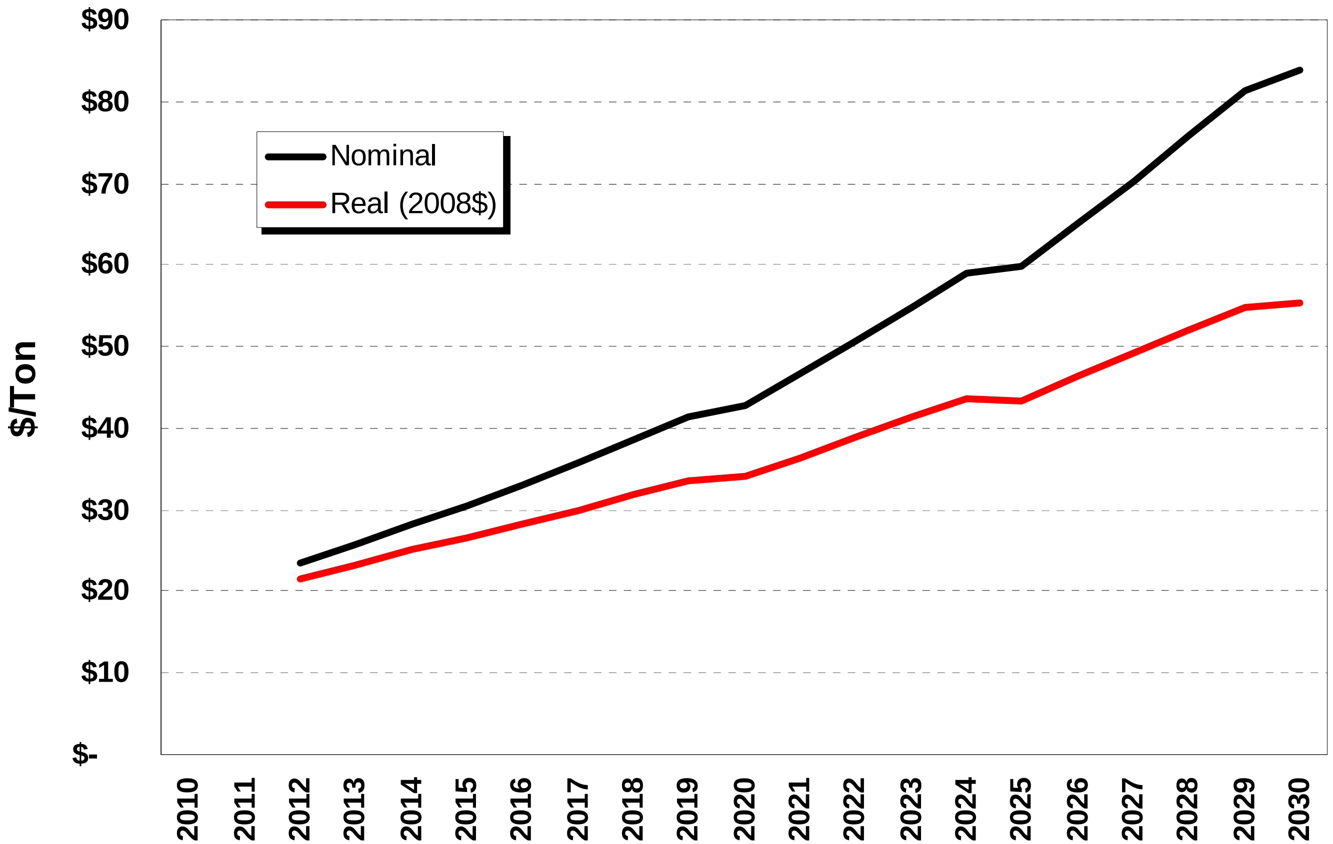
Regional Resource Options

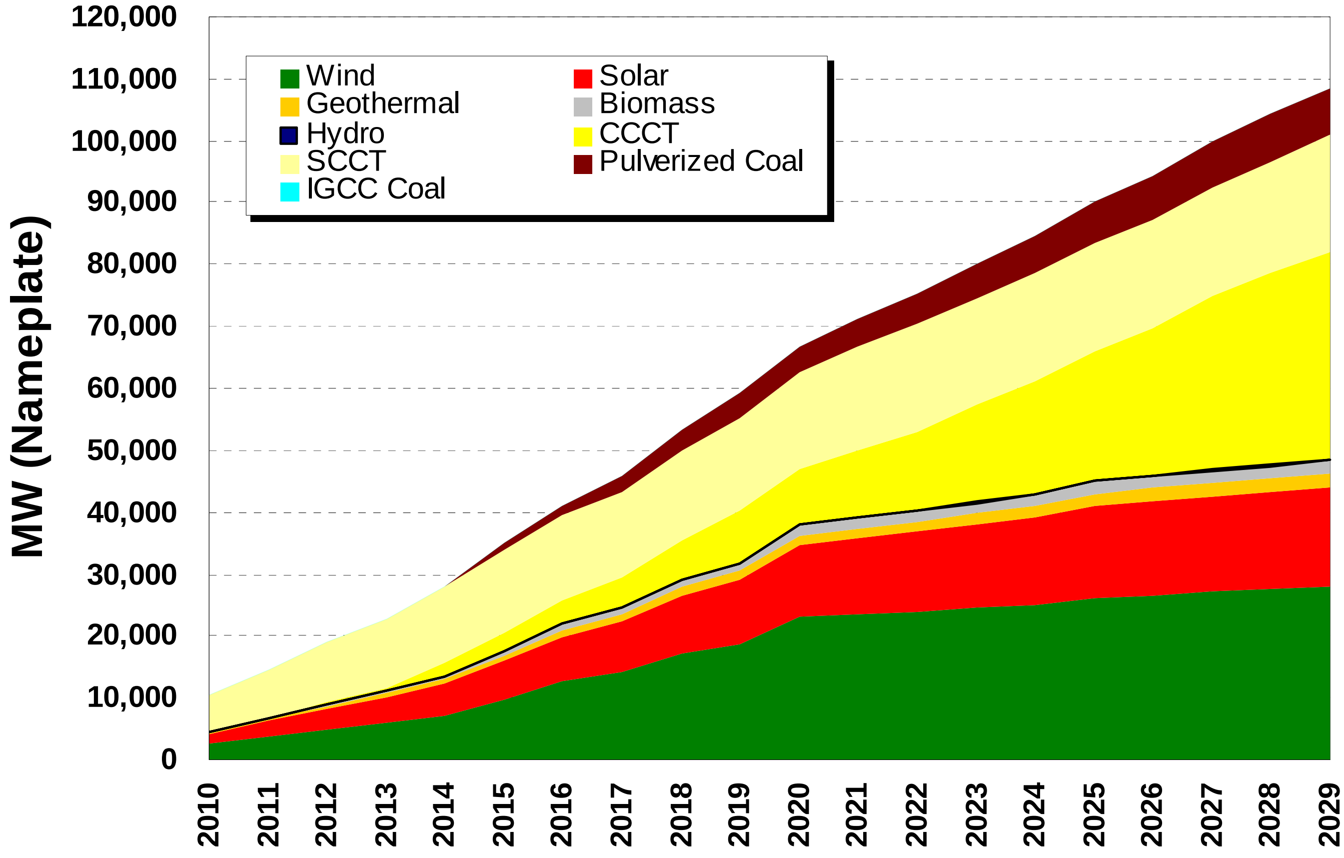
(First Year Available)

- Combined Cycle Combustion Turbine (2011)
- Single Cycle Combustion Turbine (2010)
- Wind (2010)
- Solar (2010)
- Pulverized Coal (2015)
- IGCC Coal (2015)
- IGCC Coal w/ Sequestration (2025)
- Combine Cycle Combustion Turbine w/ Sequestration (2025)
- Nuclear (2022)

Carbon Adder



New Resources by Type in the WECC



Retired 1,300 MW of High Heat Rate Natural Gas Plants between 2011-2013

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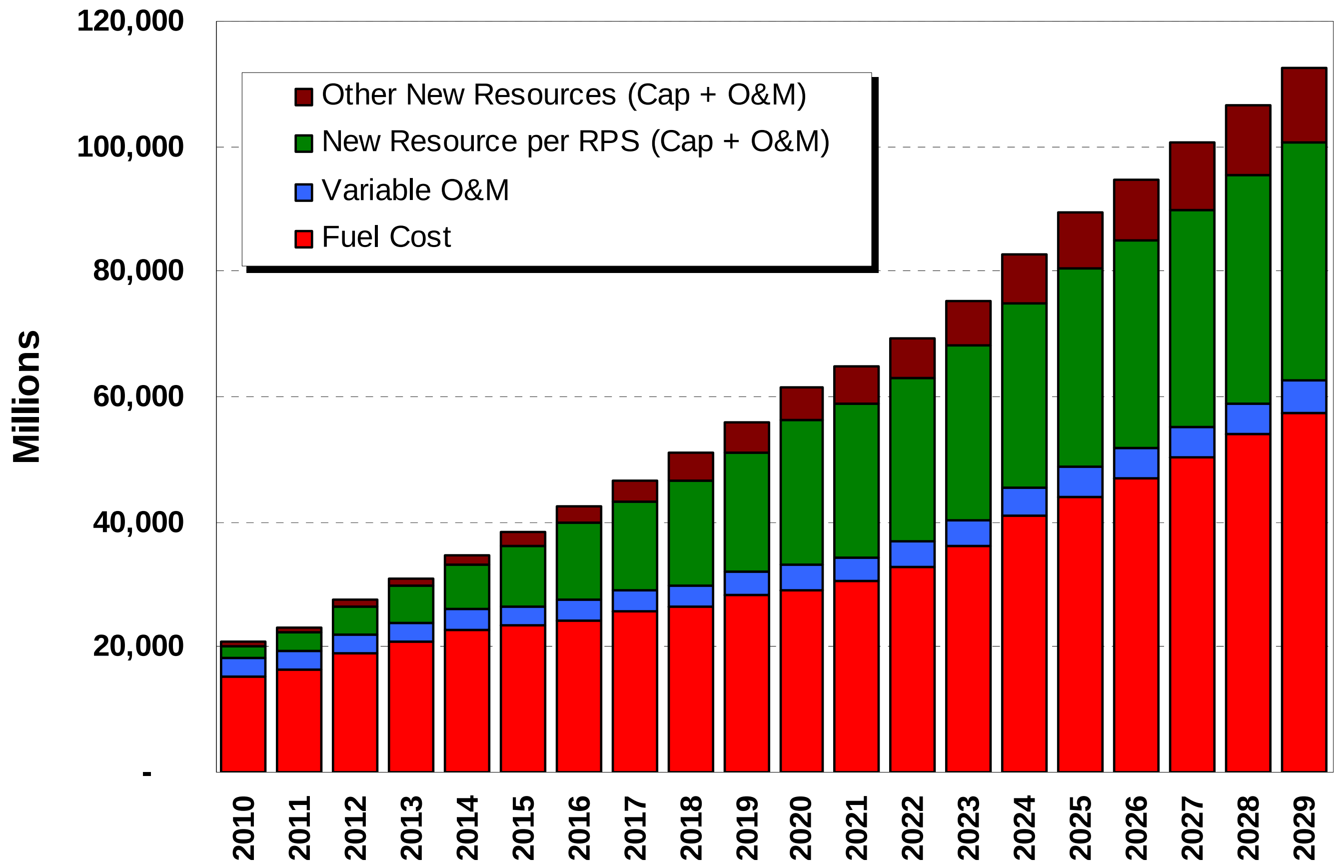
Western Interconnect System Costs
(Nominal - *Excludes Carbon Trading Costs)*



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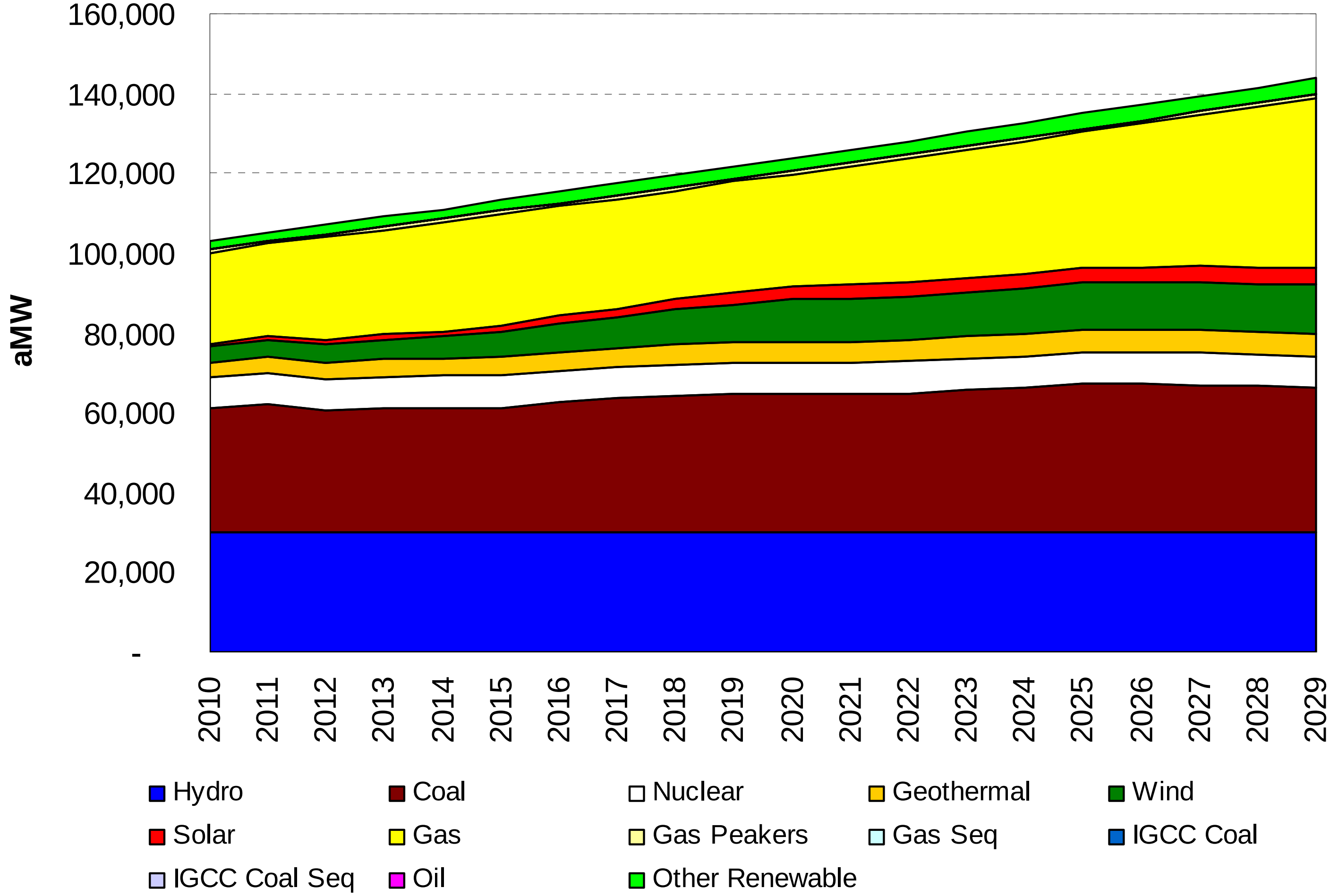
Resource Dispatch Contribution



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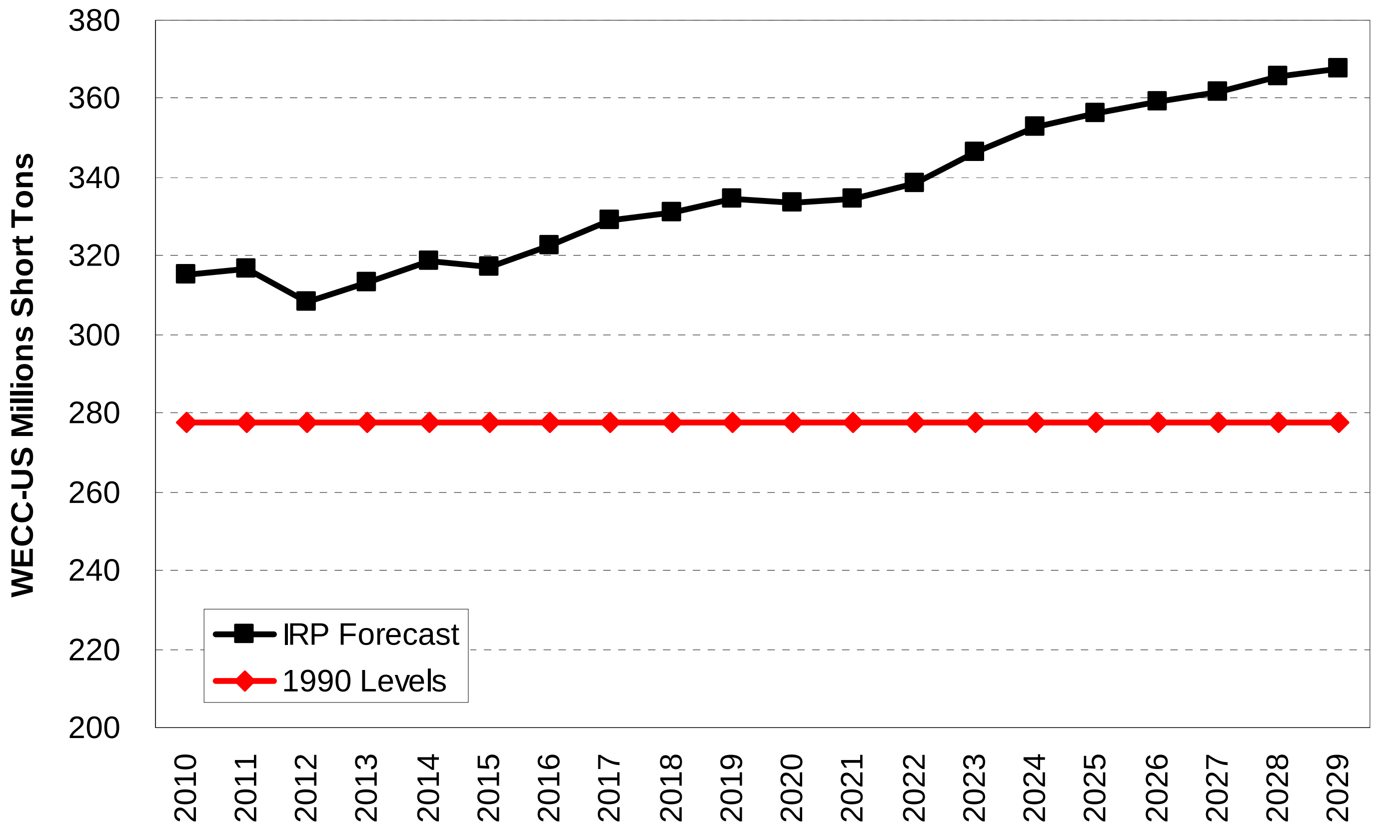
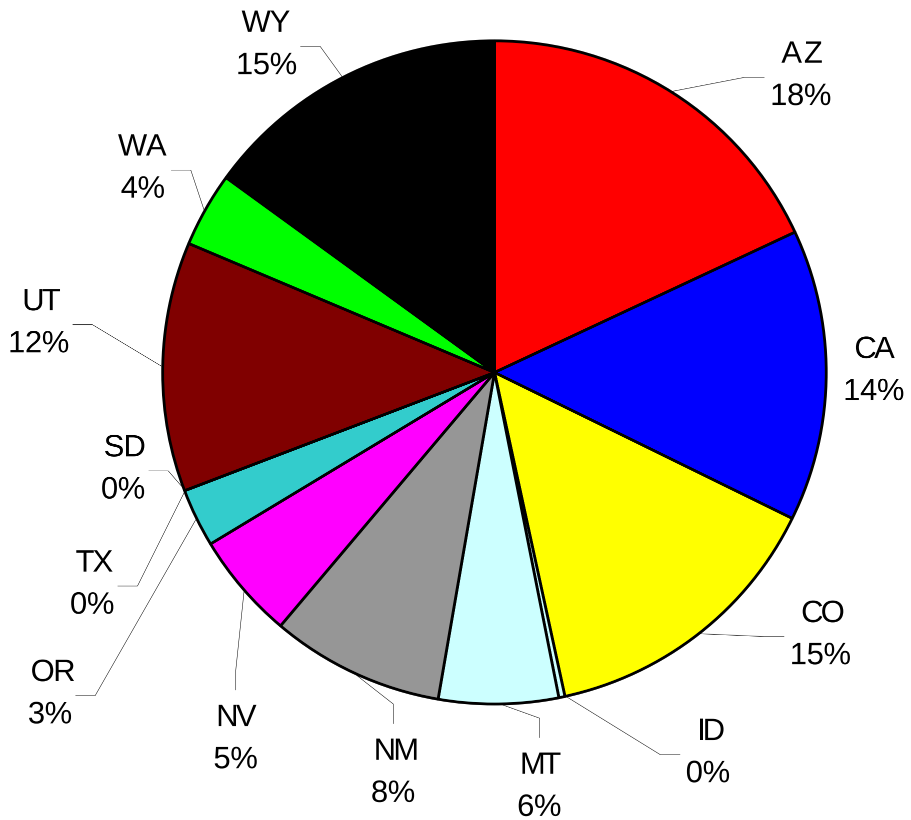
Greenhouse Gas Forecast- US Western Interconnect

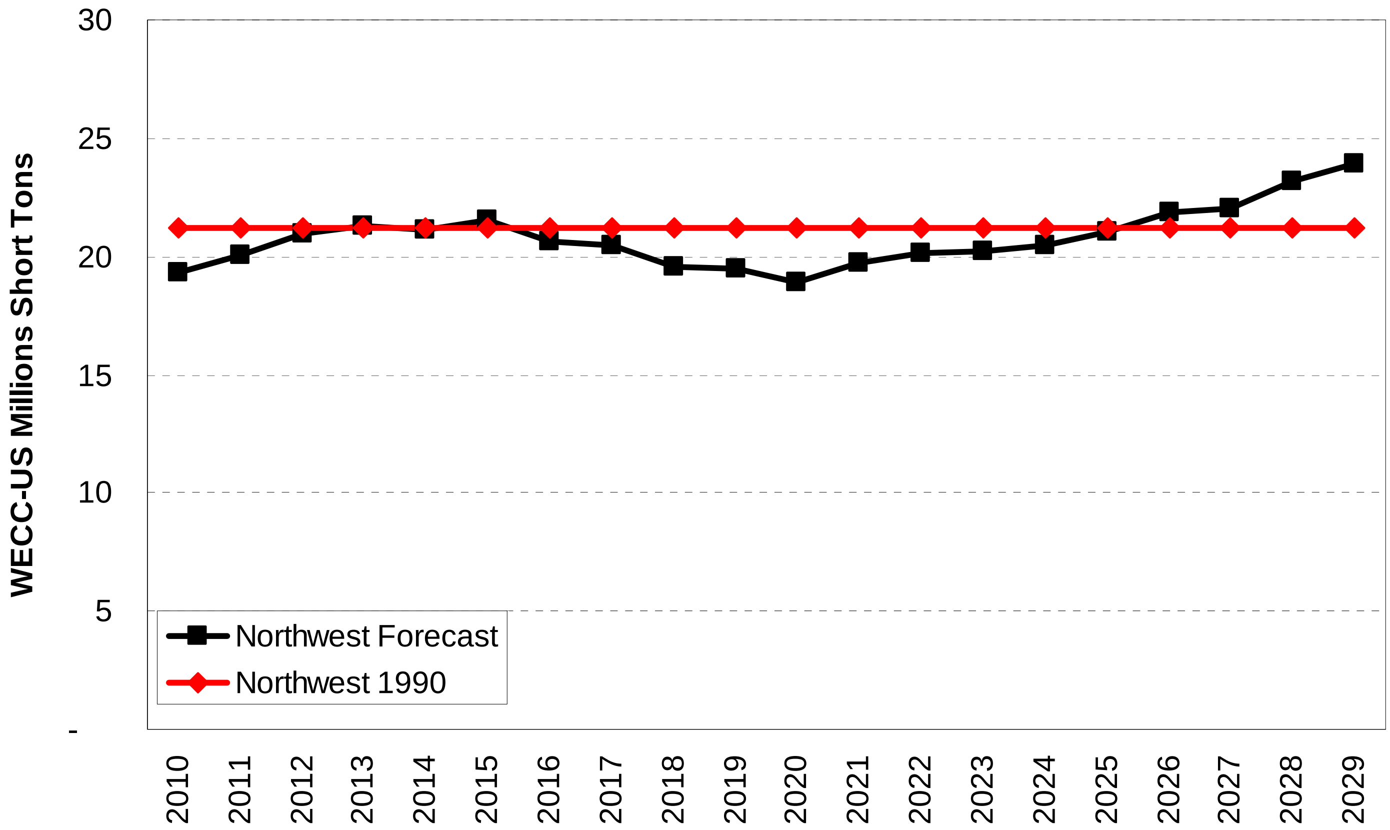


Greenhouse Gas Forecast

U.S. Western Interconnect



Greenhouse Gas Forecast- WA/OR/ID



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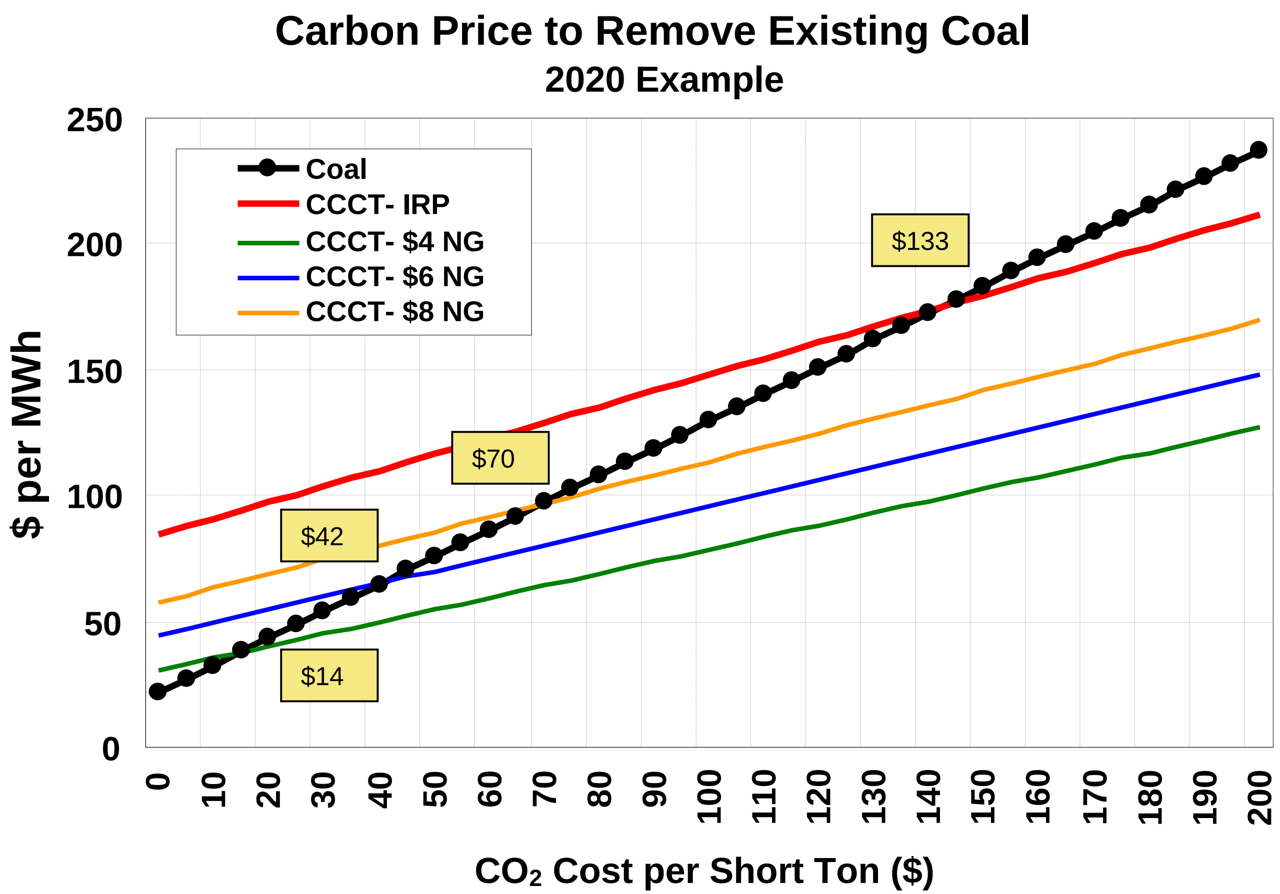
Carbon Adder High Enough, 2020 Example?



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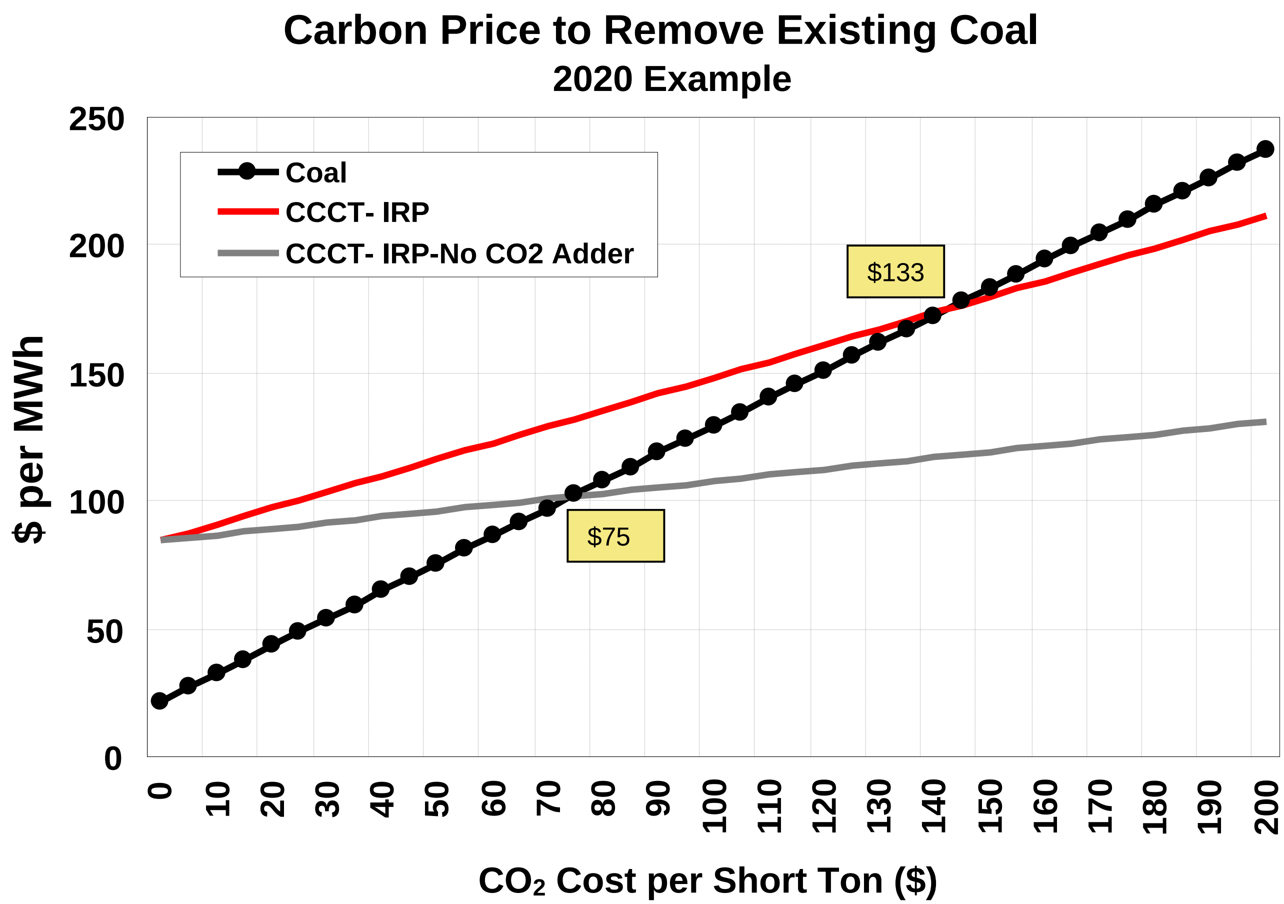
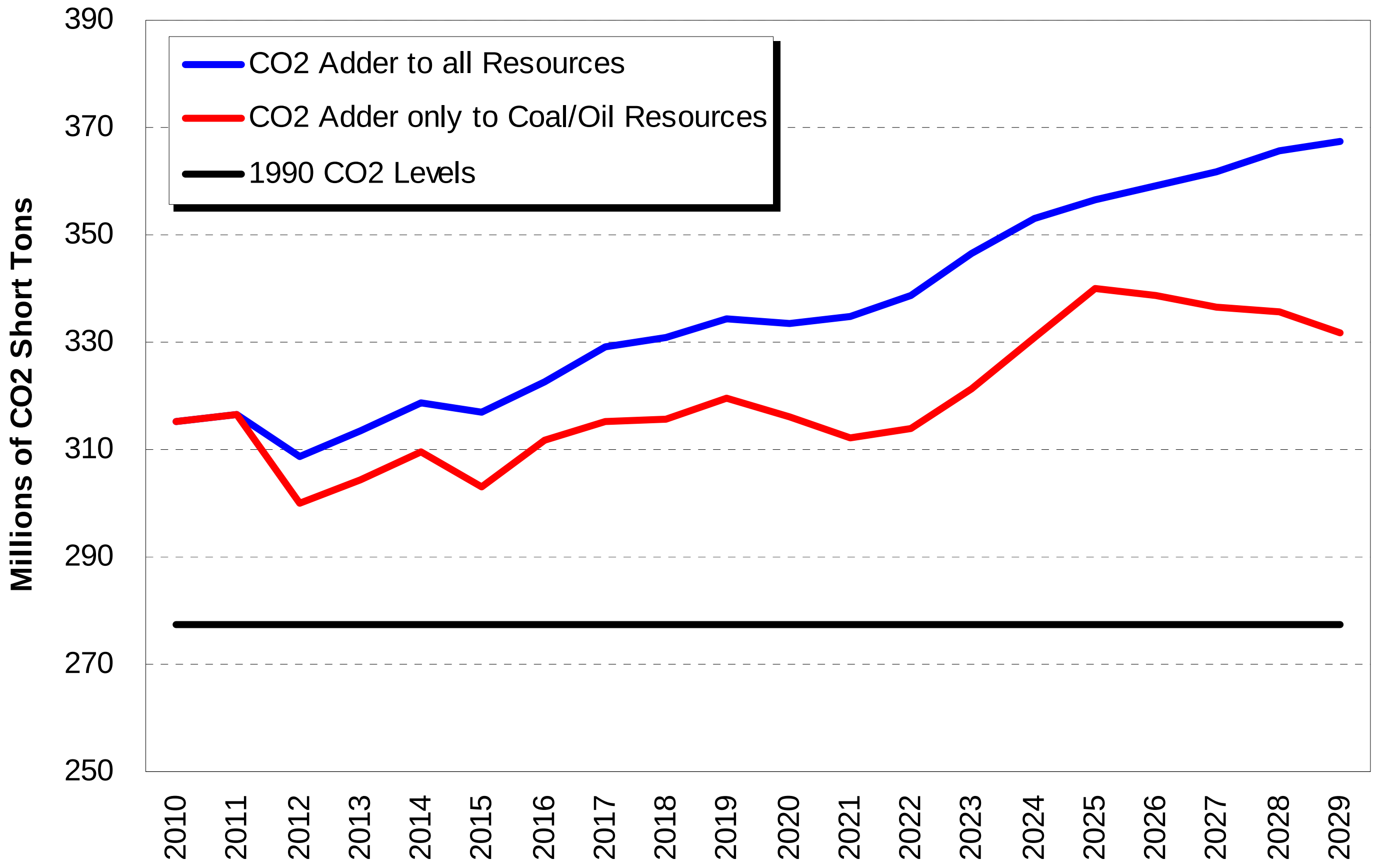
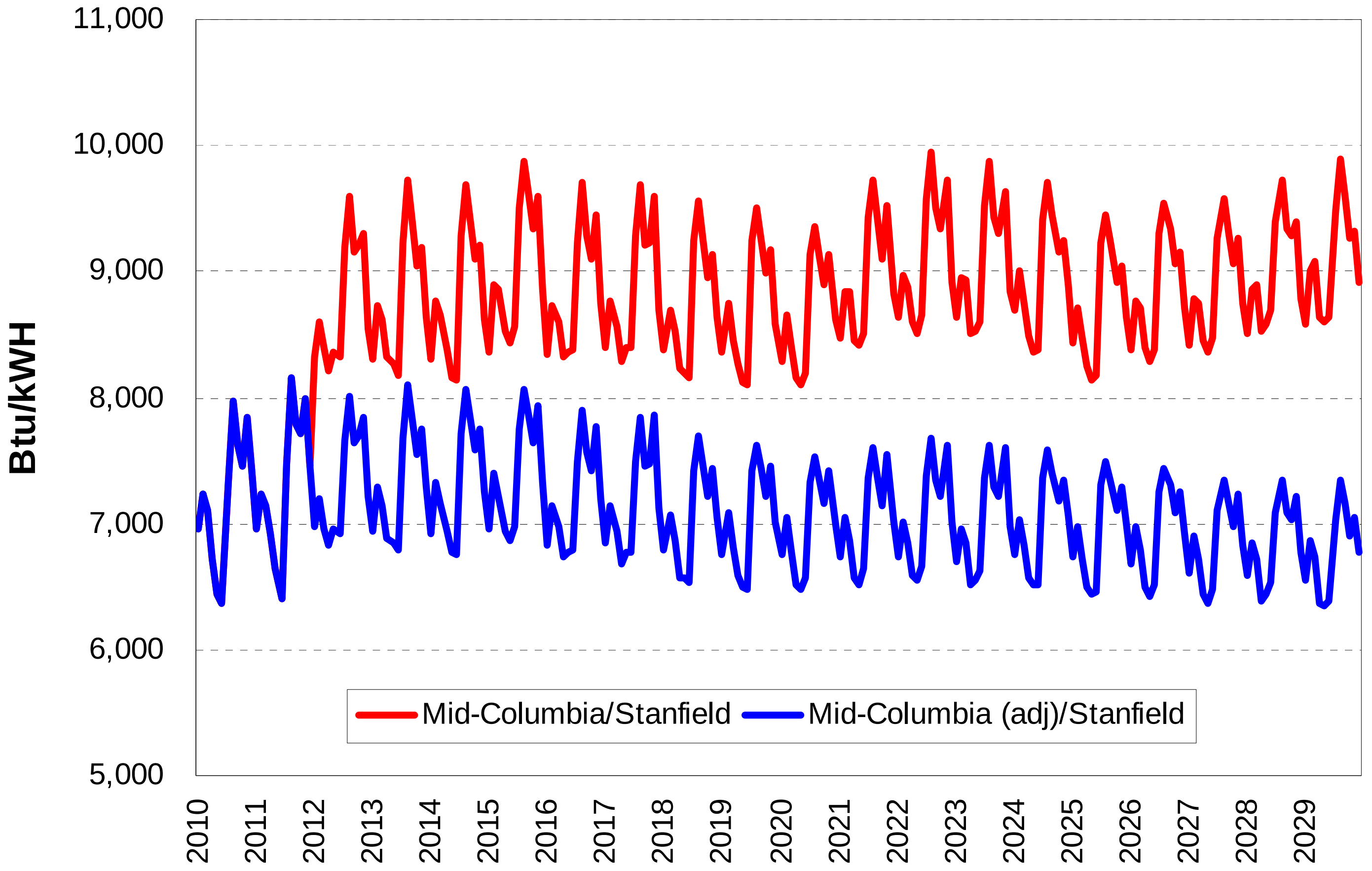
How about a Coal Carbon “adder” Instead



Greenhouse Gas Forecast- US Western Interconnect



Market Implied Heat Rates
(Mid-C/Stanfield)



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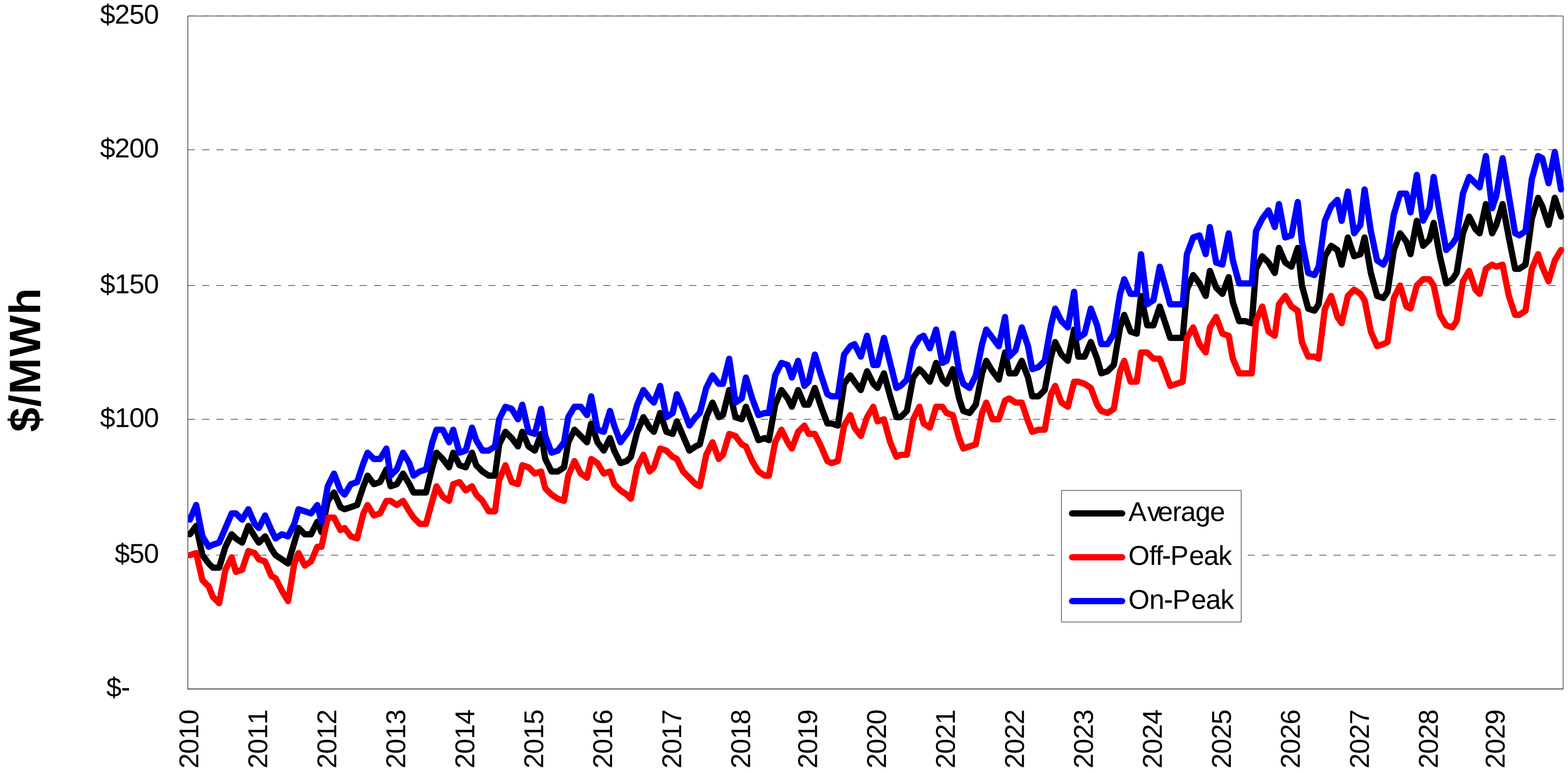
Annual On-Off Peak Mid-Columbia Prices



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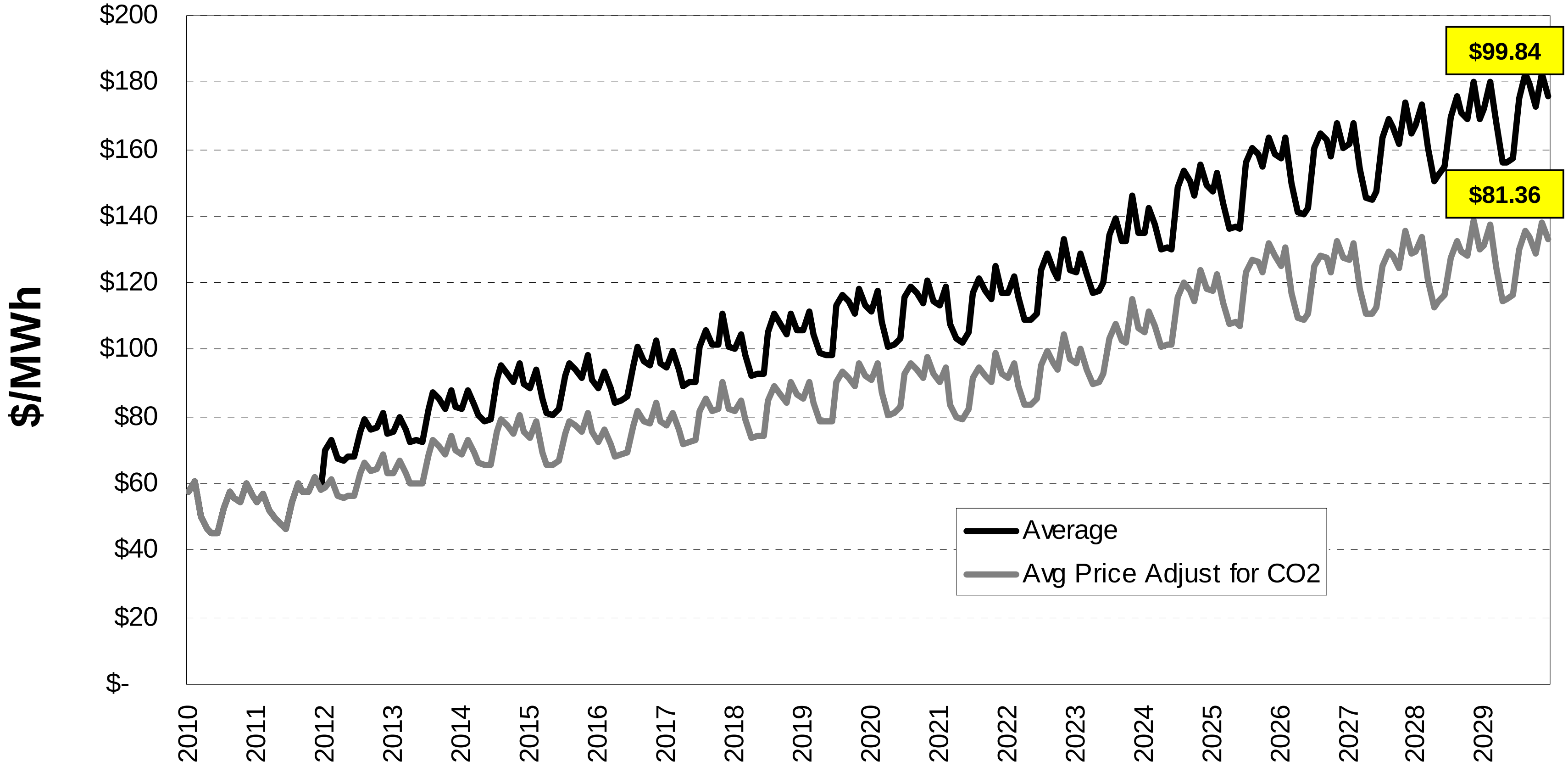
Mid-Columbia Prices would be lower if not for Carbon Costs



Mid-Columbia Levelized Prices ($/MWh)

2010-2029

	Average	On-Peak	Off-Peak
20-Year (Nominal)	99.84	109.77	86.60
20-Year (2008$)	83.15	91.41	72.13

Legislative Update

Collins Sprague

2009 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
October 22, 2007

Western Climate Initiative

- Regional cap and trade implementation
- Electricity sector obligations
- Cost containment mechanisms
- Allowances
- Market regulation and enforcement

Feed-In Tariff

- Solar – Renewable Rate Recovery and Control Act
- Anaerobic Digester ($0.12/kWh), landfill gas ($0.08/kWh), and "organic" combined heat and power ($0.09/kWh)
  - Will not qualify for utility compliance with I-937
- Renewable energy credit (public utility tax) for solar expanded to include other technologies
- Wheeling requirement for output from digesters
  - Transmission cost capped at 5%

Energy Efficiency

- Existing, new and renovated buildings
- Update Energy Code to achieve 30% reduction from current edition
- “State Building Efficiency and Carbon Reduction Strategy” – targets for building energy use intensity
- Energy benchmark disclosure requirement at time of structure sale
- Partial public utility credit for non-residential energy performance
- Expansion of Local Improvement Districts to finance energy efficiency and district heating/cooling

Other Topics

- Tax incentives
  - Broad tax incentives for combined heat and power, distributed generation, and water systems
  - Renewable energy tax incentives for large-scale generation

- "Product Stewardship" – collection and recycling of incandescent lighting by manufacturers

- Vegetation Management

- Emissions Performance standard revisions

Avista's 2009 Electric Integrated Resource Plan
Technical Advisory Committee Meeting No. 4 Agenda
January 28, 2009

	Topic	Time	Staff
1.	Introduction	9:30	Storro
2.	2008 Peak Load Event	9:35	Heath
3.	Natural Gas & Electric Price Update	10:00	Rahn / Gall
4.	Lunch	11:30	
5.	Resource Assumptions	12:30	Lyons
6.	Transmission	1:00	Gibson
7.	Draft Preferred Resource Strategy	2:00	Gall
8.	Adjourn	3:00	

2008 Peak Load Event

Heidi Heath

2009 Electric Integrated Resource Plan

Fourth Technical Advisory Committee Meeting

January 28, 2009

Top Ten Highest Hourly Loads

	Date	Load
1	***12/16/2008***	***1821***
2	***12/16/2008***	***1809***
3	***12/16/2008***	***1791***
4	2/1/1996	1796
5	***12/15/2008***	***1781***
6	***12/15/2008***	***1776***
7	2/2/1996	1770
8	1/5/2004	1766
9	***12/16/2008***	***1759***
10	***12/14/2008***	***1752***

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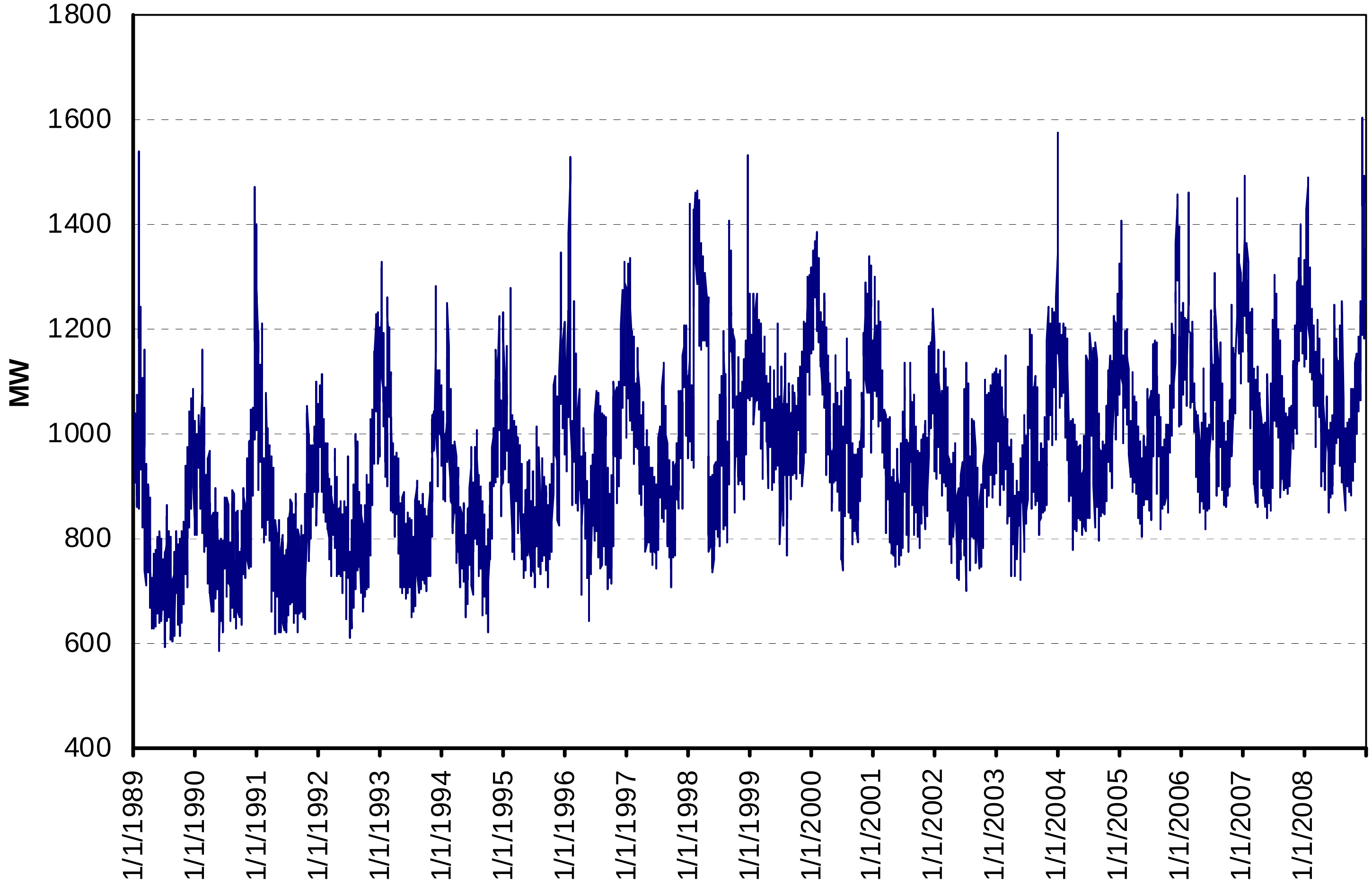
Daily Average Loads
1989-2008



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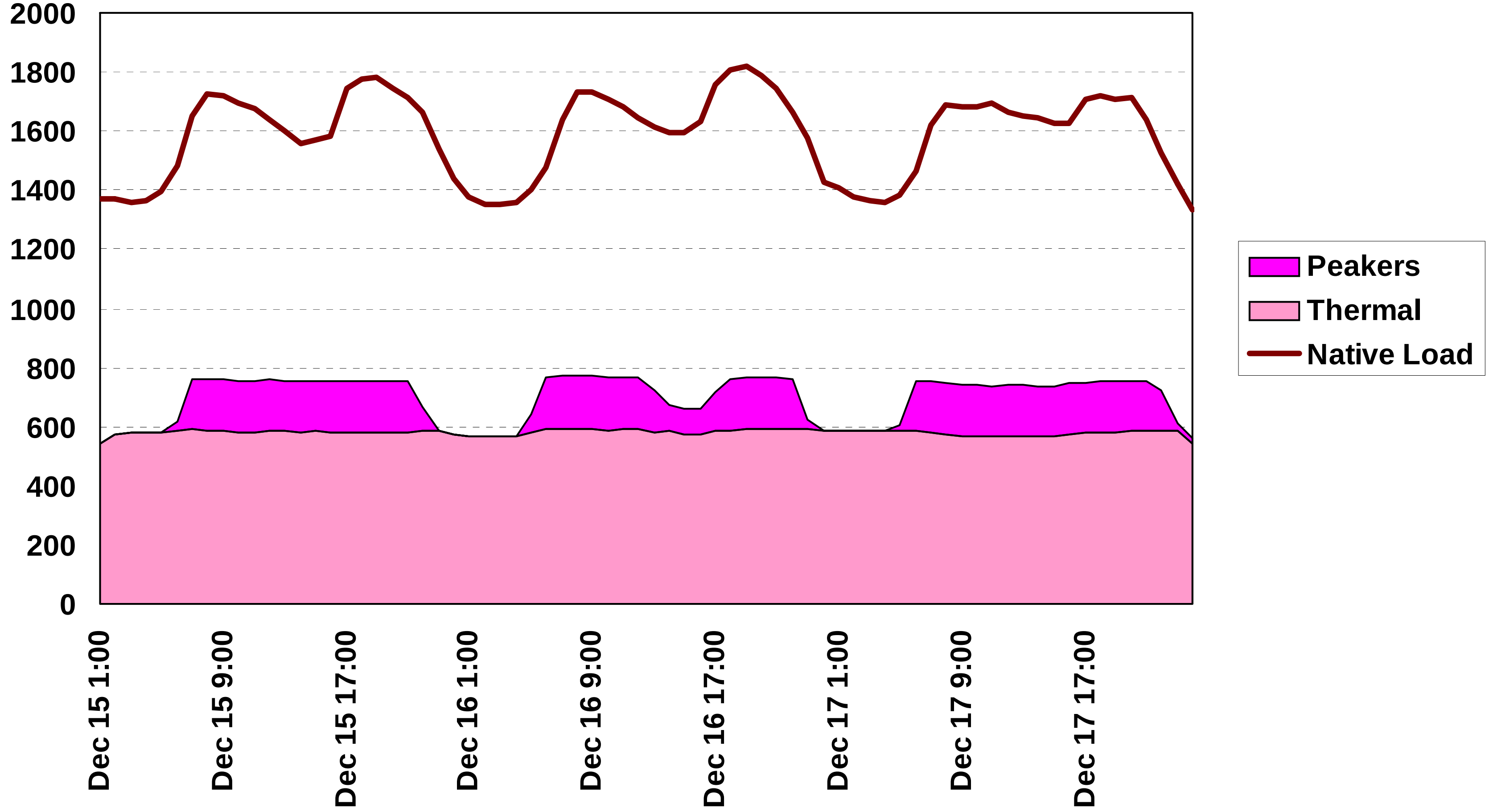
Thermal Generation



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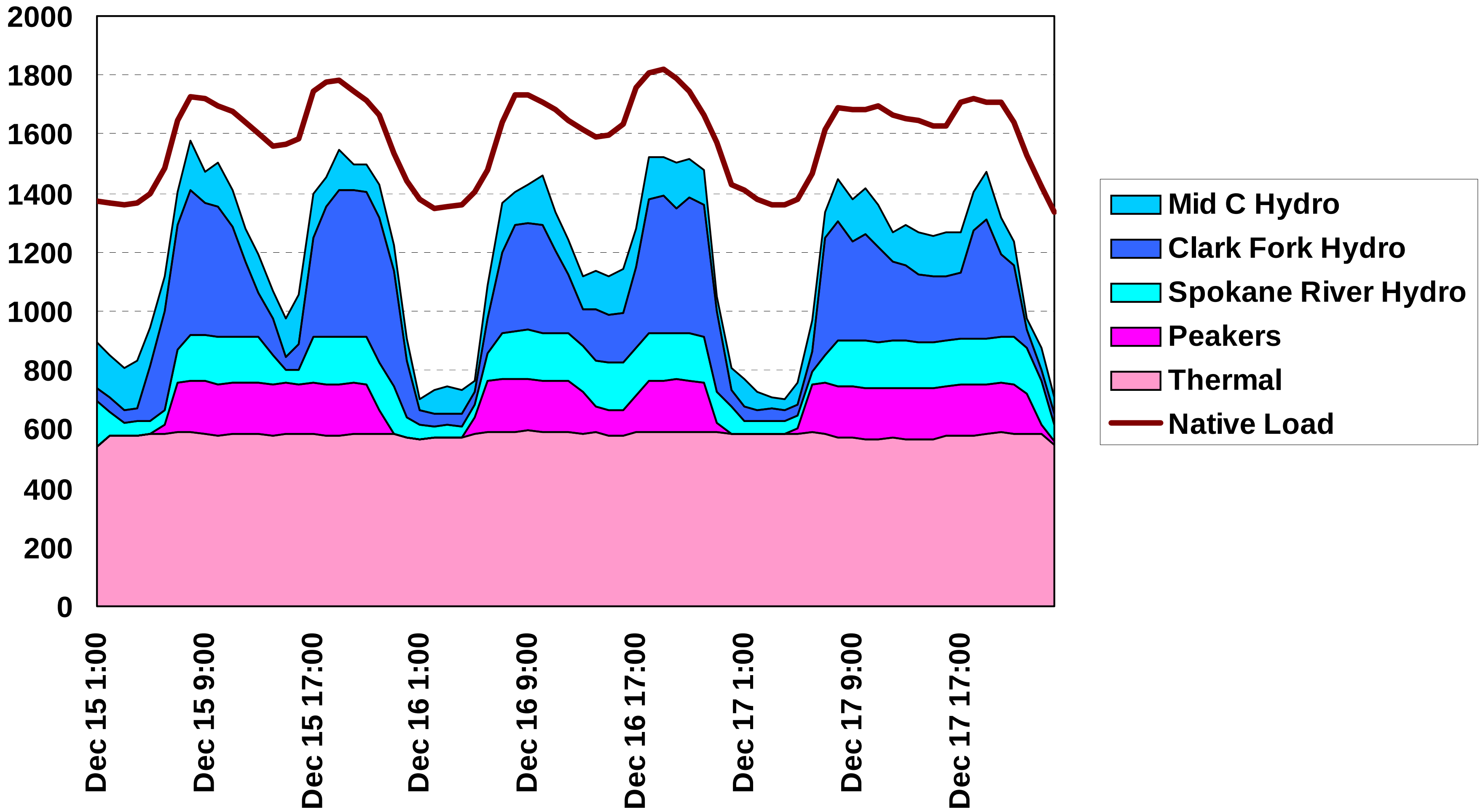
Hydro Generation



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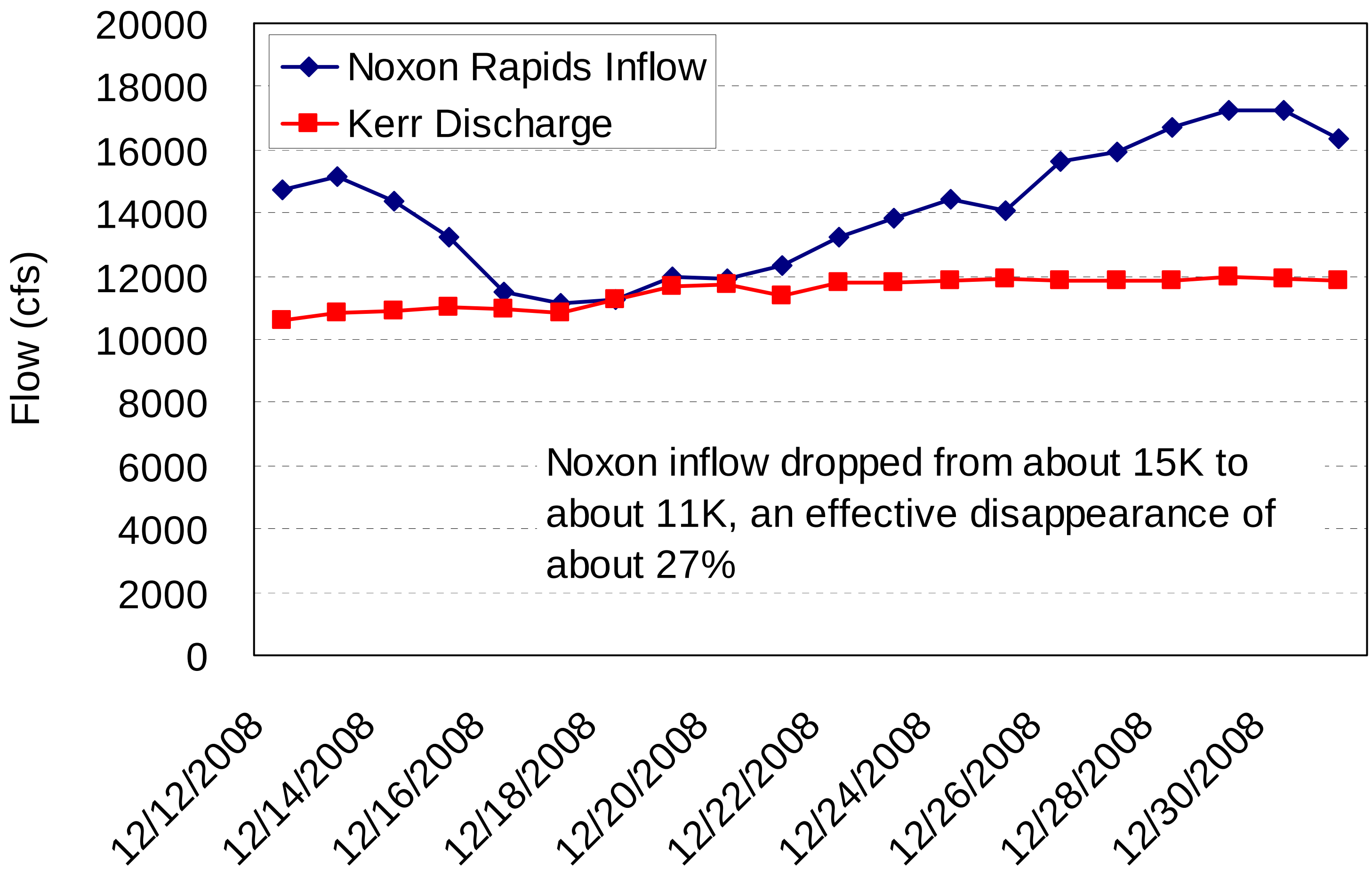
River icing was a problem!



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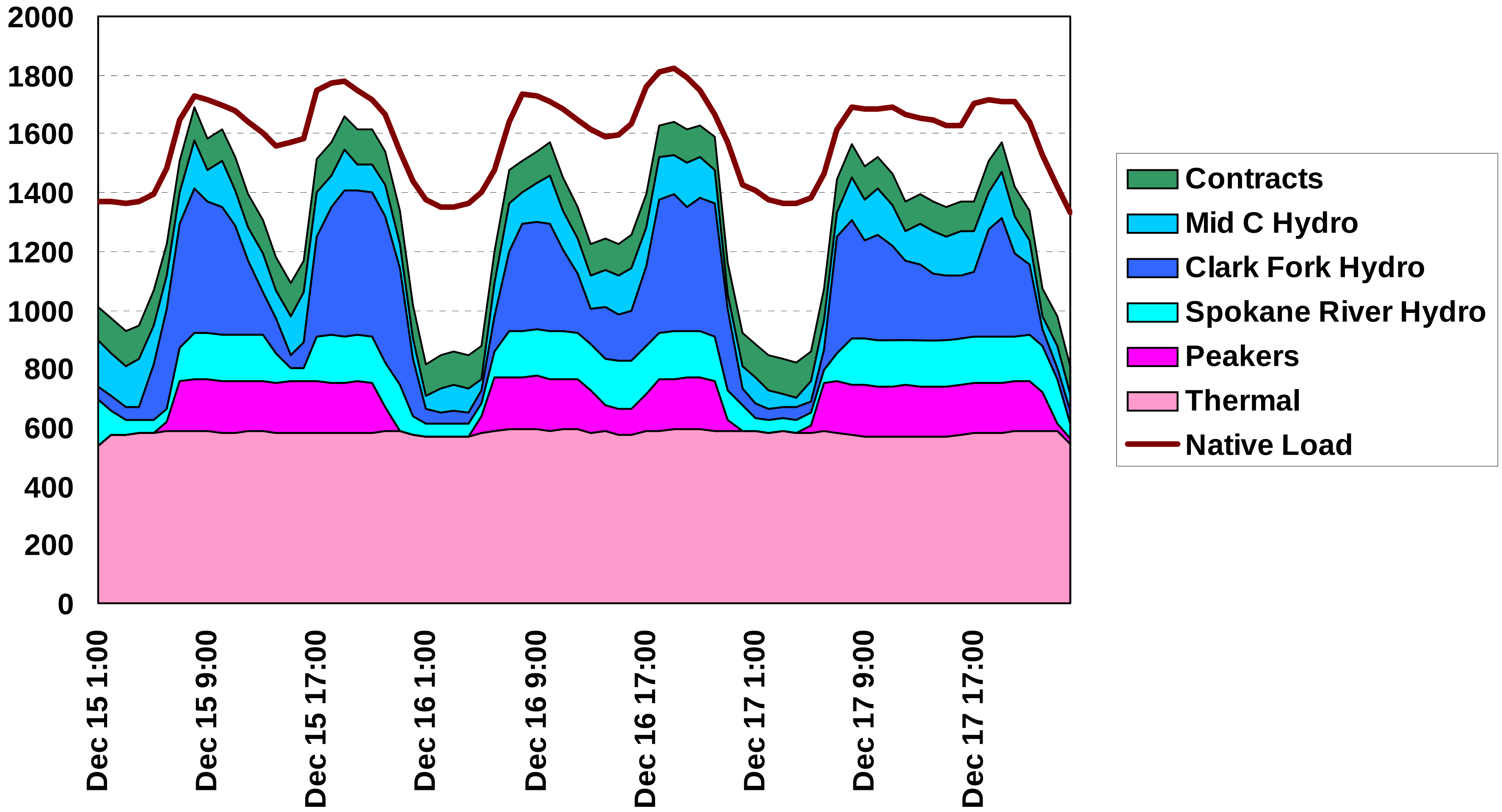
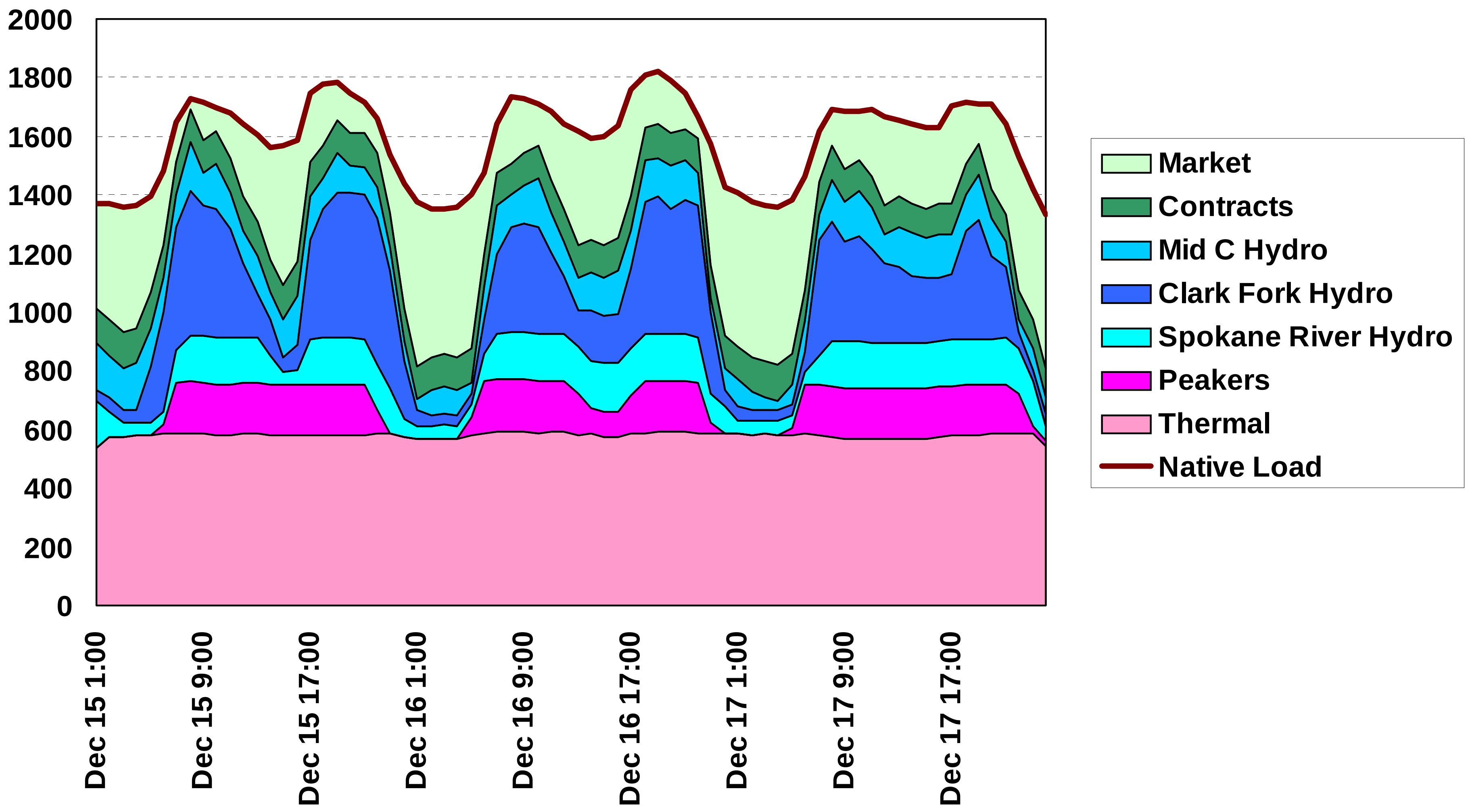
Contracts


2000
1800
1600
1400
1200
1000
800
600
400
200
0
Dec 15 1:00
Dec 15 9:00
Dec 15 17:00
Dec 16 1:00
Dec 16 9:00
Dec 16 17:00
Dec 17 1:00
Dec 17 9:00
Dec 17 17:00
Contracts
Mid C Hydro
Clark Fork Hydro
Spokane River Hydro
Peakers
Thermal
Native Load

Market Purchases



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Natural Gas & Electric Price Forecast- Update

Greg Rahn & James Gall

2009 Electric Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
January 28, 2009

Study Changes Since Last TAC

- Wood Mackenzie released its "Carbon Case #3"
  - Mid-range greenhouse gas mitigation scenario
  - Natural gas price impact from greenhouse legislation
  - Demand reductions due to greenhouse gas legislation
- Updated Natural Gas Price Forecast
  - Integrates near term economy
  - Short-term price collapse
  - Credit markets

Natural Gas Price Forecast Update

Supply Increase to Soften Price of Natural Gas

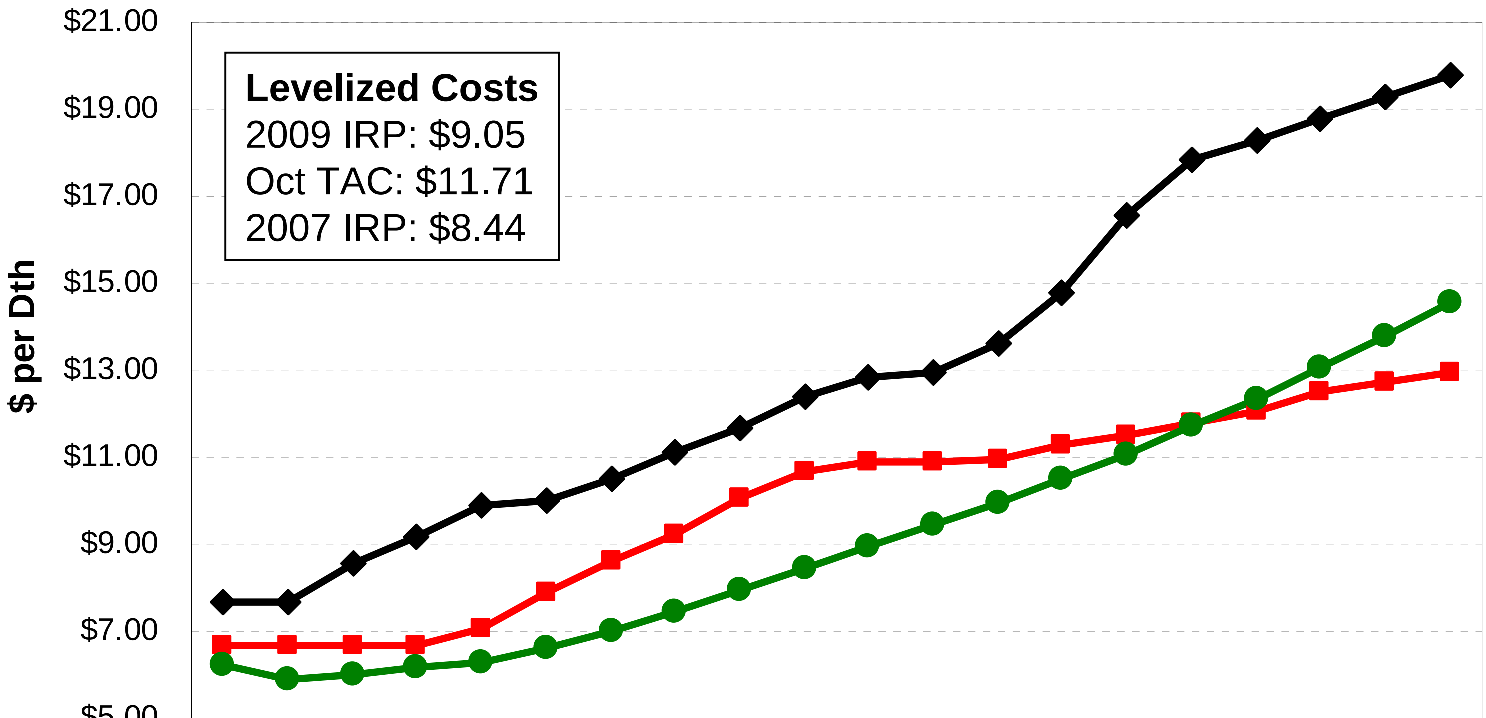
- Edinburgh, Scotland-based energy consultancy Wood Mackenzie said it expects spot prices for natural gas between $5 and $6 per million British thermal units for the next few years, with periods when prices will slip even lower.
- "We are now in a position of significant potential oversupply brought about by the huge success experienced in the development of shale gas plays," says Jen Snyder, head of North American gas research at Wood Mackenzie.

\- Russell Gold, The Wall Street Journal

November 25, 2008

Annual Natural Gas Price Comparison

Henry Hub Nominal $



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2009 IRP	6.66	6.69	6.69	6.69	7.05	7.87	8.63	9.20	10.05	10.69	10.89	10.86	10.94	11.26	11.50	11.76	12.04	12.49	12.72	12.96
Oct TAC	7.64	7.69	8.53	9.14	9.90	10.00	10.52	11.13	11.67	12.41	12.82	12.94	13.60	14.79	16.57	17.84	18.30	18.77	19.26	19.75
2007 IRP	6.23	5.91	6.00	6.15	6.30	6.59	6.98	7.47	7.95	8.44	8.94	9.43	9.95	10.50	11.08	11.70	12.35	13.04	13.77	14.55

2009 IRP: 2010-2013 Average Price of Consultants, EIA, and Forward Prices

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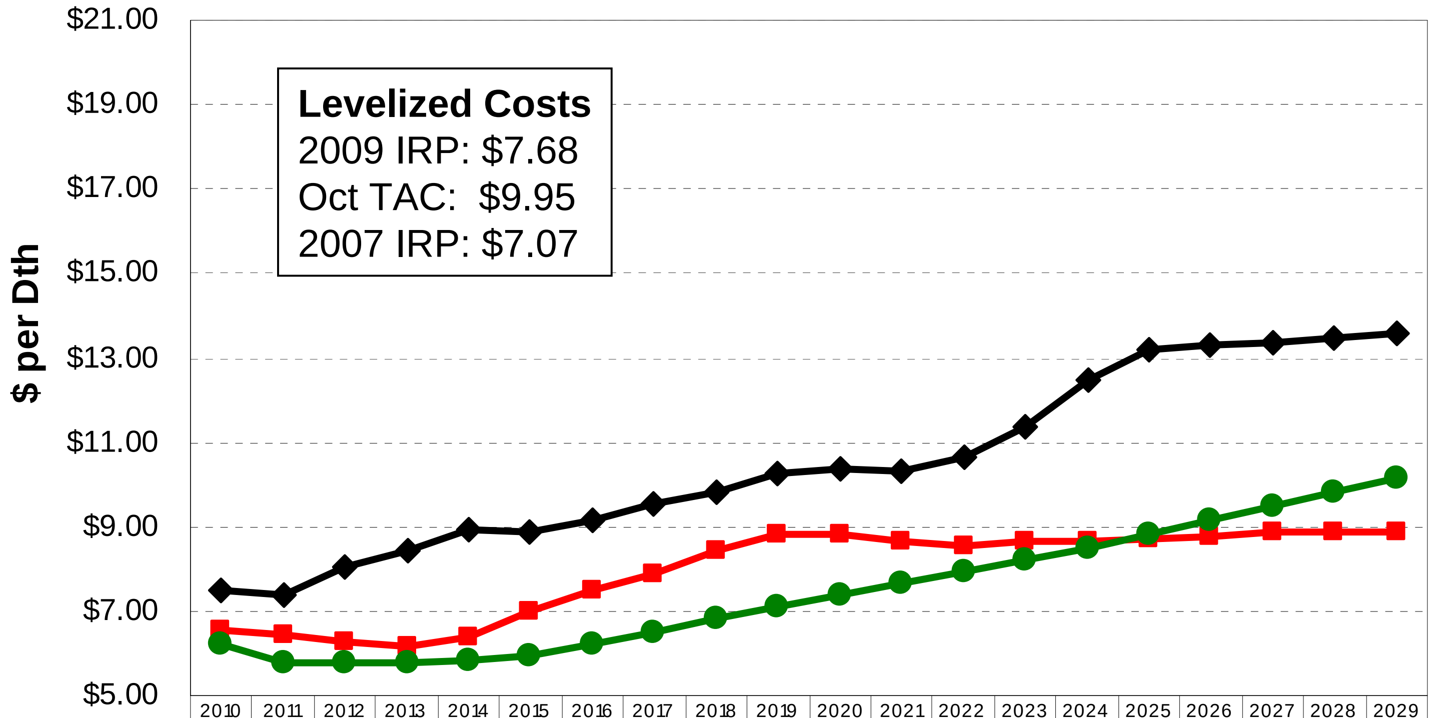
Annual Natural Gas Price Comparison

Henry Hub 2009 $



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2009 IRP	6.53	6.43	6.29	6.17	6.37	6.98	7.52	7.87	8.44	8.81	8.82	8.64	8.55	8.64	8.66	8.70	8.74	8.90	8.90	8.90
Oct TAC	7.49	7.39	8.03	8.43	8.96	8.88	9.17	9.52	9.80	10.23	10.38	10.29	10.63	11.35	12.48	13.20	13.29	13.37	13.47	13.56
2007 IRP	6.23	5.80	5.77	5.79	5.81	5.96	6.19	6.50	6.80	7.09	7.37	7.63	7.91	8.20	8.50	8.81	9.14	9.47	9.81	10.17

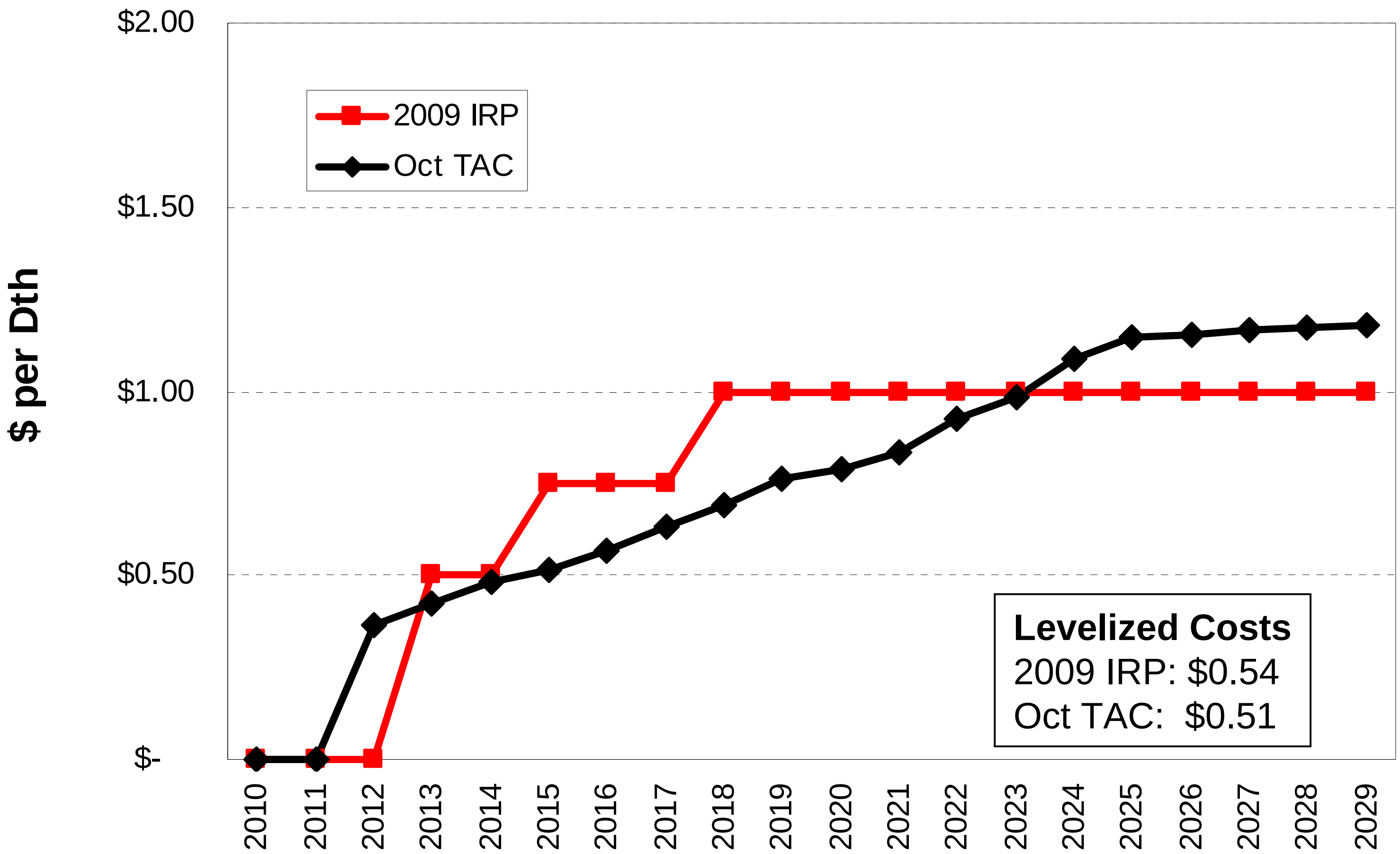
Greenhouse Gas Price Assumptions

- Based on the most recent 'discussion draft' proposal by Reps. Dingell and Boucher of the House Energy and Commerce Committee
- Wood Mackenzie made assumptions on the key components of the analysis such as caps on carbon prices, the allocation of carbon credits, the use of carbon offsets, and, nuclear and CCS technology availability.
- Wood Mackenzie's proprietary upstream oil, gas, and coal data and analysis are the cost and availability of fuel supplies, particularly to support an assumption to increase reliance on natural gas to meet near term emission reduction requirements.
- Carbon offsets/other industry represent difference between forecasted emissions and legislative goals

Source: Wood Mackenzie Carbon Case 3

Annual GHG Adder to Natural Gas Prices

2008 $



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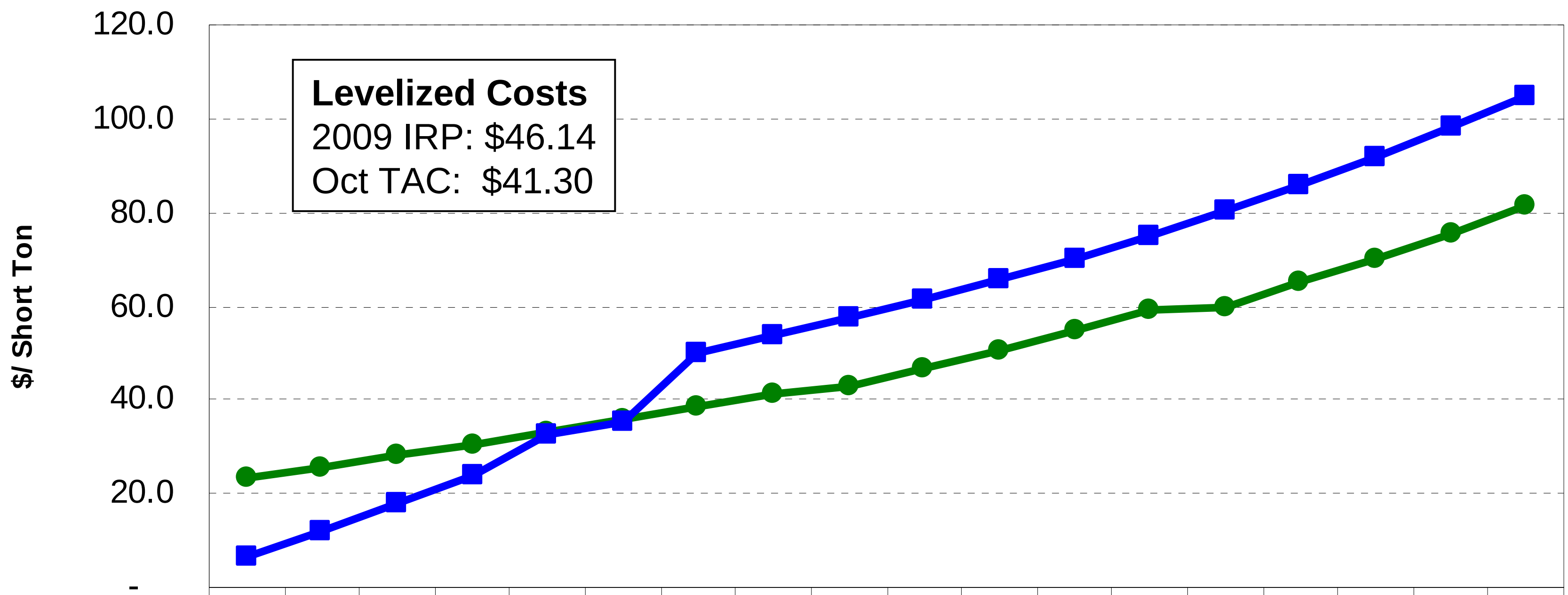
Annual GHG Adder per Ton of CO_2

Nominal $



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Oct TAC	23	26	28	30	33	36	39	41	43	47	51	55	59	60	65	70	76	81
2009 IRP	7	12	18	24	33	35	50	54	57	61	66	70	75	80	86	92	98	105

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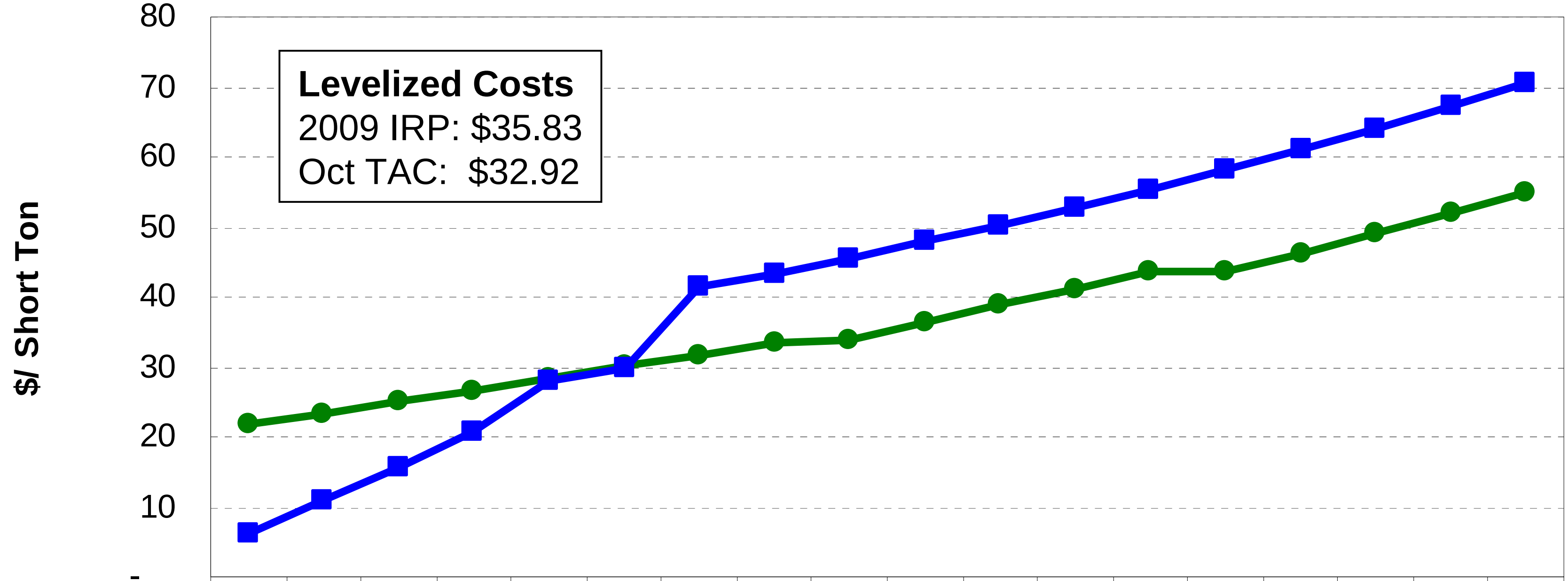
Annual GHG Adder per Ton of CO_2

2009 $



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Oct TAC	22	23	25	27	28	30	32	34	34	36	39	41	44	43	46	49	52	55
2009 IRP	6	11	16	21	28	30	41	43	46	48	50	53	55	58	61	64	67	71

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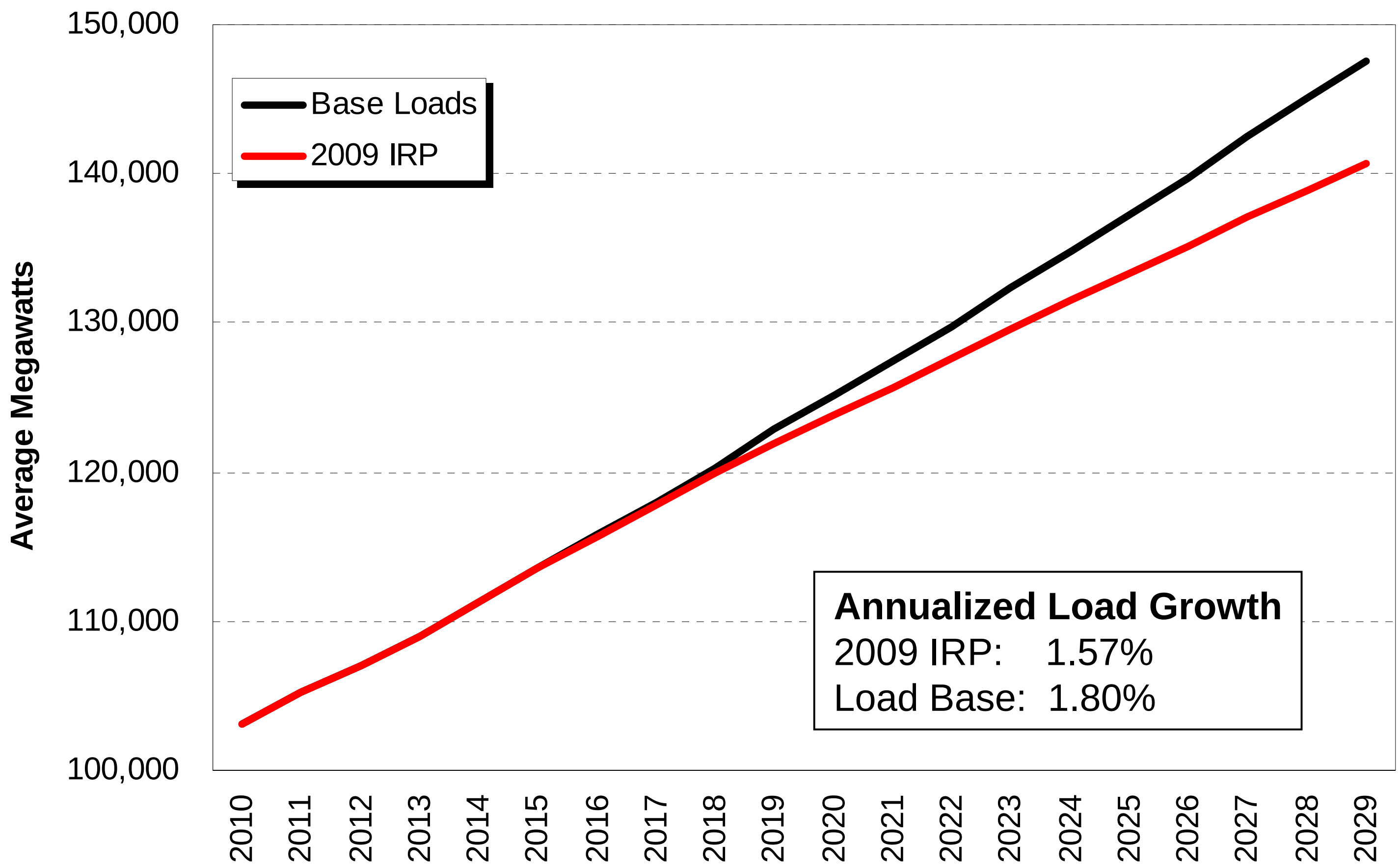
Western Interconnect Load Growth

Change with Greenhouse Gas Legislation



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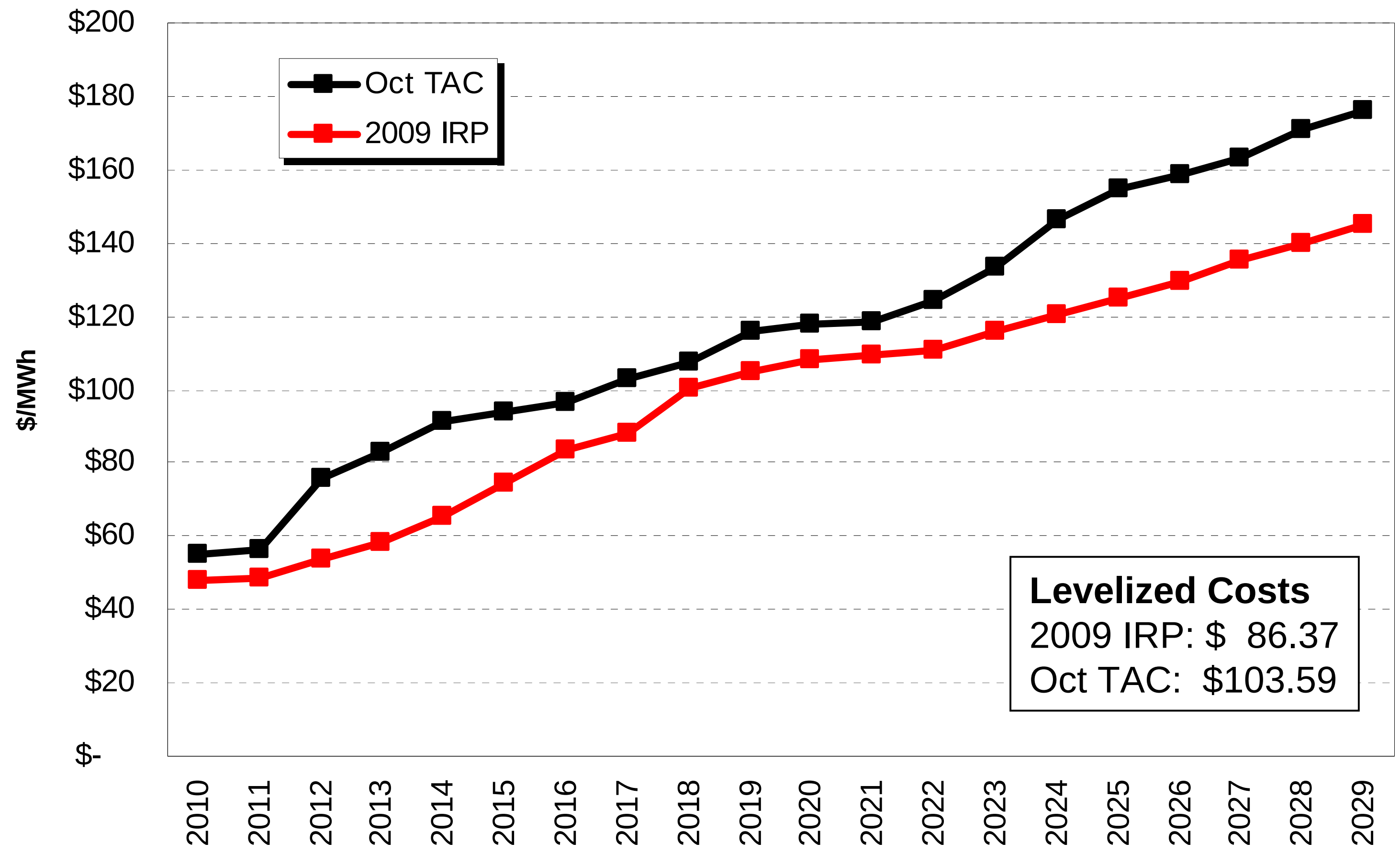
Last TAC Price Forecast vs 2009 IRP



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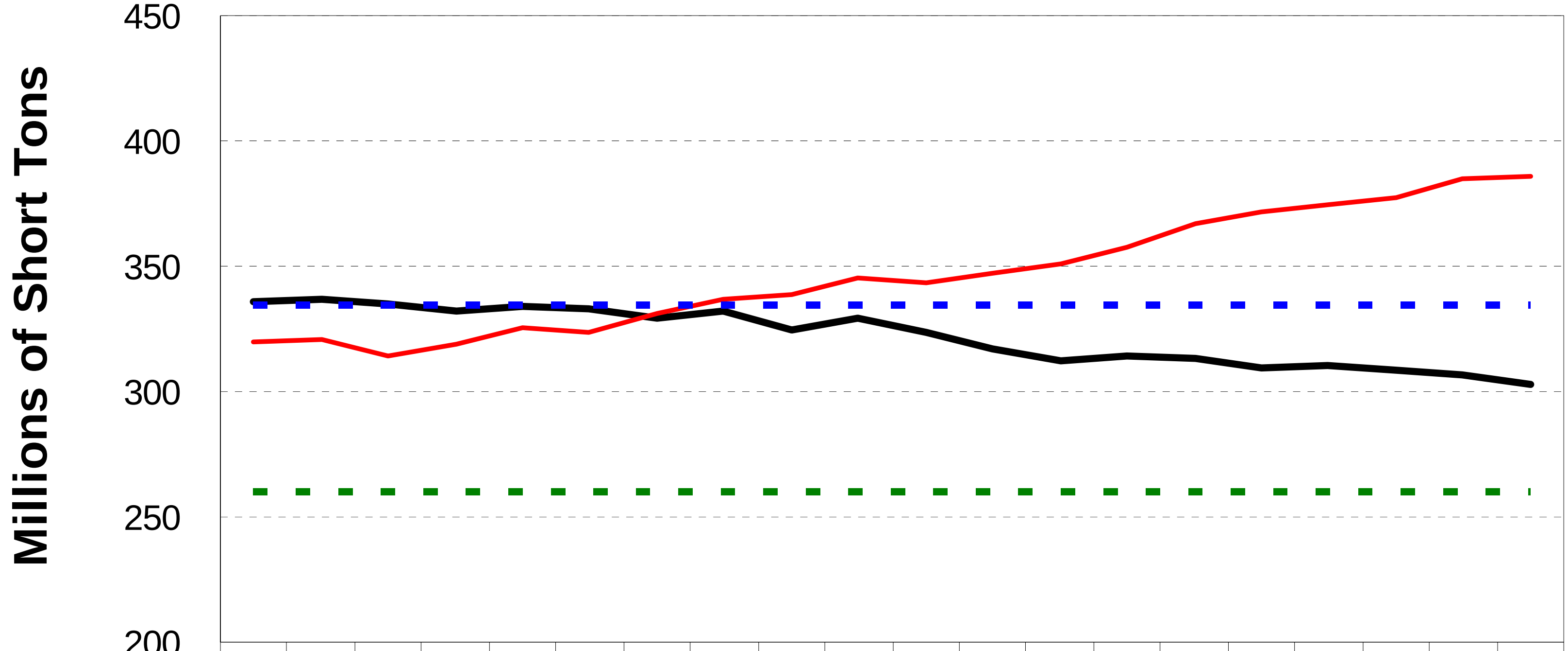
US Western Interconnect Greenhouse Gas Comparison



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2009 IRP	336	337	335	332	334	333	330	332	325	329	323	317	312	314	314	309	310	309	307	303
Oct TAC	319	321	314	319	325	324	331	337	338	345	343	347	351	357	367	371	375	377	385	385
2005 Levels	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334
1990 Levels	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259

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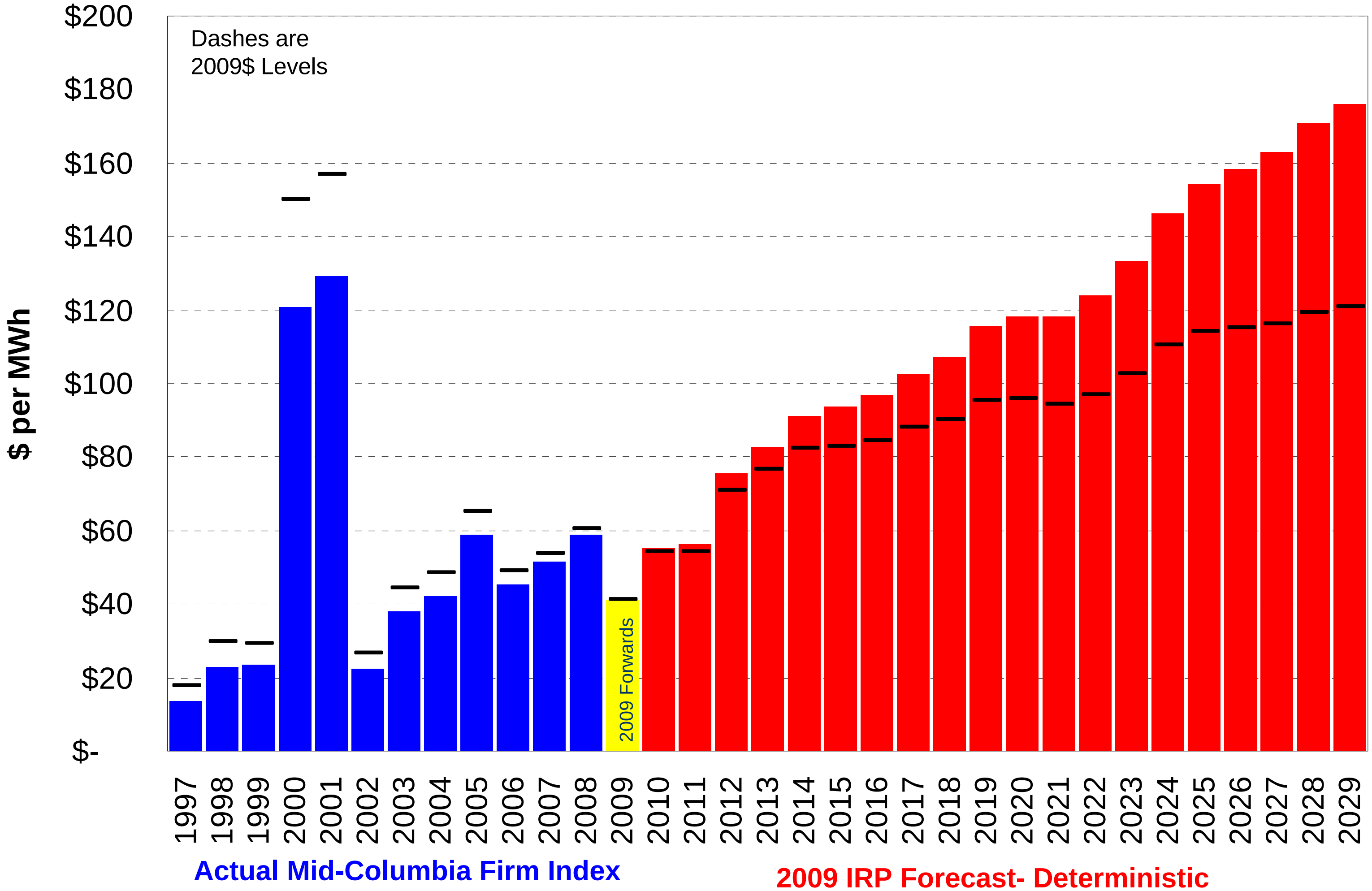
Mid-Columbia Actual & Forecast



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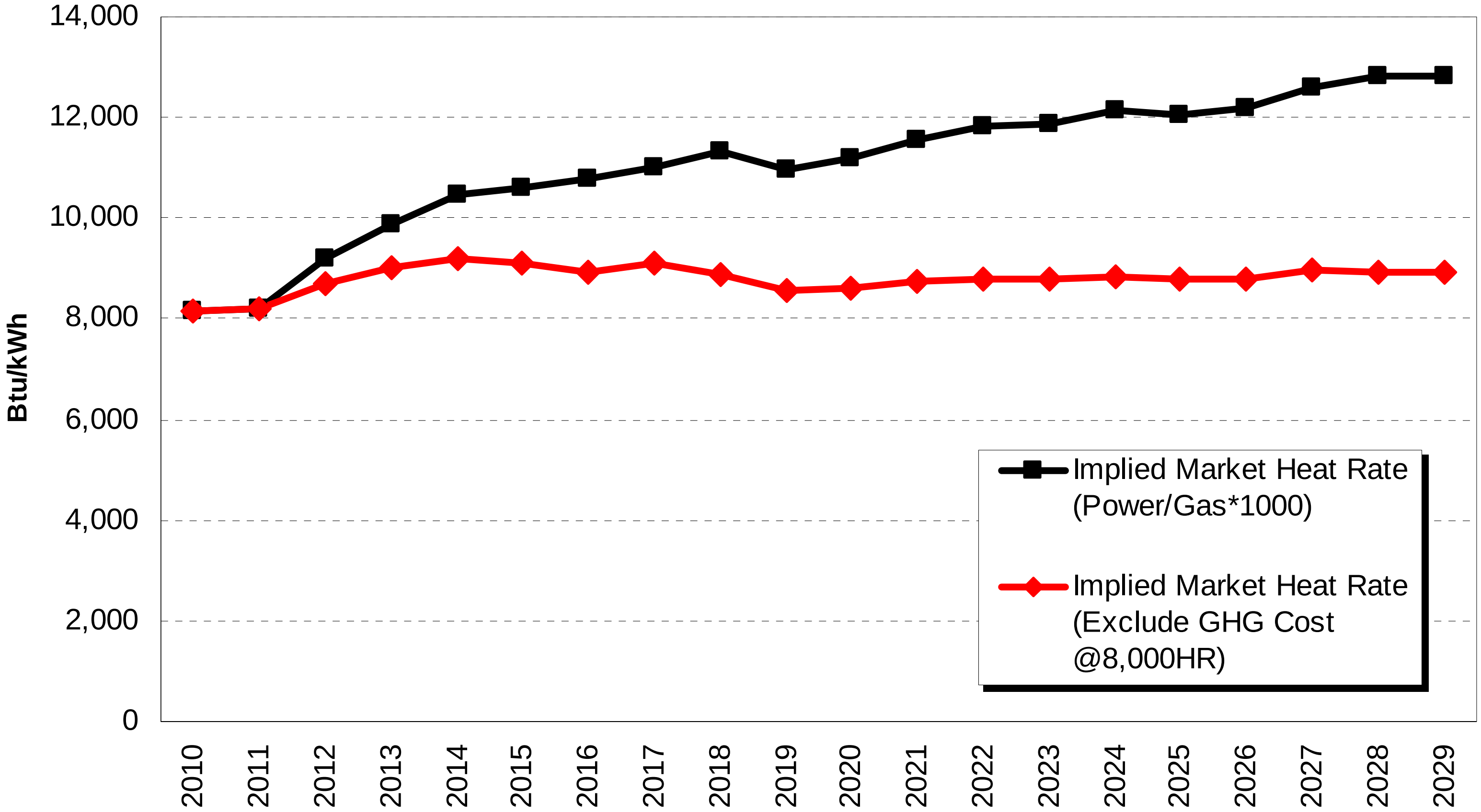
Implied Market Heat Rate

(Mid-Columbia/Stanfield*1000)



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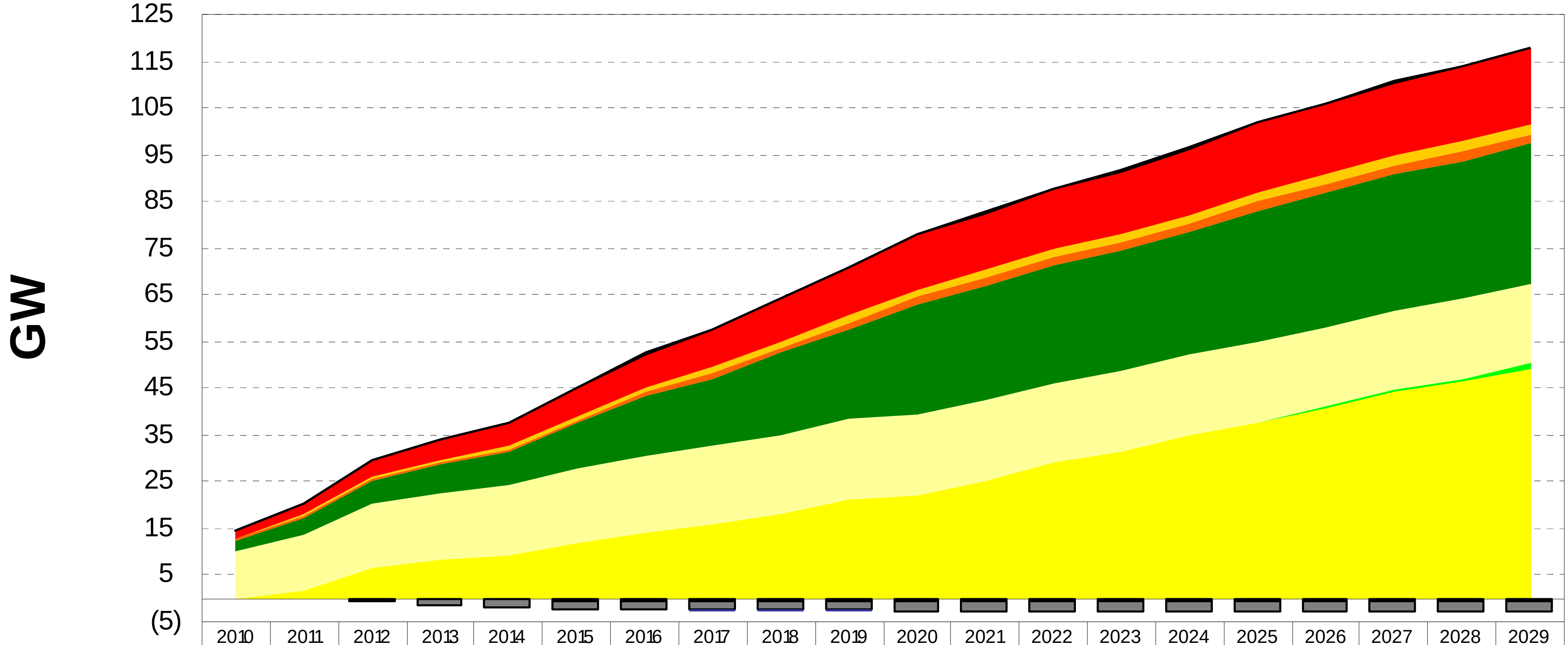
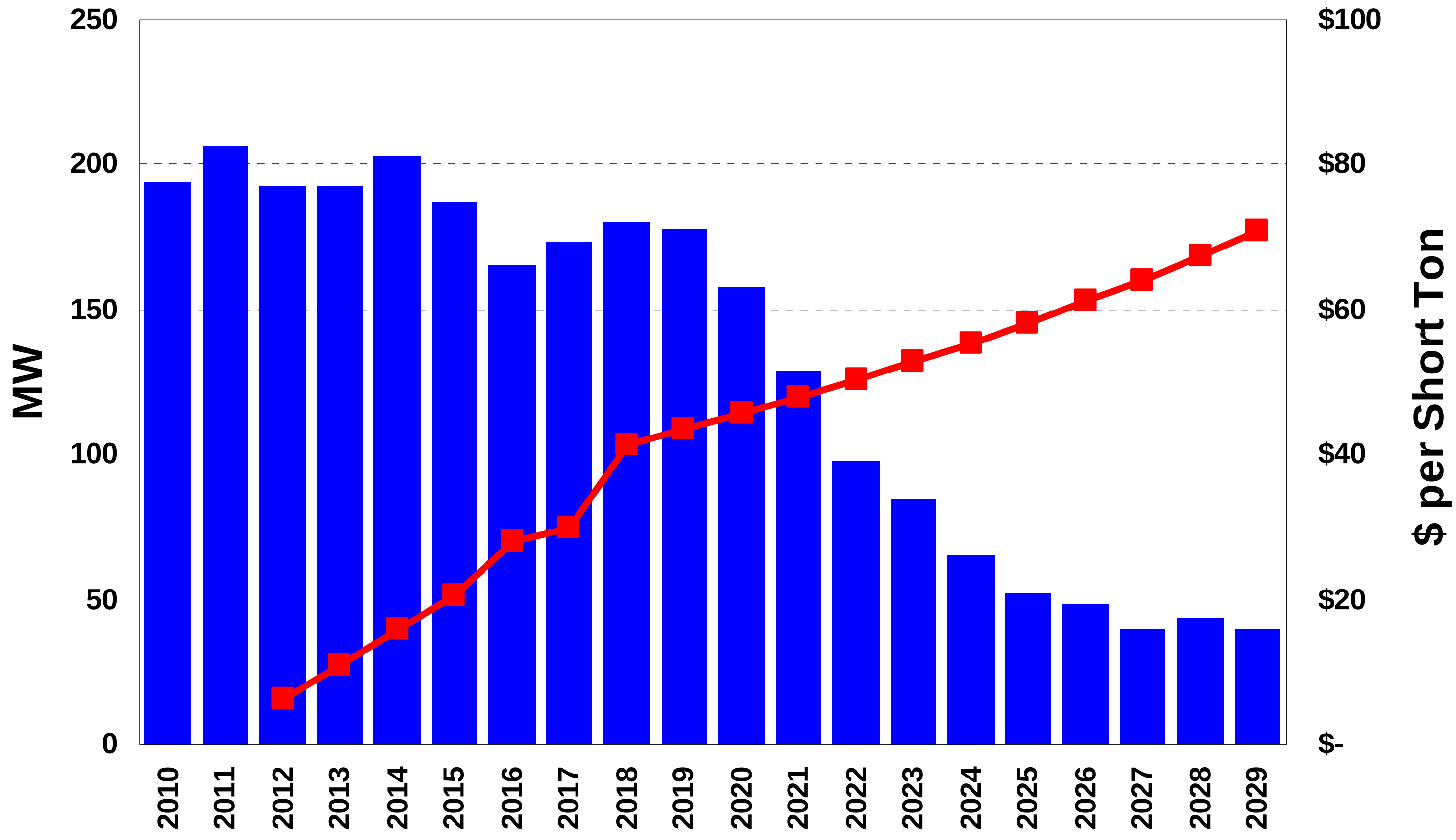
Western Interconnect New Resources



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Hydro	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	2	3	3	4	5	6	7	8	9	10	12	12	13	13	14	15	15	16	16	16
Geothermal	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2
Biomass	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2
Wind	3	4	5	6	7	10	13	15	18	19	24	25	25	26	26	28	29	29	29	30
SCCT	10	12	14	15	15	16	16	17	17	17	17	17	17	17	17	17	17	17	17	17
Coal Seq	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1
CCCT	-	2	7	8	9	12	14	16	18	21	22	25	29	32	35	38	41	44	47	49
Oil- retire	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NG- retire	(0)	(0)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Coal- retire	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)

Colstrip Generation & CO_2 Legislation



Stochastic Analysis

Stochastic Study CPU Requirements

- 20-year hourly simulations, 250 times (tested as high as 500)
- Uses 25 CPU and 1 data server
- 26.5 GB output database per study
- 6 hours per simulation, 1,500 hours of computing time
- 2.5 days to complete a study

Long-Term Correlation Matrix

	Gas Prices	GHG Prices	NO_X Prices	SO_2 Prices	New Coal Prices	Hog Fuel Prices	Load Growth
Gas Prices	1.00						
GHG Prices	0.50	1.00					
Hg Prices		-0.50	1.00				
NO_X Prices		0.75	1.00	1.00			
SO_2 Prices		0.75	1.00	1.00	1.00		
New Coal Prices		-0.25	-0.25	-0.25	1.00	1.00	
Hog Fuel Prices	0.50	0.50				1.00	1.00

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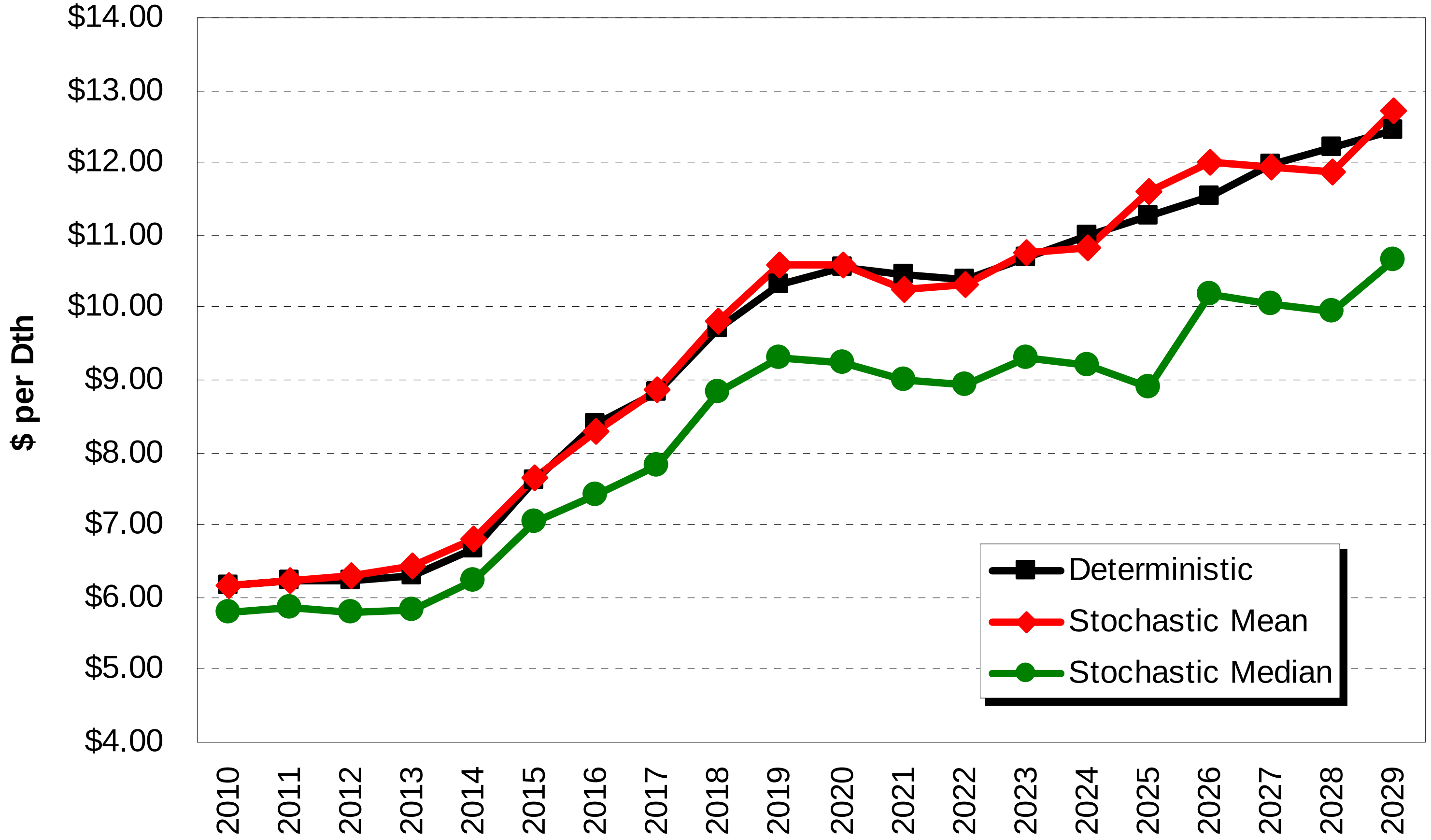
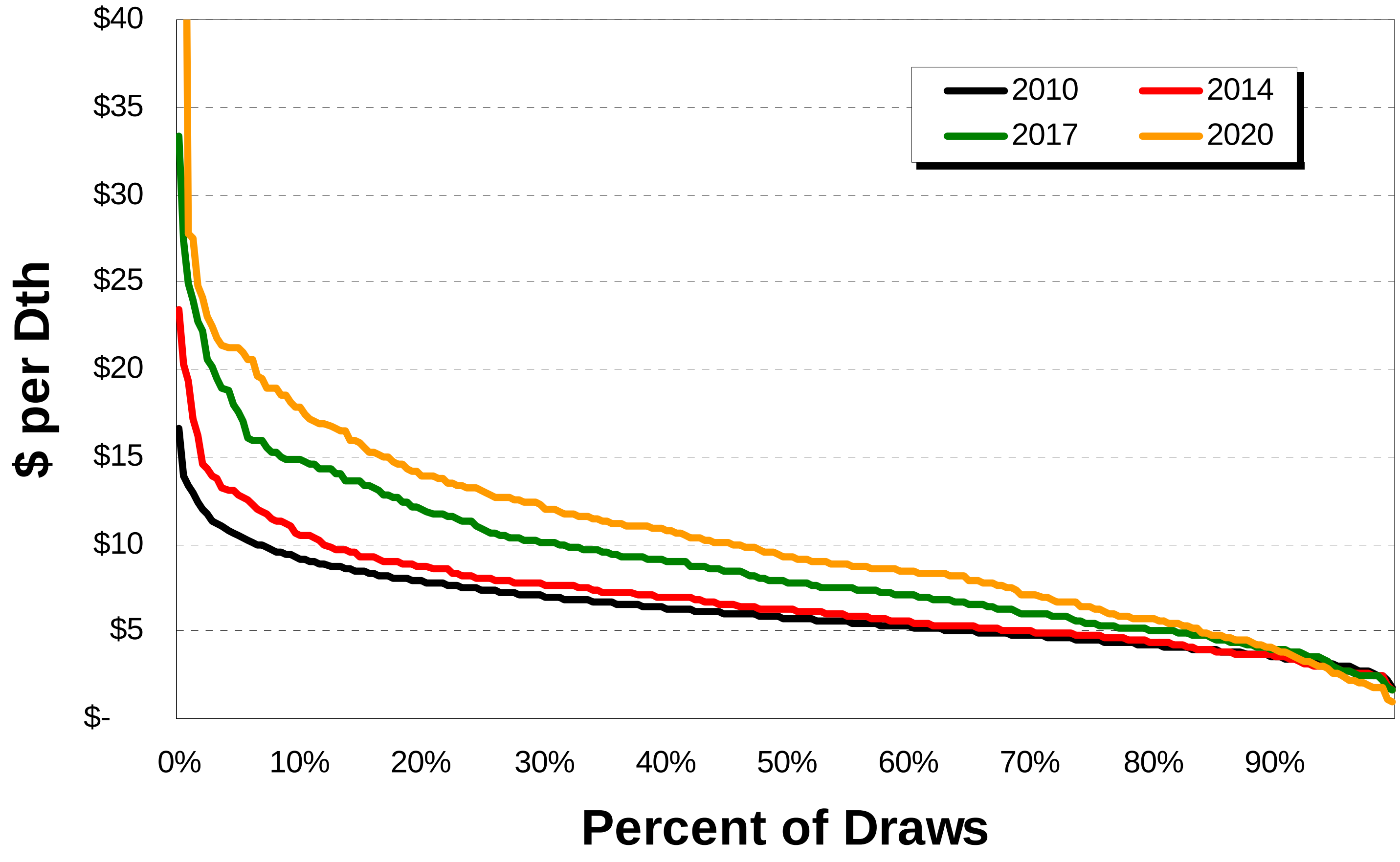
Annual Henry Hub Prices



Annual Henry Hub Prices

Select Years



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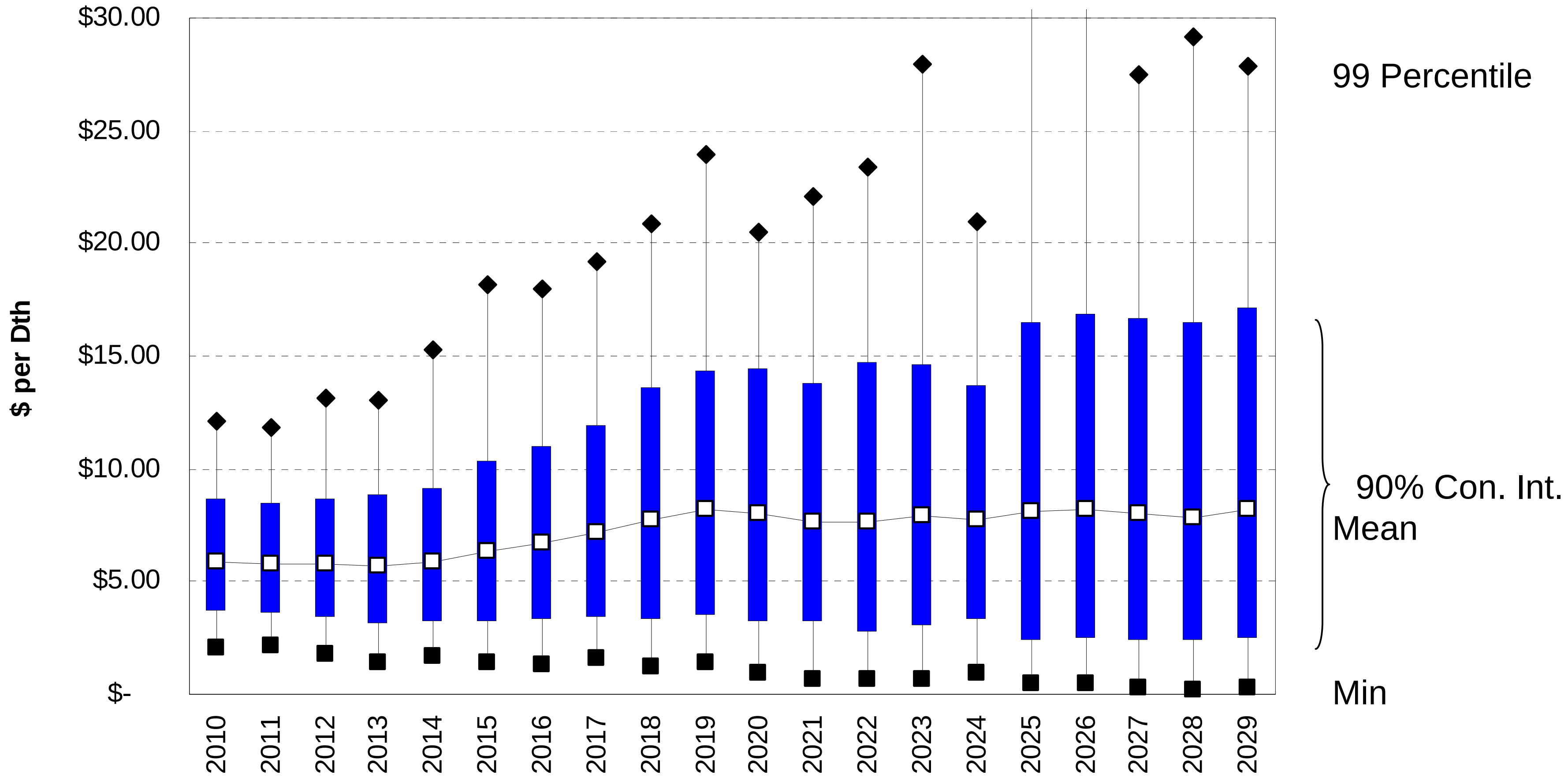
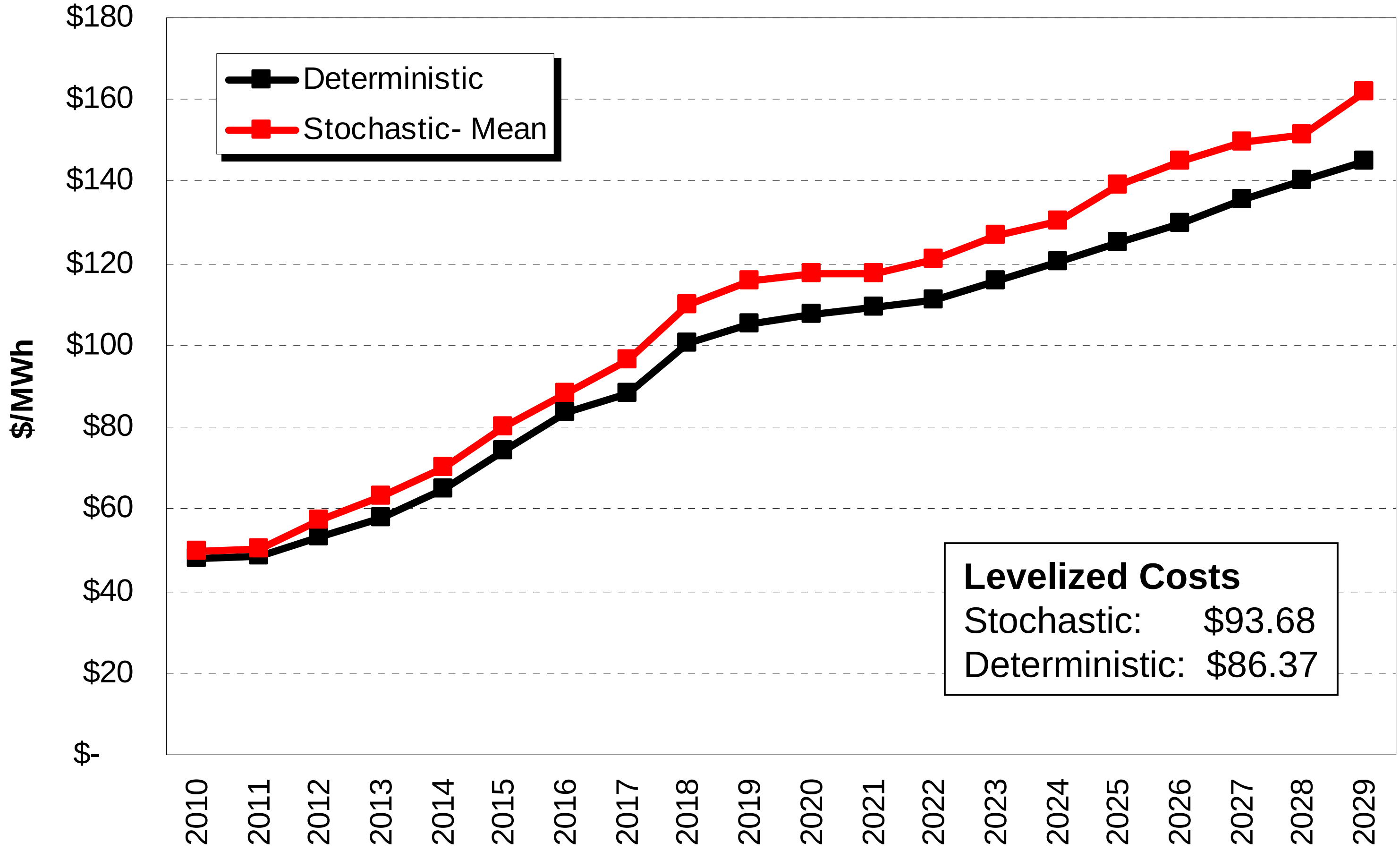
Annual Henry Hub Stochastic Price Ranges



Annual Mid-Columbia Electric Prices

Deterministic vs. Stochastic Prices



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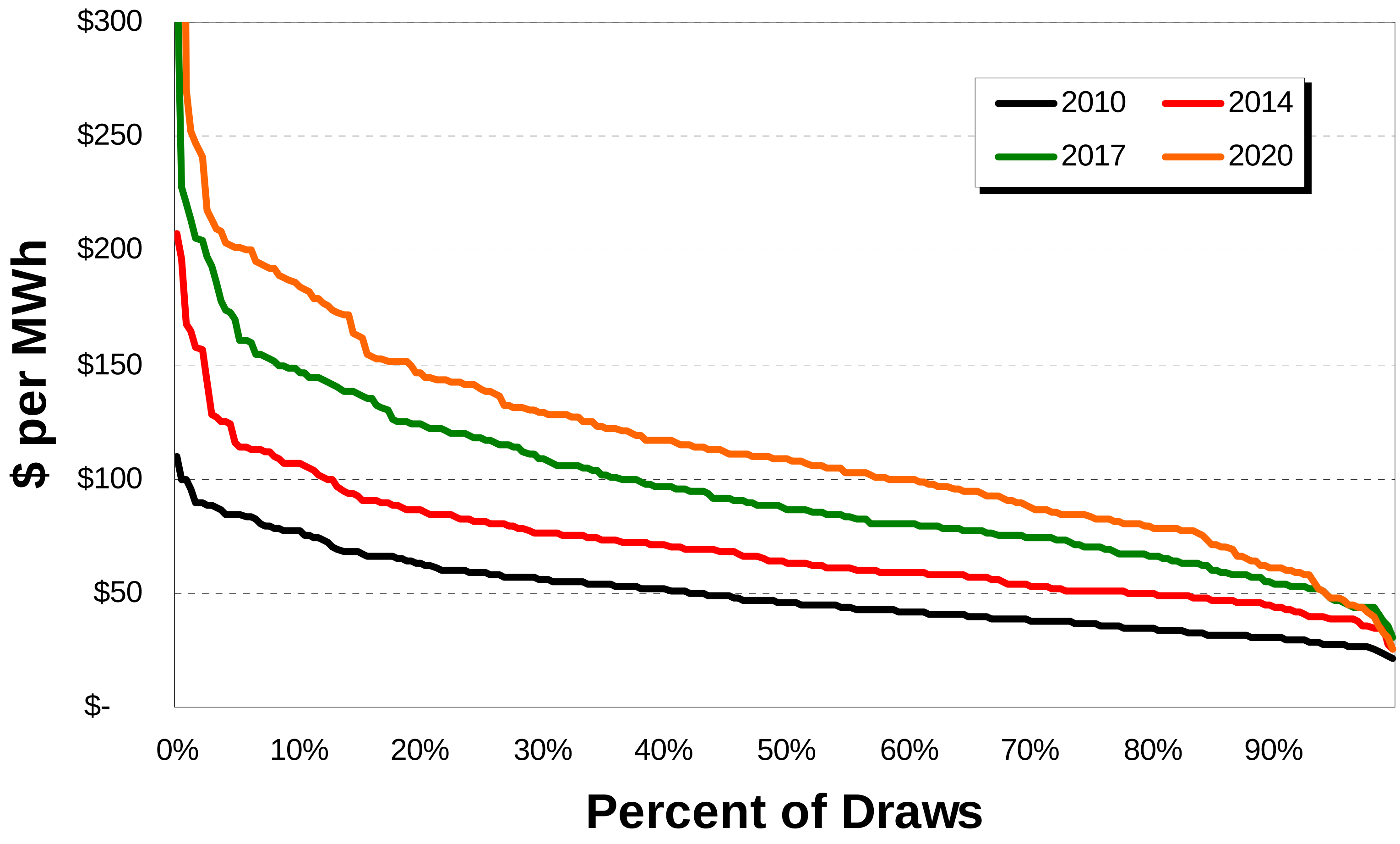
Annual Avg Mid-Columbia Prices

Select Years



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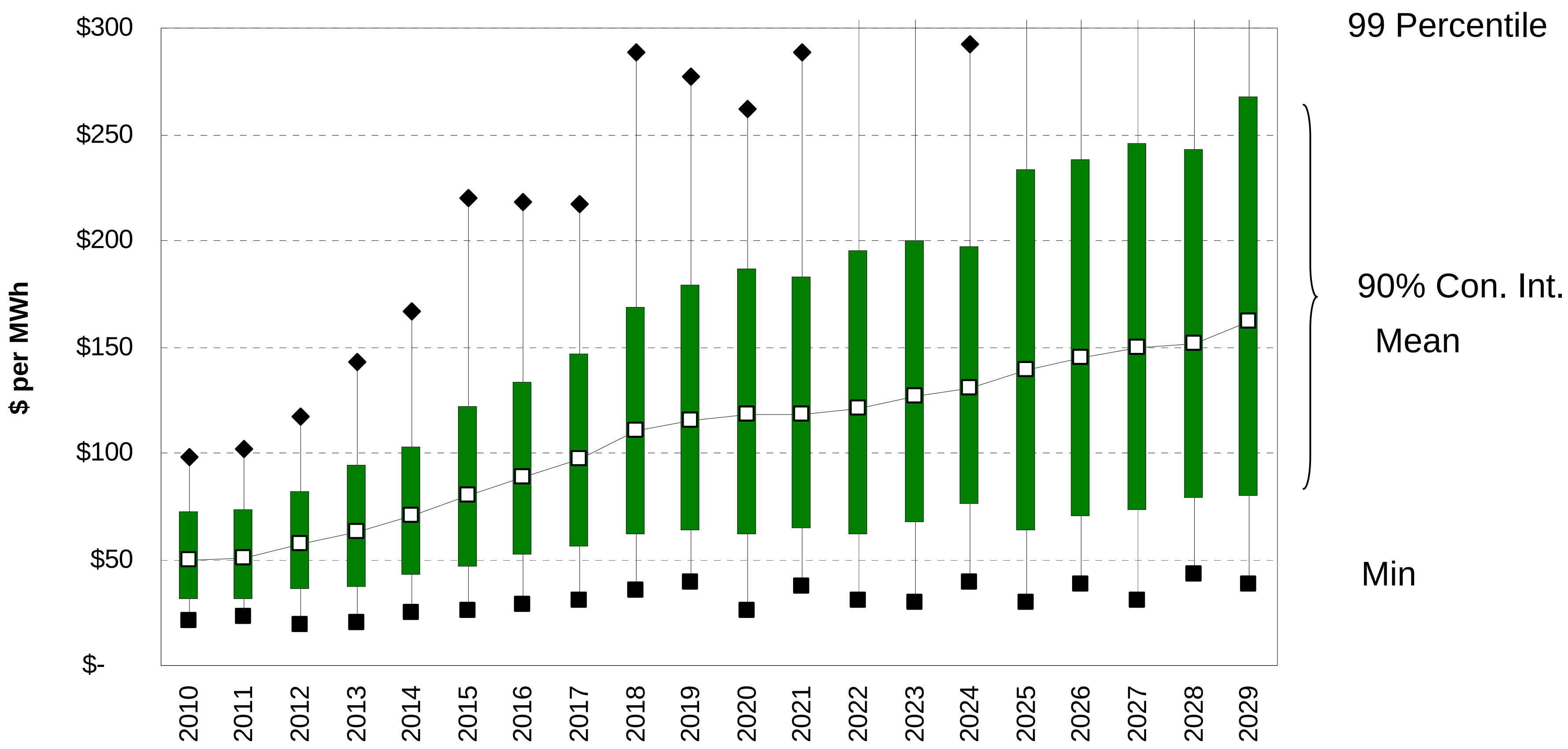
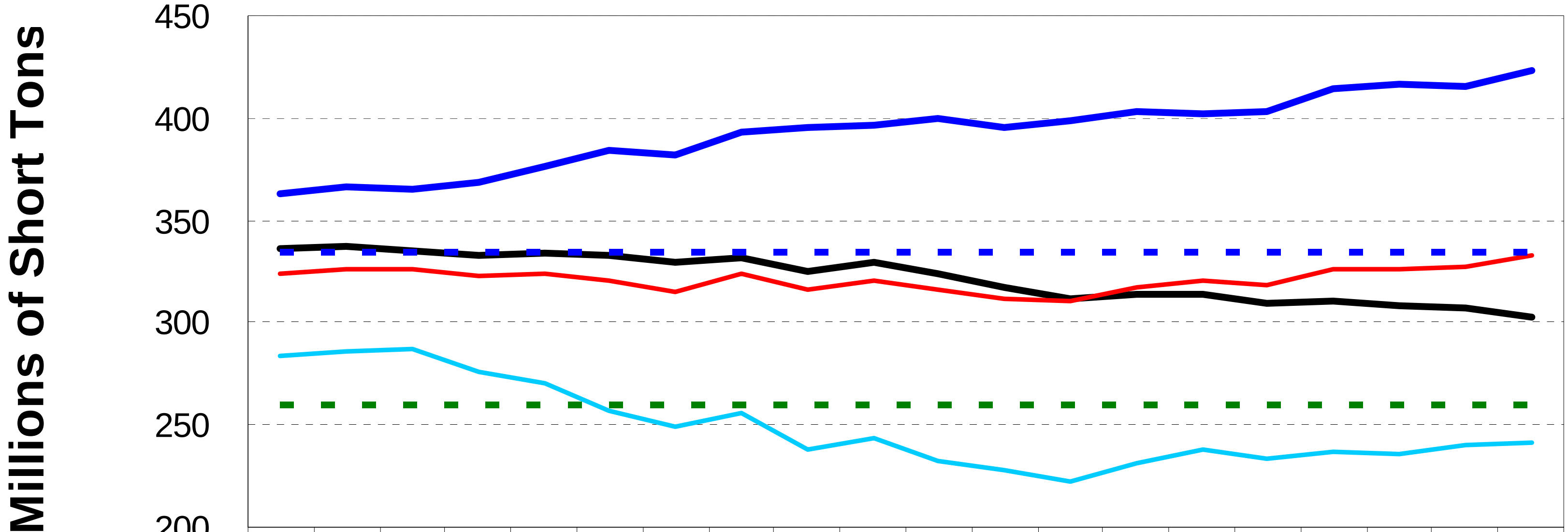
Annual Mid-Columbia Stochastic Price Results



US- Western Interconnect Greenhouse Gas Emissions By Year



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Deterministic	336	337	335	332	334	333	330	332	325	329	323	317	312	314	314	309	310	309	307	303
Mean	323	326	326	322	323	321	315	324	316	320	316	312	311	317	320	319	326	326	328	333
Upper End Int 80%	363	366	365	369	376	385	382	393	395	397	400	395	398	403	402	403	415	417	415	424
Low er End Int 80%	284	286	287	276	270	257	249	256	238	243	233	228	223	232	238	234	237	236	240	241
2005 Levels	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334
1990 Levels	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259	259

2009 IRP Resource Assumptions

John Lyons, Ph.D.

2009 Electric Integrated Resource Plan

Fourth Technical Advisory Committee Meeting

January 28, 2009

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Supply Side Resources

- Resource lists and data are developed from a variety of sources including: internal research, Power Council, consulting firms, published reports, and government studies
- Data is used to develop generic resource costs
- Fewer types of coal resources are included – only ultra critical and IGCC plants are being modeled for the 2009 IRP
- Alberta oil sands are not included as a resource option
- Adding more specifics for the Other Renewable Resources category – various geothermal, biomass, and solar resource technologies are being modeled separately for the 2009 IRP
- Pipeline cogeneration has been dropped due to lack of sufficient data

Non-Renewable Supply Side Resources

- Natural Gas Combined Cycle (CCCT)
  - 2 x 1 and 1 x 1 with duct burner water cooled (1x1 for PRS)
  - 2 x 1 and 1 x 1 with duct burner air cooled
  - 600 MW with sequestration
- Natural Gas-Fired Simple Cycle – Aero, Frame, and Hybrid
- Small cogeneration (< 5 MW)
- Coal: ultra critical, IGCC, and IGCC with sequestration
- Nuclear: only alllowed in scenario studies

Renewable Supply Side Resources

- Geothermal
- Wind – 100 MW, < 5 MW, and offshore
- CCCT Wood Boiler
- Wood Gasification Conversion
- Open Loop Biomass – landfill gas, wood, waste, etc.
- Closed Loop Biomass
- Solar Photovoltaic
- Solar Thermal
- Roof Top Solar
- Tidal Power
- Hydrokinetics
- Run of River Hydro
- Pumped Storage

Avista Resources and Upgrades

Hydro resources included as resource options

- Little Falls Unit #1 – 4 Upgrades
- Post Falls Unit #6 Upgrade
- Upper Falls Upgrade

Hydro resources considered for further study

- Long Lake new unit and new powerhouse
- Cabinet Gorge #5

Scheduled upgrades and resources presently included in the L&R

- Noxon Rapids Units #1 – 4 Upgrades (2009 – 2012)
- Lancaster Generation Facility Tolling Agreement (2010)

Transmission & Distribution Efficiencies

John Gibson

2009 Electric Integrated Resource Plan

Fourth Technical Advisory Committee Meeting

January 28, 2009

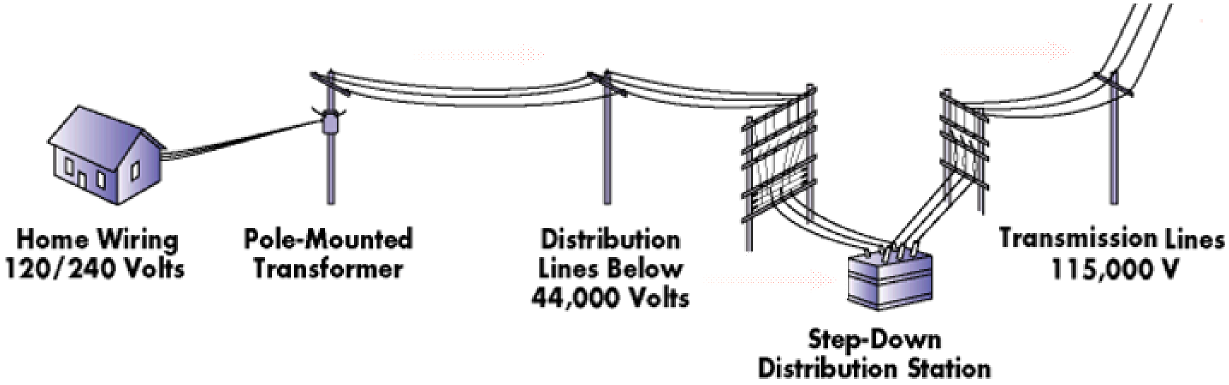
AVISTA®

Introduction – System Efficiencies

- Distribution System
  - Analysis Methodology
  - Analysis Criteria
  - Prioritization Tabulation
  - Pilot Project: 9CE12F4
- Transmission System
  - Load Density
  - Grid Topology

Distribution Efficiency Programs

- Split feeders
- Distribution transformers efficiency – no load loss
- Secondary districts
- Reconductoring
- Reactive loading
- Voltage regulation



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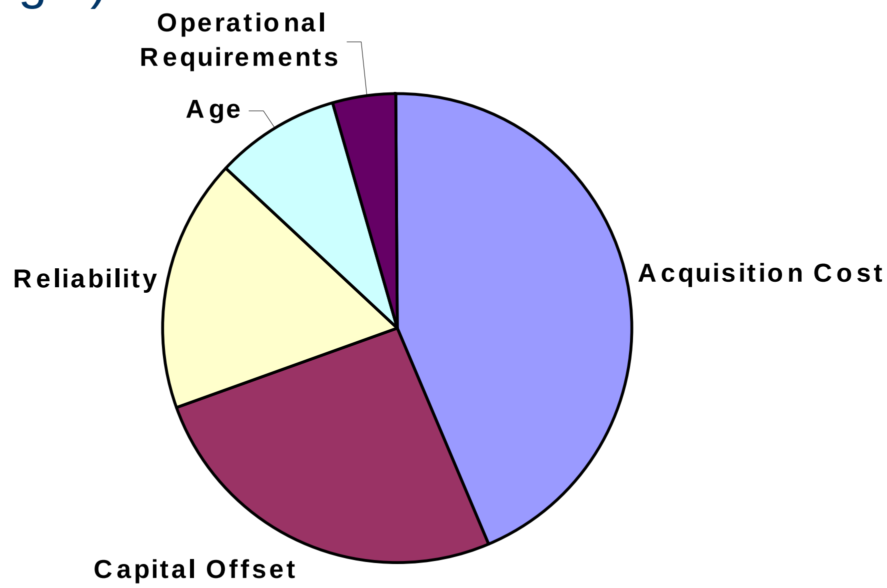
Distribution Analysis Criteria

- Energy efficiency upgrades (acquisition cost)
- Capital offset (5year capital budget)
- Reliability Index
- Equipment age profile
- Operational requirements



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Distribution Prioritization Tabulation

Feeder Project	Age	Reliability	Avoided Cost	Capital Offset	Operational Requirements	Overall Score
KET12F2	25.32	328	$85.07	$400,000	Low	0.596
ORI12F3	27.44	285	$73.30	$0	Low	0.591
SPI12F1	27.57	310	$90.76	$220,000	Low	0.558
PRV4S40	23.34	331	$94.10	$0	Low	0.544
ORO1281	30.33	197	$78.97	$0	Low	0.533
SUN12F3	25.20	312	$112.78	$0	High	0.522
COB12F2	27.32	283	$94.81	$0	Low	0.519
LAT421	27.39	309	$102.59	$0	Low	0.508
COB12F1	30.44	303	$108.77	$250,000	Low	0.502
CLV12F4	30.43	323	$108.47	$28,333	Low	0.502
LF34F1	21.71	299	$102.91	$0	Low	0.499
STM631	23.29	317	$109.19	$0	Low	0.490
SUN12F1	31.73	291	$125.03	$0	High	0.483
CLV12F2	30.06	298	$125.81	$780,833	Low	0.481

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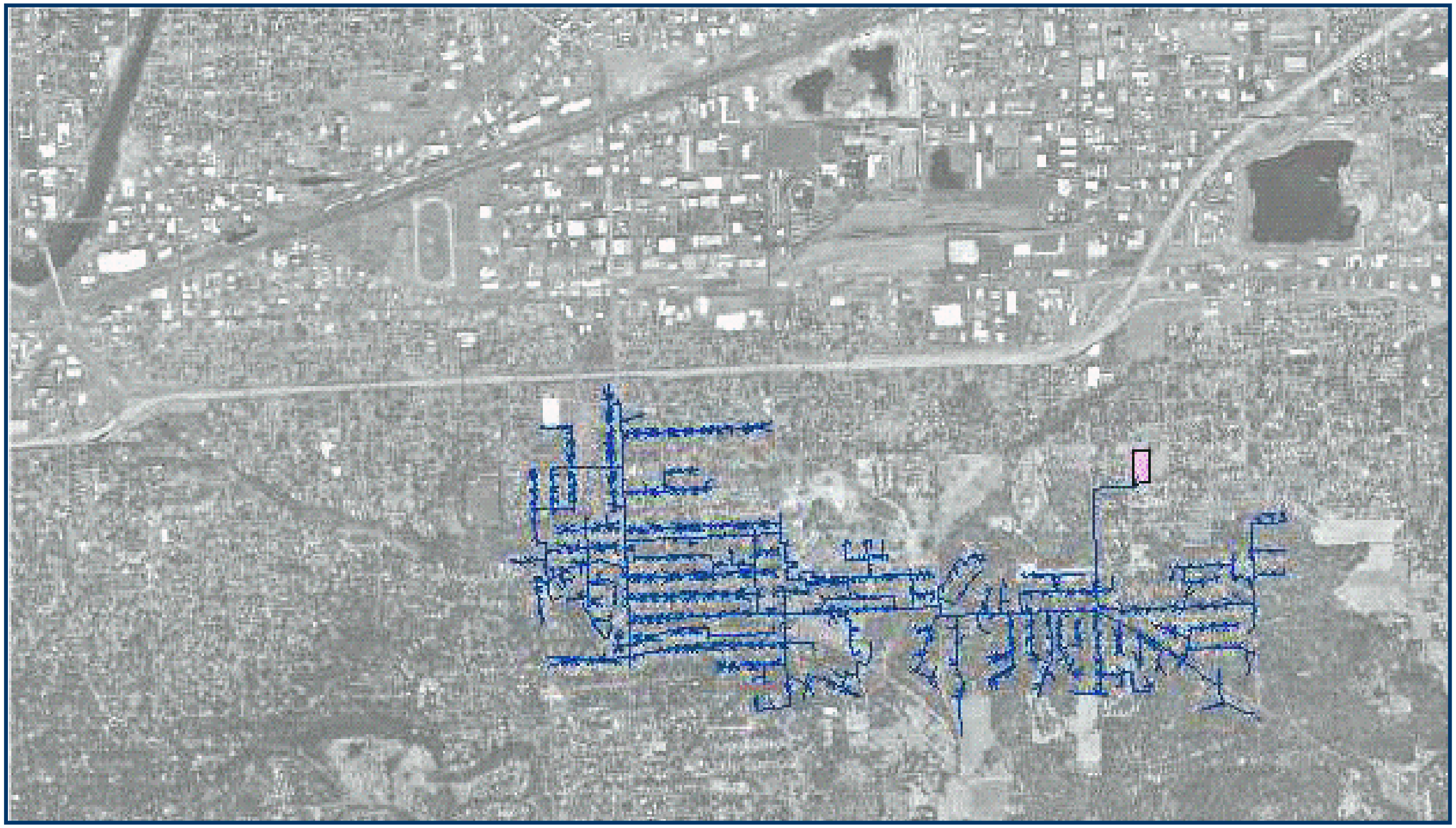
Feed Efficiency Upgrade – Pilot Project



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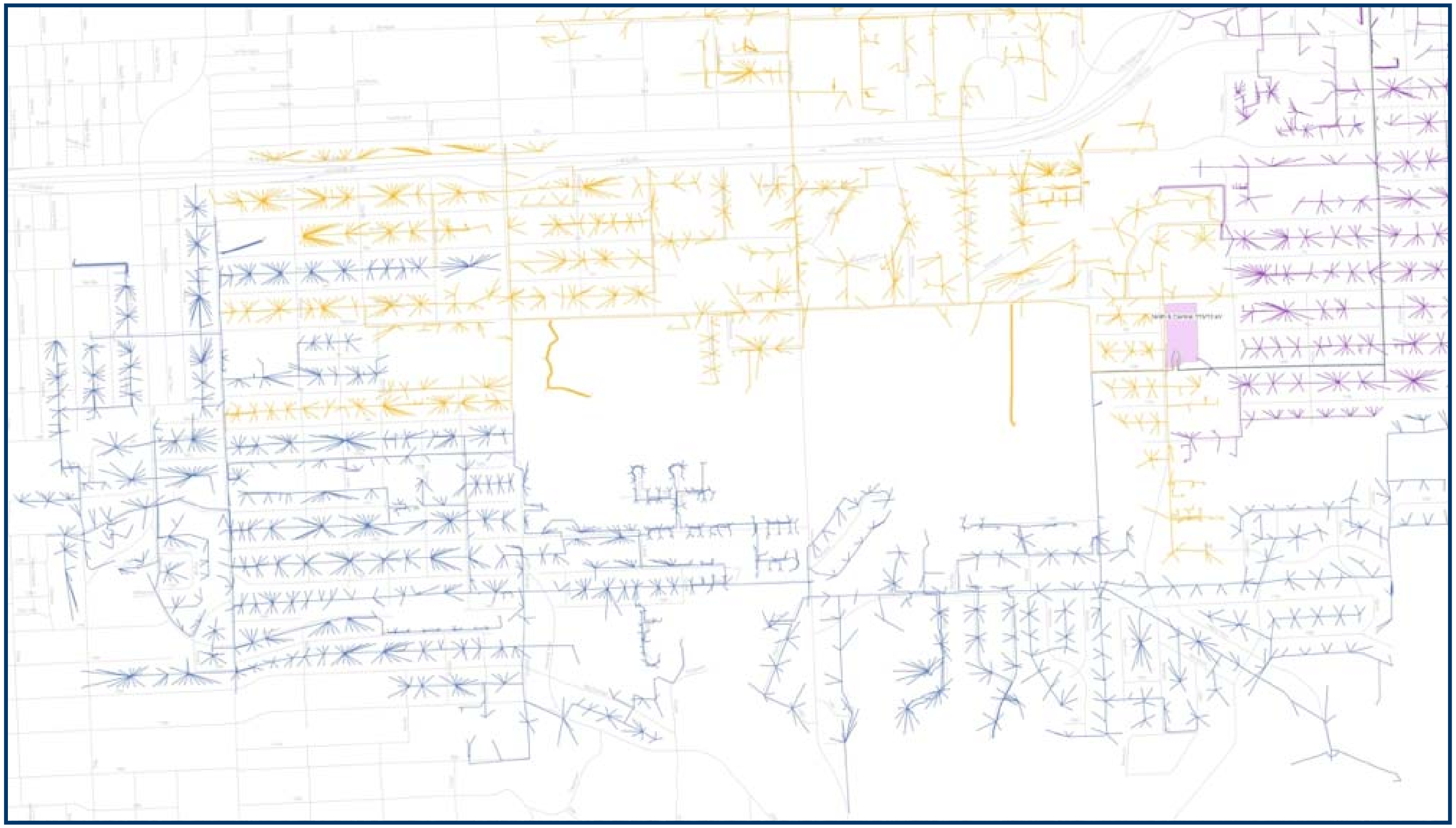
Feed Efficiency Upgrade – Pilot Project



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Feed Efficiency Upgrade – Pilot Project

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Feed Efficiency Upgrade – Pilot Project

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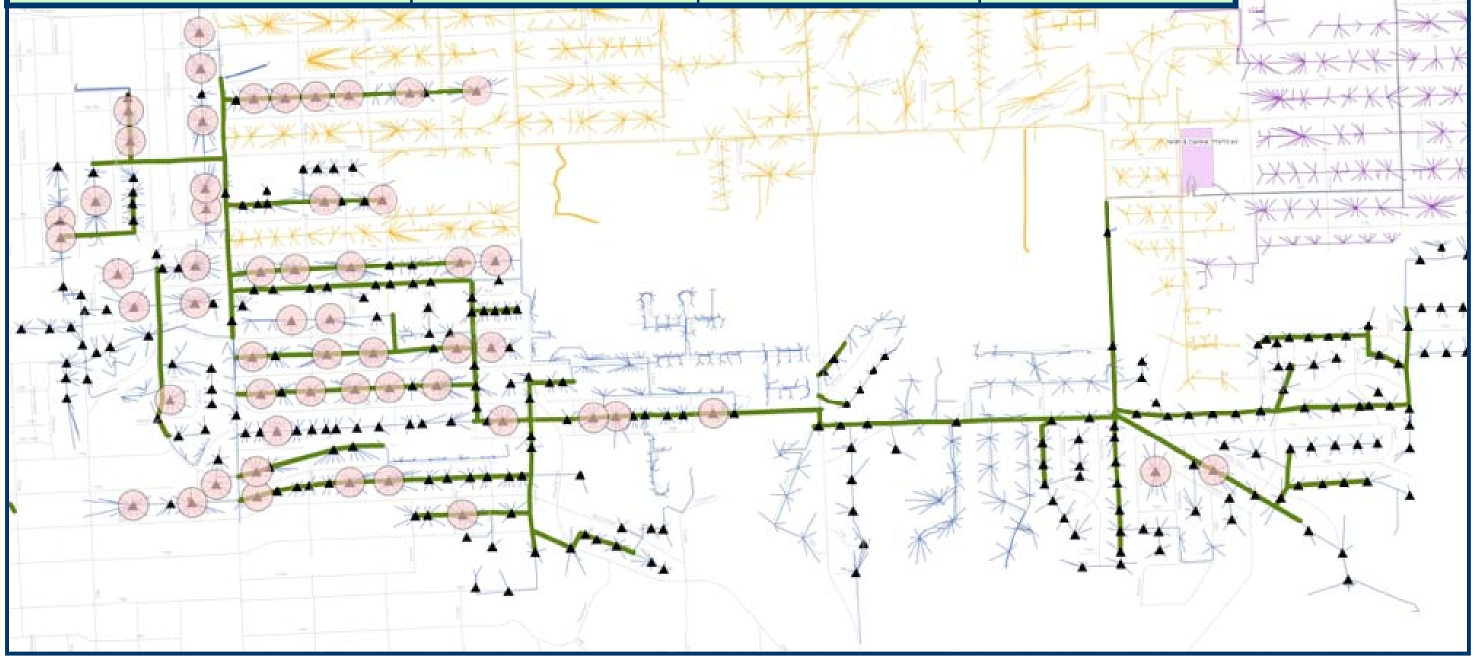
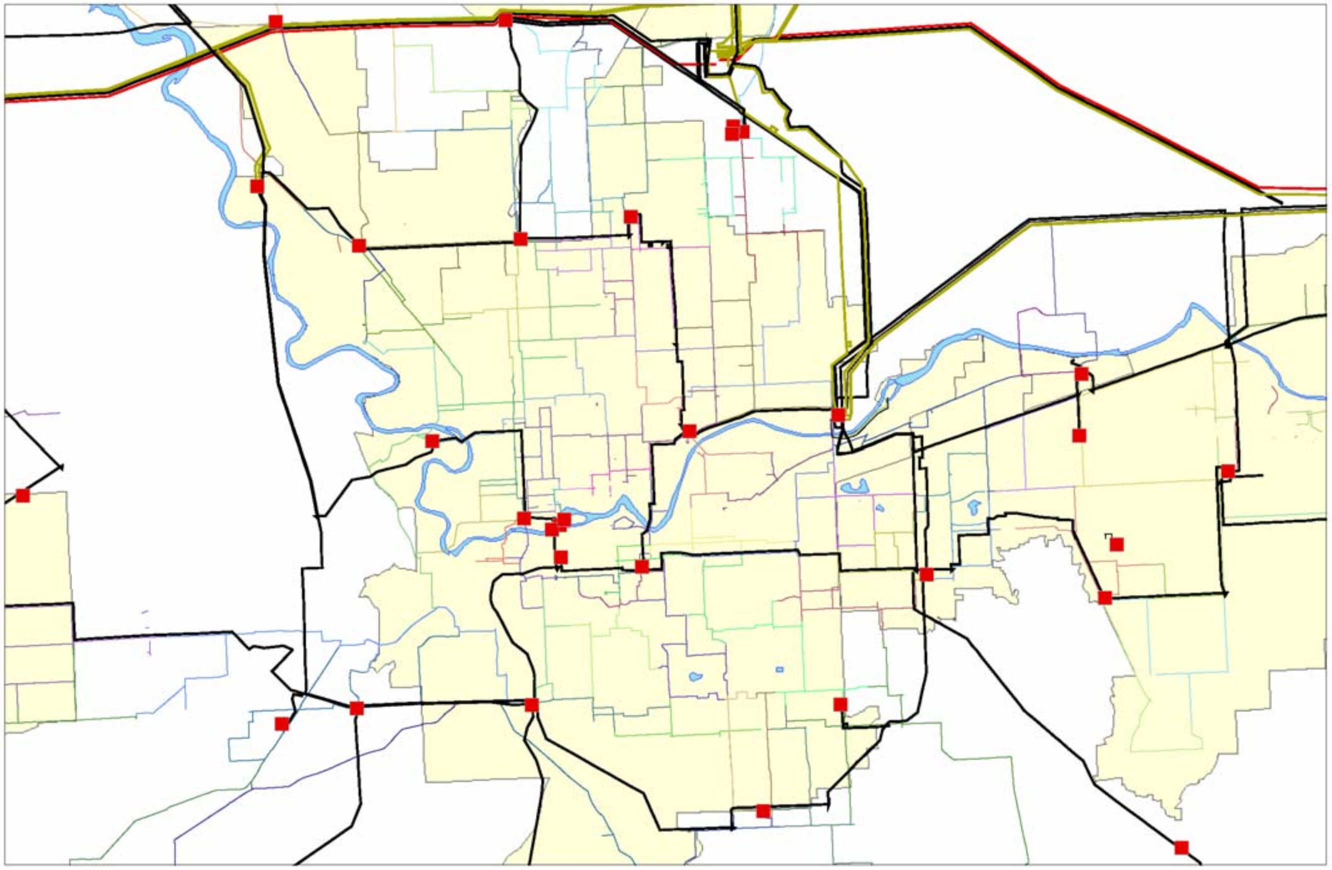
Feed Efficiency Upgrade – Pilot Project

Feeder	Capital Investment	Average Power kW	Peak Power kW
9th and Central 12F4	$1,100,000	125	230



Transmission Efficiency Initiatives

- Load density and forecasted load growth



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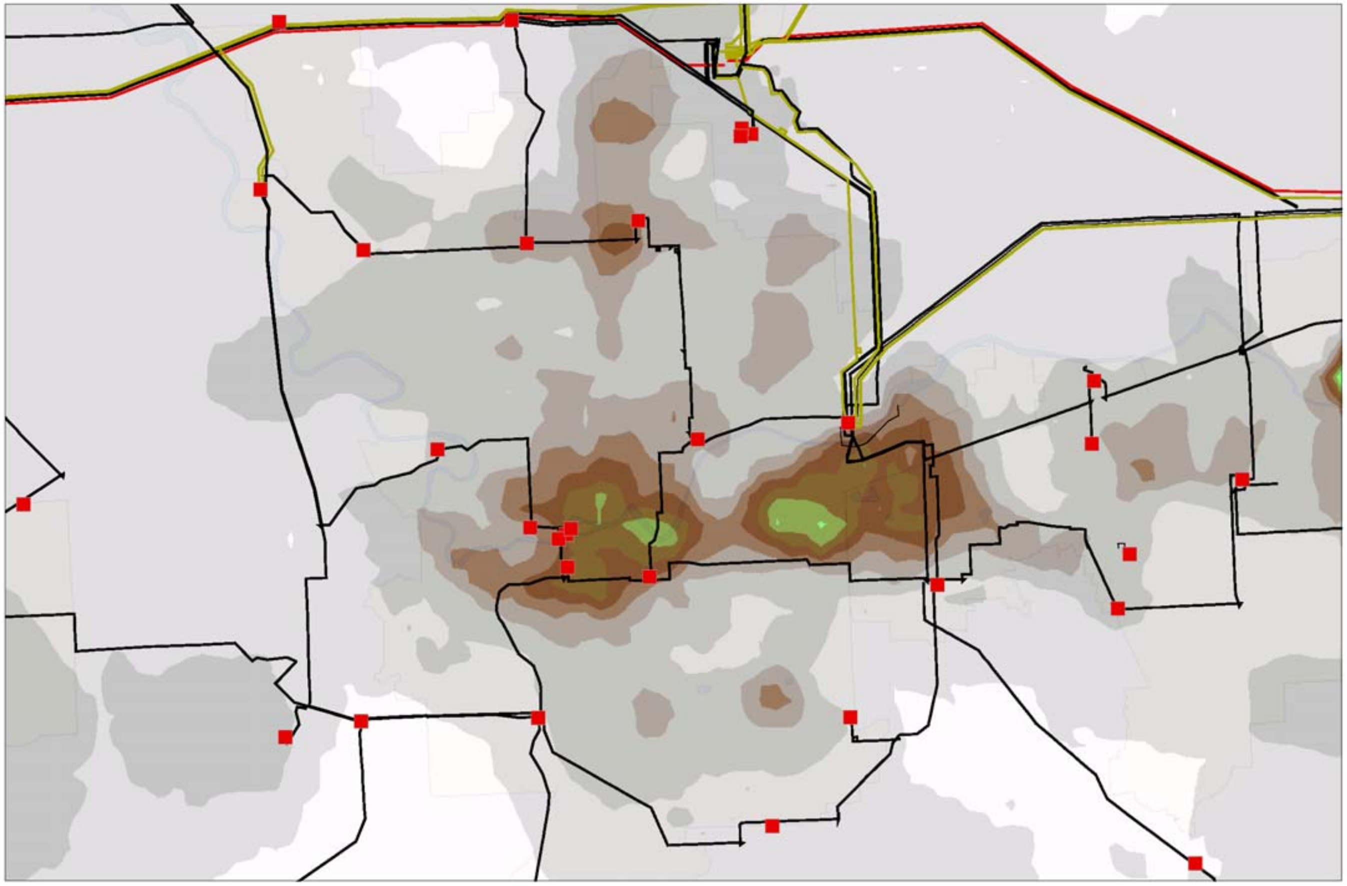
Transmission Efficiency Initiatives

- Load density and forecasted load growth



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Transmission Efficiency Initiatives

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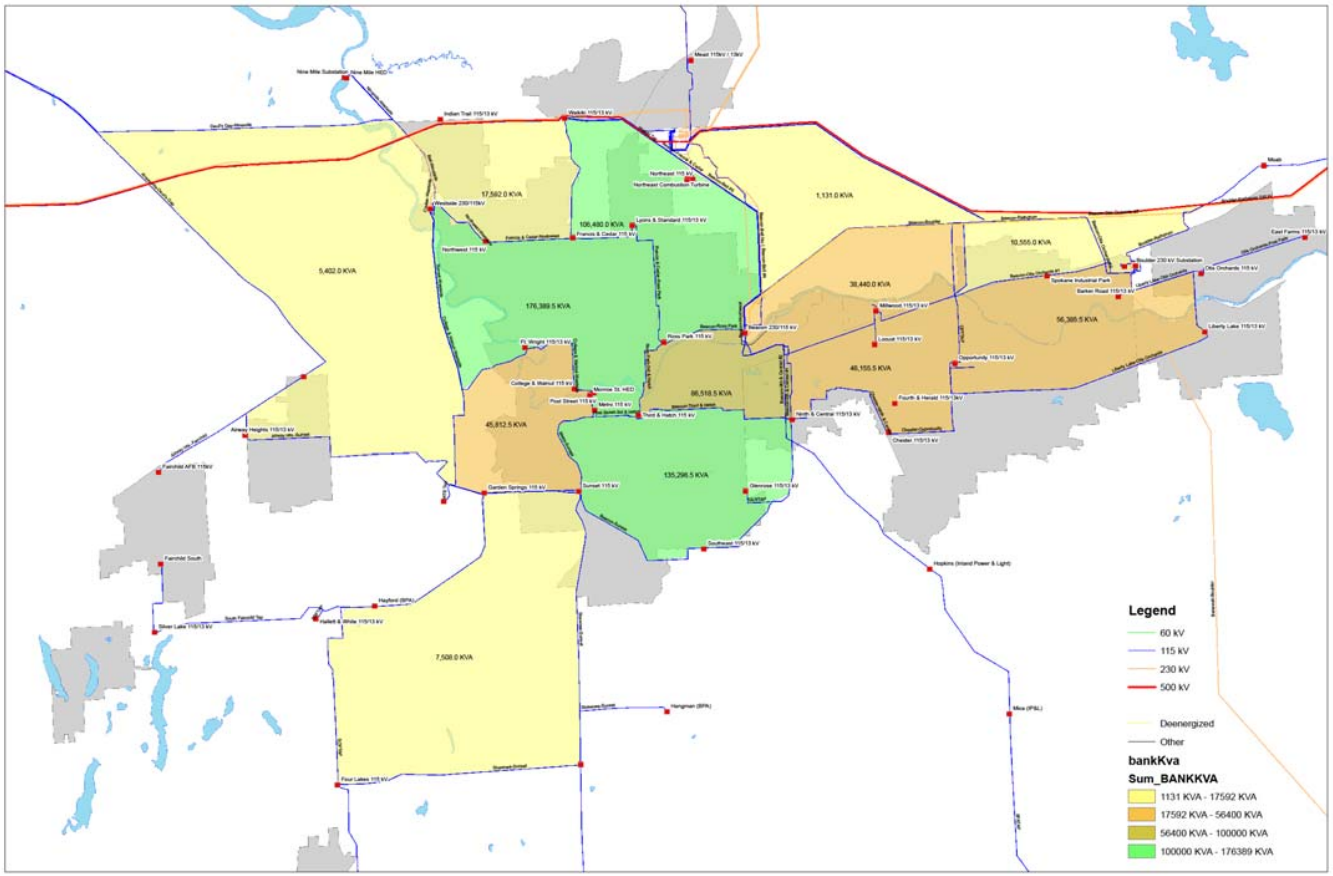

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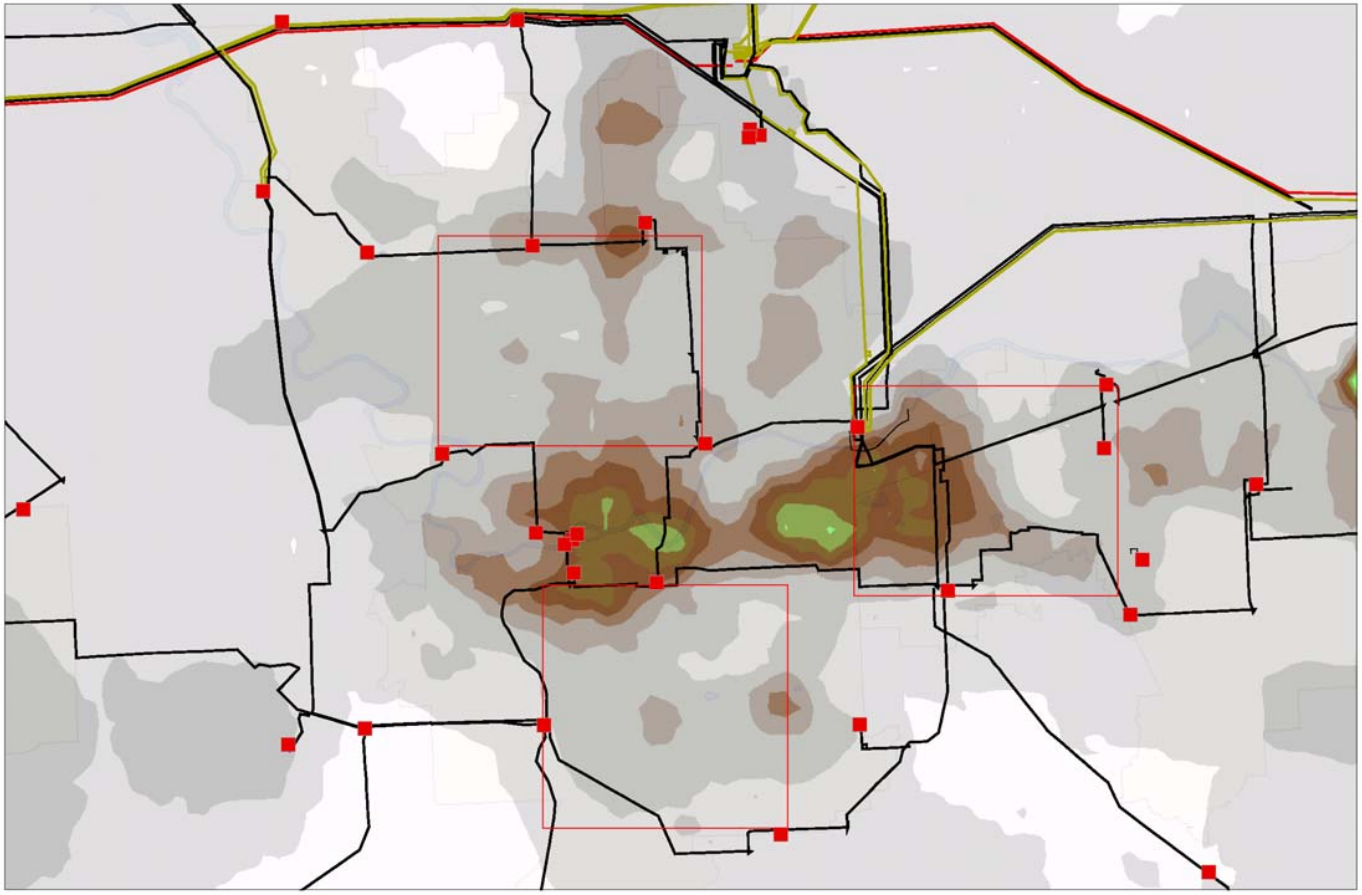
Transmission Efficiency Initiatives

- Transmission topology
- Transmission archetypes



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Transmission Efficiency Initiatives

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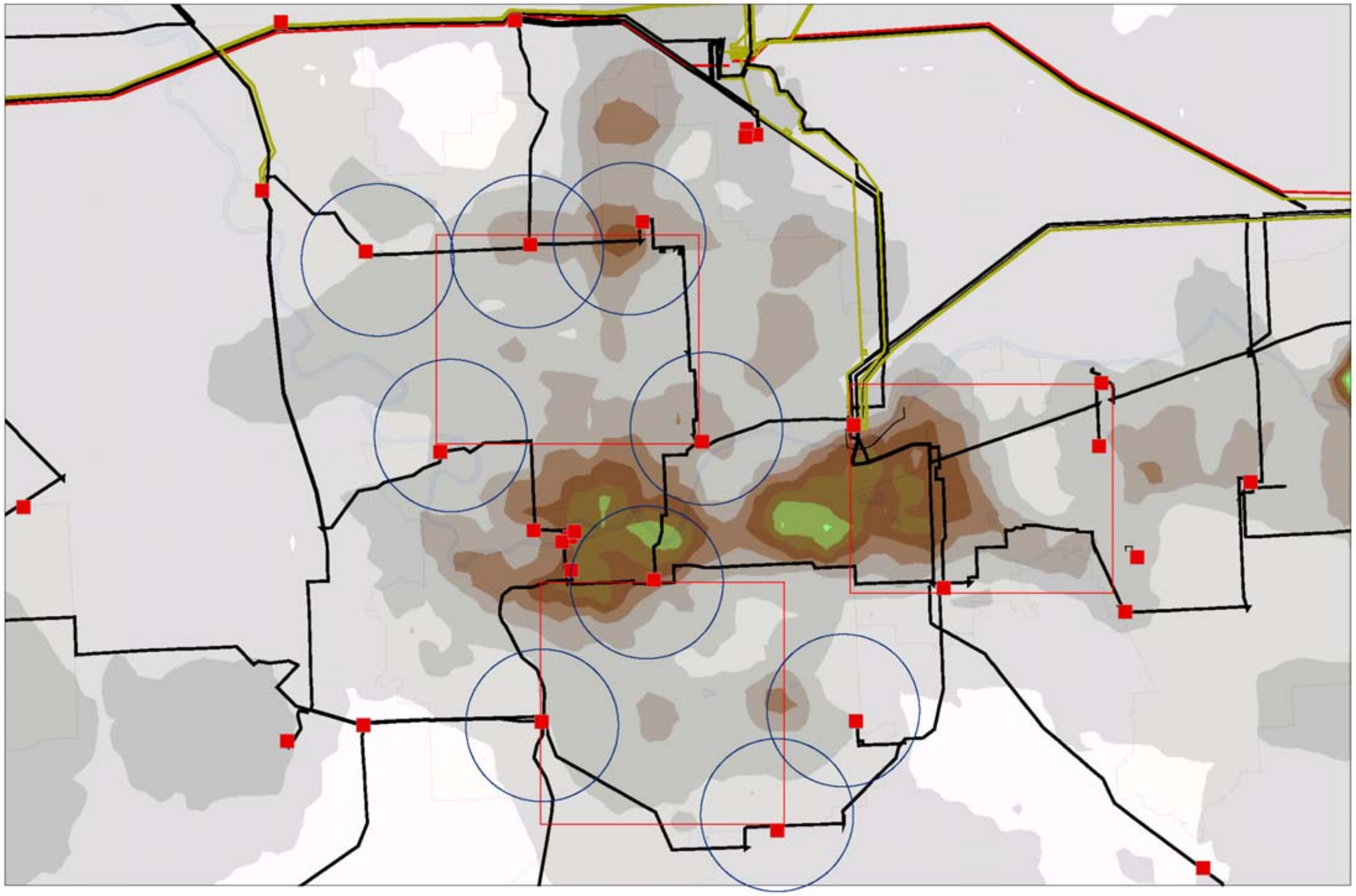
- Transmission archetypes



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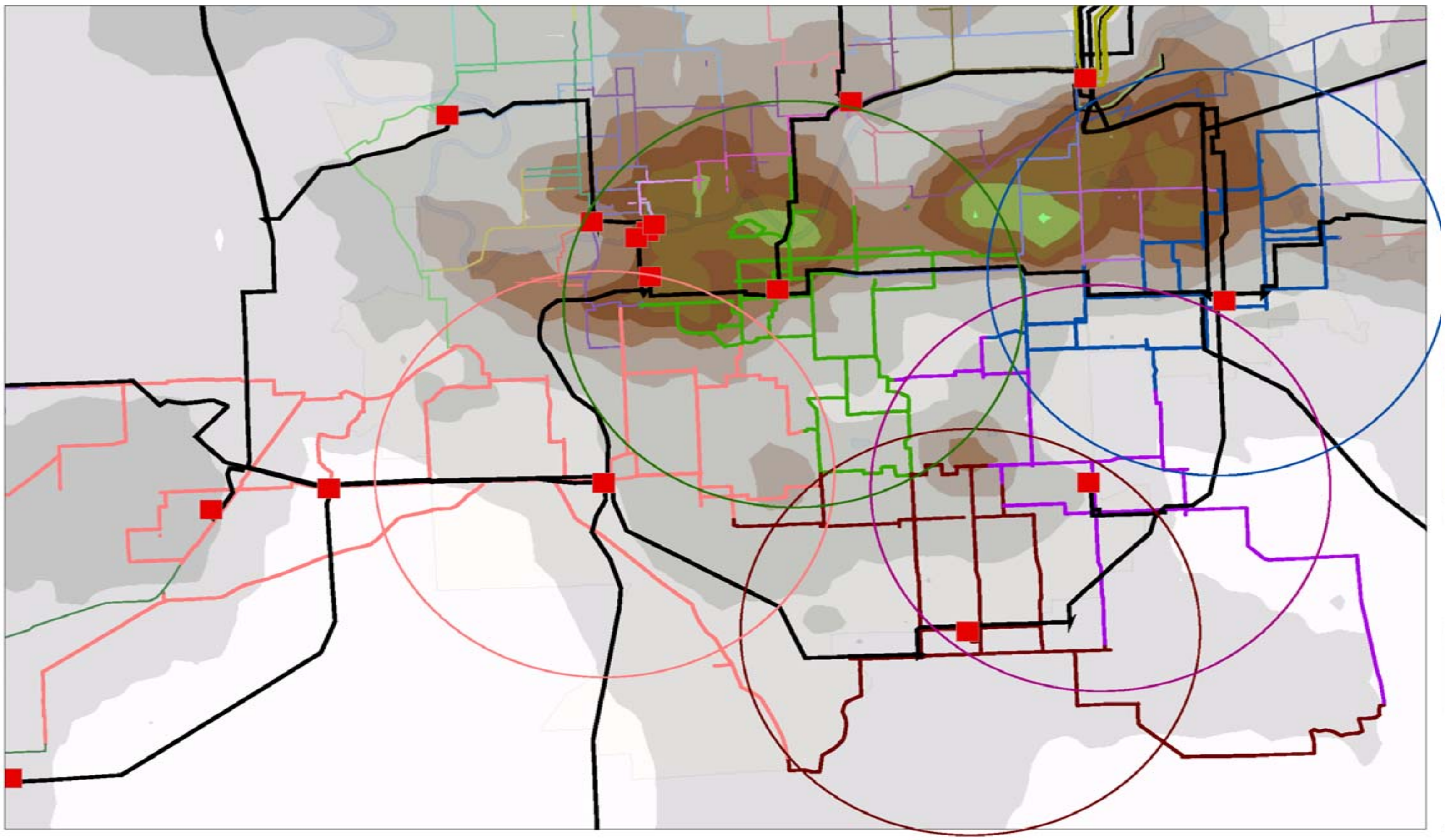
Transmission Efficiency Initiatives

- Transmission topology
- Transmission archetypes



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Preferred Resource Strategy- DRAFT

James Gall

2009 Electric Integrated Resource Plan

Fourth Technical Advisory Committee Meeting

January 28, 2009

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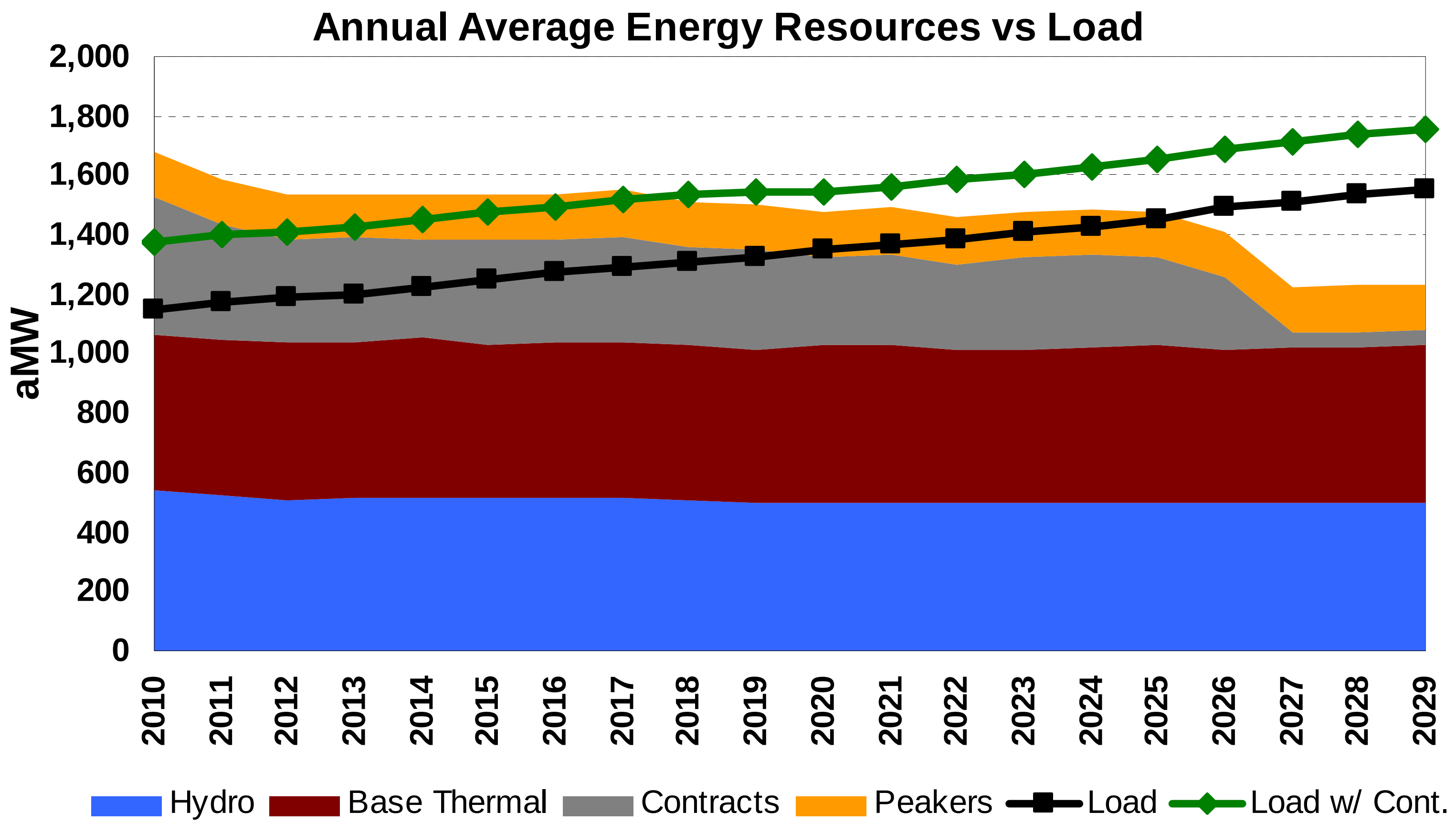
Resource Needs (Energy)



Load is net 2007 Conservation Levels

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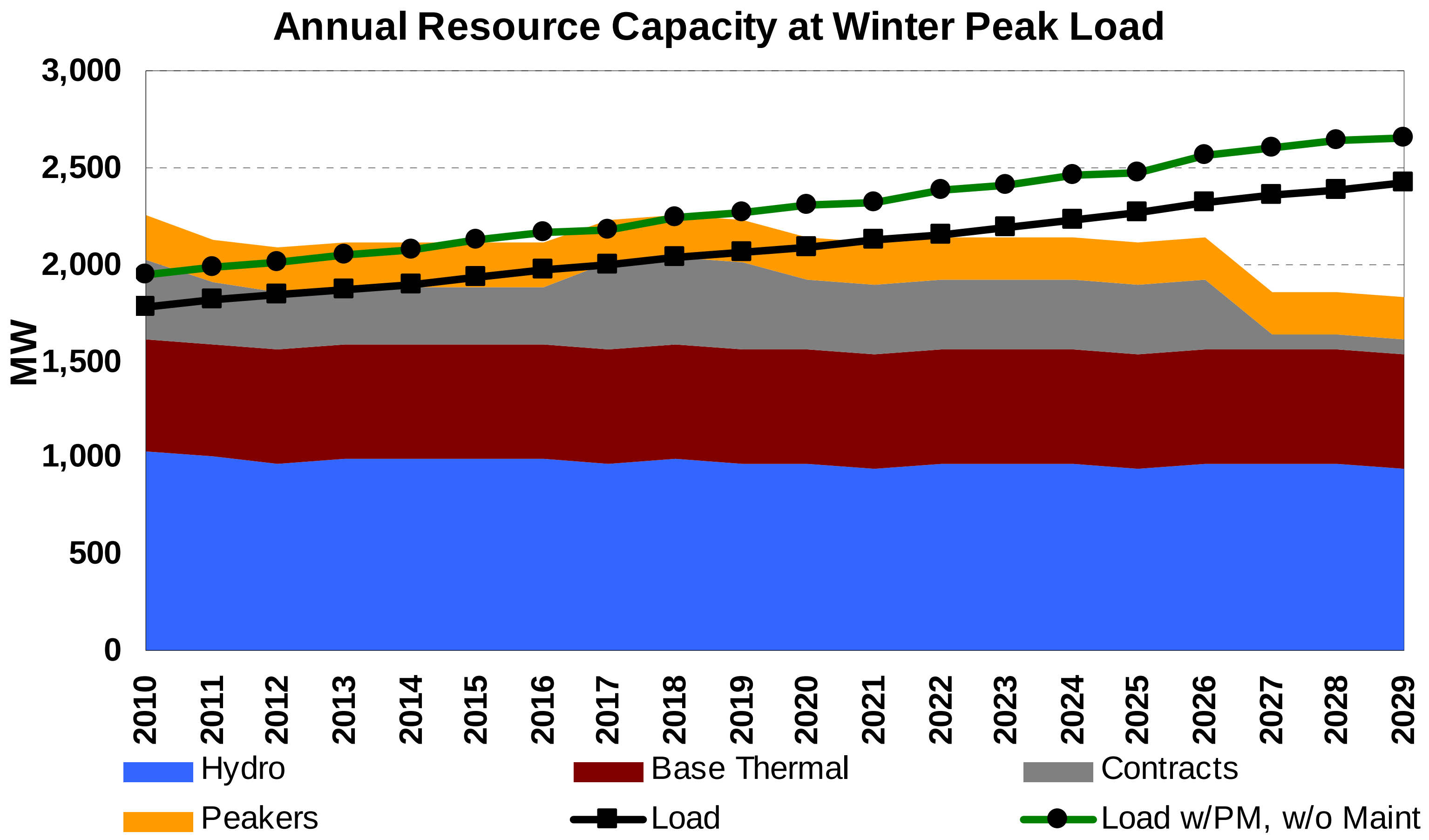
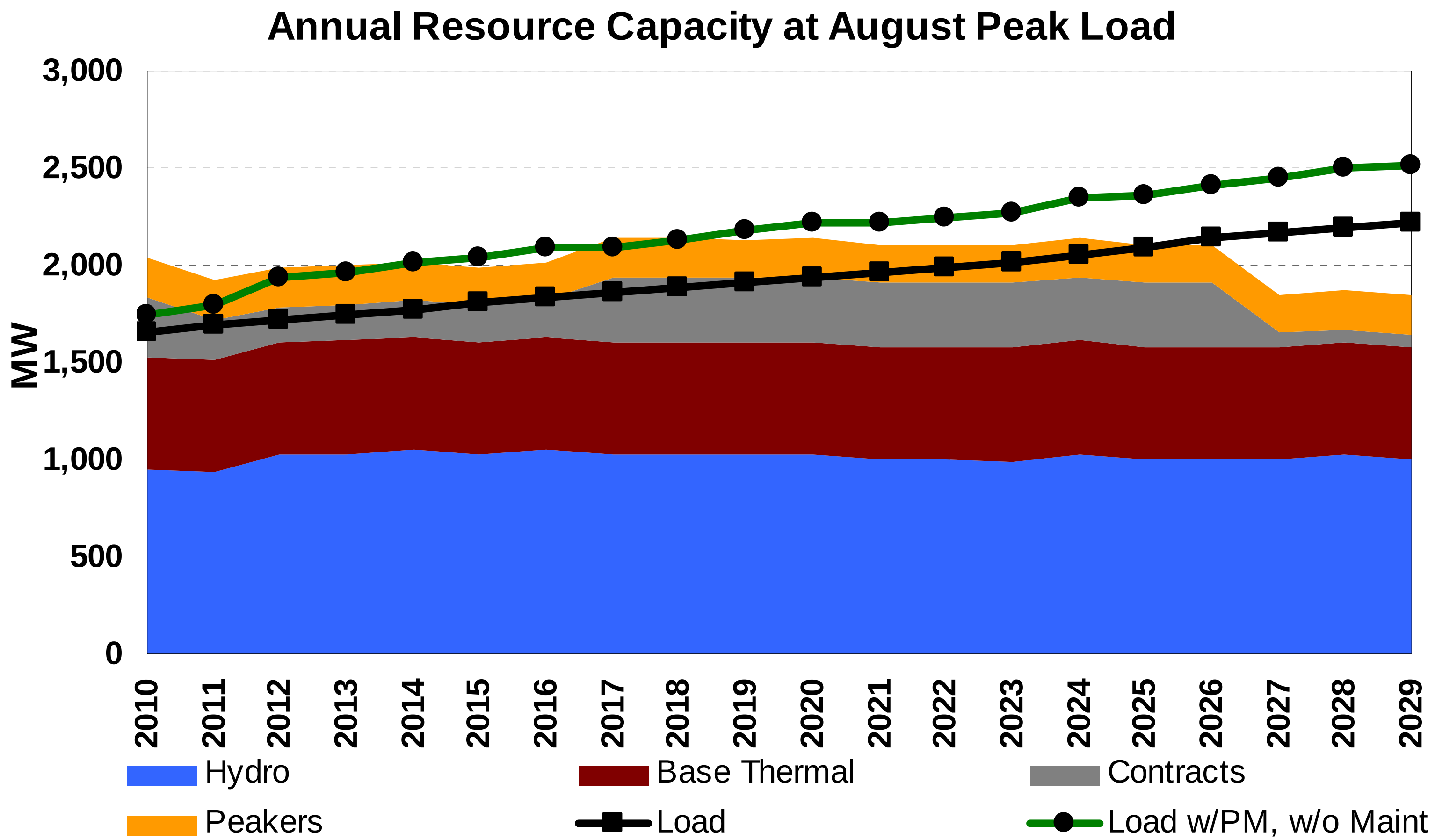
Resource Needs (Winter Capacity)



Load is net 2007 Conservation Levels

Resource Needs (Summer Capacity)



Load is net 2007 Conservation Levels

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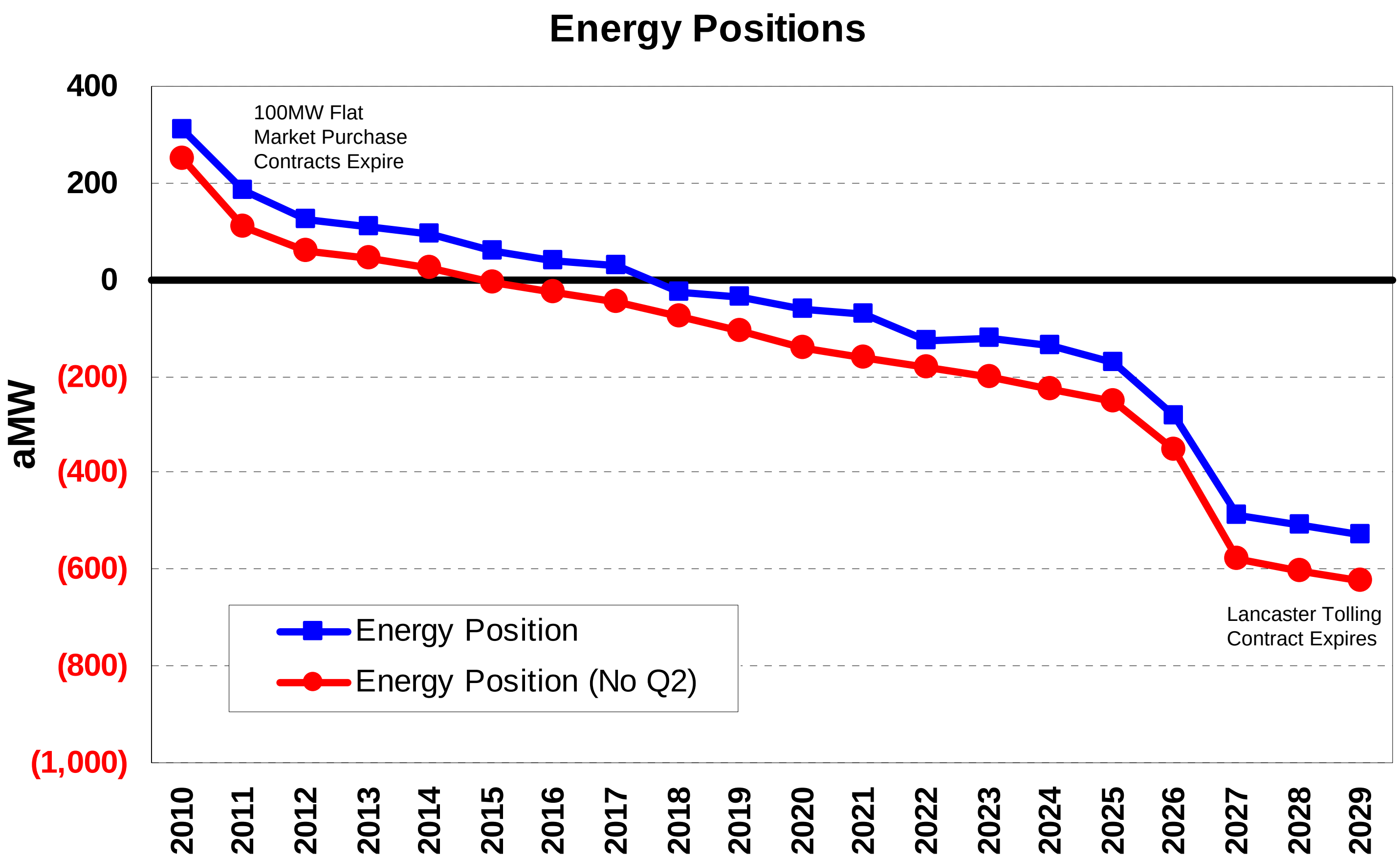
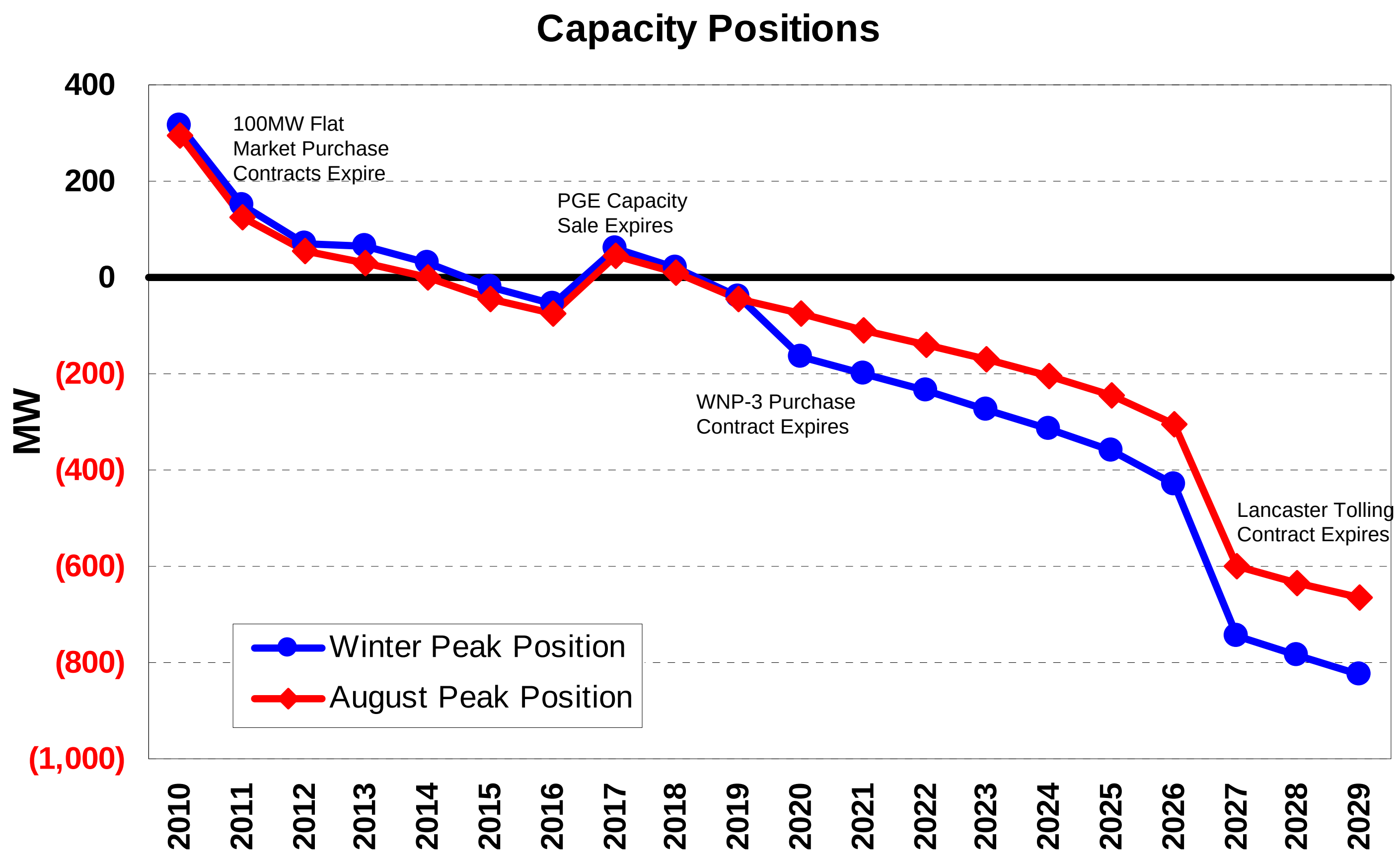
Resource Needs (Energy)



Net 2007 Conservation Levels

Resource Needs (Capacity)



Net 2007 Conservation Levels

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PRiSM Objective Function

- Linear program solving for the optimal resource strategy to meet resource deficits over planning horizon.
- Model selects its resources to reduce cost, risk, or both.

Minimize: Total Power Supply Cost on NPV basis (2010-2050 with emphasis on first 11 years of the plan

Subject to:

- Risk Level
- Capacity Need +/- deviation
- Energy Need +/- deviation
- Renewable Portfolio Standards
- Resource Limitations and Timing
- Greenhouse Gas Limits

PRiSM Data Requirements

- Expected load & resource balance for next 20 years
- 20 year by 250 iteration matrix of resource values
  - Avista's current resource portfolio cost
  - Each new resource alternatives market value (electric price less fuel costs, variable O&M, and emissions costs)
  - Existing resource market value
- Conservation estimates
- Generation capital costs, fixed operating costs, transmission costs, revenue requirements
- Availability assumptions (size, when, where)

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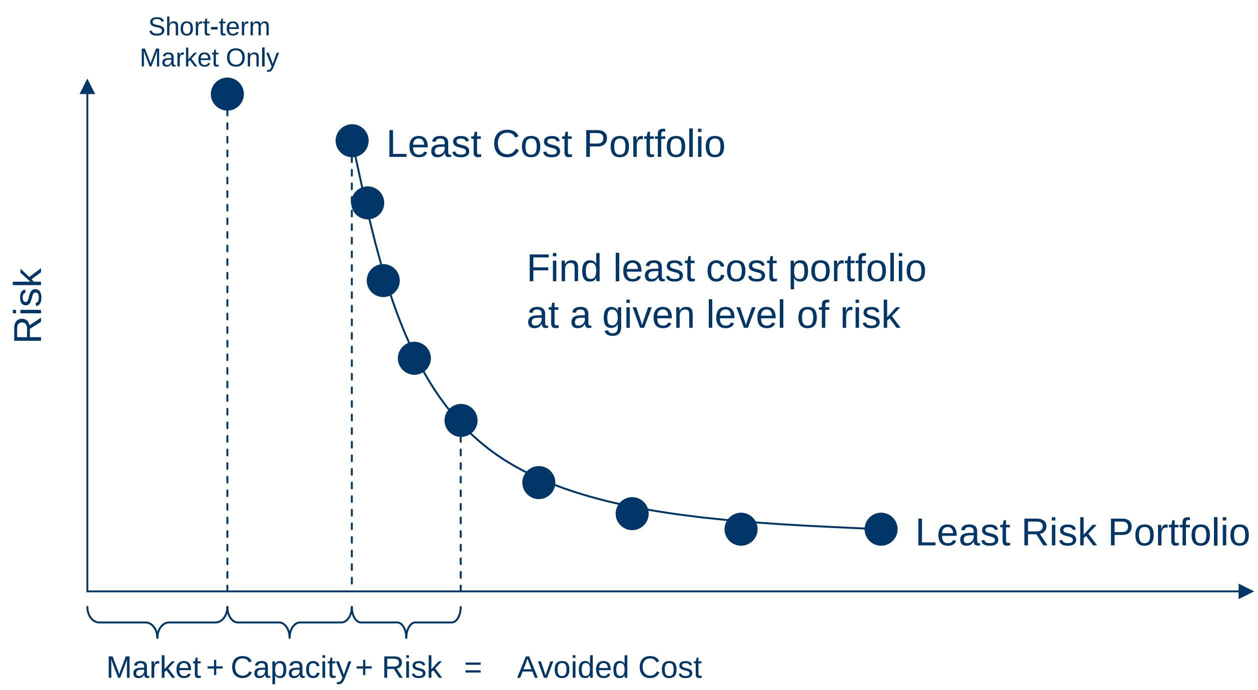
PRiSM New Enhancements

- Resources selections must be blocks of resources such as 50 MW wind, 75 MW SCCT, 125 MW CCCT (half unit)
- Use more precise method to estimate frontier curve
- Meets both summer & winter capacity requirements
- Ability to account for greenhouse gas levels
- More accurate ability to take into account post IRP time period
- Ability to retire resources *(used for sensitivity analysis only)*
- Higher cost conservation measures can be selected by the model *(available for final draft)*

Efficient Frontier

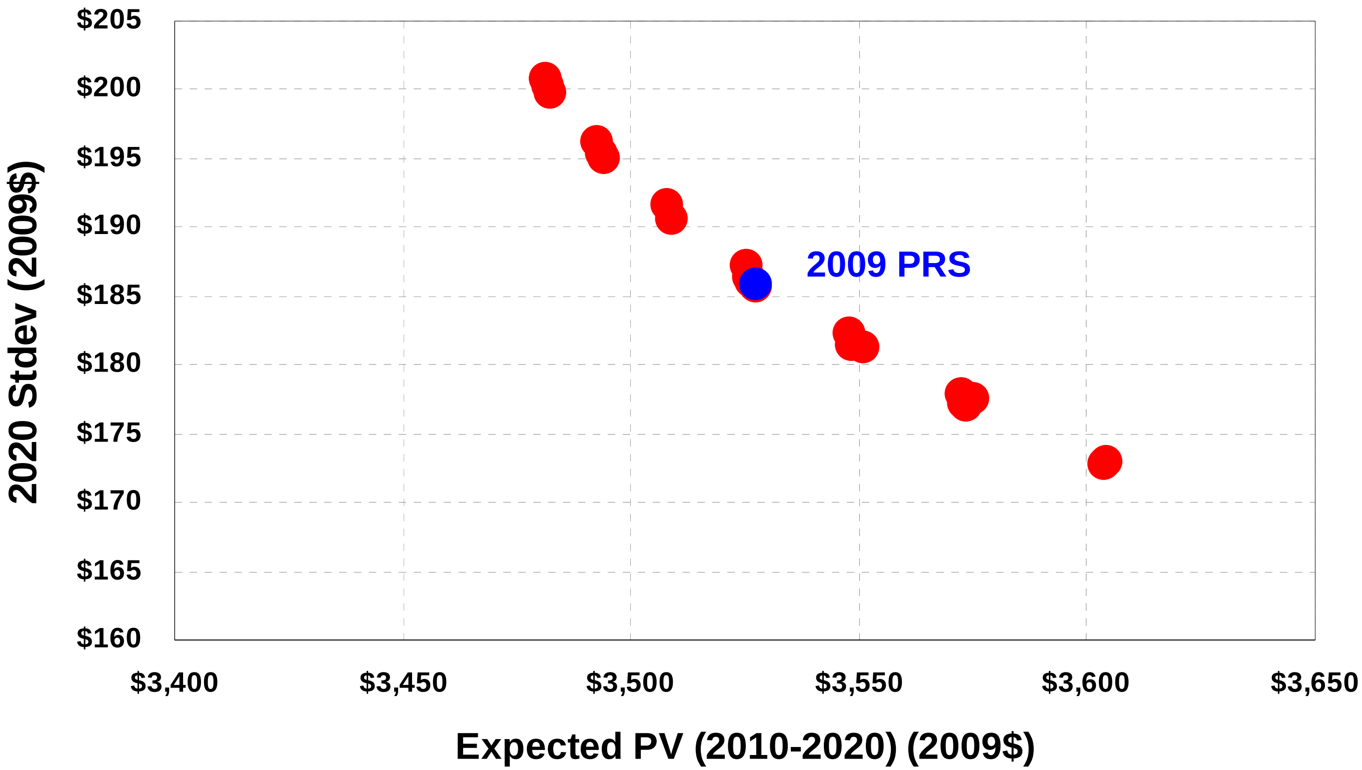
- Demonstrates the trade off of cost and risk
- Avoided Cost Method



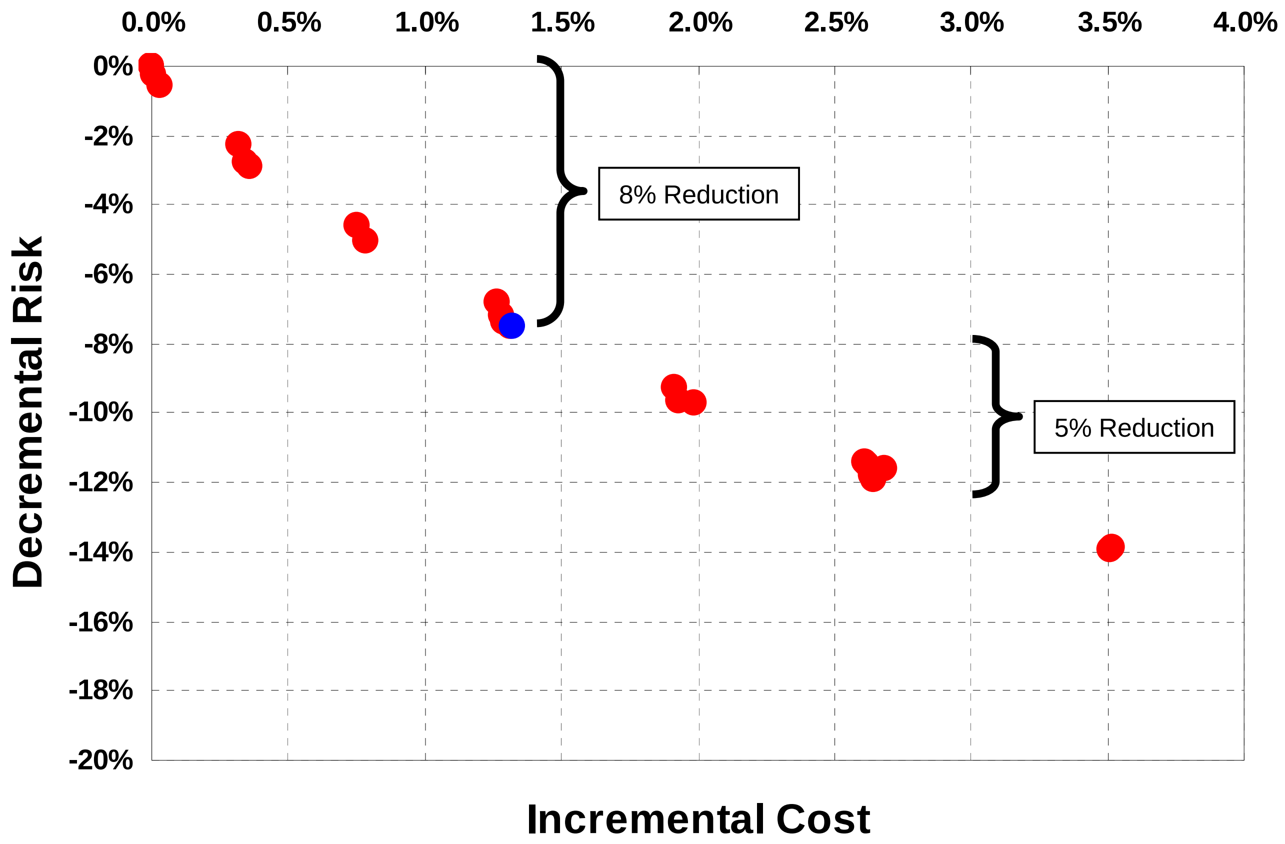
Portfolio Scenarios

1) Base Case
2) Case 1 + Small Renewable as Options
3) Case 2 + Large Hydro Upgrades as Options

Efficient Frontier (millions)



Change From Least Cost Portfolio



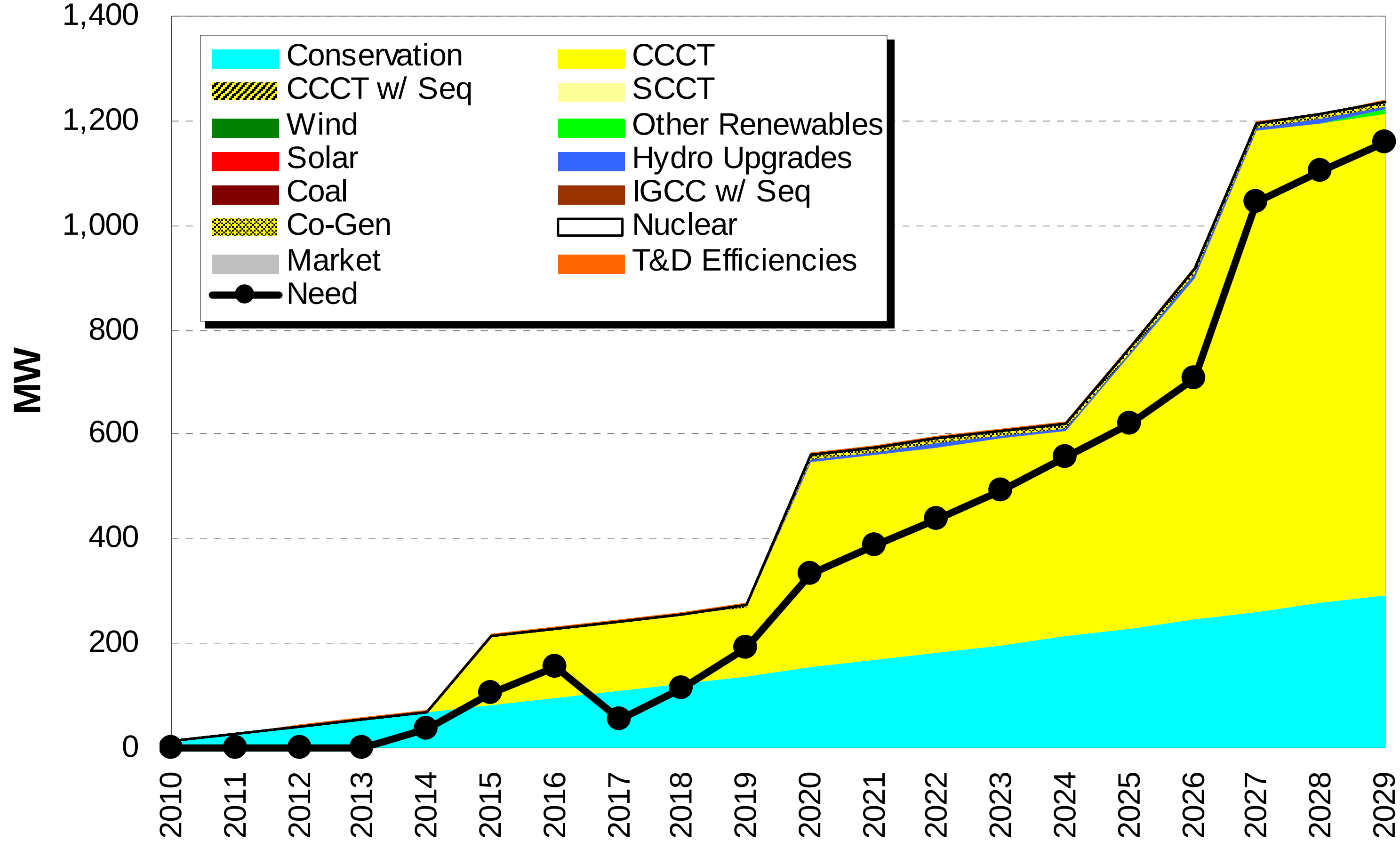
Preferred Resource Strategy (2020-2029

DRAFT- Base Case

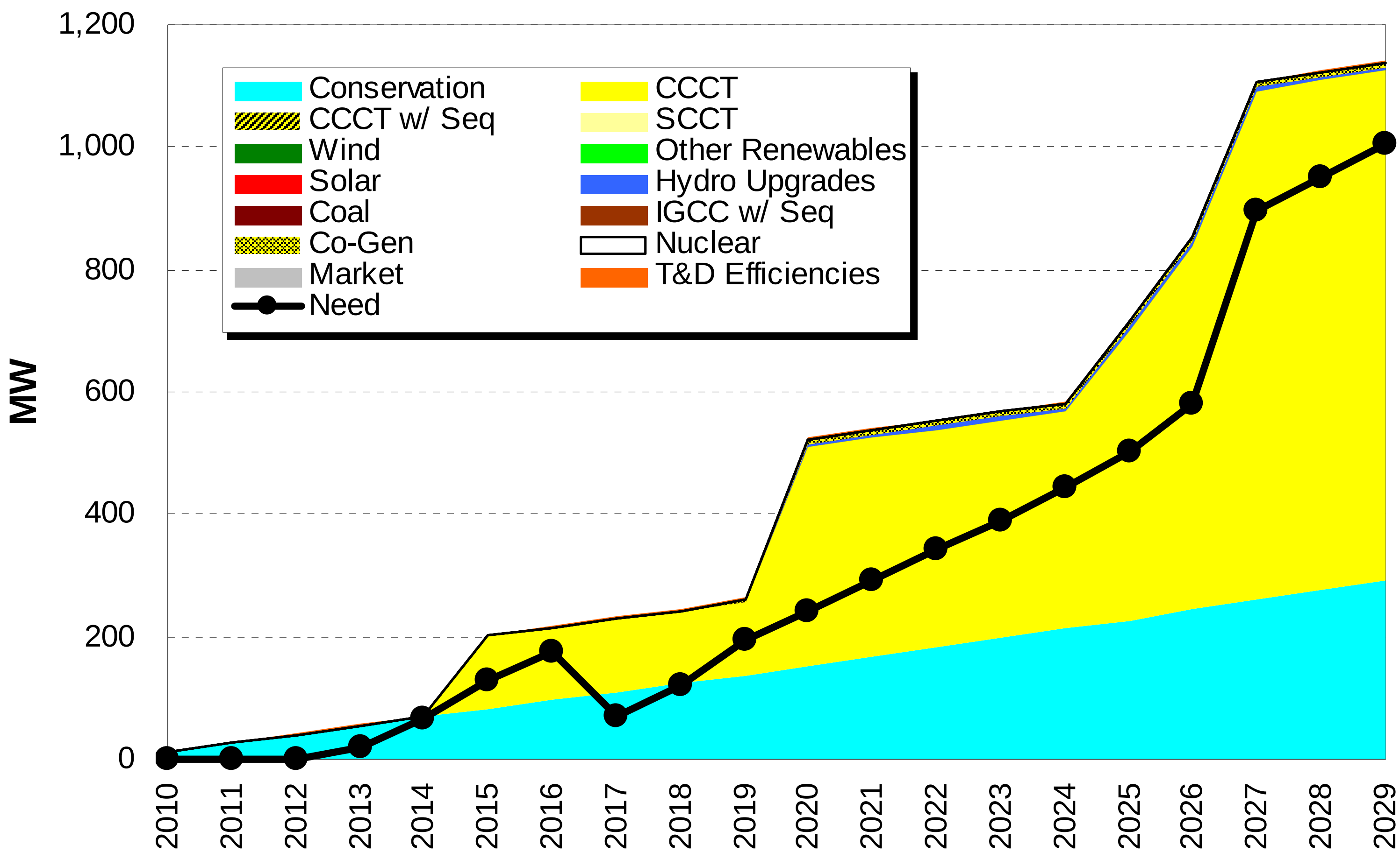
Year	CCCT	SCCT	Reardan	Wind	Other Renew	Solar	Hydro Upgrades	Coal	IGCC w/ Seq	Co-Gen	DSM	T&D	Total	Cumulative
2010											7.8	1.0	8.8	8.8
2011											7.9	1.0	8.9	17.6
2012			50.0								8.0	1.0	59.0	76.6
2013				100.0							8.2	1.0	109.2	185.8
2014											8.3	1.0	9.3	195.1
2015	125.0						1.0				8.4	1.0	135.4	330.5
2016											8.6		8.6	339.1
2017							1.0				8.7		9.7	348.8
2018				100.0							8.9		108.9	457.7
2019				100.0						2.5	9.0		111.5	569.2
2020	250.0			100.0			4.0			5.0	9.2		368.2	937.3
2021											9.3		9.3	946.7
2022											9.5		9.5	956.1
2023											9.6		9.6	965.8
2024											9.8		9.8	975.6
2025	125.0										10.0		135.0	1,110.6
2026	125.0										10.1		135.1	1,245.7
2027	250.0										10.3		260.3	1,506.0
2028				50.0							10.5		60.5	1,566.5
2029				100.0	7.0						10.7		117.7	1,684.2
2010-2019	125.0	-	50.0	300.0	-	-	2.0	-	-	2.5	83.7	6.0	569.2	
2010-2029	875.0	-	50.0	550.0	7.0	-	6.0	-	-	7.5	182.7	6.0	1,684.2	

“Yellow Light” conservation not modeled yet

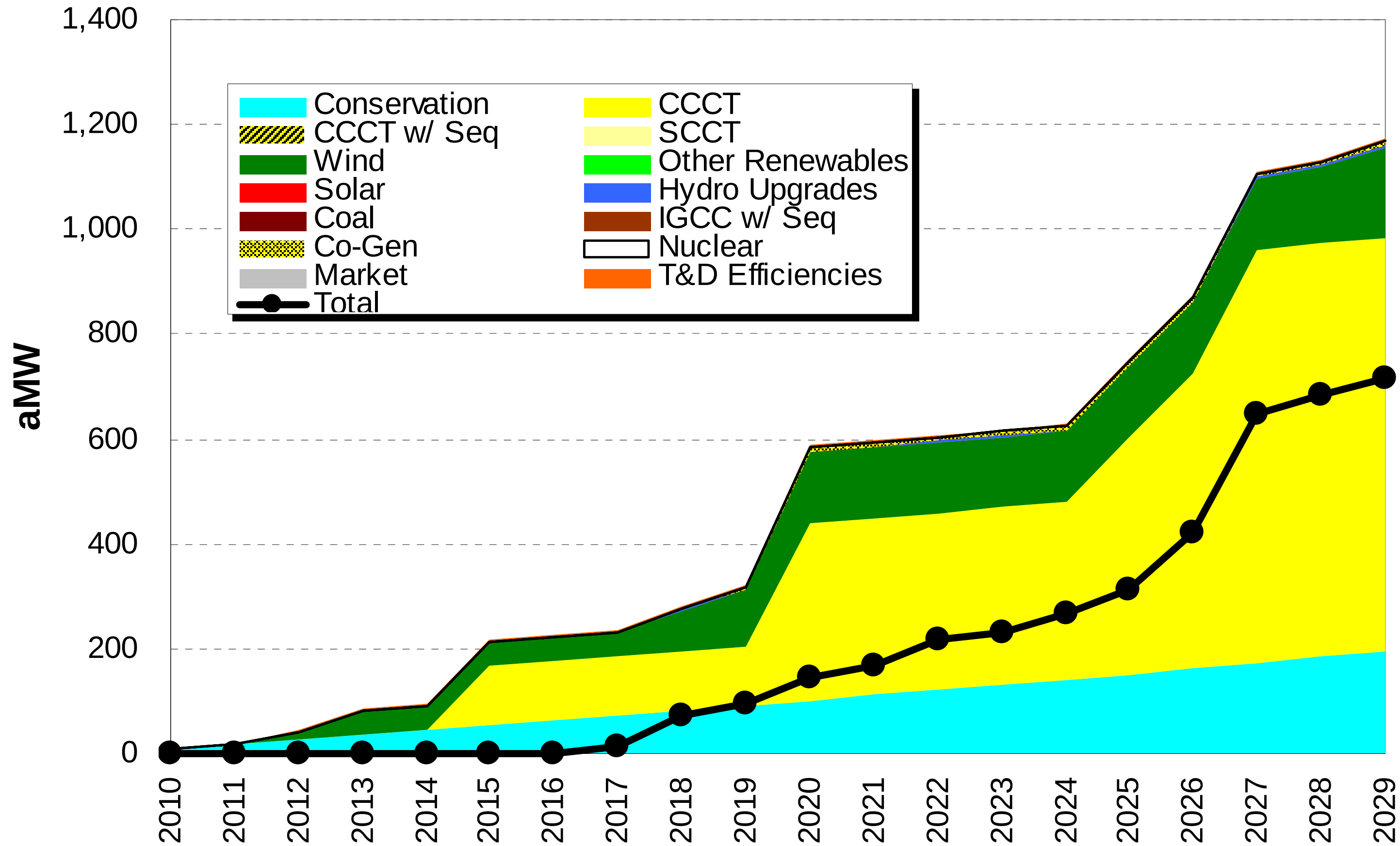
PRS: Winter Capacity



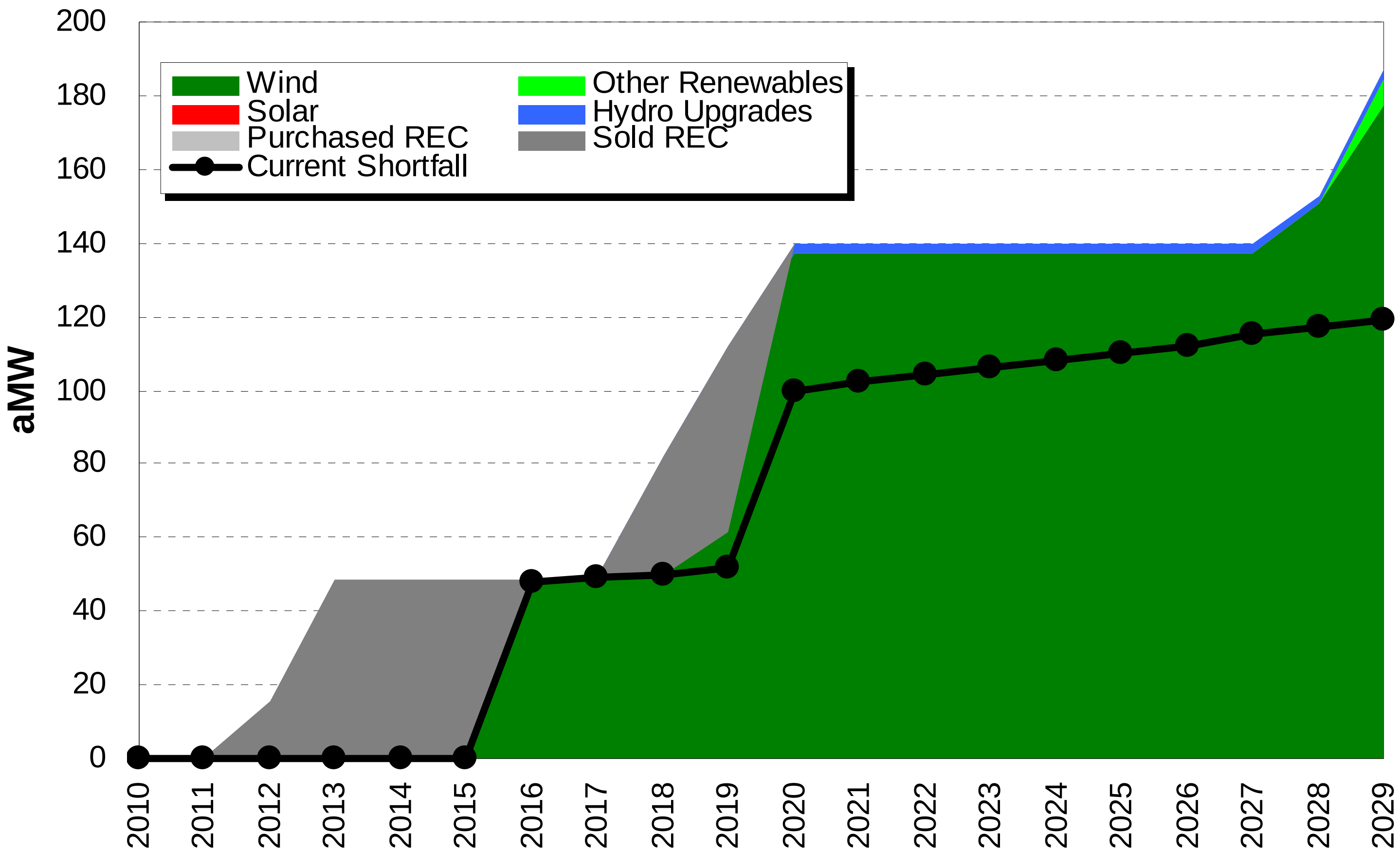
PRS: Summer Capacity



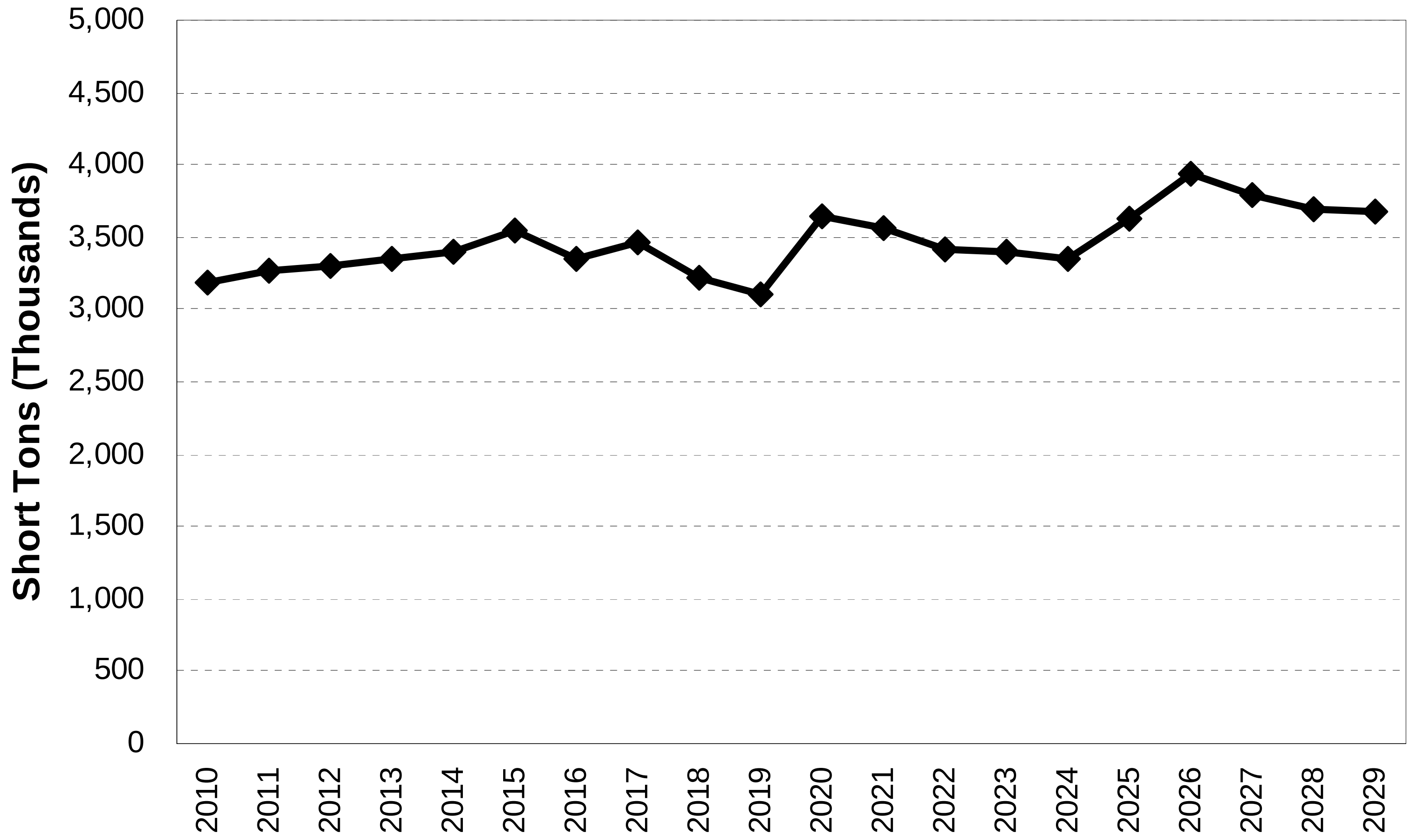
PRS: Annual Average Energy



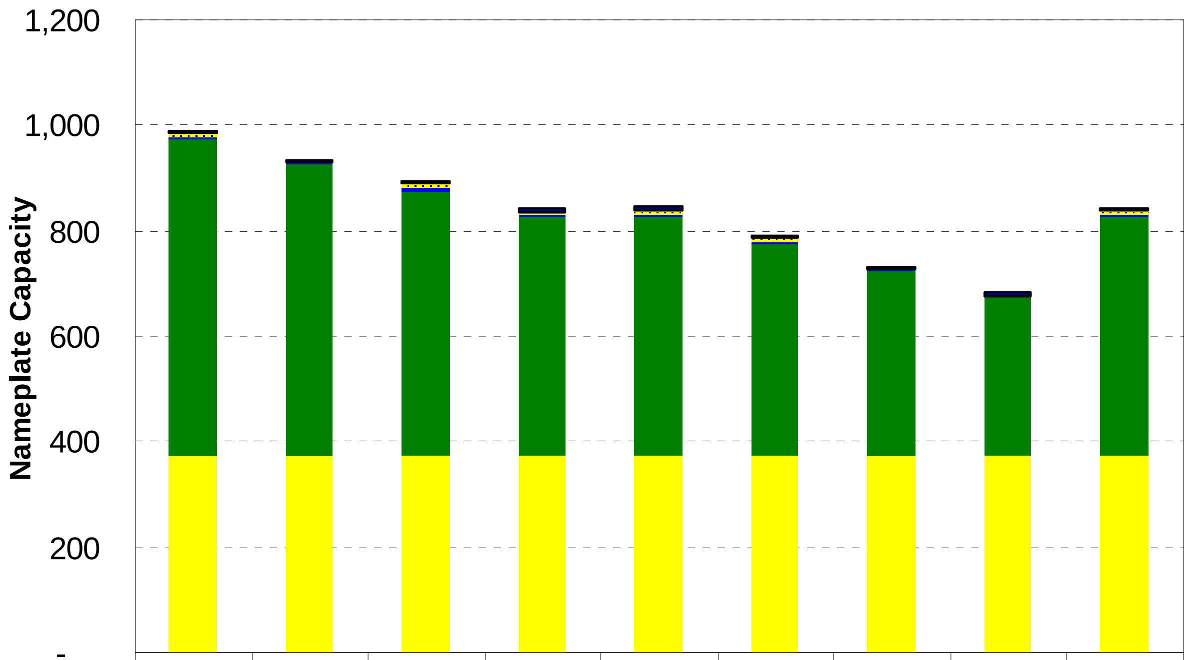
PRS: WA RPS Requirement



PRS: Greenhouse Gas Emissions



2020: Portfolios on the Efficient Frontier



	Least Risk	---	--	-	+	++	+	Least Cost	PRS
T&D Efficiencies	5	5	5	5	5	5	5	5	4
Co-Gen	5	-	8	5	8	8	-	-	8
IGCC w/ Seq	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-
Hydro Upgrades	4	4	6	6	6	4	2	2	6
Solar	-	-	-	-	-	-	-	-	-
Other Renewables	-	-	-	-	1	-	-	-	-
Wind	600	550	500	450	450	400	350	300	450
SCCT	-	-	-	-	-	-	-	-	-
CCCT	375	375	375	375	375	375	375	375	375

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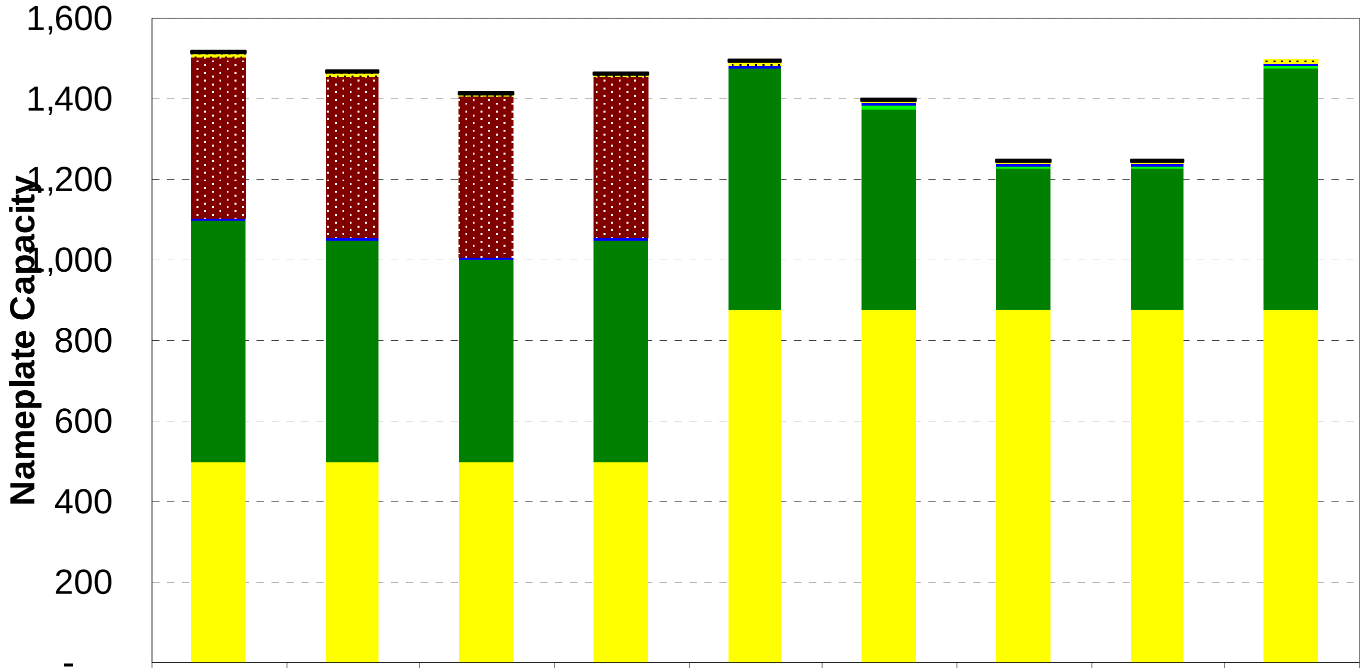
2029: Portfolios on the Efficient Frontier



	Least Risk	---	--	-	+	++	+	Least Cost	PRS
T&D Efficiencies	5	5	5	5	5	5	5	5	4
Co-Gen	10	8	8	5	10	8	8	8	8
IGCC w/ Seq	400	400	400	400	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-
Hydro Upgrades	4	6	6	6	6	5	5	5	6
Solar	-	-	-	-	-	-	-	-	-
Other Renewables	-	-	-	-	1	7	7	7	7
Wind	600	550	500	550	600	500	350	350	600
SCCT	-	-	-	-	-	-	-	-	-
CCCT	500	500	500	500	875	875	875	875	875

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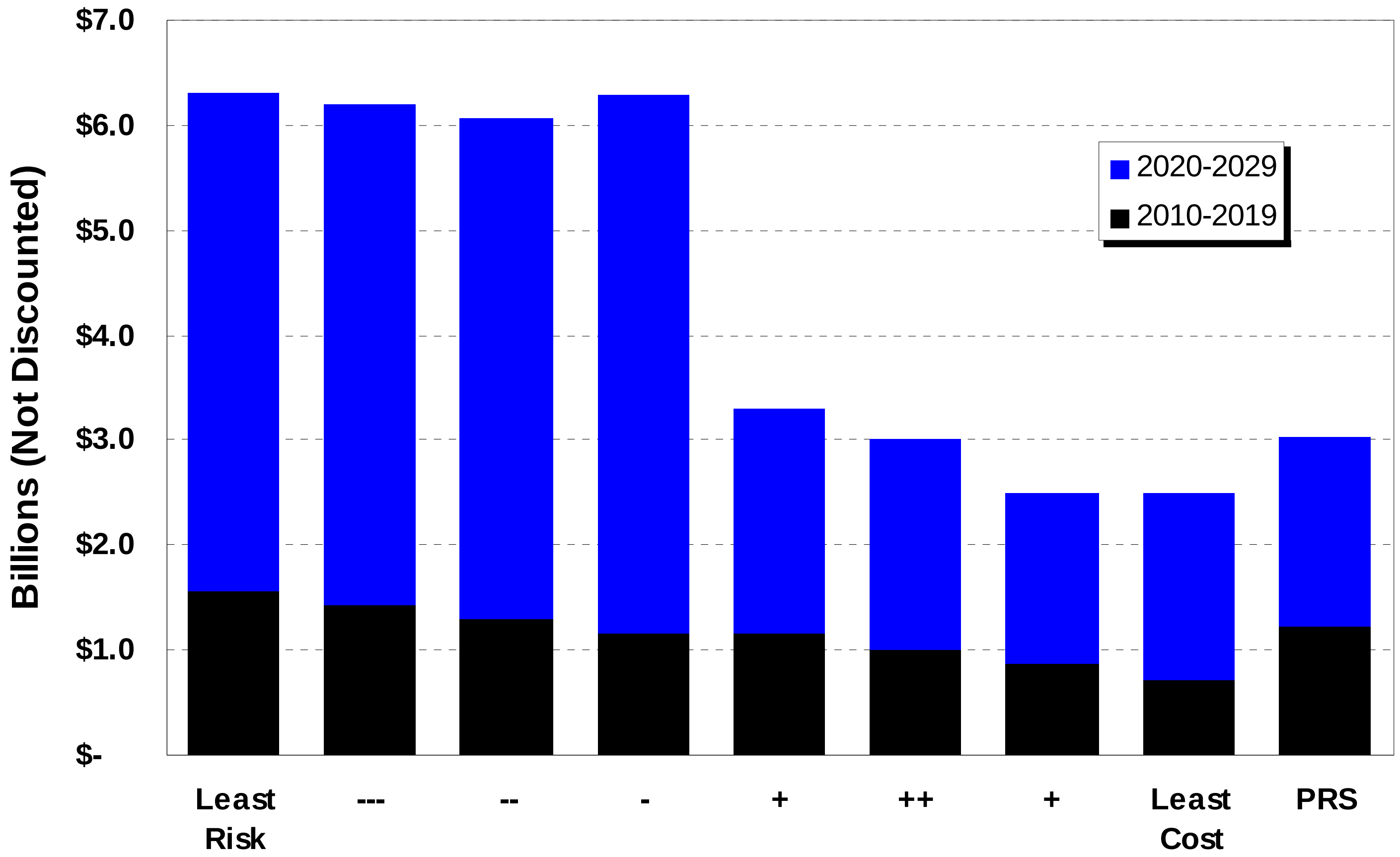
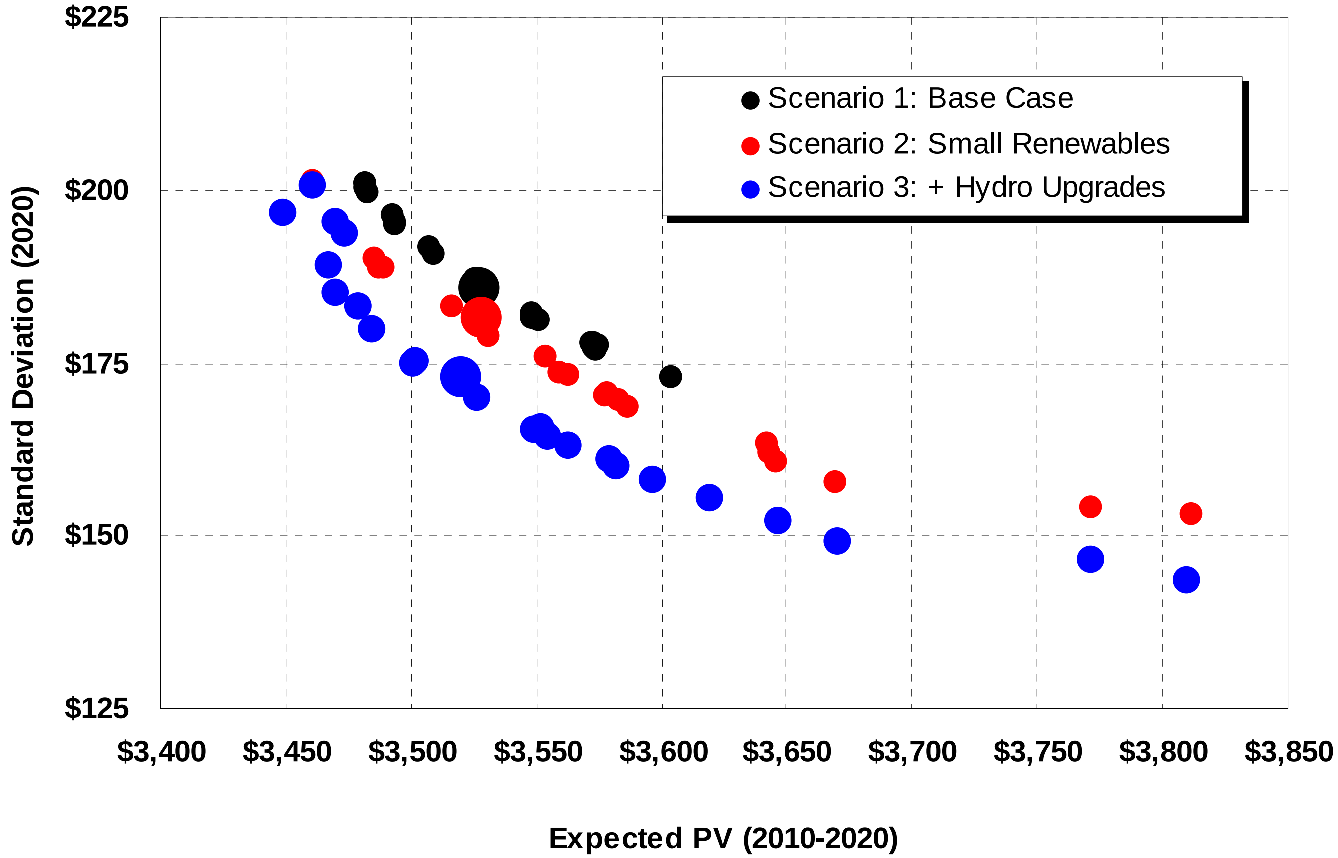
Efficient Frontier: Capital Requirements



Efficient Frontier Scenario Analysis



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Scenario 2- Resource Selection

Small Renewables an Option

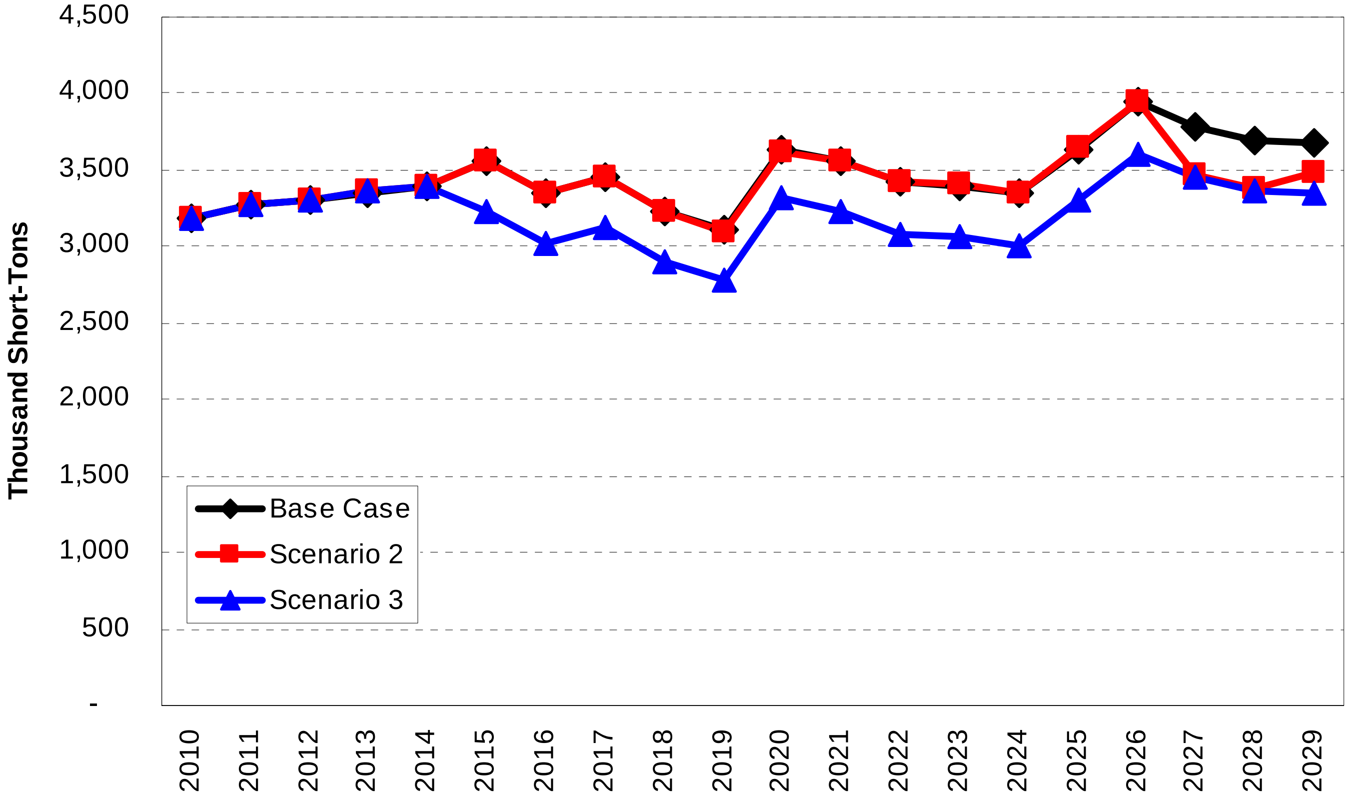
Year	CCCT	SCCT	Reardan	Wind	Other Renew	Solar	Hydro Upgrades	Coal	IGCC w/ Seq	Co-Gen	DSM	T&D	Total	Cumulative
2010											7.8	1.0	8.8	8.8
2011											7.9	1.0	8.9	17.6
2012					10.0						8.0	1.0	19.0	36.6
2013			50.0	50.0	5.0						8.2	1.0	114.2	150.8
2014											8.3	1.0	9.3	160.1
2015	125.0						1.0				8.4	1.0	135.4	295.5
2016					10.0						8.6		18.6	314.1
2017											8.7		8.7	322.8
2018				100.0	5.0						8.9		113.9	436.7
2019				100.0							9.0		109.0	545.7
2020	250.0			100.0		4.0	1.0				9.2		364.2	909.8
2021										5.0	9.3		14.3	924.2
2022							1.0			5.0	9.5		15.5	939.6
2023											9.6		9.6	949.3
2024											9.8		9.8	959.1
2025	125.0										10.0		135.0	1,094.1
2026	125.0										10.1		135.1	1,229.2
2027	125.0										10.3		135.3	1,364.5
2028											10.5		10.5	1,375.0
2029		100.0		100.0							10.7		210.7	1,585.7
2010-2019	125.0	-	50.0	250.0	30.0	-	1.0	-	-	-	83.7	6.0	545.7	
2010-2029	750.0	100.0	50.0	450.0	30.0	4.0	3.0	-	-	10.0	182.7	6.0	1,585.7	
2010-2019 (Delta)	-	-	-	(50.0)	30.0	-	(1.0)	-	-	(2.5)	-	-	(23.5)	
2010-2029 (Delta)	(125.0)	100.0	-	(100.0)	23.0	4.0	(3.0)	-	-	2.5	-	-	(98.5)	

Scenario 3- Resource Selection

Scenario 2 + Hydro Upgrades an Option

Year	CCCT	SCCT	Reardan	Wind	Other Renew	Solar	Hydro Upgrades	Coal	IGCC w/ Seq	Co-Gen	DSM	T&D	Total	Cumulative
2010											7.8	1.0	8.8	8.8
2011											7.9	1.0	8.9	17.6
2012					10.0						8.0	1.0	19.0	36.6
2013			50.0	50.0		4.0					8.2	1.0	113.2	149.8
2014						4.0					8.3	1.0	13.3	163.1
2015						4.0	60.0				8.4	1.0	73.4	236.5
2016					5.0		1.0				8.6		14.6	251.1
2017							1.0				8.7		9.7	260.8
2018				100.0							8.9		108.9	369.7
2019				100.0		4.0					9.0		113.0	482.7
2020	250.0			100.0		4.0	64.0			5.0	9.2		432.2	914.8
2021											9.3		9.3	924.2
2022											9.5		9.5	933.6
2023											9.6		9.6	943.3
2024											9.8		9.8	953.1
2025	125.0										10.0		135.0	1,088.1
2026	125.0										10.1		135.1	1,223.2
2027	250.0				5.0						10.3		265.3	1,488.5
2028				100.0							10.5		110.5	1,599.0
2029				100.0							10.7		110.7	1,709.7
2010-2019	-	-	50.0	250.0	15.0	16.0	126.0	-	-	-	83.7	6.0	482.7	
2010-2029	750.0	-	50.0	550.0	20.0	20.0	126.0	-	-	5.0	182.7	6.0	1,709.7	
2010-2019 (Delta)	(125.0)	-	-	(50.0)	15.0	16.0	124.0	-	-	(2.5)	-	-	(86.5)	
2010-2029 (Delta)	(125.0)	-	-	-	13.0	20.0	120.0	-	-	(2.5)	-	-	25.5	

Greenhouse Gas Scenario Comparison



Next Steps

- Add “Yellow Light” conservation projects as resource options
- Perform capital cost sensitivity analysis
- Study portfolios with renewable requirement changes
  - Resource Availability
  - National RPS
  - Higher WA state RPS target
- Study portfolio options with alternative market futures
- Test “Preferred Resource Strategies” against market scenarios
- Further evaluate large hydro upgrades

Avista's 2009 Electric Integrated Resource Plan
Technical Advisory Committee Meeting No. 5 Agenda
March 25, 2009

	Topic	Time	Staff
1.	Introduction	9:30	Storro
2.	Conservation	9:35	Hermanson
3.	Lunch	11:30	
4.	Preferred Resource Strategy	12:30	Gall
5.	Scenarios and Futures	1:30	Gall/Lyons
6.	2009 IRP Topics	2:30	Lyons
7.	Adjourn	3:00	

DSM in the 2009 Electric IRP

Technical Advisory Committee Meeting

Lori Hermanson

March 25, 2009

Presentation Highlights

- DSM History
- Overview of DSM
  - What, why, how and who of DSM
- Customer segments reached and offerings
- Messaging and outreach through EveryLittleBit and Website
- Tariff Rider Funding
- Metrics
- Stakeholders
- 2008 Results and 2009 Focus
- Integration of DSM into IRP
- Business planning to program development

Brief DSM History

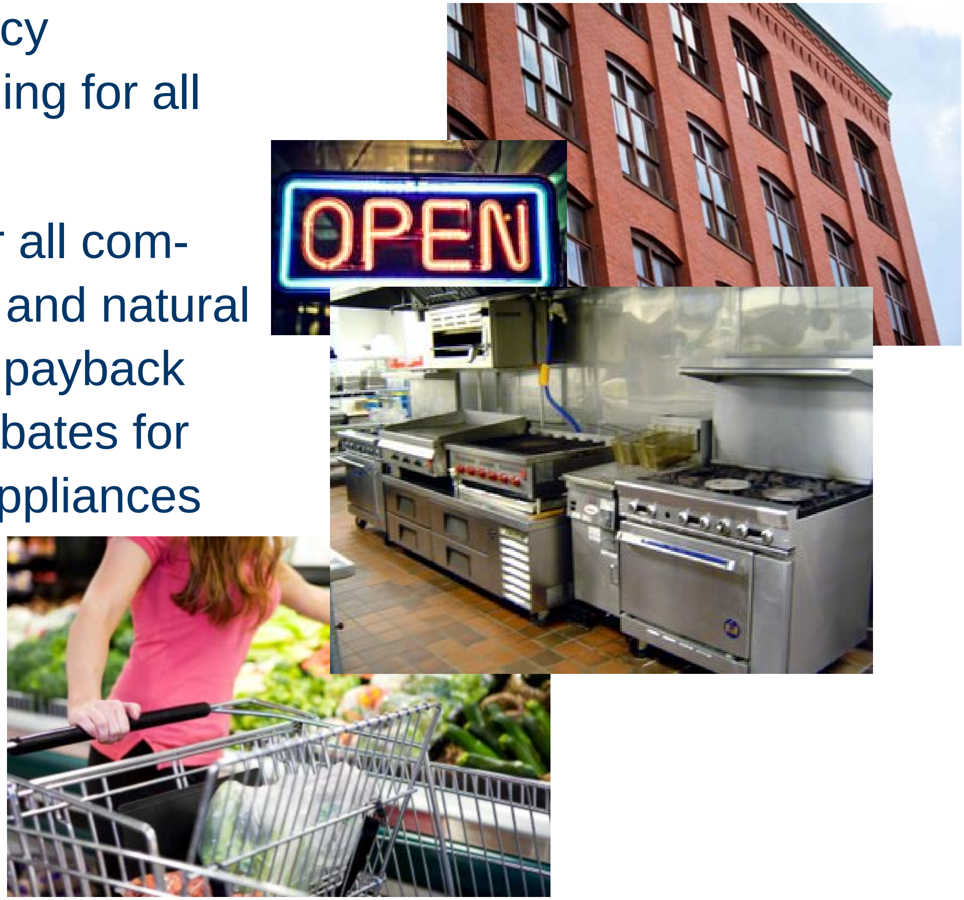
- Offered DSM since 1978
  - Energy exchanger – converted over 20,000 homes from electric to natural gas for space and water
  - Pioneered the country's first system benefit charge for energy efficiency in 1995
  - Immediate conservation response to 2001 Western energy crisis through expanded programs and enhanced incentives
    - Tripled annual savings at twice the cost
  - During the past 30 years, we acquired 138.5 aMW of energy savings
    - 109 aMW still online

What We Do

Deep and broad energy efficiency programs with strong messaging for all customers.

We provide financial rebates for all commercial and industrial electric and natural gas savings measures with a payback over one year and we offer rebates for weatherization and efficient appliances as well as low-cost/no-cost tips.

We provide renewable options and are testing end-use demand response pilots.



Why We Do It

Acquire lower cost resources to benefit all customers (IRP implementation)

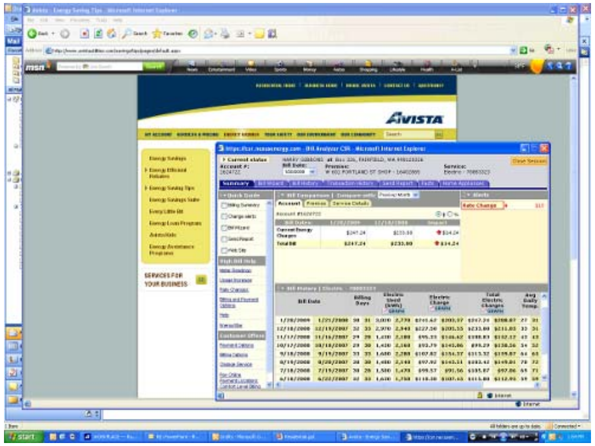
Customer assistance

- Reduction in customers' bills
- Gives customers some control in a higher energy cost environment

Regulatory obligation **and** sensibility

Reduced pressure on, or alternatives for, the capital budget

Carbon reduction and environmental focus



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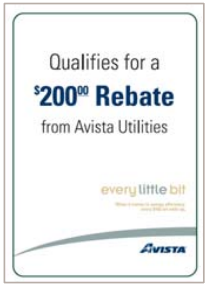
How We Do It

Pursue the Best Delivery Mechanisms for the Targeted Market

- Standard Offers ("Prescriptive") for residential & small commercial customers through mass marketing
- Custom ("Site Specific") for C&I customers with one point of contact through our Account Executive Team
- Low Income through community action agencies
- Regional through the NW Energy Efficiency Alliance
- Special projects—RFPs, Pilot Programs, etc.
- Promotion of Codes and Standards



SNAP
Spokane Neighborhood Action Programs

NORTHWEST ENERGY EFFICIENCY ALLIANCE

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Who Does It

Program Managers and Coordinators →
- Catherine Bryan
- Renee Coelho
- Leona Doege
- Chris Drake
- Camille Martin
- Lisa McGarity
- Debby Reid
- Kerry Shroy
- Greta Zink

Analytical Group →
- Jon Powell
- Lori Hermanson

Engineering Team →
- Tom Lienhard
- Mike Dillon
- Damon Fisher
- Carlos Limon
- Ron Welch

Administration →
- Pat Lynch
- Bruce Folsom
- Rachelle McGrath

Students →
- Virginia Luka
- Rachael Roig
- Nate Thompson
- Kayla Trabun

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Who Does It (cont.)

<<<Site Specific: **Account Executive Team**

Prescriptive: **Marketing Team**>>>

Contact Center assists customers with energy efficiency information

Corporate Communications provides earned media expertise

Community Relations partners with education and community involvement

State and Federal Regulation Department assists with PUC filings and communications

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C/I Energy Efficiency Site Specific

Avista Customer
Summary of Proposed
Energy Efficiency Measures
Listed in order of Simple Payback

- Custom Projects
- Technical Assistance
- Free Energy Audits and Analysis
- Design Review
- Cash Incentives

Option No.	Brief EEM Description	EEM Cost	Electric kWh Savings	Demand kW Savings	Nat. Gas Therm Savings	Energy Cost Savings	Simple Payback before incentive	Potential Incentive	**Simple Payback After Incentive**
1	Site Lighting Retrofit	**$179,335**	**519,441**	76	**(4,014)**	**$33,206**	**5.4 yrs**	**$ 62,333**	**3.5 Years**
2	Warehouse Heater replacement	**$53,395**	-	-	**2,665**	**$2,804**	**19.0 yrs**	**$ 7,995**	**16.2 yrs**
3	Roof insulation	**$180,000**	-	-	**7,742**	**$8,146**	**22.1 yrs**	**$ 23,226**	**19.2 yrs**
4	Office HVAC retrofits	**$404,240**	**93,842**	-	**6,069**	**$11,893**	**34.0 yrs**	**$ 21,961**	**32.1 yrs**

Scope of Work:

- The above incentives are based on information provided by vendor. The costs for the insulation were based on $1.50 per square foot. Any higher costs will need verification, but may increase the incentive.
- The warehouse HVAC system change is based on a building model using a warehouse setting and the insulation having already been complete.
- The office HVAC changes are based on the complete sq.ft. of the office space increasing SEER/EER values to new construction standards and a slight increase in AFUE for heating.
- All reports are attached.

C/I Energy Efficiency Prescriptive

Standard Offer Programs

- Measures that have relatively uniform savings
- Pre-determined amount
- Streamlined approach
- Marketability
- Ease of understanding for customers and contractors

Avista Utilities Commercial Lighting Table

Please complete this Lighting Table and submit with Incentive Agreement and copies of invoices. The incentive will be applied to the installed fixture count unless the initial (prior) fixture count is less. In that case, the prior fixture count will be the basis for calculating the eligible incentive.

Existing Equipment	Existing Quantity	New Equipment Installed	Installed Quantity (units)	Per Unit Incentive	Total Incentive
2-Foot Fluorescent Fixtures					
2-Lamp T12 U-Lamp	_____ fixtures	T8 U-Lamp or 2-Lamp F17 T8 Fixture/Retrofit	_____ fixtures	$15	$_____
4-Foot Fluorescent Fixtures					
4-Lamp T12 Fixture	_____ fixtures	4-Lamp T8 Fixture/Retrofit	_____ fixtures	$25	$_____
4-Lamp T12 Fixture	_____ fixtures	3-Lamp T8 Fixture*/Retrofit	_____ fixtures	$40	$_____
4-Lamp T12 Fixture	_____ fixtures	2-Lamp T8 Fixture*/Retrofit	_____ fixtures	$35	$_____
3-Lamp T12 Fixture	_____ fixtures	3-Lamp T8 Fixture/Retrofit	_____ fixtures	$25	$_____
3-Lamp T12 Fixture	_____ fixtures	2-Lamp T8 Fixture*/Retrofit	_____ fixtures	$30	$_____
2-Lamp T12 Fixture	_____ fixtures	2-Lamp T8 Fixture/Retrofit	_____ fixtures	$15	$_____
2-Lamp T12 Fixture	_____ fixtures	1-Lamp T8 Fixture*/Retrofit	_____ fixtures	$20	$_____
1-Lamp T12 Fixture	_____ fixtures	1-Lamp T8 Fixture/Retrofit	_____ fixtures	$15	$_____
8-Foot Fluorescent Fixtures					
4-Lamp T12 (or 2-Lamp HO) Fixture	_____ fixtures	4-Lamp (or 2-Lamp HO) T8 Fixture/Retrofit	_____ fixtures	$50	$_____
2-Lamp T12 Fixture	_____ fixtures	2-Lamp T8 Fixture/Retrofit (8' or 4' Lamps)	_____ fixtures	$30	$_____
1-Lamp T12 Fixture	_____ fixtures	1-Lamp T8 Fixture/Retrofit (8' or 4' Lamps)	_____ fixtures	$20	$_____
2-Lamp T12 HO or VHO Fixture	_____ fixtures	4-Lamp T5 High-Output Fixture/Retrofit	_____ fixtures	$85	$_____
HID Lighting (Metal Halide, High Pressure Sodium, Mercury Vapor)					
400 watt HID Fixture	_____ fixtures	4-Lamp T5 High-Output Fixture	_____ fixtures	$125	$_____
400 watt HID Fixture	_____ fixtures	6-Lamp T5 High-Output Fixture	_____ fixtures	$90	$_____
400 watt HID Fixture	_____ fixtures	6-Lamp T8 Fixture (4-Foot Lamps)	_____ fixtures	$125	$_____
400 watt HID Fixture	_____ fixtures	8-Lamp T8 Fixture (4-Foot Lamps)	_____ fixtures	$110	$_____
400 watt HID Fixture	_____ fixtures	200 Watt Induction Fluorescent Fixture	_____ fixtures	$220	$_____
1000 watt HID Fixture	_____ fixtures	(2) 6-Lamp T-5 High-Output Fixtures	_____ fixtures	$320	$_____
1000 watt HID Fixture	_____ fixtures	400 Watt Induction Fluorescent Fixture	_____ fixtures	$400	$_____
Incandescents					
100 watt or less Incandescent	_____ lamps	Compact Fluorescent Lamp (23 watt or Less Screw-In)	_____ lamps	$3	$_____
Over 100 watt to 200 watt Incandescent	_____ lamps	Compact Fluorescent Lamp or Fixture (45 watt)	_____ lamps	$15	$_____
Over 200 watt Incandescent	_____ lamps	Compact Fluorescent Lamp or Fixture (55-65 watt)	_____ lamps	$25	$_____
60 watt or greater Incandescent	_____ lamps	Dimmable Compact Fluorescent or Cold Cathode**	_____ lamps	$15	$_____
100 watt or greater Incandescent flood	_____ fixtures	Ceramic Metal Halide (25 watt)	_____ fixtures/lamps	$35	$_____
150 watt or greater Incandescent	_____ fixtures	New Linear T8 Fluorescent Fixture	_____ fixtures	$35	$_____
Sign Lighting or Low Wattage Applications (Minimum Runtime Greater than 12 Hours Per Day)					
20-30 watt Incandescent	_____ lamps***	LED or Low Wattage Equivalent	_____ lamps***	$15	$_____
20-60 watt Incandescent	_____ lamps	Cold Cathode	_____ lamps/fixtures	$10	$_____
Exit Signs					
Incandescent Exit Sign	_____ exit sign	New LED Exit Sign	_____ exit sign	$25	$_____
Occupancy Sensors					
Manual Light Switch	_____ sensors	Occupancy Sensor Controlling Less than 200-watts	_____ sensors	$25	$_____
Manual Light Switch	_____ sensors	Occupancy Sensor Controlling Greater than 200-watts	_____ sensors	$50	$_____
Daylight Dimming (Applicable for lights that are no more than 20 feet from a window or skylight)					
No prior dimming control	_____ fixtures	Individually Controlled Fixtures	_____ fixtures	$25	$_____
				Total Incentive	$_____

*Reducing the number of lamps in a fixture may reduce light output. In order to achieve adequate light levels a specular reflector may be needed. Testing is encouraged prior to a comprehensive lighting retrofit. **Cold cathodes are only good for replacement of incandescents up to 65 watts.
***Incentive is per incandescent in original sign configuration. 3/08

Page 3 of 4

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C/I Prescriptive (Standard Offer) Programs

- Lighting
- Food Service Equipment
- PC Network Controls
- Premium Efficiency Motors
- Steam Trap Repair/ Replacement
- Demand Controlled Ventilation
- Side Stream Filtration
- Retro-Commissioning
- LEED Certification
- Vending Machine Controllers
- Refrigerated Warehouse
- Electric to Gas Water Heater Conversions
- Variable Frequency Drives
- Commercial Clothes Washers
- Energy Smart Grocer

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Residential Prescriptive Offerings

- High efficiency equipment
- CFL lighting
- Refrigerator recycling
- Conversions from Straight Resistance
- Weatherization
- Rooftop dampers
- Ductless heat pump pilot
- UCONS Multi-family direct install
- www.everylittlebit.com (visit our house of rebates)

every little bit

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Limited Income Offerings

- Weatherization
- Windows/Doors
- Conversions
- Equipment Upgrades
- Health & Human Safety

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Regional Programs (NEEA)

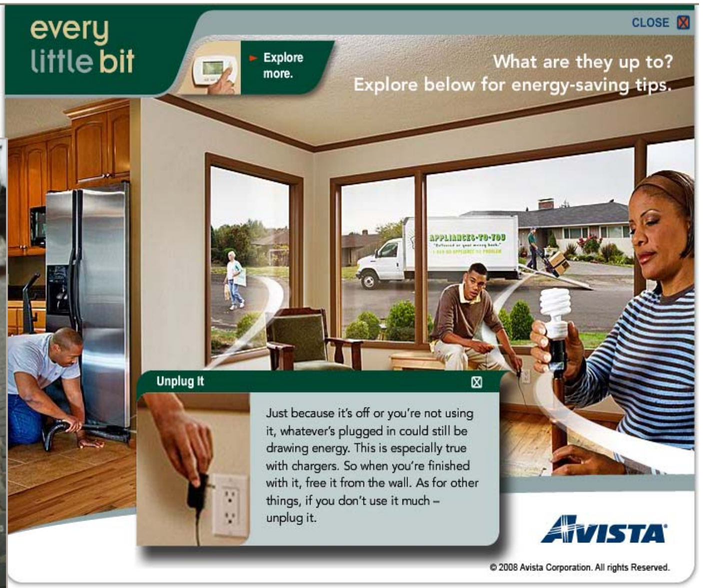
- Acquisition of electric efficiency through market transformation
- Funded by 5 IOUs, ETO, generating publics and BPA
  - Avista's portion – 3.94%
- Regional leaders are discussing expansion of efforts
  - Avista's portion will increase to 5.6%
  - Savings acquisition increase from 1.5 aMW to 2.94 aMW
- Historically been a cost-effective option to acquire resources
  - Levelized TRC cost of about 10 mills
  - Not necessarily representative of future costs

Messaging and Outreach: Every Little Bit

Market research done in 2007 found that Avista's customers believed they "were already efficiency, that energy efficiency is too expensive, and it doesn't make much difference."

In response, the EveryLittleBit campaign was launched with a website, broadcast and print media, and collateral materials in a multi-channel, multi-year approach.

every little bit



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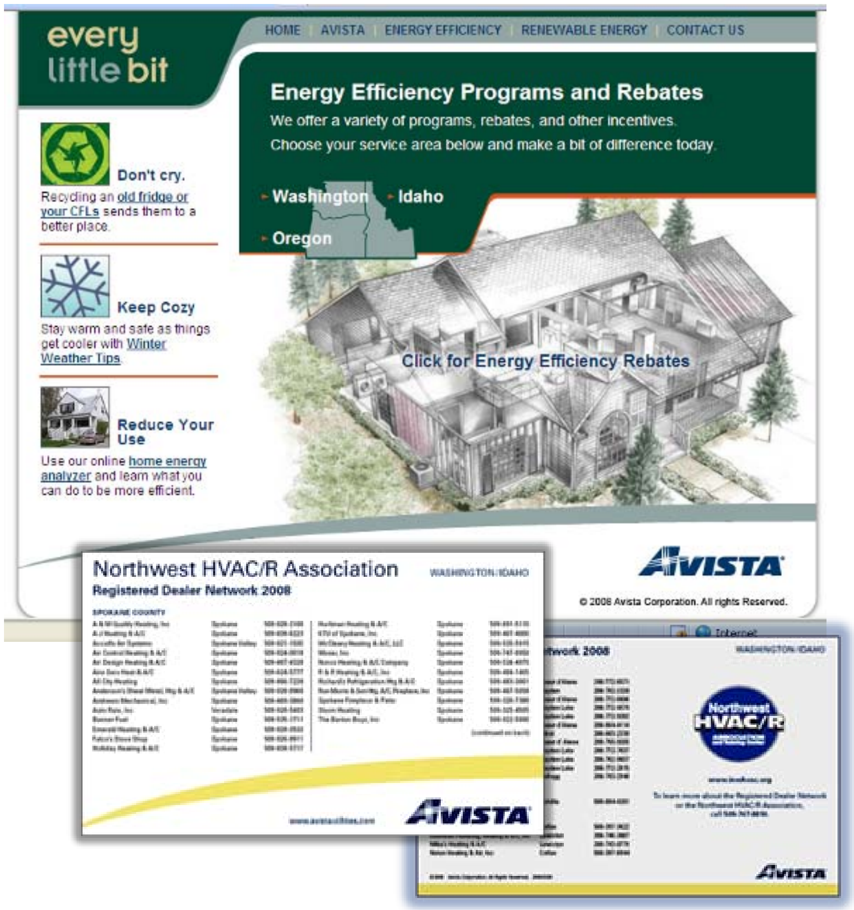
Messaging and Outreach: Online Resources



- www.everylittlebit.com
- www.avistautilities.com
- Energy Saving Tips
- House of Rebates
- Downloadable Forms
- Energy Audit
- Bill Analyzer
- RDN Dealer List
- Efficiency Ave for Business – in process

Funding of Energy Efficiency Programs

- DSM Tariff Rider
  - A percentage of every dollar paid goes to energy efficiency
  - Has multiple regulatory requirements for implementation
- Provides for $23 million annual budget
- Moving towards an annual “true-up”
- First “System Benefit Charge” in North America in 1995
- Continue to evaluate its efficacy and options

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Potential Stimulus Funding

- Funding available for energy conservation and smart grid development
- Avista is currently evaluating possible programs that could be offered with additional funding from the stimulus bill
  - One possible project – regional smart grid pilot
    - Utility and non-utility sponsors
    - Scope includes everything from Advanced Metering Infrastructure (AMI), software and support, to demand response
    - Avista still considering participation but still has not committed to participation

Resource Portfolio Standards (RPS)

- Previously I-937, requires large utilities to obtain a fixed percentage of their electricity from qualifying renewable resources in addition to all cost-effective and acquirable energy conservation
  - 3% by 2012
  - 9% by 2016
  - 15% by 2020
- Avista is working with others to change this legislation to allow utilities to use energy conservation acquisition above the cost-effective levels in lieu of renewables
  - Benefits the customer
  - Truly lower cost resource

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Metrics

Cost-Effectiveness, Measurement and Evaluation, Post-Verification, Triple E Reports, Prudence Findings in General Rate Cases

Table 15EG **Calculation of Energy Savings vs. Utility Expenditure Proportionality**

	Adjusted Proportionality Calculation				Unadjusted Proportionality Calculation			
	Electric		Gas		Electric		Gas	
Actual 1/1/08 to 12/31/08 cash expenditures	$	14,553,058	$	6,288,949	$	14,553,058	$	6,288,949
Less cash incentives	$	(9,918,978)	$	(5,085,264)	$	-	$	-
Add in derated incentives	$	9,395,623	$	5,404,090	$	-	$	-
Adjusted (for incentives) utility expenditures	$	14,029,702	$	6,607,775	$	14,553,058	$	6,288,949
Normalize NEEA expenditures	$	61,379	$	-	$	-	$	-
Total adjusted utility expenditures	$	14,091,081	$	6,607,775	$	14,553,058	$	6,288,949
DSM revenues 1/1/08 to 12/31/08	$	11,558,429	$	4,433,213	$	11,558,429	$	4,433,213
Adjusted utility expenditures divided by actual revenues		122%		149%		126%		142%
Energy savings from Triple-E Report		74,861,160		1,888,061		74,861,160		1,888,061
IRP Goal		52,966,689		1,425,070		52,966,689		1,425,070
% of goal achieved		141%		132%		141%		132%
Proportionality (kWh and therm)		**116%**		**89%**		**112%**		**93%**
Proportionality (mmbtu)		**103%**				**103%**		

NOTES:

(1) Adjustments for the difference between cash incentives and those accrued as projects move through the "pipeline" (contracted to construction to completed) remove the effect of scheduling cash payment of incentives to future dates.

(2) NEEA revenues have been adjusted to equal our annual maximum contractual obligation. Regional energy savings are not reflected in this calculation.

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Stakeholder Involvement

External Energy Efficiency Board (Triple E)

Non-binding oversight, technical advisory committee

Meets twice a year

Regular reporting

Periodic Newsletters

Avista External Energy Efficiency Board
Lynn Anderson – Idaho Public Utilities Commission
Nick Beamer –Aging and Long-Term Care of Eastern Washington
Sheryl Carter – Natural Resource Defense Council
Chris Davis – Spokane Neighborhood Action Programs
Carrie Dolwick – Northwest Energy Coalition
Michael Early – Industrial Customers of Northwest Utilities
Chuck Eberdt – The Energy Project
Tom Eckman – Northwest Power Planning Council
Donn English – Idaho Public Utilities Commission
Claire Fulenwider – Northwest Energy Efficiency Alliance
Stefanie Johnson – Washington Public Counsel
Steven Johnson – Washington Utilities and Transportation Commission
Lisa LaBolle – Idaho Office of Energy Resources
John Kaufman – Oregon Department of Energy
Mary Kimball – Washington Public Council
Lynn Kittilson – Oregon Public Utility Commission
Phil Kercher – Sacred Heart Medical Center
Ron Oscarson - Spokane County
Paula Pyron – Northwest Industrial Gas Users
Deborah Reynolds – Washington Utilities and Transportation Commission
Michael Shepard – E-Source

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Incentives/Rebates Paid in 2008

- Slightly over $15 million paid to Avista customers.
  - $7.65 million to commercial/industrial customers
    - 768 projects received an incentive
  - $6.1 million to residential customers
    - 12,890 residential customers received incentives
  - $1.2 million to limited income customers
    - More than 450 households assisted

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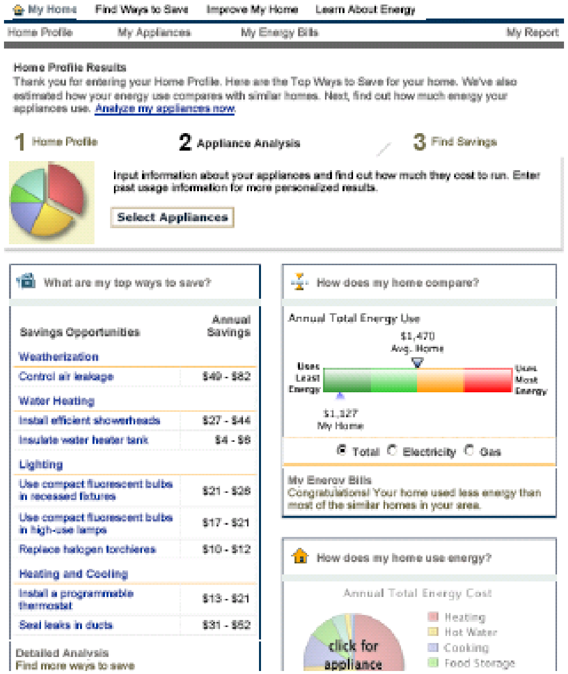
Avista's 2008 Energy Efficiency Results

- Exceeded electric IRP goal by 41% and natural gas IRP goal by 32%
- Total electric savings over 74.8 million kilowatt h
  - Commercial/Industrial over 41.8 million kwh
  - Residential over 31.1 million kwh
  - Limited Income over 1.8 million kwh
- Total natural gas savings over 1.8 million therms
  - Commercial/Industrial over 1.0 million therms
  - Residential – 749,199 therms
  - Limited Income – 102,438 therms



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2009 Focus

Increasing electric and natural gas savings targets

Continued personalization, presence, and participation for and by customers

New Programs Under Consideration: Small Commercial Initiative, Energy Champion, Energy Coaching, Behavioral Programs, Bundling

Potential changes in Resource Portfolio Standards in Washington, Energy Trust of Oregon, Decoupling in all states

Earnings opportunities and potential for expansion

"Didn't ya hear? To save energy we have to keep the thermostat at 1,100 degrees instead of 1,200 degrees!"

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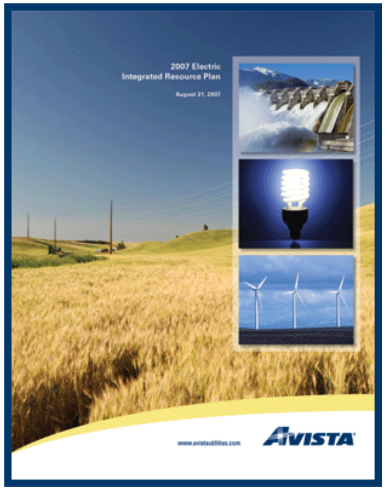
From Planning to Customer Programs



2009 Washington / Idaho DSM Business Plan

A Working Document to Plan and Guide our 2009 Strategy and Operations

Avista Washington / Idaho DSM staff
Catherine Bryan
Renee Coelho
Mike Dillon
Leona Doege
Chris Drake
Damon Fisher
Bruce Folsom
Lori Hermanson
Tom Lienhard
Carlos Limon-Granados
Camille Martin
Rachelle McGrath
Jon Powell
Ron Welch
Greta Zink

Avista External Energy Efficiency Board
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Ron Oscarson - Spokane County
Paula Pyron – Northwest Industrial Gas Users
Deborah Reynolds – Washington Utilities and Transportation Commission
Michael Shepard – E-Source

Total Company Planning with >3000 DSM measures considered

From Planning to Tariffs and Programs

>30 Programs and >300 measures offered

Integration of DSM into the 2009 Electric IRP

- Interactive process that meets regulatory requirements and produces results for the business planning process
  - Identify all commercially available technologies or measures
    - "Acceptance" or "rejection" within the IRP will not remove any technology or application from potentially being included
    - Nearly 2,500 measures were evaluated for this IRP
  - Re-evaluate existing residential measures and evaluate the inclusion of addition measures
    - May change the menu of residential offerings
    - Nearly 800 measures were evaluated for this IRP

Integration of DSM into the 2009 Electric IRP (cont.)

- Inclusion of limited income and non-residential site specific programs are done by modifying the historical baseline
  - Not necessarily limited to modifying baseline for price elasticity and load growth
  - Site specific measures that fit into the 3,000+ measures evaluated are evaluated through the normal IRP process outside of this modified historical baseline approach

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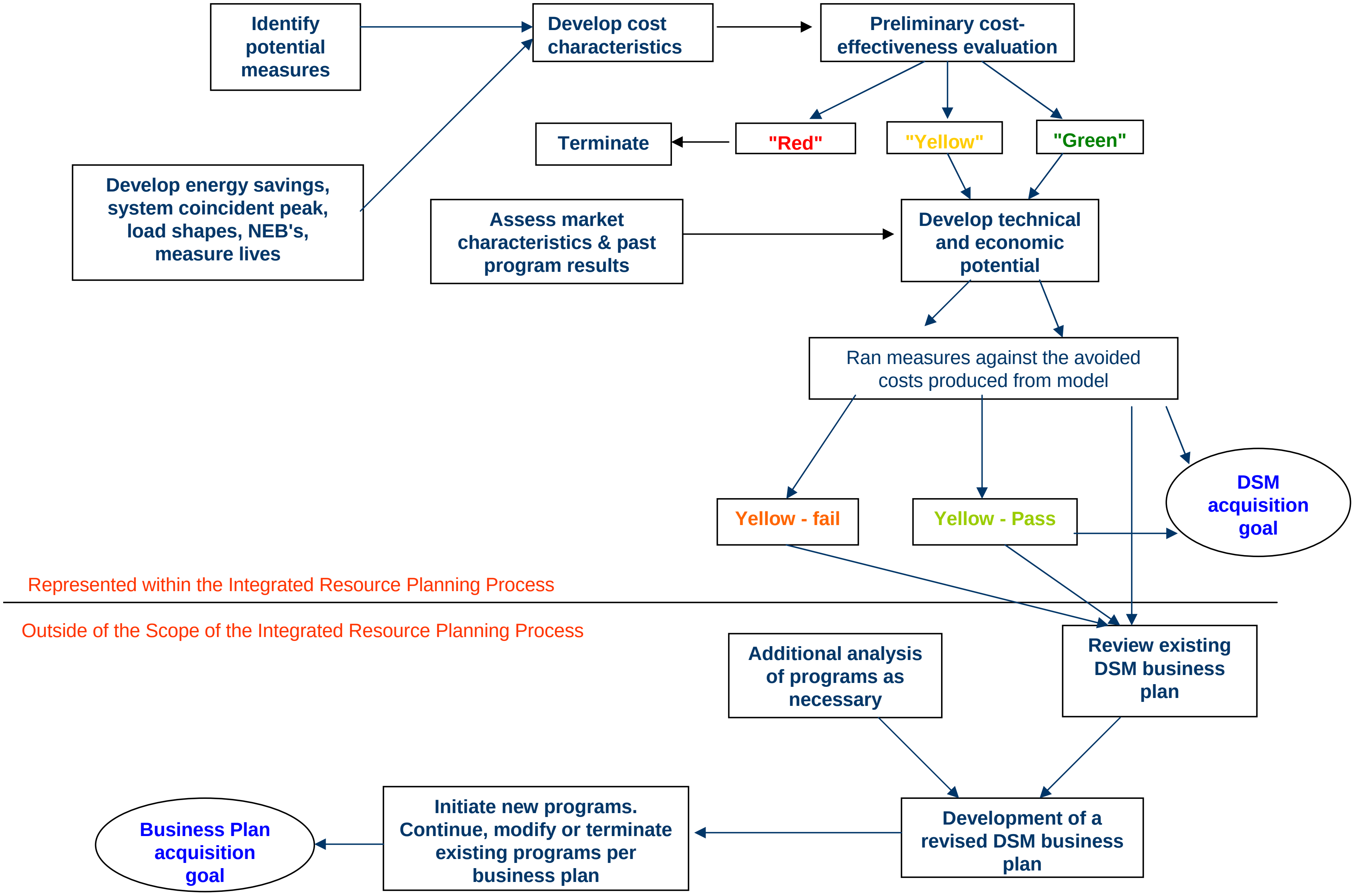
Identify potential measures
Develop cost characteristics
Preliminary cost-effectiveness evaluation
Terminate
"Red"
"Yellow"
"Green"
Develop energy savings, system coincident peak, load shapes, NEB's, measure lives
Assess market characteristics & past program results
Develop technical and economic potential
Ran measures against the avoided costs produced from model
Yellow - fail
Yellow - Pass
DSM acquisition goal
Represented within the Integrated Resource Planning Process
Outside of the Scope of the Integrated Resource Planning Process
Additional analysis of programs as necessary
Review existing DSM business plan
Business Plan acquisition goal
Initiate new programs. Continue, modify or terminate existing programs per business plan
Development of a revised DSM business plan

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Evaluation of Measures

- Based on levelized TRC, measures are categorized into “greens”, “yellows” and “reds”
  - “Greens” automatically selected and entered into model
  - “Yellows” are tested - range ended up being $90-$140/MWh
  - “Reds” – no further testing
- IRP process results in DSM goal and updated avoided costs
  - 63,119,081 kWh for 2010
  - 65,643,844 kWh for 2011
  - Avoided costs are used to evaluate new measures or technologies that may arise between IRPs

Business Planning Process

- Selected measures are further evaluated by program managers
  - Market research
  - Program bundling
  - Program development
- Budgets is prepared for individual programs
  - Update economic potential savings acquisition
  - Projection of FTE
  - Estimate of participation levels, incentives, and other expenses
- Business plan goal
  - Historically, has been at or above IRP goal

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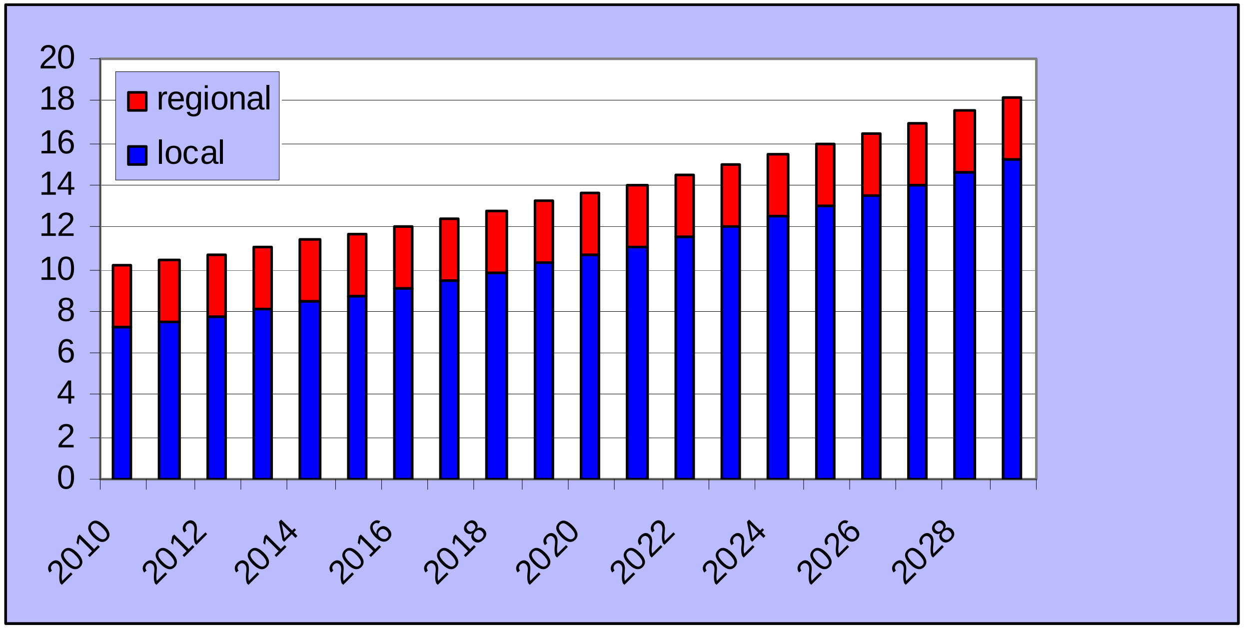
Where Are We At in the IRP Process?

- Goals complete for 2010/2011
- Projection of 20 year DSM acquisition complete



Where Are We At in the IRP Process? (cont.)

- Written contribution for the IRP document
  - Drafts to J. Powell and B. Folsom for review and edits
  - Insert final numbers and changes
  - Final document due end of March

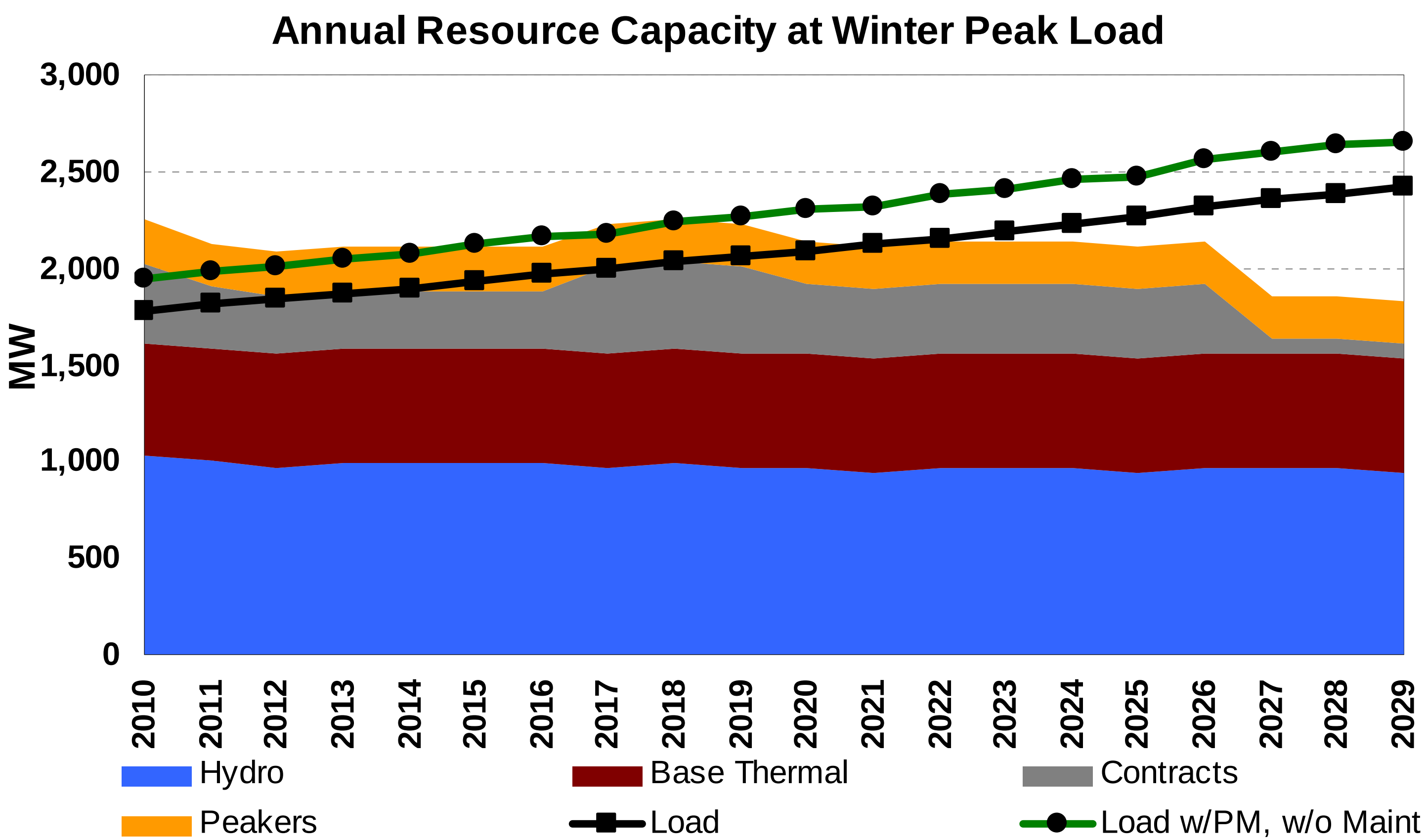
2009 Preferred Resource Strategy

James Gall

2009 Electric Integrated Resource Plan
Fifth Technical Advisory Committee Meeting
March 25, 2009

AVISTA®

January Capacity L&R Balance



Load is net 2007 Conservation Levels

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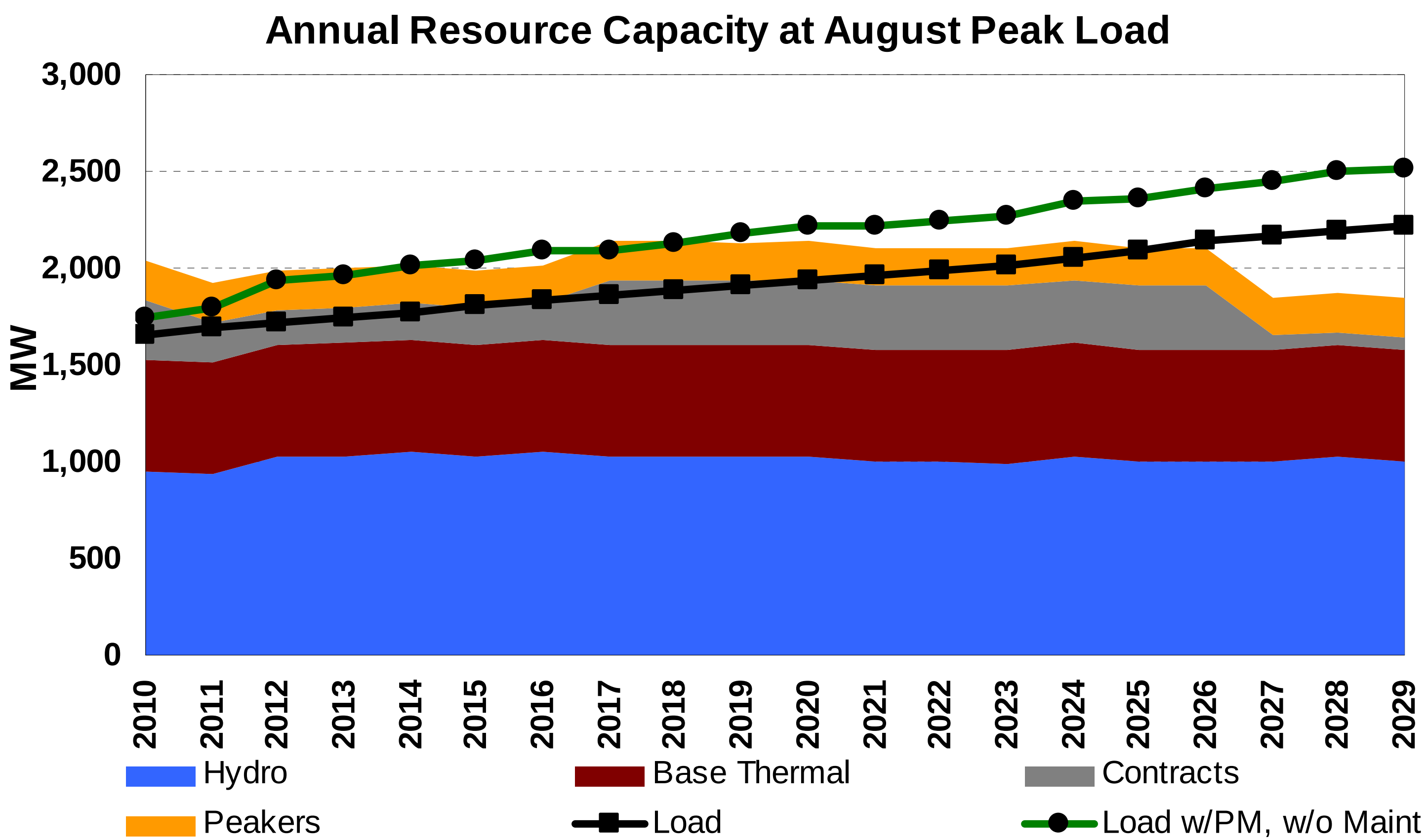
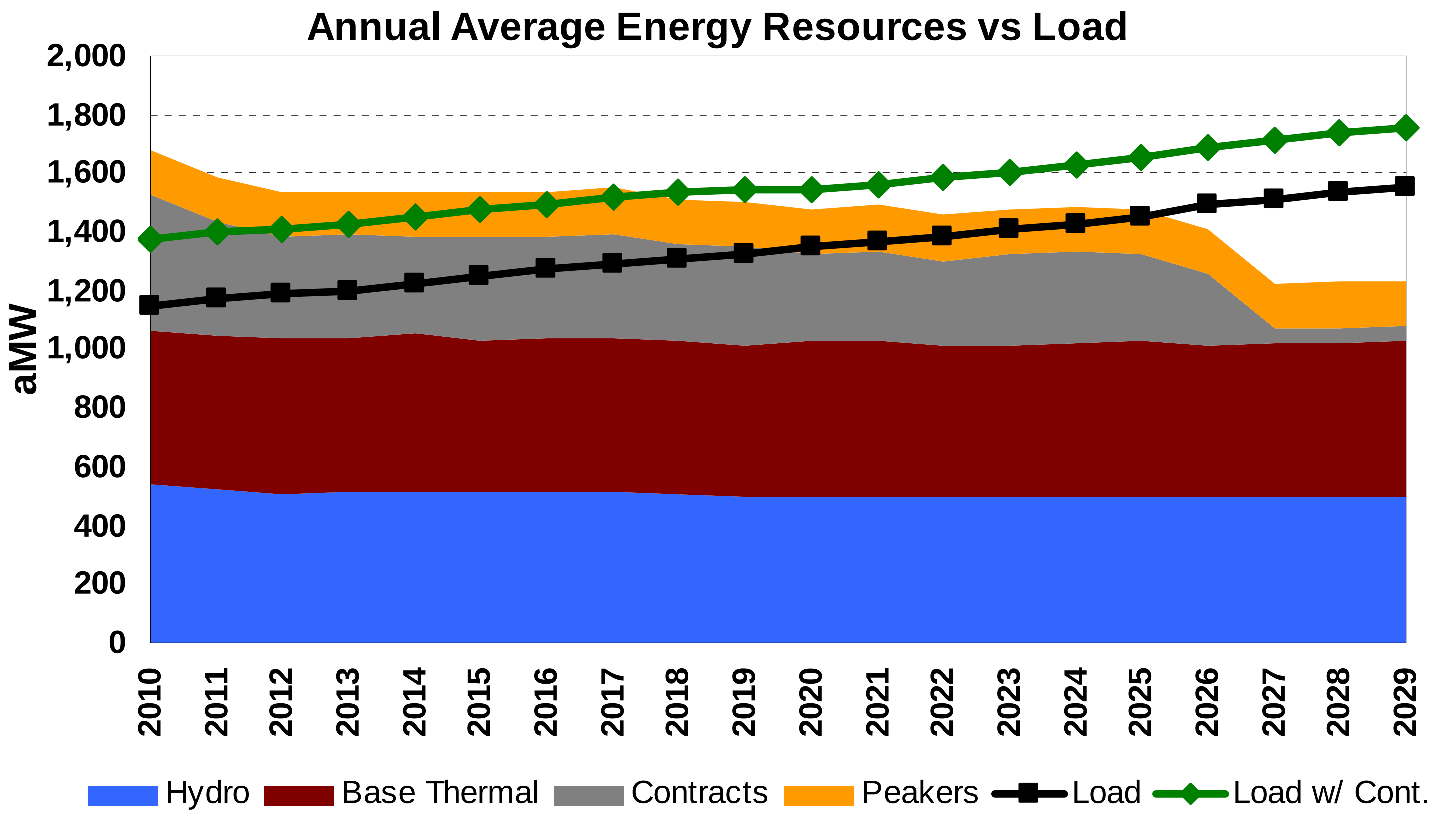
August Capacity L&R Balance



Load is net 2007 Conservation Levels

Annual Energy L&R Balance



Load is net 2007 Conservation Levels

PRiSM Objective Function

- Linear program solving for the optimal resource strategy to meet resource deficits over planning horizon.
- Model selects its resources to reduce cost, risk, or both.

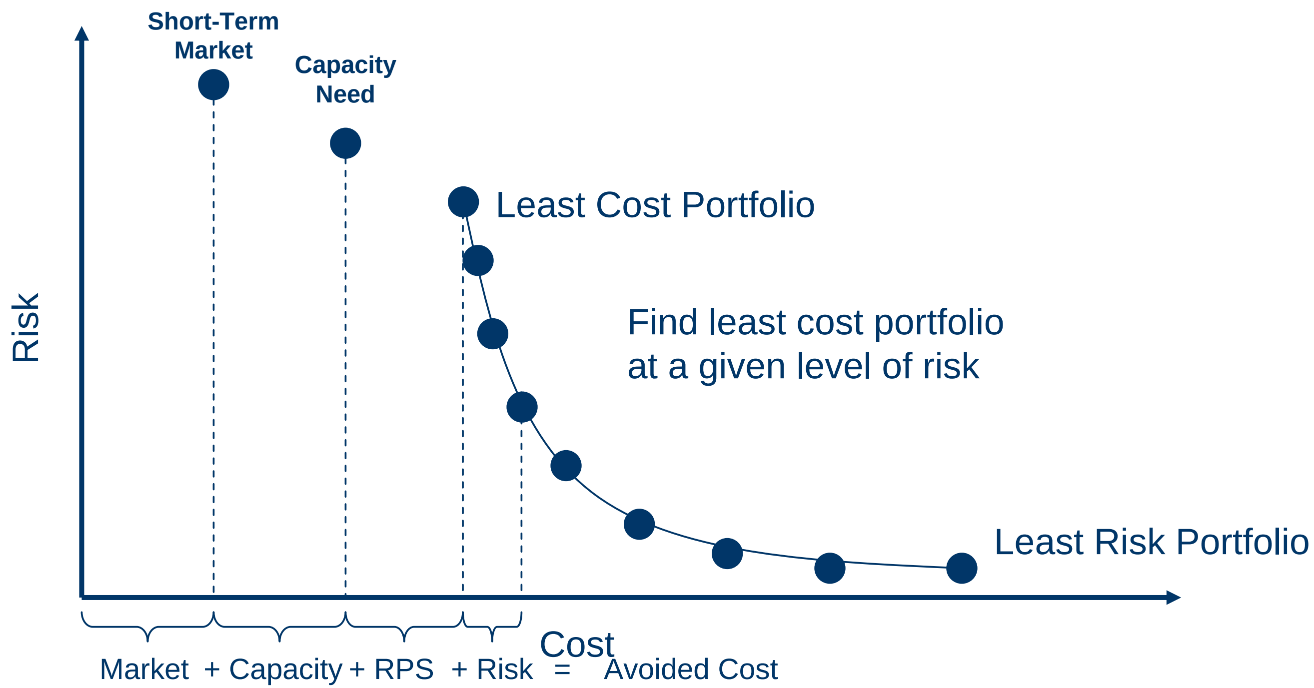
Minimize: Total Power Supply Cost on NPV basis (2010-2050 with emphasis on first 11 years of the plan)

Subject to:

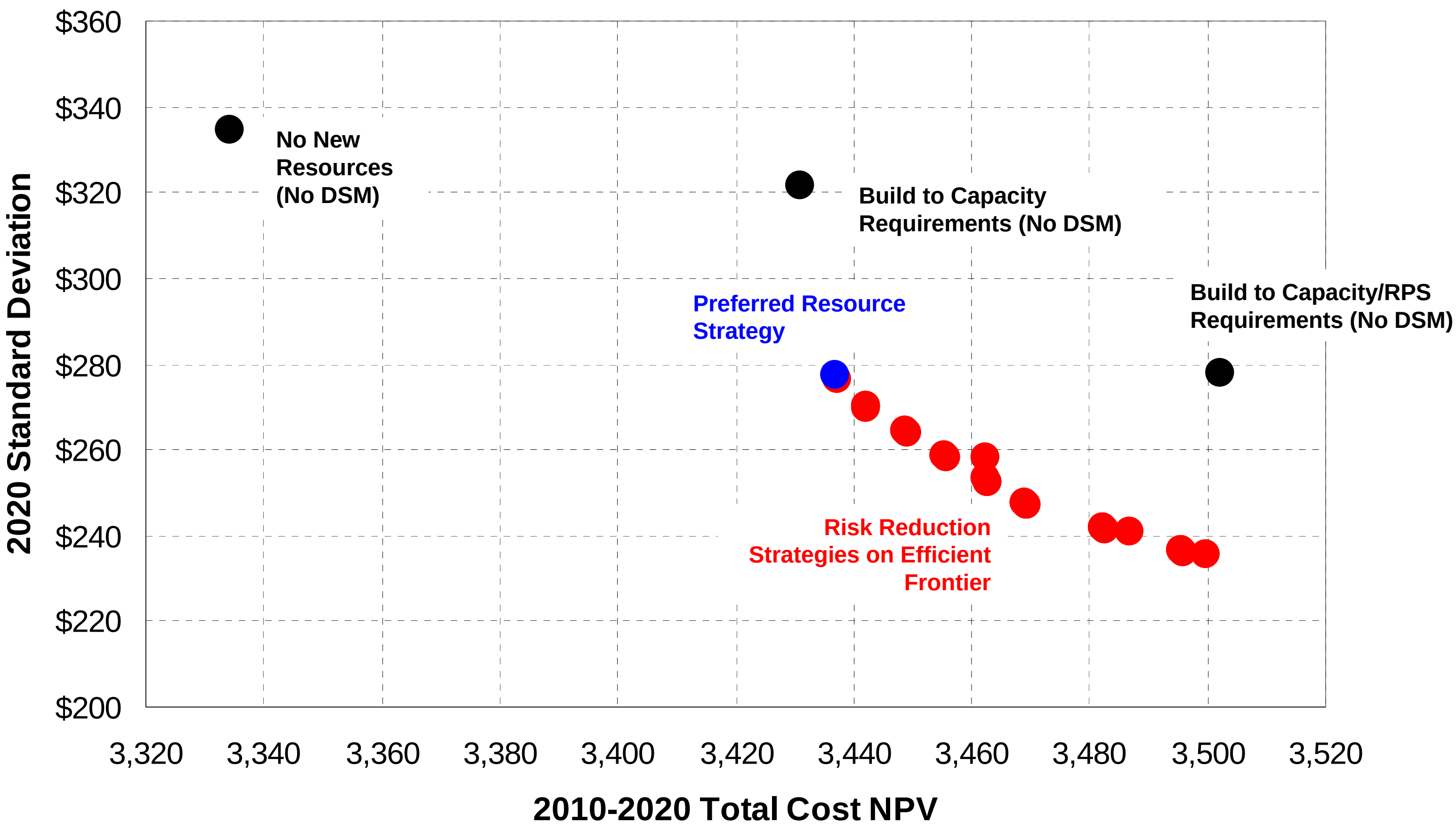
- Risk Level
- Capacity Need +/- deviation
- Energy Need +/- deviation
- Renewable Portfolio Standards
- Resource Limitations and Timing
- Greenhouse Gas Limits

Efficient Frontier

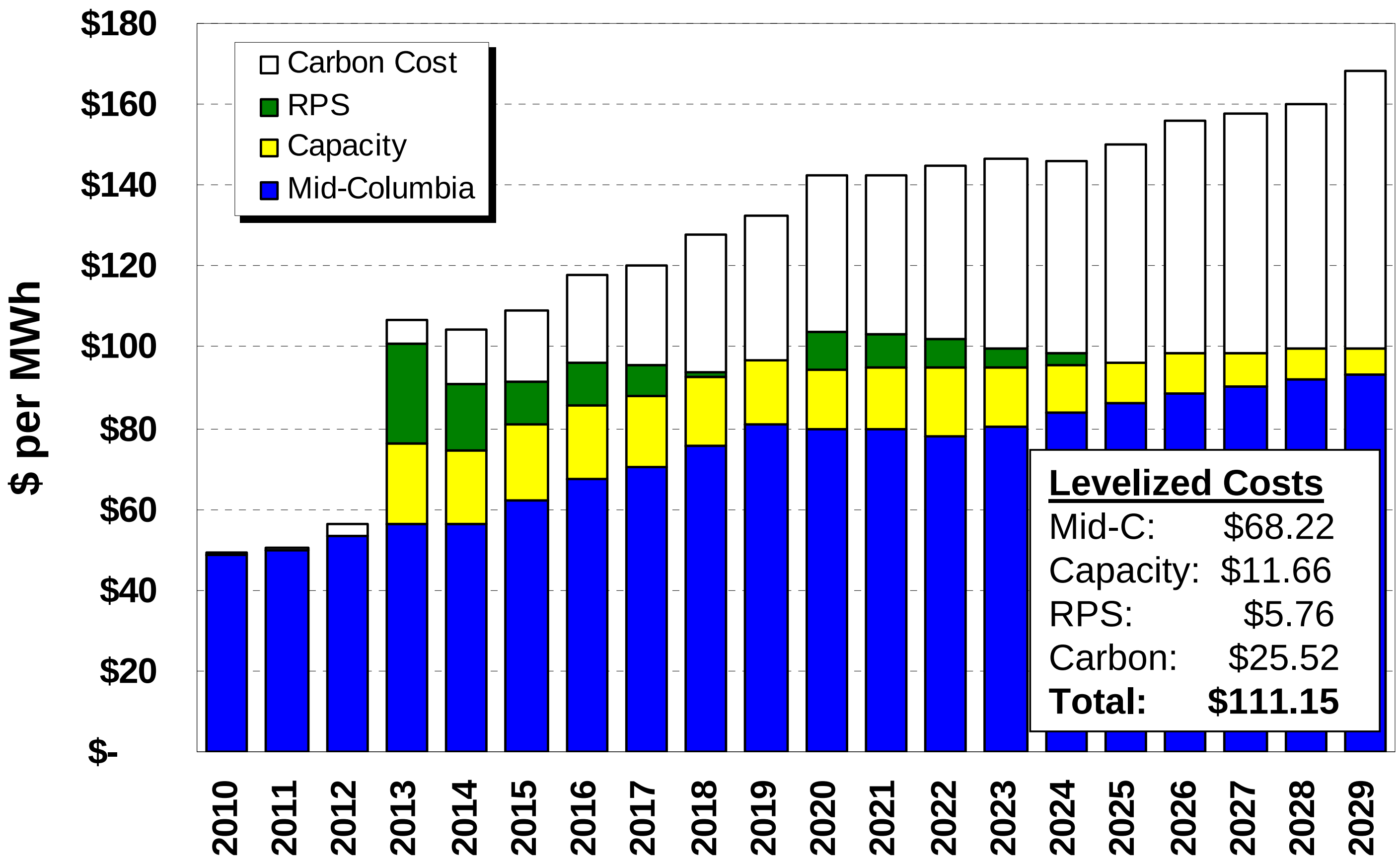
- Demonstrates the trade off of cost and risk
- Avoided Cost Calculation



Efficient Frontier



Avoided Resource Cost



2007 Preferred Resource Strategy

(Capacity MW)

Year	CCCT	SCCT	Wind	Hydro Upgrades	Non-Wind Renewables	Low Carbon Baseload	DSM	T&D Efficiency
2008	-	-	-	-	-	-	9	-
2009	-	-	-	-	-	-	10	-
2010	275	-	-	-	-	-	11	-
2011	-	-	-	-	20	-	12	-
2012	-	-	-	-	10	-	13	-
2013	-	-	-	-	-	-	14	-
2014	-	-	100	-	5	-	15	-
2015	-	-	-	-	-	-	15	-
2016	-	-	100	-	-	-	16	-
2017	-	-	100	-	-	-	16	-
2018	-	-	-	-	-	-	16	-
2019	-	-	-	-	-	-	16	-
2020	81	-	-	-	10	-	17	-
2021	32	-	-	-	10	-	17	-
2022	38	-	-	-	5	-	17	-
2023	15	-	-	-	-	-	18	-
2024	58	-	-	-	-	-	18	-
2025	38	-	-	-	-	-	18	-
2026	35	-	-	-	-	-	19	-
2027	305	-	-	-	-	-	19	-
2008-2017	275	-	300	-	35	-	130	-
2008-2027	877	-	300	-	60	-	304	-

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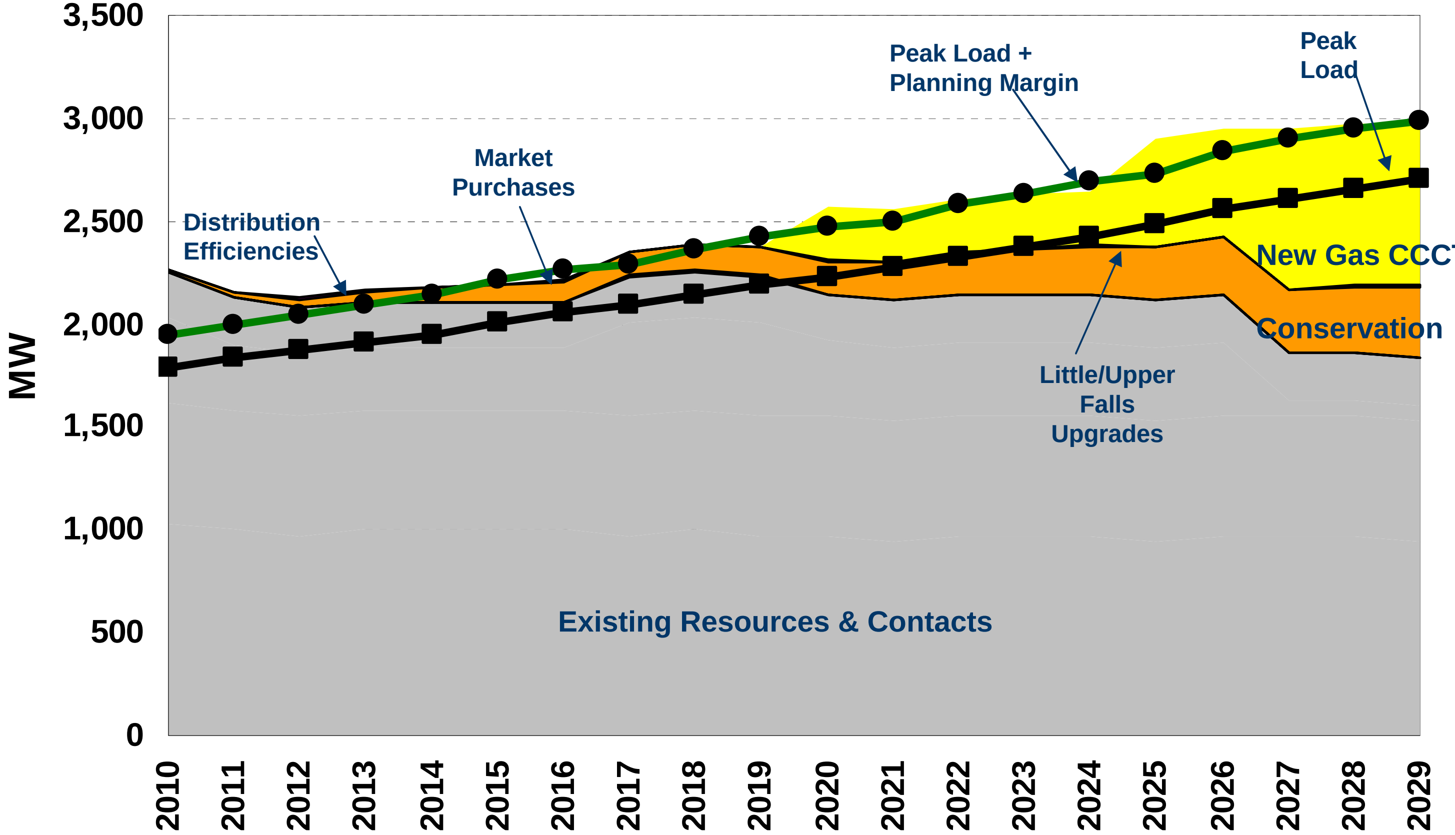
Preferred Resource Strategy

(Capacity MW)

Year	CCCT	SCCT	Wind	Hydro Upgrades	Low Carbon Baseload	DSM	T&D Effic.
2010	-	-	-	-	-	12	1
2011	-	-	-	-	-	12	1
2012	-	-	-	-	-	12	1
2013	-	-	150	-	-	12	1
2014	-	-	-	1	-	14	1
2015	-	-	-	1	-	14	-
2016	-	-	-	-	-	15	-
2017	-	-	-	1	-	15	-
2018	-	-	-	-	-	15	-
2019	-	-	-	-	-	17	-
2020	250	-	150	-	-	17	-
2021	-	-	-	2	-	18	-
2022	-	-	-	-	-	18	-
2023	-	-	50	-	-	20	-
2024	-	-	-	-	-	20	-
2025	250	-	-	-	-	21	-
2026	-	-	-	-	-	21	-
2027	250	-	-	-	-	23	-
2028	-	-	-	-	-	23	-
2029	-	-	-	-	-	24	-
2010-2019	-	-	150	3	-	137	5
2010-2029	750	-	350	5	-	339	5

January Capacity L&R w/ New Resources



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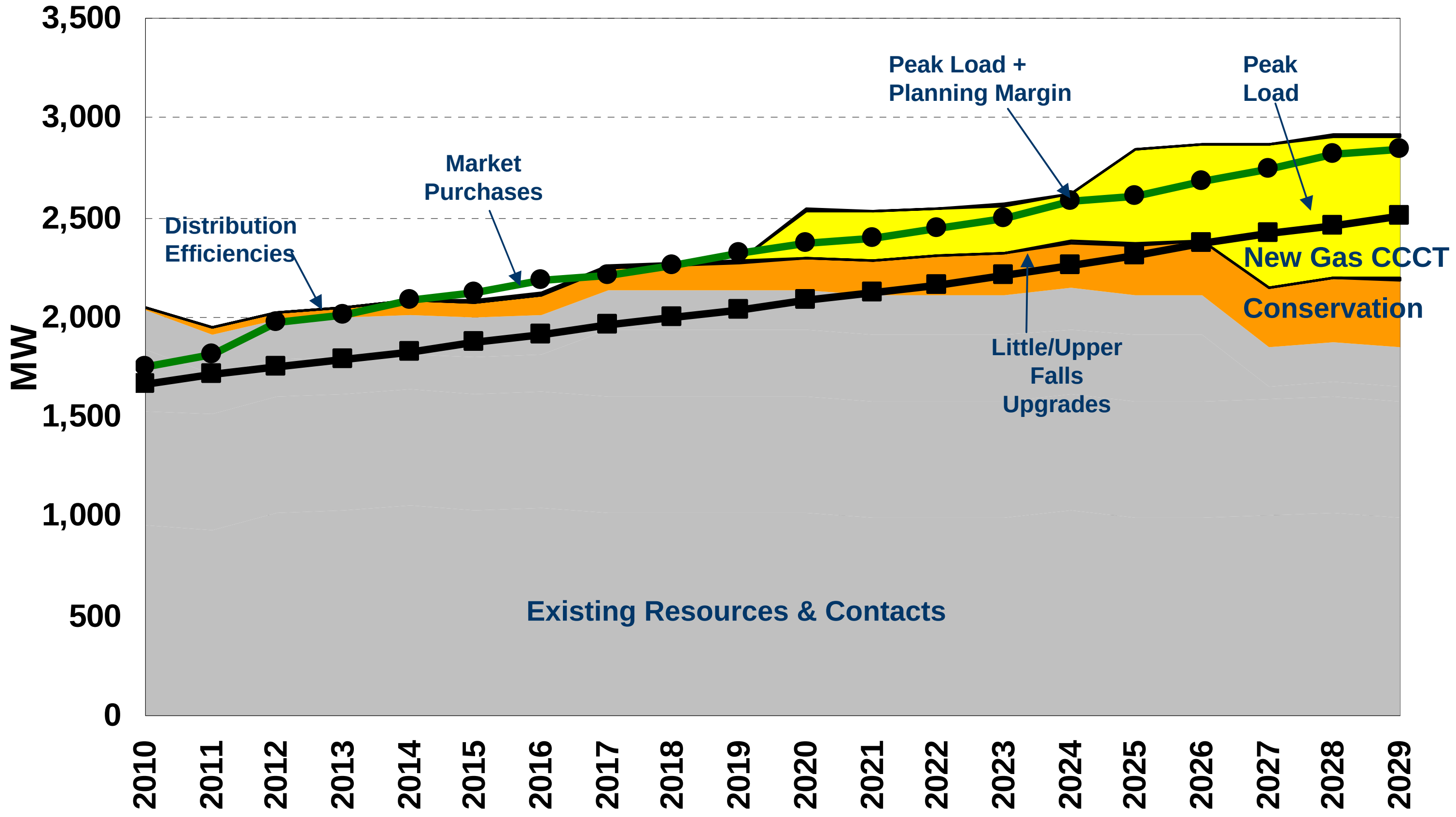
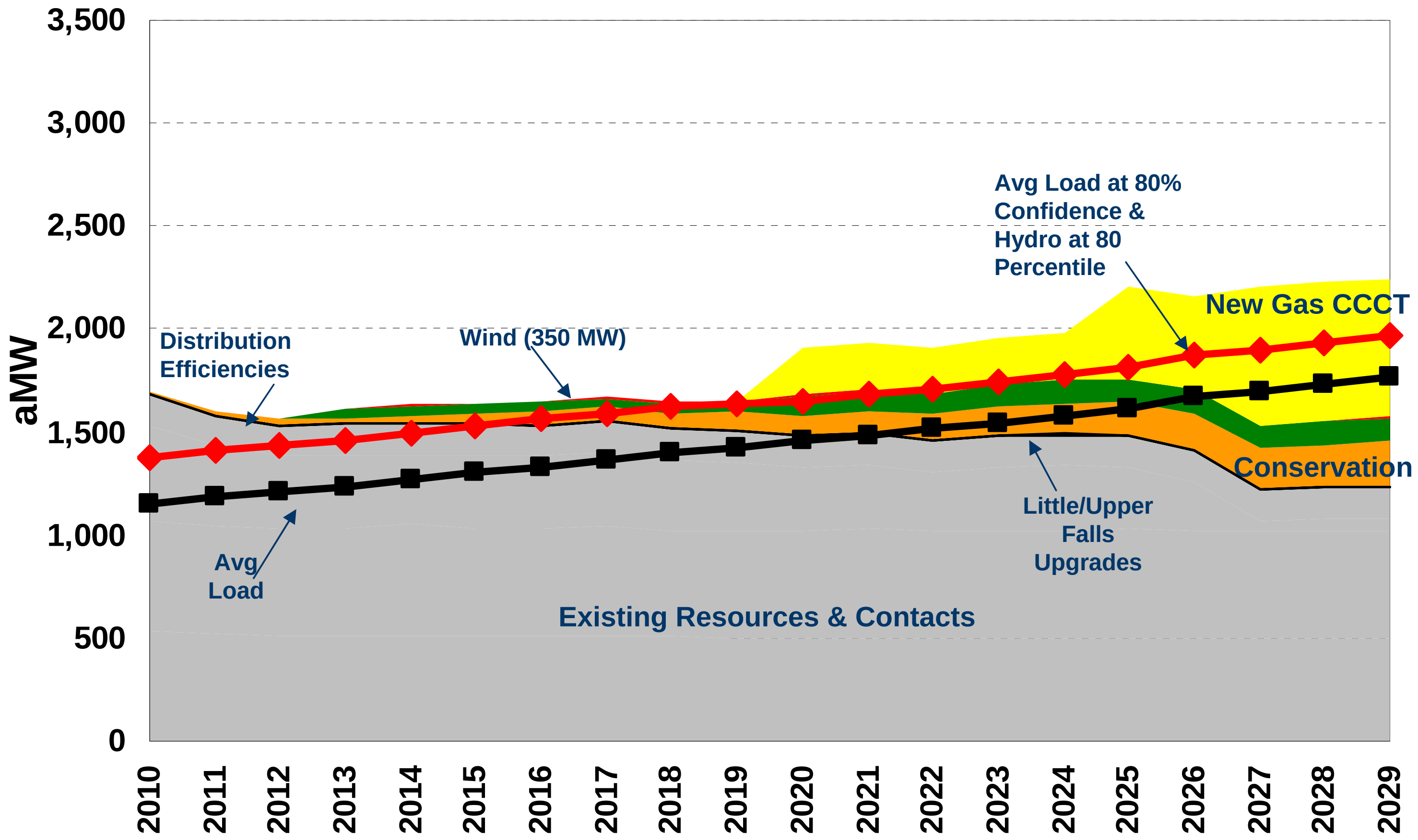
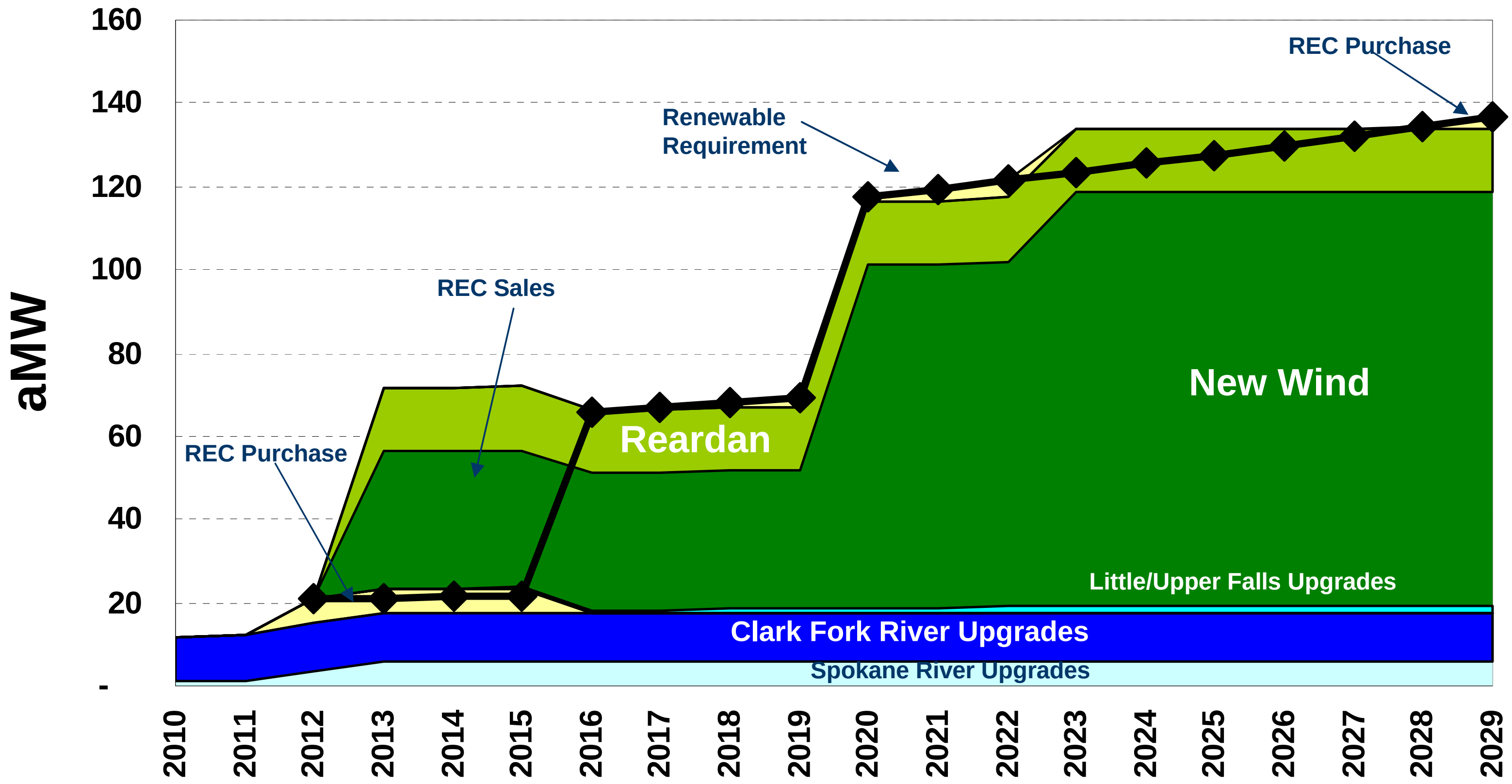
August Capacity L&R w/ New Resources



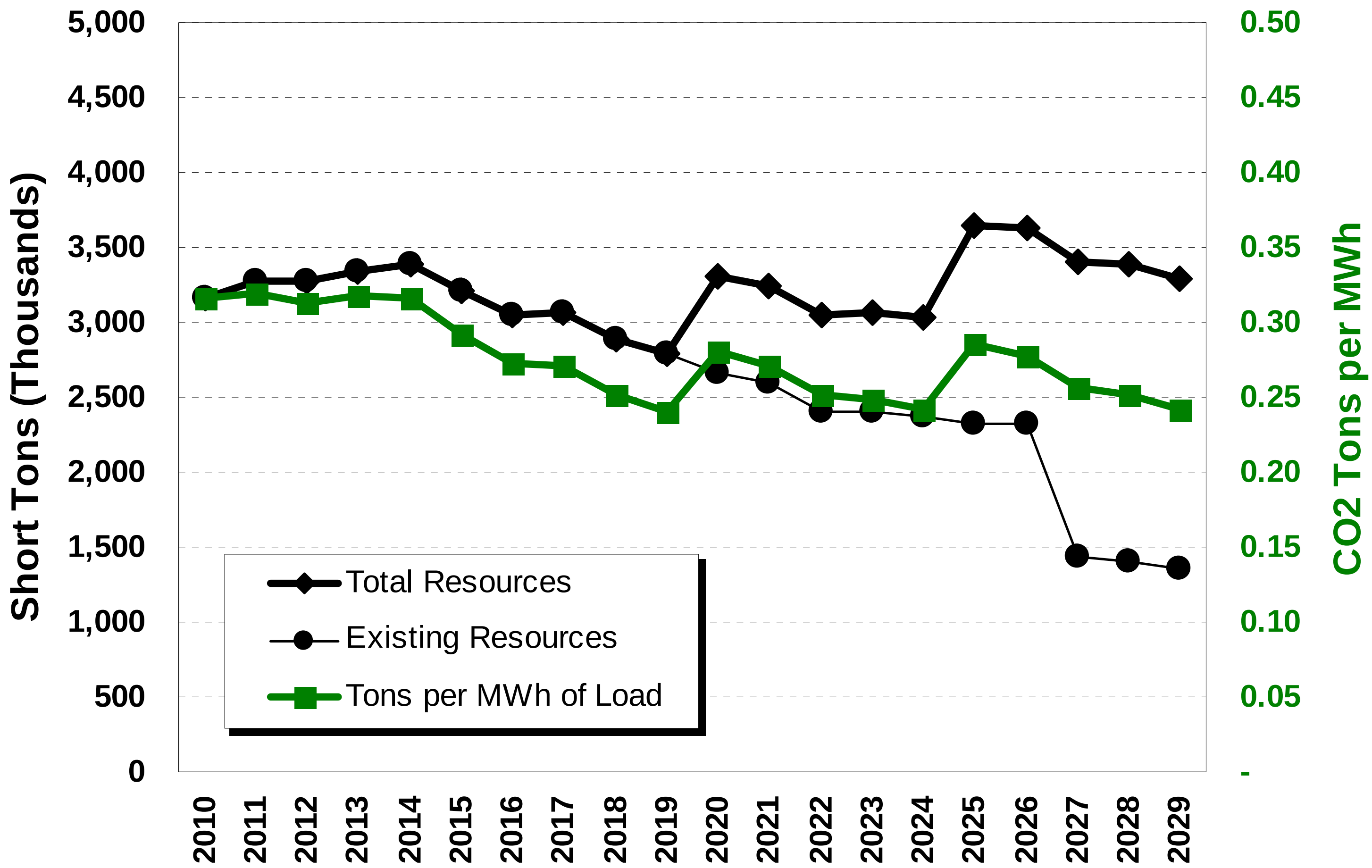
Annual Energy L&R w/ New Resources



Washington State RPS Compliance



Greenhouse Gas Emissions



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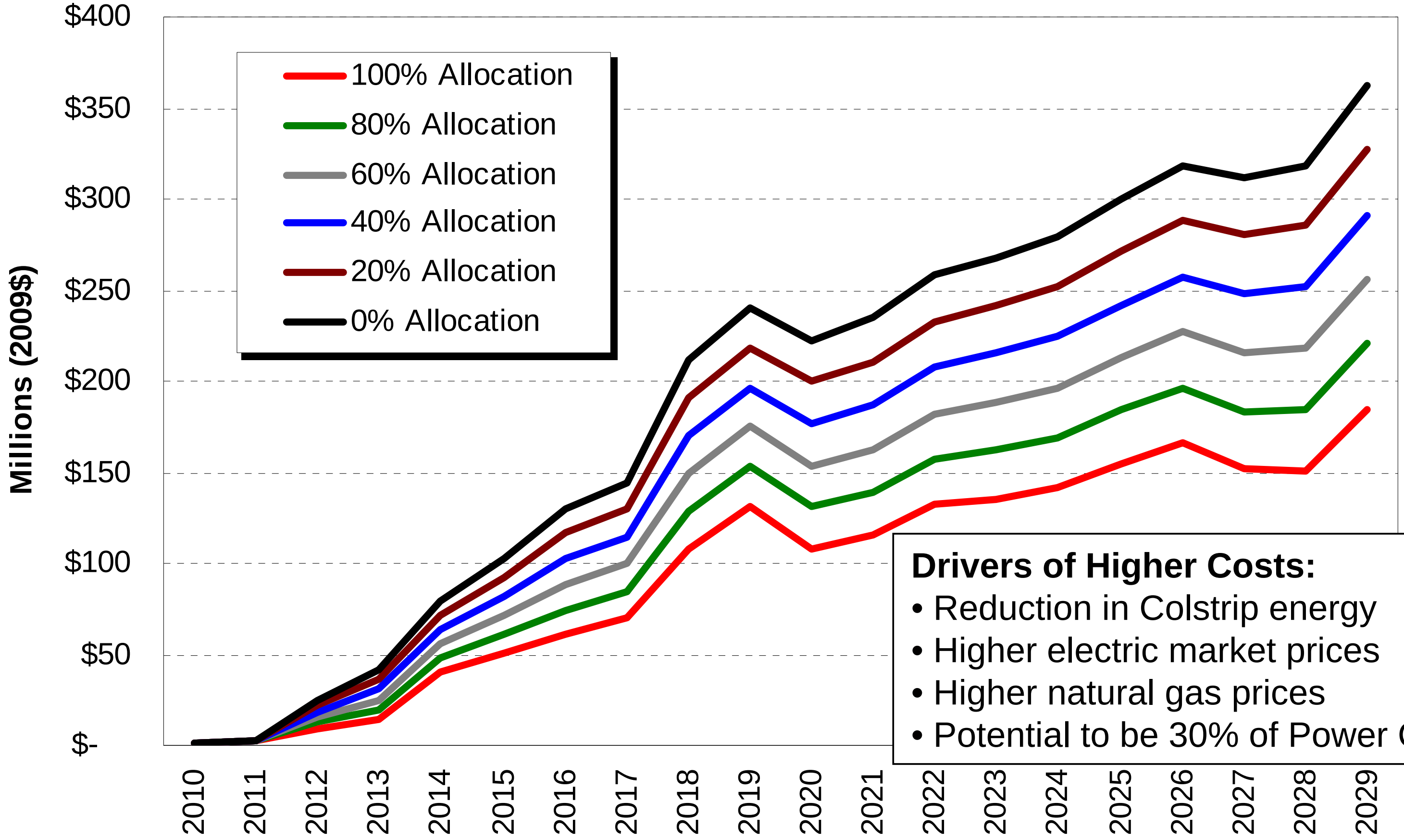
Total Cost of Carbon Legislation



Drivers of Higher Costs:
- Reduction in Colstrip energy
- Higher electric market prices
- Higher natural gas prices
- Potential to be 30% of Power Costs

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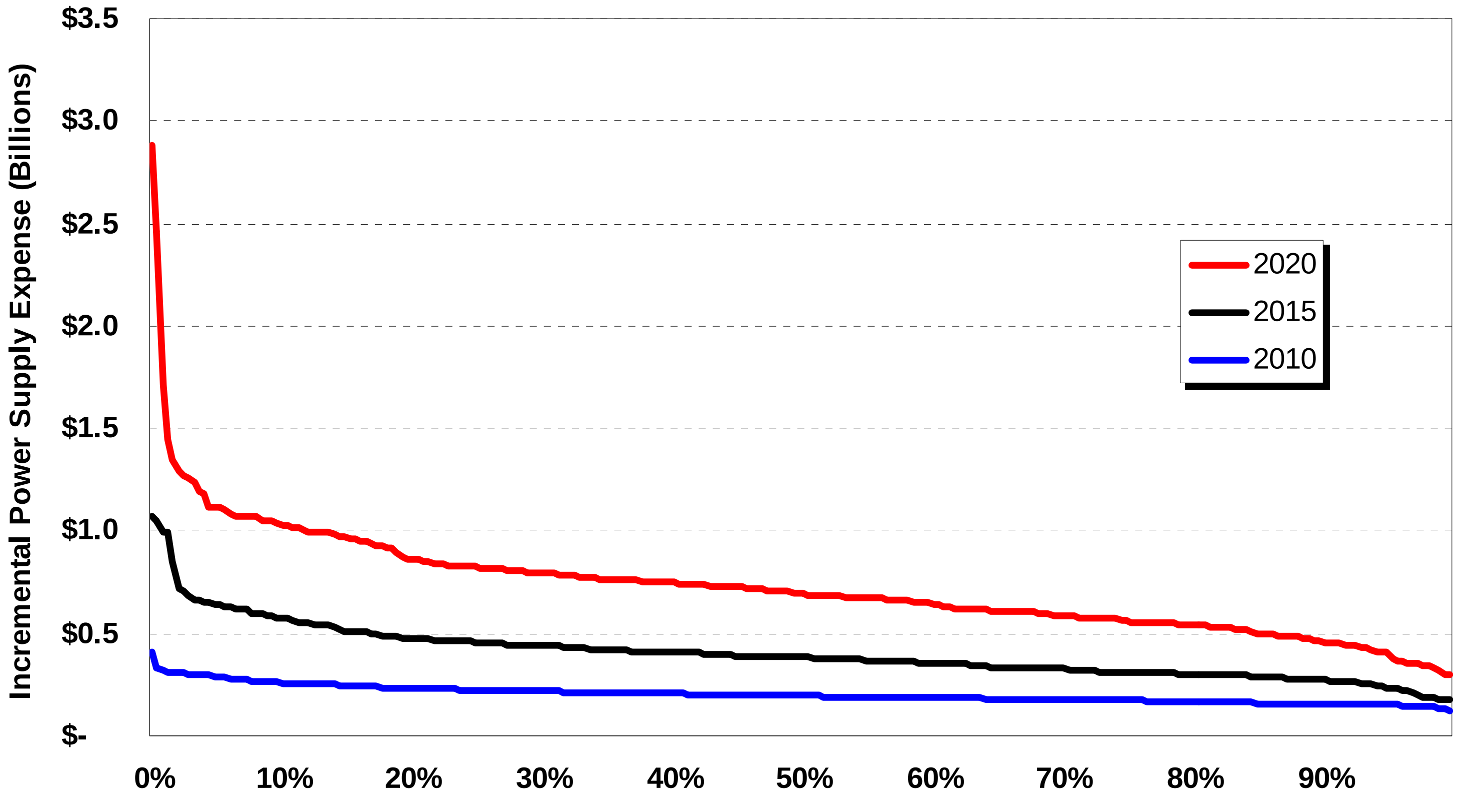
Portfolio Cost Duration Curve (2009$)



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Scenarios

James Gall & John Lyons

2009 Electric Integrated Resource Plan

Fifth Technical Advisory Committee Meeting

March 25, 2009

Market Scenarios

Market Futures (Stochastic)

- Base Case
- No Carbon Costs

Market Scenarios (Deterministic)

- High Natural Gas Prices
- Low Natural Gas Prices
- Solar Saturation ("Buck-a-Watt")

No Carbon Cost Scenario

Avista Portfolio Cost versus Risk Analysis

Portfolios:

- Market reliance
- Build to capacity requirements
- Least cost strategy
- Efficient frontier

Avista Portfolio Scenarios

Fundamental Changes

- No State RPS
- Alternative load forecasts (High/Low)
- Least carbon emissions

Capital Cost Sensitivities

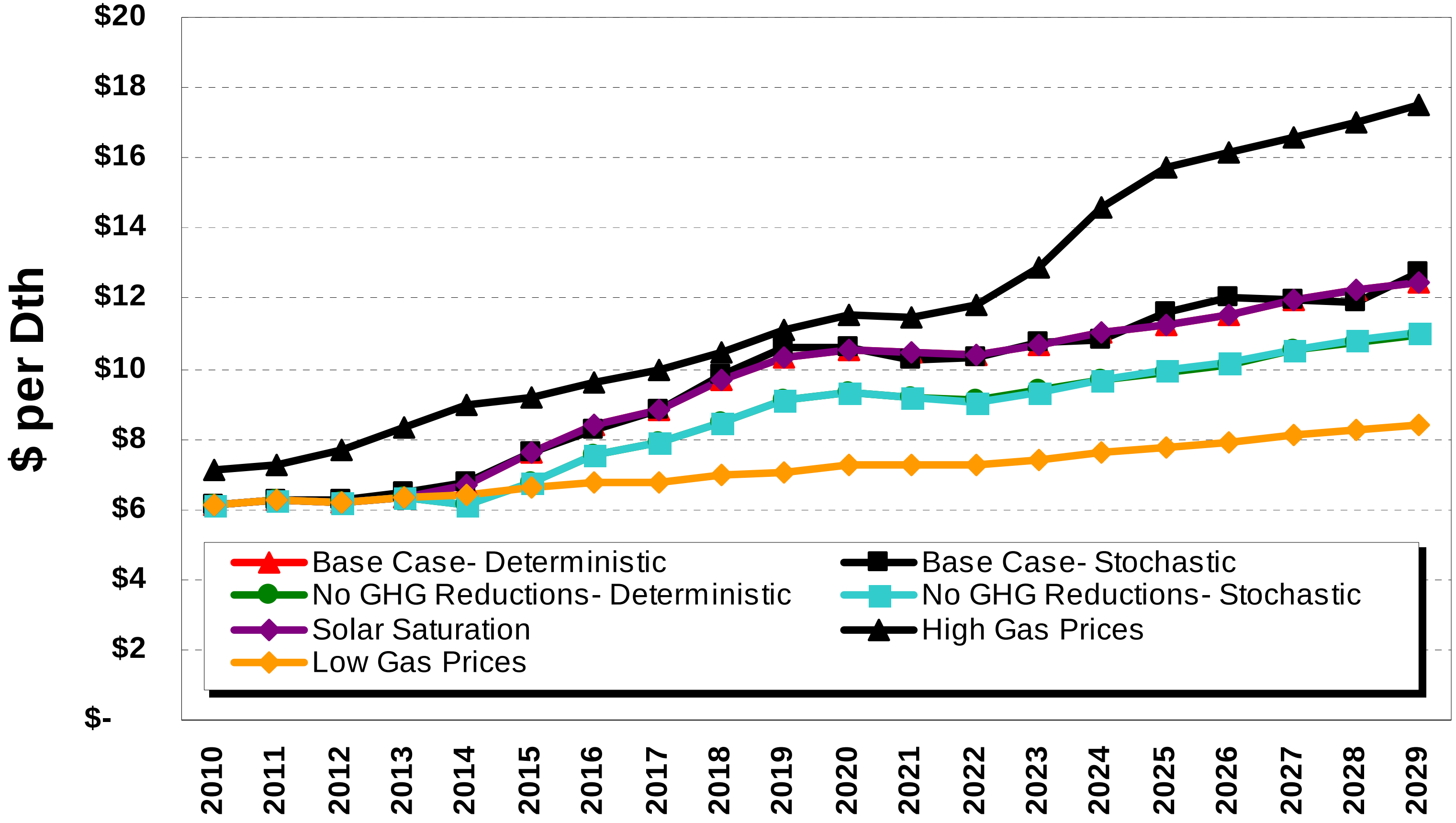
- Required capital cost to build wind in 2010
- Required capital cost to move from CCCT to SCCT

Resource Availability

- Large hydro upgrades, with capital cost sensitivities
- Other renewables (Biomass/Geothermal/Hydro Upgrades)
- Nuclear

Market Scenarios

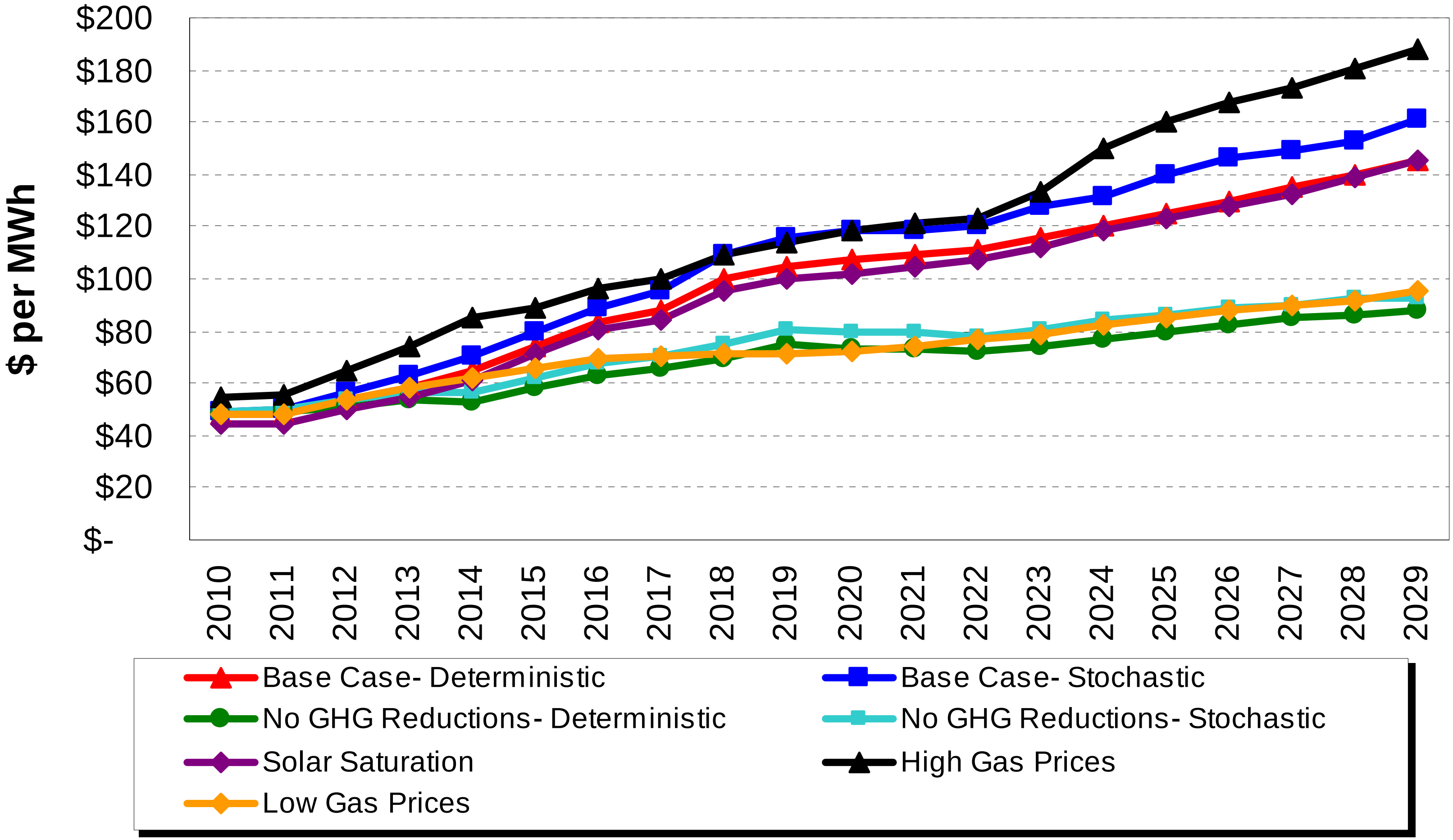
Malin Natural Gas Prices (Nominal $)



Malin Nominal Levelized Price Forecast (2010-2029)

Scenario	$/Dth
Base Case- Deterministic	$8.63
Base Case- Stochastic	$8.67
No GHG Reductions- Deterministic	$7.86
No GHG Reductions- Stochastic	$7.87
Solar Saturation	$8.63
High Gas Prices	$10.52
Low Gas Prices	$6.88
2007 IRP Base Case	$7.15
2007 Climate Stewardship Act Future	$7.15

Mid-Columbia Electric Price Forecasts (2010-2029, Nominal $)



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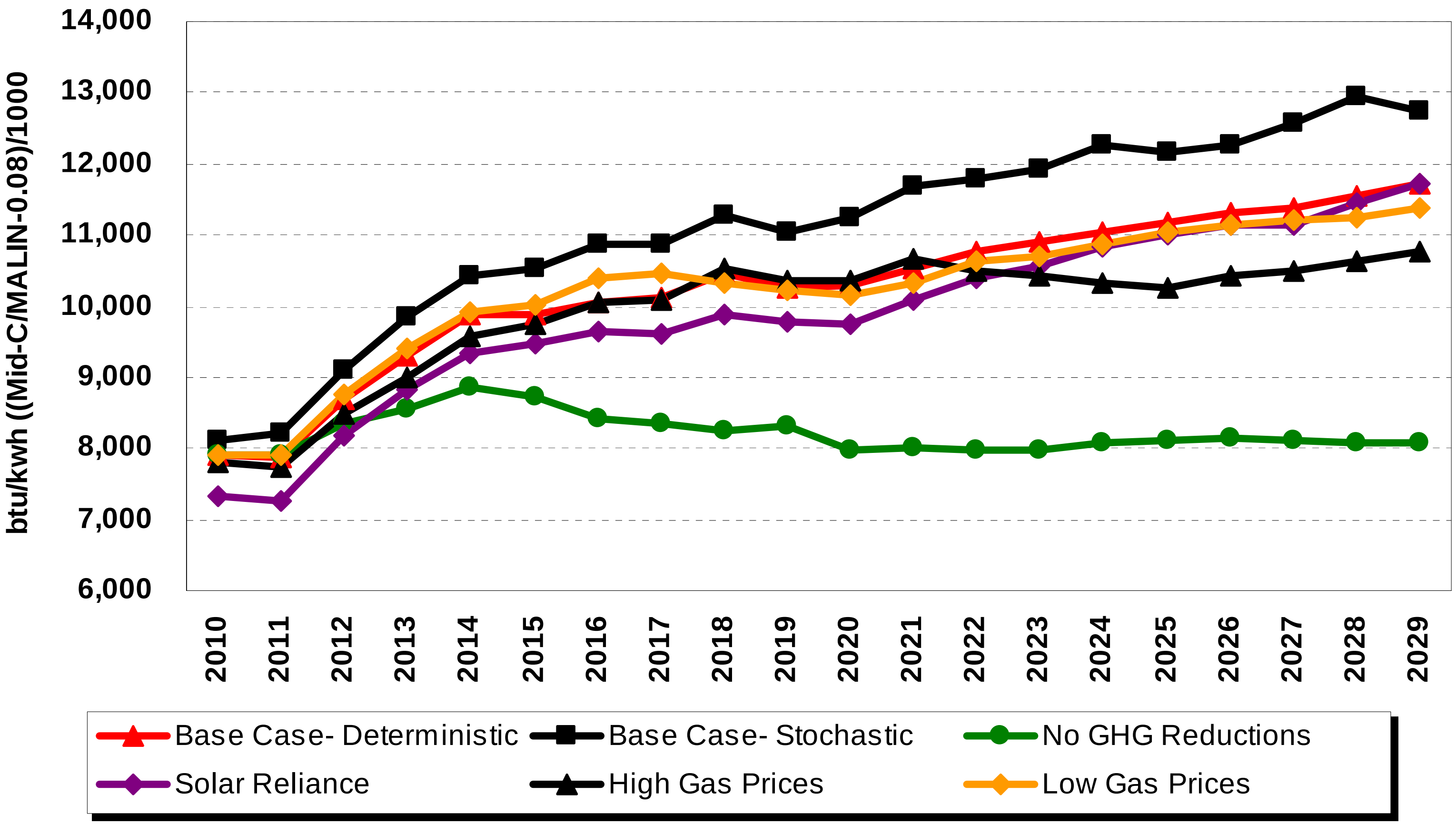
Mid-Columbia Nominal Levelized Price Forecast

Scenario	$/MWh
Base Case- Deterministic	$86.36
Base Case- Stochastic	$93.74
No GHG Reductions- Deterministic	$63.93
No GHG Reductions- Stochastic	$68.22
Solar Saturation	$82.87
High Gas Prices	$102.61
Low Gas Prices	$67.48
2007 IRP Base Case	$62.16
2007 Climate Stewardship Act Future	$73.50

More on Solar Saturation Scenario

- Reduce capital cost by 80%
- Increased solar energy in 2029 from 4,243 aMW to 20,486 aMW or 75 GW of capacity
- Reduced Western Interconnect fuel costs by 18% or $10 billion in 2029 or $36.4 billion (PV 2009$)
- Reduced 2029 power generation greenhouse gas emissions by 10%
- Small reduction in Q2 and Q3 on-peak power prices, although higher solar saturation rates could further reduce on-peak power prices

Implied Market Heat Rates



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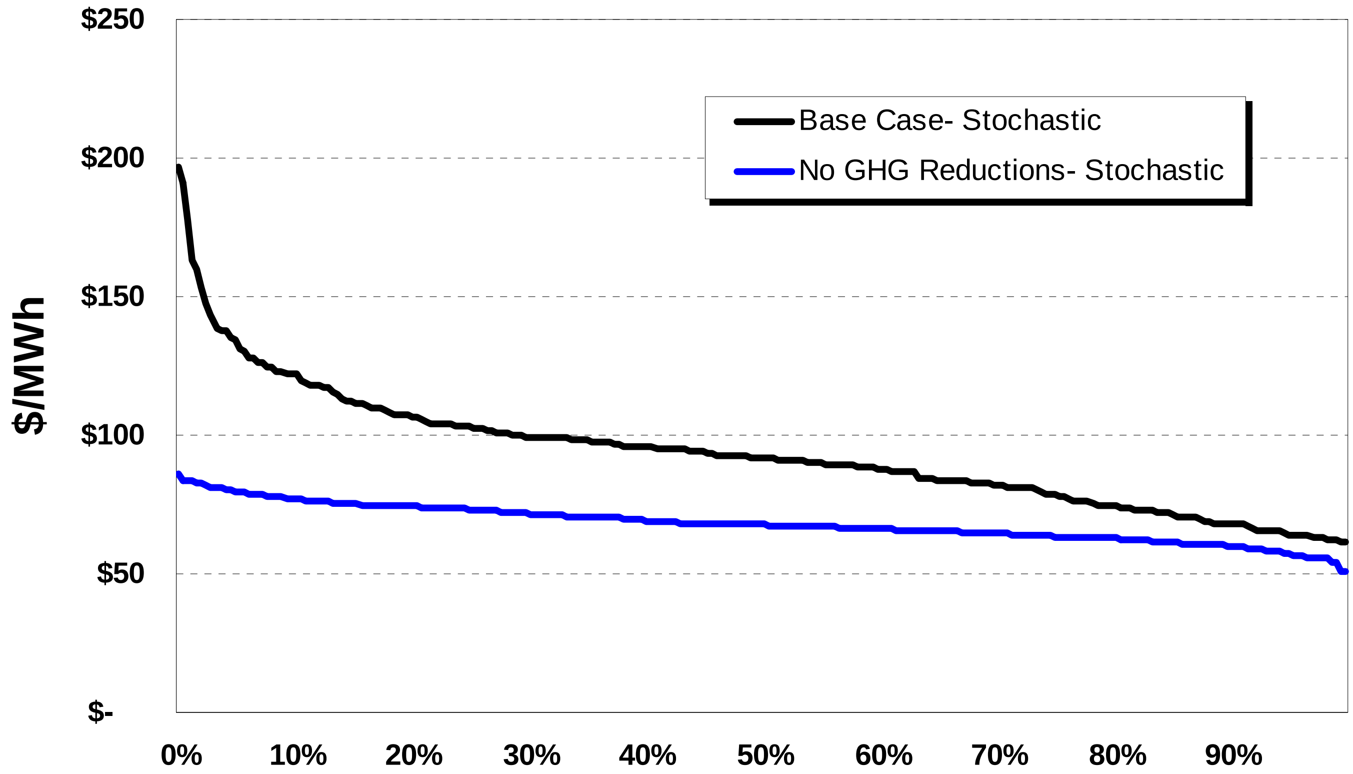
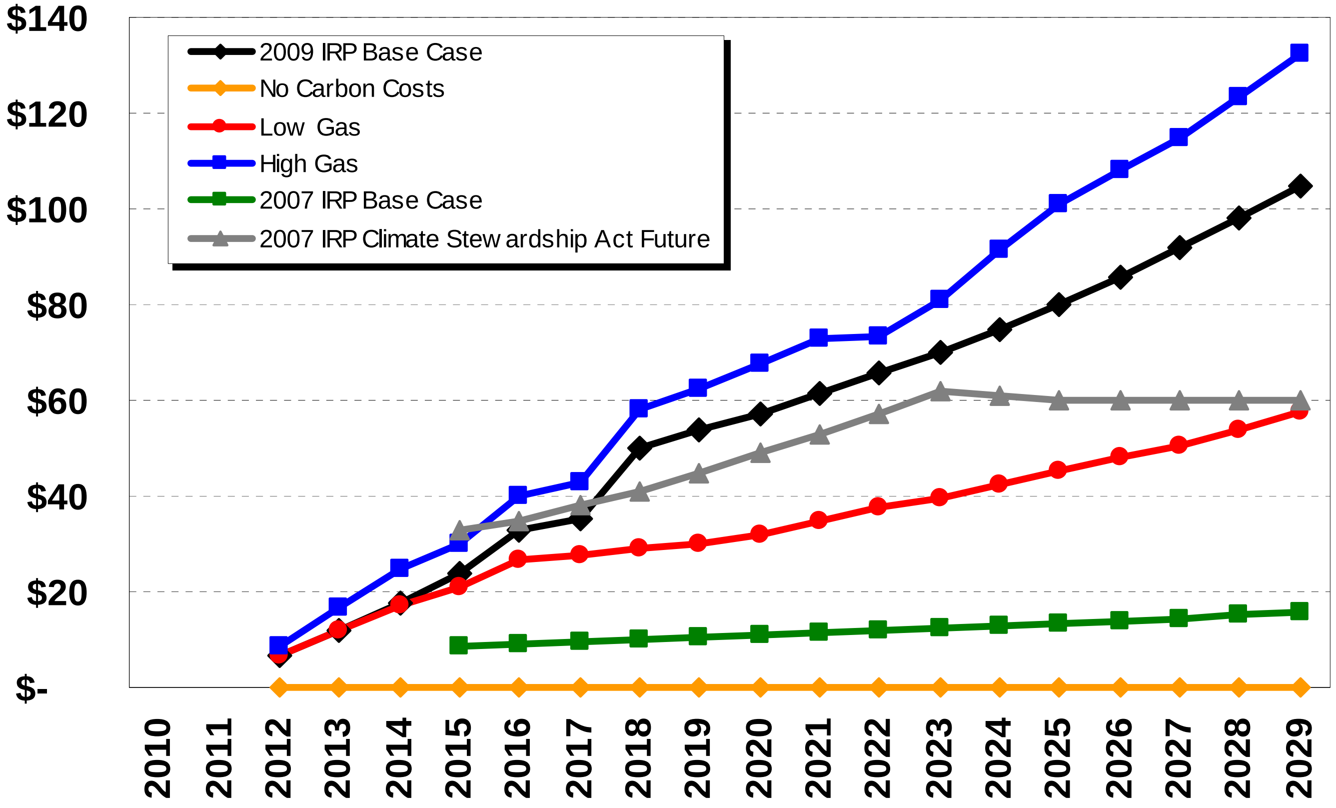
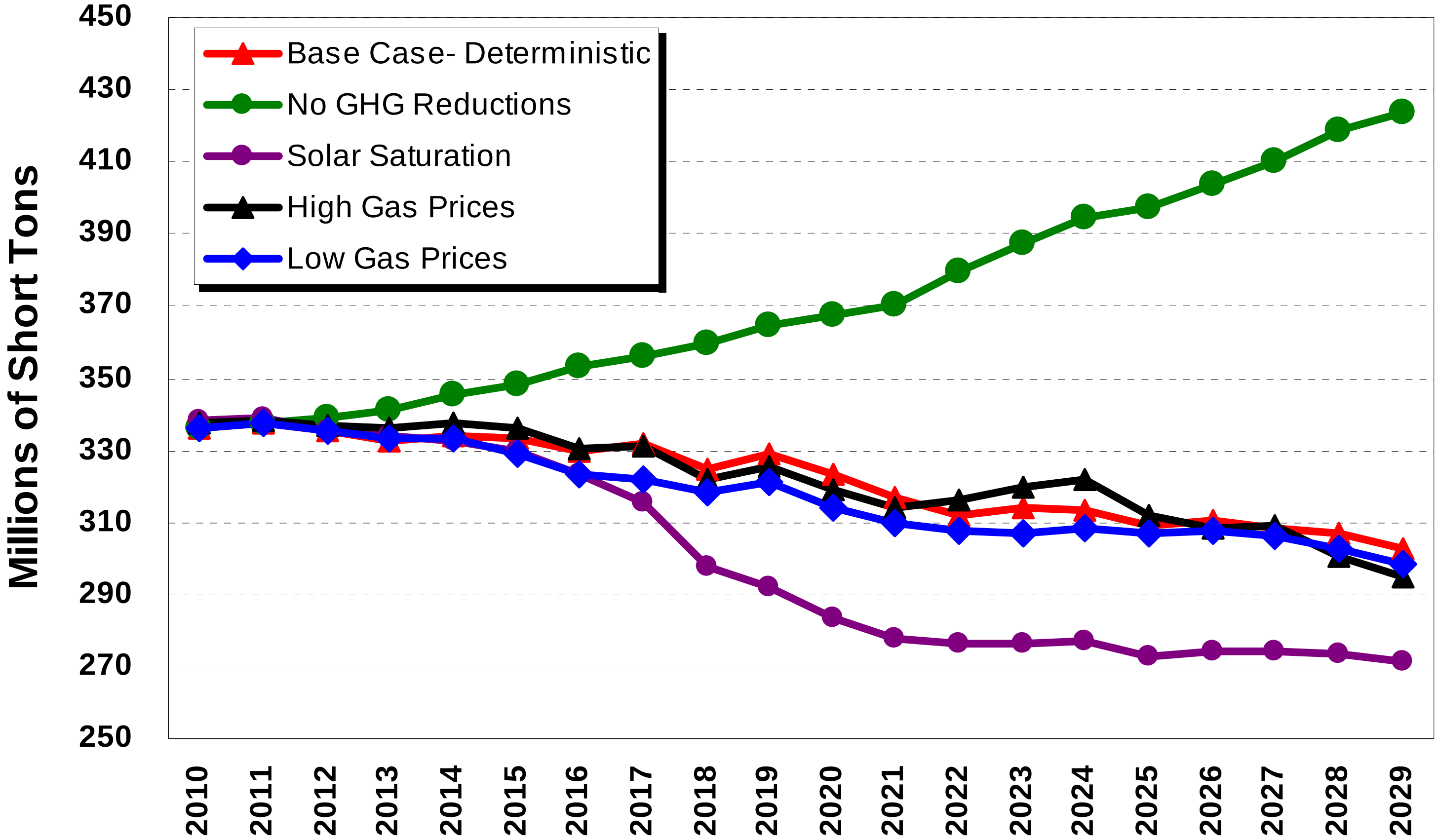
Mid-Columbia Levelized Price (2010-2029) Duration Curve



Greenhouse Gas Prices ($/Ton)



US WECC Greenhouse Gas Levels



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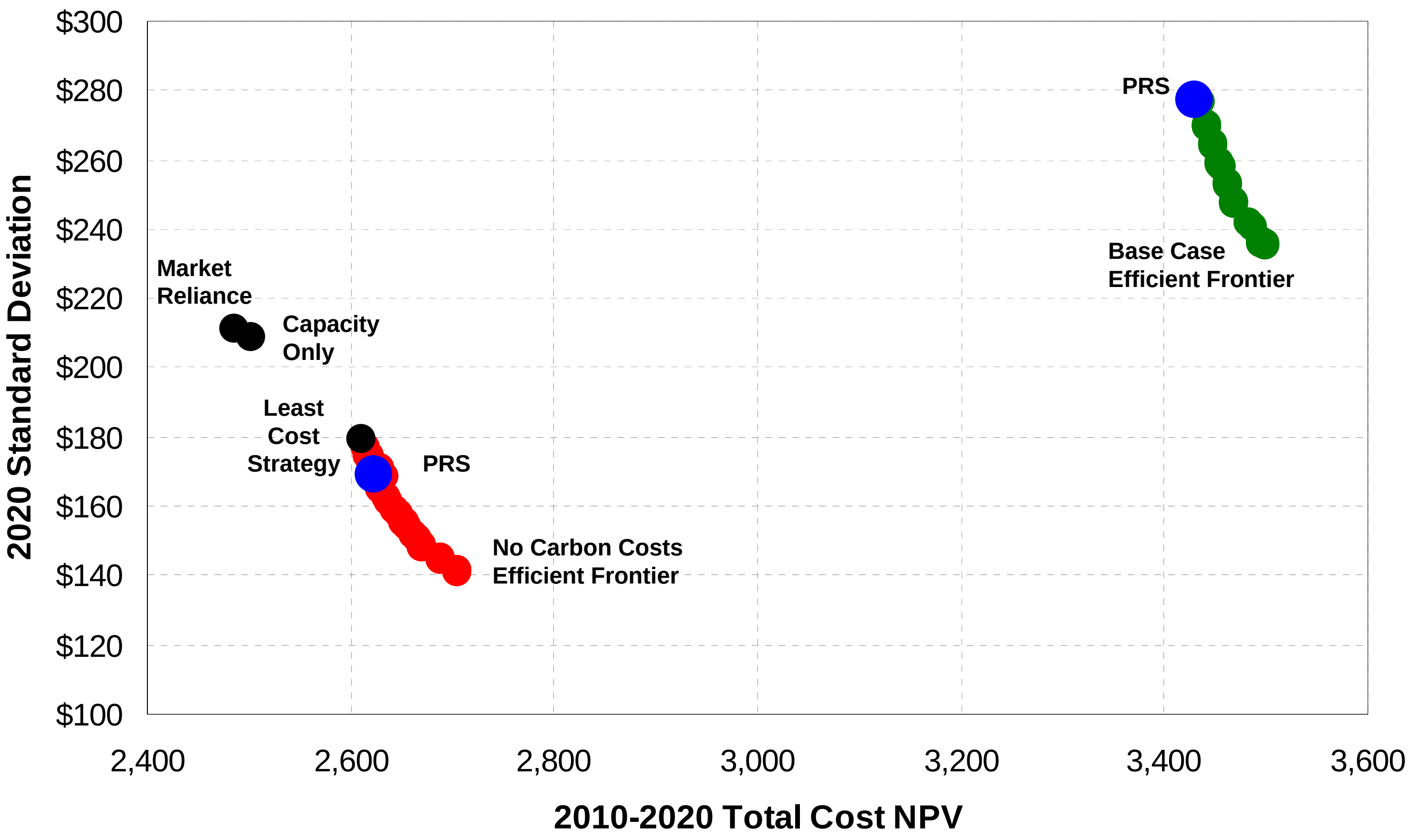
No Carbon Costs Scenario

No Carbon Costs Scenario



No CO_2 Costs: Least Cost Strategy (MW)

Year	CCCT	SCCT	Wind	Hydro Upgrades	Low Carbon Baseload	DSM	T&D Effic.
2010	-	-	-	-	-	12	1
2011	-	-	-	-	-	12	1
2012	-	-	-	-	-	12	1
2013	-	-	150	-	-	12	1
2014	-	-	-	-	-	14	1
2015	-	-	-	-	-	14	-
2016	-	-	-	-	-	15	-
2017	-	-	-	1	-	15	-
2018	-	-	-	-	-	15	-
2019	-	-	-	1	-	17	-
2020	-	200	150	-	-	17	-
2021	-	-	-	-	-	18	-
2022	-	-	-	2	-	18	-
2023	-	100	50	-	-	20	-
2024	-	-	-	-	-	20	-
2025	-	-	-	-	-	21	-
2026	-	100	-	-	-	21	-
2027	-	300	-	-	-	23	-
2028	-	-	-	-	-	23	-
2029	-	100	-	-	-	24	-
2010-2019	-	-	150	2	-	137	5
2010-2029	-	800	350	4	-	339	5

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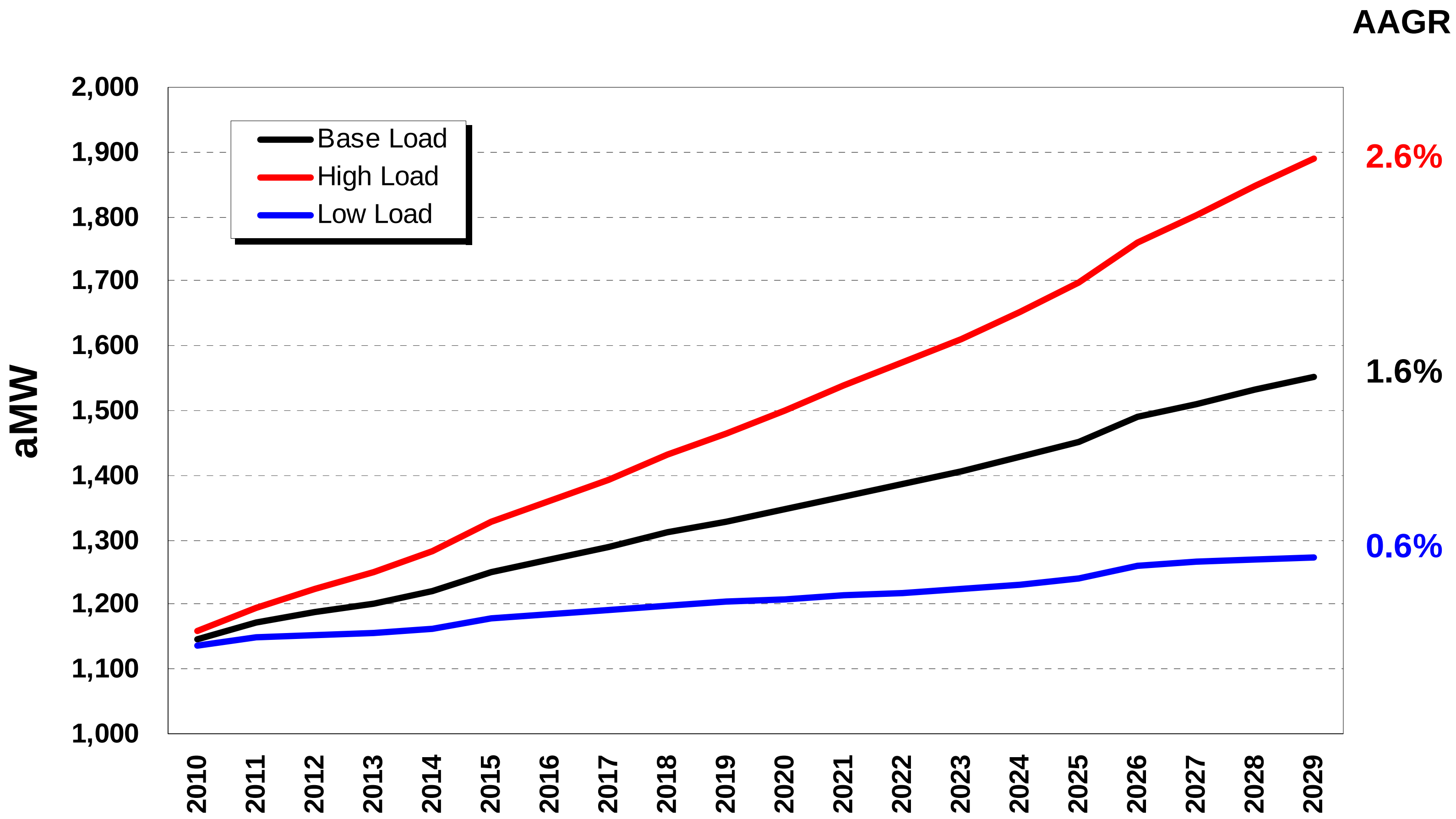
Fundamental Portfolio Changes

Alternative Load Forecasts (Energy)



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High Load Least Cost Strategy (MW)

Year	CCCT	SCCT	Wind	Hydro Upgrades	Low Carbon Baseload	DSM	T&D Effic.
2010	-	-	-	-	-	12	1
2011	-	-	-	-	-	12	1
2012	-	60	-	-	-	14	1
2013	-	-	200	-	-	14	1
2014	-	100	-	1	-	15	1
2015	-	-	-	1	-	15	-
2016	-	-	-	-	-	17	-
2017	-	-	-	1	-	17	-
2018	-	100	-	-	-	18	-
2019	-	-	-	-	-	18	-
2020	-	100	200	-	-	20	-
2021	250	-	-	2	-	20	-
2022	-	-	-	-	-	21	-
2023	-	-	50	-	-	23	-
2024	-	-	-	-	-	23	-
2025	250	-	50	-	-	24	-
2026	-	-	-	-	-	26	-
2027	500	-	-	-	-	27	-
2028	-	-	50	-	-	29	-
2029	-	-	-	-	-	29	-
2010-2019	-	260	200	3	-	150	5
2010-2029	1,000	360	550	5	-	389	5

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Low Load Least Cost Strategy (MW)

Year	CCCT	SCCT	Wind	Hydro Upgrades	Low Carbon Baseload	DSM	T&D Effic.
2010	-	-	-	-	-	12	1
2011	-	-	-	-	-	12	1
2012	-	-	-	-	-	12	1
2013	-	-	150	-	-	12	1
2014	-	-	-	1	-	14	1
2015	-	-	-	1	-	14	-
2016	-	-	-	-	-	15	-
2017	-	-	-	1	-	15	-
2018	-	-	-	-	-	15	-
2019	-	-	-	-	-	17	-
2020	-	-	100	-	-	17	-
2021	-	-	-	-	-	18	-
2022	-	-	-	-	-	18	-
2023	-	-	-	-	-	20	-
2024	-	-	-	-	-	20	-
2025	-	-	-	-	-	21	-
2026	250	-	-	-	-	21	-
2027	-	-	-	-	-	23	-
2028	-	100	-	-	-	23	-
2029	-	-	-	2	-	24	-
2010-2019	-	-	150	3	-	137	5
2010-2029	250	100	250	5	-	339	5

Least Avista Greenhouse Gas Emissions Scenario

- Model selected small renewable and hydro upgrades, simple cycle gas turbines and low carbon emitting resource (nuclear/carbon sequestration)
- Wind resources reduce Western Interconnect emissions, but likely would not significantly reduce Avista's greenhouse gas emissions
- Carbon reductions could be from retiring resources such as Colstrip and Coyote Springs 2

Capital Cost Sensitivities

Wind Capital Cost Sensitivity

Starting Point: 150 MW Wind by December 31, 2012

- 50 MW Reardan ($2,423 per kW) [2009$: $2,262]
- 100 MW Generic Wind ($2,513 kW) [2009$: $2,183]
  - – Assumes Avista can only take advantage of 90% of tax credit beginning in 2011, due to not enough tax liability

Scenario: At what capital cost does PRiSM select Reardan earlier?

- – Model selected Reardan in 2010, if capital costs are less than $1,877 per kW [2009$: $1,832]

CCCT Capital Cost Sensitivity

Starting Point: 250 MW CCCT beginning January 1, 2020

- Generic CCCT ($1,949 per kW) [2009$: $1,461]

Scenario: At what price is CCCT no longer preferred on a least cost basis, if SCCT cost remain equal.

- If cost are above ($2,051 per kW) [2009$: $1,535] the least cost strategy includes 300MW of LMS 100 in 2020-21
- Although, the 2020 standard deviation of power supply expense increases by 3.5%

Resource Availability Scenarios

Large Hydro Upgrades

- Base Case does not include Cabinet Gorge Unit 5 or Long Lake 2nd PH/Unit 5 as options.
- These units were not considered options at this time, due to cost uncertainty.
- Assumption (2009$):
  - Cabinet Gorge 5: $1,478 kW
  - Long Lake U5: $2,168 kW
  - Long Lake 2nd PH: $2,000 kW

This analysis first allows these units to be available at estimated costs, then studies how cost change impacts the PRS.

Least Cost Strategy: *With Large Hydro Options (MW)*

Year	CCCT	SCCT	Wind	Hydro Upgrades	Low Carbon Baseload	DSM	T&D Effic.
2010	-	-	-	-	-	12	1
2011	-	-	-	-	-	12	1
2012	-	-	-	-	-	12	1
2013	-	-	150	-	-	12	1
2014	-	-	-	1	-	14	1
2015	-	-	-	1	-	14	-
2016	-	-	-	-	-	15	-
2017	-	-	-	1	-	15	-
2018	-	-	-	-	-	15	-
2019	-	-	-	-	-	17	-
2020	-	100	100	60	-	17	-
2021	250	-	-	-	-	18	-
2022	-	-	-	-	-	18	-
2023	-	-	50	-	-	20	-
2024	-	-	-	-	-	20	-
2025	-	-	-	-	-	21	-
2026	-	-	-	-	-	21	-
2027	400	-	-	-	-	23	-
2028	-	-	-	-	-	23	-
2029	-	-	-	2	-	24	-
2010-2019	-	-	150	3	-	137	5
2010-2029	650	100	300	65	-	339	5

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Least Cost Strategy With *Cabinet 4 and Long Lake 2nd PH (MW)*

Year	CCCT	SCCT	Wind	Hydro Upgrades	Low Carbon Baseload	DSM	T&D Effic.
2010	-	-	-	-	-	12	1
2011	-	-	-	-	-	12	1
2012	-	-	-	-	-	12	1
2013	-	-	150	-	-	12	1
2014	-	-	-	1	-	14	1
2015	-	-	-	61	-	14	-
2016	-	-	-	-	-	15	-
2017	-	-	-	1	-	15	-
2018	-	-	-	-	-	15	-
2019	-	-	-	-	-	17	-
2020	-	-	100	60	-	17	-
2021	250	-	-	-	-	18	-
2022	-	-	-	-	-	18	-
2023	-	-	50	-	-	20	-
2024	-	-	-	-	-	20	-
2025	-	-	-	-	-	21	-
2026	-	-	-	-	-	21	-
2027	400	-	-	-	-	23	-
2028	-	-	-	-	-	23	-
2029	-	-	-	2	-	24	-
2010-2019	-	-	150	63	-	137	5
2010-2029	650	-	300	125	-	339	5

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Large Hydro Upgrade Capital Cost Analysis

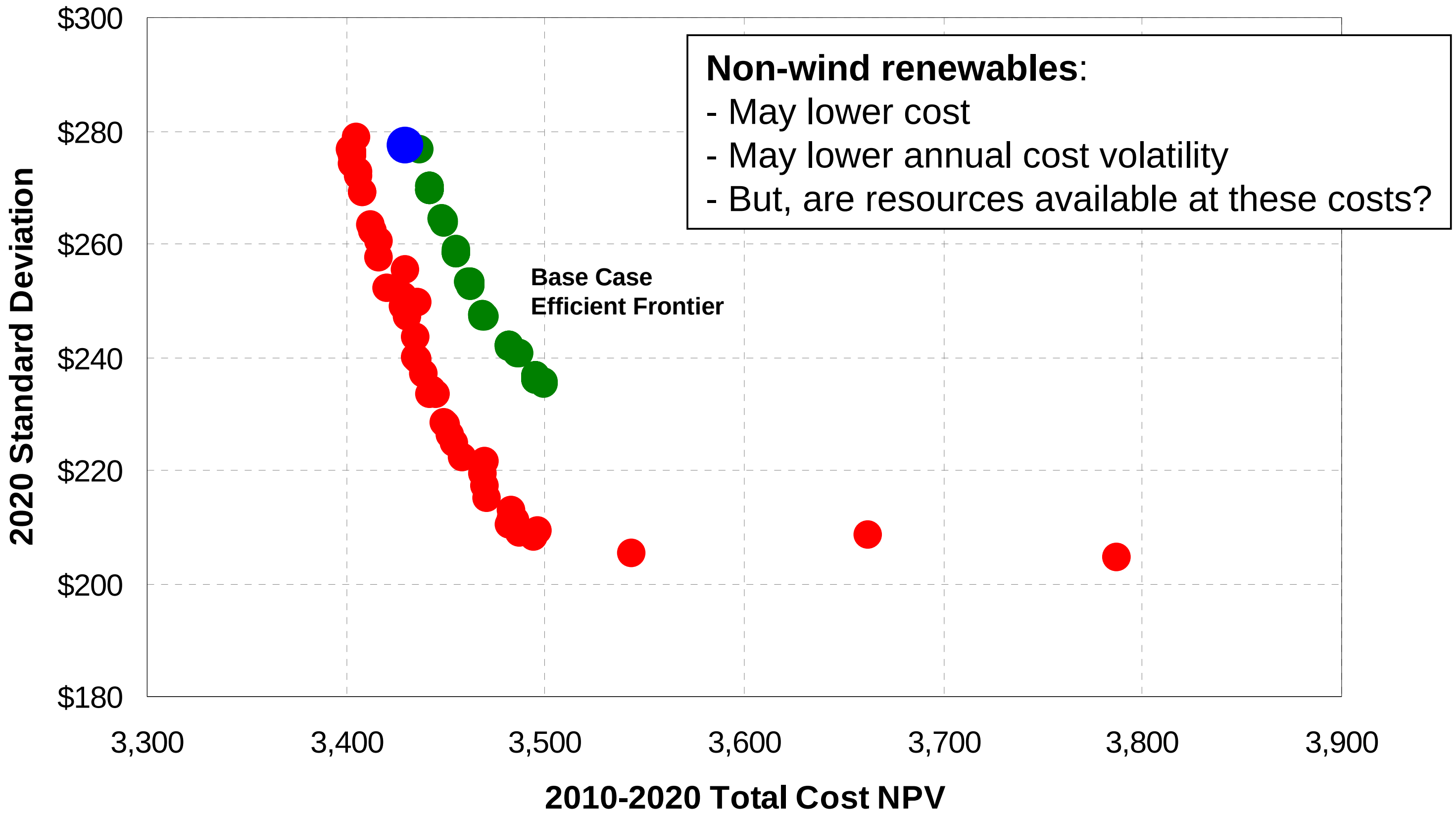
Long Lake 2nd Powerhouse is favored by PRiSM, due to larger capacity size and similar cost per MWh

- The plant is selected as least cost resource until the cost reaches $2,150 kW

Cabinet Gorge U5 is not selected as a least cost resource, due to low capacity factor, if costs were less than $1,100 per kW, the plant would be selected

While these resources have capital cost uncertainty, they are a viable alternative to reduce carbon emissions

Non-Wind Renewable Resources Available



Least Cost Strategy- Small Renewables Available (MW)

Year	CCCT	SCCT	Wind	Non-Wind Renewable	Hydro Upgrades	Low Carbon Baseload	DSM	T&D Effic.
2010	-	-	-	-	-	-	12	1
2011	-	-	-	-	-	-	12	1
2012	-	-	-	10	-	-	12	1
2013	-	-	100	5	-	-	12	1
2014	-	-	-	5	1	-	14	1
2015	-	-	-	-	-	-	14	-
2016	-	-	-	-	1	-	15	-
2017	-	-	-	-	1	-	15	-
2018	-	-	-	5	-	-	15	-
2019	-	-	-	-	-	-	17	-
2020	-	100	100	7	2	-	17	-
2021	250	-	-	-	-	-	18	-
2022	-	-	-	-	-	-	18	-
2023	-	-	-	-	-	-	20	-
2024	-	-	50	-	-	-	20	-
2025	-	-	-	-	-	-	21	-
2026	-	-	-	-	-	-	21	-
2027	400	-	-	-	-	-	23	-
2028	-	-	-	-	-	-	23	-
2029	-	-	-	-	-	-	24	-
2010-2019	-	-	100	25	3	-	137	5
2010-2029	650	100	250	32	5	-	339	5

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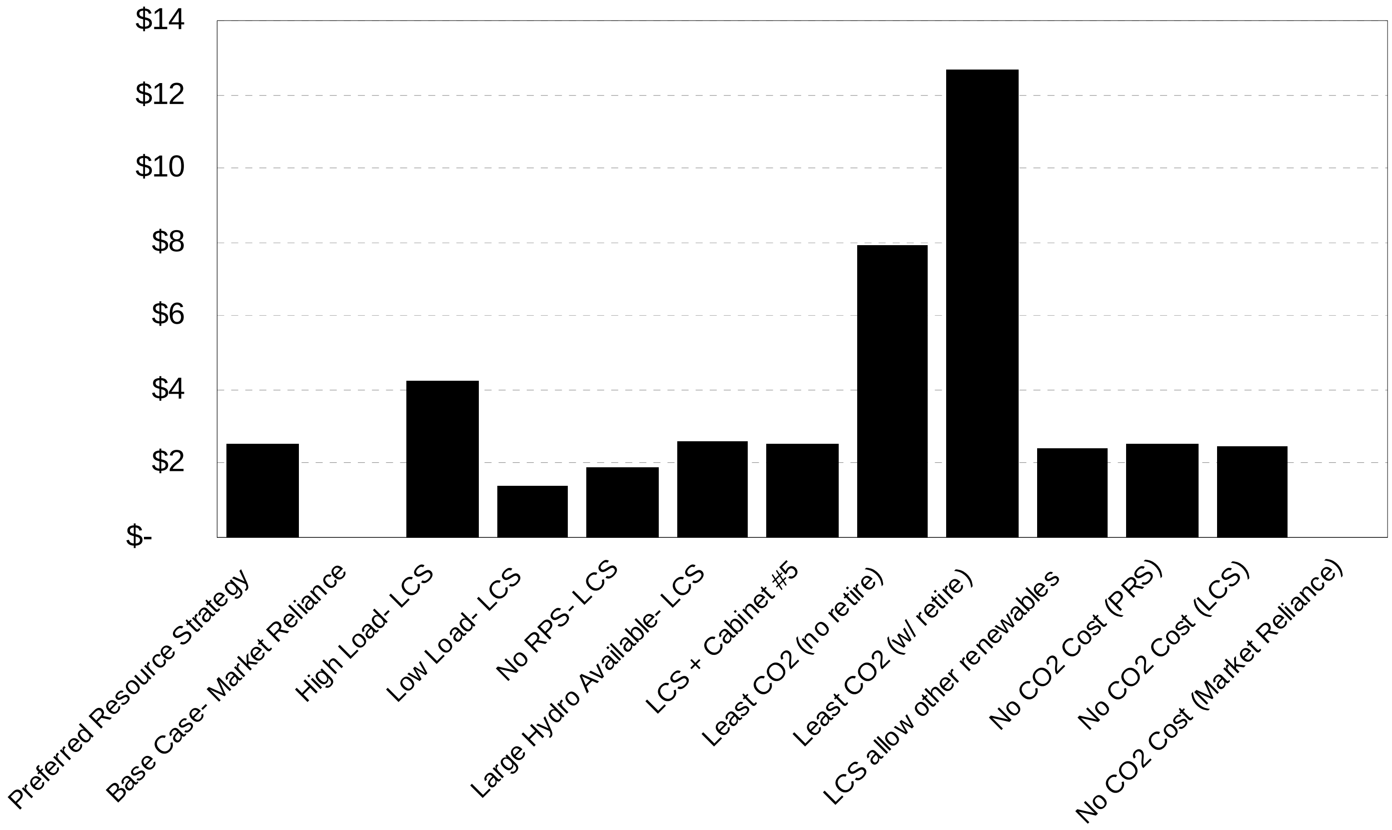
Nuclear

If Nuclear was allowed as a resource beginning in 2020 at a 2009$ capital cost of $5,500 per kW in 250 MW sizes.

- At this cost it would not be selected in the Least Cost Strategy.
- Although, if costs were $3,800 per kW the resource would be selected
- If Avista were to acquire the plant in 100MW quantities it would be least cost at $4,000 per kW.

Capital Expense in Billions Dollars
(Nominal 2010-29)



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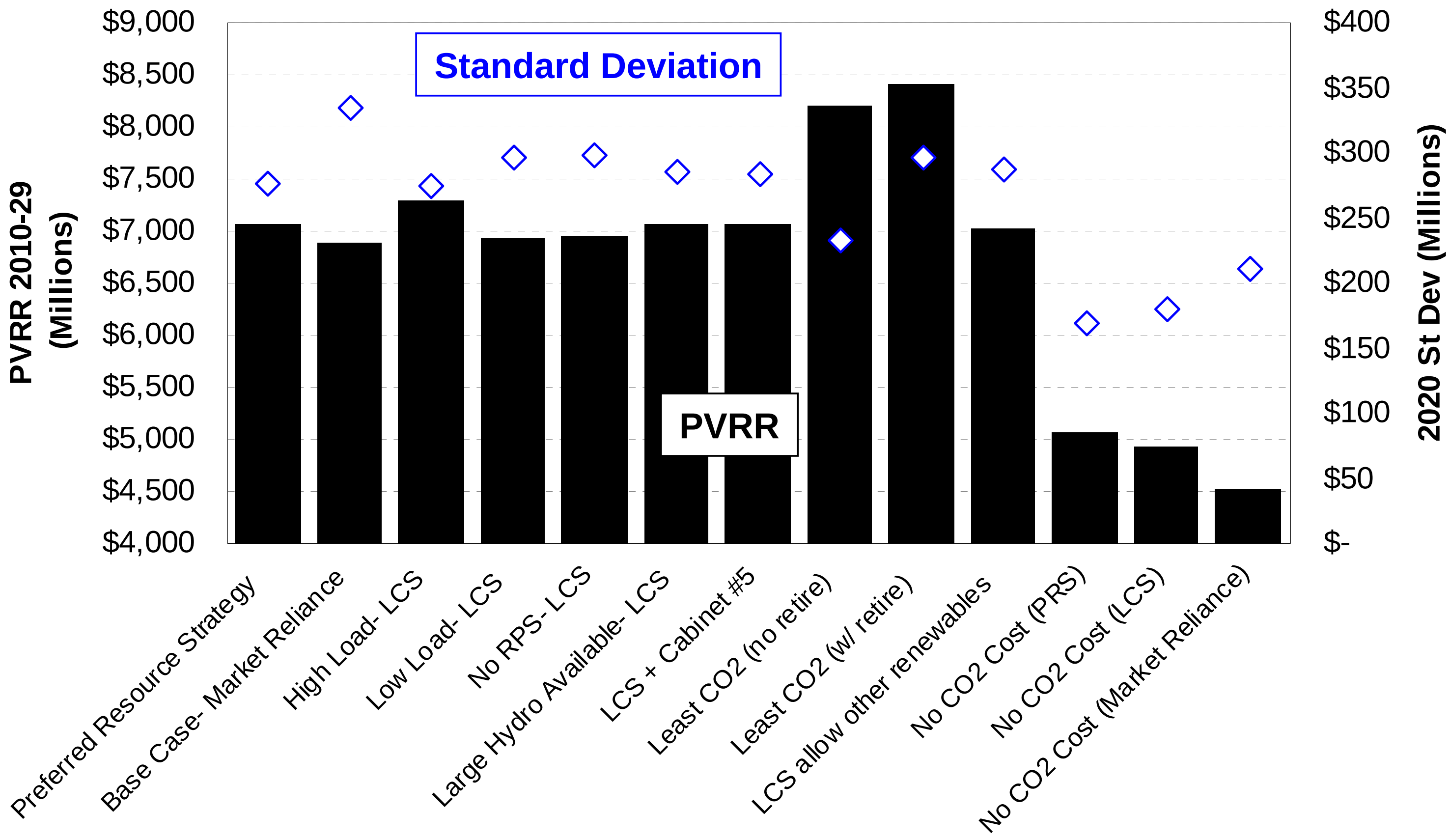
Portfolio Cost/Risk Comparison



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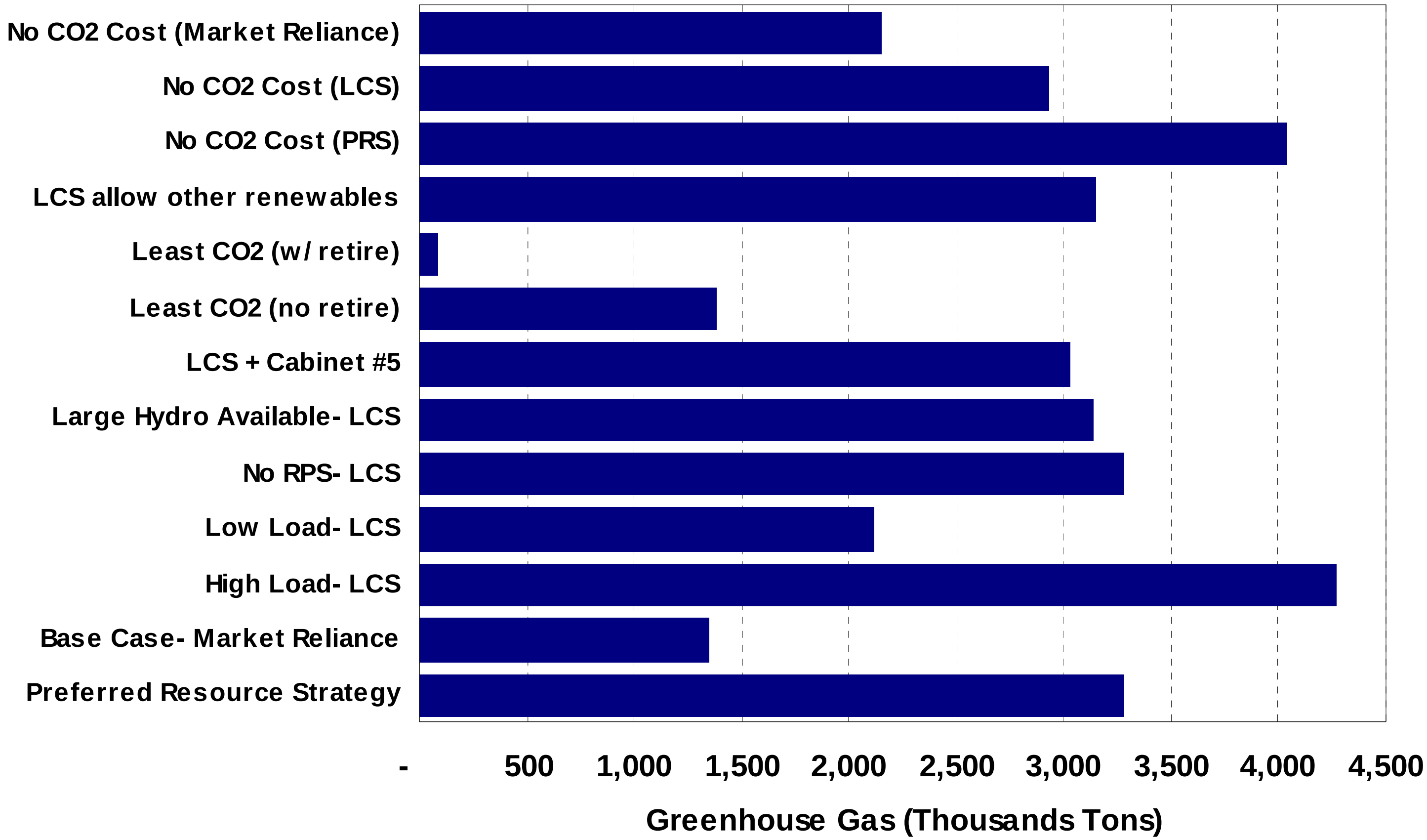
Avista Greenhouse Gas Emissions (2029)



2009 IRP Topics

John Lyons

2009 Electric Integrated Resource Plan
Fifth Technical Advisory Committee Meeting
March 25, 2009

Executive Summary

- Resource needs
- Modeling and results
- Electricity and natural gas market price forecasts
- Demand side management
- Preferred Resource Strategy
- Environmental issues
- Action items

Introduction & Stakeholder Involvement

- IRP process
- Public involvement
- 2009 IRP chapter overview

Loads and Resources

- Economic forecast
- Load forecast
- Forecast scenarios
- Overview of current resources
- Planning margins and resource requirements

Demand Side Management

- Overview of DSM programs
  - Historical
  - Residential
  - Commercial and Industrial
- DSM programs for 2009 IRP
  - Programs considered
  - Analytics
  - DSM business plan and future commitments

Environmental Issues

- Environmental initiatives and policies
- Avista's Climate Change Committee
- State and federal renewable portfolio standards issues
- State and federal greenhouse gas legislation

Transmission & Distribution Planning

- Overview of Avista's transmission system
- Regional transmission issues
- Transmission cost estimates
- Distribution efficiency projects
- Transmission efficiency projects

Modeling Approach

- Market modeling
- Key assumptions and inputs
  - Hydro
  - Fuel prices: coal and natural gas
  - Emissions: SO_2, NO_x and greenhouse gases
  - Risk modeling
  - Resource alternatives
- PRiSM model

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Market Modeling Results

- Base Case
- Market Scenarios
- Portfolio Scenarios
  - Fundamental changes
  - Capital cost sensitivities
  - Resource availability

Preferred Resource Strategy

- 2009 Preferred Resource Strategy
- Comparisons with prior plans
- Portfolio strategies and performance across scenarios

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2009 IRP Action Items

- Progress on 2007 IRP Action Items
- 2009 Action Items
  - Renewables
  - DSM
  - Greenhouse gas issues
  - Modeling and forecasting enhancements
  - Transmission planning

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Avista's 2009 Electric Integrated Resource Plan
Technical Advisory Committee Meeting No. 6 Agenda
June 24, 2009

	Topic	Time	Staff
1.	Introductions	10:00	Storro
2.	IRP Section Highlights	10:05	Kalich
3.	Preferred Resource Strategy	10:30	Gall
4.	Lunch	11:30	
5.	Preferred Resource Strategy	12:30	Kalich/Gall
6.	IRP Action Items	1:30	Lyons
7.	Adjourn	2:00	

Draft Chapter Highlights

Loads & Resources

- Weak economic growth is expected until 2011 in the service territory.
- Historic conservation acquisitions are included in the load forecast; higher acquisition levels anticipated in this IRP reduce the load forecast further.
- Annual electricity sales growth from 2010-2020 averages 1.6 percent over the next decade (199 aMW) and 1.8 percent over the entire 20-year forecast.
- Peak loads are expected to grow at 1.6 percent annual rate over the next 10 years (312 MW) and also 1.6 percent over the entire 20-year forecast.
- Avista's resource deficits begin 2018; without conservation resources deficits would begin in 2016.
- Capacity deficiencies now are the predominate driver of resource need.

Energy Efficiency

- Avista has offered conservation programs for over 30 years.
- The Company has acquired 138.5 aMW of electric-efficiency in the past three decades; an estimated 109 aMW is still in service, reducing overall load by approximately 10 percent.
- 20,000 additional customers heat their homes with natural gas today because of Avista's first fuel-switching program.
- The Company has developed and maintains the infrastructure necessary to respond quickly to an energy efficiency ramp-up if another energy crisis or opportunity occurs.
- Approximately 3,000 concepts were evaluated by Avista's demand-side management analysts for the 2009 IRP.
- 7 aMW of local and 2.9 aMW of regional conservation is expected in 2010
- Conservation additions provide 26 percent of new supplies through 2020.
- 2009 IRP includes 0.3 aMW (3.3%) more annual conservation acquisition than 2007 plan, building on a 50% increase in the 2005 and another 25% in the 2007 IRP.

Transmission & Distribution

- Avista has completed a $130 million transmission improvement project.
- Avista has over 2,200 miles of high voltage transmission.
- Avista remains actively involved in regional transmission planning efforts.
- The cost of selected new transmission lines and upgrades are included in the 2009 Preferred Resource Strategy.
- 2.7 aMW of distribution efficiencies are included in this IRP.

Generation Resource Options

- Only resources with well known costs were considered in the PRS analysis, other resources were studied in sensitivities.
- Federal tax credits were extended to 1/1/2013 for wind and 1/1/2014 for non-wind renewables with a choice of the PTC ($20/mwh or 30% ITC)
- Large hydro upgrades at Long Lake and Cabinet Gorge are not considered as new resources, but will be further studied for inclusion in the 2011 IRP analysis.
- Small hydro upgrades and wood fired upgrades were considered in this IRP.
- Solar is included as resource option for this first time.

Market Analysis

- Mid-Columbia electric and Malin natural gas prices are 27 and 20 percent higher than the 2007 IRP, primarily due to carbon legislation impacts
- Mid-Columbia electric prices are expected to be $79.56 per megawatt-hour over the next 20 years
- Malin natural gas prices are expected to be $7.36 per decatherm over the next 20 years
- Gas-fired resources continue to serve most new loads and take the place of coal generation to reduce greenhouse gas emissions
- Future carbon credit prices will depend on reduction goals and the differential between natural gas and coal prices
- Carbon legislation increases total fuel expenses in the Western Interconnect by over 16 percent

Preferred Resource Strategy

- Avista’s physical energy needs begin in 2018; capacity needs begin in 2016.
- Near-term resource acquisitions are driven by pending environmental regulation and risk reduction.
- The first supply-side resource acquisitions are 150 MW of wind by 2012.
- Conservation additions provide 26 percent of new supplies through 2020.
- A 250 MW natural gas-fired combined cycle project is required by 2020.
- Large hydro upgrades have the potential to change the preferred resource mix.
- The 2020 CCCT acquisition could be moved forward to as soon as 2015 without a significant impact on the preferred resource strategy.

Draft Action Items Highlights

Resource Additions & Analysis

- Continue to explore the potential for wind and non-renewable resources.
- Issue an RFP for turbines at Reardan and up to 100 MW of wind or other renewables in 2009.
- Finish studies regarding the costs and environmental benefits of the large hydro upgrades at Cabinet Gorge, Long Lake, Post Falls, and Monroe Street.
- Study potential locations for the natural gas fired resource identified to be on-line between 2015 and 2020.

Demand Side Management

- Pursue American Reinvestment and Recovery Act funding and its affect on the amount of low income weatherization.
- Analyze and report on the results of the July 2007 through December 2009 demand response pilot in Moscow and Sandpoint.

Environmental Policy

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

Modeling and Forecasting Enhancements

- Refine the stochastic model for cost driver relationships.
- Continue to refine the PRiSM model.
- Continue developing Loss of Load Probability and Sustained Peaking analysis for inclusion in the IRP process

Transmission Planning

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

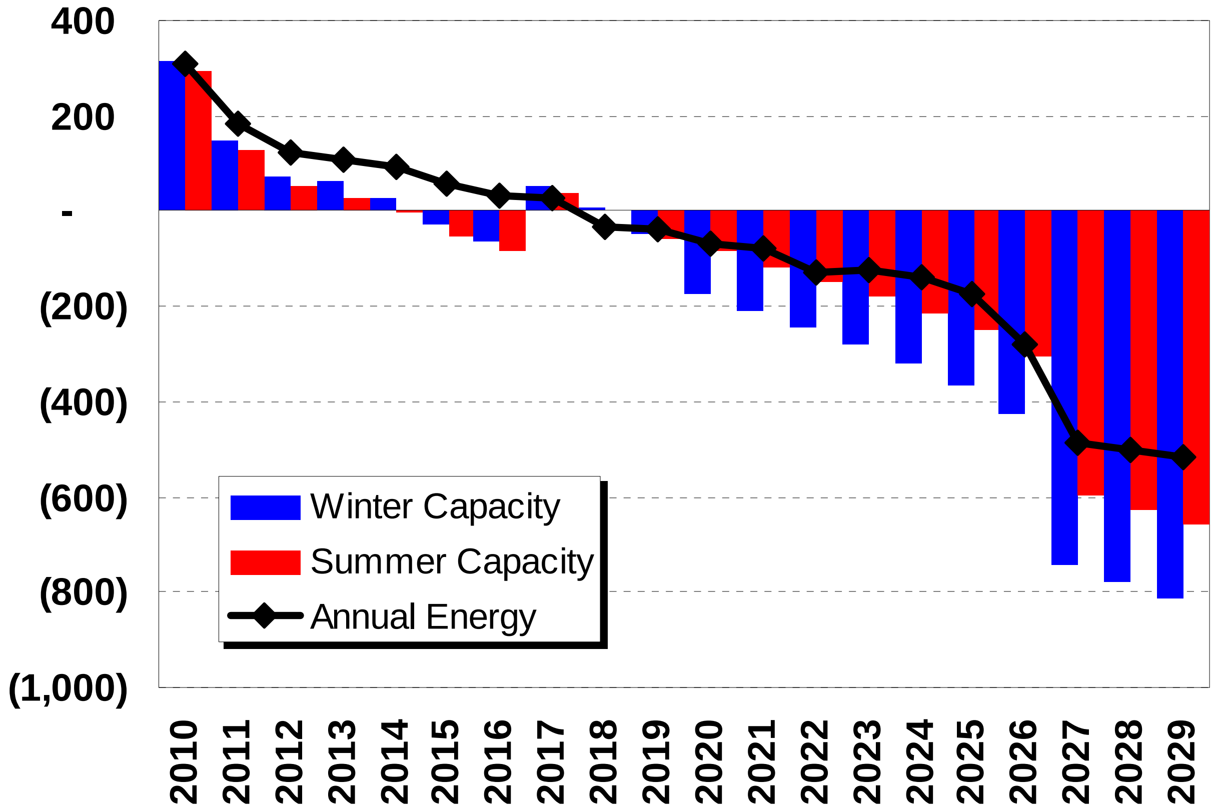
2009 IRP
Preferred Resource Strategy

2009 Electric Integrated Resource Plan

Sixth Technical Advisory Committee Meeting

June 24, 2009

L&R Balances



Load is net 2007 Conservation Levels

Preferred Resource Strategy Approach

Least Cost Strategy that meets

1. Capacity Needs
2. Energy Needs
3. RPS Requirements
4. Conservation Requirements
5. Emissions Regulation
6. Actionable

Flexible Strategy

Preferred Resource Strategy

But, what if?

- Capital Costs Change
- Load Growth Rate Changes
- Large Hydro Upgrades Are Cost Effective
- Non-Wind Renewables Become Abundant
- Is Nuclear a Solution

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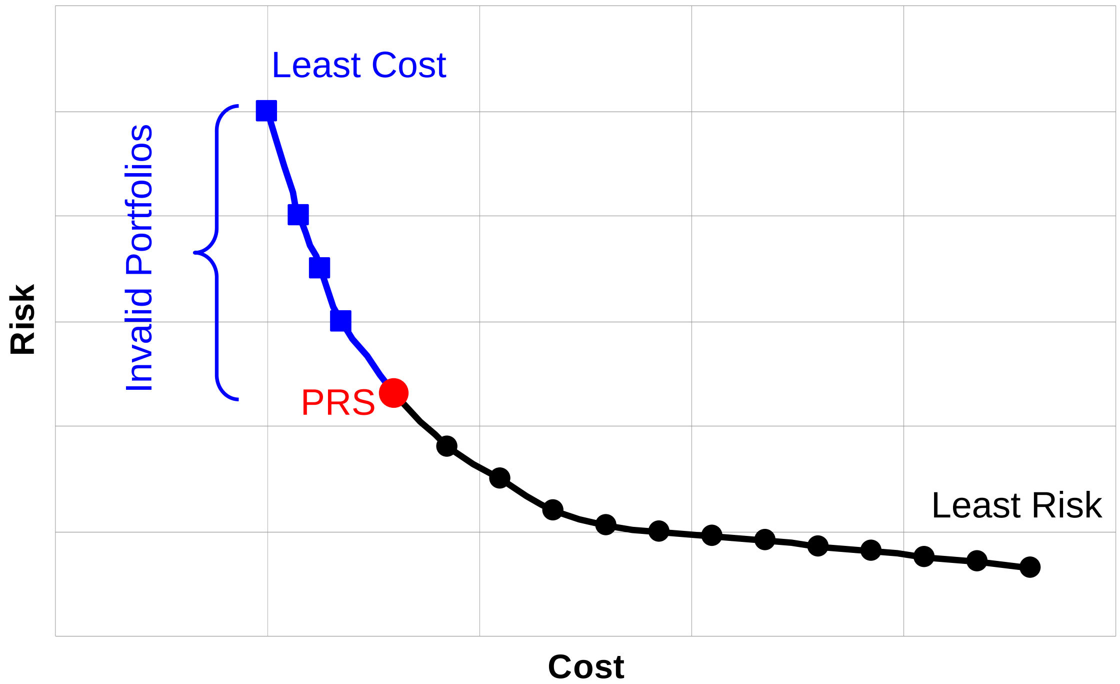
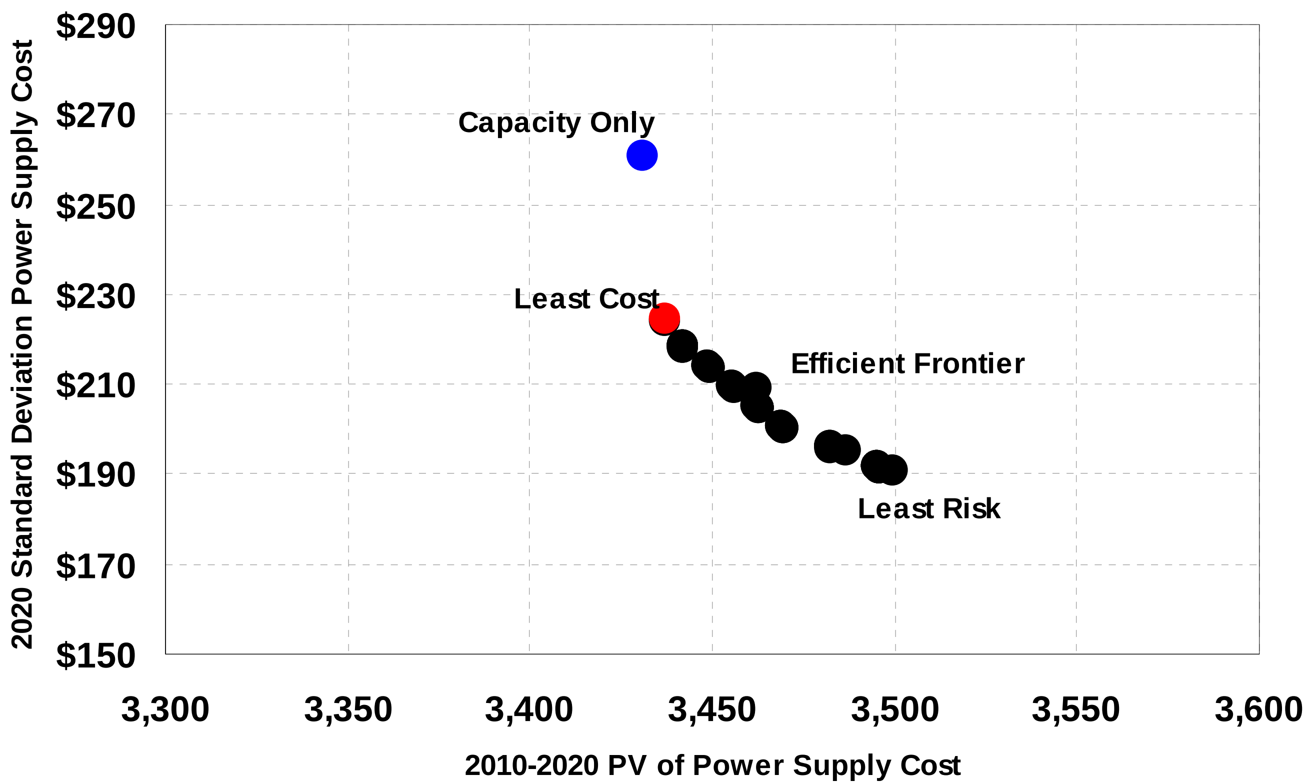
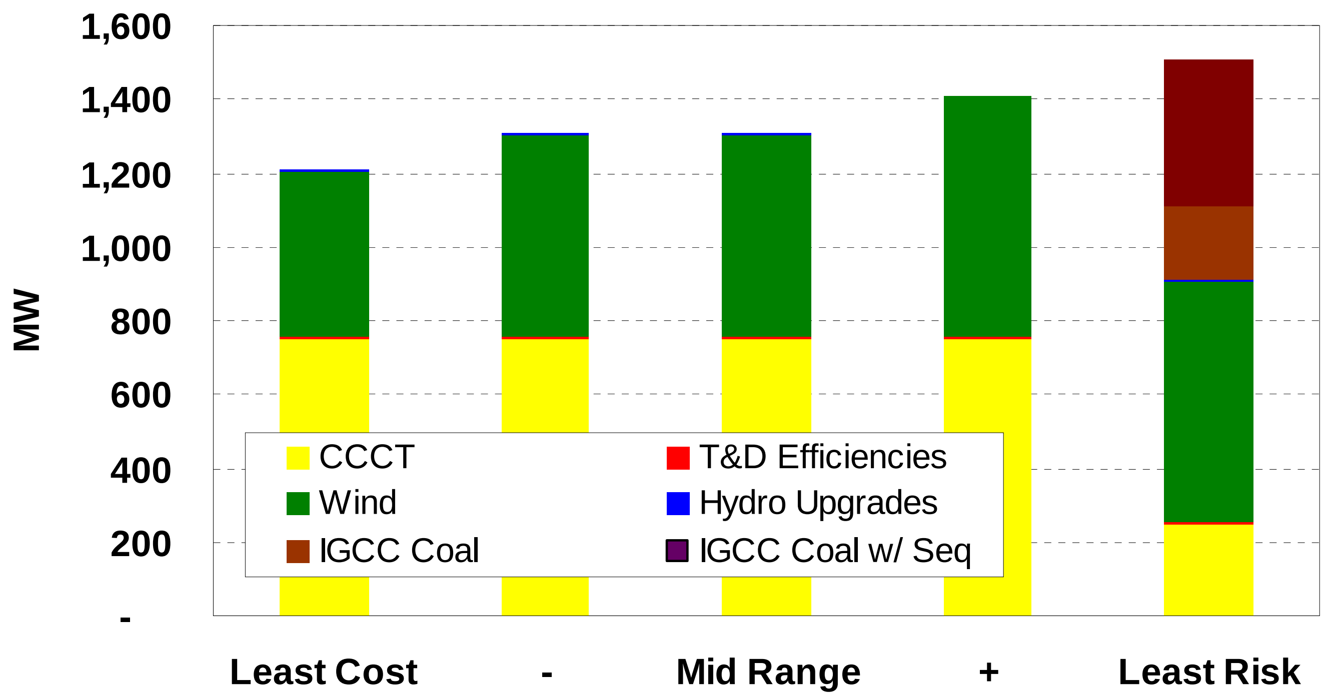
Conceptual Efficient Frontier



Efficient Frontier



Efficient Frontier Portfolios



2009 Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Energy (aMW)
NW Wind	2012	150.0	50.0
Distribution Efficiencies	2010-2015	5.0	2.0
Little Falls 1	2013	1.0	0.3
Little Falls 2	2014	1.0	0.3
Little Falls 4	2016	1.0	0.3
NW Wind	2019	150.0	50.0
CCCT	2019	250.0	225.0
Upper Falls	2020	2.0	1.0
NW Wind	2022	50.0	17.0
CCCT	2024	250.0	225.0
CCCT	2027	250.0	225.0
Conservation	All Years	339.0	226.0
Total		**1,449.0**	**1,019.9**

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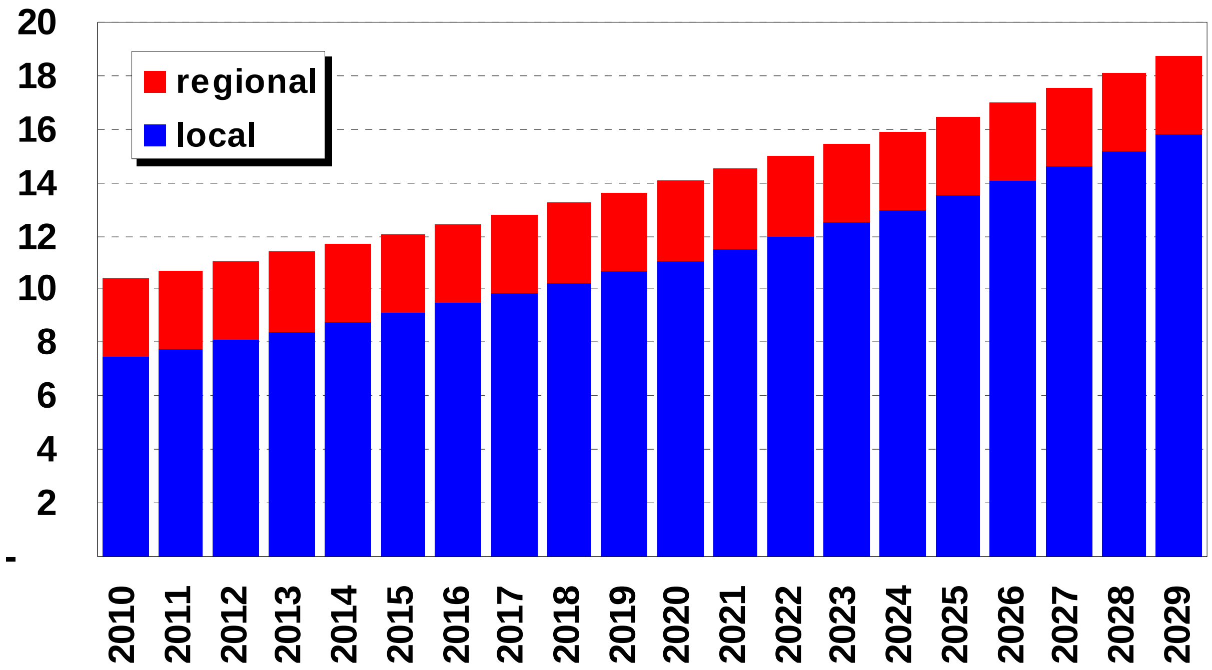
Annual Conservation Acquisition



<u>Local</u>
90 aMW over first 10 years
226 aMW over 20 years

<u>Regional</u>
29 aMW over first 10 years
59 aMW over 20 years

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Local Energy Efficiency Targets

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

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Rate Base Additions for Capital Expenditures (Millions)

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

Totals *
$0.3 billion thru 2019
$2.5 billion thru 2029 **

* Excludes conservation funding
** $1.0 billion NPV @ 8% discount rate

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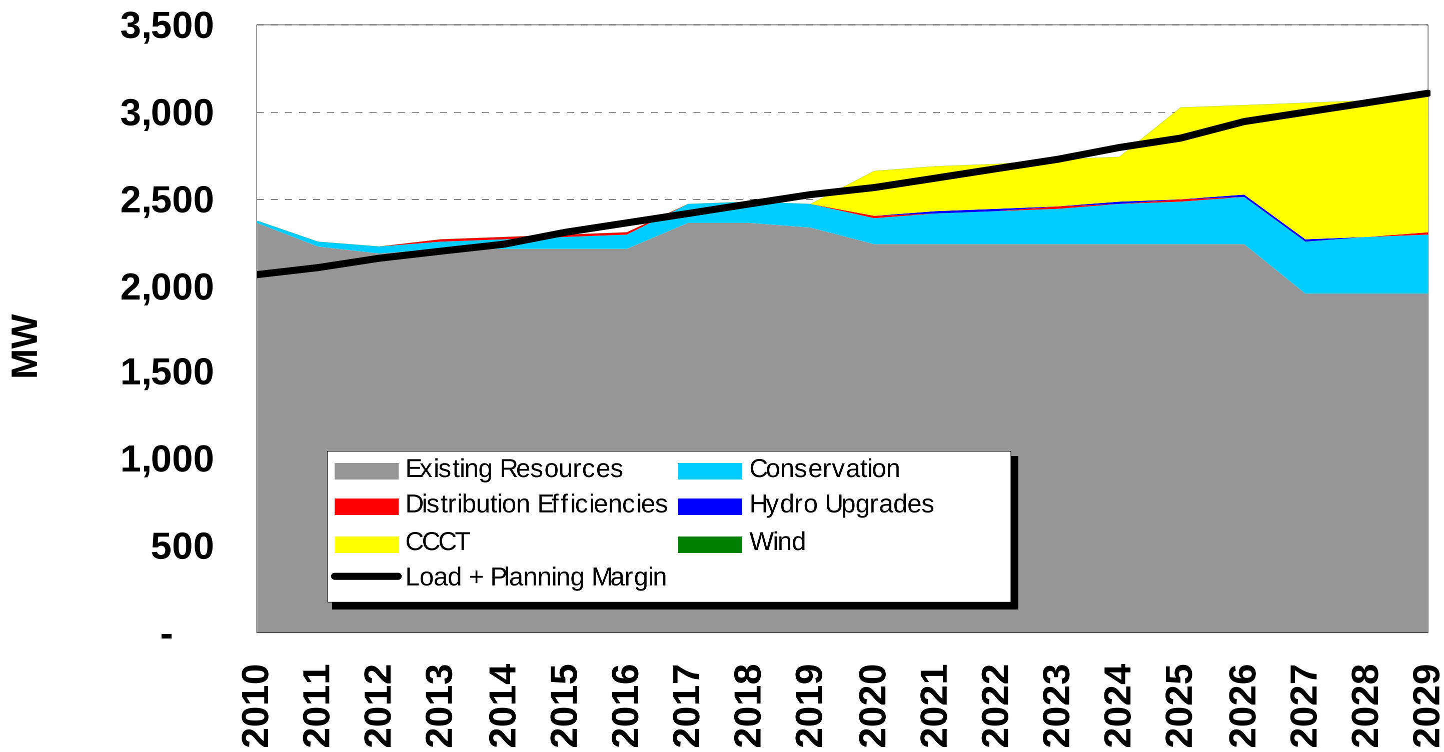
January Capacity L&R w/ New Resources



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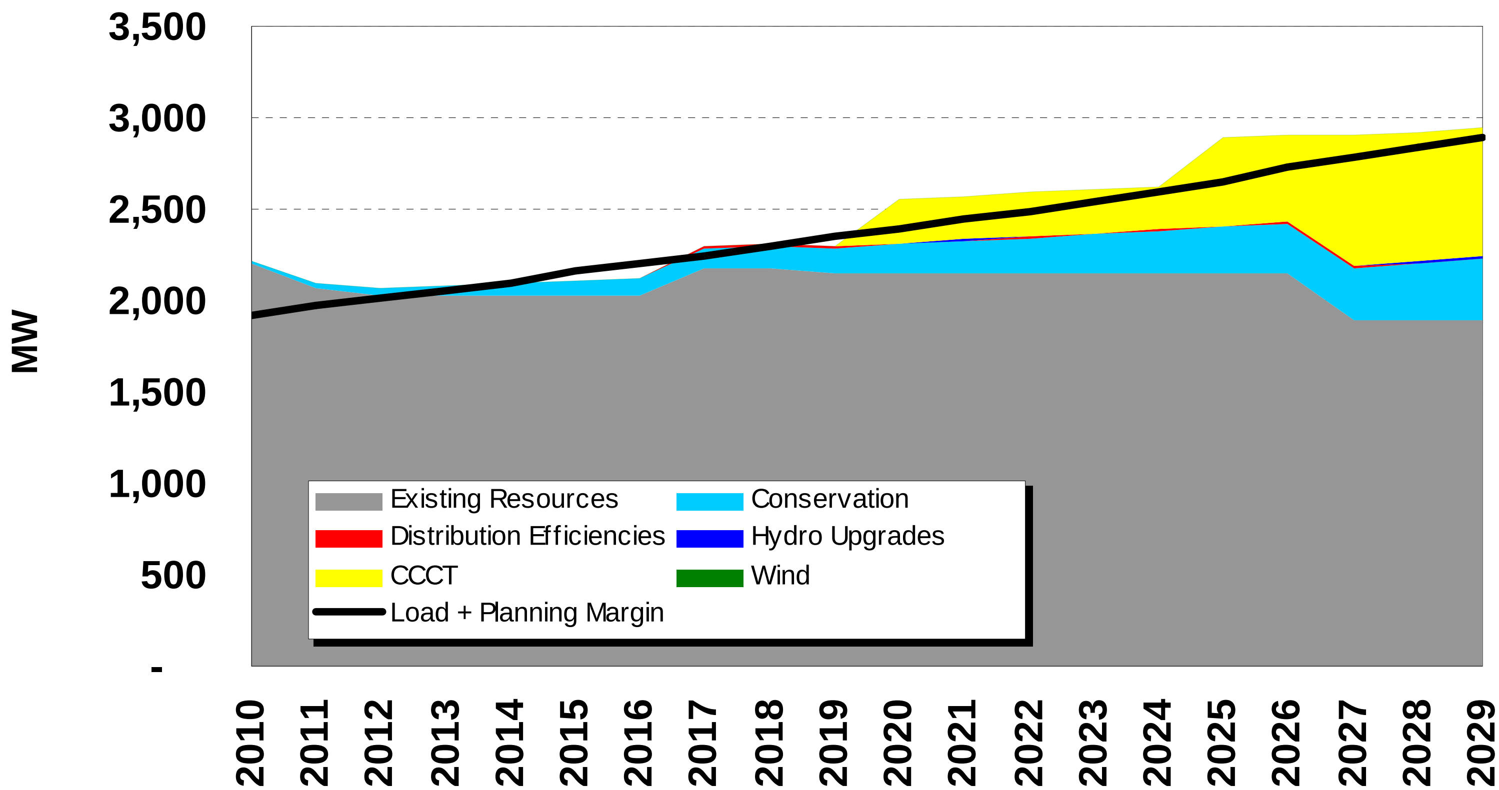
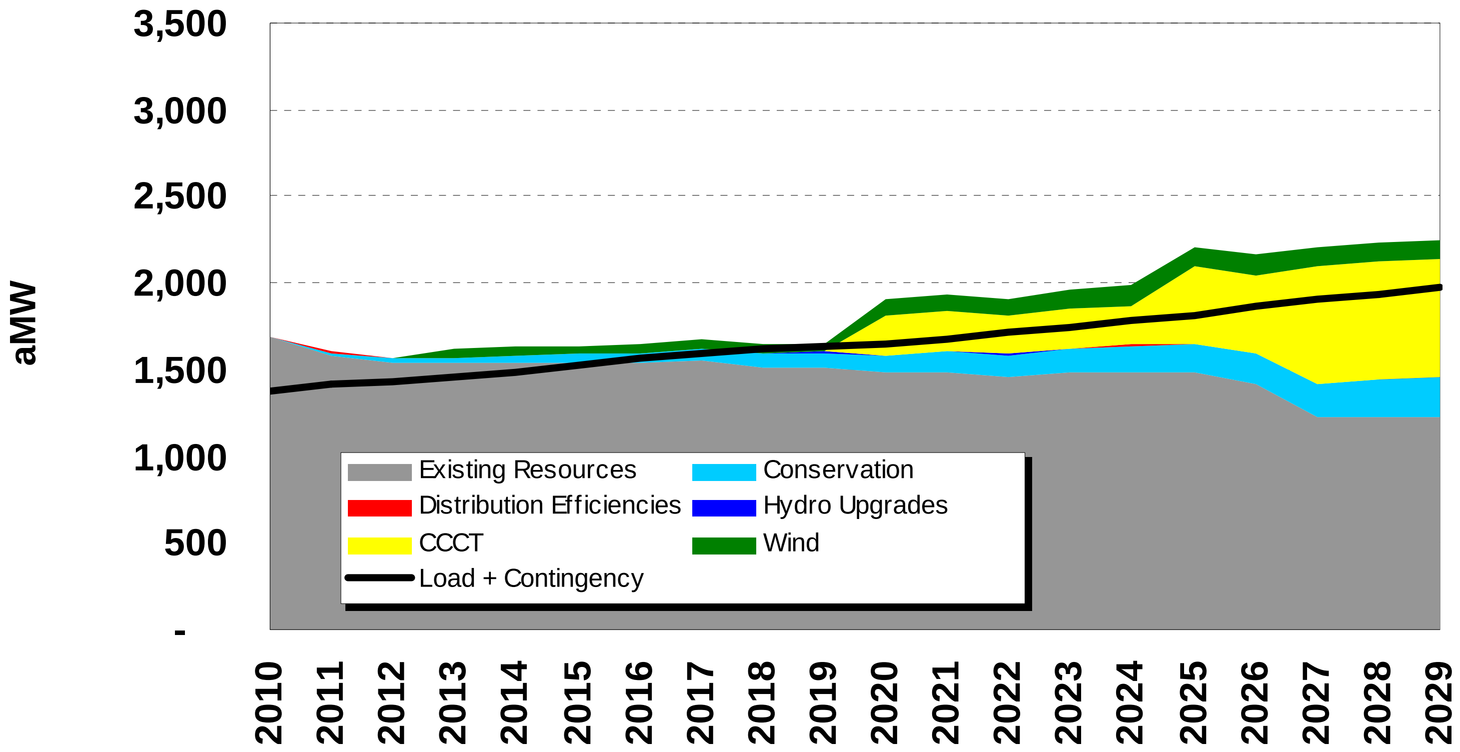
August Capacity L&R w/ New Resources



Annual Energy L&R w/ New Resources



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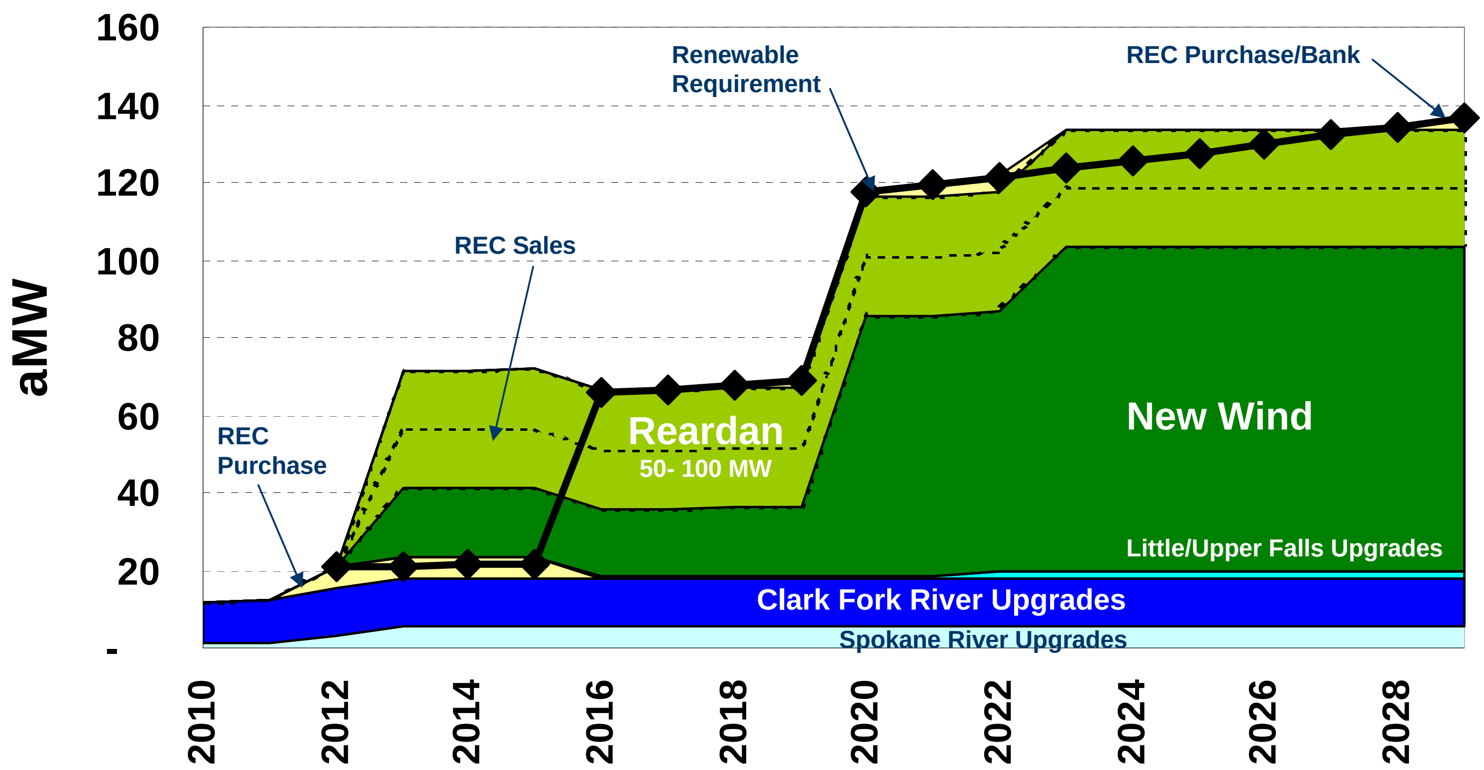
Washington State RPS Compliance



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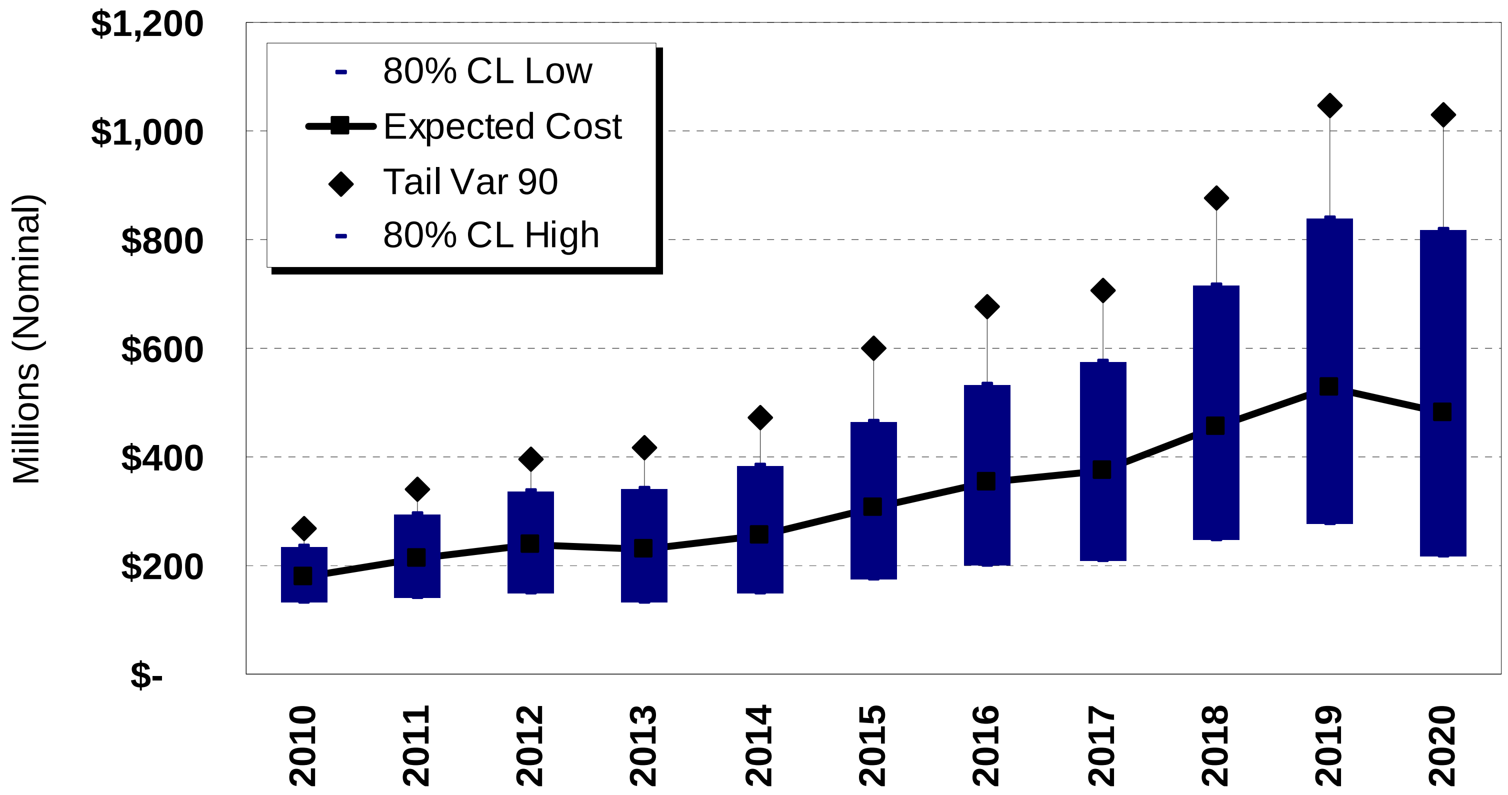
Power Supply Cost Variation



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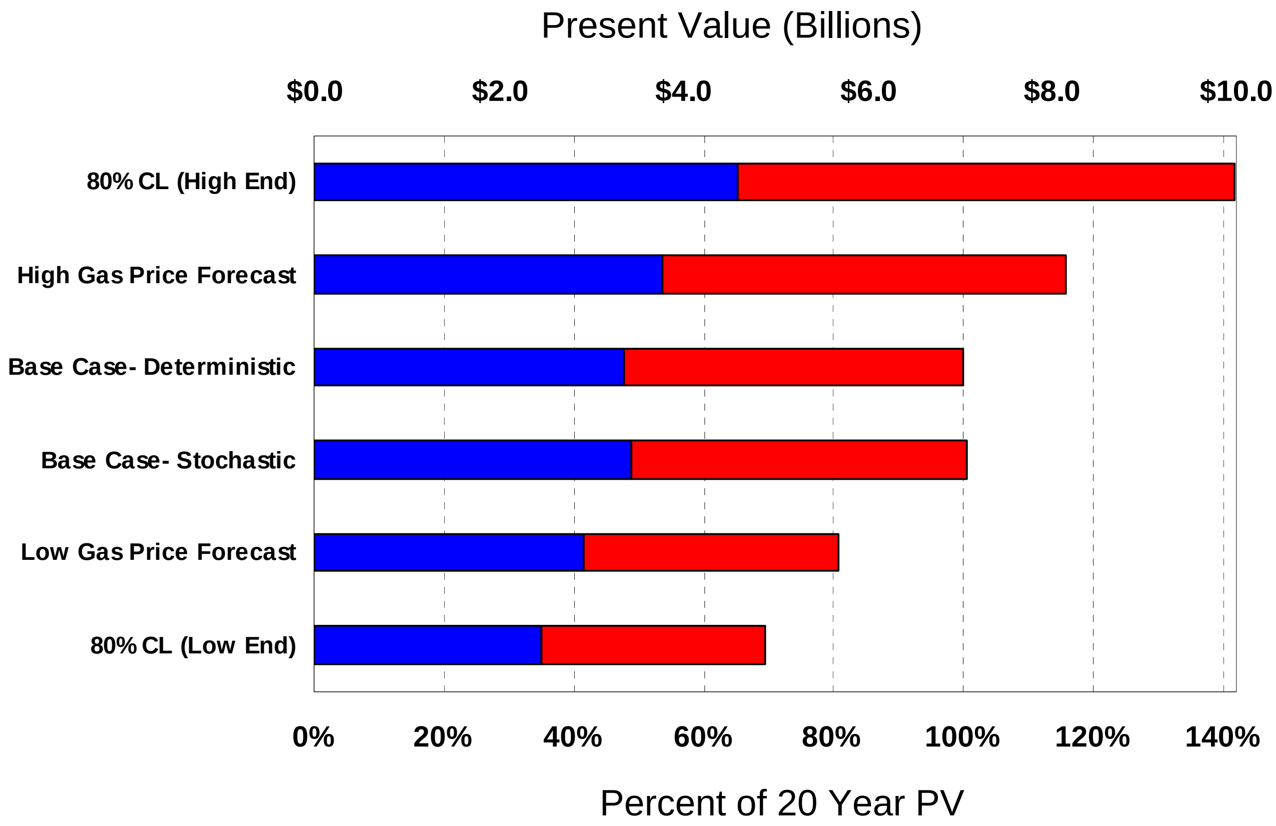
Power Supply Cost Ranges



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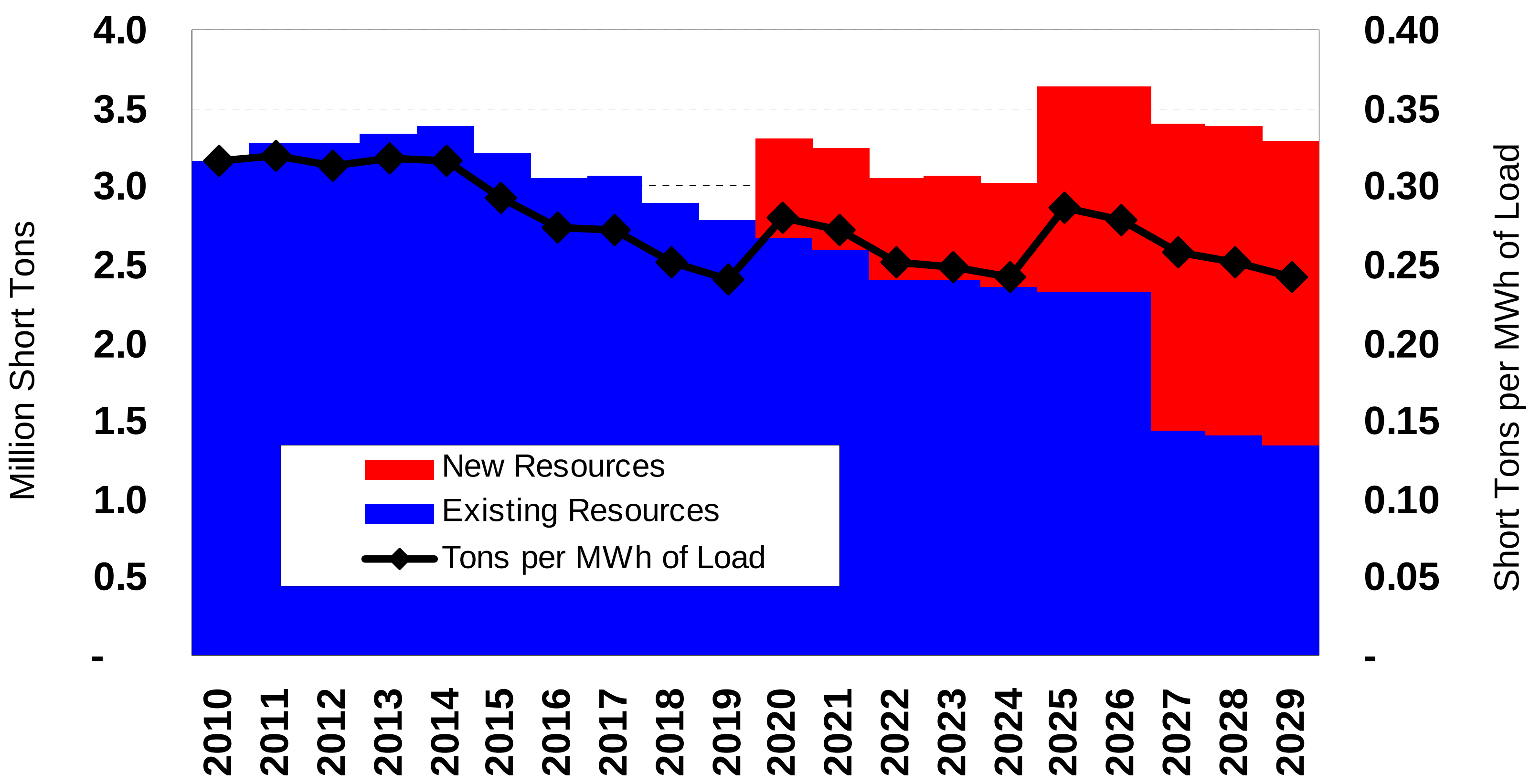
Avista Generator GHG Emissions



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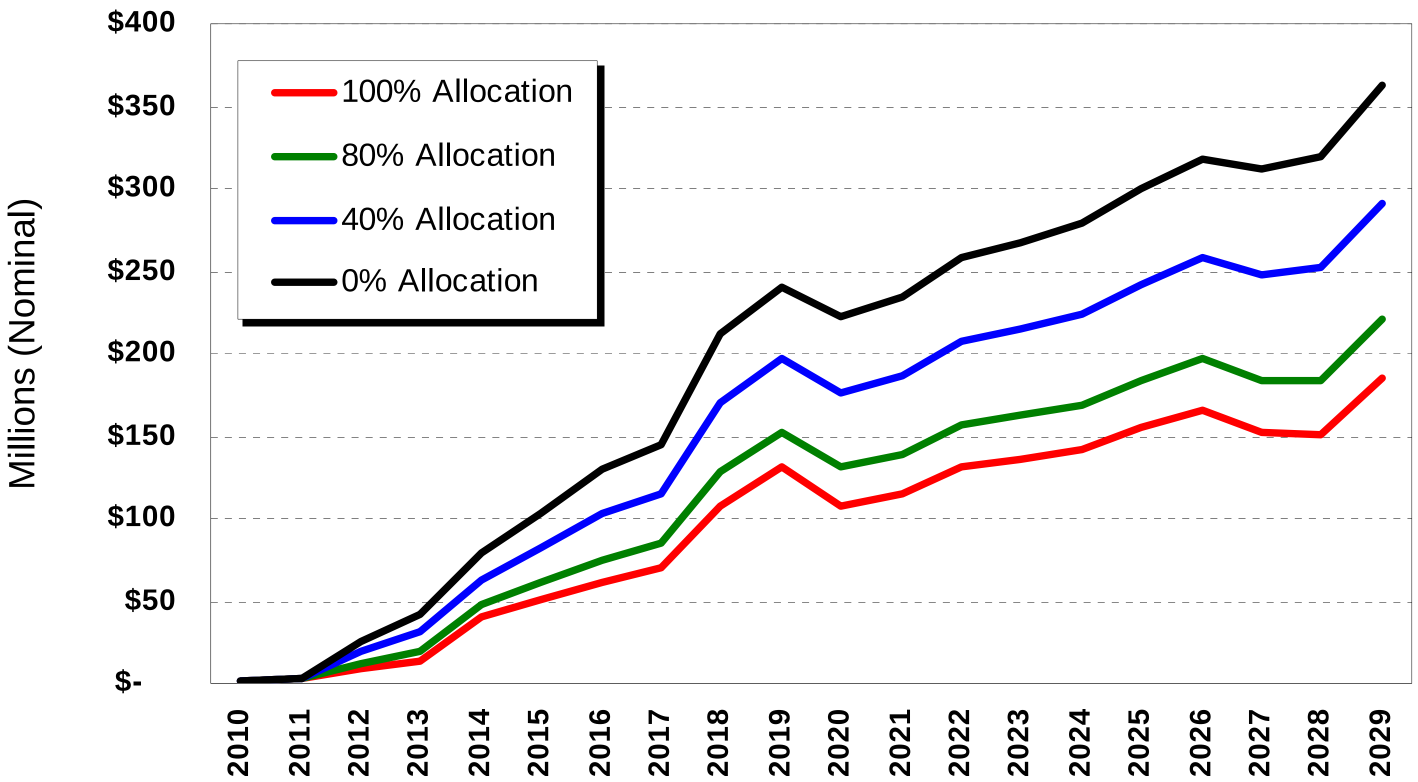
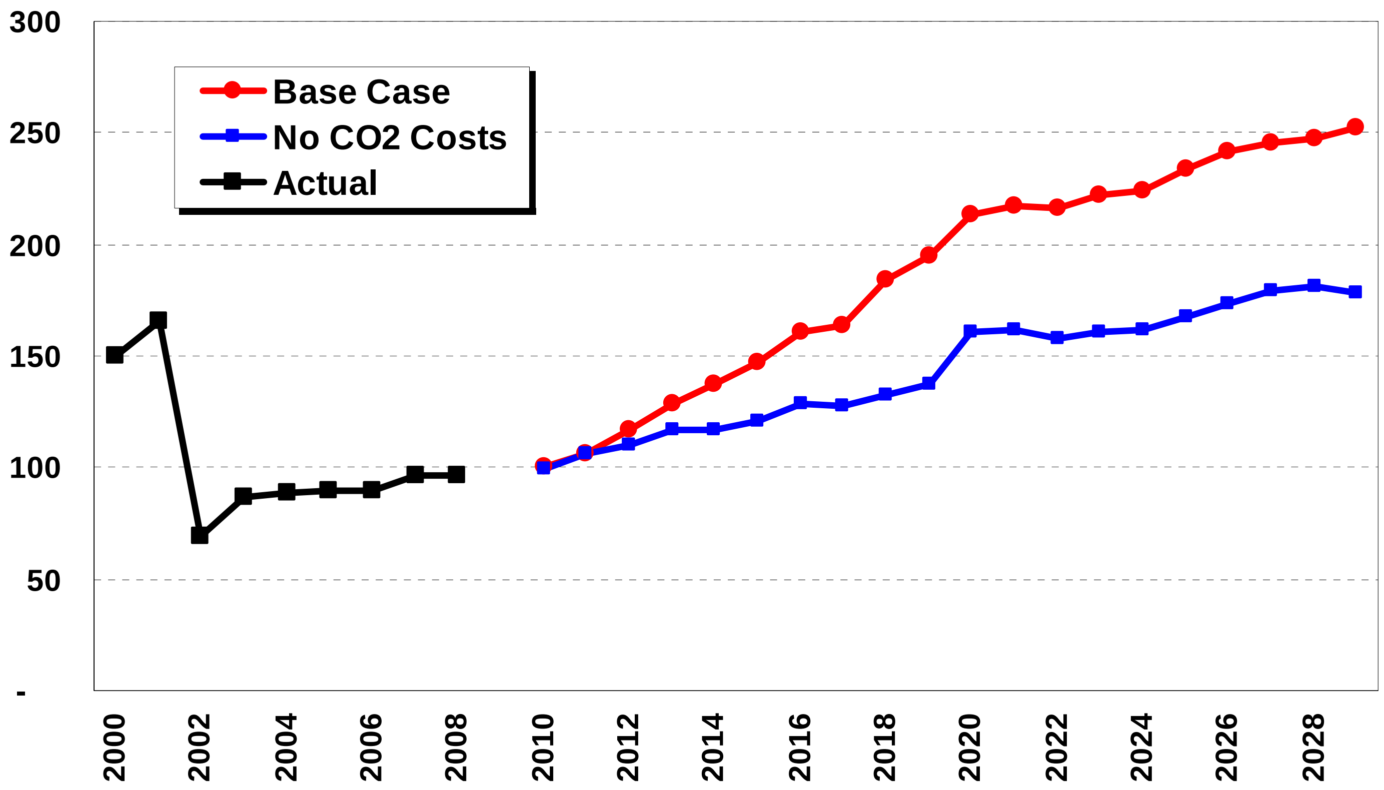
Total Cost GHG Legislation



Future Power Supply Costs
(Index: 2010= 100)



Flexible Strategy

What are the tipping points for key capital costs?

- wind capital cost <$1,830/kW, build early
- CCCT cost >$1,610/kW, consider SCCT

What are the impacts of load growth changes?

- High: 260/100 MW more gas/wind next 10 years
- Low: 250/50 MW less gas/wind in next 10 years

What if large hydro upgrades are viable?

- eliminate 50/100 MW of wind/gas over 20 years?

What if non-wind renewables are abundant?

- non-wind renewables replace some wind; could reduce gas by 100 MW

Is Nuclear a solution?

- least-cost if <=$4,000/kW (current range $5-$10k)

Schedule

June 22:	Internal draft released
June 24:	Final Technical Advisory Committee meeting
July 1:	“Big Picture” internal comments
July 6:	External draft released
July 20:	Comment deadline
Aug 31:	IRP Filed with Commissions
~April 2010:	Begin 2011 IRP Process

2009 IRP Action Items

John Lyons

2009 Electric Integrated Resource Plan
Sixth Technical Advisory Committee Meeting
June 24, 2009

2007 IRP Action Items

- Renewable Energy
- Demand Side Management
- Emissions
- Modeling and Forecasting Enhancements
- Transmission Planning

Renewable Energy

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

Demand Side Management

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

Emissions

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

Modeling and Forecasting Enhancements

- Study the potential for fixing natural gas prices through financial instruments, coal gasification, investments in gas fields, or other means.
- Continue studying the efficient frontier modeling approach to identify more and better uses for its information.
- Further enhance and refine the PRiSM LP model
- Continue to study the impact of climate on the load forecast.
- Monitor the following conditions relevant to the load forecast: large commercial load additions, Shoshone county mining developments, and the market penetration of electric cars.

Transmission Planning

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

2009 IRP Action Items

- Resource Additions and Analysis
- Demand Side Management
- Environmental Policies
- Modeling and Forecasting Enhancements
- Transmission and Distribution Planning

Resource Additions and Analysis

- Continue to explore the potential for wind and non-renewable resources.
- Issue an RFP for turbines at Reardan and up to 100 MW of wind or other renewables in 2009.
- Finish studies regarding the costs and environmental benefits of the large hydro upgrades at Cabinet Gorge, Long Lake, Post Falls, and Monroe Street.
- Study potential locations for the natural gas fired resource identified to be on-line between 2015 and 2020.

Demand Side Management

- Pursue American Reinvestment and Recovery Act funding
- Analyze and report on the results of the demand response pilot in Moscow and Sandpoint
- Processing and implementing I-937 requirements

Environmental Policies

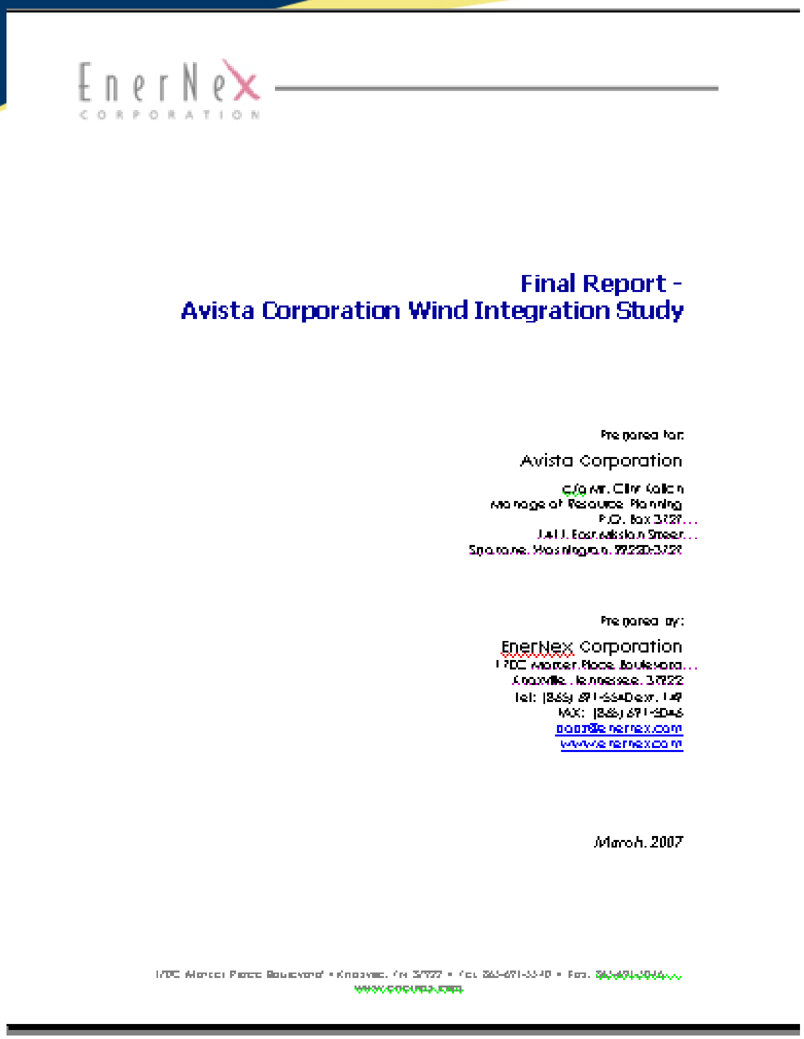
- Continue to study the potential impact of state and federal climate change and renewable portfolio legislation
  - Western Climate Initiative
  - Waxman-Markey – American Clean Energy and Security Act of 2009
- Continue to report on Avista's Climate Change Committee

Modeling and Forecasting Enhancements

- Refine the stochastic model for cost driver relationships
- Continue to refine the PRiSM model
- Continue developing Loss of Load Probability and Sustained Peaking analysis for inclusion in the IRP process
- Study cooling degree day trend coefficient for inclusion in the load forecast

Transmission and Distribution Planning

- Work to maintain and retain existing transmission rights on Avista's transmission system
- Continued involvement in BPA transmission processes and rate proceedings
- Continued participation in regional and sub-regional efforts to establish new regional transmission structures and to facilitate long-term expansion of the regional transmission system
- Evaluate costs to integrate new resources across Avista's service territory and from regions outside of the Northwest
- Study and implement distribution feeder rebuild projects
- Study transmission re-configurations to reduce system losses


Final Report -
Avista Corporation Wind Integration Study

Prepared for:
Avista Corporation

Prepared by:
EnerNex Corporation

March, 2007

Defining Wind Integration & Overview of Avista Study

Clint Kalich
Manager of Resource Planning & Power Supply Analyses
clint.kalich@avistacorp.com
October 21, 2008

Outline of Presentation

- Defining Wind Integration
- Overview of Avista's System
- Evaluating Overall Cost of Wind
- Methodology Overview
- Wind Integration Cost Components
- Impact of Shorter Market Time Step
- Benefit of Wind Feathering
- Hydro Re-Dispatch Costs
- Next Steps/Modeling Enhancements
- Other Wind Integration Study Results

Defining Wind Integration

- **Incremental Reserves (Avista Study Method)**
  - Regulation (<1 minute)
  - Load following
    - covers timeframe from end of regulation up to next ramp (1 hour in WECC)
  - Forecast error
    - difference between forecast and actual generation
- **Other Things Sometimes Called Wind Integration**
  - Shape of delivered energy
  - Fuel savings from wind operations
  - Capital costs
  - Environmental attributes

Bottom Line: Be Careful When Assuming 2 Studies are "Apples-to-Apples"

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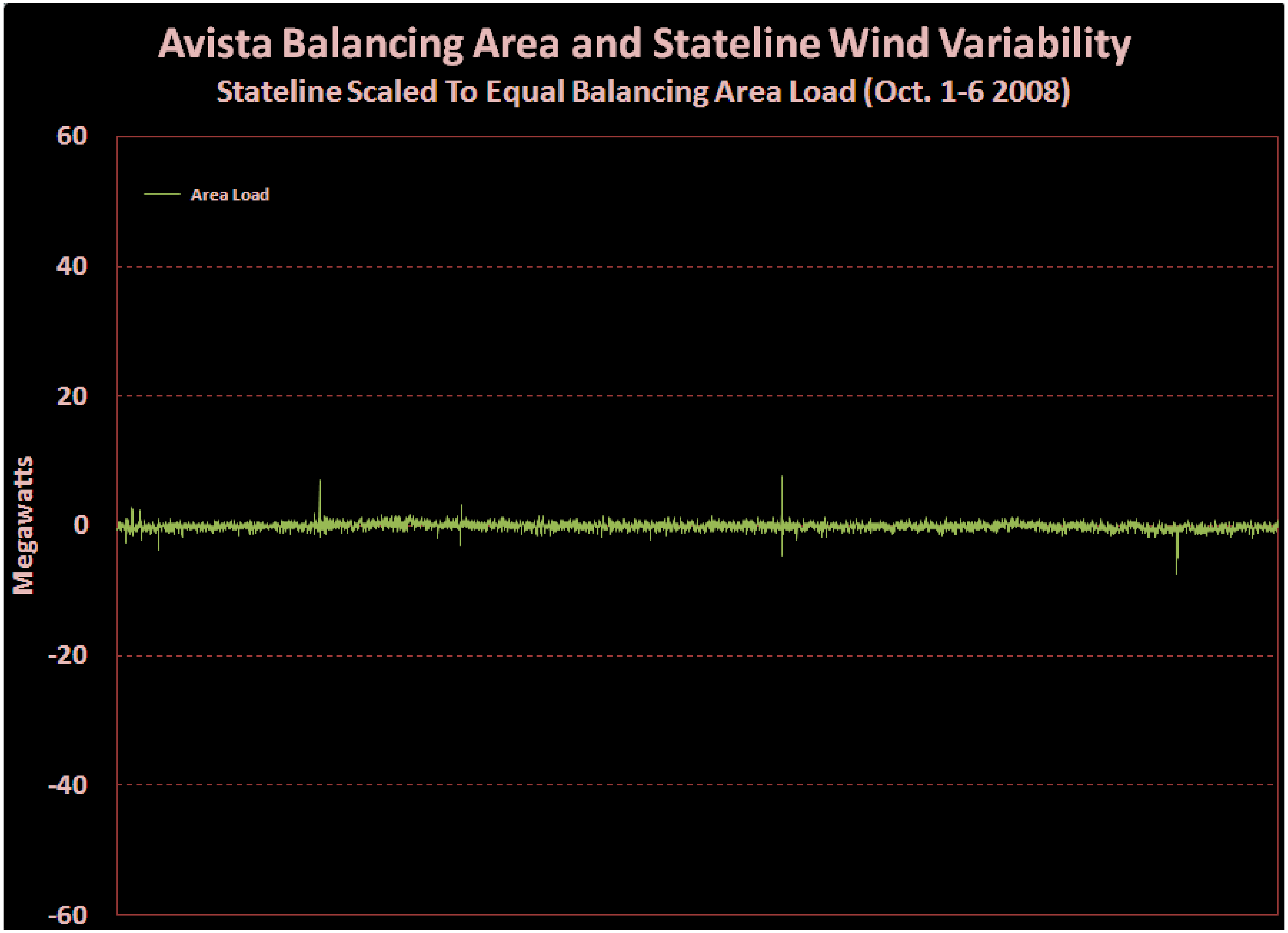
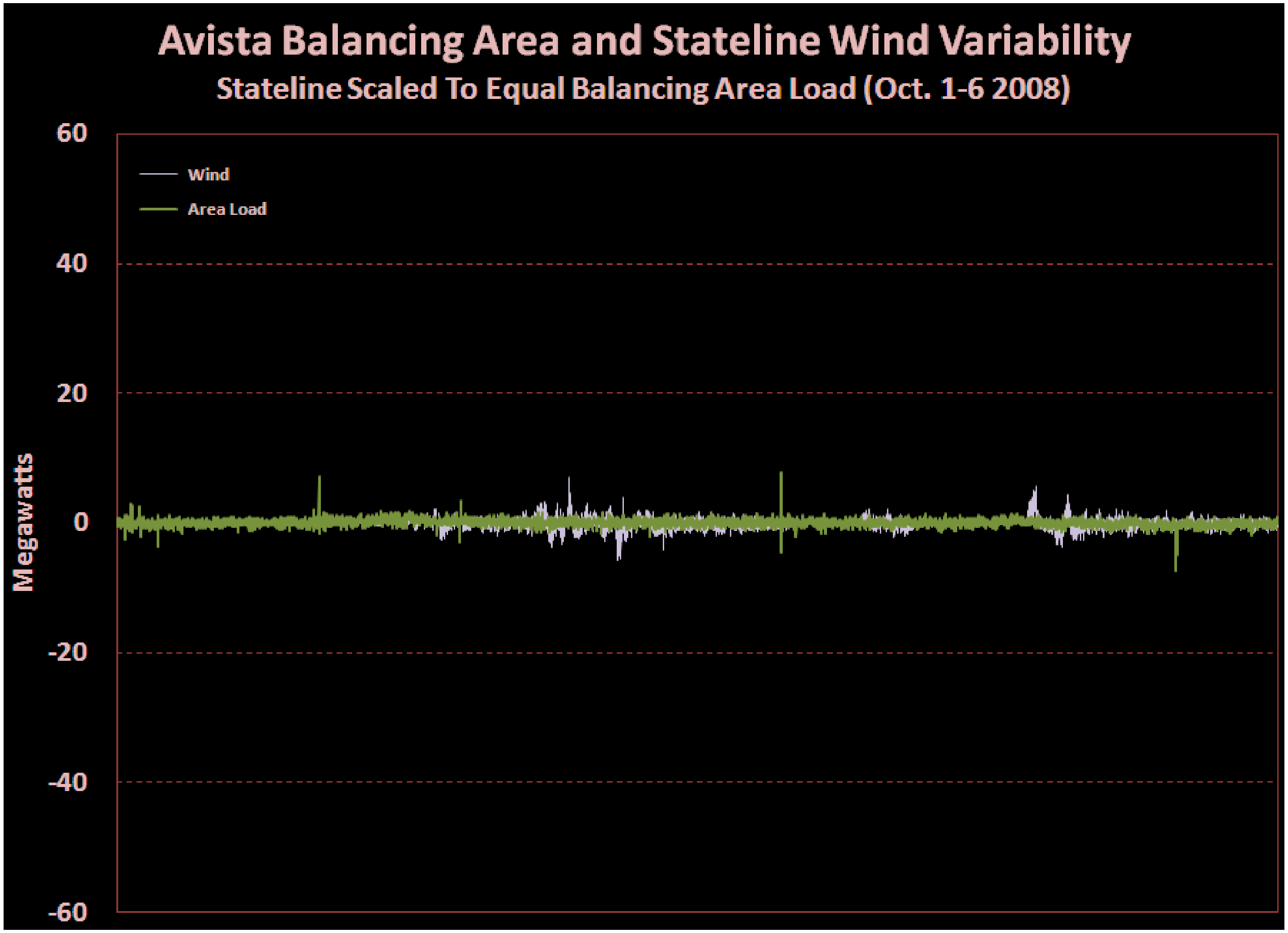
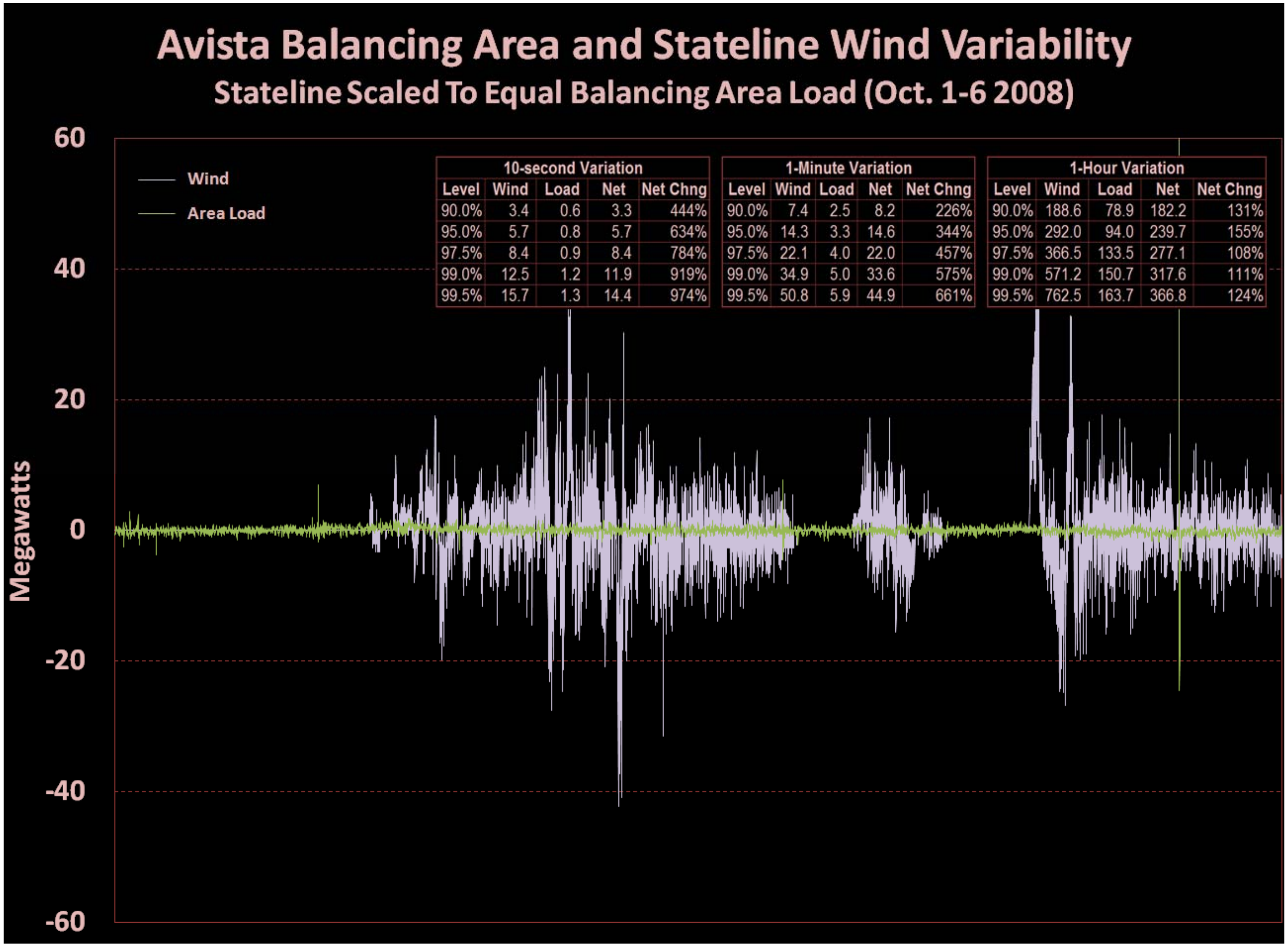
Defining Wind Integration — A Graphical View



Defining Wind Integration — A Graphical View



Defining Wind Integration — A Graphical View



10-second Variation				
Level	Wind	Load	Net	Net Chng
90.0%	3.4	0.6	3.3	444%
95.0%	5.7	0.8	5.7	634%
97.5%	8.4	0.9	8.4	784%
99.0%	12.5	1.2	11.9	919%
99.5%	15.7	1.3	14.4	974%

1-Minute Variation				
Level	Wind	Load	Net	Net Chng
90.0%	7.4	2.5	8.2	226%
95.0%	14.3	3.3	14.6	344%
97.5%	22.1	4.0	22.0	457%
99.0%	34.9	5.0	33.6	575%
99.5%	50.8	5.9	44.9	661%

1-Hour Variation				
Level	Wind	Load	Net	Net Chng
90.0%	188.6	78.9	182.2	131%
95.0%	292.0	94.0	239.7	155%
97.5%	366.5	133.5	277.1	108%
99.0%	571.2	150.7	317.6	111%
99.5%	762.5	163.7	366.8	124%

Overview of Avista's System (2010)

- **2,200 MW Control Area Peak**
- **875 MW Minimum Load**
- **1,200 MW Hydro**
  - Very flexible with generous short-term storage
  - Provides majority of reserves for wind
    - regulation, spinning, supplemental
- **785 MW Gas Turbines**
  - 550 MW CCCT with 100 MW of spinning & supplemental reserves
  - 210 MW (4 units) provide only supplemental reserves
  - Remaining 7 (small) units cannot provide reserves

Overview of Avista's System, Cont

- **230 MW Coal & 50 MW Biomass**
  - Do not provide reserves
- **35 MW of Stateline Wind**
- **~750 MW Contracts Rights**
  - 350 MW for "native load"
  - 400 MW 3rd party resources to serve 3rd party loads in control area
  - No reserve capabilities
- **~200 MW Capacity Contract Obligations**
  - Sales of AGC and spinning reserves for 3rd party load and wind

Evaluating Overall Cost of Wind

- **Commodity Value of Energy**
  - Consider hourly pattern
  - Wind doesn't generate flat or at the operator's control
- **Transmission Cost ~ 3 Times Traditional Resources**
- **Impact on Operation of Other Owned Resources**
  - Fuel savings and/or impact on market sales & purchases
- **Incremental Reserve Obligations**
  - Avista definition of wind integration
  - Regulation, load following, forecast error
    - load following and forecast error are greatly affected by spot market timeframe
- **Capital Recovery and Operation Costs**
- **Environmental Attribute Values (green tags, reduced CO_2)**
- **Capacity Contribution (or lack thereof)**

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Methodology Overview

- **Develop Hourly LP Model Of Avista System**
  - Model of both Real-Time and Pre-Schedule timeframes
    - pre-schedule commitment and market transactions “honored” in Real-Time
  - Represent inherent flexibility and constraints
    - hydro storage and minimum flow
    - minimum up/down requirements
    - reserve capabilities and ramping rates
    - transmission paths
    - hydro spill and wind “feathering”
  - Access to energy market for balancing and optimization
    - pre-schedule and real-time markets

Methodology Overview (Cont.)

- **Run Model With and Without Wind Variability**
  - Over same historical timeframe (2002-04)
    - using actual loads
    - wind is priced in each hour at market
    - eliminates potential for wind shape to bias result
    - carry additional reserves in "With Wind" case
- **Compare System Values**
  - Change is spread over wind deliveries to arrive at an integration cost
    - per MWh (absolute or % of market price)
    - per kW-month (absolute or % of market price)

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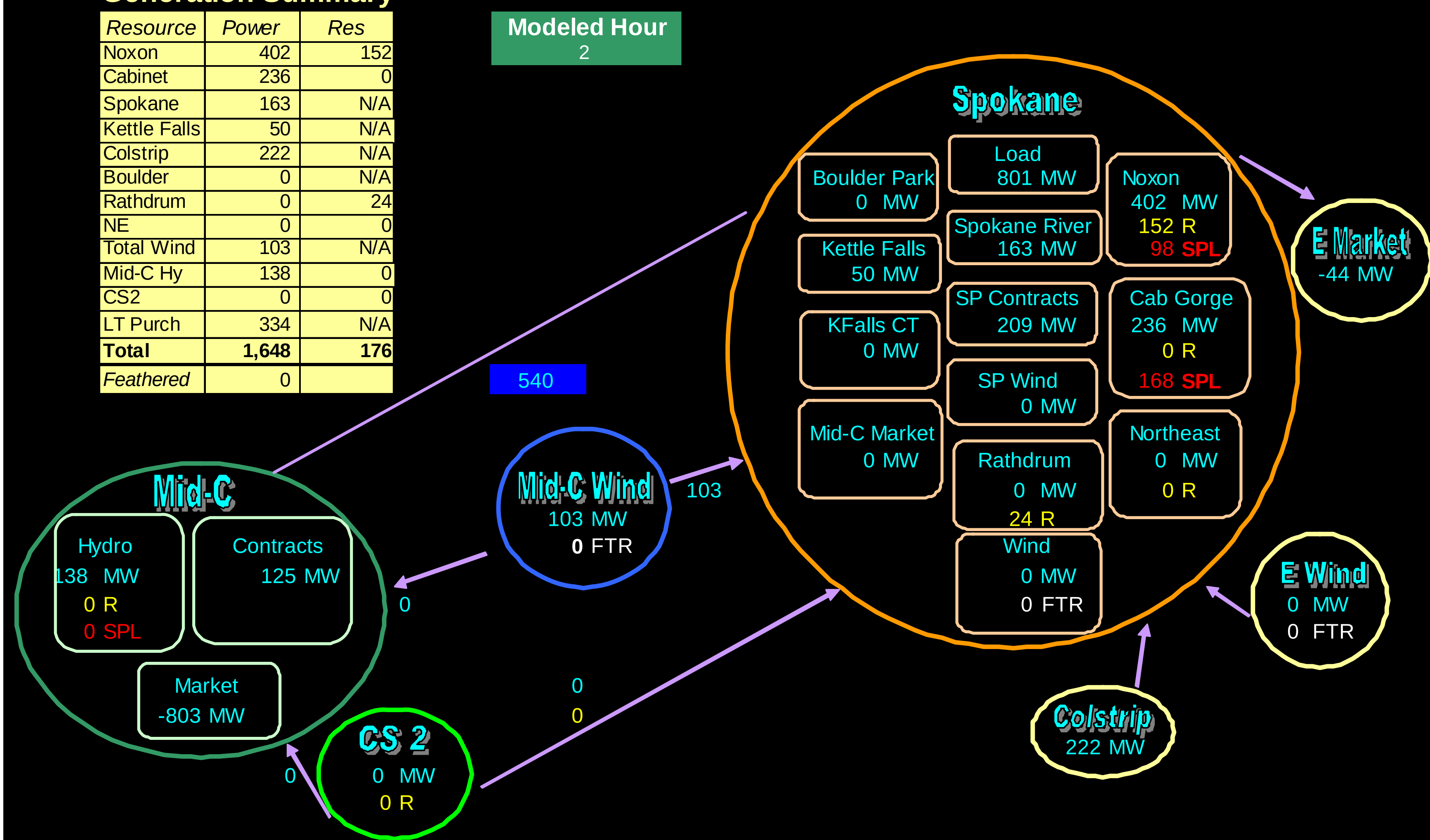
Pre-Schedule Wind Model Delivery Schematic

Generation Summary

Resource	*Power*	*Res*
Noxon	402	152
Cabinet	236	0
Spokane	163	N/A
Kettle Falls	50	N/A
Colstrip	222	N/A
Boulder	0	N/A
Rathdrum	0	24
NE	0	0
Total Wind	103	N/A
Mid-C Hy	138	0
CS2	0	0
LT Purch	334	N/A
Total	**1,648**	**176**
Feathered	0	



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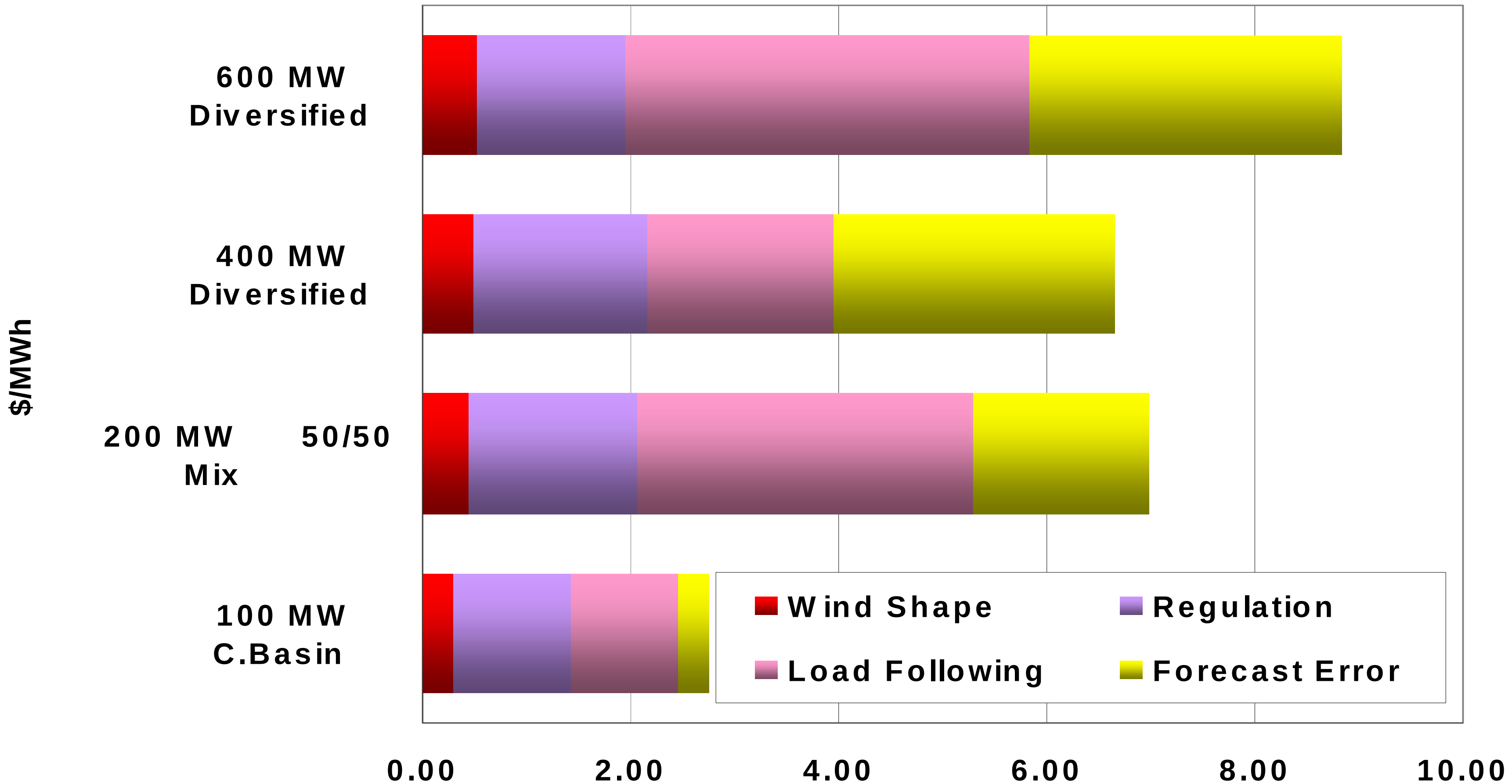
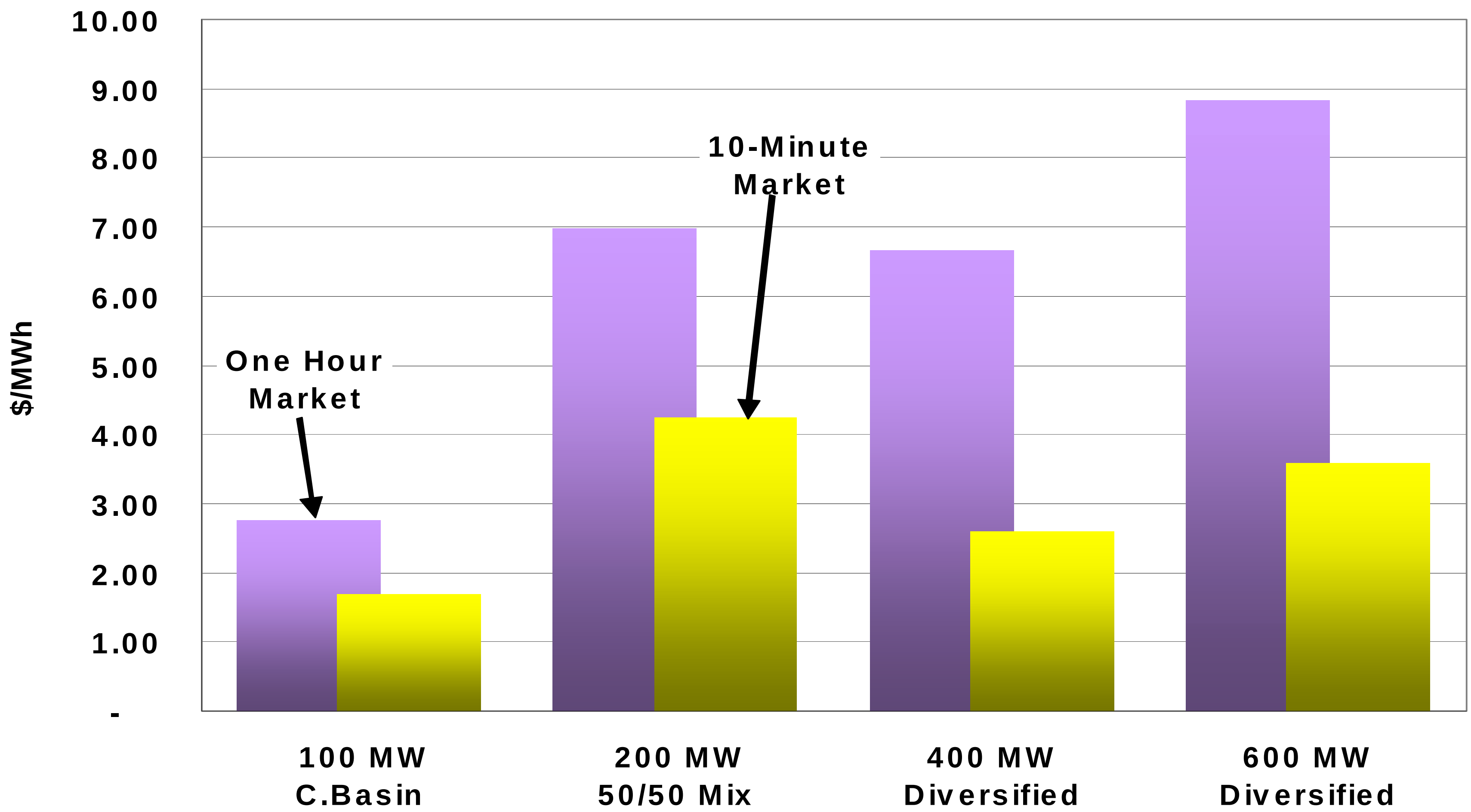
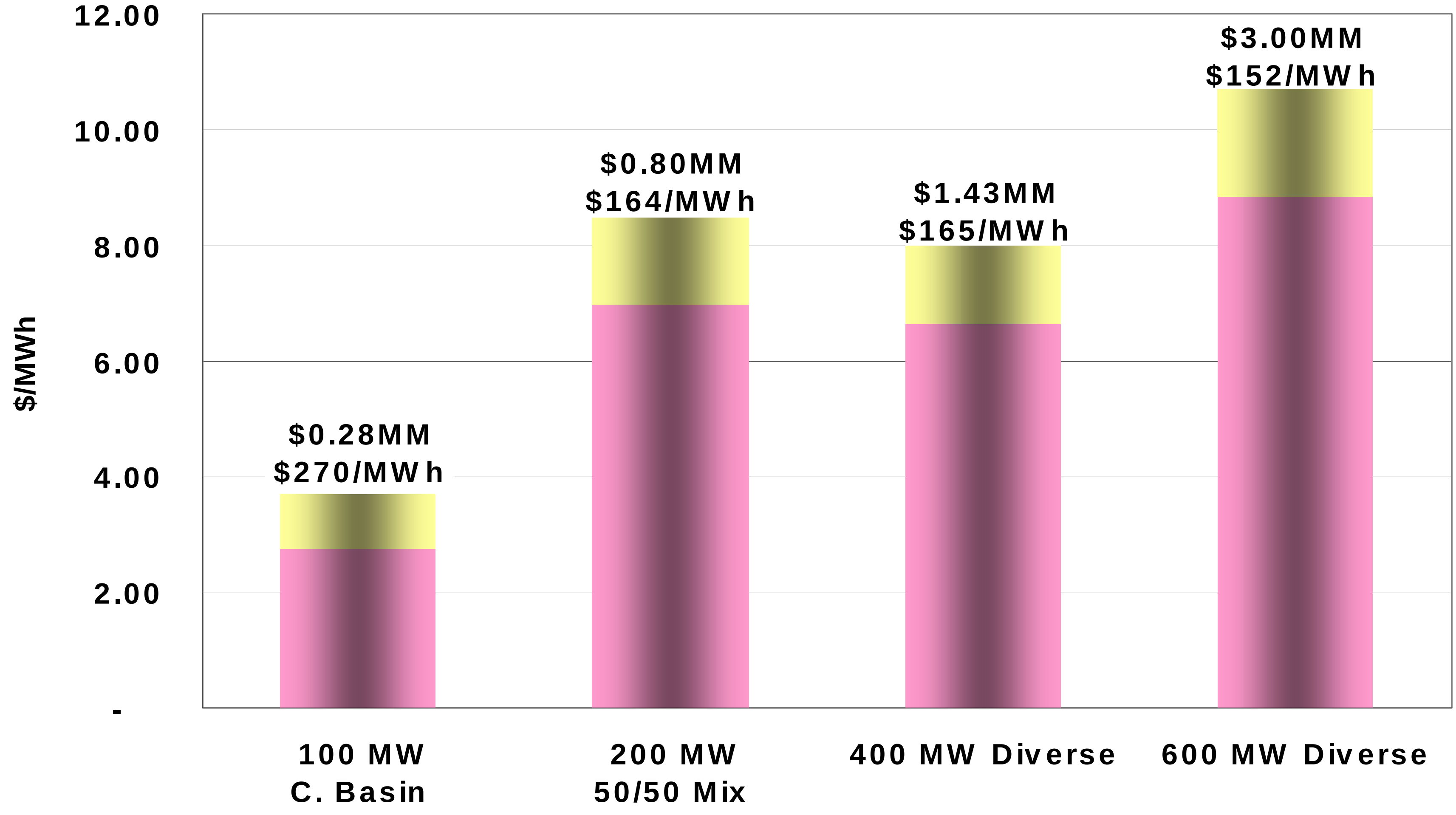
Wind Integration Cost Components



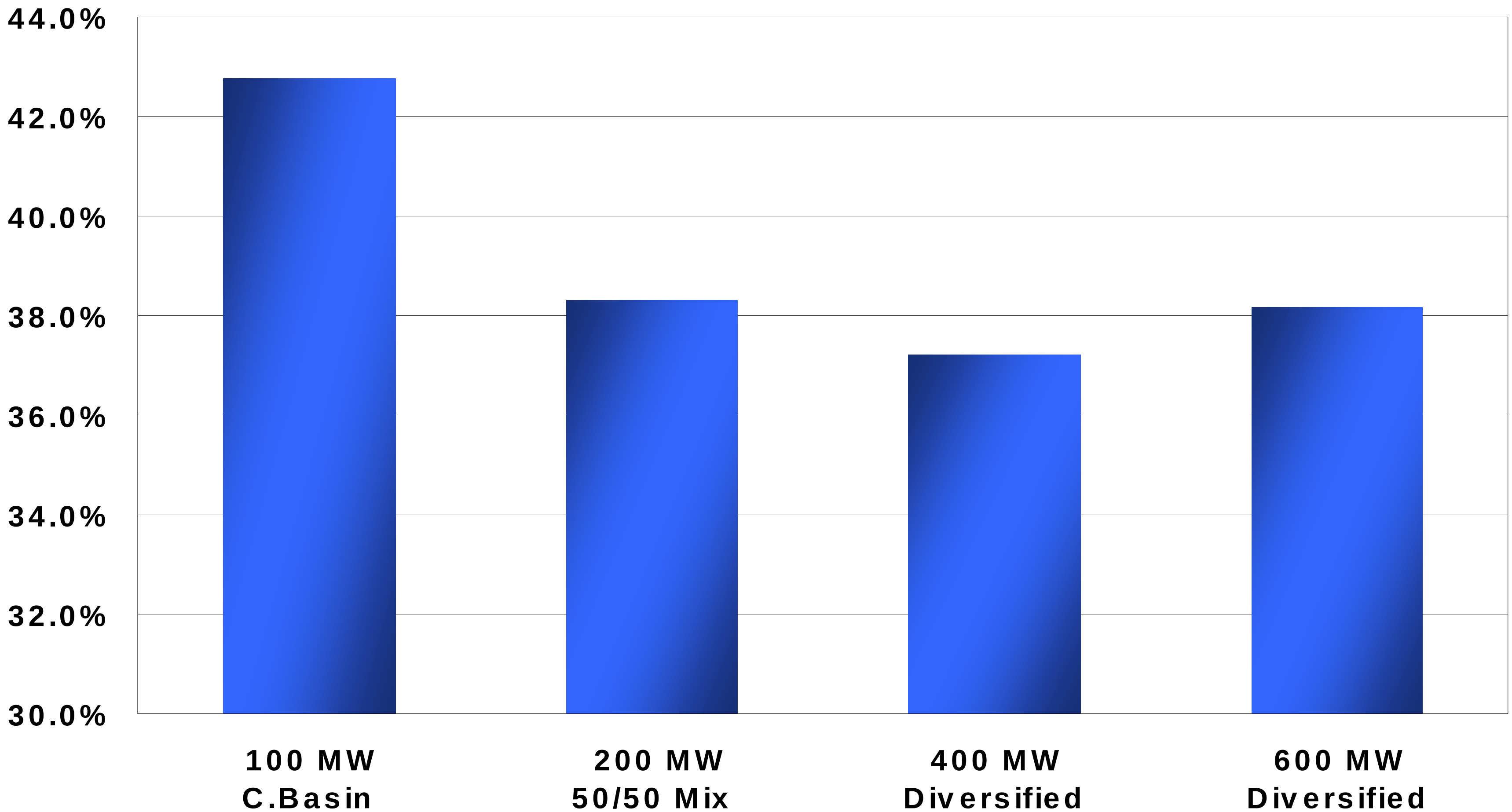
Impact of Shorter Market Time Step



Benefit of Wind Feathering



Hydro Re-Dispatch Costs



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Next Steps/Modeling Enhancements

- **Update With Latest Data**
  - Augment limited NW data sets with data from outside the NW
  - Update to data through 2006
  - Use NPCC/BPA 3-Tier meso-scale wind data when available
- **Evaluate Regulation, Load Following, Forecast Errors Using Root-Mean-Squares Method**
- **Search For Better Wind Forecasting Algorithms**
- **Enhance Start-Up Cost Logic For Thermal Plants**
- **Model Reserve Capabilities of Coal-Fired Plants**
- **Evaluate Real-Time to Pre-Schedule Relationships**

Other Integration Study Results

Wind Integration Study Costs ($US/MWh)					
Entity	Low	High	Entity	Low	High
APS 2007	0.91	4.08	Maritimes (E. Canada) 2007	3.66	6.13
Avista 2007	2.75	9.00	Minnesota 2004	2.25	5.25
BPA 2007	1.90	4.60	Minnesota 2006	3.45	5.10
BPA 2008			Nordic 2004	1.50	3.15
California	0.45		Norway (Greennet)	0.30	0.68
Colorado 2007	4.00	8.00	PacifiCorp 2006	1.86	5.94
Denmark (Greennet)	0.60		Puget Sound Energy	3.73	4.06
Finland (Greennet)	0.30	2.10	Sweden (Greennet)	0.38	0.90
Finland 2004	3.00	4.50	UK 2002	5.10	6.08
Germany (Greennet)	3.23		UK 2007	2.10	5.10
Idaho Power 2007	6.00	9.00	WeEnergies 2003	1.90	2.90
Ireland	0.38	0.75			

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The End

Defining Wind Integration in the 2009 Integrated Resource Plan

Clint Kalich
Manager of Resource Planning & Power Supply Analyses
clint.kalich@avistacorp.com
May 22, 2009

Agenda

10:00 Introductions

10:15 Wind Integration and the 2009 IRP

11:15 Questions/Suggestions for Further Work

12:00 Adjourn

Defining Wind Integration and Its Costs

2009 Integrated Resource Plan

Outline of Presentation

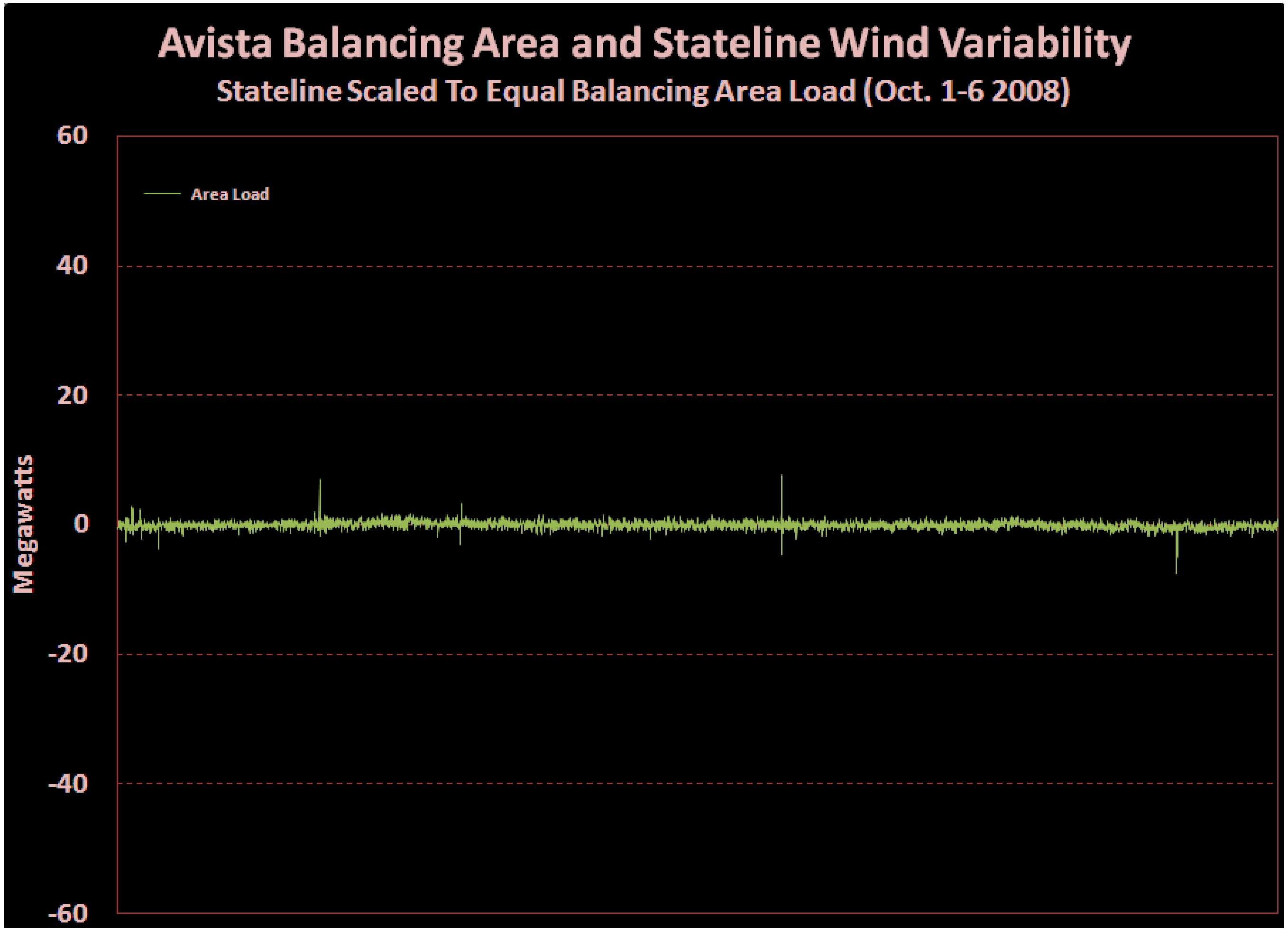
- **Defining Wind Integration**
- **Wind Integration Cost Components**
- **Preferred Resource Strategy Model (PRiSM)**
  - What is PRiSM?
  - The Efficient Frontier
    - covers timeframe from end of regulation up to next ramp (1 hour in WECC)
  - Wind modeling in 2009 IRP
  - Recent enhancements to PRiSM
- **Questions**

Defining Wind Integration

- **Incremental Reserves (Avista Study Method)**
  - Regulation (<1 minute)
  - Load following
    - covers timeframe from end of regulation up to next ramp (1 hour in WECC)
  - Forecast error
    - difference between forecast and actual generation
- **Other Things Sometimes Called Wind Integration**
  - Shape of delivered energy
  - Fuel savings from wind operations
  - Capital costs
  - Environmental attributes

Bottom Line: Be Careful When Assuming 2 Studies are "Apples-to-Apples"

Defining Wind Integration — A Graphical View



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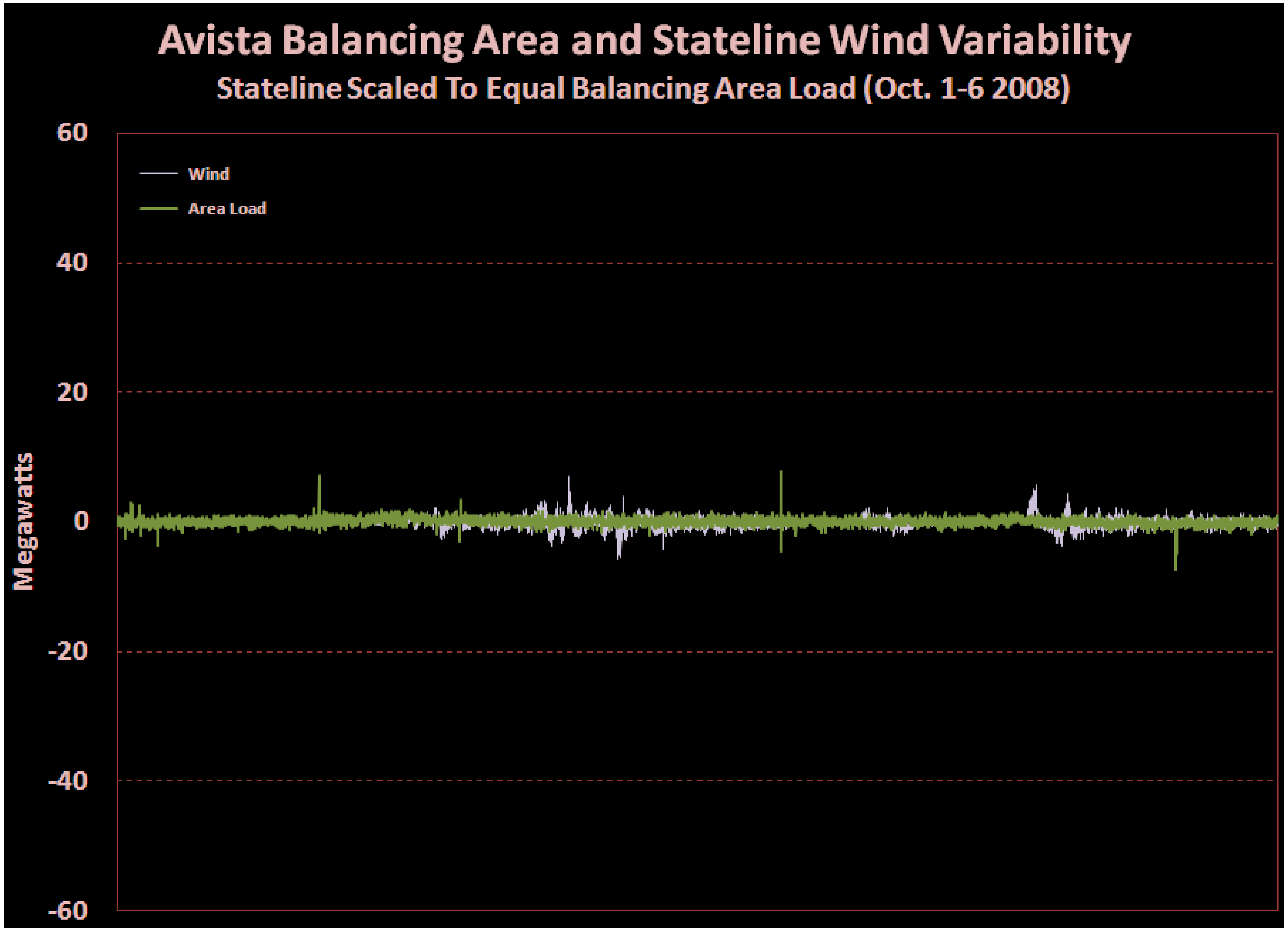
Defining Wind Integration — A Graphical View



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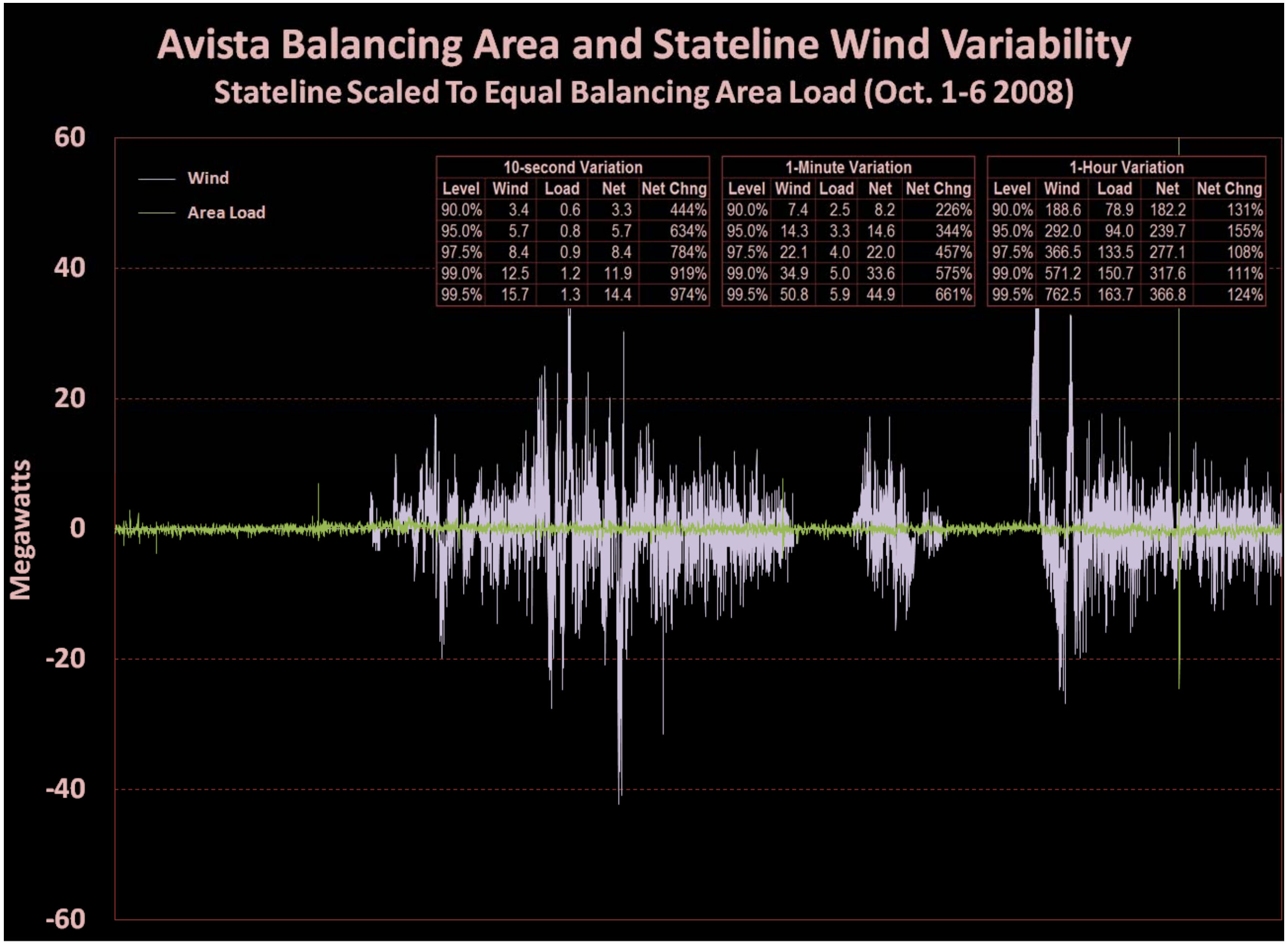
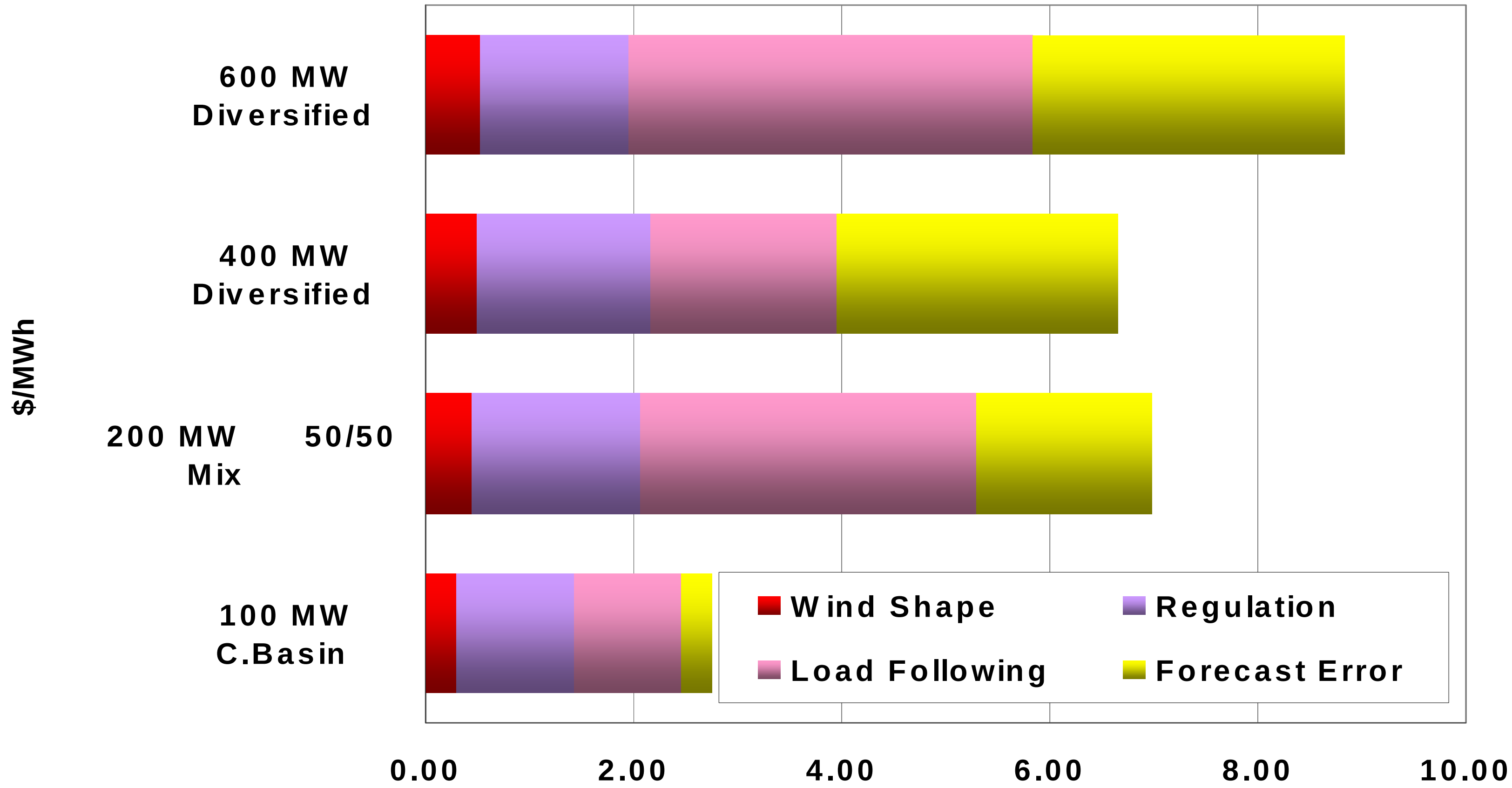
Defining Wind Integration — A Graphical View



Wind Integration Cost Components



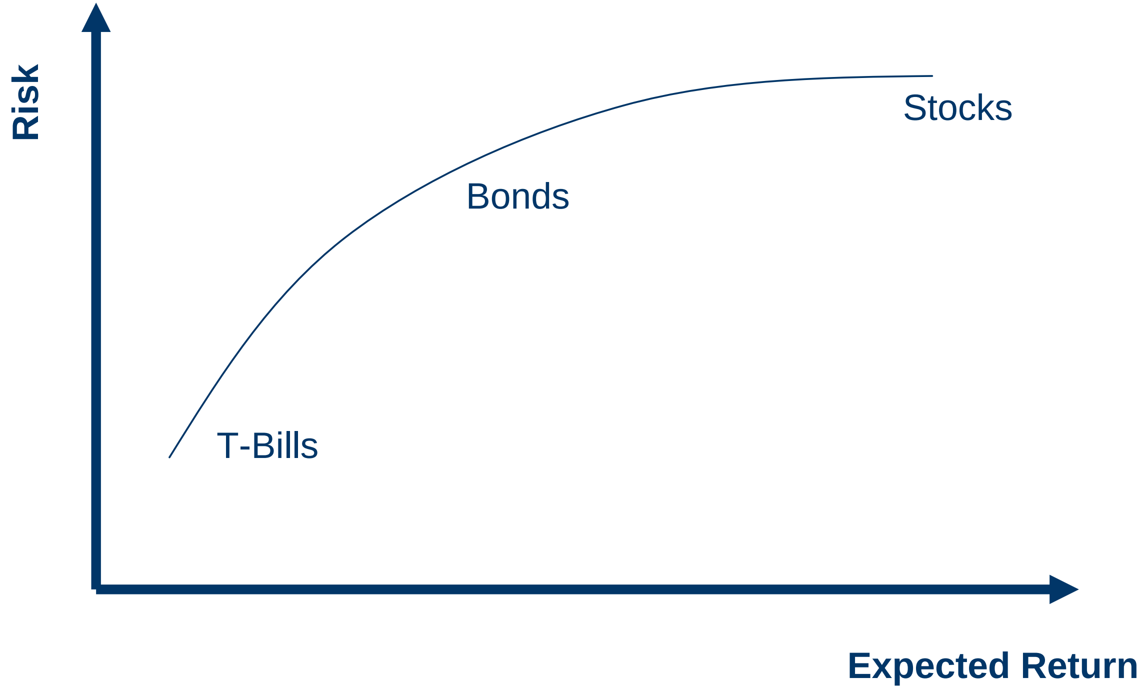
PRiSM
(Preferred Resource Strategy Model)

2009 Integrated Resource Plan

What is PRiSM?

- Preferred Resource Strategy Model
  - *Selects resource & conservation opportunities on an optimal cost and risk basis using a linear program (What's Best!)*
- Objective function is to either select resource strategies to meet our energy/capacity/market/RPS/CO_2 requirements on a least cost and/or least risk basis
- Cost is measured by the present value of incremental fuel & O&M expenses and new capital investment
- Risk is measured by the variation in fuel, emissions, load, wind, forced outages, and variable O&M expenses in years 2019/29

Efficient Frontier- An Introduction 1 (stock portfolios)



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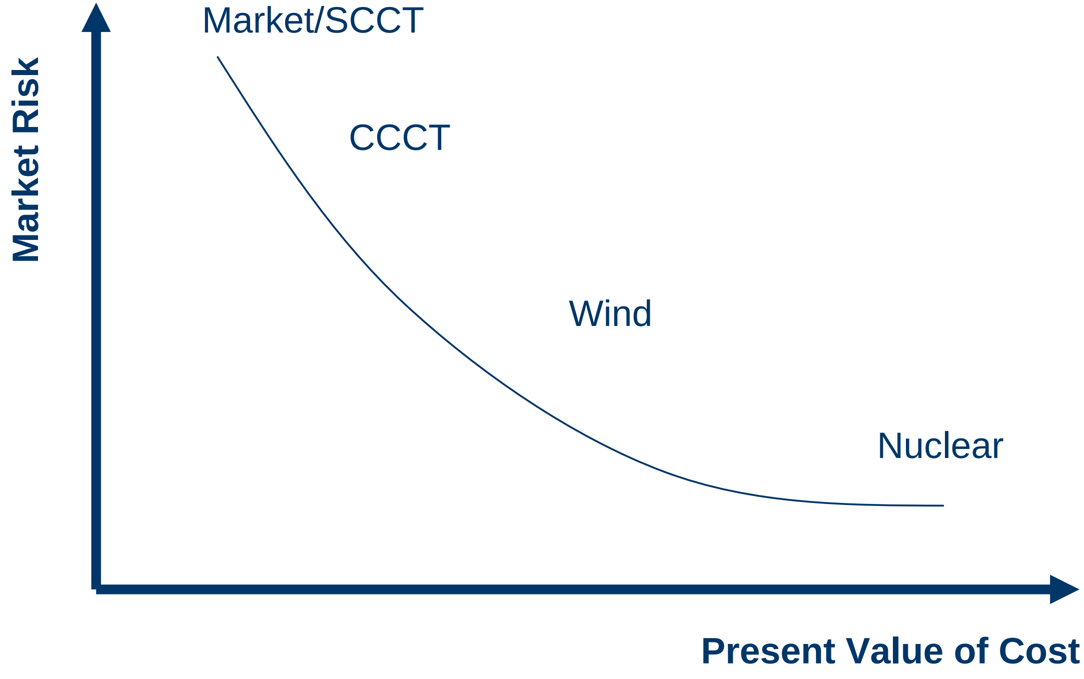
Efficient Frontier- An Introduction (Avista IRP)



Wind Modeling in 2009 IRP

- Various Wind Resource Options
  - *Small wind (DG)*
  - *Northwest Wind (Tier 1 and Tier 2)*
  - *Montana Wind*
  - *Reardan Wind Project*

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

- Wind Integration Cost of $3.50 per MWh (2009$)
  - *Reflective of low penetration rate presently on system*
  - *Rates will rise as penetration increases*

New Enhancements

- Conservation measures are selected in model rather than an input (only measures that are between $xx/MWh & $xxx/MWh)
- Resources are now added in increments rather than any amount
- Use more precise method to estimate frontier curve
- Meets both summer & winter capacity requirements
- Ability to retire resources
- Ability to account for greenhouse gas caps
- More accurate ability to take into account post IRP time period

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Questions/Open Discussion

2009

Electric
Integrated Resource Plan

Appendix B – 2009 Integrated Resource Planning Work Plan

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August 31, 2009

2009 Integrated Resource Planning Work Plan

This Work Plan is provided in response to the WUTC's Integrated Resource Planning (IRP) rules (WAC 480-100-238). It outlines the process Avista will follow to develop its 2009 Integrated Resource Plan to be filed with Washington and Idaho Commissions by August 31, 2009. Avista uses a public process to obtain technical expertise and guidance throughout the planning period through a series of public Technical Advisory Committee (TAC) meetings. The first of these meetings was held on May 14, 2008.

The 2009 Integrated Resource Plan process will be similar to those used to produce the previous three published plans. Avista will be using AURORA^{xmp} for electric market forecasting, resource valuation, and for conducting Monte-Carlo style risk analyses. Results from AURORA^{xmp} will be used to select the Preferred Resource Strategy using the proprietary PRiSM 2.0 model. This tool fills future capacity and energy deficits using an efficient frontier approach to evaluate quantitative portfolio risk versus portfolio cost while accounting for environmental legislation. Qualitative risk will be evaluated in a separate analysis. The process to identify the Preferred Resource Strategy is shown in Exhibit 1 and the process time line is shown in Exhibit 2.

For this plan, Avista intends to use more detailed and site-specific resource assumptions to be determined by an ongoing process to evaluate renewable, gas, and other supply-side resources. This plan will also study environmental costs, sustained peaking requirements, and detailed analyses of demand-side management programs. This IRP will develop a strategy that meets or exceeds renewable portfolio standards and greenhouse gas emissions legislation.

It is Avista's intention to "stress" or test the Preferred Resource Strategy against a variety of scenarios and stochastic futures. The TAC will be an important factor to determine the underlying assumptions used in the scenarios and futures. The IRP process is a very technical and data intensive process; public comments are welcome and will require input in a timely manner for appropriate inclusion into the process so the plan can be submitted according to the contemplated schedule.

Tentative timeline for public Technical Advisory Committee meetings:

- **May 14, 2008 –** Load & resource balance, climate change, loss of load probability analysis, work plan, and analytical process changes
- **August 27, 2008 –** Risk and resource assumptions, scenarios and futures, and demand side management
- **October 22, 2008 –** Load forecast, electric and gas price forecasts, load & resource forecast balance, and transmission cost studies
- **January 28, 2009 –** Review of final modeling and assumptions, and draft PRS
- **March 25, 2009 –** Review of scenarios and futures, and portfolio analysis
- **April 22, 2009 –** Review of final PRS and action items
- **June 24, 2009 –** Review of the 2009 IRP

2009 Electric IRP Draft Outline

This section provides a draft outline of the major sections in the 2009 Electric IRP. This outline will be updated as IRP studies are completed and input from the Technical Advisory Committee has been received.

1. Executive Summary
2. Introduction and Stakeholder Involvement
3. Loads and Resources
    a. Economic Conditions
    b. Load Forecast
    c. Forecast Scenarios
    d. Supply Side Resources
    e. Reserve Margins
    f. Resource Requirements
4. Demand Side Management
5. Environmental Issues
6. Transmission Planning
7. Modeling Approach
    a. Assumptions and Inputs
    b. Risk Modeling
    c. Resource Alternatives
    d. The PRiSM Model
8. Market Modeling Approach
    a. Futures
    b. Scenarios
    c. Avoided Costs
9. Preferred Resource Strategy & Stress Analysis
10. Action Items

Exhibit 1: Avista's 2009 IRP Modeling Process

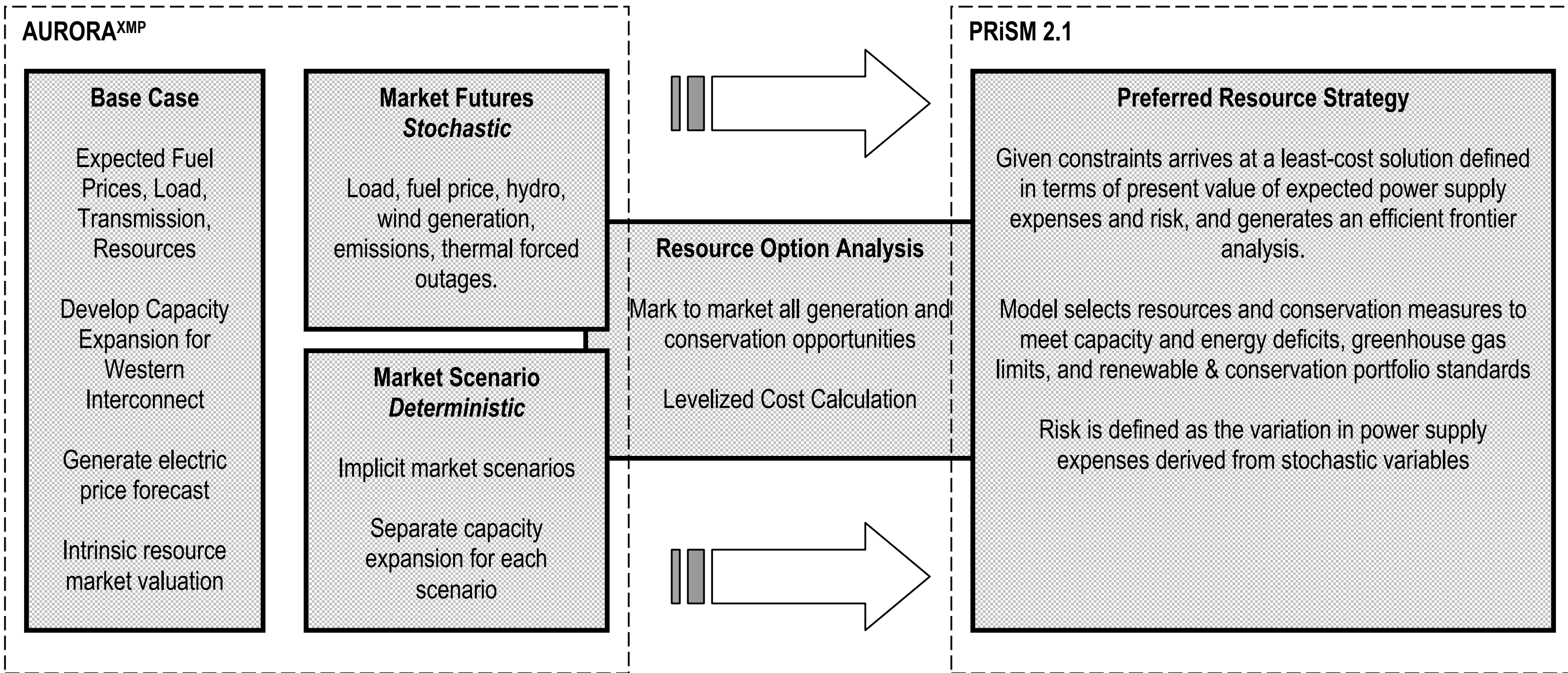


Exhibit 2: Avista's 2009 IRP Timeline

Task	Target Date
Preferred Resource Strategy (PRS)	
Finalize load forecast	7/31/2008
Identify regional resource options for electric market price forecast	8/15/2008
Identify Avista's supply & conservation resource options	8/31/2008
Update AURORA^{xmp} database for electric market price forecast	9/29/2008
Select natural gas price forecast	9/29/2008
Finalize deterministic base case	10/17/2008
Finalize datasets/statistics variables for risk studies	10/31/2008
Draft transmission study due	10/31/2008
Demand-side management load shapes input into AURORA	10/31/2008
Base case stochastic study complete	11/30/2008
Finalize PRiSM 2.1 model	12/19/2008
Final transmission study due	12/31/2008
Develop efficient frontier & PRS	1/30/2009
Simulation of risk studies "futures" complete	2/10/2009
Simulate market scenarios in AURORA^{xmp}	2/27/2009
Evaluate resource strategies against market futures & scenarios	3/20/2009
Present to TAC preliminary study and PRS	3/31/2009
Writing Tasks	
File 2009 integrated resource planning work plan	8/30/2008
Prepare report and appendix outline	9/15/2008
Prepare text drafts	4/15/2009
Prepare charts and tables	4/15/2009
Internal draft released	5/1/2009
External draft released	6/15/2009
Final editing and printing	8/1/2009
Final report distribution	8/30/2009

2009

Electric Integrated Resource Plan

Appendix C – Residential and Non-residential Load Profiles

August 31, 2009

Load Shape	Description
1	Res Space Heat
2	Res AC
3	Res Lighting
4	Res Refrigeration
5	Res Water Heating
6	Res Dishwasher
7	Res Washer Dryer
8	Res Misc
9	Res Furnace Fan
10	NonRes Comp Air
11	NonRes Cooking
12	NonRes Space Cooling
13	NonRes Ext Lighting
14	NonRes Space Heating
15	NonRes Water Heating
16	NonRes Int Lighting
17	NonRes Misc
18	NonRes Motors
19	NonRes Office Equipment
20	NonRes Process
21	NonRes Refrigeration
22	NonRes Ventillation
23	Flat
24	NonRes Space Heat/Cool
25	NonRes Space Heat/Cool/Vent
26	NonRes LEED
27	NonRes Refrigerated Warehouses
28	Traffic Signal Red
29	Traffic Signal Green
30	Renewables
31	Multifamily Market Transformation
32	Res Heat/Cool
33	Res Energy Star Homes

2009

Electric Integrated Resource Plan

Appendix D – DSM Concepts Reaching the Evaluation Stage

August 31, 2009

Segment	Measure
Non-Res	Anti-Sweat Heat Controls
Non-Res	Auto-Closers for Coolers and Freezers
Non-Res	Built-Up HVAC Controls Optimization-Anchor-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Anchor-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Anchor-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Big Box-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Big Box-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Big Box-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-High End-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-High End-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-High End-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Hospital-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Hospital-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Hospital-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-K-12-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-K-12-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-K-12-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Large Off-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Large Off-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Large Off-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Lodging-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Lodging-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Lodging-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Medium Off-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Medium Off-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Medium Off-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-MIniMart-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-MIniMart-GasHt-Retro

Non-Res	Built-Up HVAC Controls Optimization-Other-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Other-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-OtherHealth-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-OtherHealth-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-OtherHealth-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Other-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Restaurant-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Restaurant-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Restaurant-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Small Box-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Small Box-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Small Box-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Small Off-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Small Off-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Small Off-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Supermarket-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Supermarket-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Supermarket-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-University-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-University-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-University-HtPmpHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Warehouse-ElecHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Warehouse-GasHt-Retro
Non-Res	Built-Up HVAC Controls Optimization-Warehouse-HtPmpHt-Retro
Non-Res	Controls Commission-New
Non-Res	EE Ice Maker from FEMP Baseline
Non-Res	EE Reach-In Freezer from E-Star Baseline
Non-Res	EE Reach-In Refrigerator from E-Star Baseline
Non-Res	EE Vending Machine from Average Baseline
Non-Res	EE Vending Machine from E-Star Baseline
Non-Res	Evaporative fan controller on walk-in
Non-Res	F96T12 to T8HP-Anchor-New-GasHt

Non-Res	F96T12 to T8HP-Anchor-Retro-ElecHt-PRE1987
Non-Res	F96T12 to T8HP-Anchor-Retro-ElecHt-V1987_1994
Non-Res	F96T12 to T8HP-Anchor-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-Anchor-Retro-GasHt-PRE1987
Non-Res	F96T12 to T8HP-Anchor-Retro-GasHt-V1987_1994
Non-Res	F96T12 to T8HP-Anchor-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-Anchor-Retro-HtPmpHt-PRE1987
Non-Res	F96T12 to T8HP-Anchor-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12 to T8HP-Anchor-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-Big Box-Retro-ElecHt-V1987_1994
Non-Res	F96T12 to T8HP-Big Box-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-Big Box-Retro-GasHt-V1987_1994
Non-Res	F96T12 to T8HP-Big Box-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-Big Box-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12 to T8HP-Big Box-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-High End-Retro-ElecHt-V1987_1994
Non-Res	F96T12 to T8HP-High End-Retro-GasHt-V1987_1994
Non-Res	F96T12 to T8HP-High End-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12 to T8HP-Hospital-New-GasHt
Non-Res	F96T12 to T8HP-Hospital-Retro-ElecHt-PRE1987
Non-Res	F96T12 to T8HP-Hospital-Retro-ElecHt-V1987_1994
Non-Res	F96T12 to T8HP-Hospital-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-Hospital-Retro-GasHt-PRE1987
Non-Res	F96T12 to T8HP-Hospital-Retro-GasHt-V1987_1994
Non-Res	F96T12 to T8HP-Hospital-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-Hospital-Retro-HtPmpHt-PRE1987
Non-Res	F96T12 to T8HP-Hospital-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12 to T8HP-Hospital-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-K-12-Retro-ElecHt-V1995_2001

Non-Res	F96T12 to T8HP-K-12-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-K-12-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-Large Off-Retro-ElecHt-PRE1987
Non-Res	F96T12 to T8HP-Large Off-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-Large Off-Retro-GasHt-PRE1987
Non-Res	F96T12 to T8HP-Large Off-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-Large Off-Retro-HtPmpHt-PRE1987
Non-Res	F96T12 to T8HP-Large Off-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-Lodging-New-GasHt
Non-Res	F96T12 to T8HP-Lodging-Retro-ElecHt-PRE1987
Non-Res	F96T12 to T8HP-Lodging-Retro-ElecHt-V1987_1994
Non-Res	F96T12 to T8HP-Lodging-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-Lodging-Retro-GasHt-PRE1987
Non-Res	F96T12 to T8HP-Lodging-Retro-GasHt-V1987_1994
Non-Res	F96T12 to T8HP-Lodging-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-Lodging-Retro-HtPmpHt-PRE1987
Non-Res	F96T12 to T8HP-Lodging-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12 to T8HP-Lodging-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-Medium Off-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-Medium Off-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-Medium Off-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-MIniMart-New-GasHt
Non-Res	F96T12 to T8HP-MIniMart-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-MIniMart-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-MIniMart-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-OtherHealth-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-OtherHealth-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-OtherHealth-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-Other-Retro-ElecHt-PRE1987
Non-Res	F96T12 to T8HP-Other-Retro-ElecHt-V1987_1994

Non-Res	F96T12 to T8HP-Other-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-Other-Retro-GasHt-PRE1987
Non-Res	F96T12 to T8HP-Other-Retro-GasHt-V1987_1994
Non-Res	F96T12 to T8HP-Other-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-Other-Retro-HtPmpHt-PRE1987
Non-Res	F96T12 to T8HP-Other-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12 to T8HP-Other-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-Restaurant-New-GasHt
Non-Res	F96T12 to T8HP-Restaurant-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-Restaurant-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-Restaurant-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-Small Box-New-GasHt
Non-Res	F96T12 to T8HP-Small Box-Retro-ElecHt-PRE1987
Non-Res	F96T12 to T8HP-Small Box-Retro-ElecHt-V1987_1994
Non-Res	F96T12 to T8HP-Small Box-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-Small Box-Retro-GasHt-PRE1987
Non-Res	F96T12 to T8HP-Small Box-Retro-GasHt-V1987_1994
Non-Res	F96T12 to T8HP-Small Box-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-Small Box-Retro-HtPmpHt-PRE1987
Non-Res	F96T12 to T8HP-Small Box-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12 to T8HP-Small Box-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-Small Off-New-GasHt
Non-Res	F96T12 to T8HP-Small Off-Retro-ElecHt-V1987_1994
Non-Res	F96T12 to T8HP-Small Off-Retro-GasHt-V1987_1994
Non-Res	F96T12 to T8HP-Small Off-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12 to T8HP-Supermarket-New-GasHt
Non-Res	F96T12 to T8HP-Supermarket-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-Supermarket-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-Supermarket-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-University-Retro-ElecHt-PRE1987
Non-Res	F96T12 to T8HP-University-Retro-ElecHt-V1995_2001

Non-Res	F96T12 to T8HP-University-Retro-GasHt-PRE1987
Non-Res	F96T12 to T8HP-University-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-University-Retro-HtPmpHt-PRE1987
Non-Res	F96T12 to T8HP-University-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12 to T8HP-Warehouse-New-GasHt
Non-Res	F96T12 to T8HP-Warehouse-Retro-ElecHt-PRE1987
Non-Res	F96T12 to T8HP-Warehouse-Retro-ElecHt-V1987_1994
Non-Res	F96T12 to T8HP-Warehouse-Retro-ElecHt-V1995_2001
Non-Res	F96T12 to T8HP-Warehouse-Retro-GasHt-PRE1987
Non-Res	F96T12 to T8HP-Warehouse-Retro-GasHt-V1987_1994
Non-Res	F96T12 to T8HP-Warehouse-Retro-GasHt-V1995_2001
Non-Res	F96T12 to T8HP-Warehouse-Retro-HtPmpHt-PRE1987
Non-Res	F96T12 to T8HP-Warehouse-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12 to T8HP-Warehouse-Retro-HtPmpHt-V1995_2001
Non-Res	F96T12VHO to T8HP-4-K-12-Retro-ElecHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-K-12-Retro-ElecHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-K-12-Retro-GasHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-K-12-Retro-GasHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-K-12-Retro-HtPmpHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-K-12-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Large Off-Retro-ElecHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Large Off-Retro-GasHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Large Off-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Medium Off-Retro-ElecHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-Medium Off-Retro-ElecHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Medium Off-Retro-GasHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-Medium Off-Retro-GasHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Medium Off-Retro-HtPmpHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-Medium Off-Retro-HtPmpHt-V1987_1994

Non-Res	F96T12VHO to T8HP-4-MIniMart-Retro-ElecHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-MIniMart-Retro-GasHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-MIniMart-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Small Off-Retro-ElecHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-Small Off-Retro-ElecHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Small Off-Retro-GasHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-Small Off-Retro-GasHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Small Off-Retro-HtPmpHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-Small Off-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Supermarket-Retro-ElecHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Supermarket-Retro-GasHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Supermarket-Retro-HtPmpHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Warehouse-Retro-ElecHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-Warehouse-Retro-ElecHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Warehouse-Retro-GasHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-Warehouse-Retro-GasHt-V1987_1994
Non-Res	F96T12VHO to T8HP-4-Warehouse-Retro-HtPmpHt-PRE1987
Non-Res	F96T12VHO to T8HP-4-Warehouse-Retro-HtPmpHt-V1987_1994
Non-Res	Floating Head Pressure Controller
Non-Res	Glass Doors on Open Display Cases (LT)
Non-Res	Glass Doors on Open Display Cases (MT)
Non-Res	INC to CFL-Hospital-New-ElecHt
Non-Res	INC to CFL-Hospital-New-GasHt
Non-Res	INC to CFL-Hospital-New-HtPmpHt
Non-Res	INC to CFL-Hospital-Retro-ElecHt-PRE1987
Non-Res	INC to CFL-Hospital-Retro-ElecHt-V1987_1994
Non-Res	INC to CFL-Hospital-Retro-ElecHt-V1995_2001
Non-Res	INC to CFL-Hospital-Retro-GasHt-PRE1987
Non-Res	INC to CFL-Hospital-Retro-GasHt-V1987_1994
Non-Res	INC to CFL-Hospital-Retro-GasHt-V1995_2001
Non-Res	INC to CFL-Hospital-Retro-HtPmpHt-PRE1987
Non-Res	INC to CFL-Hospital-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CFL-Hospital-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CFL-K-12-New-ElecHt
Non-Res	INC to CFL-K-12-New-GasHt
Non-Res	INC to CFL-K-12-New-HtPmpHt
Non-Res	INC to CFL-K-12-Retro-ElecHt-PRE1987

Non-Res	INC to CFL-K-12-Retro-ElecHt-V1987_1994
Non-Res	INC to CFL-K-12-Retro-ElecHt-V1995_2001
Non-Res	INC to CFL-K-12-Retro-GasHt-PRE1987
Non-Res	INC to CFL-K-12-Retro-GasHt-V1987_1994
Non-Res	INC to CFL-K-12-Retro-GasHt-V1995_2001
Non-Res	INC to CFL-K-12-Retro-HtPmpHt-PRE1987
Non-Res	INC to CFL-K-12-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CFL-K-12-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CFL-Large Off-New-ElecHt
Non-Res	INC to CFL-Large Off-New-GasHt
Non-Res	INC to CFL-Large Off-New-HtPmpHt
Non-Res	INC to CFL-Large Off-Retro-ElecHt-PRE1987
Non-Res	INC to CFL-Large Off-Retro-ElecHt-V1987_1994
Non-Res	INC to CFL-Large Off-Retro-ElecHt-V1995_2001
Non-Res	INC to CFL-Large Off-Retro-GasHt-PRE1987
Non-Res	INC to CFL-Large Off-Retro-GasHt-V1987_1994
Non-Res	INC to CFL-Large Off-Retro-GasHt-V1995_2001
Non-Res	INC to CFL-Large Off-Retro-HtPmpHt-PRE1987
Non-Res	INC to CFL-Large Off-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CFL-Large Off-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CFL-Lodging-New-ElecHt
Non-Res	INC to CFL-Lodging-New-GasHt
Non-Res	INC to CFL-Lodging-New-HtPmpHt
Non-Res	INC to CFL-Lodging-Retro-ElecHt-PRE1987
Non-Res	INC to CFL-Lodging-Retro-ElecHt-V1987_1994
Non-Res	INC to CFL-Lodging-Retro-ElecHt-V1995_2001
Non-Res	INC to CFL-Lodging-Retro-GasHt-PRE1987
Non-Res	INC to CFL-Lodging-Retro-GasHt-V1987_1994
Non-Res	INC to CFL-Lodging-Retro-GasHt-V1995_2001
Non-Res	INC to CFL-Lodging-Retro-HtPmpHt-PRE1987
Non-Res	INC to CFL-Lodging-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CFL-Lodging-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CFL-Medium Off-New-ElecHt
Non-Res	INC to CFL-Medium Off-New-GasHt
Non-Res	INC to CFL-Medium Off-New-HtPmpHt
Non-Res	INC to CFL-Medium Off-Retro-ElecHt-PRE1987
Non-Res	INC to CFL-Medium Off-Retro-ElecHt-V1987_1994
Non-Res	INC to CFL-Medium Off-Retro-ElecHt-V1995_2001
Non-Res	INC to CFL-Medium Off-Retro-GasHt-PRE1987
Non-Res	INC to CFL-Medium Off-Retro-GasHt-V1987_1994
Non-Res	INC to CFL-Medium Off-Retro-GasHt-V1995_2001
Non-Res	INC to CFL-Medium Off-Retro-HtPmpHt-PRE1987
Non-Res	INC to CFL-Medium Off-Retro-HtPmpHt-V1987_1994

Non-Res	INC to CFL-Medium Off-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CFL-OtherHealth-New-ElecHt
Non-Res	INC to CFL-OtherHealth-New-GasHt
Non-Res	INC to CFL-OtherHealth-New-HtPmpHt
Non-Res	INC to CFL-OtherHealth-Retro-ElecHt-PRE1987
Non-Res	INC to CFL-OtherHealth-Retro-ElecHt-V1987_1994
Non-Res	INC to CFL-OtherHealth-Retro-ElecHt-V1995_2001
Non-Res	INC to CFL-OtherHealth-Retro-GasHt-PRE1987
Non-Res	INC to CFL-OtherHealth-Retro-GasHt-V1987_1994
Non-Res	INC to CFL-OtherHealth-Retro-GasHt-V1995_2001
Non-Res	INC to CFL-OtherHealth-Retro-HtPmpHt-PRE1987
Non-Res	INC to CFL-OtherHealth-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CFL-OtherHealth-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CFL-Other-New-ElecHt
Non-Res	INC to CFL-Other-New-GasHt
Non-Res	INC to CFL-Other-New-HtPmpHt
Non-Res	INC to CFL-Other-Retro-ElecHt-PRE1987
Non-Res	INC to CFL-Other-Retro-ElecHt-V1995_2001
Non-Res	INC to CFL-Other-Retro-GasHt-PRE1987
Non-Res	INC to CFL-Other-Retro-GasHt-V1995_2001
Non-Res	INC to CFL-Other-Retro-HtPmpHt-PRE1987
Non-Res	INC to CFL-Other-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CFL-Restaurant-New-ElecHt
Non-Res	INC to CFL-Restaurant-New-GasHt
Non-Res	INC to CFL-Restaurant-New-HtPmpHt
Non-Res	INC to CFL-Restaurant-Retro-ElecHt-PRE1987
Non-Res	INC to CFL-Restaurant-Retro-ElecHt-V1987_1994
Non-Res	INC to CFL-Restaurant-Retro-ElecHt-V1995_2001
Non-Res	INC to CFL-Restaurant-Retro-GasHt-PRE1987
Non-Res	INC to CFL-Restaurant-Retro-GasHt-V1987_1994
Non-Res	INC to CFL-Restaurant-Retro-GasHt-V1995_2001
Non-Res	INC to CFL-Restaurant-Retro-HtPmpHt-PRE1987
Non-Res	INC to CFL-Restaurant-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CFL-Restaurant-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CFL-Small Off-New-ElecHt
Non-Res	INC to CFL-Small Off-New-GasHt
Non-Res	INC to CFL-Small Off-New-HtPmpHt
Non-Res	INC to CFL-Small Off-Retro-ElecHt-PRE1987
Non-Res	INC to CFL-Small Off-Retro-ElecHt-V1987_1994
Non-Res	INC to CFL-Small Off-Retro-ElecHt-V1995_2001

Non-Res	INC to CFL-Small Off-Retro-GasHt-PRE1987
Non-Res	INC to CFL-Small Off-Retro-GasHt-V1987_1994
Non-Res	INC to CFL-Small Off-Retro-GasHt-V1995_2001
Non-Res	INC to CFL-Small Off-Retro-HtPmpHt-PRE1987
Non-Res	INC to CFL-Small Off-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CFL-Small Off-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CFL-University-Retro-ElecHt-PRE1987
Non-Res	INC to CFL-University-Retro-ElecHt-V1995_2001
Non-Res	INC to CFL-University-Retro-GasHt-PRE1987
Non-Res	INC to CFL-University-Retro-GasHt-V1995_2001
Non-Res	INC to CFL-University-Retro-HtPmpHt-PRE1987
Non-Res	INC to CFL-University-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CFL-Warehouse-New-ElecHt
Non-Res	INC to CFL-Warehouse-New-GasHt
Non-Res	INC to CFL-Warehouse-New-HtPmpHt
Non-Res	INC to CFL-Warehouse-Retro-ElecHt-V1995_2001
Non-Res	INC to CFL-Warehouse-Retro-GasHt-V1995_2001
Non-Res	INC to CFL-Warehouse-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CMH-Anchor-Retro-ElecHt-V1987_1994
Non-Res	INC to CMH-Anchor-Retro-GasHt-V1987_1994
Non-Res	INC to CMH-Anchor-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CMH-Big Box-New-ElecHt
Non-Res	INC to CMH-Big Box-New-GasHt
Non-Res	INC to CMH-Big Box-New-HtPmpHt
Non-Res	INC to CMH-Big Box-Retro-ElecHt-V1995_2001
Non-Res	INC to CMH-Big Box-Retro-GasHt-V1995_2001
Non-Res	INC to CMH-Big Box-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CMH-High End-New-ElecHt
Non-Res	INC to CMH-High End-New-GasHt
Non-Res	INC to CMH-High End-New-HtPmpHt
Non-Res	INC to CMH-High End-Retro-ElecHt-PRE1987
Non-Res	INC to CMH-High End-Retro-ElecHt-V1987_1994
Non-Res	INC to CMH-High End-Retro-ElecHt-V1995_2001
Non-Res	INC to CMH-High End-Retro-GasHt-PRE1987
Non-Res	INC to CMH-High End-Retro-GasHt-V1987_1994
Non-Res	INC to CMH-High End-Retro-GasHt-V1995_2001
Non-Res	INC to CMH-High End-Retro-HtPmpHt-PRE1987
Non-Res	INC to CMH-High End-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CMH-High End-Retro-HtPmpHt-V1995_2001

Non-Res	INC to CMH-MIniMart-New-ElecHt
Non-Res	INC to CMH-MIniMart-New-GasHt
Non-Res	INC to CMH-MIniMart-New-HtPmpHt
Non-Res	INC to CMH-MIniMart-Retro-ElecHt-PRE1987
Non-Res	INC to CMH-MIniMart-Retro-ElecHt-V1987_1994
Non-Res	INC to CMH-MIniMart-Retro-ElecHt-V1995_2001
Non-Res	INC to CMH-MIniMart-Retro-GasHt-PRE1987
Non-Res	INC to CMH-MIniMart-Retro-GasHt-V1987_1994
Non-Res	INC to CMH-MIniMart-Retro-GasHt-V1995_2001
Non-Res	INC to CMH-MIniMart-Retro-HtPmpHt-PRE1987
Non-Res	INC to CMH-MIniMart-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CMH-MIniMart-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CMH-Small Box-New-ElecHt
Non-Res	INC to CMH-Small Box-New-GasHt
Non-Res	INC to CMH-Small Box-New-HtPmpHt
Non-Res	INC to CMH-Small Box-Retro-ElecHt-V1987_1994
Non-Res	INC to CMH-Small Box-Retro-ElecHt-V1995_2001
Non-Res	INC to CMH-Small Box-Retro-GasHt-V1987_1994
Non-Res	INC to CMH-Small Box-Retro-GasHt-V1995_2001
Non-Res	INC to CMH-Small Box-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CMH-Small Box-Retro-HtPmpHt-V1995_2001
Non-Res	INC to CMH-Supermarket-Retro-ElecHt-PRE1987
Non-Res	INC to CMH-Supermarket-Retro-ElecHt-V1987_1994
Non-Res	INC to CMH-Supermarket-Retro-GasHt-PRE1987
Non-Res	INC to CMH-Supermarket-Retro-GasHt-V1987_1994
Non-Res	INC to CMH-Supermarket-Retro-HtPmpHt-PRE1987
Non-Res	INC to CMH-Supermarket-Retro-HtPmpHt-V1987_1994
Non-Res	INC to CMH-University-New-ElecHt
Non-Res	INC to CMH-University-New-GasHt
Non-Res	INC to CMH-University-New-HtPmpHt
Non-Res	Large MH to T5HO-Big Box-New-ElecHt
Non-Res	Large MH to T5HO-Big Box-New-GasHt
Non-Res	Large MH to T5HO-Big Box-New-HtPmpHt
Non-Res	Large MH to T5HO-Big Box-Retro-ElecHt-PRE1987
Non-Res	Large MH to T5HO-Big Box-Retro-ElecHt-V1987_1994
Non-Res	Large MH to T5HO-Big Box-Retro-ElecHt-V1995_2001
Non-Res	Large MH to T5HO-Big Box-Retro-GasHt-PRE1987
Non-Res	Large MH to T5HO-Big Box-Retro-GasHt-V1987_1994

Non-Res	Large MH to T5HO-Big Box-Retro-GasHt-V1995_2001
Non-Res	Large MH to T5HO-Big Box-Retro-HtPmpHt-PRE1987
Non-Res	Large MH to T5HO-Big Box-Retro-HtPmpHt-V1987_1994
Non-Res	Large MH to T5HO-Big Box-Retro-HtPmpHt-V1995_2001
Non-Res	Large MH to T5HO-Other-New-ElecHt
Non-Res	Large MH to T5HO-Other-New-GasHt
Non-Res	Large MH to T5HO-Other-New-HtPmpHt
Non-Res	Large MH to T5HO-Other-Retro-ElecHt-PRE1987
Non-Res	Large MH to T5HO-Other-Retro-ElecHt-V1987_1994
Non-Res	Large MH to T5HO-Other-Retro-GasHt-PRE1987
Non-Res	Large MH to T5HO-Other-Retro-GasHt-V1987_1994
Non-Res	Large MH to T5HO-Other-Retro-HtPmpHt-PRE1987
Non-Res	Large MH to T5HO-Other-Retro-HtPmpHt-V1987_1994
Non-Res	Large MH to T5HO-Warehouse-New-ElecHt
Non-Res	Large MH to T5HO-Warehouse-New-GasHt
Non-Res	Large MH to T5HO-Warehouse-New-HtPmpHt
Non-Res	Large MH to T5HO-Warehouse-Retro-ElecHt-PRE1987
Non-Res	Large MH to T5HO-Warehouse-Retro-ElecHt-V1987_1994
Non-Res	Large MH to T5HO-Warehouse-Retro-ElecHt-V1995_2001
Non-Res	Large MH to T5HO-Warehouse-Retro-GasHt-PRE1987
Non-Res	Large MH to T5HO-Warehouse-Retro-GasHt-V1987_1994
Non-Res	Large MH to T5HO-Warehouse-Retro-GasHt-V1995_2001
Non-Res	Large MH to T5HO-Warehouse-Retro-HtPmpHt-PRE1987
Non-Res	Large MH to T5HO-Warehouse-Retro-HtPmpHt-V1987_1994
Non-Res	Large MH to T5HO-Warehouse-Retro-HtPmpHt-V1995_2001
Non-Res	Med MH to T5HO-Other-New-ElecHt
Non-Res	Med MH to T5HO-Other-New-GasHt
Non-Res	Med MH to T5HO-Other-New-HtPmpHt
Non-Res	Med MH to T5HO-Supermarket-New-ElecHt
Non-Res	Med MH to T5HO-Supermarket-New-GasHt
Non-Res	Med MH to T5HO-Supermarket-New-HtPmpHt
Non-Res	Med MH to T8HP-Anchor-New-GasHt
Non-Res	Med MH to T8HP-Anchor-Retro-ElecHt-V1987_1994
Non-Res	Med MH to T8HP-Anchor-Retro-ElecHt-V1995_2001
Non-Res	Med MH to T8HP-Anchor-Retro-GasHt-V1987_1994

Non-Res	Med MH to T8HP-Anchor-Retro-GasHt-V1995_2001
Non-Res	Med MH to T8HP-Anchor-Retro-HtPmpHt-V1987_1994
Non-Res	Med MH to T8HP-Anchor-Retro-HtPmpHt-V1995_2001
Non-Res	Med MH to T8HP-High End-Retro-ElecHt-V1987_1994
Non-Res	Med MH to T8HP-High End-Retro-GasHt-V1987_1994
Non-Res	Med MH to T8HP-High End-Retro-HtPmpHt-V1987_1994
Non-Res	Med MH to T8HP-Hospital-New-GasHt
Non-Res	Med MH to T8HP-Hospital-Retro-ElecHt-V1995_2001
Non-Res	Med MH to T8HP-Hospital-Retro-GasHt-V1995_2001
Non-Res	Med MH to T8HP-Hospital-Retro-HtPmpHt-V1995_2001
Non-Res	Med MH to T8HP-K-12-Retro-ElecHt-PRE1987
Non-Res	Med MH to T8HP-K-12-Retro-ElecHt-V1987_1994
Non-Res	Med MH to T8HP-K-12-Retro-ElecHt-V1995_2001
Non-Res	Med MH to T8HP-K-12-Retro-GasHt-PRE1987
Non-Res	Med MH to T8HP-K-12-Retro-GasHt-V1987_1994
Non-Res	Med MH to T8HP-K-12-Retro-GasHt-V1995_2001
Non-Res	Med MH to T8HP-K-12-Retro-HtPmpHt-PRE1987
Non-Res	Med MH to T8HP-K-12-Retro-HtPmpHt-V1987_1994
Non-Res	Med MH to T8HP-K-12-Retro-HtPmpHt-V1995_2001
Non-Res	Med MH to T8HP-Large Off-Retro-ElecHt-V1987_1994
Non-Res	Med MH to T8HP-Large Off-Retro-ElecHt-V1995_2001
Non-Res	Med MH to T8HP-Large Off-Retro-GasHt-V1987_1994
Non-Res	Med MH to T8HP-Large Off-Retro-GasHt-V1995_2001
Non-Res	Med MH to T8HP-Large Off-Retro-HtPmpHt-V1987_1994
Non-Res	Med MH to T8HP-Large Off-Retro-HtPmpHt-V1995_2001
Non-Res	Med MH to T8HP-Medium Off-Retro-ElecHt-V1987_1994
Non-Res	Med MH to T8HP-Medium Off-Retro-ElecHt-V1995_2001
Non-Res	Med MH to T8HP-Medium Off-Retro-GasHt-V1987_1994
Non-Res	Med MH to T8HP-Medium Off-Retro-GasHt-V1995_2001
Non-Res	Med MH to T8HP-Medium Off-Retro-HtPmpHt-V1987_1994

Non-Res	Med MH to T8HP-Medium Off-Retro-HtPmpHt-V1995_2001
Non-Res	Med MH to T8HP-MIniMart-Retro-ElecHt-V1987_1994
Non-Res	Med MH to T8HP-MIniMart-Retro-ElecHt-V1995_2001
Non-Res	Med MH to T8HP-MIniMart-Retro-GasHt-V1987_1994
Non-Res	Med MH to T8HP-MIniMart-Retro-GasHt-V1995_2001
Non-Res	Med MH to T8HP-MIniMart-Retro-HtPmpHt-V1987_1994
Non-Res	Med MH to T8HP-MIniMart-Retro-HtPmpHt-V1995_2001
Non-Res	Med MH to T8HP-OtherHealth-New-GasHt
Non-Res	Med MH to T8HP-OtherHealth-Retro-ElecHt-V1995_2001
Non-Res	Med MH to T8HP-OtherHealth-Retro-GasHt-V1995_2001
Non-Res	Med MH to T8HP-OtherHealth-Retro-HtPmpHt-V1995_2001
Non-Res	Med MH to T8HP-Other-Retro-ElecHt-V1995_2001
Non-Res	Med MH to T8HP-Other-Retro-GasHt-V1995_2001
Non-Res	Med MH to T8HP-Other-Retro-HtPmpHt-V1995_2001
Non-Res	Med MH to T8HP-Small Box-New-GasHt
Non-Res	Med MH to T8HP-Small Box-Retro-ElecHt-PRE1987
Non-Res	Med MH to T8HP-Small Box-Retro-ElecHt-V1987_1994
Non-Res	Med MH to T8HP-Small Box-Retro-ElecHt-V1995_2001
Non-Res	Med MH to T8HP-Small Box-Retro-GasHt-PRE1987
Non-Res	Med MH to T8HP-Small Box-Retro-GasHt-V1987_1994
Non-Res	Med MH to T8HP-Small Box-Retro-GasHt-V1995_2001
Non-Res	Med MH to T8HP-Small Box-Retro-HtPmpHt-PRE1987
Non-Res	Med MH to T8HP-Small Box-Retro-HtPmpHt-V1987_1994
Non-Res	Med MH to T8HP-Small Box-Retro-HtPmpHt-V1995_2001
Non-Res	Med MH to T8HP-Supermarket-Retro-ElecHt-V1995_2001
Non-Res	Med MH to T8HP-Supermarket-Retro-GasHt-V1995_2001
Non-Res	Med MH to T8HP-Supermarket-Retro-HtPmpHt-V1995_2001
Non-Res	Med MH to T8HP-University-Retro-ElecHt-V1987_1994
Non-Res	Med MH to T8HP-University-Retro-GasHt-V1987_1994

Non-Res	Med MH to T8HP-University-Retro-HtPmpHt-V1987_1994
Non-Res	Night Covers for Display Cases - Horizontal
Non-Res	Night Covers for Display Cases - Vertical
Non-Res	Outdoor Sign Ballast - 24
Non-Res	Outdoor Sign Ballast - 24 - Retro
Non-Res	Outdoor Sign Ballast - Night
Non-Res	Outdoor Sign Ballast - Night - Retro
Non-Res	Perimeter Day lighting Controls (Advanced)-New-K-12-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-K-12-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-K-12-HtPmpHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-Large Off-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-Large Off-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-Large Off-HtPmpHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-Medium Off-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-Medium Off-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-Medium Off-HtPmpHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-OtherHealth-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-OtherHealth-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-OtherHealth-HtPmpHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-Small Off-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-Small Off-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-Small Off-HtPmpHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-University-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-University-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-New-University-HtPmpHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-K-12-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-K-12-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-K-12-HtPmpHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-Large Off-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-Large Off-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-Large Off-HtPmpHt

Non-Res	Perimeter Day lighting Controls (Advanced)-NR-Medium Off-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-Medium Off-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-Medium Off-HtPmpHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-OtherHealth-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-OtherHealth-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-OtherHealth-HtPmpHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-Small Off-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-Small Off-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-Small Off-HtPmpHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-University-ElecHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-University-GasHt
Non-Res	Perimeter Day lighting Controls (Advanced)-NR-University-HtPmpHt
Non-Res	Replace 12 inch Green Incandescent Left Turn Bay with 12 inchGreen LED module
Non-Res	Replace 12 inch Green Incandescent Thru Lane with 12 inch Green LED module
Non-Res	Replace 12 inch Red Incandescent Left Turn Bay with 12 inch Red LED module
Non-Res	Replace 12 inch Red Incandescent Thru Lane with 12 inch Red LED module
Non-Res	Replace 8 inch Red Incandescent Left Turn Bay with 8 inch Red LED module
Non-Res	Replace 8 inch Red Incandescent Thru Lane with 8 inch Red LED module
Non-Res	Special Doors with Low/No Anti-Sweat Heat
Non-Res	Strip Curtains for Walk-in Boxes
Non-Res	T12-2 to T8HP-1-Other-Retro-ElecHt-PRE1987
Non-Res	T12-2 to T8HP-1-Other-Retro-GasHt-PRE1987
Non-Res	T12-2 to T8HP-1-Other-Retro-HtPmpHt-PRE1987
Non-Res	T12-3 to T8HP-2-High End-New-GasHt
Non-Res	T12-3 to T8HP-2-High End-Retro-ElecHt-V1995_2001
Non-Res	T12-3 to T8HP-2-High End-Retro-GasHt-V1995_2001
Non-Res	T12-3 to T8HP-2-High End-Retro-HtPmpHt-V1995_2001
Non-Res	T12-3 to T8HP-2-K-12-Retro-ElecHt-V1987_1994
Non-Res	T12-3 to T8HP-2-K-12-Retro-GasHt-V1987_1994
Non-Res	T12-3 to T8HP-2-K-12-Retro-HtPmpHt-V1987_1994
Non-Res	T12-3 to T8HP-2-Small Off-Retro-ElecHt-V1995_2001

Non-Res	T12-3 to T8HP-2-Small Off-Retro-GasHt-V1995_2001
Non-Res	T12-3 to T8HP-2-Small Off-Retro-HtPmpHt-V1995_2001
Non-Res	T12-3 to T8HP-3-Anchor-Retro-ElecHt-V1987_1994
Non-Res	T12-3 to T8HP-3-Anchor-Retro-GasHt-V1987_1994
Non-Res	T12-3 to T8HP-3-Anchor-Retro-HtPmpHt-V1987_1994
Non-Res	T12-3 to T8HP-3-Big Box-Retro-ElecHt-PRE1987
Non-Res	T12-3 to T8HP-3-Big Box-Retro-GasHt-PRE1987
Non-Res	T12-3 to T8HP-3-Big Box-Retro-HtPmpHt-PRE1987
Non-Res	T12-3 to T8HP-3-High End-Retro-ElecHt-PRE1987
Non-Res	T12-3 to T8HP-3-High End-Retro-ElecHt-V1987_1994
Non-Res	T12-3 to T8HP-3-High End-Retro-GasHt-PRE1987
Non-Res	T12-3 to T8HP-3-High End-Retro-GasHt-V1987_1994
Non-Res	T12-3 to T8HP-3-High End-Retro-HtPmpHt-PRE1987
Non-Res	T12-3 to T8HP-3-High End-Retro-HtPmpHt-V1987_1994
Non-Res	T12-3 to T8HP-3-MIniMart-Retro-ElecHt-PRE1987
Non-Res	T12-3 to T8HP-3-MIniMart-Retro-GasHt-PRE1987
Non-Res	T12-3 to T8HP-3-MIniMart-Retro-HtPmpHt-PRE1987
Non-Res	T12-3 to T8HP-3-OtherHealth-Retro-ElecHt-PRE1987
Non-Res	T12-3 to T8HP-3-OtherHealth-Retro-ElecHt-V1987_1994
Non-Res	T12-3 to T8HP-3-OtherHealth-Retro-GasHt-PRE1987
Non-Res	T12-3 to T8HP-3-OtherHealth-Retro-GasHt-V1987_1994
Non-Res	T12-3 to T8HP-3-OtherHealth-Retro-HtPmpHt-PRE1987
Non-Res	T12-3 to T8HP-3-OtherHealth-Retro-HtPmpHt-V1987_1994
Non-Res	T12-3 to T8HP-3-Restaurant-Retro-ElecHt-PRE1987
Non-Res	T12-3 to T8HP-3-Restaurant-Retro-ElecHt-V1987_1994
Non-Res	T12-3 to T8HP-3-Restaurant-Retro-GasHt-PRE1987
Non-Res	T12-3 to T8HP-3-Restaurant-Retro-GasHt-V1987_1994
Non-Res	T12-3 to T8HP-3-Restaurant-Retro-HtPmpHt-PRE1987

Non-Res	T12-3 to T8HP-3-Restaurant-Retro-HtPmpHt-V1987_1994
Non-Res	T12-3 to T8HP-3-Supermarket-Retro-ElecHt-PRE1987
Non-Res	T12-3 to T8HP-3-Supermarket-Retro-GasHt-PRE1987
Non-Res	T12-3 to T8HP-3-Supermarket-Retro-HtPmpHt-PRE1987
Non-Res	T12-3 to T8HP-3-University-Retro-ElecHt-V1987_1994
Non-Res	T12-3 to T8HP-3-University-Retro-GasHt-V1987_1994
Non-Res	T12-3 to T8HP-3-University-Retro-HtPmpHt-V1987_1994
Non-Res	T12-4 to T8HP-2-Large Off-Retro-ElecHt-PRE1987
Non-Res	T12-4 to T8HP-2-Large Off-Retro-ElecHt-V1987_1994
Non-Res	T12-4 to T8HP-2-Large Off-Retro-GasHt-PRE1987
Non-Res	T12-4 to T8HP-2-Large Off-Retro-GasHt-V1987_1994
Non-Res	T12-4 to T8HP-2-Large Off-Retro-HtPmpHt-PRE1987
Non-Res	T12-4 to T8HP-2-Large Off-Retro-HtPmpHt-V1987_1994
Non-Res	T12-4 to T8HP-2-Medium Off-Retro-ElecHt-PRE1987
Non-Res	T12-4 to T8HP-2-Medium Off-Retro-ElecHt-V1987_1994
Non-Res	T12-4 to T8HP-2-Medium Off-Retro-GasHt-PRE1987
Non-Res	T12-4 to T8HP-2-Medium Off-Retro-GasHt-V1987_1994
Non-Res	T12-4 to T8HP-2-Medium Off-Retro-HtPmpHt-PRE1987
Non-Res	T12-4 to T8HP-2-Medium Off-Retro-HtPmpHt-V1987_1994
Non-Res	T12-4 to T8HP-2-MIniMart-Retro-ElecHt-V1987_1994
Non-Res	T12-4 to T8HP-2-MIniMart-Retro-GasHt-V1987_1994
Non-Res	T12-4 to T8HP-2-MIniMart-Retro-HtPmpHt-V1987_1994
Non-Res	T12-4 to T8HP-2-Small Off-Retro-ElecHt-PRE1987
Non-Res	T12-4 to T8HP-2-Small Off-Retro-ElecHt-V1987_1994
Non-Res	T12-4 to T8HP-2-Small Off-Retro-GasHt-PRE1987
Non-Res	T12-4 to T8HP-2-Small Off-Retro-GasHt-V1987_1994
Non-Res	T12-4 to T8HP-2-Small Off-Retro-HtPmpHt-PRE1987
Non-Res	T12-4 to T8HP-2-Small Off-Retro-HtPmpHt-V1987_1994

Non-Res	T12-4 to T8HP-2-Supermarket-Retro-ElecHt-V1987_1994
Non-Res	T12-4 to T8HP-2-Supermarket-Retro-GasHt-V1987_1994
Non-Res	T12-4 to T8HP-2-Supermarket-Retro-HtPmpHt-V1987_1994
Non-Res	T12-4 to T8HP-3-Anchor-Retro-ElecHt-PRE1987
Non-Res	T12-4 to T8HP-3-Anchor-Retro-GasHt-PRE1987
Non-Res	T12-4 to T8HP-3-Anchor-Retro-HtPmpHt-PRE1987
Non-Res	T12-4 to T8HP-3-Big Box-Retro-ElecHt-V1987_1994
Non-Res	T12-4 to T8HP-3-Big Box-Retro-GasHt-V1987_1994
Non-Res	T12-4 to T8HP-3-Big Box-Retro-HtPmpHt-V1987_1994
Non-Res	T12-4 to T8HP-3-Small Box-Retro-ElecHt-PRE1987
Non-Res	T12-4 to T8HP-3-Small Box-Retro-GasHt-PRE1987
Non-Res	T12-4 to T8HP-3-Small Box-Retro-HtPmpHt-PRE1987
Non-Res	Vending Machine Controller-Large Machine w/Illuminated Front
Non-Res	Vending Machine Controller-Small Machine or Machine without Illuminated Front
Non-Res	VSD Large Fan
Non-Res	VSD Medium fan
Non-Res	VSD Pump
Non-Res	VSD Small Fan
Res	Biradiant Oven
Res	Bottom Freezer - No Ice
Res	Energy Conservation School Program
Res	Energy Star Dishwasher (EF 68) - PNW DHW Fuel Average + NEB Waste Water Treatment Savings
Res	Energy Star Dishwasher (EF58) - PNW DHW Fuel Average + NEB of Waste Water Treatment Savings
Res	Energy Star Dishwasher (EF76) - PNW DHW Fuel Average + NEB Waste Water Treatment Savings
Res	Energy Star Dishwasher (EF85) - PNW DHW Fuel Average + NEB Waste Water Treatment Savings
Res	Heat Traps + Increased Insulation (3 1/2" foam) + Insulated Tank Bottom & Plastic Tank w/minimum 10 yr warranty
Res	Heat Traps + Increased Insulation (3" foam) + Insulated Tank Bottom w/minimum 10 year Warranty
Res	Heating System Maintenance (tune-up/filter)
Res	Improved Oven Insulation
Res	Improved Oven Seals

Res	Manufactured Home NonSGC Forced Air Furnace w/CAC - PTCS Duct Sealing and System Commissioning Heat Zone 1
Res	Manufactured Home NonSGC Forced Air Furnace w/CAC - PTCS Duct Sealing and System Commissioning Heat Zone 2
Res	Manufactured Home NonSGC Forced Air Furnace w/CAC - PTCS Duct Sealing Heat Zone 1
Res	Manufactured Home NonSGC Forced Air Furnace w/CAC - PTCS Duct Sealing Heat Zone 2
Res	Manufactured Home NonSGC Forced Air Furnace w/o CAC - PTCS Duct Sealing Heat Zone 1
Res	Manufactured Home NonSGC Forced Air Furnace w/o CAC - PTCS Duct Sealing Heat Zone 2
Res	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 1
Res	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 2
Res	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing Heat Zone 1
Res	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing Heat Zone 2
Res	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing, Commissioning and Controls Heat Zone 1
Res	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing, Commissioning and Controls Heat Zone 2
Res	Manufactured Home NonSGC Heat Pump - PTCS System Commissioning Heat Zone 1
Res	Manufactured Home NonSGC Heat Pump - PTCS System Commissioning Heat Zone 2
Res	Manufactured Home SGC Forced Air Furnace w/CAC - PTCS Duct Sealing and System Commissioning Heat Zone 1
Res	Manufactured Home SGC Forced Air Furnace w/CAC - PTCS Duct Sealing and System Commissioning Heat Zone 2
Res	Manufactured Home SGC Forced Air Furnace w/CAC - PTCS Duct Sealing Heat Zone 1
Res	Manufactured Home SGC Forced Air Furnace w/CAC - PTCS Duct Sealing Heat Zone 2
Res	Manufactured Home SGC Forced Air Furnace w/o CAC - PTCS Duct Sealing Heat Zone 1
Res	Manufactured Home SGC Forced Air Furnace w/o CAC - PTCS Duct Sealing Heat Zone 2
Res	Manufactured Home SGC Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 1

Res	Manufactured Home SGC Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 2
Res	Manufactured Home SGC Heat Pump - PTCS Duct Sealing Heat Zone 1
Res	Manufactured Home SGC Heat Pump - PTCS Duct Sealing Heat Zone 2
Res	Manufactured Home SGC Heat Pump - PTCS Duct Sealing, Commissioning and Controls Heat Zone 1
Res	Manufactured Home SGC Heat Pump - PTCS Duct Sealing, Commissioning and Controls Heat Zone 2
Res	Manufactured Home SGC Heat Pump - PTCS System Commissioning Heat Zone 1
Res	Manufactured Home SGC Heat Pump - PTCS System Commissioning Heat Zone 2
Res	Manufactured Home Weatherization - Heating Zone 1
Res	Manufactured Home Weatherization - Heating Zone 2
Res	Multifamily Weatherization - Heating Zone 1
Res	Multifamily Weatherization - Heating Zone 2
Res	New MultiFamily Construction, DHW & Shower Preheat, Electric Resistance
Res	New MultiFamily Construction, DHW Preheat, Electric Resistance
Res	New MultiFamily Construction, Shower Preheat, Electric Resistance
Res	New Single Family Construction, DHW & Shower Preheat, Electric Resistance
Res	New Single Family Construction, DHW Preheat, Electric Resistance
Res	New Single Family Construction, Shower Preheat, Electric Resistance
Res	Post79/Pre93 Single Family Construction CAC Upgrade SEER - Cooling Zone 3
Res	Post79/Pre93 Single Family Construction CAC Upgrade SEER - Cooling Zone 3
Res	Post79/Pre93 Single Family Construction CAC Upgrade SEER - Cooling Zone 3
Res	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating

Res	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Post79/Pre93 Single Family Construction Convert Zonal Heating w/o CAC to HP HSPF 8/SEER 13 - Heat
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 2
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 2

Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 2
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2
Res	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2

Res	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1
Res	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1
Res	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1
Res	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2
Res	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2
Res	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2
Res	Post92 Single Family Construction CAC Upgrade SEER - Cooling Zone 3
Res	Post92 Single Family Construction CAC Upgrade SEER - Cooling Zone 3
Res	Post92 Single Family Construction CAC Upgrade SEER - Cooling Zone 3
Res	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Post92 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Post92 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Post92 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Post92 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Post92 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat

Res	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1
Res	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1
Res	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1
Res	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2
Res	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2
Res	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2
Res	Post92 Single Family Contruction Geothermal Heat Pump vs Air Source Heat Pump - Zone 1
Res	Post92 Single Family Contruction Geothermal Heat Pump vs Air Source Heat Pump - Zone 2
Res	Post92 Single Family Contruction Geothermal Heat Pump vs Air Source Heat Pump - Zone 2
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 1
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 1
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 1
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 2
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 2
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 2
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 1
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 1
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 1
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 2
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 2
Res	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 2
Res	Post92 Single Family Contruction Geothermal Heat Pump vs Zonal Heating - Zone 2
Res	Post92 Single Family Contruction Geothermal Heat Pump vs Zonal Heating - Zone 2
Res	Post92 Single Family Contruction Geothermal Heat Pump vs Zonal Heating - Zone 2
Res	Post93 Manufactured Home NonSGC CAC Upgrade SEER w/PTCS - Cooling Zone 3
Res	Post93 Manufactured Home NonSGC Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating
Res	Post93 Manufactured Home NonSGC Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating
Res	Post93 Manufactured Home NonSGC Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating

Res	Post93 Manufactured Home NonSGC Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating
Res	Post93 Manufactured Home NonSGC HP Upgrade HSPF 8 w/PTCS - Cooling Zone 1
Res	Post93 Manufactured Home NonSGC HP Upgrade HSPF 8 w/PTCS - Cooling Zone 2
Res	Post93 NonSGC Manufactured Home Convert FAF w/CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 1
Res	Post93 NonSGC Manufactured Home Convert FAF w/CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2
Res	Post93 NonSGC Manufactured Home Convert FAF w/o CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 1
Res	Post93 NonSGC Manufactured Home Convert FAF w/o CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2
Res	Pre80 Single Family Construction CAC Upgrade SEER - Cooling Zone 3
Res	Pre80 Single Family Construction CAC Upgrade SEER - Cooling Zone 3
Res	Pre80 Single Family Construction CAC Upgrade SEER - Cooling Zone 3
Res	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating
Res	Pre80 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Pre80 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Pre80 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat

Res	Pre80 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 2
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 2
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1

Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2
Res	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2
Res	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1
Res	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1
Res	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1
Res	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2
Res	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2
Res	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2
Res	Pre94 Manufactured Home CAC Upgrade SEER w/PTCS - Cooling Zone 3
Res	Pre94 Manufactured Home Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating
Res	Pre94 Manufactured Home Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating
Res	Pre94 Manufactured Home Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating
Res	Pre94 Manufactured Home Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating
Res	Pre94 NonSGC Manufactured Home Convert FAF w/CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 1
Res	Pre94 NonSGC Manufactured Home Convert FAF w/CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2
Res	Pre94 NonSGC Manufactured Home Convert FAF w/o CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 1
Res	Pre94 NonSGC Manufactured Home Convert FAF w/o CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2
Res	Reduced Oven Ventilation Rate
Res	SGC - Heating Zone 1
Res	SGC - Heating Zone 2
Res	SGC - Zone 1
Res	SGC - Zone 2
Res	SGC Manufactured Home CAC Upgrade SEER w/PTCS - Cooling Zone 3

Res	SGC Manufactured Home Convert FAF w/CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2
Res	SGC Manufactured Home Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating
Res	SGC Manufactured Home Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating
Res	SGC Manufactured Home Convert FAF w/o CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2
Res	SGC Manufactured Home Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating
Res	SGC Manufactured Home Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating
Res	SGCSF - Heating Zone 1
Res	SGCSF - Heating Zone 2
Res	Side-by-Side Model - Ice
Res	Side-by-Side Model - No Ice
Res	Single Family Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 1
Res	Single Family Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 2
Res	Single Family Heat Pump - PTCS System Commissioning Heat Zone 1
Res	Single Family Heat Pump - PTCS System Commissioning Heat Zone 2
Res	Single Family Weatherization - Zone 1
Res	Single Family Weatherization - Zone 2
Res	Top Freezer - Ice
Res	Top Freezer - No Ice
Res	Weighted Average - Interior & Exterior Wattage - 92 Watt

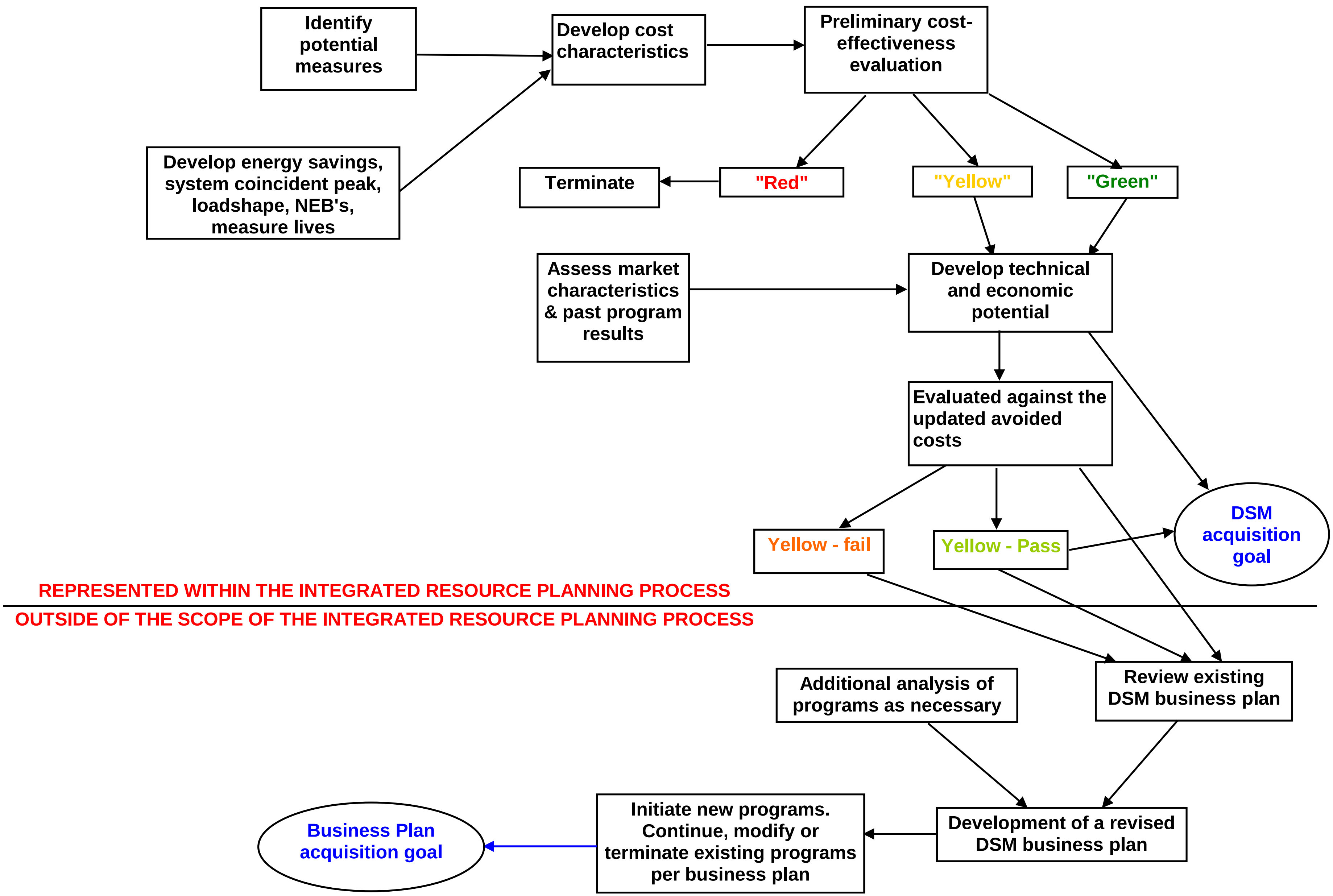
2009

Electric
Integrated Resource Plan

Appendix E – Integration of DSM within the 2009 Electric IRP

August 31, 2009

Integration of DSM within the 2009 Electric IRP



2009

Electric Integrated Resource Plan

Appendix F – Achievable 20-Year Potential for Residential and Non-Residential DSM Programs

August 31, 2009

Acheiveable Potential (20-yr) for Res and Non-Res (excludes low-income/non-res site specific)

(in 2009 $s)

Meas #	Segment	Category	Measure	achievable potential (20 yr)	levelized trc cost 2009	Life
46.5	Res	Dishwash	Energy Star Dishwasher (EF58) - PNW DHW Fuel Average + NEB of Waste Water Treatment Savings	835,250	0.00	9
52.5	Res	Dishwash	Energy Star Dishwasher (EF 68) - PNW DHW Fuel Average + NEB Waste Water Treatment Savings	835,250	0.01	9
58.5	Res	Dishwash	Energy Star Dishwasher (EF76) - PNW DHW Fuel Average + NEB Waste Water Treatment Savings	835,250	0.61	9
64.5	Res	Dishwash	Energy Star Dishwasher (EF85) - PNW DHW Fuel Average + NEB Waste Water Treatment Savings	835,250	1.98	9
104	Res	Lighting	Weighted Average - Interior & Exterior Wattage - 92 Watt	250,452,883	0.03	9
106	Res	Appliance	Bottom Freezer - No Ice	659,410	0.04	19
107	Res	Appliance	Side-by-Side Model - No Ice	659,410	0.03	19
108	Res	Appliance	Side-by-Side Model - Ice	659,410	0.52	19
109	Res	Appliance	Top Freezer - No Ice	659,410	0.24	19
110	Res	Appliance	Top Freezer - Ice	659,410	0.13	19
111	Res	DHW	New Single Family Construction, Shower Preheat, Electric Resistance	44,117	0.11	40
113	Res	DHW	New Single Family Construction, DHW & Shower Preheat, Electric Resistance	126,027	0.08	40
115	Res	DHW	New Single Family Construction, DHW Preheat, Electric Resistance	50,419	0.10	40
117	Res	DHW	New MultiFamily Construction, Shower Preheat, Electric Resistance	17,638	0.09	40
119	Res	DHW	New MultiFamily Construction, DHW & Shower Preheat, Electric Resistance	50,419	0.07	40
121	Res	DHW	New MultiFamily Construction, DHW Preheat, Electric Resistance	20,155	0.08	40
129	Res	Cooking	Reduced Oven Ventilation Rate	24,336	0.03	20
130	Res	Cooking	Improved Oven Insulation	23,712	0.11	20
131	Res	Cooking	Improved Oven Seals	7,904	0.86	20
132	Res	Cooking	Biradiant Oven	163,072	0.26	20
133	Res	DHW	Heat Traps + Increased Insulation (3" foam) + Insulated Tank Bottom w/minimum 10 year Warranty	92,976	0.03	12
134	Res	DHW	Heat Traps + Increased Insulation (3 1/2" foam) + Insulated Tank Bottom & Plastic Tank w/minimum 10 yr warranty	29,370	0.04	12
172	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1	892,459	0.18	30
175	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2	892,459	0.13	30
178	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1	892,459	0.09	30

181	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 2	892,459	0.07	30
184	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1	892,459	0.09	30
187	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2	892,459	0.06	30
190	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1	892,459	0.09	30
193	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2	892,459	0.06	30
196	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1	892,459	0.15	30
199	Res	HP Upgrade	Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2	892,459	0.11	30
202	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1	892,459	0.08	30
205	Res	HP Upgrade	Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 2	892,459	0.06	30
208	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1	892,459	0.06	30
211	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2	892,459	0.04	30
214	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1	892,459	0.06	30
217	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2	892,459	0.04	30
223	Res	HP Upgrade	Post92 Single Family Contruction Geothermal Heat Pump vs Zonal Heating - Zone 2	892,459	0.18	30
226	Res	HP Upgrade	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 1	892,459	0.11	30
229	Res	HP Upgrade	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 2	892,459	0.07	30
232	Res	HP Upgrade	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 1	892,459	0.11	30
235	Res	HP Upgrade	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 2	892,459	0.07	30
238	Res	HP Upgrade	Post92 Single Family Contruction Geothermal Heat Pump vs Air Source Heat Pump - Zone 1	892,459	0.14	30
241	Res	HP Upgrade	Post92 Single Family Contruction Geothermal Heat Pump vs Air Source Heat Pump - Zone 2	892,459	0.10	30
244	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1	892,459	0.17	30
247	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2	892,459	0.12	30
250	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1	892,459	0.17	30

256	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1	892,459	0.11	30
259	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2	892,459	0.08	30
262	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1	892,459	0.11	30
265	Res	HP Upgrade	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2	892,459	0.08	30
268	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1	892,459	0.15	30
271	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2	892,459	0.11	30
274	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1	892,459	0.14	30
277	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 2	892,459	0.11	30
280	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1	892,459	0.08	30
283	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2	892,459	0.06	30
286	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1	892,459	0.08	30
289	Res	HP Upgrade	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2	892,459	0.06	30
295	Res	HP Conv	Post92 Single Family Contruction Geothermal Heat Pump vs Zonal Heating - Zone 2	484,272	0.17	30
298	Res	HP Conv	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 1	484,272	0.14	30
301	Res	HP Conv	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 2	484,272	0.10	30
304	Res	HP Conv	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 1	484,272	0.14	30
307	Res	HP Conv	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 2	484,272	0.10	30
313	Res	HP Conv	Post92 Single Family Contruction Geothermal Heat Pump vs Air Source Heat Pump - Zone 2	484,272	0.18	30
316	Res	HP Conv	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1	484,272	0.17	30
319	Res	HP Conv	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2	484,272	0.12	30
322	Res	HP Conv	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1	484,272	0.22	30

325	Res	HP Conv	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 2	484,272	0.17	30
328	Res	HP Conv	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1	484,272	0.13	30
331	Res	HP Conv	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2	484,272	0.09	30
334	Res	HP Conv	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1	484,272	0.13	30
337	Res	HP Conv	Pre80 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2	484,272	0.09	30
340	Res	HP Conv	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 1	484,272	0.14	30
343	Res	HP Conv	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Zonal Heating - Zone 2	484,272	0.10	30
346	Res	HP Conv	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 1	484,272	0.18	30
349	Res	HP Conv	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on Air Source HP - Zone 2	484,272	0.14	30
352	Res	HP Conv	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 1	484,272	0.09	30
355	Res	HP Conv	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/oCAC - Zone 2	484,272	0.07	30
358	Res	HP Conv	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 1	484,272	0.09	30
361	Res	HP Conv	Post79/Pre93 Single Family Construction Geothermal Heat Pump Retrofit w/PTCS on FAF w/CAC - Zone 2	484,272	0.07	30
367	Res	HP Conv	Post92 Single Family Contruction Geothermal Heat Pump vs Zonal Heating - Zone 2	484,272	0.17	30
370	Res	HP Conv	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 1	484,272	0.16	30
373	Res	HP Conv	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/oCAC - Zone 2	484,272	0.11	30
376	Res	HP Conv	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 1	484,272	0.16	30
379	Res	HP Conv	Post92 Single Family Contruction Geothermal Heat Pump vs FAF w/CAC - Zone 2	484,272	0.11	30
388	Res	MH HP Conv	Pre94 Manufactured Home Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating	410,091	0.09	18
390	Res	MH HP Conv	Pre94 Manufactured Home Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating	527,124	0.07	18
392	Res	MH HP Conv	Post93 Manufactured Home NonSGC Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating	341,756	0.10	18
394	Res	MH HP Conv	Post93 Manufactured Home NonSGC Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating	450,441	0.08	18
396	Res	MH HP Conv	SGC Manufactured Home Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating	217,385	0.14	18

398	Res	MH HP Conv	SGC Manufactured Home Convert FAF w/o CAC to HP HSPF 8/SEER 12 - Heating	300,697	0.10	18
400	Res	MH HP Conv	Pre94 Manufactured Home Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating	410,091	0.08	18
402	Res	MH HP Conv	Pre94 Manufactured Home Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating	527,124	0.07	18
404	Res	MH HP Conv	Post93 Manufactured Home NonSGC Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating	341,756	0.10	18
406	Res	MH HP Conv	Post93 Manufactured Home NonSGC Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating	450,441	0.08	18
408	Res	MH HP Conv	SGC Manufactured Home Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating	217,385	0.13	18
410	Res	MH HP Conv	SGC Manufactured Home Convert FAF w/CAC to HP HSPF 8/SEER 12 - Heating	300,697	0.10	18
412	Res	Shell	SGC - Heating Zone 1	31,387	0.05	70
413	Res	Shell	SGC - Heating Zone 2	92,577	0.05	70
414	Res	Shell	Single Family Weatherization - Zone 1	2,263,516	0.04	45
415	Res	Shell	Single Family Weatherization - Zone 2	4,334,121	0.03	45
416	Res	Shell	Multifamily Weatherization - Heating Zone 1	1,060,596	0.05	45
417	Res	Shell	Multifamily Weatherization - Heating Zone 2	1,394,411	0.04	45
418	Res	Shell	SGCSF - Heating Zone 1	2,416,877	0.06	70
419	Res	Shell	SGCSF - Heating Zone 2	3,931,820	0.05	70
420	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.12	18
422	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.10	18
424	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.07	18
426	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.06	18
428	Res	HP Conv	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.11	18
430	Res	HP Conv	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.09	18
432	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.12	18
434	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.10	18
436	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.07	18
438	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.06	18
440	Res	HP Conv	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.11	18
442	Res	HP Conv	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.09	18
444	Res	HP Conv	Pre80 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.15	18
446	Res	HP Conv	Pre80 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.13	18
448	Res	HP Conv	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.09	18

450	Res	HP Conv	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.08	18
452	Res	HP Conv	Post92 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.13	18
454	Res	HP Conv	Post92 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.11	18
468	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.14	18
470	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.12	18
472	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.08	18
474	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.07	18
476	Res	HP Conv	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.13	18
478	Res	HP Conv	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.10	18
480	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.14	18
482	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.12	18
484	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.08	18
486	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.07	18
488	Res	HP Conv	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.13	18
490	Res	HP Conv	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.10	18
492	Res	HP Conv	Pre80 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.14	18
494	Res	HP Conv	Pre80 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.12	18
496	Res	HP Conv	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.08	18
498	Res	HP Conv	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.07	18
500	Res	HP Conv	Post92 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.13	18
502	Res	HP Conv	Post92 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.10	18
510	Res	HP Conv	Post79/Pre93 Single Family Construction Convert Zonal Heating w/o CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.13	18

516	Res	Shell	Manufactured Home Weatherization - Heating Zone 1	6,151,873	0.07	25
517	Res	Shell	Manufactured Home Weatherization - Heating Zone 2	7,870,990	0.06	25
529	Res	MF Duc Seal	Manufactured Home NonSGC Forced Air Furnace w/o CAC - PTCS Duct Sealing Heat Zone 1	60,322	0.05	20
530	Res	MF Duc Seal	Manufactured Home NonSGC Forced Air Furnace w/o CAC - PTCS Duct Sealing Heat Zone 2	89,539	0.04	20
531	Res	MF Duc Seal	Manufactured Home SGC Forced Air Furnace w/o CAC - PTCS Duct Sealing Heat Zone 1	32,672	0.10	20
532	Res	MF Duc Seal	Manufactured Home SGC Forced Air Furnace w/o CAC - PTCS Duct Sealing Heat Zone 2	52,508	0.06	20
537	Res	SF Com	Single Family Heat Pump - PTCS System Commissioning Heat Zone 1	222,025	0.26	5
539	Res	SF Com	Single Family Heat Pump - PTCS System Commissioning Heat Zone 2	383,505	0.15	5
541	Res	SF Com	Single Family Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 1	1,183,530	0.05	20
543	Res	SF Com	Single Family Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 2	2,038,711	0.03	20
549	Res	MH Duct Seal	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing Heat Zone 1	37,507	0.09	20
551	Res	MH Duct Seal	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing Heat Zone 2	65,568	0.05	20
553	Res	MH Com	Manufactured Home NonSGC Heat Pump - PTCS System Commissioning Heat Zone 1	17,514	0.28	5
555	Res	MH Com	Manufactured Home NonSGC Heat Pump - PTCS System Commissioning Heat Zone 2	30,317	0.16	5
557	Res	MH Duct Seal	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 1	55,020	0.09	20
559	Res	MH Duct Seal	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 2	95,885	0.05	20
561	Res	MH Duct Seal	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing, Commissioning and Controls Heat Zone 1	62,104	0.10	20
563	Res	MH Duct Seal	Manufactured Home NonSGC Heat Pump - PTCS Duct Sealing, Commissioning and Controls Heat Zone 2	92,314	0.06	20
565	Res	MH Duct Seal	Manufactured Home SGC Heat Pump - PTCS Duct Sealing Heat Zone 1	20,752	0.15	20
567	Res	MH Duct Seal	Manufactured Home SGC Heat Pump - PTCS Duct Sealing Heat Zone 2	39,129	0.08	20
569	Res	MH Com	Manufactured Home SGC Heat Pump - PTCS System Commissioning Heat Zone 1	9,692	0.51	5
571	Res	MH Com	Manufactured Home SGC Heat Pump - PTCS System Commissioning Heat Zone 2	18,094	0.27	5
573	Res	MH Duct Seal	Manufactured Home SGC Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 1	30,444	0.17	20
575	Res	MH Duct Seal	Manufactured Home SGC Heat Pump - PTCS Duct Sealing and System Commissioning Heat Zone 2	57,223	0.09	20
577	Res	MH Duct Seal	Manufactured Home SGC Heat Pump - PTCS Duct Sealing, Commissioning and Controls Heat Zone 1	34,399	0.17	20

579	Res	MH Duct Seal	Manufactured Home SGC Heat Pump - PTCS Duct Sealing, Commissioning and Controls Heat Zone 2	55,088	0.11	20
593	Res	MH Duct Seal	Manufactured Home NonSGC Forced Air Furnace w/CAC - PTCS Duct Sealing Heat Zone 1	60,322	0.05	20
595	Res	MH Duct Seal	Manufactured Home NonSGC Forced Air Furnace w/CAC - PTCS Duct Sealing Heat Zone 2	89,539	0.04	20
601	Res	MH Duct Seal	Manufactured Home NonSGC Forced Air Furnace w/CAC - PTCS Duct Sealing and System Commissioning Heat Zone 1	60,322	0.05	20
603	Res	MH Duct Seal	Manufactured Home NonSGC Forced Air Furnace w/CAC - PTCS Duct Sealing and System Commissioning Heat Zone 2	89,539	0.04	20
605	Res	MH Duct Seal	Manufactured Home SGC Forced Air Furnace w/CAC - PTCS Duct Sealing Heat Zone 1	32,672	0.10	20
607	Res	MH Duct Seal	Manufactured Home SGC Forced Air Furnace w/CAC - PTCS Duct Sealing Heat Zone 2	52,508	0.06	20
613	Res	MH Duct Seal	Manufactured Home SGC Forced Air Furnace w/CAC - PTCS Duct Sealing and System Commissioning Heat Zone 1	32,672	0.10	20
615	Res	MH Duct Seal	Manufactured Home SGC Forced Air Furnace w/CAC - PTCS Duct Sealing and System Commissioning Heat Zone 2	52,508	0.06	20
617	Res	Shell	SGC - Zone 1	538,582	0.05	45
618	Res	Shell	SGC - Zone 2	1,089,896	0.04	45
625	Res	HP Conv	Pre94 NonSGC Manufactured Home Convert FAF w/o CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 1	484,272	0.09	30
628	Res	HP Conv	Pre94 NonSGC Manufactured Home Convert FAF w/o CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2	484,272	0.07	30
631	Res	HP Conv	Pre94 NonSGC Manufactured Home Convert FAF w/CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 1	484,272	0.09	30
634	Res	HP Conv	Pre94 NonSGC Manufactured Home Convert FAF w/CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2	484,272	0.07	30
643	Res	HP Conv	Post93 NonSGC Manufactured Home Convert FAF w/o CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 1	484,272	0.13	30
646	Res	HP Conv	Post93 NonSGC Manufactured Home Convert FAF w/o CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2	484,272	0.09	30
649	Res	HP Conv	Post93 NonSGC Manufactured Home Convert FAF w/CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 1	484,272	0.13	30
652	Res	HP Conv	Post93 NonSGC Manufactured Home Convert FAF w/CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2	484,272	0.09	30
658	Res	HP Conv	SGC Manufactured Home Convert FAF w/o CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2	484,272	0.13	30
664	Res	HP Conv	SGC Manufactured Home Convert FAF w/CAC to Energy Star Geothermal Heat Pump w/PTCS Specifications - Heating Zone 2	484,272	0.13	30
673	Res	AC Upgrade	Pre80 Single Family Construction CAC Upgrade SEER - Cooling Zone 3	224,848	0.56	18

674	Res	AC Upgrade	Post79/Pre93 Single Family Construction CAC Upgrade SEER - Cooling Zone 3	224,848	0.36	18
675	Res	AC Upgrade	Post92 Single Family Construction CAC Upgrade SEER - Cooling Zone 3	224,848	0.47	18
676	Res	HP Upgrade	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1	892,459	0.17	18
678	Res	HP Upgrade	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2	892,459	0.10	18
680	Res	HP Upgrade	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1	892,459	0.10	18
682	Res	HP Upgrade	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2	892,459	0.06	18
684	Res	HP Upgrade	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1	892,459	0.16	18
686	Res	HP Upgrade	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2	892,459	0.09	18
688	Res	AC Upgrade	Pre80 Single Family Construction CAC Upgrade SEER - Cooling Zone 3	224,848	0.33	18
689	Res	AC Upgrade	Post79/Pre93 Single Family Construction CAC Upgrade SEER - Cooling Zone 3	224,848	0.21	18
690	Res	AC Upgrade	Post92 Single Family Construction CAC Upgrade SEER - Cooling Zone 3	224,848	0.28	18
691	Res	HP Upgrade	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1	892,459	0.06	18
693	Res	HP Upgrade	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2	892,459	0.04	18
695	Res	HP Upgrade	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1	892,459	0.04	18
697	Res	HP Upgrade	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2	892,459	0.02	18
699	Res	HP Upgrade	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1	892,459	0.06	18
701	Res	HP Upgrade	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2	892,459	0.03	18
703	Res	AC Upgrade	Pre94 Manufactured Home CAC Upgrade SEER w/PTCS - Cooling Zone 3	224,848	0.28	18
704	Res	AC Upgrade	Post93 Manufactured Home NonSGC CAC Upgrade SEER w/PTCS - Cooling Zone 3	224,848	0.29	18
705	Res	AC Upgrade	SGC Manufactured Home CAC Upgrade SEER w/PTCS - Cooling Zone 3	224,848	0.39	18
710	Res	HP Upgrade	Post93 Manufactured Home NonSGC HP Upgrade HSPF 8 w/PTCS - Cooling Zone 1	892,459	0.09	18
712	Res	HP Upgrade	Post93 Manufactured Home NonSGC HP Upgrade HSPF 8 w/PTCS - Cooling Zone 2	892,459	0.04	18
718	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.10	18
720	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.08	18
722	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.06	18
724	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.05	18
726	Res	HP Conv	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.09	18
728	Res	HP Conv	Post92 Single Family Construction Convert FAF w/o CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.07	18

730	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.10	18
732	Res	HP Conv	Pre80 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.08	18
734	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.06	18
736	Res	HP Conv	Post79/Pre93 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.05	18
738	Res	HP Conv	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.09	18
740	Res	HP Conv	Post92 Single Family Construction Convert FAF w/CAC to HP HSPF 8/SEER 13 - Heating	484,272	0.07	18
746	Res	HP Conv	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.11	18
748	Res	HP Conv	Post79/Pre93 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.10	18
752	Res	HP Conv	Post92 Single Family Construction Convert Zonal Heating w/CAC to HP HSPF 8/SEER 13 - Heat	484,272	0.15	18
766	Res	AC Upgrade	Pre80 Single Family Construction CAC Upgrade SEER - Cooling Zone 3	224,848	0.41	18
767	Res	AC Upgrade	Post79/Pre93 Single Family Construction CAC Upgrade SEER - Cooling Zone 3	224,848	0.26	18
768	Res	AC Upgrade	Post92 Single Family Construction CAC Upgrade SEER - Cooling Zone 3	224,848	0.34	18
769	Res	HP Upgrade	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1	892,459	0.12	18
771	Res	HP Upgrade	Pre80 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2	892,459	0.07	18
773	Res	HP Upgrade	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1	892,459	0.07	18
775	Res	HP Upgrade	Post79/Pre93 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2	892,459	0.04	18
777	Res	HP Upgrade	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 1	892,459	0.11	18
779	Res	HP Upgrade	Post92 Single Family Construction HP Upgrade HSPF 8 - Heating Zone 2	892,459	0.06	18
783	Res	Lighting	Energy Conservation School Program	13,728,000	0.02	7
785	Res	HVAC	Heating System Maintenance (tune-up/filter)	416,000	0.00	12
21	Non-Res	HVAC	VSD Small Fan	13,000,000	0.16	15
22	Non-Res	HVAC	VSD Medium fan	13,000,000	0.10	15
23	Non-Res	HVAC	VSD Large Fan	13,000,000	0.07	15
24	Non-Res	HVAC	VSD Pump	13,000,000	0.11	15
27	Non-Res	Energy Smart	Night Covers for Display Cases - Vertical	9,464,000	0.02	5
28	Non-Res	Energy Smart	Night Covers for Display Cases - Horizontal	9,464,000	0.04	5
29	Non-Res	Energy Smart	Strip Curtains for Walk-in Boxes	9,464,000	0.00	4
30	Non-Res	Energy Smart	Glass Doors on Open Display Cases (LT)	9,464,000	0.03	12
31	Non-Res	Energy Smart	Glass Doors on Open Display Cases (MT)	9,464,000	0.08	12
34	Non-Res	Energy Smart	Special Doors with Low/No Anti-Sweat Heat	9,464,000	0.05	12
35	Non-Res	Energy Smart	Anti-Sweat Heat Controls	9,464,000	0.03	11
36	Non-Res	Energy Smart	Auto-Closers for Coolers and Freezers	9,464,000	0.01	8
37	Non-Res	Energy Smart	Evaporative fan controller on walk-in	9,464,000	0.07	5
40	Non-Res	Energy Smart	Floating Head Pressure Controller	9,464,000	0.04	12
44	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Large Off-GasHt-Retro	260,000	0.07	8

45	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Medium Off-GasHt-Retro	260,000	0.08	8
46	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Small Off-GasHt-Retro	260,000	0.25	8
47	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Big Box-GasHt-Retro	260,000	0.10	8
48	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Small Box-GasHt-Retro	260,000	0.23	8
49	Non-Res	HVAC	Built-Up HVAC Controls Optimization-High End-GasHt-Retro	260,000	0.17	8
50	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Anchor-GasHt-Retro	260,000	0.06	8
51	Non-Res	HVAC	Built-Up HVAC Controls Optimization-K-12-GasHt-Retro	260,000	0.29	8
52	Non-Res	HVAC	Built-Up HVAC Controls Optimization-University-GasHt-Retro	260,000	0.10	8
53	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Warehouse-GasHt-Retro	260,000	0.28	8
54	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Supermarket-GasHt-Retro	260,000	0.08	8
55	Non-Res	HVAC	Built-Up HVAC Controls Optimization-MIniMart-GasHt-Retro	260,000	0.11	8
56	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Restaurant-GasHt-Retro	260,000	0.10	8
57	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Lodging-GasHt-Retro	260,000	0.08	8
58	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Hospital-GasHt-Retro	260,000	0.06	8
59	Non-Res	HVAC	Built-Up HVAC Controls Optimization-OtherHealth-GasHt-Retro	260,000	0.07	8
60	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Other-GasHt-Retro	260,000	0.23	8
61	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Large Off-ElecHt-Retro	260,000	0.05	8
62	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Medium Off-ElecHt-Retro	260,000	0.05	8
63	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Small Off-ElecHt-Retro	260,000	0.15	8
64	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Big Box-ElecHt-Retro	260,000	0.09	8
65	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Small Box-ElecHt-Retro	260,000	0.17	8
66	Non-Res	HVAC	Built-Up HVAC Controls Optimization-High End-ElecHt-Retro	260,000	0.14	8
67	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Anchor-ElecHt-Retro	260,000	0.05	8
68	Non-Res	HVAC	Built-Up HVAC Controls Optimization-K-12-ElecHt-Retro	260,000	0.05	8
69	Non-Res	HVAC	Built-Up HVAC Controls Optimization-University-ElecHt-Retro	260,000	0.06	8
70	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Warehouse-ElecHt-Retro	260,000	0.11	8
71	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Supermarket-ElecHt-Retro	260,000	0.05	8
72	Non-Res	HVAC	Built-Up HVAC Controls Optimization-MIniMart-ElecHt-Retro	260,000	0.09	8
73	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Restaurant-ElecHt-Retro	260,000	0.08	8

74	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Lodging-ElecHt-Retro	260,000	0.05	8
75	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Hospital-ElecHt-Retro	260,000	0.04	8
76	Non-Res	HVAC	Built-Up HVAC Controls Optimization-OtherHealth-ElecHt-Retro	260,000	0.04	8
77	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Other-ElecHt-Retro	260,000	0.13	8
78	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Large Off-HtPmpHt-Retro	260,000	0.06	8
79	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Medium Off-HtPmpHt-Retro	260,000	0.07	8
80	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Small Off-HtPmpHt-Retro	260,000	0.19	8
81	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Big Box-HtPmpHt-Retro	260,000	0.09	8
82	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Small Box-HtPmpHt-Retro	260,000	0.20	8
83	Non-Res	HVAC	Built-Up HVAC Controls Optimization-High End-HtPmpHt-Retro	260,000	0.17	8
84	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Anchor-HtPmpHt-Retro	260,000	0.06	8
85	Non-Res	HVAC	Built-Up HVAC Controls Optimization-K-12-HtPmpHt-Retro	260,000	0.08	8
86	Non-Res	HVAC	Built-Up HVAC Controls Optimization-University-HtPmpHt-Retro	260,000	0.08	8
87	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Warehouse-HtPmpHt-Retro	260,000	0.17	8
88	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Supermarket-HtPmpHt-Retro	260,000	0.07	8
90	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Restaurant-HtPmpHt-Retro	260,000	0.10	8
91	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Lodging-HtPmpHt-Retro	260,000	0.06	8
92	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Hospital-HtPmpHt-Retro	260,000	0.05	8
93	Non-Res	HVAC	Built-Up HVAC Controls Optimization-OtherHealth-HtPmpHt-Retro	260,000	0.05	8
94	Non-Res	HVAC	Built-Up HVAC Controls Optimization-Other-HtPmpHt-Retro	260,000	0.17	8
115	Non-Res		Controls Commission-New	21,960	0.07	12
117	Non-Res	Traffic Lights	Replace 12 inch Red Incandescent Left Turn Bay with 12 inch Red LED module	208,000	0.02	5
118	Non-Res	Traffic Lights	Replace 12 inch Green Incandescent Left Turn Bay with 12 inchGreen LED module	208,000	0.06	16
119	Non-Res	Traffic Lights	Replace 12 inch Red Incandescent Thru Lane with 12 inch Red LED module	208,000	0.02	6
120	Non-Res	Traffic Lights	Replace 12 inch Green Incandescent Thru Lane with 12 inch Green LED module	208,000	0.05	7
121	Non-Res	Traffic Lights	Replace 8 inch Red Incandescent Left Turn Bay with 8 inch Red LED module	208,000	0.04	5
123	Non-Res	Traffic Lights	Replace 8 inch Red Incandescent Thru Lane with 8 inch Red LED module	208,000	0.04	6
129	Non-Res	Lighting-CFL	INC to CFL-Large Off-New-ElecHt	163,800	0.01	15
132	Non-Res	Lighting-CFL	INC to CFL-Large Off-New-HtPmpHt	163,800	0.01	15
135	Non-Res	Lighting-CFL	INC to CFL-Large Off-New-GasHt	163,800	0.01	15
138	Non-Res	Lighting-CFL	INC to CFL-Medium Off-New-ElecHt	163,800	0.01	15
141	Non-Res	Lighting-CFL	INC to CFL-Medium Off-New-HtPmpHt	163,800	0.01	15

144	Non-Res	Lighting-CFL	INC to CFL-Medium Off-New-GasHt	163,800	0.01	15
148	Non-Res	Lighting-CFL	INC to CFL-Small Off-New-ElecHt	163,800	0.01	15
152	Non-Res	Lighting-CFL	INC to CFL-Small Off-New-HtPmpHt	163,800	0.01	15
154	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Off-New-GasHt	602,173	0.01	15
156	Non-Res	Lighting-CFL	INC to CFL-Small Off-New-GasHt	163,800	0.02	15
159	Non-Res	Lighting-CFL	INC to CMH-Big Box-New-ElecHt	81,900	0.04	15
161	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-New-ElecHt	441,447	0.00	15
163	Non-Res	Lighting-CFL	INC to CMH-Big Box-New-HtPmpHt	81,900	0.03	15
165	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-New-HtPmpHt	441,447	0.00	15
167	Non-Res	Lighting-CFL	INC to CMH-Big Box-New-GasHt	81,900	0.04	15
169	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-New-GasHt	441,447	0.01	15
173	Non-Res	Lighting-CFL	INC to CMH-Small Box-New-ElecHt	81,900	0.06	15
178	Non-Res	Lighting-CFL	INC to CMH-Small Box-New-HtPmpHt	81,900	0.04	15
180	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Box-New-GasHt	602,173	0.01	15
183	Non-Res	Lighting-CFL	INC to CMH-Small Box-New-GasHt	81,900	0.05	15
184	Non-Res	Lighting-HID	Med MH to T8HP-Small Box-New-GasHt	441,447	0.01	15
187	Non-Res	Lighting-CFL	INC to CMH-High End-New-ElecHt	81,900	0.06	15
192	Non-Res	Lighting-CFL	INC to CMH-High End-New-HtPmpHt	81,900	0.05	15
195	Non-Res	Lighting-T12T8	T12-3 to T8HP-2-High End-New-GasHt	602,173	0.00	15
197	Non-Res	Lighting-CFL	INC to CMH-High End-New-GasHt	81,900	0.05	15
208	Non-Res	Lighting-T12T8	F96T12 to T8HP-Anchor-New-GasHt	602,173	0.01	15
211	Non-Res	Lighting-HID	Med MH to T8HP-Anchor-New-GasHt	441,447	0.01	15
214	Non-Res	Lighting-CFL	INC to CFL-K-12-New-ElecHt	145,600	0.02	15
218	Non-Res	Lighting-CFL	INC to CFL-K-12-New-HtPmpHt	145,600	0.01	15
222	Non-Res	Lighting-CFL	INC to CFL-K-12-New-GasHt	145,600	0.03	15
225	Non-Res	Lighting-CFL	INC to CMH-University-New-ElecHt	145,600	0.08	15
228	Non-Res	Lighting-CFL	INC to CMH-University-New-HtPmpHt	145,600	0.06	15
231	Non-Res	Lighting-CFL	INC to CMH-University-New-GasHt	145,600	0.06	15
235	Non-Res	Lighting-CFL	INC to CFL-Warehouse-New-ElecHt	655,200	0.01	15
237	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-New-ElecHt	441,447	0.00	15
240	Non-Res	Lighting-CFL	INC to CFL-Warehouse-New-HtPmpHt	655,200	0.01	15
242	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-New-HtPmpHt	441,447	0.00	15
243	Non-Res	Lighting-T12T8	F96T12 to T8HP-Warehouse-New-GasHt	602,173	0.00	15
245	Non-Res	Lighting-CFL	INC to CFL-Warehouse-New-GasHt	655,200	0.02	15
247	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-New-GasHt	441,447	0.01	15
252	Non-Res	Lighting-HID	Med MH to T5HO-Supermarket-New-ElecHt	441,447	0.01	15
257	Non-Res	Lighting-HID	Med MH to T5HO-Supermarket-New-HtPmpHt	441,447	0.01	15
258	Non-Res	Lighting-T12T8	F96T12 to T8HP-Supermarket-New-GasHt	602,173	0.00	15
262	Non-Res	Lighting-HID	Med MH to T5HO-Supermarket-New-GasHt	441,447	0.01	15
265	Non-Res	Lighting-CFL	INC to CMH-MIniMart-New-ElecHt	81,900	0.03	15
269	Non-Res	Lighting-CFL	INC to CMH-MIniMart-New-HtPmpHt	81,900	0.03	15
271	Non-Res	Lighting-T12T8	F96T12 to T8HP-MIniMart-New-GasHt	602,173	0.01	15
273	Non-Res	Lighting-CFL	INC to CMH-MIniMart-New-GasHt	81,900	0.04	15
278	Non-Res	Lighting-CFL	INC to CFL-Restaurant-New-ElecHt	72,800	0.01	15
283	Non-Res	Lighting-CFL	INC to CFL-Restaurant-New-HtPmpHt	72,800	0.01	15
285	Non-Res	Lighting-T12T8	F96T12 to T8HP-Restaurant-New-GasHt	602,173	0.01	15
288	Non-Res	Lighting-CFL	INC to CFL-Restaurant-New-GasHt	72,800	0.03	15
292	Non-Res	Lighting-CFL	INC to CFL-Lodging-New-ElecHt	218,400	0.01	15
297	Non-Res	Lighting-CFL	INC to CFL-Lodging-New-HtPmpHt	218,400	0.01	15
300	Non-Res	Lighting-T12T8	F96T12 to T8HP-Lodging-New-GasHt	602,173	0.01	15
302	Non-Res	Lighting-CFL	INC to CFL-Lodging-New-GasHt	218,400	0.02	15
307	Non-Res	Lighting-CFL	INC to CFL-Hospital-New-ElecHt	9,100	0.02	15
311	Non-Res	Lighting-CFL	INC to CFL-Hospital-New-HtPmpHt	9,100	0.01	15
313	Non-Res	Lighting-T12T8	F96T12 to T8HP-Hospital-New-GasHt	602,173	0.02	15
315	Non-Res	Lighting-CFL	INC to CFL-Hospital-New-GasHt	9,100	0.03	15
316	Non-Res	Lighting-HID	Med MH to T8HP-Hospital-New-GasHt	441,447	0.02	15

319	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-New-ElecHt	9,100	0.01	15
324	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-New-HtPmpHt	9,100	0.01	15
329	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-New-GasHt	9,100	0.01	15
331	Non-Res	Lighting-HID	Med MH to T8HP-OtherHealth-New-GasHt	441,447	0.00	15
334	Non-Res	Lighting-CFL	INC to CFL-Other-New-ElecHt	145,600	0.01	15
335	Non-Res	Lighting-HID	Med MH to T5HO-Other-New-ElecHt	441,447	0.01	15
336	Non-Res	Lighting-HID	Large MH to T5HO-Other-New-ElecHt	441,447	0.00	15
339	Non-Res	Lighting-CFL	INC to CFL-Other-New-HtPmpHt	145,600	0.01	15
340	Non-Res	Lighting-HID	Med MH to T5HO-Other-New-HtPmpHt	441,447	0.01	15
341	Non-Res	Lighting-HID	Large MH to T5HO-Other-New-HtPmpHt	441,447	0.00	15
344	Non-Res	Lighting-CFL	INC to CFL-Other-New-GasHt	145,600	0.01	15
345	Non-Res	Lighting-HID	Med MH to T5HO-Other-New-GasHt	441,447	0.02	15
346	Non-Res	Lighting-HID	Large MH to T5HO-Other-New-GasHt	441,447	0.01	15
347	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Large Off-Retro-ElecHt-PRE1987	602,173	0.02	15
350	Non-Res	Lighting-CFL	INC to CFL-Large Off-Retro-ElecHt-PRE1987	163,800	0.03	15
351	Non-Res	Lighting-T12T8	F96T12 to T8HP-Large Off-Retro-ElecHt-PRE1987	602,173	0.08	15
352	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Large Off-Retro-HtPmpHt-PRE1987	602,173	0.01	15
355	Non-Res	Lighting-CFL	INC to CFL-Large Off-Retro-HtPmpHt-PRE1987	163,800	0.03	15
356	Non-Res	Lighting-T12T8	F96T12 to T8HP-Large Off-Retro-HtPmpHt-PRE1987	602,173	0.07	15
357	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Large Off-Retro-GasHt-PRE1987	602,173	0.02	15
360	Non-Res	Lighting-CFL	INC to CFL-Large Off-Retro-GasHt-PRE1987	163,800	0.03	15
361	Non-Res	Lighting-T12T8	F96T12 to T8HP-Large Off-Retro-GasHt-PRE1987	602,173	0.07	15
362	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Medium Off-Retro-ElecHt-PRE1987	602,173	0.02	15
365	Non-Res	Lighting-CFL	INC to CFL-Medium Off-Retro-ElecHt-PRE1987	163,800	0.04	15
366	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Medium Off-Retro-ElecHt-PRE1987	602,173	0.01	15
368	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Medium Off-Retro-HtPmpHt-PRE1987	602,173	0.02	15
371	Non-Res	Lighting-CFL	INC to CFL-Medium Off-Retro-HtPmpHt-PRE1987	163,800	0.03	15
372	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Medium Off-Retro-HtPmpHt-PRE1987	602,173	0.01	15
374	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Medium Off-Retro-GasHt-PRE1987	602,173	0.02	15
377	Non-Res	Lighting-CFL	INC to CFL-Medium Off-Retro-GasHt-PRE1987	163,800	0.04	15
378	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Medium Off-Retro-GasHt-PRE1987	602,173	0.02	15
380	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Small Off-Retro-ElecHt-PRE1987	602,173	0.03	15
383	Non-Res	Lighting-CFL	INC to CFL-Small Off-Retro-ElecHt-PRE1987	163,800	0.06	15
384	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Small Off-Retro-ElecHt-PRE1987	602,173	0.02	15
386	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Small Off-Retro-HtPmpHt-PRE1987	602,173	0.02	15
389	Non-Res	Lighting-CFL	INC to CFL-Small Off-Retro-HtPmpHt-PRE1987	163,800	0.04	15
390	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Small Off-Retro-HtPmpHt-PRE1987	602,173	0.02	15
392	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Small Off-Retro-GasHt-PRE1987	602,173	0.03	15

395	Non-Res	Lighting-CFL	INC to CFL-Small Off-Retro-GasHt-PRE1987	163,800	0.05	15
396	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Small Off-Retro-GasHt-PRE1987	602,173	0.03	15
398	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Big Box-Retro-ElecHt-PRE1987	602,173	0.04	15
401	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-Retro-ElecHt-PRE1987	441,447	0.05	15
402	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Big Box-Retro-HtPmpHt-PRE1987	602,173	0.03	15
405	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-Retro-HtPmpHt-PRE1987	441,447	0.04	15
406	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Big Box-Retro-GasHt-PRE1987	602,173	0.04	15
409	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-Retro-GasHt-PRE1987	441,447	0.05	15
410	Non-Res	Lighting-T12T8	T12-4 to T8HP-3-Small Box-Retro-ElecHt-PRE1987	602,173	0.03	15
412	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Box-Retro-ElecHt-PRE1987	602,173	0.12	15
414	Non-Res	Lighting-HID	Med MH to T8HP-Small Box-Retro-ElecHt-PRE1987	441,447	0.13	15
415	Non-Res	Lighting-T12T8	T12-4 to T8HP-3-Small Box-Retro-HtPmpHt-PRE1987	602,173	0.02	15
417	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Box-Retro-HtPmpHt-PRE1987	602,173	0.09	15
419	Non-Res	Lighting-HID	Med MH to T8HP-Small Box-Retro-HtPmpHt-PRE1987	441,447	0.09	15
420	Non-Res	Lighting-T12T8	T12-4 to T8HP-3-Small Box-Retro-GasHt-PRE1987	602,173	0.03	15
422	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Box-Retro-GasHt-PRE1987	602,173	0.09	15
424	Non-Res	Lighting-HID	Med MH to T8HP-Small Box-Retro-GasHt-PRE1987	441,447	0.10	15
425	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-High End-Retro-ElecHt-PRE1987	602,173	0.05	15
427	Non-Res	Lighting-CFL	INC to CMH-High End-Retro-ElecHt-PRE1987	81,900	0.09	15
430	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-High End-Retro-HtPmpHt-PRE1987	602,173	0.04	15
432	Non-Res	Lighting-CFL	INC to CMH-High End-Retro-HtPmpHt-PRE1987	81,900	0.07	15
435	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-High End-Retro-GasHt-PRE1987	602,173	0.05	15
437	Non-Res	Lighting-CFL	INC to CMH-High End-Retro-GasHt-PRE1987	81,900	0.08	15
440	Non-Res	Lighting-T12T8	T12-4 to T8HP-3-Anchor-Retro-ElecHt-PRE1987	602,173	0.03	15
442	Non-Res	Lighting-T12T8	F96T12 to T8HP-Anchor-Retro-ElecHt-PRE1987	602,173	0.11	15
445	Non-Res	Lighting-T12T8	T12-4 to T8HP-3-Anchor-Retro-HtPmpHt-PRE1987	602,173	0.02	15
447	Non-Res	Lighting-T12T8	F96T12 to T8HP-Anchor-Retro-HtPmpHt-PRE1987	602,173	0.08	15
450	Non-Res	Lighting-T12T8	T12-4 to T8HP-3-Anchor-Retro-GasHt-PRE1987	602,173	0.03	15
452	Non-Res	Lighting-T12T8	F96T12 to T8HP-Anchor-Retro-GasHt-PRE1987	602,173	0.08	15
455	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-K-12-Retro-ElecHt-PRE1987	602,173	0.03	15
458	Non-Res	Lighting-CFL	INC to CFL-K-12-Retro-ElecHt-PRE1987	145,600	0.09	15
459	Non-Res	Lighting-HID	Med MH to T8HP-K-12-Retro-ElecHt-PRE1987	441,447	0.25	15

460	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-K-12-Retro-HtPmpHt-PRE1987	602,173	0.02	15
463	Non-Res	Lighting-CFL	INC to CFL-K-12-Retro-HtPmpHt-PRE1987	145,600	0.06	15
464	Non-Res	Lighting-HID	Med MH to T8HP-K-12-Retro-HtPmpHt-PRE1987	441,447	0.16	15
465	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-K-12-Retro-GasHt-PRE1987	602,173	0.03	15
468	Non-Res	Lighting-CFL	INC to CFL-K-12-Retro-GasHt-PRE1987	145,600	0.07	15
469	Non-Res	Lighting-HID	Med MH to T8HP-K-12-Retro-GasHt-PRE1987	441,447	0.16	15
470	Non-Res	Lighting-T12T8	F96T12 to T8HP-University-Retro-ElecHt-PRE1987	602,173	0.15	15
473	Non-Res	Lighting-CFL	INC to CFL-University-Retro-ElecHt-PRE1987	145,600	0.06	15
475	Non-Res	Lighting-T12T8	F96T12 to T8HP-University-Retro-HtPmpHt-PRE1987	602,173	0.11	15
478	Non-Res	Lighting-CFL	INC to CFL-University-Retro-HtPmpHt-PRE1987	145,600	0.04	15
480	Non-Res	Lighting-T12T8	F96T12 to T8HP-University-Retro-GasHt-PRE1987	602,173	0.11	15
483	Non-Res	Lighting-CFL	INC to CFL-University-Retro-GasHt-PRE1987	145,600	0.05	15
485	Non-Res	Lighting-T12T8	F96T12 to T8HP-Warehouse-Retro-ElecHt-PRE1987	602,173	0.14	15
487	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Warehouse-Retro-ElecHt-PRE1987	602,173	0.02	15
489	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-Retro-ElecHt-PRE1987	441,447	0.09	15
490	Non-Res	Lighting-T12T8	F96T12 to T8HP-Warehouse-Retro-HtPmpHt-PRE1987	602,173	0.11	15
492	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Warehouse-Retro-HtPmpHt-PRE1987	602,173	0.02	15
494	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-Retro-HtPmpHt-PRE1987	441,447	0.07	15
495	Non-Res	Lighting-T12T8	F96T12 to T8HP-Warehouse-Retro-GasHt-PRE1987	602,173	0.10	15
497	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Warehouse-Retro-GasHt-PRE1987	602,173	0.03	15
499	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-Retro-GasHt-PRE1987	441,447	0.07	15
500	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Supermarket-Retro-ElecHt-PRE1987	602,173	0.03	15
502	Non-Res	Lighting-CFL	INC to CMH-Supermarket-Retro-ElecHt-PRE1987	81,900	0.04	15
504	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Supermarket-Retro-HtPmpHt-PRE1987	602,173	0.02	15
506	Non-Res	Lighting-CFL	INC to CMH-Supermarket-Retro-HtPmpHt-PRE1987	81,900	0.04	15
508	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Supermarket-Retro-GasHt-PRE1987	602,173	0.03	15
510	Non-Res	Lighting-CFL	INC to CMH-Supermarket-Retro-GasHt-PRE1987	81,900	0.04	15
512	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-MIniMart-Retro-ElecHt-PRE1987	602,173	0.03	15
514	Non-Res	Lighting-CFL	INC to CMH-MIniMart-Retro-ElecHt-PRE1987	81,900	0.05	15
515	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-MIniMart-Retro-HtPmpHt-PRE1987	602,173	0.02	15
517	Non-Res	Lighting-CFL	INC to CMH-MIniMart-Retro-HtPmpHt-PRE1987	81,900	0.04	15
518	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-MIniMart-Retro-GasHt-PRE1987	602,173	0.04	15
520	Non-Res	Lighting-CFL	INC to CMH-MIniMart-Retro-GasHt-PRE1987	81,900	0.05	15
521	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Restaurant-Retro-ElecHt-PRE1987	602,173	0.07	15
522	Non-Res	Lighting-CFL	INC to CFL-Restaurant-Retro-ElecHt-PRE1987	72,800	0.06	15

523	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Restaurant-Retro-HtPmpHt-PRE1987	602,173	0.04	15
524	Non-Res	Lighting-CFL	INC to CFL-Restaurant-Retro-HtPmpHt-PRE1987	72,800	0.03	15
525	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Restaurant-Retro-GasHt-PRE1987	602,173	0.05	15
526	Non-Res	Lighting-CFL	INC to CFL-Restaurant-Retro-GasHt-PRE1987	72,800	0.05	15
527	Non-Res	Lighting-T12T8	F96T12 to T8HP-Lodging-Retro-ElecHt-PRE1987	602,173	0.12	15
529	Non-Res	Lighting-CFL	INC to CFL-Lodging-Retro-ElecHt-PRE1987	218,400	0.05	15
530	Non-Res	Lighting-T12T8	F96T12 to T8HP-Lodging-Retro-HtPmpHt-PRE1987	602,173	0.10	15
532	Non-Res	Lighting-CFL	INC to CFL-Lodging-Retro-HtPmpHt-PRE1987	218,400	0.04	15
533	Non-Res	Lighting-T12T8	F96T12 to T8HP-Lodging-Retro-GasHt-PRE1987	602,173	0.09	15
535	Non-Res	Lighting-CFL	INC to CFL-Lodging-Retro-GasHt-PRE1987	218,400	0.05	15
536	Non-Res	Lighting-T12T8	F96T12 to T8HP-Hospital-Retro-ElecHt-PRE1987	602,173	0.18	15
538	Non-Res	Lighting-CFL	INC to CFL-Hospital-Retro-ElecHt-PRE1987	9,100	0.07	15
539	Non-Res	Lighting-T12T8	F96T12 to T8HP-Hospital-Retro-HtPmpHt-PRE1987	602,173	0.08	15
541	Non-Res	Lighting-CFL	INC to CFL-Hospital-Retro-HtPmpHt-PRE1987	9,100	0.03	15
542	Non-Res	Lighting-T12T8	F96T12 to T8HP-Hospital-Retro-GasHt-PRE1987	602,173	0.08	15
544	Non-Res	Lighting-CFL	INC to CFL-Hospital-Retro-GasHt-PRE1987	9,100	0.05	15
545	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-OtherHealth-Retro-ElecHt-PRE1987	602,173	0.04	15
547	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-Retro-ElecHt-PRE1987	9,100	0.04	15
548	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-OtherHealth-Retro-HtPmpHt-PRE1987	602,173	0.04	15
550	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-Retro-HtPmpHt-PRE1987	9,100	0.03	15
551	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-OtherHealth-Retro-GasHt-PRE1987	602,173	0.04	15
553	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-Retro-GasHt-PRE1987	9,100	0.04	15
554	Non-Res	Lighting-T12T8	F96T12 to T8HP-Other-Retro-ElecHt-PRE1987	602,173	0.09	15
556	Non-Res	Lighting-T12T8	T12-2 to T8HP-1-Other-Retro-ElecHt-PRE1987	602,173	0.03	15
557	Non-Res	Lighting-CFL	INC to CFL-Other-Retro-ElecHt-PRE1987	145,600	0.04	15
558	Non-Res	Lighting-HID	Large MH to T5HO-Other-Retro-ElecHt-PRE1987	441,447	0.06	15
559	Non-Res	Lighting-T12T8	F96T12 to T8HP-Other-Retro-HtPmpHt-PRE1987	602,173	0.08	15
561	Non-Res	Lighting-T12T8	T12-2 to T8HP-1-Other-Retro-HtPmpHt-PRE1987	602,173	0.02	15
562	Non-Res	Lighting-CFL	INC to CFL-Other-Retro-HtPmpHt-PRE1987	145,600	0.03	15
563	Non-Res	Lighting-HID	Large MH to T5HO-Other-Retro-HtPmpHt-PRE1987	441,447	0.05	15
564	Non-Res	Lighting-T12T8	F96T12 to T8HP-Other-Retro-GasHt-PRE1987	602,173	0.08	15
566	Non-Res	Lighting-T12T8	T12-2 to T8HP-1-Other-Retro-GasHt-PRE1987	602,173	0.03	15
567	Non-Res	Lighting-CFL	INC to CFL-Other-Retro-GasHt-PRE1987	145,600	0.04	15
568	Non-Res	Lighting-HID	Large MH to T5HO-Other-Retro-GasHt-PRE1987	441,447	0.05	15
569	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Large Off-Retro-ElecHt-V1987_1994	602,173	0.02	15
572	Non-Res	Lighting-CFL	INC to CFL-Large Off-Retro-ElecHt-V1987_1994	163,800	0.03	15
573	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Large Off-Retro-ElecHt-V1987_1994	602,173	0.01	15

574	Non-Res	Lighting-HID	Med MH to T8HP-Large Off-Retro-ElecHt-V1987_1994	441,447	0.08	15
575	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Large Off-Retro-HtPmpHt-V1987_1994	602,173	0.01	15
578	Non-Res	Lighting-CFL	INC to CFL-Large Off-Retro-HtPmpHt-V1987_1994	163,800	0.03	15
579	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Large Off-Retro-HtPmpHt-V1987_1994	602,173	0.01	15
580	Non-Res	Lighting-HID	Med MH to T8HP-Large Off-Retro-HtPmpHt-V1987_1994	441,447	0.08	15
581	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Large Off-Retro-GasHt-V1987_1994	602,173	0.02	15
584	Non-Res	Lighting-CFL	INC to CFL-Large Off-Retro-GasHt-V1987_1994	163,800	0.03	15
585	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Large Off-Retro-GasHt-V1987_1994	602,173	0.02	15
586	Non-Res	Lighting-HID	Med MH to T8HP-Large Off-Retro-GasHt-V1987_1994	441,447	0.08	15
587	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Medium Off-Retro-ElecHt-V1987_1994	602,173	0.02	15
589	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Medium Off-Retro-ElecHt-V1987_1994	602,173	0.01	15
590	Non-Res	Lighting-CFL	INC to CFL-Medium Off-Retro-ElecHt-V1987_1994	163,800	0.04	15
591	Non-Res	Lighting-HID	Med MH to T8HP-Medium Off-Retro-ElecHt-V1987_1994	441,447	0.10	15
592	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Medium Off-Retro-HtPmpHt-V1987_1994	602,173	0.02	15
594	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Medium Off-Retro-HtPmpHt-V1987_1994	602,173	0.01	15
595	Non-Res	Lighting-CFL	INC to CFL-Medium Off-Retro-HtPmpHt-V1987_1994	163,800	0.03	15
596	Non-Res	Lighting-HID	Med MH to T8HP-Medium Off-Retro-HtPmpHt-V1987_1994	441,447	0.09	15
597	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Medium Off-Retro-GasHt-V1987_1994	602,173	0.02	15
599	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Medium Off-Retro-GasHt-V1987_1994	602,173	0.02	15
600	Non-Res	Lighting-CFL	INC to CFL-Medium Off-Retro-GasHt-V1987_1994	163,800	0.04	15
601	Non-Res	Lighting-HID	Med MH to T8HP-Medium Off-Retro-GasHt-V1987_1994	441,447	0.09	15
602	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Small Off-Retro-ElecHt-V1987_1994	602,173	0.03	15
604	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Small Off-Retro-ElecHt-V1987_1994	602,173	0.02	15
605	Non-Res	Lighting-CFL	INC to CFL-Small Off-Retro-ElecHt-V1987_1994	163,800	0.06	15
606	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Off-Retro-ElecHt-V1987_1994	602,173	0.14	15
608	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Small Off-Retro-HtPmpHt-V1987_1994	602,173	0.02	15
610	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Small Off-Retro-HtPmpHt-V1987_1994	602,173	0.02	15
611	Non-Res	Lighting-CFL	INC to CFL-Small Off-Retro-HtPmpHt-V1987_1994	163,800	0.04	15
612	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Off-Retro-HtPmpHt-V1987_1994	602,173	0.10	15

614	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Small Off-Retro-GasHt-V1987_1994	602,173	0.03	15
616	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Small Off-Retro-GasHt-V1987_1994	602,173	0.03	15
617	Non-Res	Lighting-CFL	INC to CFL-Small Off-Retro-GasHt-V1987_1994	163,800	0.05	15
618	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Off-Retro-GasHt-V1987_1994	602,173	0.10	15
620	Non-Res	Lighting-T12T8	T12-4 to T8HP-3-Big Box-Retro-ElecHt-V1987_1994	602,173	0.02	15
622	Non-Res	Lighting-T12T8	F96T12 to T8HP-Big Box-Retro-ElecHt-V1987_1994	602,173	0.07	15
624	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-Retro-ElecHt-V1987_1994	441,447	0.05	15
625	Non-Res	Lighting-T12T8	T12-4 to T8HP-3-Big Box-Retro-HtPmpHt-V1987_1994	602,173	0.01	15
627	Non-Res	Lighting-T12T8	F96T12 to T8HP-Big Box-Retro-HtPmpHt-V1987_1994	602,173	0.06	15
629	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-Retro-HtPmpHt-V1987_1994	441,447	0.04	15
630	Non-Res	Lighting-T12T8	T12-4 to T8HP-3-Big Box-Retro-GasHt-V1987_1994	602,173	0.02	15
632	Non-Res	Lighting-T12T8	F96T12 to T8HP-Big Box-Retro-GasHt-V1987_1994	602,173	0.06	15
634	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-Retro-GasHt-V1987_1994	441,447	0.04	15
635	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Box-Retro-ElecHt-V1987_1994	602,173	0.11	15
637	Non-Res	Lighting-CFL	INC to CMH-Small Box-Retro-ElecHt-V1987_1994	81,900	0.09	15
638	Non-Res	Lighting-HID	Med MH to T8HP-Small Box-Retro-ElecHt-V1987_1994	441,447	0.12	15
639	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Box-Retro-HtPmpHt-V1987_1994	602,173	0.08	15
641	Non-Res	Lighting-CFL	INC to CMH-Small Box-Retro-HtPmpHt-V1987_1994	81,900	0.06	15
642	Non-Res	Lighting-HID	Med MH to T8HP-Small Box-Retro-HtPmpHt-V1987_1994	441,447	0.09	15
643	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Box-Retro-GasHt-V1987_1994	602,173	0.09	15
645	Non-Res	Lighting-CFL	INC to CMH-Small Box-Retro-GasHt-V1987_1994	81,900	0.07	15
646	Non-Res	Lighting-HID	Med MH to T8HP-Small Box-Retro-GasHt-V1987_1994	441,447	0.09	15
647	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-High End-Retro-ElecHt-V1987_1994	602,173	0.05	15
649	Non-Res	Lighting-T12T8	F96T12 to T8HP-High End-Retro-ElecHt-V1987_1994	602,173	0.11	15
650	Non-Res	Lighting-CFL	INC to CMH-High End-Retro-ElecHt-V1987_1994	81,900	0.09	15
652	Non-Res	Lighting-HID	Med MH to T8HP-High End-Retro-ElecHt-V1987_1994	441,447	0.12	15
653	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-High End-Retro-HtPmpHt-V1987_1994	602,173	0.04	15
655	Non-Res	Lighting-T12T8	F96T12 to T8HP-High End-Retro-HtPmpHt-V1987_1994	602,173	0.09	15
656	Non-Res	Lighting-CFL	INC to CMH-High End-Retro-HtPmpHt-V1987_1994	81,900	0.07	15

658	Non-Res	Lighting-HID	Med MH to T8HP-High End-Retro-HtPmpHt-V1987_1994	441,447	0.10	15
659	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-High End-Retro-GasHt-V1987_1994	602,173	0.06	15
661	Non-Res	Lighting-T12T8	F96T12 to T8HP-High End-Retro-GasHt-V1987_1994	602,173	0.10	15
662	Non-Res	Lighting-CFL	INC to CMH-High End-Retro-GasHt-V1987_1994	81,900	0.08	15
664	Non-Res	Lighting-HID	Med MH to T8HP-High End-Retro-GasHt-V1987_1994	441,447	0.11	15
665	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Anchor-Retro-ElecHt-V1987_1994	602,173	0.05	15
667	Non-Res	Lighting-T12T8	F96T12 to T8HP-Anchor-Retro-ElecHt-V1987_1994	602,173	0.10	15
668	Non-Res	Lighting-CFL	INC to CMH-Anchor-Retro-ElecHt-V1987_1994	81,900	0.08	15
670	Non-Res	Lighting-HID	Med MH to T8HP-Anchor-Retro-ElecHt-V1987_1994	441,447	0.11	15
671	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Anchor-Retro-HtPmpHt-V1987_1994	602,173	0.03	15
673	Non-Res	Lighting-T12T8	F96T12 to T8HP-Anchor-Retro-HtPmpHt-V1987_1994	602,173	0.08	15
674	Non-Res	Lighting-CFL	INC to CMH-Anchor-Retro-HtPmpHt-V1987_1994	81,900	0.06	15
676	Non-Res	Lighting-HID	Med MH to T8HP-Anchor-Retro-HtPmpHt-V1987_1994	441,447	0.08	15
677	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Anchor-Retro-GasHt-V1987_1994	602,173	0.06	15
679	Non-Res	Lighting-T12T8	F96T12 to T8HP-Anchor-Retro-GasHt-V1987_1994	602,173	0.09	15
680	Non-Res	Lighting-CFL	INC to CMH-Anchor-Retro-GasHt-V1987_1994	81,900	0.07	15
682	Non-Res	Lighting-HID	Med MH to T8HP-Anchor-Retro-GasHt-V1987_1994	441,447	0.10	15
683	Non-Res	Lighting-T12T8	T12-3 to T8HP-2-K-12-Retro-ElecHt-V1987_1994	602,173	0.05	15
686	Non-Res	Lighting-CFL	INC to CFL-K-12-Retro-ElecHt-V1987_1994	145,600	0.09	15
687	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-K-12-Retro-ElecHt-V1987_1994	602,173	0.03	15
688	Non-Res	Lighting-HID	Med MH to T8HP-K-12-Retro-ElecHt-V1987_1994	441,447	0.24	15
689	Non-Res	Lighting-T12T8	T12-3 to T8HP-2-K-12-Retro-HtPmpHt-V1987_1994	602,173	0.04	15
692	Non-Res	Lighting-CFL	INC to CFL-K-12-Retro-HtPmpHt-V1987_1994	145,600	0.06	15
693	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-K-12-Retro-HtPmpHt-V1987_1994	602,173	0.02	15
694	Non-Res	Lighting-HID	Med MH to T8HP-K-12-Retro-HtPmpHt-V1987_1994	441,447	0.16	15
695	Non-Res	Lighting-T12T8	T12-3 to T8HP-2-K-12-Retro-GasHt-V1987_1994	602,173	0.05	15
698	Non-Res	Lighting-CFL	INC to CFL-K-12-Retro-GasHt-V1987_1994	145,600	0.07	15
699	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-K-12-Retro-GasHt-V1987_1994	602,173	0.04	15
700	Non-Res	Lighting-HID	Med MH to T8HP-K-12-Retro-GasHt-V1987_1994	441,447	0.15	15
701	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-University-Retro-ElecHt-V1987_1994	602,173	0.07	15
705	Non-Res	Lighting-HID	Med MH to T8HP-University-Retro-ElecHt-V1987_1994	441,447	0.16	15
706	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-University-Retro-HtPmpHt-V1987_1994	602,173	0.05	15

710	Non-Res	Lighting-HID	Med MH to T8HP-University-Retro-HtPmpHt-V1987_1994	441,447	0.11	15
711	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-University-Retro-GasHt-V1987_1994	602,173	0.06	15
715	Non-Res	Lighting-HID	Med MH to T8HP-University-Retro-GasHt-V1987_1994	441,447	0.11	15
716	Non-Res	Lighting-T12T8	F96T12 to T8HP-Warehouse-Retro-ElecHt-V1987_1994	602,173	0.14	15
718	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Warehouse-Retro-ElecHt-V1987_1994	602,173	0.02	15
720	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-Retro-ElecHt-V1987_1994	441,447	0.09	15
721	Non-Res	Lighting-T12T8	F96T12 to T8HP-Warehouse-Retro-HtPmpHt-V1987_1994	602,173	0.10	15
723	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Warehouse-Retro-HtPmpHt-V1987_1994	602,173	0.02	15
725	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-Retro-HtPmpHt-V1987_1994	441,447	0.07	15
726	Non-Res	Lighting-T12T8	F96T12 to T8HP-Warehouse-Retro-GasHt-V1987_1994	602,173	0.10	15
728	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Warehouse-Retro-GasHt-V1987_1994	602,173	0.03	15
730	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-Retro-GasHt-V1987_1994	441,447	0.07	15
731	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Supermarket-Retro-ElecHt-V1987_1994	602,173	0.01	15
733	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Supermarket-Retro-ElecHt-V1987_1994	602,173	0.01	15
734	Non-Res	Lighting-CFL	INC to CMH-Supermarket-Retro-ElecHt-V1987_1994	81,900	0.04	15
737	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Supermarket-Retro-HtPmpHt-V1987_1994	602,173	0.01	15
739	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Supermarket-Retro-HtPmpHt-V1987_1994	602,173	0.01	15
740	Non-Res	Lighting-CFL	INC to CMH-Supermarket-Retro-HtPmpHt-V1987_1994	81,900	0.04	15
743	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-Supermarket-Retro-GasHt-V1987_1994	602,173	0.03	15
745	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-Supermarket-Retro-GasHt-V1987_1994	602,173	0.02	15
746	Non-Res	Lighting-CFL	INC to CMH-Supermarket-Retro-GasHt-V1987_1994	81,900	0.05	15
749	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-MIniMart-Retro-ElecHt-V1987_1994	602,173	0.01	15
751	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-MIniMart-Retro-ElecHt-V1987_1994	602,173	0.01	15
752	Non-Res	Lighting-CFL	INC to CMH-MIniMart-Retro-ElecHt-V1987_1994	81,900	0.05	15
754	Non-Res	Lighting-HID	Med MH to T8HP-MIniMart-Retro-ElecHt-V1987_1994	441,447	0.07	15
755	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-MIniMart-Retro-HtPmpHt-V1987_1994	602,173	0.01	15
757	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-MIniMart-Retro-HtPmpHt-V1987_1994	602,173	0.01	15
758	Non-Res	Lighting-CFL	INC to CMH-MIniMart-Retro-HtPmpHt-V1987_1994	81,900	0.04	15
760	Non-Res	Lighting-HID	Med MH to T8HP-MIniMart-Retro-HtPmpHt-V1987_1994	441,447	0.05	15
761	Non-Res	Lighting-T12T8	T12-4 to T8HP-2-MIniMart-Retro-GasHt-V1987_1994	602,173	0.03	15

763	Non-Res	Lighting-T12T8	F96T12VHO to T8HP-4-MIniMart-Retro-GasHt-V1987_1994	602,173	0.03	15
764	Non-Res	Lighting-CFL	INC to CMH-MIniMart-Retro-GasHt-V1987_1994	81,900	0.05	15
766	Non-Res	Lighting-HID	Med MH to T8HP-MIniMart-Retro-GasHt-V1987_1994	441,447	0.07	15
767	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Restaurant-Retro-ElecHt-V1987_1994	602,173	0.06	15
768	Non-Res	Lighting-CFL	INC to CFL-Restaurant-Retro-ElecHt-V1987_1994	72,800	0.06	15
770	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Restaurant-Retro-HtPmpHt-V1987_1994	602,173	0.04	15
771	Non-Res	Lighting-CFL	INC to CFL-Restaurant-Retro-HtPmpHt-V1987_1994	72,800	0.03	15
773	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-Restaurant-Retro-GasHt-V1987_1994	602,173	0.06	15
774	Non-Res	Lighting-CFL	INC to CFL-Restaurant-Retro-GasHt-V1987_1994	72,800	0.05	15
776	Non-Res	Lighting-T12T8	F96T12 to T8HP-Lodging-Retro-ElecHt-V1987_1994	602,173	0.12	15
778	Non-Res	Lighting-CFL	INC to CFL-Lodging-Retro-ElecHt-V1987_1994	218,400	0.05	15
779	Non-Res	Lighting-T12T8	F96T12 to T8HP-Lodging-Retro-HtPmpHt-V1987_1994	602,173	0.09	15
781	Non-Res	Lighting-CFL	INC to CFL-Lodging-Retro-HtPmpHt-V1987_1994	218,400	0.04	15
782	Non-Res	Lighting-T12T8	F96T12 to T8HP-Lodging-Retro-GasHt-V1987_1994	602,173	0.09	15
784	Non-Res	Lighting-CFL	INC to CFL-Lodging-Retro-GasHt-V1987_1994	218,400	0.05	15
785	Non-Res	Lighting-T12T8	F96T12 to T8HP-Hospital-Retro-ElecHt-V1987_1994	602,173	0.17	15
787	Non-Res	Lighting-CFL	INC to CFL-Hospital-Retro-ElecHt-V1987_1994	9,100	0.07	15
788	Non-Res	Lighting-T12T8	F96T12 to T8HP-Hospital-Retro-HtPmpHt-V1987_1994	602,173	0.08	15
790	Non-Res	Lighting-CFL	INC to CFL-Hospital-Retro-HtPmpHt-V1987_1994	9,100	0.03	15
791	Non-Res	Lighting-T12T8	F96T12 to T8HP-Hospital-Retro-GasHt-V1987_1994	602,173	0.08	15
793	Non-Res	Lighting-CFL	INC to CFL-Hospital-Retro-GasHt-V1987_1994	9,100	0.05	15
794	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-OtherHealth-Retro-ElecHt-V1987_1994	602,173	0.04	15
796	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-Retro-ElecHt-V1987_1994	9,100	0.04	15
797	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-OtherHealth-Retro-HtPmpHt-V1987_1994	602,173	0.04	15
799	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-Retro-HtPmpHt-V1987_1994	9,100	0.03	15
800	Non-Res	Lighting-T12T8	T12-3 to T8HP-3-OtherHealth-Retro-GasHt-V1987_1994	602,173	0.04	15
802	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-Retro-GasHt-V1987_1994	9,100	0.04	15
803	Non-Res	Lighting-T12T8	F96T12 to T8HP-Other-Retro-ElecHt-V1987_1994	602,173	0.08	15
807	Non-Res	Lighting-HID	Large MH to T5HO-Other-Retro-ElecHt-V1987_1994	441,447	0.05	15
808	Non-Res	Lighting-T12T8	F96T12 to T8HP-Other-Retro-HtPmpHt-V1987_1994	602,173	0.07	15
812	Non-Res	Lighting-HID	Large MH to T5HO-Other-Retro-HtPmpHt-V1987_1994	441,447	0.05	15
813	Non-Res	Lighting-T12T8	F96T12 to T8HP-Other-Retro-GasHt-V1987_1994	602,173	0.08	15

817	Non-Res	Lighting-HID	Large MH to T5HO-Other-Retro-GasHt-V1987_1994	441,447	0.05	15
818	Non-Res	Lighting-T12T8	F96T12 to T8HP-Large Off-Retro-ElecHt-V1995_2001	602,173	0.07	15
821	Non-Res	Lighting-CFL	INC to CFL-Large Off-Retro-ElecHt-V1995_2001	163,800	0.03	15
822	Non-Res	Lighting-HID	Med MH to T8HP-Large Off-Retro-ElecHt-V1995_2001	441,447	0.08	15
823	Non-Res	Lighting-T12T8	F96T12 to T8HP-Large Off-Retro-HtPmpHt-V1995_2001	602,173	0.07	15
826	Non-Res	Lighting-CFL	INC to CFL-Large Off-Retro-HtPmpHt-V1995_2001	163,800	0.03	15
827	Non-Res	Lighting-HID	Med MH to T8HP-Large Off-Retro-HtPmpHt-V1995_2001	441,447	0.08	15
828	Non-Res	Lighting-T12T8	F96T12 to T8HP-Large Off-Retro-GasHt-V1995_2001	602,173	0.07	15
831	Non-Res	Lighting-CFL	INC to CFL-Large Off-Retro-GasHt-V1995_2001	163,800	0.03	15
832	Non-Res	Lighting-HID	Med MH to T8HP-Large Off-Retro-GasHt-V1995_2001	441,447	0.08	15
833	Non-Res	Lighting-T12T8	F96T12 to T8HP-Medium Off-Retro-ElecHt-V1995_2001	602,173	0.09	15
836	Non-Res	Lighting-CFL	INC to CFL-Medium Off-Retro-ElecHt-V1995_2001	163,800	0.04	15
837	Non-Res	Lighting-HID	Med MH to T8HP-Medium Off-Retro-ElecHt-V1995_2001	441,447	0.10	15
838	Non-Res	Lighting-T12T8	F96T12 to T8HP-Medium Off-Retro-HtPmpHt-V1995_2001	602,173	0.08	15
841	Non-Res	Lighting-CFL	INC to CFL-Medium Off-Retro-HtPmpHt-V1995_2001	163,800	0.03	15
842	Non-Res	Lighting-HID	Med MH to T8HP-Medium Off-Retro-HtPmpHt-V1995_2001	441,447	0.09	15
843	Non-Res	Lighting-T12T8	F96T12 to T8HP-Medium Off-Retro-GasHt-V1995_2001	602,173	0.08	15
846	Non-Res	Lighting-CFL	INC to CFL-Medium Off-Retro-GasHt-V1995_2001	163,800	0.04	15
847	Non-Res	Lighting-HID	Med MH to T8HP-Medium Off-Retro-GasHt-V1995_2001	441,447	0.09	15
848	Non-Res	Lighting-T12T8	T12-3 to T8HP-2-Small Off-Retro-ElecHt-V1995_2001	602,173	0.03	15
851	Non-Res	Lighting-CFL	INC to CFL-Small Off-Retro-ElecHt-V1995_2001	163,800	0.06	15
853	Non-Res	Lighting-T12T8	T12-3 to T8HP-2-Small Off-Retro-HtPmpHt-V1995_2001	602,173	0.03	15
856	Non-Res	Lighting-CFL	INC to CFL-Small Off-Retro-HtPmpHt-V1995_2001	163,800	0.04	15
858	Non-Res	Lighting-T12T8	T12-3 to T8HP-2-Small Off-Retro-GasHt-V1995_2001	602,173	0.04	15
861	Non-Res	Lighting-CFL	INC to CFL-Small Off-Retro-GasHt-V1995_2001	163,800	0.05	15
863	Non-Res	Lighting-T12T8	F96T12 to T8HP-Big Box-Retro-ElecHt-V1995_2001	602,173	0.07	15
865	Non-Res	Lighting-CFL	INC to CMH-Big Box-Retro-ElecHt-V1995_2001	81,900	0.06	15
867	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-Retro-ElecHt-V1995_2001	441,447	0.05	15
868	Non-Res	Lighting-T12T8	F96T12 to T8HP-Big Box-Retro-HtPmpHt-V1995_2001	602,173	0.06	15
870	Non-Res	Lighting-CFL	INC to CMH-Big Box-Retro-HtPmpHt-V1995_2001	81,900	0.05	15

872	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-Retro-HtPmpHt-V1995_2001	441,447	0.04	15
873	Non-Res	Lighting-T12T8	F96T12 to T8HP-Big Box-Retro-GasHt-V1995_2001	602,173	0.06	15
875	Non-Res	Lighting-CFL	INC to CMH-Big Box-Retro-GasHt-V1995_2001	81,900	0.05	15
877	Non-Res	Lighting-HID	Large MH to T5HO-Big Box-Retro-GasHt-V1995_2001	441,447	0.04	15
878	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Box-Retro-ElecHt-V1995_2001	602,173	0.10	15
881	Non-Res	Lighting-CFL	INC to CMH-Small Box-Retro-ElecHt-V1995_2001	81,900	0.08	15
882	Non-Res	Lighting-HID	Med MH to T8HP-Small Box-Retro-ElecHt-V1995_2001	441,447	0.12	15
883	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Box-Retro-HtPmpHt-V1995_2001	602,173	0.08	15
886	Non-Res	Lighting-CFL	INC to CMH-Small Box-Retro-HtPmpHt-V1995_2001	81,900	0.06	15
887	Non-Res	Lighting-HID	Med MH to T8HP-Small Box-Retro-HtPmpHt-V1995_2001	441,447	0.09	15
888	Non-Res	Lighting-T12T8	F96T12 to T8HP-Small Box-Retro-GasHt-V1995_2001	602,173	0.08	15
891	Non-Res	Lighting-CFL	INC to CMH-Small Box-Retro-GasHt-V1995_2001	81,900	0.07	15
892	Non-Res	Lighting-HID	Med MH to T8HP-Small Box-Retro-GasHt-V1995_2001	441,447	0.09	15
893	Non-Res	Lighting-T12T8	T12-3 to T8HP-2-High End-Retro-ElecHt-V1995_2001	602,173	0.03	15
895	Non-Res	Lighting-CFL	INC to CMH-High End-Retro-ElecHt-V1995_2001	81,900	0.08	15
898	Non-Res	Lighting-T12T8	T12-3 to T8HP-2-High End-Retro-HtPmpHt-V1995_2001	602,173	0.02	15
900	Non-Res	Lighting-CFL	INC to CMH-High End-Retro-HtPmpHt-V1995_2001	81,900	0.07	15
903	Non-Res	Lighting-T12T8	T12-3 to T8HP-2-High End-Retro-GasHt-V1995_2001	602,173	0.04	15
905	Non-Res	Lighting-CFL	INC to CMH-High End-Retro-GasHt-V1995_2001	81,900	0.08	15
908	Non-Res	Lighting-T12T8	F96T12 to T8HP-Anchor-Retro-ElecHt-V1995_2001	602,173	0.10	15
911	Non-Res	Lighting-HID	Med MH to T8HP-Anchor-Retro-ElecHt-V1995_2001	441,447	0.11	15
912	Non-Res	Lighting-T12T8	F96T12 to T8HP-Anchor-Retro-HtPmpHt-V1995_2001	602,173	0.08	15
915	Non-Res	Lighting-HID	Med MH to T8HP-Anchor-Retro-HtPmpHt-V1995_2001	441,447	0.08	15
916	Non-Res	Lighting-T12T8	F96T12 to T8HP-Anchor-Retro-GasHt-V1995_2001	602,173	0.09	15
919	Non-Res	Lighting-HID	Med MH to T8HP-Anchor-Retro-GasHt-V1995_2001	441,447	0.10	15
920	Non-Res	Lighting-T12T8	F96T12 to T8HP-K-12-Retro-ElecHt-V1995_2001	602,173	0.21	15
923	Non-Res	Lighting-CFL	INC to CFL-K-12-Retro-ElecHt-V1995_2001	145,600	0.08	15
924	Non-Res	Lighting-HID	Med MH to T8HP-K-12-Retro-ElecHt-V1995_2001	441,447	0.23	15
925	Non-Res	Lighting-T12T8	F96T12 to T8HP-K-12-Retro-HtPmpHt-V1995_2001	602,173	0.14	15
928	Non-Res	Lighting-CFL	INC to CFL-K-12-Retro-HtPmpHt-V1995_2001	145,600	0.06	15
929	Non-Res	Lighting-HID	Med MH to T8HP-K-12-Retro-HtPmpHt-V1995_2001	441,447	0.16	15

930	Non-Res	Lighting-T12T8	F96T12 to T8HP-K-12-Retro-GasHt-V1995_2001	602,173	0.14	15
933	Non-Res	Lighting-CFL	INC to CFL-K-12-Retro-GasHt-V1995_2001	145,600	0.06	15
934	Non-Res	Lighting-HID	Med MH to T8HP-K-12-Retro-GasHt-V1995_2001	441,447	0.15	15
935	Non-Res	Lighting-T12T8	F96T12 to T8HP-University-Retro-ElecHt-V1995_2001	602,173	0.14	15
937	Non-Res	Lighting-CFL	INC to CFL-University-Retro-ElecHt-V1995_2001	145,600	0.06	15
939	Non-Res	Lighting-T12T8	F96T12 to T8HP-University-Retro-HtPmpHt-V1995_2001	602,173	0.10	15
941	Non-Res	Lighting-CFL	INC to CFL-University-Retro-HtPmpHt-V1995_2001	145,600	0.04	15
943	Non-Res	Lighting-T12T8	F96T12 to T8HP-University-Retro-GasHt-V1995_2001	602,173	0.10	15
945	Non-Res	Lighting-CFL	INC to CFL-University-Retro-GasHt-V1995_2001	145,600	0.05	15
947	Non-Res	Lighting-T12T8	F96T12 to T8HP-Warehouse-Retro-ElecHt-V1995_2001	602,173	0.14	15
949	Non-Res	Lighting-CFL	INC to CFL-Warehouse-Retro-ElecHt-V1995_2001	655,200	0.06	15
951	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-Retro-ElecHt-V1995_2001	441,447	0.09	15
952	Non-Res	Lighting-T12T8	F96T12 to T8HP-Warehouse-Retro-HtPmpHt-V1995_2001	602,173	0.10	15
954	Non-Res	Lighting-CFL	INC to CFL-Warehouse-Retro-HtPmpHt-V1995_2001	655,200	0.04	15
956	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-Retro-HtPmpHt-V1995_2001	441,447	0.07	15
957	Non-Res	Lighting-T12T8	F96T12 to T8HP-Warehouse-Retro-GasHt-V1995_2001	602,173	0.10	15
959	Non-Res	Lighting-CFL	INC to CFL-Warehouse-Retro-GasHt-V1995_2001	655,200	0.05	15
961	Non-Res	Lighting-HID	Large MH to T5HO-Warehouse-Retro-GasHt-V1995_2001	441,447	0.07	15
962	Non-Res	Lighting-T12T8	F96T12 to T8HP-Supermarket-Retro-ElecHt-V1995_2001	602,173	0.05	15
966	Non-Res	Lighting-HID	Med MH to T8HP-Supermarket-Retro-ElecHt-V1995_2001	441,447	0.06	15
967	Non-Res	Lighting-T12T8	F96T12 to T8HP-Supermarket-Retro-HtPmpHt-V1995_2001	602,173	0.05	15
971	Non-Res	Lighting-HID	Med MH to T8HP-Supermarket-Retro-HtPmpHt-V1995_2001	441,447	0.05	15
972	Non-Res	Lighting-T12T8	F96T12 to T8HP-Supermarket-Retro-GasHt-V1995_2001	602,173	0.06	15
976	Non-Res	Lighting-HID	Med MH to T8HP-Supermarket-Retro-GasHt-V1995_2001	441,447	0.06	15
977	Non-Res	Lighting-T12T8	F96T12 to T8HP-MIniMart-Retro-ElecHt-V1995_2001	602,173	0.06	15
979	Non-Res	Lighting-CFL	INC to CMH-MIniMart-Retro-ElecHt-V1995_2001	81,900	0.05	15
980	Non-Res	Lighting-HID	Med MH to T8HP-MIniMart-Retro-ElecHt-V1995_2001	441,447	0.07	15
981	Non-Res	Lighting-T12T8	F96T12 to T8HP-MIniMart-Retro-HtPmpHt-V1995_2001	602,173	0.05	15
983	Non-Res	Lighting-CFL	INC to CMH-MIniMart-Retro-HtPmpHt-V1995_2001	81,900	0.04	15
984	Non-Res	Lighting-HID	Med MH to T8HP-MIniMart-Retro-HtPmpHt-V1995_2001	441,447	0.05	15

985	Non-Res	Lighting-T12T8	F96T12 to T8HP-MIniMart-Retro-GasHt-V1995_2001	602,173	0.07	15
987	Non-Res	Lighting-CFL	INC to CMH-MIniMart-Retro-GasHt-V1995_2001	81,900	0.05	15
988	Non-Res	Lighting-HID	Med MH to T8HP-MIniMart-Retro-GasHt-V1995_2001	441,447	0.07	15
989	Non-Res	Lighting-T12T8	F96T12 to T8HP-Restaurant-Retro-ElecHt-V1995_2001	602,173	0.14	15
992	Non-Res	Lighting-CFL	INC to CFL-Restaurant-Retro-ElecHt-V1995_2001	72,800	0.06	15
994	Non-Res	Lighting-T12T8	F96T12 to T8HP-Restaurant-Retro-HtPmpHt-V1995_2001	602,173	0.08	15
997	Non-Res	Lighting-CFL	INC to CFL-Restaurant-Retro-HtPmpHt-V1995_2001	72,800	0.03	15
999	Non-Res	Lighting-T12T8	F96T12 to T8HP-Restaurant-Retro-GasHt-V1995_2001	602,173	0.09	15
1002	Non-Res	Lighting-CFL	INC to CFL-Restaurant-Retro-GasHt-V1995_2001	72,800	0.05	15
1004	Non-Res	Lighting-T12T8	F96T12 to T8HP-Lodging-Retro-ElecHt-V1995_2001	602,173	0.12	15
1006	Non-Res	Lighting-CFL	INC to CFL-Lodging-Retro-ElecHt-V1995_2001	218,400	0.05	15
1008	Non-Res	Lighting-T12T8	F96T12 to T8HP-Lodging-Retro-HtPmpHt-V1995_2001	602,173	0.09	15
1010	Non-Res	Lighting-CFL	INC to CFL-Lodging-Retro-HtPmpHt-V1995_2001	218,400	0.04	15
1012	Non-Res	Lighting-T12T8	F96T12 to T8HP-Lodging-Retro-GasHt-V1995_2001	602,173	0.09	15
1014	Non-Res	Lighting-CFL	INC to CFL-Lodging-Retro-GasHt-V1995_2001	218,400	0.05	15
1016	Non-Res	Lighting-T12T8	F96T12 to T8HP-Hospital-Retro-ElecHt-V1995_2001	602,173	0.17	15
1018	Non-Res	Lighting-CFL	INC to CFL-Hospital-Retro-ElecHt-V1995_2001	9,100	0.07	15
1019	Non-Res	Lighting-HID	Med MH to T8HP-Hospital-Retro-ElecHt-V1995_2001	441,447	0.19	15
1020	Non-Res	Lighting-T12T8	F96T12 to T8HP-Hospital-Retro-HtPmpHt-V1995_2001	602,173	0.08	15
1022	Non-Res	Lighting-CFL	INC to CFL-Hospital-Retro-HtPmpHt-V1995_2001	9,100	0.03	15
1023	Non-Res	Lighting-HID	Med MH to T8HP-Hospital-Retro-HtPmpHt-V1995_2001	441,447	0.08	15
1024	Non-Res	Lighting-T12T8	F96T12 to T8HP-Hospital-Retro-GasHt-V1995_2001	602,173	0.08	15
1026	Non-Res	Lighting-CFL	INC to CFL-Hospital-Retro-GasHt-V1995_2001	9,100	0.05	15
1027	Non-Res	Lighting-HID	Med MH to T8HP-Hospital-Retro-GasHt-V1995_2001	441,447	0.09	15
1028	Non-Res	Lighting-T12T8	F96T12 to T8HP-OtherHealth-Retro-ElecHt-V1995_2001	602,173	0.09	15
1030	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-Retro-ElecHt-V1995_2001	9,100	0.04	15
1031	Non-Res	Lighting-HID	Med MH to T8HP-OtherHealth-Retro-ElecHt-V1995_2001	441,447	0.10	15
1032	Non-Res	Lighting-T12T8	F96T12 to T8HP-OtherHealth-Retro-HtPmpHt-V1995_2001	602,173	0.08	15
1034	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-Retro-HtPmpHt-V1995_2001	9,100	0.03	15
1035	Non-Res	Lighting-HID	Med MH to T8HP-OtherHealth-Retro-HtPmpHt-V1995_2001	441,447	0.09	15
1036	Non-Res	Lighting-T12T8	F96T12 to T8HP-OtherHealth-Retro-GasHt-V1995_2001	602,173	0.08	15
1038	Non-Res	Lighting-CFL	INC to CFL-OtherHealth-Retro-GasHt-V1995_2001	9,100	0.04	15

1039	Non-Res	Lighting-HID	Med MH to T8HP-OtherHealth-Retro-GasHt-V1995_2001	441,447	0.09	15
1040	Non-Res	Lighting-T12T8	F96T12 to T8HP-Other-Retro-ElecHt-V1995_2001	602,173	0.08	15
1042	Non-Res	Lighting-CFL	INC to CFL-Other-Retro-ElecHt-V1995_2001	145,600	0.03	15
1043	Non-Res	Lighting-HID	Med MH to T8HP-Other-Retro-ElecHt-V1995_2001	441,447	0.09	15
1044	Non-Res	Lighting-T12T8	F96T12 to T8HP-Other-Retro-HtPmpHt-V1995_2001	602,173	0.07	15
1046	Non-Res	Lighting-CFL	INC to CFL-Other-Retro-HtPmpHt-V1995_2001	145,600	0.03	15
1047	Non-Res	Lighting-HID	Med MH to T8HP-Other-Retro-HtPmpHt-V1995_2001	441,447	0.08	15
1048	Non-Res	Lighting-T12T8	F96T12 to T8HP-Other-Retro-GasHt-V1995_2001	602,173	0.07	15
1050	Non-Res	Lighting-CFL	INC to CFL-Other-Retro-GasHt-V1995_2001	145,600	0.03	15
1051	Non-Res	Lighting-HID	Med MH to T8HP-Other-Retro-GasHt-V1995_2001	441,447	0.08	15
1058	Non-Res	Lighting-Signs	Outdoor Sign Ballast - Night	546,000	0.01	13
1059	Non-Res	Lighting-Signs	Outdoor Sign Ballast - 24	546,000	0.01	7
1060	Non-Res	Lighting-Signs	Outdoor Sign Ballast - Night - Retro	546,000	0.11	13
1061	Non-Res	Lighting-Signs	Outdoor Sign Ballast - 24 - Retro	546,000	0.09	7
1065	Non-Res		EE Reach-In Refrigerator from E-Star Baseline	189,800	0.03	9
1067	Non-Res		EE Reach-In Freezer from E-Star Baseline	351,800	0.01	9
1070	Non-Res		EE Ice Maker from FEMP Baseline	82,043	0.07	9
1071	Non-Res		EE Vending Machine from Average Baseline	147,056	0.04	9
1072	Non-Res		EE Vending Machine from E-Star Baseline	115,544	0.02	9
1146	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-Large Off-ElecHt	60,667	0.09	21
1147	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-Large Off-HtPmpHt	60,667	0.08	21
1148	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-Large Off-GasHt	60,667	0.08	21
1149	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-Medium Off-ElecHt	60,667	0.13	21
1150	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-Medium Off-HtPmpHt	60,667	0.12	21
1151	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-Medium Off-GasHt	60,667	0.11	21
1152	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-Small Off-ElecHt	60,667	0.18	21
1153	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-Small Off-HtPmpHt	60,667	0.13	21
1154	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-Small Off-GasHt	60,667	0.11	21
1155	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-K-12-ElecHt	60,667	0.22	21
1156	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-K-12-HtPmpHt	60,667	0.15	21
1157	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-K-12-GasHt	60,667	0.13	21
1158	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-University-ElecHt	60,667	0.17	21
1159	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-University-HtPmpHt	60,667	0.13	21
1160	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-University-GasHt	60,667	0.11	21
1161	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-OtherHealth-ElecHt	60,667	0.11	21

1162	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-OtherHealth-HtPmpHt	60,667	0.10	21
1163	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-New-OtherHealth-GasHt	60,667	0.10	21
1164	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-Large Off-ElecHt	60,667	0.09	21
1165	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-Large Off-HtPmpHt	60,667	0.08	21
1166	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-Large Off-GasHt	60,667	0.08	21
1167	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-Medium Off-ElecHt	60,667	0.13	21
1168	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-Medium Off-HtPmpHt	60,667	0.12	21
1169	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-Medium Off-GasHt	60,667	0.11	21
1170	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-Small Off-ElecHt	60,667	0.18	21
1171	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-Small Off-HtPmpHt	60,667	0.13	21
1172	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-Small Off-GasHt	60,667	0.11	21
1173	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-K-12-ElecHt	60,667	0.23	21
1174	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-K-12-HtPmpHt	60,667	0.15	21
1175	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-K-12-GasHt	60,667	0.13	21
1176	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-University-ElecHt	60,667	0.18	21
1177	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-University-HtPmpHt	60,667	0.13	21
1178	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-University-GasHt	60,667	0.11	21
1179	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-OtherHealth-ElecHt	60,667	0.11	21
1180	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-OtherHealth-HtPmpHt	60,667	0.10	21
1181	Non-Res	Lighting-Daylig	Perimeter Day lighting Controls (Advanced)-NR-OtherHealth-GasHt	60,667	0.10	21
1290	Non-Res	Appliances	Vending Machine Controller-Large Machine w/Illuminated Front	49,920	0.02	10
1291	Non-Res	Appliances	Vending Machine Controller-Small Machine or Machine without Illuminated Front	33,280	0.03	10

2009

Electric Integrated Resource Plan

Appendix G – Avista Distribution System Efficiencies Program

AVISTA®

August 31, 2009

Avista Distribution System Efficiencies Program

Programs to Reduce Energy Loss across Avista's Distribution System

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Executive Summary

Avista's Distribution System consists of approximately three hundred and thirty feeders covering a geographical area of 30,000 square miles. The distribution feeders range in distribution voltage from 4.16 kV to 34.5 kV phase to phase and are typically rated to meet 10 MVA load for the typical 13.2 kV feeder. The distribution feeders reside in urban, suburban and rural areas and can range in length from 3 to 73 miles. The distribution feeders are typically designed to provide service for approximately one to two thousand residential customers.

The engineering analysis summarized in this report determines losses across the distribution system for the following program areas: 1) Conductor losses, 2) Distribution Transformers, 3) Secondary Districts and 4) VAr compensation. Although additional programs like phase balancing and Conservation Voltage Reduction (CVR) could have been included in the analysis, they were intentionally left out since daily operational activity may negate the energy savings. The energy loss, capital investment and reduction in O&M costs resulting from the individual efficiencies programs were combined on a per feeder basis. This approach provided a means to rank and compare energy savings and net resource cost for each feeder.

The efficiency analysis of the distribution feeders evaluated the existing energy losses and energy savings resulting from implementing the program upgrades. The study identified the existing distribution system losses to be approximately 3.6%. Assuming, all of the distribution feeders studied were economically viable to upgrade, the resulting system energy losses would be reduced by 2%. The total energy savings corresponding to the implementation of the upgrades would correspond to an energy savings of approximately 29.2 MW on peak and 13.5 MW on average.

Although it may not be prudent to upgrade all of the distribution feeders, this study ranks the feeders by diminishing economic return. The economic metric used to rank feeders was net resource cost. The net resource cost for each feeder was determined for O&M offsets forecasted on a five, ten and fifteen year time horizon. This variable O&M forecast provided a means to filter on or off the number of economically viable feeder upgrades. Other criteria used to reduce the number of viable feeder upgrade projects included capital investment greater then $0.5 million and net resource cost less then $100 per Mwh.

The feeder upgrade program by itself falls short of being a strategic vision. However, it can be used as a first step towards a broader strategic view to be included in programs like capital budgeting, energy efficiency, and O&M reduction. A more robust corporate strategic vision for aging infrastructure rehabilitation would need to incorporate the following elements: 1) Movement of bulk power across our transmission system, 2) Optimum distribution topologies, 3) Substation size, locations and architectures, and 4) Reliable forecasts of geographical centered load growth. Once these elements are incorporated into the existing feeder upgrade program, a long term plan for Avista's electric infrastructure can be developed to move infrastructure upgrades from a tactical or reactive approach to a planned replacement strategy.

Introduction

Objective

The objective of the system efficiency analysis was to obtain a first order of magnitude assessment of energy savings across Avista's electric distribution system. The analysis was constructed to address the following two questions: 1) How much energy savings is available across Avista's distribution system? 2) Which feeders provide the most cost-effective for the least investment across the system?

Concession

The analysis did not include operational or design options to assist in refining cost estimates or selecting feeders for upgrade. Also, this analysis focused solely on the distribution system and did not consider system changes which may incorporate the installation of substations or new transmission lines.

Background

Avista's electric distribution system consists of approximately three hundred and thirty feeders covering a geographical area of 30,000 square miles. The distribution feeders range in voltage from 4.16 kV to 34.5 kV phase to phase and are typically rated to meet 10 MVA load for a typical 13.2 kV feeder. The distribution feeders reside in urban, suburban and rural areas and can range in length from 3 to 73 miles. The distribution feeders are typically designed to provide service from one to two thousand residential customers.

Past efficiency studies on Avista's distribution system have typically focused on either individual reinforcement projects or specific equipment upgrades. This current analysis differs from past analysis by combining several efficiency programs across most of Avista's distribution feeders. The results of the analysis provided an overall assessment of the energy savings on a per feeder basis. Also, this analysis incorporated capital, operational and maintenance costs into the economic assessment in order to determine the net resource value.

Analysis Tool Set

To determine efficiency gains associated with upgrading the distribution feeders, an analysis framework was developed by combining complementary technologies existing at Avista. For example, the SynerGEE Electric tool and its corresponding analysis engine Solver was leveraged to perform power flow analysis. Avista's Facility Management (AFM) system and Major Equipment Tracking (MET) system were queried to obtain the number, age and sizes of transformers on the distribution feeders. In addition, Avista's Substation Control and Data Acquisition (SCADA) system provided annual peak load and VAr consumption at the substation buses. Finally, the economic analysis of the annual Operation and Maintenance (O&M) forecast was approximated by Asset Managements Isograph Availability Workbench.

Engineering Analysis Methodology

The engineering analysis evaluated losses across the distribution system for the following program areas: 1) Conductor losses, 2) Distribution Transformers, 3) Secondary Districts and 4) VAr compensation. The energy losses, capital investment and reduction in O&M costs resulting from the individual efficiencies programs were combined on a per feeder basis. This analysis approach provided a means to rank and compare energy savings, along with return on investment, for each feeder. The individual programs methodology and assumptions are summarized in the descriptions below.

Reconductoring

The Distribution Engineering Group builds and maintains the SynerGEE distribution databases. The SynerGEE databases require material size, type and network topology for Avista's distribution feeders as provided by the Avista Facilities Management (AFM) system. These databases provide a network model from which a power flow analysis can be performed to evaluate thermal and voltage performance of each feeder. The power flow analysis accuracy is dependent upon these SynerGEE databases being both current and accurate. The internal work processes used to maintain the SynerGEE models are summarized below.

- *Avista's AFM system is maintained by applications which support the design of new facilities, outages, operations and maintenance activities on the distribution system.*
- *An internally developed AFM application called Model Builder is used to upload the AFM data into a SynerGEE Model database*
- *Distribution Engineering reviews the SynerGEE Models and performs system calibration of the models.*
- *At the distribution feeder bus, a peak current meter read is recorded and inputted by Distribution Planning.*

In order to perform a power flow analysis for all three hundred plus feeders, in this system efficiency analysis, the process was automated by utilizing Advantica's Solver engine. By using Solver, a scripting tool was developed to run multiple power flow iterations utilizing the SynerGEE models. The first iteration evaluated the energy loss with existing conductor and flagged conductor which did not adhere to Distribution Engineering's new economic conductor standard summarized in Table 1. The second iteration updated the flagged conductor with the new conductor standard and evaluated the energy loss.

Table 1 Economic Conductor Standard

Ampacity Range	Selected Conductor
0 to 25 Amps	2ACSR
26 to 100 Amps	4/0AAC
101 to 250 Amps	556AAC
251 to 700 Amps	795AAC

The incremental energy savings resulting from reconductoring the feeder was determined by evaluating the peak loss of KW for the existing conductor versus the new conductor standards. Once the peak incremental loss was determined between the two runs, an average energy loss was calculated. The average energy loss was determined by multiplying the peak loss by a loss factor. The loss factor was determined by squaring the load factor. The assumptions used in the analysis are summarized in the list below.

- *The load factor for the distribution feeders were approximated by evaluating the load factor at several of the substation buses with hourly SCADA data*
- *The load factor used for the distribution analysis was 50 percent*
- *The loss factor used for the distribution analysis was 25 percent*

Overhead Transformers
Between 1986 and 1987, Distribution Engineering conducted a set of no-load tests on approximately two hundred overhead transformers of various sizes, types and vintages. From the tests, a set of curves were developed to approximate the no-load losses for a transformer rating and age class (see Appendix). As a result, the no-load curves showed the loss for a particular transformer could be categorized into the following three vintages of transformers: 1) Pre-1960, 2) 1960 – 1983, 3) Post 1983.

In 2008, Distribution Engineering implemented a new design standard for overhead transformers which is based on a life-cycle cost analysis and recently established an avoided cost of energy value of $66/MW. Consequently, the new transformer design standards specify transformers with no-load losses less then recently enacted Department of Energy (DOE) transformer efficiency standards. Upgrading the older overhead transformers accounted for a significant incremental energy savings in no-load losses.

A software script was developed within the AFM system to retrieve the number, size and vintage of transformers located on distribution feeders. The analysis assumed the overhead transformers would be replaced in-kind with the new lower no load loss overhead transformers. The difference between the no-load loss of the old and new transformer accounts for the incremental energy savings. The overhead transformer no-load loss occurs every hour of the year and is independent of the actual load. Therefore, the incremental energy savings are an average value. The transformer population for particular vintage classes is summarized in Table 2, for overhead transformers only.

Table 2 Overhead Transformer Vintages

Vintage	Population Number
Pre1963	10,416
1963 - 1983	32,788
Post 1983	43,204

Secondary Districts
Up to the late 1960's, Avista designed and constructed large secondary districts in residential neighborhoods. A secondary district is designed with a distribution transformer and a three wire secondary lines which provided service tie positions for up to thirty customers. At the time of construction, these districts were economically viable since they increased the customer to transformer ratio. Due to the increased cost of energy and associated operational O&M costs, the elimination or redesign of the secondary districts were evaluated for efficiency gains.

To determine the number of secondary districts on a feeder, an AFM script was written to identify the number of customers connected to a distribution transformer. To support the analysis, a secondary district was defined as an overhead transformer with twelve or more service premises. Using this classification, the ten feeders with the most secondary districts returned from the AFM query is summarized in Table 3.

Table 3 Feeder Secondary Districts

Feeder Name	Number of Secondary Districts
Ross Park 12F1	56
Ross Park 12F6	55
Ross Park 12F5	53
Sunset 12F3	52
Lyons & Standard 12F2	49
Francis & Cedar 12F1	47
Fort Wright 12F1	43
Beacon 12F5	40
Collage & Walnut 12F5	39
Third & Hatch 12F2	37

In order to evaluate the reduction in energy losses, a SynerGEE power flow analysis was performed on some typical secondary districts. To improve the efficiency of the secondary districts, two options were considered: 1) Reduce the district length by the addition of a transformer, 2) Reconductoring the district with insulated triplex conductor. The power flow analysis concluded districts with more then twenty two service premises should be reduced in length by the addition of an overhead transformer, while districts with less then twenty two service premises should be replaced using overhead triplex wire.

The secondary district analysis only reviewed the reduction of energy loss and did not consider other design considerations such as flicker and reliability. Although an operational case could be made to eliminate districts by the addition of transformers for every four services, the energy loss in the transformers exceed the energy savings in the elimination of the district. The average KW loss associated with the district types is summarized in Table 4 below.

Table 4 Secondary District Type

Secondary District Type	Average KW Loss
10-12	.234
12-22	.356
22 and up	1.03

VAr Compensation

Another efficiency program evaluated the reduction of current on the line by offsetting the reactive load with the installation of switched capacitors. A VAr controller operates the switched capacitor to respond to adverse reactive loading on a feeder. The amount of energy savings associated with the installation of switched capacitors depends upon the feeder power factor. To a large extent, motor loading required for air conditioning drives the reactive loading on a feeder. Consequently, the number of hours a switched capacitor operates is seasonal. The analysis methodology developed for evaluating the energy savings associated for a feeder is described below.

The Ninth and Central feeders were modeled to determine the size and type of switched capacitors as well as the annual hours of operation. A SCADA point located at Ninth and Central provided the amount of MVAr loading on a substation transformer on a per hour basis. A load duration curve developed from this data determined the capacitor size and hours of operation. Once sized, SynerGEE's capacitor placement application optimized both the peak power savings and the ideal placement of the capacitor. The energy savings obtained by installing the capacitor was determined by multiplying the number of hours of operation by the KW savings to MVAr ratio.

This analysis methodology was simplified for the rest of the feeders by assuming the KW to MVAr ratio for all distribution feeders. The capacitor size for the rest of the feeders was assumed to be a single 900 KVAr bank. The hours of operation for the 900 KVAr were based on the load duration curve.

Economic Analysis

The economic analysis for the feeder upgrade programs estimated the capital investment, calculated the energy savings and forecasted operational and maintenance expense and interim capital investments. The capital investment required to implement the efficiencies programs were obtained from engineering estimates described below. The energy savings for a feeder upgrade was determined by the efficiency programs described previously. Finally, Asset Management modeled the feeders using their tools and forecasted the reduction in operational and maintenance expense resulting from the feeder upgrade, also described below.

Engineering Estimate

Reconductoring

The material and labor estimate were performed by Distribution Engineering in conjunction with Planning and are based on 2008 material and labor costs. The reconductoring estimate was based on whether the conductor was being replaced or whether new construction was necessary to install the conductor. The assumptions made in the unit pricing for each case are summarized in the list below.

New Construction

- New Pole
- New Anchors
- New Cross Arms

Replacement

- 40 % replacement of the poles, cross arms and anchors

The conductor replacement unit price is summarized in the Table 5 below.

Table 5 Conductor Unit Price

CONDUCTOR_TYPE	Replacement $/Per Mile	New Construction $/Per Mile
795AAC	$60,000	$85,000
556AAC	$45,000	$71,000
4/0AAC	$35,000	$52,000
2ACSR	$30,000	$42,000

Distribution Transformers

The engineering estimates for distribution transformers were obtained from Purchasing and are based on 2008 material and labor costs. The overhead transformers met the new design requirements for no-load losses. The estimated unit prices for various sized overhead transformers are summarized in Table 6.

Table 6 Overhead Transformers

Overhead Transformers	Installed Cost
15 KVA	$1,014
25 KVA	$1,301
37.5 KVA	$1,952
75 KVA	$2,519
100 KVA	$3,278
150 KVA	$3,430
225 KVA	$3,936
300 KVA	$4,310

Secondary Districts

The engineering estimates to redesign secondary districts were determined for three distinct archetypes. The secondary district archetypes were based on the number of customers attached to overhead transformers. The labor and material costs to redesign the secondary districts for the distinct archetypes are listed in Table 7.

Table 7 Secondary Districts

Secondary District Archetypes	Cost
10-12 Customer Service Points	$5,728 - $8,687
13-22 Customer Service Points	$6,181 - $8,820
>22 Customer Service Points	$7,539 - $10,498

VAr Compensation

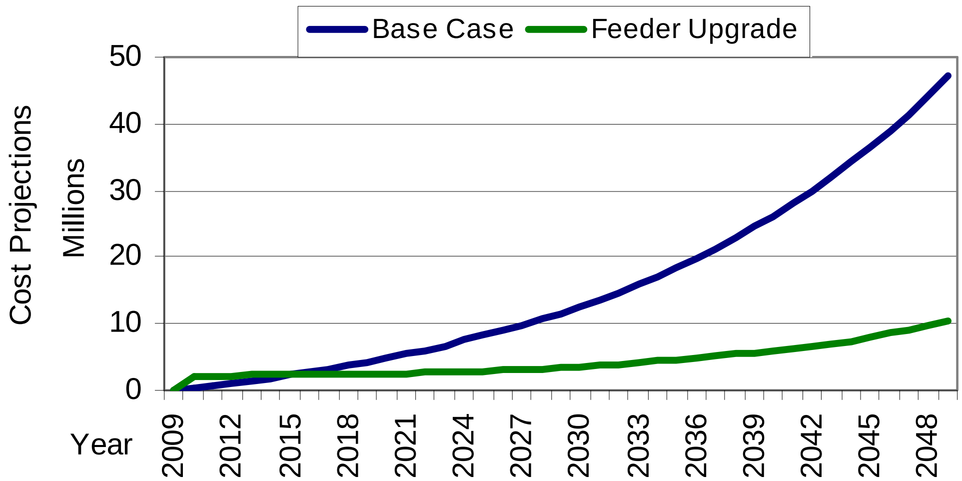
The labor and material estimate for switched capacitors were based on recently purchased and installed capacitors. The cost for the purchased and installed capacitors for a 900 KVAr bank was $11,000.

Asset Management

The Asset Management team developed the Availability Workbench Model for six distribution feeders. The Availability Workbench Model combines input from the following areas: 1) system performance, 2) facility data, 3) manager and crafts 4) industry data, and 5) key performance indicators. From these inputs, the workbench application generates a forecasted annualized O&M and Capital cost model. The cost model is generated by comparing O&M expense resulting after a feeder upgrade versus the O&M expense for a base case. Asset Managements base case assumes the equipment will be replaced upon failure.

The Asset Management analysis results indicated that upgrading the feeders reduces forecasted O&M expense when compared to the base case. The feeder upgrade program replaces aged equipment with new equipment to improve system efficiencies and reliability. The replacement of equipment reduces future O&M expenditures which is an economic benefit to the project and is included in the analysis. The reduction and avoidance of future increases in O&M expenditures are illustrated in Figure 1. The base case curve shows an exponential growth in O&M costs resulting from failure of the aging equipment failing. The feeder upgrade curve shows an initial increase in revenue requirement corresponding to the cost of the upgrade but shows how the revenue requirement rises slower due to the replacement of the aging facility.

Figure 1 O&M Cost Programs



The Asset Management program conducted an O&M analysis for the following six feeders: 1) 9CE12F4, 2) SUN12F3, 3) SUN12F1, 4) SUN12F2, 5) COL12F2, 6) KET12F2. The Asset Management team estimated the time to develop a Workbench model to determine the O&M expenditure was approximately thirty hours per feeder. To reduce the time to perform the analysis, the O&M expenditure curve determined for the six feeders was used to interpolate the expenditure for the other feeders. The linear interpolation was based on a strong correlation between the O&M expense and the length of the feeders analyzed.

In order to limit the interpolation, the O&M expense was generated only for feeders with lengths between 12.5 miles (SUN12F3) and149 miles (KET12F2). Consequently, feeders with lengths outside this range were not included in the net resource cost analysis. Although the feeders were not included in the analysis the may still be economically viable. One example is the ORI12F3 feeder which ranks first in energy savings as shown Table 12. However, the feeder was not included in the net resource cost analysis since its length of 170 miles exceeded the maximum mileage criteria used for the analysis.

Energy Results

The efficiency analysis of the distribution feeders evaluated the existing energy losses and energy savings resulting from implementing the program upgrades. The study identified the existing distribution system losses to be approximately 3.6%. Assuming, all of the distribution feeders studied were economically viable to upgrade, the resulting system energy losses would be reduced by 2%. The total energy savings corresponding to the implementation of the upgrades would correspond to an energy savings of approximately 29.2 MW on peak and 13.5 MW on average. The energy savings break down across each program is described below.

Reconductoring

The reconductoring program as mentioned previously used the SynerGEE application to determine the conductor losses across our feeders. The distribution conductor operating at twenty percent or greater of its rated ampacity was upgraded to the new distribution standard, if warranted. The analysis was run again to determine the incremental reduction in conductor losses corresponding to the conductor upgrade. The results of the analysis are summarized in Table 8.

Table 8 Reconductoring Power Savings

Number of Feeders	Peak Loss KW	Average Loss KW	Peak Loss Savings KW	Average Loss Savings KW
302	35,676	8,919	14,973	3,743

Overhead Transformers

The efficiency analysis evaluated the no-load losses across the existing transformer population to determine the average no-load transformer loss on Avista's distribution feeders. The incremental energy savings was determined by taking the difference between the no-load losses of the new transformer standard versus the older vintage transformers. The results of the analysis are summarized in Table 9.

Table 9 Overhead Transformer Power Savings

Vintage	Total number of Transformers	Average Loss KW	Average Loss Savings KW
Pre1963	10,416	4700	1,907
1963 To 1983	32,788	9470	5,710

Secondary Districts

The energy losses corresponding to the secondary districts were categorized by the number of service premises connected to the district. The incremental energy savings from the redesign of these districts was determined by taking the difference between the existing losses and the new designed district losses. The results of the analysis are summarized in Table 10.

Table 10 Secondary Districts Power Savings

Archetypes	Number of Districts	Peak Loss KW	Avg. Power Loss KW	Peak Loss Savings KW	Avg. Power Savings KW
10 - 12 Customer Service Points	3,414	5,516	1,379	3,196	799
13 - 22 Customer Service Points	1,302	3,156	789	1,856	464
> 22 Customer Service Points	32	196	49	132	33
TOTAL	4,748	8,868	2,217	5,184	1,296

VAr Compensation

A VAr duration curve across Avista's load was developed from the electric transmission SCADA data. This load duration curve helped to book mark the amount of reactive load on Avista's system. The analysis assumed approximately 100 MVAr of reactive load could be offset in the distribution system. It was also assumed that standard switched bank installation of 900 KVAr would be deployed for a single feeder. Therefore, approximately 112 feeders would have switched capacitors installed. Finally, as mentioned previously the ratio between kilowatts savings for megavar compensation was determined by evaluating several distribution feeders. The results of the savings are shown in Table 11.

Table 11 VAr Compensation Power Savings

Number of Feeders	Bank Size	KW Savings	Average Hours Operation	Peak Power Savings KW	Avg Power Savings KW
112	900 KVAr	13	5100	1456	847

In addition to reviewing the individual programs for energy savings, the programs were combined on a per feeder basis. This allowed the feeders to be ranked on the total amount of energy savings available on a per feeder basis. Table 12 provides the number of feeders which would provided power savings over one hundred kilowatts. The list of feeders and corresponding power savings is listed in Table 12.

Table 12 Top Feeder Power Savings

Feeder Name	Total Cost	Total Average kW
ORI12F3	$1,170,357	201
CHW12F3	$1,682,503	184
SPI12F1	$1,243,066	172
WIL12F2	$1,705,623	155
KET12F2	$968,669	143
STM631	$1,211,798	139
CLV34F1	$1,765,413	127
F&C12F1	$1,499,055	123
ROX751	$1,069,310	120
BEA12F2	$1,423,808	116
SUN12F3	$1,224,379	113
GIF34F2	$1,253,973	112
BEA12F1	$1,221,446	111
COB12F2	$822,727	109
RAT231	$1,111,882	108
ORO1281	$669,953	107
CLV12F4	$907,259	105
ROS12F1	$1,428,530	104
ROS12F6	$1,316,652	102
L&S12F2	$1,101,072	101
BEA12F5	$1,210,094	101

Economic Ranking

Although it may not be prudent to upgrade all of the distribution feeders, this study ranks the feeders by diminishing economic return. The economic metric used to rank feeders was net resource cost. The net resource cost for each feeder was determined for O&M offsets forecasted on a five, ten and fifteen year time horizon. This variable O&M forecast provided a means to filter on or off the number of economically viable feeder upgrades. Other criteria used to reduce the number of viable feeder upgrade projects included capital investment greater then $0.5 million and net resource cost less then $100 per MW.

The ranking of the most viable economic feeder upgrades are illustrated in the following three tables. Table 13, Table 14 and Table 15 is based on a five, ten and fifteen year O&M time horizon respectively.

Table 13 Net Resource Cost - Five Year O&M

Feeder	Net Resource Cost $/Mwh	Capital Investment	KW
KET12F2	$55.00	$968,669.0	142.99
SPI12F1	$67.73	$1,243,065.8	171.98
ORO1281	$68.58	$669,953.1	106.53
COL12F2	$74.92	$822,726.8	108.96
COB12F2	$74.92	$822,726.8	108.96
LF34F1	$76.29	$595,875.0	72.71
COB12F1	$82.87	$671,737.4	77.55
PVW241	$89.40	$528,985.4	53.68
CLV12F4	$89.83	$907,259.4	105.03
L&R512	$94.53	$546,237.7	55.02
OLD721	$94.87	$608,545.7	67.75
ARD12F2	$95.35	$817,711.5	82.33
STM631	$97.26	$1,211,797.7	139.36
ROX751	$99.44	$1,069,309.6	120.48

Table 14 Net Resource Cost – Ten Year O&M

Feeder	Net Resource Cost $/Mwh	Capital Investment	KW
KET12F2	$31.00	$968,669.0	142.99
SPI12F1	$49.19	$1,243,065.8	171.98
LF34F1	$51.54	$595,875.0	72.71
PVW241	$56.55	$528,985.4	53.68
ORO1281	$56.75	$669,953.1	106.53
COL12F2	$57.56	$822,726.8	108.96
COB12F2	$57.56	$822,726.8	108.96
COB12F1	$59.29	$671,737.4	77.55
CHW12F2	$60.29	$600,325.8	41.95
L&R512	$63.81	$546,237.7	55.02
ARD12F2	$70.17	$817,711.5	82.33

Feeder	Net Resource Cost $/Mwh	Capital Investment	KW
CLV12F4	$72.60	$907,259.4	105.03
GIF34F2	$72.61	$1,253,972.5	112.27
OLD721	$73.12	$608,545.7	67.75
MIS431	$79.16	$780,915.9	57.44
F&C12F2	$80.57	$610,746.1	65.07
RDN12F1	$81.47	$519,904.7	34.81
ORI12F1	$81.53	$832,306.2	75.82
FOR12F1	$81.55	$560,782.7	39.13
CKF711	$83.62	$912,659.4	88.03
STM631	$85.11	$1,211,797.7	139.36
PF213	$85.38	$579,843.8	55.23
PRA222	$85.48	$543,659.3	51.64
NE12F2	$85.54	$508,476.3	45.31
ROX751	$86.10	$1,069,309.6	120.48
RAT231	$86.36	$1,111,881.6	108.16
PUL112	$86.42	$528,311.9	44.24
SE12F2	$86.66	$714,903.4	69.83
TEN1256	$87.12	$789,201.9	85.49
GLN12F2	$88.33	$584,770.4	51.32
LIB12F3	$88.64	$529,971.6	46.50
CLV12F2	$88.87	$904,207.9	90.25
PUL116	$89.22	$537,639.7	45.27
CRG1261	$89.84	$561,702.8	44.85
APW112	$91.22	$522,196.7	45.53
WAK12F1	$93.01	$560,901.0	48.81
DEE12F2	$93.14	$743,960.8	69.63
GRV1274	$94.16	$671,626.1	66.96
PDL1202	$94.22	$581,246.6	55.32
SUN12F5	$95.38	$642,722.3	52.58
LIB12F2	$95.47	$726,778.1	58.98
DAL131	$97.14	$870,985.5	84.97
SAG741	$97.29	$634,916.4	44.82
BKR12F1	$98.20	$683,595.8	64.18
DEE12F1	$98.39	$996,523.0	67.68
M15515	$99.16	$540,077.6	44.53
SE12F4	$99.42	$686,532.3	59.34
M15512	$99.50	$531,004.8	43.84

Table 15 Net Resource Cost - Fifteen Year O&M

Feeder	Net Resource Cost $/Mwh	Capital Investment	KW
CHW12F2	$2.9	$600,325.8	41.95
KET12F2	$4.6	$968,669.0	142.99
PVW241	$23.3	$528,985.4	53.68

Feeder	Net Resource Cost $/Mwh	Capital Investment	KW
LF34F1	$26.4	$595,875.0	72.71
SPI12F1	$28.9	$1,243,065.8	171.98
RDN12F1	$29.4	$519,904.7	34.81
L&R512	$32.8	$546,237.7	55.02
FOR12F1	$34.0	$560,782.7	39.13
MIS431	$35.1	$780,915.9	57.44
COB12F1	$35.3	$671,737.4	77.55
GIF34F2	$39.5	$1,253,972.5	112.27
COL12F2	$39.9	$822,726.8	108.96
COB12F2	$39.9	$822,726.8	108.96
ARD12F2	$44.1	$817,711.5	82.33
ORO1281	$44.8	$669,953.1	106.53
AIR12F1	$48.7	$615,395.6	49.12
OLD721	$51.3	$608,545.7	67.75
PUL112	$51.6	$528,311.9	44.24
CRG1261	$54.0	$561,702.8	44.85
ORI12F1	$54.7	$832,306.2	75.82
CLV12F4	$55.1	$907,259.4	105.03
NE12F2	$55.5	$508,476.3	45.31
PUL116	$56.2	$537,639.7	45.27
DEE12F1	$56.5	$996,523.0	67.68
SAG741	$57.4	$634,916.4	44.82
GLN12F2	$58.3	$584,770.4	51.32
LIB12F3	$59.0	$529,971.6	46.50
PF213	$60.1	$579,843.8	55.23
PRA222	$60.3	$543,659.3	51.64
F&C12F2	$60.5	$610,746.1	65.07
CKF711	$61.5	$912,659.4	88.03
ODN731	$61.9	$627,946.4	44.01
APW112	$62.8	$522,196.7	45.53
SE12F2	$64.1	$714,903.4	69.83
SUN12F5	$64.6	$642,722.3	52.58
WAK12F1	$65.2	$560,901.0	48.81
LIB12F2	$65.8	$726,778.1	58.98
RAT231	$65.9	$1,111,881.6	108.16
CLV12F2	$70.0	$904,207.9	90.25
M15515	$70.7	$540,077.6	44.53
DEE12F2	$70.8	$743,960.8	69.63
M15512	$71.5	$531,004.8	43.84
TEN1256	$71.6	$789,201.9	85.49
ROX751	$72.7	$1,069,309.6	120.48
STM631	$72.8	$1,211,797.7	139.36
SE12F4	$74.2	$686,532.3	59.34
PDL1202	$74.6	$581,246.6	55.32
SPT4S30	$75.7	$541,420.5	44.99

Feeder	Net Resource Cost $/Mwh	Capital Investment	KW
CHE12F4	$76.2	$667,293.8	57.48
OGA611	$76.5	$780,992.8	58.08
GRV1274	$77.5	$671,626.1	66.96
SOT522	$77.7	$632,142.6	51.02
CFD1210	$78.0	$563,163.3	45.20
SOT521	$78.4	$538,938.7	46.10
BKR12F1	$79.3	$683,595.8	64.18
NE12F1	$79.6	$687,832.8	62.33
DAL131	$79.8	$870,985.5	84.97
PDL1203	$81.8	$559,682.9	45.75
CFD1211	$82.4	$734,775.9	65.51
MIL12F3	$82.8	$619,499.7	55.10
CDA123	$83.5	$672,854.8	56.29
9CE12F1	$83.5	$616,123.8	54.88
MEA12F2	$83.7	$750,315.2	63.99
SIP12F4	$84.3	$634,440.7	53.05
CHE12F1	$84.3	$629,576.6	54.28
SOT523	$84.9	$1,023,389.6	89.92
NW12F1	$85.1	$788,923.6	73.66
WIL12F2	$86.5	$1,705,622.8	155.22
TEN1254	$86.6	$582,980.2	48.35
ECL222	$86.7	$686,592.4	60.28
CDA124	$86.8	$641,838.7	55.52
M15513	$87.1	$736,558.1	67.36
F&C12F6	$88.2	$658,978.5	57.70
TEN1255	$89.2	$607,926.6	50.49
SLK12F1	$89.4	$854,712.8	72.56
MIL12F4	$89.6	$831,468.1	75.37
LOL1359	$90.7	$830,015.9	73.31
CHE12F2	$90.8	$642,694.9	54.26
SPU123	$91.2	$724,338.0	60.68
9CE12F2	$92.9	$764,865.0	66.97
CDA121	$92.9	$623,762.0	50.00
TEN1257	$93.0	$740,138.0	65.15
WAK12F2	$93.6	$765,628.4	67.80
9CE12F4	$93.7	$774,787.7	68.61
SLW1358	$93.7	$717,636.7	62.17
CDA125	$94.4	$863,793.5	70.73
EFM12F1	$95.0	$950,734.3	79.18
NW12F3	$96.7	$746,886.7	62.10
M23621	$97.1	$641,972.3	43.52
MIL12F1	$100.3	$798,146.0	68.01
SUN12F6	$101.5	$789,282.4	66.28

Conclusion

The intent of this system efficiency analysis was to develop and implement a methodology to identify and quantify remedies to reducing losses across Avista's distribution system. The results of this analysis can then be folded into a broader infrastructure strategy. A program to systematically refresh feeders can be combined with existing internal programs like asset management and capital budgeting to identify synergistic work alignments. For example, a project schedule could be developed to upgrade feeders based on energy, operational, reliability and maintenance priorities. Today, capital work is typically driven by system capacity constraints. With the results obtained in this analysis, capital projects could be aligned with corporate economic goals of reducing energy loss and offsetting O&M expenditures.

The benefits identified in the feeder upgrade program assumed the upgrades would be deployed in a comprehensive manner. The temptation to implement individual efficiency program components across the system may compromise the performance of a feeder as an energy delivery system. The efficient and reliable delivery of electrical energy across the Avista feeders is best met by incorporating all of the electrical components in the upgrade. This systemic approach may help guide how programs should be implemented across the organization.

Today, Avista implements projects in fairly discrete work silos influenced by departmental task structure and budget constraints. Examples of these type of programs are joint use, pole test and treat, failed equipment, new revenue and specific capital project budgeting. Consequently, the programs are dispersed across multiple feeders resulting in different crews working on the same feeder at different times over multiple years. The feeder upgrade program could be used not only to achieve energy savings but also be used as a springboard to consolidate and coordinate work efforts. Rather than referring to work groups by departmental names like Distribution Engineering, Operations or Asset Management, they may be better served by being aligned with actual work processes like capital and operational feeder programs.

The feeder upgrade program by itself falls short of being a strategic vision. However, it can be used as a first step towards a broader strategic view to be included in programs like capital budgeting, energy efficiency, and O&M cost reduction. A more robust corporate strategic vision for aging infrastructure rehabilitation would need to incorporate the following elements: 1) Movement of bulk power across our transmission system, 2) Optimum distribution topologies, 3) Substation size, locations and architectures, and 4) Reliable forecasts of geographical centered load growth. Once these elements are incorporated into the existing feeder upgrade program, a long term plan for Avista's electric infrastructure can be developed to move infrastructure upgrades from a tactical or reactive approach to a planned replacement strategy.

2009

Electric
Integrated Resource Plan

Appendix H – 2009 Electric IRP Avista New Resource Table

August 31, 2009

2009 Avista IRP

New Resource Table

Resource	Resource Location	POR or Local Area	POD	Start	Stop	Capacity MW	Year Total
Lancaster CCCT	Rathdrum, ID	Bell/Westside	AVA System	1/1/2010	10/31/2026	125.0	
Lancaster CCCT	Rathdrum, ID	Mid-C	AVA System	1/1/2010	10/31/2026	150.0	275.0
Noxon 3 (incremental)	Noxon, MT	Noxon, MT	AVA System	1/1/2010	Indefinite	14.0	14.0
Noxon 2 (incremental)	Noxon, MT	Noxon, MT	AVA System	1/1/2011	Indefinite	14.0	14.0
Noxon 4 (incremental)	Noxon, MT	Noxon, MT	AVA System	1/1/2012	Indefinite	14.0	
Nine Mile (incremental)	Nine Mile, WA	Nine Mile, WA	AVA System	1/1/2012	Indefinite	8.8	
Wind	Reardan, WA	Reardan, WA	AVA System	1/1/2012	Indefinite	90.0	
Wind	TBD	TBD	AVA System	1/1/2012	Indefinite	60.0	172.8
Little Falls (incremental)	Ford, WA	Little Falls, WA	AVA System	1/1/2013	Indefinite	1.0	1.0
Little Falls (incremental)	Ford, WA	Little Falls, WA	AVA System	1/1/2014	Indefinite	1.0	1.0
Little Falls (incremental)	Ford, WA	Little Falls, WA	AVA System	1/1/2016	Indefinite	1.0	1.0
Wind	TBD	TBD	AVA System	1/1/2019	Indefinite	150.0	
CCCT	TBD	Bell/Westside	AVA System	1/1/2019	Indefinite	250.0	400.0
Upper Falls (incremental)	Spokane, WA	Spokane, WA	AVA System	1/1/2020	Indefinite	2.0	2.0
Wind	TBD	TBD	AVA System	1/1/2022	Indefinite	50.0	50.0
CCCT	TBD	TBD	AVA System	1/1/2024	Indefinite	250.0	250.0
CCCT	TBD	TBD	AVA System	1/1/2027	Indefinite	250.0	250.0
					Total	1431	1431

August 26, 2009