Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

June 29, 2007

via E-Filing and US Mail

Filing Center
Public Utility Commission of Oregon
550 Capitol St., NE, Suite No. 215
Salem, OR 97308-2148

RE: Portland General Electric Company's ("PGE") 2007 Integrated Resource Plan

Enclosed for filing are an original and seven copies of PGE's 2007 Integrated Resource Plan ("Plan"). We ask the Public Utility Commission of Oregon ("Commission") to reach two decisions after reviewing this Plan:

1. Find that it meets the requirements Order No. 07-002; and
2. Acknowledge, pursuant to Order 07-002, the Plan in full, specifically with respect to resource actions PGE proposes in the Action Plan found in Chapter 13 of the Plan.

Because the analysis we conducted for this Plan shows that PGE should initiate long-term resource procurement actions in the near future, we respectfully request that a prehearing conference be promptly set to allow the establishment of a schedule.

Please direct communications, formal correspondence, and Commission Staff requests regarding this filing to:

pge.opuc.filings@pgn.com
Rates & Regulatory Affairs
Portland General Electric
121 SW Salmon St.
Portland, OR 97204
Phone: 503.464.7857
Facsimile: 502.464.7651

richard.george@pgn.com
Richard George, Assistant General Counsel
Legal Department
Portland General Electric Company
121 SW Salmon St., 1 WTC 1301
Portland, OR 97204
Phone: 503.464.7611
Facsimile: 503.464.2200

Sincerely,

Randy Dahlgren
Director, Regulatory Policy & Affairs

RD:lh

Enclosures

cc:
Jim Lobdell
Patrick G. Hager
Brian Kuehne

2007 Integrated Resource Plan

Portland General Electric

2007 Integrated Resource Plan

Portland General Electric Co.

June 29, 2007

This 2007 Integrated Resource Plan (the "IRP") represents the views of Portland General Electric Company at the time of preparation, based on information available at such time. The IRP includes forward-looking information that is based on our current expectations, estimates, and assumptions concerning the future. This information is subject to uncertainties that are difficult to predict. As a result, the IRP is not a guarantee of future performance. We intend to revisit the plans and strategies set forth in the IRP on an ongoing basis and, as new information becomes available or as circumstances change, to make such changes as we deem advisable.

For more information, contact:

Brian Kuehne

Manager, Integrated Resource Planning

Portland General Electric Co.

121 SW Salmon St. 3WTC BR06

Portland, OR 97204

(503) 464-8424

brian.kuehne@pgn.com

Table of Contents

Figures

Tables

List of Acronyms and Abbreviations

AEO	Energy Information Agency's Annual Energy Outlook
AGC	Automated Generation Control
AMI	Advanced Metering Infrastructure
ATC	Available transmission capacity
BACT	Best available control technology
BPA	Bonneville Power Administration
CAES	Compressed air energy storage
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCCT	Combined-cycle combustion turbine
CHP	Combined heat and power
COS	Cost of Service
CPP	Critical peak pricing
CSP	Concentrating solar power
CT	Combustion turbine
CUB	Citizen's Utility Board
DBB	Demand buy-back
DEQ	Oregon Department of Environmental Quality
DLC	Direct load control
DR	Demand Response
DSG	Dispatchable Standby Generation
EE	Energy efficiency
EIA	U.S. Energy Information Agency
EIS	Energy Information Services
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESS	Energy Services Supplier
ETO	Energy Trust of Oregon
EUE	Expected unserved energy
FERC	Federal Energy Regulatory Commission
FOR	Forced outage rate
FTE	Full time employee
GADS	Generating Availability Data System
GECC	General Electric Capital Corporation
HRSG	Heat recovery steam generator
ICNU	Industrial Customers of Northwest Utilities
IGCC	Integrated gasification combined cycle
IPP	Independent power producer
IR	Integration of Resources transmission agreement
IRP	Integrated Resource Plan
LNG	Liquefied natural gas

LOLP	Loss of load probability
Mid-C	Mid-Columbia
MTTR	Mean-time-to-repair
NCEP	National Commission on Energy Policy
NERC	North American Electric Reliability Corporation
NPV	Net present value
NPVRR	Net present value of revenue requirements
NRC	Nuclear Regulatory Commission
NTAC	Northwest Transmission Assessment Committee
NWEC	Northwest Energy Coalition
NWPCC	Northwest Power and Conservation Council
OASIS	Open Access Same-Time Information System
ODOE	Oregon Department of Energy
OEFSC	Oregon Energy Facility Siting Council
OPT	Oregon Power Technologies
OPUC	Oregon Public Utility Commission
OSU	Oregon State University
PC	Pulverized coal
PGE	Portland General Electric
PPA	Power purchase agreement
PPM	PPM Energy, Inc.
PRB	Powder River Basin
PTC	Production Tax Credit
PTP	Point-to-Point transmission agreement
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
REC	Renewable energy credit
RFP	Request for proposals
RH BART	Regional Haze Best Available Retrofit Technology
RPS	Renewable Portfolio Standard
RNP	Renewable Northwest Project
RTO	Regional transmission organization
RVI	Rate Variability Index
SCCT	Simple-cycle combustion turbine
SCPC	Super critical pulverized coal
SPP	State-wide pricing pilot
TOU	Time of Use
TRC	Tradable renewable energy credit
Tribes	Confederated Tribes of Warm Springs
VPO	Variable pricing options
WECC	Western Electricity Coordinating Council
WGA	Western Governor's Association
WREGIS	Western Renewable Energy Generation Information System

Executive Summary

Introduction and Overview

As Oregon's largest utility, Portland General Electric (PGE) serves approximately 793,000 customers in 52 Oregon cities. PGE's current power supply portfolio has a diverse mix of generating resources that includes hydropower, coal and natural gas combustion, and wind resources representing 1,945 megawatts (MW) of total generating capability. This total will increase with the additions of the Port Westward natural-gas fired plant and Phase I of the Biglow Canyon wind project, both of which will be completed by the end of 2007.

Because our region continues to grow, by 2012 our expected long-term customer load growth of 2.2% per year, coupled with expiring contracts, will require that we supplement our existing portfolio with additional new resources. To ensure that we are able to meet our customers' ongoing electricity requirements, PGE has conducted a rigorous analytical and public process for our 2007 Integrated Resource Plan (IRP).

A Time of Uncertainty and Change

We are developing this IRP in a time of significant energy supply uncertainty. Climate change has moved to the forefront of public awareness and is a potential paradigm-changing issue. Global competition and geopolitical instability associated with energy supplies and, more broadly, natural resources, have increased substantially and have contributed to a rise in fossil fuel prices and price volatility. This, in turn, has created demand for increased domestic energy independence. Meanwhile, federal and state policies regarding renewable resource subsidies, carbon regulation, and emissions and renewable portfolio standards (RPS) are also still evolving and have the potential to vastly change the energy industry.

Concerns about climate change, domestic energy security, and the increasing tightness and volatility of global energy markets are creating higher demand for renewable resources. Even though some renewable technologies, such as wind generation, have expanded rapidly, the emergence of RPS legislation throughout the Western Electricity Coordinating Council (WECC) has created the potential that the demand for renewable resources will exceed their supply at competitive prices. At the same time, traditional coal combustion is falling from favor because of uncertainty surrounding greenhouse gas legislation and the lack of permanent disposal solutions for CO_2. With significant public acceptance barriers to nuclear power remaining and a fully developed regional hydro system, future supply options appear to be somewhat limited.

The development of promising new supply technologies that could serve as a substitute for traditional thermal generation, such as integrated gasification combined-cycle coal (IGCC) with carbon sequestration, wave energy, and thermal and photovoltaic solar, has recently accelerated. However, the commercial maturity date for these resources is unknown. Furthermore, the transmission system in the Pacific Northwest is becoming increasingly congested. This is particularly true from points to the north and east of PGE's service area, where new central station power supplies are likely to be located.

This environment of increased uncertainty has created new challenges for resource planning. We believe that diversification and flexibility are the best solution to meeting these challenges and hedging against an uncertain future. Given that, our preferred portfolio contains a diverse mix of energy efficiency, customer-sited demand response, renewable resources, and market contracts while avoiding further reliance on fossil-fueled, baseload generation.

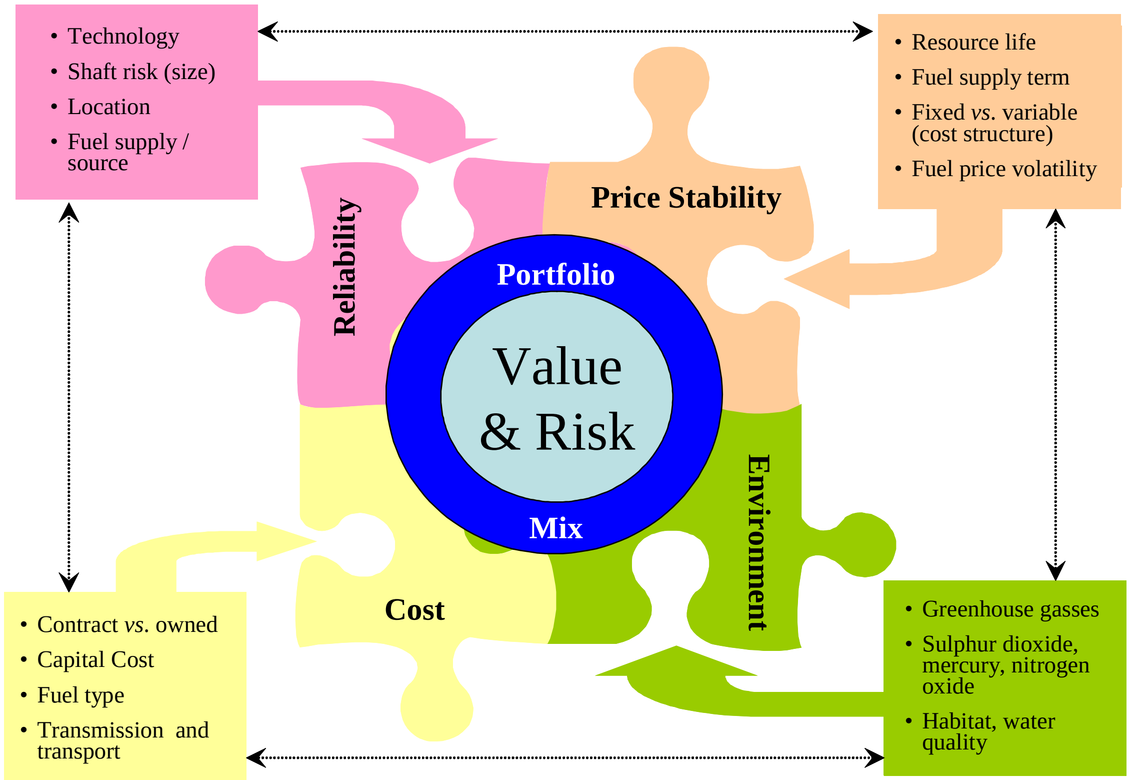
On the following pages we summarize our research on demand and supply alternatives and subsequent portfolio analysis and associated risk assessments. We also present modeling results and our conclusions with respect to future power supply requirements and alternatives to meet those needs. From this analysis and public input received during the IRP process, we prepared our recommended portfolio of new resources.

IRP Objectives

PGE files an Integrated Resource Plan (IRP) periodically with the Oregon Public Utility Commission (OPUC). The OPUC recently updated its IRP planning principles and analysis guidelines in Order 07-002. Consistent with the Order, the objective of PGE's IRP process is to identify new electric generation, demand-side, and transmission resources which, when considered with our existing portfolio, provide the best combination of expected cost and associated risks for PGE and our customers. At the same time, we must continue to ensure that we maintain a safe, reliable supply of electricity and that we are responsible stewards of the environment and good corporate citizens in the communities we serve.

Figure ES-1 illustrates the complexity and competing objectives of portfolio decision-making and the interaction of the many cost, risk, and reliability considerations that must be taken into account in formulating our IRP.

Figure ES-1: Scope of Integrated Resource Planning



Research and Public Process

Through the IRP process, PGE shares with stakeholders the results of our research, analysis, and findings for meeting our customers' future electricity needs. We solicit input from customers and stakeholders to ensure that we understand and consider their perspectives and needs in developing this IRP.

To accomplish these objectives, PGE conducted seven day-long public meetings during which we discussed our planning approach, the analysis we performed, and our conclusions. As part of our public process, experts from the Northwest Power and Conservation Council (NWPCC), Energy Trust of Oregon (ETO), and a customer research firm presented their independent findings concerning regional load and resource adequacy, energy efficiency, and our customers' attitudes and preferences toward power supply.

IRP public meetings included representatives from several stakeholder groups, including the OPUC staff, Oregon Department of Energy (ODOE) staff, Citizens' Utility Board (CUB), Renewable Northwest Project (RNP), Northwest Energy Coalition (NWEC), Industrial Customers of Northwest Utilities (ICNU), the NWPCC, and other Northwest utilities. Throughout the public process to date, our stakeholders have provided valuable feedback and, where appropriate, we have incorporated their suggestions into our analysis.

In this IRP process we conducted extensive fundamental research with respect to expected future availability and costs for various resource types and fuels, as well as future technology and policy developments that could impact portfolio choices. In the past two years, PGE has undertaken studies covering IGCC coal, CO_2 sequestration, fuel supply and costs for natural gas and coal, potential federal and state climate legislation, local climate change impacts, wind integration costs, transmission congestion and solutions, and customer knowledge, concerns and preferences. We are also actively participating in several regional planning committees regarding resource adequacy, transmission, and wind integration.

PGE's Resource Need

IRP analysis begins with an assessment of demand growth, changes to generating supply, and the resulting energy and capacity requirements to serve our customers' future electricity needs.

Demand

PGE's year-over-year long-term load growth, net of existing ETO energy efficiency acquisition, is approximately 2.2% per year. PGE's summer load and peaks are growing faster than the winter load and peaks due to increasing residential central air conditioning saturation. While PGE currently remains a winter peaking utility under normal weather, we are moving toward dual-season peaking.

Increasing summer load growth translates to a slightly improving annual load factor over time. However, forecasted peaks continue to increase each year by roughly 50% more than the growth (in MW) of annual average loads, thereby increasing our aggregate capacity requirements. In addition, PGE operates in a direct access environment in which some customers may elect to opt out of PGE's cost-of-service (COS) rates, adding additional uncertainty to future customer demand. Currently, we plan to meet the annual energy and peak demand needs of all of our jurisdictional customers, with the exception of our customers on the 5-year opt-out tariff (see Section 3.2), who are assumed to remain with their current suppliers.

Supply

In addition to steady load growth, PGE's resource balance is further affected by the loss of some existing supply sources upon expiration of certain contracts. By 2012, expiring contracts total almost 300 MWa of energy and more than 800 MW of capacity. For this reason, we target 2012 as the year in which our load-resource gap becomes large enough that significant new supply actions are necessary to address the deficit.

Balancing Resources to Loads

For baseload energy needs, PGE's goal for this IRP is to be in approximate load/ resource balance on an expected annual average basis under normal hydro conditions. This approach is similar to the regional approach of the NWPCC. In past IRPs, we have estimated our energy and capacity requirements solely based on physical resource adequacy. With this IRP, we also consider expected energy production on an economic dispatch basis related to the position of our Beaver plant in the regional resource stack. Based on expected economic dispatch, we now exclude up to 370 MW of Beaver generating capability in determining an appropriate annual average energy load/resource balance. The practical effect of this treatment of Beaver will be to reduce our dependence on volatile short-term electricity markets, leading PGE to acquire medium and longer-term resources to meet our expected energy needs. However, we do not propose any changes to actual Beaver operations and the plant remains a flexible resource to help meet our current and future power supply requirements. All other PGE thermal resources are baseload and thus included in our load/resource balance on a resource capability basis.

To determine our capacity needs, we plan to the one-hour peak at normal weather for winter and summer, including appropriate reserves. We first apply the required approximately 6% operating reserve, plus an additional 6% contingency reserve. Such reserves help ensure reliability in the face of weather and load excursions or unexpected generating plant outages.

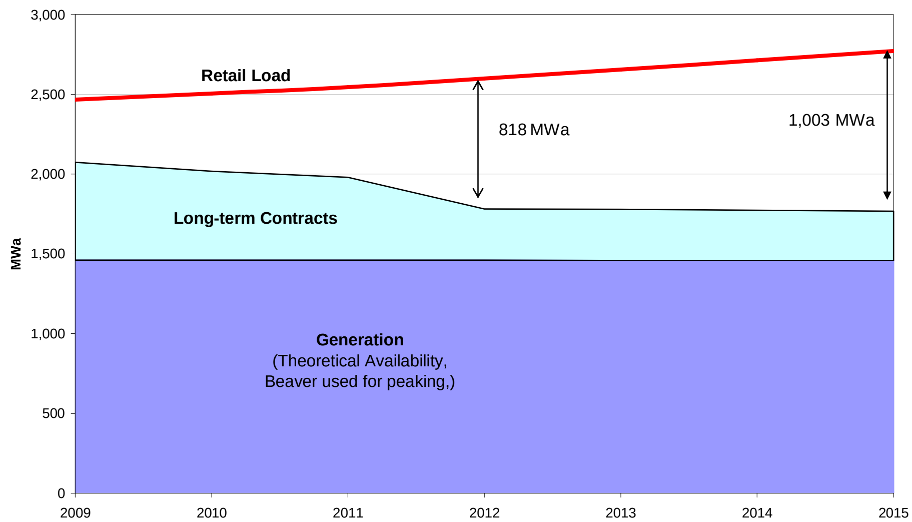
PGE's Resulting Resource Gap

In 2012, our forecasted load/resource balance yields an annual average energy resource deficit after economic dispatch of about 818 MWa. Our one-hour annual peak need, before the capacity brought by new energy actions, is about 1540 MW, inclusive of about 500 MW for reserves as described above. Figure ES-2 displays the growth in our forecast energy gap from 2009[1] through 2015.

---

[1] Our planning horizon begins in 2009, as this is the first year new resources are assumed to be available (due to lead-time and construction requirements).

Figure ES-2: PGE Energy Load Resource Balance to 2015



Demand Response and Supply Alternatives

In this IRP, we evaluated customer-sited energy efficiency (EE) and demand response (DR) options on an equal basis with utility supply options. Energy efficiency and DR solutions generally use little fuel, have small emissions footprints, and avoid transmission and distribution congestion. We also examined the potential to acquire additional cost-effective EE beyond what is currently being captured by the ETO with available public purpose charge funding. We further examined expanded DR opportunities and discuss the potential for the installation of automated meters later this decade to facilitate increased DR program participation among our residential and commercial customers.

We also evaluated costs and availability for new utility scale supply-side resources, including wind, biomass, geothermal, combined-cycle and simple-cycle combustion turbines (CCCTs and SCCTs), traditional pulverized coal and gasified coal plants with and without sequestration. For thermal resources, we reviewed fuel commodity and transportation costs, as well as availability. These resources, along with EE and assumed short- and mid-term fixed price Purchase Power Agreements (PPAs), are examined in varying combinations in the supply portfolios we tested. We also reviewed solar photovoltaic and solar thermal plants, nuclear, and wave energy, but we did not include these in our portfolio analysis due to expected high costs, lack of public acceptance, or technical immaturity for the current IRP resource acquisition horizon.

Policy and Planning Assumptions

Public policy and macroeconomic drivers play a fundamental role in our outlook for major new generating resources. Some key assumptions in our reference case portfolio analysis include:

- Continuation of the federal Production Tax Credit (PTC) for renewable resources in its current form through 2012;
- Imposition in 2010 of a tax of $7.72 per short ton with subsequent nominal escalation of 5% per year on all CO_2 emissions, based on the original National Commission on Energy Policy (NCEP) legislative recommendation.
- Imposition of an Oregon Renewable Portfolio Standard (RPS) which requires a target of 15% of load served by renewable resources by 2015; and,
- Natural gas prices based on a combination of the reference case fundamental forecast by PIRA Energy Group and forward market prices. Gas prices are expected to decline in the near term and are forecast to be about $6.4 per MMBTU ($2006, real levelized) over the planning horizon.

Analytical Process

We then use the demand response and supply alternatives and policy and planning assumptions described above to model the performance and value of potential future resource portfolio options. We evaluated the expected costs of each portfolio of incremental resources under the reference case assumptions described above. We then employed a variety of modeling methods to assess risk by stress-testing performance under stochastic variability and potential structural, or more permanent, shifts in the future planning environment. Our analysis does not point to the selection of one "right" portfolio to meet customers' needs. Rather, we combine analytical insights with business judgment to identify the portfolio of incremental resources that offers the best possible outcome, taking into account both cost and risk.

All thirteen candidate resource portfolios examined in this IRP were designed to have the same energy and capacity values for delivery by no later than 2012. This portfolio standardization allowed us to make careful and consistent comparisons of performance. Candidate portfolios included both single resources such as gas, coal, renewables, or market reliance, as well as a more balanced, diversified mix of resources.

We then stress-tested our reference case assumptions by constructing 19 alternative scenarios or futures. These alternate futures included higher CO_2 taxes, higher and lower gas prices, higher and lower loads, and several combinations of loads and gas prices, as well as other variables. We then tested all portfolios against all futures and analyzed performance. We also conducted stochastic analysis using weather-induced load variance, differing hydro years, natural gas price volatility, and unplanned generating resource outages.

Our analytical tools and techniques have continued to evolve. Since our last IRP we have implemented a new model, AURORAxmp® by EPIS, Inc., that allows us to assess Western electricity supply and demand, as well as resource dispatch costs and resulting market prices on an hourly basis for the entire WECC region across our planning horizon (2009 to 2031). In addition to the increased scope and granularity that the new model provides, we are also able to gain better insights into the impacts of different potential future resource choices, both by PGE and other regional participants, through more advanced sensitivity and scenario testing capabilities.

We used AURORAxmp to conduct a WECC-wide simulation of loads, resources, and constrained transmission topology. To analyze performance for each combination of portfolio and future, we ran the AURORAxmp model hourly from 2009 to 2031 to see how plants dispatch against market prices derived from our WECC simulation. To develop the expected cost (defined as the net present value of revenue requirements, or NPVRR) for each portfolio, we combined the variable costs from AURORAxmp with full life-cycle revenue requirements for the capital and fixed costs of each resource calculated using PGE's spreadsheet-based revenue requirements model.

We evaluated various measures of risk, each providing a somewhat different but valuable insight into the performance of a given portfolio. For deterministic scenario analysis, we measured risk as changes in cost, as well as the highest cost. For stochastic analysis, we use the TailVaR90, or the average value of the worst ten percent outcomes. We examined how well a given portfolio performed on each risk measure, as well as the incidence of poor performance across alternative futures. In addition, we considered how candidate portfolios compare in terms of CO_2 intensity, initial rate increases, shaft risk, variable cost concentration, distance to load, transmission access, and investment requirements.

Recognizing the critical nature of transmission for the region, we examined the transmission constraints that make access to new supply-side resources challenging for PGE. We also conducted several studies to evaluate potential transmission solutions and related cost impacts for meeting future resource needs.

Results of Analysis

One primary method of examining the cost/risk trade-off of any portfolio decision is to plot the performance of candidate alternatives on a graph with one axis representing risk and the other representing cost or value. Once this data is plotted, an efficient frontier can be determined whereby value maximization and risk minimization are optimized for the options examined. Figure ES-3 shows the efficient frontier resulting from our deterministic portfolio analysis. In this graphic, the x-axis reflects the expected cost under reference case assumptions for each portfolio of incremental resources. The y-axis reflects the difference between the NPVRR of the worst-performing future and the NPVRR of the reference case.

The efficient frontier provides the following insights:

1. Diversified portfolios outperform predominantly single-resource portfolios – diversified portfolios tend to cluster on or near the efficient frontier.

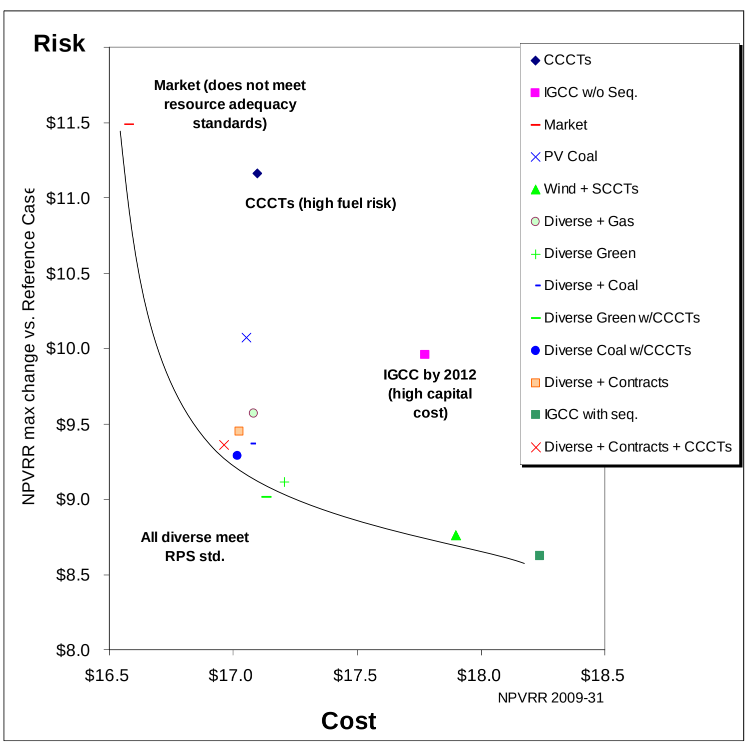
2. The efficient frontier has a very steep shape initially, indicating that risk can be greatly reduced at relatively little incremental cost. However, the curve then flattens, reflecting either diminishing marginal returns or that increasing levels of risk reduction require incrementally higher cost increases.

3. The diversified portfolios tend to lie at the inflection point of the curve, where risk reduction begins to diminish for the extra cost incurred.

4. The diversified portfolios contain some resources which are more costly than others, but which also demonstrate more effective risk mitigation properties.

5. The diversified portfolios are tightly clustered in terms of both cost and risk. Hence, small changes to cost assumptions could alter outcomes.

Figure ES-3: Efficient Frontier – Risk vs. Cost



While Figure ES-3 displays some of our core analysis and conclusions, Chapters 10 through 12 of the IRP contain significantly more detail on our modeling methods and results. They also discuss other benefits of supply diversity, such as shaft and fuel diversity and hedging against other types of risk. The totality of our analysis confirms that of all the portfolios that we assessed, the Diverse + Contracts portfolio performed consistently well across both scenario and stochastic analyses. We recommend this portfolio for our IRP action plan because it provides technology and fuel diversification to our existing portfolio, while hedging against carbon risk by avoiding more long-term concentration of fossil-fueled, baseload generation. We also came to similar conclusions as the NWPCC in its 5th Power Plan in that our preferred portfolio focuses heavily on energy efficiency and renewable resources to meet future load growth.

Proposed Energy Action Plan

Our analysis suggests that there is no obvious single generation solution to meet our future energy needs. As a result, we must make informed choices that involve trade-offs between expected costs and various uncertain risks. Our analysis confirms that diversification of our portfolio offers the best alternative for an uncertain future environment, while underscoring that the results of an RFP will better inform exact actions to be taken. Table ES-1 details our proposed Energy Action Plan.

Table ES-1: 2012 Resource Need and Potential Energy Supply Actions

	Energy		*Capacity*
	MWa @ Normal Hydro	**% of Target**	**MW @ Normal Hydro**
PGE system load at normal weather (net of ETO EE)	2,630		
Remove assumed 5-yr. opt-out load	(30)		
Existing PGE & contract resources in 2012	(2,150)		
Add back implied ETO EE savings 2008-2012	85		
Recognize Beaver as an intermediate resource	368		
PGE 2012 Resource Target[1]	**903**		
Expected & Potential Resource Actions:			
ETO EE savings target 2007-2012	85	9%	111
Additional cost-effective EE 2008-2012	45	5%	59
Plant efficiency upgrades	7	1%	13
Partial contracts renewals (hydro)	70	8%	170
Biglow Canyon 2 & 3 (300 MW nameplate, by 2010)	105	12%	45
PPAs of up to 5-year terms for load uncertainty	180	20%	180
PPAs of 6- to 10-year terms for bridging	192	21%	192
Required added renewables to meet 2015 RPS target	218	24%	133
Total of Recommended Actions	**903**	**100%**	**904**

[1] *The resource target does not include ETO energy efficiency, which we recognize as an action item. After ETO EE is accounted for, the 2012 energy resource gap will be 818 MWa.*

Our energy action plan further diversifies PGE's existing portfolio by:

- Pursuing a significant new initiative to acquire all technically achievable and cost-effective EE beyond what the ETO has currently targeted through use of public purpose charge funds.

- Focusing on new renewable resources. Our Energy Action Plan slightly exceeds the Oregon RPS target of meeting 15% of load with renewables by 2015. This portion of the plan is first achieved by the build-out of 300 MW of additional nameplate wind at our new Biglow Canyon project by 2010. We already own the development rights to Biglow Canyon and are currently constructing the first 125 MW phase of the project, which includes building the infrastructure needed to serve the entire project.

- Entering into fixed-price PPAs of varying durations to reduce our current short-term market dependence, better match supply to elections made by our direct-access eligible customers, and provide flexibility and remain adaptive to changing future conditions.

The Energy Action Plan is both diverse and serves as a bridging strategy. It avoids major new long-term, baseload thermal plant commitments while allowing time for national energy and environmental policy to coalesce and emerging technologies to mature and move closer to commercialization.

Proposed Capacity Action Plan

Due to several internal and external factors, our emphasis on capacity needs and resource alternatives has increased substantially for this IRP:

- Our supply of flexible and high capacity value hydro resources is declining.

- Both PGE and the entire Western electric system continue to add ever-increasing levels of variable wind resources.

- Increased central air-conditioning and changes in consumption patterns have also caused us to increasingly experience both summer and winter demand peaks.

- We expect a regional and West-wide tightening of the load-resource balance as we move past the end of the current decade.

Based on these factors, we no longer believe that it is wise to rely on spot-markets to meet a significant portion of our capacity needs. As a result we recommend a capacity action plan that focuses on filling our needs through reliable and longer-term demand and supply resources.

Our recommended Energy Action Plan fills about 60% of our 2012 peak capacity needs. The remaining capacity gap is approximately 740 MW, inclusive of 6% operating and 6% contingency reserves. While this shortfall appears daunting, the highest 500 MW of the peaking requirement is limited in duration, occurring over approximately 50 hours of the year under normal weather conditions. The following table presents our proposed approach to filling our peak capacity requirement, taking into account both cost and risk.

Table ES-2: 2012 Resource Need and Potential Capacity Supply Actions

	Capacity - Winter		***Capacity - Summer***	
	MW @Normal Hydro	**% of Target**	**MW @Normal Hydro**	**% of Target**
PGE system peak at normal weather (net of ETO EE)	4,127		3,761	
Add required operating reserve at 6% of peak load	248		226	
Add weather / plant contingency reserve at 6% of peak load	248		226	
Remove assumed 5-yr. opt-out load (w/reserves)	(32)		(38)	-
Existing PGE & contract resources in 2012	(3,050)		(2,845)	
Add back implied ETO EE savings 2008-2012	111	-	111	
PGE 2012 Resource Target[1]	**1,652**		**1,440**	
Year-round Resource Actions:				
Capacity value from proposed Energy Actions	904	55%	904	63%
Dual-purpose (capacity and wind following) SCCTs	100	6%	100	7%
Customer-based Solutions:				
Direct Load Control, if economic (space & water heat, A/C)	25	2%	23	2%
Curtailment tariff, critical peak pricing	35	2%	35	2%
Continuation of DSG program @ 13.5 MW / Yr.	80	5%	80	6%
Seasonally Targeted Resources:				
Bi-seasonal via demand and supply RFPs	299	18%	299	20%
Winter-only via supply RFP	210	13%	0	0%
Total of Potential Actions	**1,652**	**100%**	**1,440**	**100%**

[1] *The resource target does not include ETO energy efficiency, which we recognize as an action item. After ETO EE is accounted for, the 2012 capacity resource gap will be 1540 MW.*

Our proposed Capacity Action Plan includes:

- Continuation and expansion of our industry-leading Dispatchable Standby Generation (DSG) program. This program provides standby operating reserves with distributed and centrally dispatchable, customer-sited generation at very low investment cost. It also incurs fuel costs only when called upon, and contributes to customer reliability and satisfaction.

- Implementation of retail customer curtailment tariffs and direct load control for fifty hours or less per year, once our plan to install advanced metering infrastructure throughout our service territory is implemented at the end of this decade. Due to increasing capacity needs that take place over a very small portion of the year, we believe that it makes sense to maintain system reliability by first seeking firm actions from our customers.

- Acquisition via ownership or contract for 100 MW of peaking capacity for the dual purpose of supplemental wind integration and meeting summer/winter peaking needs. Our IRP analysis shows that compared to SCCTs, CCCT units tend to both lower cost and reduce risk. However, they do not have the operating flexibility required for load following. We will continue to examine this topic and evaluate the results of market solicitations to better inform our choices. We also intend to develop one or more internal benchmark resource alternatives. As with Port Westward in the last IRP, we will submit a sealed bid in advance of receiving outside proposals.

Policy and Regulatory Support for our Action Plans

To facilitate our proposed Energy and Capacity Action Plans, we recommend a few changes to electric utility regulation and public policy in Oregon. For instance:

- To achieve a 2015 RPS target, PGE will most likely need to acquire suitable wind sites in advance of project implementation in order to preserve the best remaining locations for our customers. However, current regulatory policy does not provide a return to shareholders for the carrying cost of sites held for future use.

- We plan to assist the ETO in acquiring all economic EE. Appropriate changes are needed to provide incentives and ensure EE regulatory cost recovery so that this resource can compete fairly with other resource options.

- Further development of federal and state policies would simplify planning by reducing uncertainty associated with climate change and carbon regulation. In December 2006, CEO Peggy Fowler announced PGE's support for national carbon legislation similar to the original NCEP proposal. We have also worked with stakeholders and other interested parties to develop and implement an effective Oregon RPS.

Next Steps: Action Plan Implementation

We propose to first issue an energy supply RFP as soon as practicable to begin acquiring the more time-sensitive resources proposed in our Action Plans. We will work with the OPUC staff and our stakeholders to determine how to best accomplish this. We propose to then issue a capacity RFP for both demand and supply proposals. We will also continue to evaluate the transmission studies conducted for this IRP and actively work with BPA and others to develop transmission capacity over the Cascades so that additional resources are accessible to PGE customers at a reasonable price.

Conclusion

We find ourselves in a planning environment that is changing and unpredictable. During the post-filing, six-month data discovery and review process, new information or insights may emerge which could cause modifications to our recommendations. Subsequent market solicitations could also cause minor course alterations, but we expect the central elements and strategic emphasis of the plan to remain to:

- Maintain an adequate, reliable, and economic supply of power to our customers;
- Focus on overall portfolio diversity and flexibility;
- Acquire cost-effective renewable resources to achieve the Oregon RPS targets;
- Acquire all cost-effective EE, including incremental EE beyond the EE acquired by the ETO.
- Expand on our industry-leading DSG program;
- Actively develop and pursue DR opportunities; and
- Enter into mid-term PPAs as a bridge to the future.

We believe that these proposed actions are both progressive and cautious. They position PGE to continue to reliably serve customers for the future while being wise stewards of natural resources and the environment. As we move forward to complete our current IRP process, we continue to welcome suggestions regarding effective ways to provide our customers the best possible electricity solutions, while remaining responsive to the interests of our investors and other constituents.

1. IRP Process and Stakeholder Involvement

The primary goal of the Integrated Resource Plan is to identify a resource action plan that, when considered with PGE's existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for the utility and our customers. We do this by evaluating the performance of various portfolios of new resources against varying potential futures over a planning horizon of at least twenty years (for this IRP from 2009 to 2031). Our planning is guided by regulatory orders issued by the Oregon Public Utility Commission (OPUC). Through the IRP process we share with customers, regulators and other stakeholders the results of our research, analysis and findings with respect to anticipated resource requirements and alternatives for serving our customers' future electricity needs. The next sections briefly discuss the regulatory requirements and public dialogue that have helped shape this IRP.

Chapter Highlights

- The primary goal of the IRP, as defined in OPUC Order No. 07-002 governing utility planning, is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.
- PGE actively seeks input from customers, OPUC staff, and other stakeholders throughout the IRP process.
- PGE hosted seven, five-hour public workshops to discuss with stakeholders our future energy needs, assumptions, modeling methods and analytical results.
- We incorporated in our analysis several new sensitivities suggested by stakeholders during the public process.
- PGE also participates in a number of regional forums that inform and influence our planning.

1.1 Regulatory Requirements

Order 04-375: Acknowledgment of 2002 Final Action Plan

We initially filed our last IRP in August 2002. Given our large resource need at the time, the 2002 IRP called for significant resource acquisitions, approximately 790 MWa of energy resources, and an additional 955 MW of incremental capacity resources. To address our large energy and capacity deficits and further inform our resource action plan, we issued a Request for Proposal (RFP) in June 2003 for up to 600 MW/h[2] of energy resources and up to 400 MW of capacity resources. The RFP process also included the Port Westward natural gas, combined-cycle, self-build option, which represented a benchmark resource in the RFP process.

After careful evaluation of the resource options proposed under the RFP, we determined our proposed resource actions and filed our Final Action Plan in March 2004. After an extensive public input and evaluation process, OPUC Order No. 04-375 acknowledged the Final Action Plan. By the end of 2007, all of PGE's proposed supply-side resource actions will have been accomplished, including commercial operations of the Port Westward plant and the development of Phase I of the Biglow Canyon wind project. Order 04-375 contained conditions related to further actions regarding demand response and transmission which we address in this Plan in Chapters 4 and 9. A more detailed discussion of resource additions resulting from the 2002 IRP Final Action Plan is included in Chapter 2.

Order No. 07-002: Adoption of IRP Guidelines

In January 2007, the OPUC updated its IRP guidelines in Order No. 07-002. According to the new Order, which supersedes the OPUC's previous IRP Order No. 89-507, the primary goal of the IRP remains the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. However, the new Order clarifies and updates certain elements of the prior resource planning guidelines, and also adds some new procedural and analytical requirements. We believe that this IRP meets the requirements of the new IRP Order, while at the same time recognizing the changing power supply and policy environment that we face. Specifically, our IRP incorporates:

- Energy efficiency provided by the ETO as well as incremental EE acquisitions.

[2] Flat quantity of MW across the entire hour.

- All system load in our load forecasts, except that of customers expected to opt out of PGE service on a long-term basis.

- An evaluation of all supply-side resource options, including distributed generation and resources not yet commercially available, but which are expected to be available in the near future.

- More extensive risk analysis, both on stochastic (i.e., analysis incorporating random fluctuations in inputs) and scenario bases.

- Several other sensitivities beyond those required in Order No. 07-002 (see Chapter 10).

- The following cost and risk measures:

    - Net present value of revenue requirement (NPVRR) and associated risk for each candidate resource portfolio, including both variability of costs and the severity of bad outcomes.

    - Reliability measures, including loss of load probability, expected unserved energy, and 95th and 99th percentile unserved energy.

    - Customer year-to-year rate variability (or stability).

    - Stochastic as well as long-term scenarios.

    - A wide range of possible future CO_2 taxes.

We provide a detailed description of how we comply with the provisions of Order No. 07-002 in *Appendix A: Order No. 07-002 Compliance Checklist*.

1.2 Public Outreach

As part of the IRP process, PGE solicits input from various stakeholder groups to ensure that we understand and consider the perspectives and feedback of our external constituents, and to demonstrate that our conclusions meet the cost and risk objectives of the IRP. Our public outreach takes three forms: 1) public meetings at which we review and allow stakeholders and customers the opportunity to comment on key assumptions, research and analysis; 2) direct outreach activities to PGE customers; and 3) participation in state and regional planning efforts.

Public Meetings

To help ensure that the views of our customers and other stakeholders are well-represented in this IRP, PGE hosted seven public workshops. In these workshops PGE discussed with the parties the fundamental building blocks of the IRP as well as our assumptions, modeling techniques, and analytical results.

Participants in our public meetings included representatives from the following organizations:

- Avista Utilities
- Bonneville Power Administration (BPA)
- Citizens' Utility Board (CUB)
- Energy Trust of Oregon (ETO)
- Industrial Customers of Northwest Utilities (ICNU)
- NW Energy Coalition (NWEC)
- NW Natural
- Northwest Power and Conservation Council (NWPCC)
- Oregon Department of Energy (ODOE)
- Oregon Pubic Utility Commission (OPUC)
- PacifiCorp
- PGE key account customers
- Renewable Northwest Project (RNP)

Some of the fundamental building block discussions included:

- Load/resource balance (future energy and capacity requirements)
- Customer resource preference survey results
- Fuel market fundamentals and forecasts (natural gas and coal)
- Transmission and natural gas transportation considerations
- Energy and capacity resource options
- Demand-side resources
- Supply-side generation resources
- Federal and state policy developments, including potential climate change and renewable portfolio standard (RPS) legislation, and
- Modeling approach and IRP risk metrics

See *Appendix B: Agendas of IRP Public Meetings* for a detailed description of topics covered throughout our public process.

To facilitate ease of communication with interested parties PGE published all the presentation materials from the public meetings on our website at www.portlandgeneral.com[3]. In addition, PGE will make available copies of this IRP and the accompanying technical appendices on this website.

Throughout our public meetings, participants were encouraged to ask questions about our analytical process, comment on our candidate resource action plans, and request additional information. The results and findings from such requests were presented at subsequent meetings. We found these meetings to be very valuable, and as a result of the stakeholder dialogue, we incorporated a number of suggested sensitivities and modifications in our research and modeling. For example:

- We incorporated the following analytical sensitivities:
    - 25-year life for coal plants
    - $15/MMbtu gas and low WECC load growth
    - High WECC load growth
    - IGCC with carbon sequestration and no CO_2 emissions
    - 10% and 20% decreases in gas price and 10% and 20% increases in the cost of renewable resources
    - Additional CCCTs instead of SCCTs in portfolios that have wind in order to provide backup capacity
- We changed our scenario analysis risk metric to the difference between the reference and highest cost cases instead of the difference between low and high cost scenarios.
- We added different views of the cost/risk tradeoff. For the scenario analysis, we added a plot of reference case cost vs. the maximum cost scenario. In the stochastic analysis, we added a plot of the average cost vs. the TailVaR90 of the variable cost across simulations.
- We showed the likelihood of worst performance across scenarios for each portfolio of resources.
- We modified our stochastic modeling to include forced outages and more sustained gas price shocks.

1.3 Other Customer Outreach Activities

On March 1, 2006, and again on April 24, 2007, we gave an overview presentation on the 2007 Integrated Resource Plan to PGE key account customers[4]. The presentation included information about PGE's future resource

---

[3] In several areas, information and assumptions presented in the workshops, which began in April 2006, were subsequently revised. The material contained in this document takes precedent over all previously published material.

[4] Key account customers are PGE customers with annual electricity usage greater or equal to 0.5 MWa.

needs, the scope of integrated resource planning, an overview of resource options, and a summary of studies being conducted for the 2007 IRP. We have also provided IRP updates via our *Power Report* newsletter (sent to the energy managers of our key account customers) and *Plugged In* newsletter (sent to other stakeholders and community and business leaders). In addition, PGE management discussed the IRP in the keynote address to the Industrial Customers of Northwest Utilities (ICNU)/Northwest Industrial Gas Users Joint Conference on May 9, 2006.

IRP Customer Preference Surveys and Focus Groups

PGE contracted with two market research firms, KEMA and Momentum Market Intelligence, to conduct qualitative and quantitative research regarding customers' preferences for power supply resource alternatives. The market research was conducted in late 2005 and early 2006. Research included focus groups, as well as interviews and surveys of residential, commercial, and industrial customers. The results of this work provided us with direct customer feedback regarding customer perspectives, preferences and concerns related to how electricity is produced and supplied by PGE. We believe that feedback and remaining responsive to customer preferences for energy supply are critical to our ability to provide high levels of satisfaction and service to our customers. Chapter 8 contains a detailed discussion of the results of these interviews and surveys.

1.4 Participation in Regional Planning

PGE also participates in a number of regional forums that inform and influence our planning process. We believe that it is important for the Company to be aware of and help guide and shape regional initiatives and industry groups that address resource planning and utility operations. By doing so, we are better able to identify and influence emerging issues and policy developments that could either favorably or adversely impact future portfolio choices. These include:

- ColumbiaGrid
- Governor's Renewable Energy Working Group (assessing Oregon RPS legislation)
- Governor's Task Force on Carbon Allocation
- Northwest Transmission Assessment Committee (NTAC):
    - Montana-Northwest Study Group
    - Canada-Northwest-California Study Group
    - Northwest Wind Integration Study Group
- Northwest Wind Integration Action Plan
- OPUC-sponsored Coal Technologies Workshop

- Pacific Northwest Resource Adequacy Forum
- People of Oregon for Wave Energy Resources (POWER)
- Active involvement in the UM-1056, UM-1182, UM-1276, and UM-1302 dockets addressing resource planning, competitive bidding, utility build vs. buy issues and carbon tax

1.5 Other Activities in Support of IRP Development

In addition to the outreach activities described above, research and analysis conducted in connection with this IRP has been a major factor influencing the development or modification of PGE's internal policies and external advocacy positions. These developments include our public support of federal carbon tax legislation, our encouragement of stakeholders to generate support for committing additional funds for cost-effective EE acquisition beyond the ETO limits, and support of an effective Oregon RPS. PGE has further adopted a set of Climate Change Principles based, in part on research, analysis and insights gained through the IRP process. These principles do not constitute a set of rules or policies, but rather establish a framework that will help guide the Company's vision and strategies with respect to future energy supply, operations and public policy advocacy. See Section 6.1 to review PGE's Climate Change Principles.

In December 2006, PGE sponsored the "2006 Energy Summit: Powering the Northwest into the 21st Century," a symposium on long-term power supply options and technologies held at the Oregon Convention Center. The purpose of this event was to gather a broad mix of regional policy-makers, regulators and regulatory staffs, utility planners, and resource vendors to share the latest perspectives on the current state and the future of the electric power industry. In the introductory address, PGE CEO Peggy Fowler announced PGE's support for the recommendations of the bipartisan National Commission on Energy Policy (NCEP, December 8, 2004). The original NCEP recommendations form the basis for the carbon tax used in our portfolio analysis (see Section 6.2 for more detail).

The public process and dialogue to date has been invaluable to helping PGE develop a thorough and well-considered resource plan that addresses the perspectives, concerns and preferences of our many constituents. Recognizing that many of the resource choices identified in this IRP will, if implemented, have long-lasting influence on our energy supply, it is important to broadly discuss and debate the assumptions, alternatives, modeling methods, risk and value quantification, as well as the many other qualitative elements that shape the IRP. We believe that the public process for this IRP has been particularly robust and, as a result, we believe that the research, analysis and results have been well-informed.

2. Existing Resources

In this chapter we provide an overview of PGE's diverse portfolio of generating assets, contracts, and transmission resources used to provide electricity to customers today. PGE's existing resources include thermal and hydro-electric generating plants, and wholesale market purchases. With the completion in 2007 of our new Port Westward natural gas-fired plant and Phase I of the Biglow Canyon wind farm, PGE's power supply portfolio in 2008 will include annual average energy availability (by fuel type) of approximately 41% from natural gas-fired generation, 22% PGE-owned hydroelectric generation and long-term contracts for Mid-Columbia hydro, 23% coal, 10% other long-term contracts, and almost 4% from non-hydro renewable resources.

The next sections give brief descriptions of PGE's portfolio today, actions taken since our previous IRP, and our generation resources by type, followed by a summary of their capacity and annual average energy capabilities. The final section of this chapter lists expiring contracts with their corresponding energy and capacity values. The expiration of several energy and capacity contracts by the year 2012 is one of the primary drivers of our resource need going forward.

Chapter Highlights

- PGE's current generating resources include four thermal plants and eight hydroelectric plants with total combined generating availability of 1,421 MWa. In addition, we have 620 MWa of long-term contracts.
- By year-end 2007, we will have completed the construction of the 425 MW Port Westward natural gas combined-cycle generating plant and Phase I (125 MW) of the Biglow Canyon wind project.
- Actions taken since the acknowledgement of our 2002 IRP Final Action Plan will have added over 790 MWa of energy resources with a capacity value of 957 MW and 970 MW of additional capacity resources by year-end 2007.
- Contract resource expirations of almost 300 MWa in energy and over 800 MW of capacity are driving our need for new resources in 2012.

2.1 PGE Today

PGE serves approximately 793,000 customers in 52 Oregon cities. Approximately 1.6 million people reside in our 4,000-square mile service territory. As Oregon's largest utility, our service territory attracts major employers in diverse industries, such as high technology and health care. Economic growth in northwest Oregon continues to fuel PGE's customer growth rate. At approximately two percent annual load growth, our growth rate is faster than the national average. In 2006, total retail energy deliveries increased 4.9% over 2005 levels to 19,708,000 MWh.

In April 2006, PGE once again became a public company after being privately held since July of 1997. Today PGE's common stock trades on the New York Stock Exchange under the ticker symbol POR and once again provides PGE access to financial equity markets to finance the Company's capital expenditure needs.

PGE's current power supply portfolio is a diverse mix of generating resources that includes hydropower, coal and natural gas combustion, and wind resources currently providing 1,421 MWa of total generating annual average availability. In addition, we can rely on long-term contracts for another 620 MWa. By the end of 2007, two new power plants will be complete: Biglow Phase I, a wind plant with annual average availability of 47 MWa, and Port Westward, a natural gas plant with annual average availability of 374 MWa. During 2008, we will complete the decommissioning of the Bull Run hydro plant, reducing our generating availability by 11 MWa. In 2008, our total power supply availability will be 2,451 MWa. Figure 2-1 shows PGE's 2008 energy resource mix on an annual average availability basis.

Figure 2-1: PGE 2008 Annual Average Energy Resource Mix (Availability)

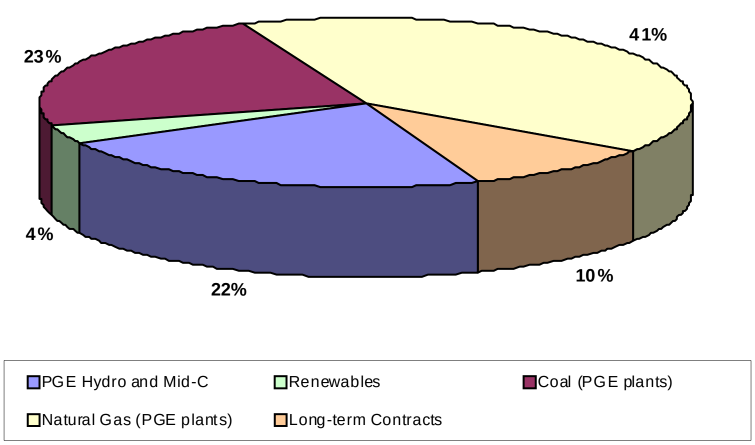
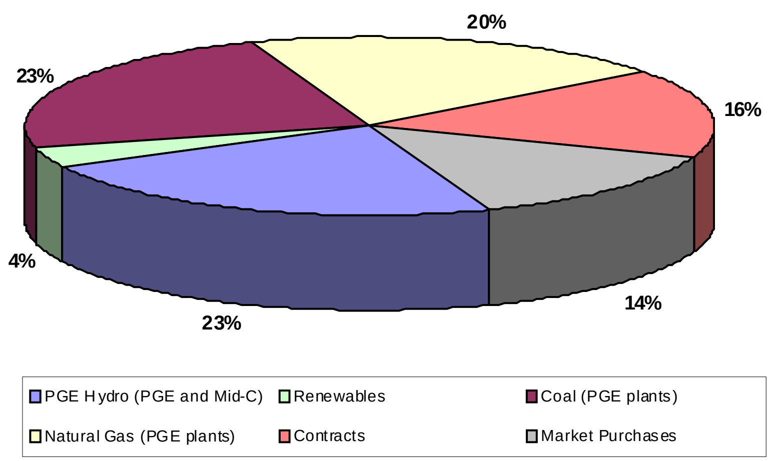


Figure 2-2 below shows our expected 2008 resource mix after economic dispatch. This is a more realistic view of how PGE meets retail load. This graph shows how a significant share of our gas plants is displaced by market purchases. This behavior is largely driven by our Beaver plant. We discuss the ongoing economic displacement of Beaver in the next chapter.

Figure 2-2: PGE 2008 Annual Average Resource Mix (After Economic Dispatch)



2.2 Actions from the Acknowledged 2002 IRP Final Action Plan

PGE is now in the process of implementing the final resource additions to complete the Action Plan targeted in our last IRP. Pursuant to this Plan, the Company added a diverse mix of new supply that includes over 790 MWa of energy resources and 1,927 MW of capacity, of which 970 MW were additional to the capacity value of energy actions. On the energy supply side, these actions included implementation of a long-term power purchase agreement from the Klondike II wind project, execution of 132 MWa of mid-to-long-term power contracts, EE programs implemented by the ETO, efficiency upgrades at existing PGE generating facilities and construction of the Port Westward natural gas combined-cycle generating plant.

The Port Westward plant became available for commercial operation on June 12, 2007. In addition, we are currently in the process of constructing Phase I of the Biglow Canyon wind project. The project is expected to be completed by the end of 2007. At approximately 125 MW, Biglow Canyon Phase I will complete our remaining resource actions pursuant to our acknowledged 2002 IRP Action Plan.

To meet our capacity needs, PGE has acquired additional peaking resources beyond the capacity acquired with our energy actions. These additional capacity actions include an expansion of our DSG program at customer sites and the purchase of winter peaking contracts from other energy market participants. PGE has also sought additional demand response opportunities through our various programs, including demand buy-back, energy information services, time-of-use pricing, load curtailment contracts, residential direct load control, advanced metering infrastructure and real-time pricing. We discuss demand response programs in more detail in Chapter 4.

Table 2-1 provides a summary overview of the resource actions from our acknowledged 2002 IRP Action Plan as well the resources that we have implemented pursuant to that plan.

Table 2-1: 2002 IRP Actions

	2002 IRP Action Plan		**Resource Acquired to Date (May 2007)**	
	MWa	**MW**	**MWa**	**MW**
Short-term Acquisitions[1]	125	125	125	125
Plant Upgrades	41	50	36	41
Other Operating Changes[2]	5	0	5	0
Hydro Contract Extension[3]	14	116	14	116
EE per the Energy Trust of Oregon[4]	55	79	48	69
Fixed Price PPAs	135	150	132	150
Wind (assumes capacity value = energy[5])	65	65	74	74
Port Westward	350	375	360	382
Total Energy Actions	790	960	794	957
Additional Capacity Actions				
Dispatchable Standby Generation		30		45
Port Westward Duct Firing		25		25
Peak Tolling from Bids		400		400
Fill-in Short-Term from the Market[1]		500		500
Total Additional Capacity Actions		955		970

Notes:

[1] *Purchased as needed to balance resources to load.*

[2] *Represents PGE's expectation of operation of the Bull Run hydro project until decommissioning in 2008.*

[3] *2002 IRP Target included an additional 49 MWa of energy at market index price, which is included here in the 125 MWa of short-term acquisitions. Total energy from hydro contract extension is 63 MWa.*

[4] *ETO target of 55 MWa is for acquisitions through December 31, 2007; 48 MWa was acquired for 2004 to 2006. MW savings are estimates based on implied load factors.*

[5] *In the 2002 IRP we assumed that capacity value of wind was equal to its annual average energy; in this IRP we assign to wind a capacity value of 15% of nameplate capacity.*

2.3 Thermal Plants

With the completion of Port Westward, PGE now owns five thermal resources – two coal-fired and three gas-fired – with combined January peaking capacities of 1,891 MW in 2012. The following section provides a description of PGE's current portfolio of resources, as well as those under construction.

Port Westward - PGE's new Port Westward power plant became available for commercial operation on June 12, 2007. The CCCT plant is the most efficient natural gas-fired generator of its type in the Northwest region of the United States. Port Westward is powered by a Mitsubishi G-class combustion turbine, which is more efficient and has lower operating costs than turbines using the older F-class technology. The new plant will supply approximately 425 MW of capacity in January (based on expected ambient temperature), including almost 400 MW base load plus 25 MW duct firing, with a heat rate of approximately 6,800 Btu/kWh (Higher Heating Value, or HHV). Expected average annual energy capability will be approximately 374 MWa.

Port Westward is located in Clatskanie, Oregon. The site selection process took advantage of existing electrical transmission and gas transportation infrastructure. The project included construction of a 20-mile, 230 kV transmission line from the Port Westward site to PGE's decommissioned Trojan site to allow for delivery of power directly into PGE's grid.

PGE contracted with NW Natural for a 10-year firm natural gas storage service agreement under which we are able to store up to 1.26 million dekatherms of natural gas in the Mist gas storage facility near Clatskanie. We will use the stored gas to augment gas pipeline transportation service to our Beaver and Port Westward plants. PGE also holds 57,000 dekatherms per day of capacity at the Sumas Hub and 30,000 dekatherms per day of capacity at the Rockies Hub for a total of 87,000 dekatherms per day of gas pipeline capacity. This allows PGE to fully supply Port Westward's base load and peaking operations, and to supply Beaver with sufficient transport and storage capacity to meet its expected dispatch and fueling needs.

Beaver is a CCCT facility located in Clatskanie, Oregon. It has been in service since 1976, and we expect it to operate through 2024. Beaver has a peak January capacity of 521 MW and an average annual energy availability of 398 MWa[5]. The six combustion turbines are dual fuel, operating on either natural gas (pipeline or storage at Mist) or No. 2 diesel fuel oil via on-site tank storage. Beaver has four 250,000-barrel storage tanks, of which three are in service, and three 50,000-barrel tanks. In 2001, PGE added a separate simple cycle unit to the site, Beaver 8,

---

[5] Combustion turbine capacities vary inversely with temperature over the year.

which has average annual energy availability of 19 MWa and a January peaking capacity of 24 MW.

Coyote Springs I is a gas-fired CCCT facility located in Boardman, Oregon. It has been in service since 1995, and the original book life extends to 2025. It has January capacity of 245 MW and forecasted average annual energy availability of 210 MWa, including 2 MW of duct firing capacity.

Boardman is a pulverized coal plant located in Boardman, Oregon. It went into service in 1980, and we expect its economic life to extend through 2040 if scrubbers are installed (see Chapter 6 for more information regarding Boardman emissions controls). Coal for Boardman is imported from Powder River Basin coal fields under rail transportation contracts. PGE is the operator of the plant, and we have a 65 percent, or 380 MW, share of the plant output. Forecasted average annual energy availability for PGE's share is 318 MWa.

Colstrip Units 3 and 4 are coal-burning units located in Colstrip, Montana. The plants went into service in 1985. They are expected to run through at least 2024. The plants are operated and managed by PPL Montana. PGE owns 20 percent of the units, and our share of the capacity is 296 MW as of July 2007. Colstrip is a mine-mouth plant, with coal transported by conveyor belt directly from the mine to the boiler. Forecasted average annual energy availability for PGE's share of Colstrip Units 3 and 4 is 252 MWa.

2.4 Hydro

PGE owns and operates eight hydroelectric plants. They are:

- Two plants located on the Deschutes River near Madras, Oregon: Pelton (PGE share 73 MW[6]) and Round Butte (PGE share 225 MW).
- Four plants located on the Clackamas River: Oak Grove (33 MW), North Fork (43 MW), Faraday (43 MW), and River Mill (23 MW).
- Sullivan (16 MW), located on the Willamette River at Willamette Falls.
- PGE also owns the Bull Run Hydro facility (22 MW), but will begin decommissioning this facility later this year.

[6] The figures used in this section refer to *useable* capacity, i.e. the maximum generation maintainable for four hours.

The Pelton Round Butte project is the only PGE-owned hydro resource that provides material reservoir storage flexibility. The other projects are limited in their ability to store and shape water or energy and are generally operated as run-of-the-river projects. At the usable capacity numbers listed above, these hydro resources account for approximately 12 percent of PGE's current generation capacity. In addition to energy production, these resources (particularly Pelton Round Butte) provide valuable peaking and load following capabilities. A portion of PGE's hydro capacity is also used to meet spinning and supplemental (operating) reserve requirements, which are necessary for responding to system emergencies.

Hydro Relicensing

PGE's hydro plants operate under long-term (30- to 50-year) licenses issued by the Federal Energy Regulatory Commission (FERC). FERC issued a new 50-year license for Pelton and Round Butte on June 21, 2005, and a new 30-year license for Willamette Falls, which covers our Sullivan plant, on December 8, 2005. PGE is in the process of renewing its licenses on the four hydro plants located on the Clackamas River, which are covered by long-term licenses for the Oak Grove (Oak Grove plant) and North Fork (North Fork, Faraday, and River Mill plants) Projects. These licenses expired at the end of August 2006. The four plants will continue to operate under annual licenses until FERC issues a new long-term license. Relicensing is very cost-effective, as the costs of relicensing are substantially lower than procurement of other resource alternatives[7].

2.5 Non-hydro Renewable Resources

Biglow Canyon – In 2005, PGE purchased the development rights to the Biglow Canyon Wind Farm located in the lower Columbia River Gorge near Wasco, OR. Biglow Canyon will have a capacity of up to 450 MW at full build-out. A phased build-out approach is expected to meet our growing renewable energy needs. A turbine supply agreement for Phase I was signed in November 2006 with Vestas for 76 V82, 1.65-MW wind turbines, for a total nameplate capacity of approximately 125 MW. This first phase of Biglow Canyon is expected to be complete at the end of 2007. Phase I is expected to provide 47 MWa average annual energy at a forecast 38% capacity factor.

The project will be interconnected to a new 230 KV transmission line and substation that are currently under construction and will terminate at BPA's John

[7] Pages 23 – 25 of PGE Exhibit 300 in Docket UE 180 provide a detailed discussion of the relative costs of relicensing and other supply alternatives.

Day 500-KV substation. PGE currently holds 150 MW of interconnection contract rights from BPA for Biglow. Since PGE has requested BPA control area service, BPA will absorb intra-hour fluctuations in accordance with applicable tariff terms and conditions, and PGE will receive the hourly scheduled energy from BPA into PGE's system.

PGE expects to complete the two subsequent phases of Biglow Canyon by 2010, assuming extension of the federal PTC and continued cost-effectiveness. Biglow Canyon qualified for the short-list under PGE's 2003 RFP evaluation process based on a combination of price and non-price characteristics. OPUC Order 04-375 acknowledged additional wind energy commensurate with Klondike II and Phase I of Biglow. Our proposed Energy Action Plan seeks acknowledgement of the remaining phases required for full build-out, up to an additional 325 MW, at the Biglow site, subject to PTC renewal and the project otherwise remaining economic.

Klondike II - In December 2004 PGE executed a PPA with PPM Energy, Inc. (PPM) for the acquisition of 100% of the generation output of the Klondike II Wind Farm located in Sherman County, Oregon. The expected output of this facility is 27 MWa on an annual basis. Effective December 1, 2005, PGE began taking delivery of the entire output of this wind farm subject to an energy firming and shaping service provided by PPM.

Vansycle Ridge – PGE entered into a PPA in 1997 with ESI Vansycle Partners to purchase 25 MW (expected annual average energy of 8 MWa) of output from the Vansycle Ridge Wind Farm located north of Pendleton along the Washington/Oregon border. The PPA expires in 2027. Firming and shaping is provided by BPA.

2.6 Other Contracts

Hydro Output Shares - PGE has contracts for specified output shares of the hydro facilities on the Mid-Columbia identified below. We receive percentage shares of the output in exchange for paying a proportional share of the plants' costs[8].

- **Wells** – PGE has a contract with Douglas County PUD at Wells on the middle section of the Columbia River (Mid-C) for 147 MW of capacity and 88 MWa of energy under normal water conditions. This contract expires in 2018.

[8] Capacity, in the paragraphs below means usable peaking capacity and energy is measured under average water conditions.

- **Rocky Reach** - PGE has a contract with Chelan County PUD at Rocky Reach on the Mid-C for 137 MW of capacity and 84 MWa of energy under normal water conditions. This contract expires in 2011.

- **Wanapum** - PGE has a contract with Grant County PUD at Wanapum on the Mid-C for 166 MW of capacity and 83 MWa of energy under normal water conditions. This contract expires in 2009.

- **Grant County PUD Settlement Agreement** - In 2001, PGE reached a new agreement with Grant County PUD for the purchase of a share of the energy output of the Priest Rapids and, starting in 2009, Wanapum hydro projects, also on the Mid-C. PGE's share of these projects (as of 2008) provides approximately 104 MW of capacity and 80 MWa of energy under normal water conditions[9].

Pelton Round Butte Agreement - In 2001, PGE and the Confederated Tribes of Warm Springs (Tribes) reached an agreement relating to the Tribes' share of the Pelton Round Butte project. Under this agreement, the Tribes will sell the energy generated by their share of the plants to PGE through 2012. The agreement also provides for PGE to purchase from the Tribes the 9 MWa expected output from the Pelton re-regulation dam.

Portland Hydro - We have a take-or-pay contract (i.e., a contract with obligation of payment for the contracted energy regardless of the actual purchase) with the City of Portland to purchase the output of the Portland Hydro Project, located on the Bull Run River. The contract runs through 2017.

Canadian Entitlement Allocation Agreement - This agreement relates to the Mid-C contracts. Columbia River storage reservoirs located in Canada are operated so as to increase the overall value of the Columbia River hydro system. However, these benefits are shared with Canada. The current agreement ended in 2003, but an extension agreement will be effective through most of 2024.

Covanta Marion - We purchase the output of the Covanta Marion municipal solid waste burning facility located in Brooks, OR, under a Public Utility Regulatory Policies Act of 1978 (PURPA) contract that expires in the middle of 2014. This plant has a capacity rating of 16 MW, and produces about 10 MWa of energy output.

[9] Output from this agreement varies each year until 2012, when the contract will provide 134 MW of capacity and 69 MWa of energy under normal water conditions.

Wells Settlement Agreement - Under this agreement with Douglas County PUD, which runs through August, 2018, we purchase 21 MW of January capacity and approximately 27 MWa of energy.

Capacity Exchange Contracts - PGE has two long-term exchange agreements that provide daily/weekly storage and capacity. Under the agreements we receive energy and capacity during peak hours and return the energy during off-peak hours:

- Spokane Energy (formerly Washington Water Power) – 150 MW, under contract running through 2017.

- Eugene Water and Electric Board – 10 MW, under a contract that ends in the middle of 2014.

Winter Capacity Contracts - PGE has two long-term capacity contracts signed pursuant to the 2002 IRP Final Action Plan. We have the option of acquiring 100 MW and 300 MW of capacity in the winter months. These contracts expire in 2010 and 2011 respectively.

TransAlta - We executed a 10-year, 100 MW fixed price PPA with TransAlta as an action item pursuant to our 2002 IRP Final Action Plan. PGE receives energy under this agreement, which extends until 2016.

Peak Tolling Agreement – We executed a 5-year, 25 MW on-peak gas tolling agreement as an action pursuant to our 2002 IRP Final Action Plan. The agreement expires in 2009.

Flat Energy Purchase Agreement – Pursuant to our 2002 IRP Final Action Plan, we signed a 5-year agreement for the purchase of 25 MWa of energy, flat across the year, at a fixed price. This agreement expires in 2011.

Chelan Exchange - The Chelan Exchange agreement with Chelan County PUD, under which PGE receives up to 50 MW of summer capacity, with energy returns taking place both in summer and winter, expires in February 2011.

Glendale Exchange – This agreement with the City of Glendale, California, provides PGE with 30 MW of capacity during the months of November, December, January, and February. We have similar obligations to Glendale during the months of June, July, August, and September, yielding zero net annual energy. This agreement runs through February 2012.

Glendale Long-Term Sale – The City of Glendale purchases 20 MW of year-round capacity with the right to purchase related energy from PGE. This contract expires in 2012.

BPA Subscription

Currently BPA provides PGE with no subscription power.

Expiring Contracts

PGE has a number of contracts that expire on or before 2012. These expirations are one of the significant drivers of our need for additional resources in the 2012 – 2015 timeframe; see Table 2-2 . Expiring resources are listed along with their full-year energy and capacity volume in the expiration year.

Table 2-2: Expiring Contracts

Contract	Expiration	Energy	Capacity
Confederated Tribes	2012	66 MWa	167 MW
Chelan Exchange	2011	7/-8 MWa	50/-33 MW
Flat Energy Agreement*	2011	25 MWa	25 MW
Glendale Exchange	2012	0 MWa	30 MW
Glendale Long-Term Sale	2012	-10 MWa	-20 MW
Peak Tolling Agreement*	2009	14 MWa**	25 MW
Rocky Reach	2011	84 MWa	137 MW
Wanapum	2009	83 MWa	166 MW
Winter Capacity I*	2010	NA	100 MW
Winter Capacity II*	2011	NA	300 MW

* *Contract names have not been disclosed due to confidentiality agreements with counterparties.*
** *Availability*

Table 2-3 summarizes the total contracts and resources remaining in our portfolio in 2012. Figure 2-3 and Figure 2-4 display PGE's owned and contracted energy availability from energy resources[10] for 2012, before any new actions recommended in this IRP Action Plan. The physical shortfall is assumed to be met by sport market purchases. We also show expected economic generation, which results in a material increase in short-term purchases.

[10] Although 50MWa of the plant output will count as a qualifying renewable resource per the proposed Oregon Renewable Portfolio Standard, all of Pelton and Round Butte are included here in PGE and Contract Hydro.

Table 2-3: Existing PGE Resources in 2012 – Before New Actions

Type	Plants	In-Service Date	Annual Energy MWa *	January Capacity MW
Coal	Boardman	1980	318	380
Coal	Colstrip	1985	252	296
Gas	Beaver	1976	416	521
Gas	Beaver 8	2001	20	24
Gas	Port Westward	2007	374	425
Gas	Coyote	1995	210	245
Wind	Biglow Canyon Wind Project	2008	47	19
Hydro	Oak Grove	1924	24	33
Hydro	North Fork	1958	27	43
Hydro	Faraday	1907	24	43
Hydro	River Mill	1911	13	23
Hydro	Sullivan	1895	8	16
Hydro	Round Butte	1964	75	225
Hydro	Pelton	1957	35	73
Capacity	Dispatchable Standby Generation (DSG)	2000	0	44
	Total PGE Plants		1,849	2,411
Type	Contracts			
Hydro	Wells		88	147
Hydro	Grant PUD Deal		69	134
Hydro	Portland Hydro		10	36
Wind	PPM Klondike II		27	20
Wind	Vansycle Ridge		8	8
Capacity	Spokane Energy Capacity		0	150
Capacity	EWEB Capacity		0	10
Hydro	Canadian Entitlement Ext.		-10	-18
Other	Covanta Marion		10	16
Other	Glendale Long-Term Sale		-10	-15
Capacity	Glendale Exchange		0	30
Hydro	Wells Settlement Agreement		26	21
Other	TransAlta		93	100
	Total Longer-term Contracts		311	639
	Total Resources		**2,160**	**3,050**

** Theoretical Annual Average Availability Using Average Hydro.*

Figure 2-3: PGE Projected 2012 Energy Resource Mix (Availability)

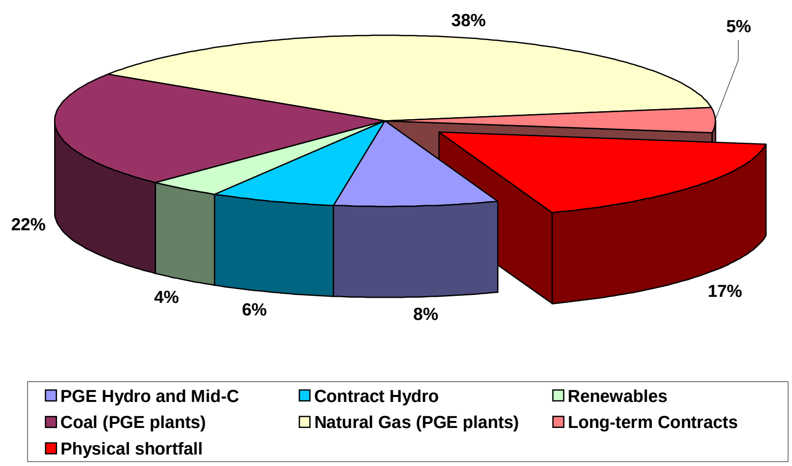
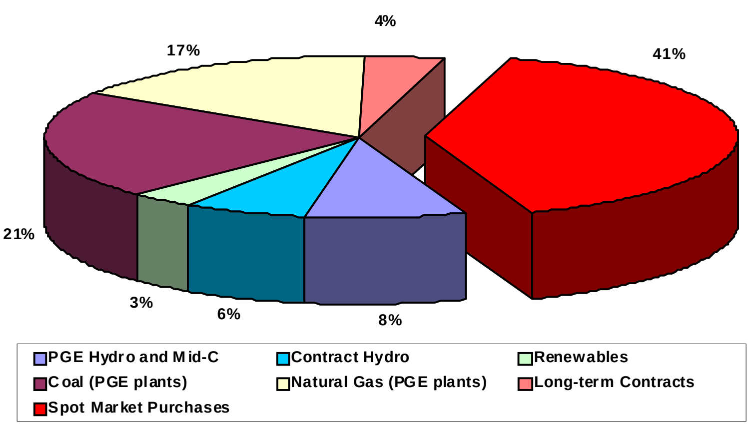


Figure 2-4: PGE Projected 2012 Energy Resource Mix (After Economic Dispatch)



3. Resource Requirements

After considering PGE's existing generation and contract resources, we turn to demand and our annual average energy and one-hour peaking capacity load-resource balance. We focus our point estimate analysis and discussion on 2012, our target year for new resource needs based on forecast portfolio deficits. As discussed previously, PGE's current portfolio is insufficient to meet our customers' expected future energy and capacity requirements. As a result, we forecast a need for significant new resources. This is driven primarily by two factors: load growth and expiration of existing resources. The last chapter described our resource expirations over time. With respect to future demand, PGE's year-over-year long-term load, net of existing ETO energy efficiency acquisition, is forecast to grow at a rate of 2.2% per year. PGE's summer load and peaks are growing faster than the winter load and peaks due to increasing commercial cooling load and residential central air-conditioning saturation.

Based on our changing demand and supply situation, we are forecasting a load-resource deficit for annual average energy of 818 MWa and a peak capacity need of 1,540 MW by 2012, based on normal weather conditions and average water. On a forecast basis our maximum annual demand requirements are in the winter (January). As a result, our winter capacity deficit continues to drive our overall capacity need. However, our summer demand is growing faster than winter demand and is expected to overtake our winter peak demand around the end of the next decade. This evolution may require us to seek capacity resources that are available in both the summer and the winter over time. Our evolving capacity needs are discussed in greater detail in Chapter 12.

When assessing our future load-resource balance, we model our energy needs under normal hydro conditions, while taking into account impacts of critical hydro conditions as sensitivities and for the purposes of risk analysis. We also account for our thermal resources based on expected annual generation capability. The only exception to this approach is our Beaver natural gas plant. Beaver is unique in our portfolio of thermal resources based on its dispatch characteristics, which make it an intermediate duty plant with a higher heat rate. Accordingly, Beaver dispatches and provides power primarily during high demand periods such as the peak summer and winter months. Our coal-fired plants, Boardman and Colstrip, as well as our baseload natural gas plants (Port Westward and Coyote) provide a relatively low dispatch cost (compared to market) and, as a result are expected to dispatch and provide power for most hours of the year. Given Beaver's dispatch characteristics, we have reduced the amount of expected annual energy in our forecast by about 370 MWa. The treatment of the Beaver plant with respect to determining our future load-resource balance was presented and discussed with stakeholders in our 6th public workshop. Overall stakeholder feedback was supportive of the approach as realistic given current conditions and future expectations.

Consistent with past IRPs, we evaluate peaking needs by calculating the difference between our forecast annual 1-hour maximum load, based on normal (1-in-2) weather conditions, inclusive of approximately 6% operating and 6% contingency reserves, and the annual average energy capability of our resources.

Chapter Highlights

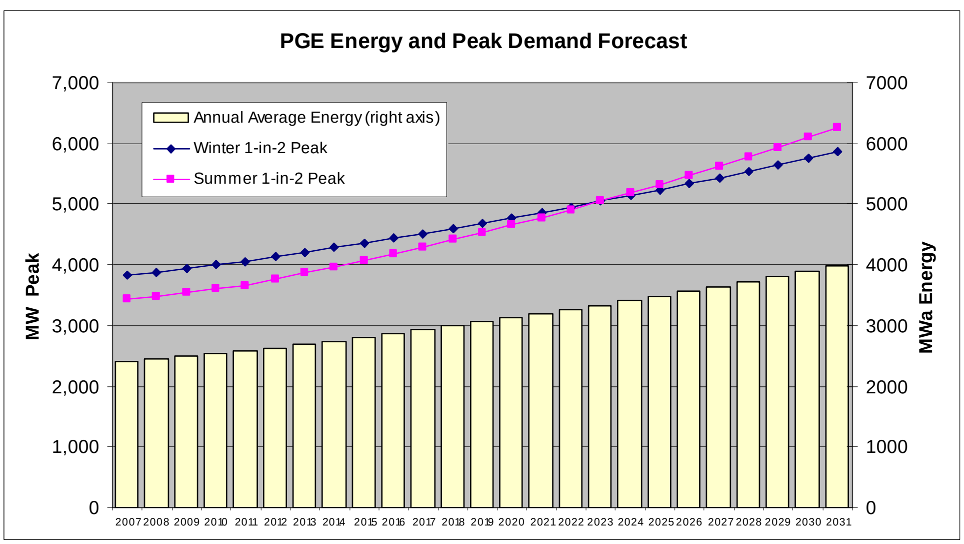
- In our reference case, long-term energy demand is growing 2.2% per year, while peak demand is growing 1.8% in winter and 2.7% in summer.
- Our load-resource balance projects an energy need of 818 MWa and a winter peak capacity need of 1,540 MW by 2012.
- We do not plan long-term energy resources for 5-year opt-out customers (currently about 30 MWa).
- We propose to recognize Beaver in this IRP as an intermediate resource and remove up to about 370 MWa from our existing energy resource total.
- We propose to retain a minimum peak reserve margin of 12%, which includes a 6% contingency reserve margin and the required approximately 6% operating reserve.
- The 2012 critical hydro adjustment for PGE is about 93 MWa; however, we do not propose any adjustments to our supply targets for critical hydro conditions.
- PGE is actively taking part in regional efforts to assess reliability standards for electric utilities; however, we have not adopted the NWPCC's approach to establishing capacity needs for this IRP. Such changes may be adopted in the future after the proposed standards are more widely reviewed and accepted.

3.1 Demand

PGE's long-term system load forecast was last updated in November 2006. For IRP purposes, we identify annual energy needs under our reference (i.e., expected or most likely) case and high load and low load forecasts, assuming normal weather conditions. We report annual peak demand using 1-in-2, or expected (normal) weather conditions, meaning that there is a 1-in-2 or 50% probability that the actual peak load will exceed the forecasted peak load during the stated time frame. Figure 3-1 displays annual load and peak demand under our reference case from 2009 to 2031 (the first and last years of analysis). The reference case load growth varies between 1.5% and 2.2% in the mid-term and is 2.2% from 2012 forward. Long-term peak demand is growing 1.8% in winter and 2.7% in summer.

PGE and the Pacific Northwest have historically been winter peaking, but summer demand has been growing and is projected to increase at a faster rate than winter demand. This is a result of the residential and commercial sectors' faster summer growth driven by cooling demand and the residential sector's slower winter growth due to declining electric space and water heat penetration. This trend, if continued, will likely transform PGE's system from winter-peaking to summer-peaking in 15 to 20 years. From an energy perspective, a shift to higher overall consumption in the summer will not occur as quickly, as forecasts continue to reflect an expectation for more heating days than cooling days in a year in the Pacific Northwest.

Figure 3-1: PGE Reference Case Load Forecast 2009 - 2031



The demand forecast was developed from historical data, i.e., net of EE savings. It does not, however, include potential savings from future incremental EE programs above past implementation rates.

Historically, there were brief periods (anywhere from 1 to 5 years) during which demand for electricity in PGE-served areas declined due to boundary changes, business cycles, departures of large customers from the system or significant macroeconomic shocks. However, overall demand has always rebounded to grow over time based on macroeconomic and fundamental drivers. PGE expects this trend to continue in the future. The following factors are fundamental drivers of PGE's reference or base-case demand forecast:

- The economy, demographic trends such as in-migration and life expectancy, and a business environment that favor future growth.
- Oregon's position as a magnet state, the presence of prominent industry leaders, continued gains in productivity and emerging sectors sustaining and creating new growth.
- The high-technology sector continues to be a strong force in the local economy.

PGE expects that the following trends will continue and will, over time, alter the composition and characteristics of various customer sectors:

- Faster growth in the commercial sector, dominated by cooling load, will continue in the forecast period. This sector's share of load grew from 34% to 40% between 1985 and 2005.
- Slower growth in the residential sector (in part due to declining space and water heat penetration), will continue. This sector's share of load fell from 43% to 39% between 1985 and 2005.
- Industrial load volatility and uncertainty will increase as industrial customers react more quickly to changing market conditions and business cycles. Our 20 largest industrial customers account for two-thirds of industrial load. Their business decisions can cause load to deviate significantly from our long-term forecast.

In addition to a reference case forecast, PGE projects high and low long-term growth cases. These demand cases are constructed from historical parameters[11]. They do not reflect specific changes to assumptions for customer usage patterns or consumption rates or shifts in aggregate demand due to fundamental pattern changes (e.g., sustained out-migration, rebound in space heat penetration or renaissance of certain key industries). These high and low cases essentially serve

[11] Monthly sector energy demands are individually projected to grow at the mean (average) rates plus one standard error for the high case and minus one standard error for the low case.

as demand boundaries, or jaws, and are sufficiently large to incorporate a mid-term departure from the reference forecast caused by business cycle and/or macroeconomic fluctuations. However, brief excursions outside the boundaries could occur in the short-run due to large shocks to the economy or departures from normal weather conditions.

Table 3-1 displays projected 2012 loads and annual load growth for 2012 (the reference year in our Action Plans) to 2031.

Table 3-1: Reference Case, High and Low Load Growth Rates

	Energy		Winter Capacity		Summer Capacity	
	2012 MWa	2012-31 growth	2012 MW	2012-31 growth	2012 MW	2012-31 growth
Reference	2,630	2.2%	4,127	1.8%	3,761	2.7%
High	2,716	3.1%	4,509	2.8%	4,074	3.5%
Low	2,555	1.2%	4,015	0.8%	3,750	1.8%

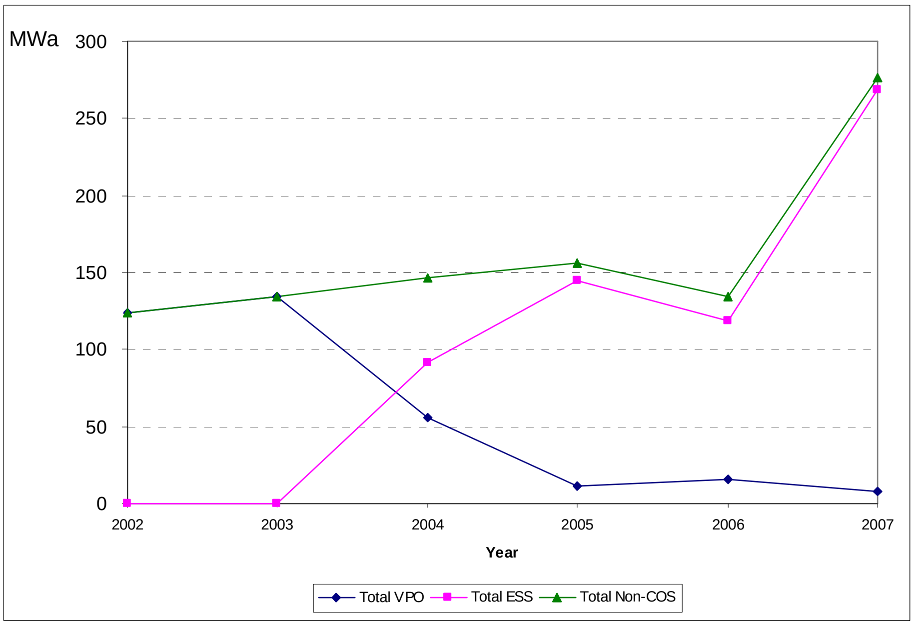
3.2 PGE's Cost-of-Service Load

Under Oregon law, PGE must offer our cost-of-service (COS) rates to all customers. COS rates are PGE's regulated, cost-based tariffs, which are based on the cost forecasts approved by the OPUC in either PGE's general rate case or annual update tariff filings. Our COS rates are available to all customers within PGE's service territory based on applicable customer class tariffs. We must offer to all non-residential customers the choice of leaving COS rates and electing either 1) PGE's daily or monthly index rates (i.e., variable price options or VPO), or 2) a registered Energy Services Supplier (ESS) as a supplier for one, three or five years. However, according to Oregon legislation and related OPUC rules, PGE also remains the provider of last resort for all customers in our system.

Customer load eligible for the 3- and 5-year ESS options is limited to an aggregate cap of 300 MWa per Schedule 483 and 489 of PGE's electric tariff. Based on our experience to date, our planning assumption for the 1-year and 3-year opt-out customers is that some customers may default back to PGE's rates over time. However, we assume that the 5-year opt-out customers will not. Our assumption for the 5-year opt-out group is based on the requirement that these customers must complete five years before becoming eligible to elect COS rates and must provide a two-year notice to PGE before returning. Based on the extended term and reduced return flexibility of the 5-year opt-out program, we have assumed that these customers have made a longer term decision to leave PGE's COS rate plans and, consequently we are not planning for their long-term power supply needs. Guideline 9 of Order 07-002 confirms that our load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

In 2007, PGE has about 275 MWa of load on non-COS tariffs (roughly 11% of retail load). Between 2004 and 2006 about 150 MWa were on non-COS tariffs. Figure 3-2 below summarizes this recent historical trend.

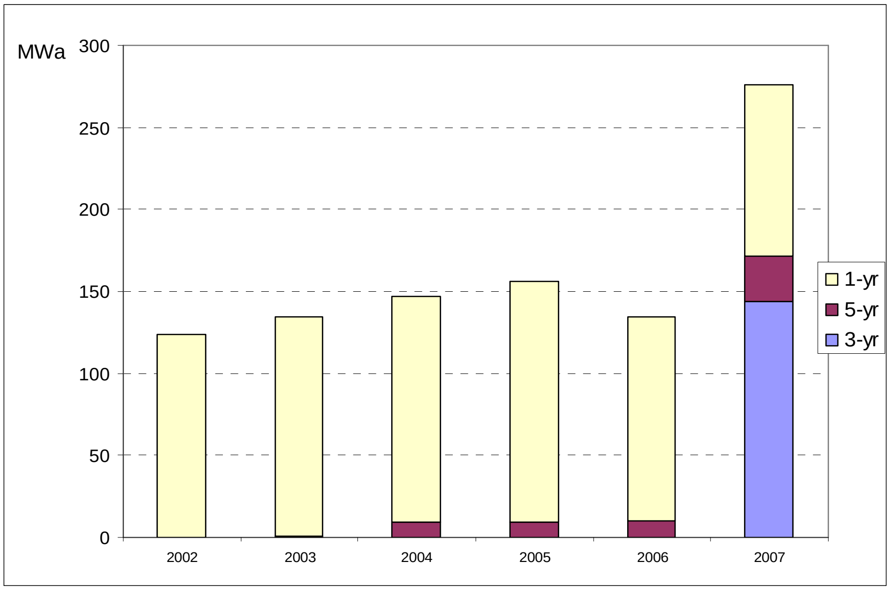
Figure 3-2: Non Cost-of-Service Load



The 3- and 5-year opt-out load reached 170 MWa in 2007 compared to average historical elections of 10 MWa. The increase in longer-term opt-out load can be attributed primarily to the change in forward power market conditions during the most recent opt-out election window. From a long-term planning perspective, we do not know from one year to the next exactly how much of the eligible load may choose to opt out from COS rates. Figure 3-3 shows a detailed break-out of non-COS customers by duration of election.

Planning and procurement of new resources in a direct access environment proves challenging because opt-out/opt-in election decisions magnify future load uncertainties and the related risk of having to procure or sell electricity in an adverse market. To address the uncertainties related to opt-out eligible load, PGE proposes the following planning approach. In accordance with the guidance of Order 07-002, PGE will not plan energy resources for 5-year opt-out customers (currently about 30 MWa). For the shorter-term opt-out eligible load we suggest a balanced approach that will avoid being overly short during times when more customers choose utility COS tariff offerings or being overly long during times of increased opt-out elections by our customers.

Figure 3-3: Non Cost-of-Service Customer Load by Duration of Election



To achieve this balance we propose to acquire long-term resources for one-third of the remaining 270 MWa (90 MWa) for customers potentially eligible for 3- and 5-year opt-out (and not currently on a 5-year opt-out), and to acquire shorter-term resources as needed for the remaining eligible load (180 MWa). This strategy provides a more responsive supply position whereby we are neither overly long nor short with respect to the load we may be required to serve over time. We thus remain flexible in matching supply against changing customer demand.

For capacity purposes, we have an obligation to serve as provider of last resort for all jurisdictional customers. Given the guidance in Order 07-002 regarding our 5-year opt-out customers, we propose to meet their capacity needs as needed in the short-term market. We do not propose to acquire long-term capacity resources to meet this potential emergency demand, which is currently about 32 MW. We make an adjustment to our capacity load-resource balance to remove this load.

3.3 Load Resource Balance

Regional Load-Resource Balance Estimates

According to the NWPCC's Fifth Northwest Electric Power and Conservation Plan (5th Plan), the expected load-resource balance for the region in 2007 under critical water conditions is a resource surplus of about 1,500 MWa over expected demand. The NWPCC expects the region to remain in surplus until 2014. Under medium-low demand forecast conditions, the region remains in surplus until 2015. However, with medium-high demand growth, the region would be deficit after 2008.

The NWPCC notes that not all resources are contractually committed to regional loads. Independent power producers (IPP) own most of the current and near-term forecast surplus. However, because it is assumed that making long-term firm sales out of the region would be difficult due to lack of firm transmission, the NWPCC concluded in the 5th Plan that these resources, priced at the market, would be available to meet Northwest peak loads. The WECC-wide heat event in July 2006 did not support this premise. The NWPCC changed its assumption in its pilot resource adequacy standard and now believes that no out-of-region imports or in-region uncommitted IPP capacity can be counted as firm resources to meet regional peaking needs during the summer.

Finally, the NWPCC recognizes that while the region as a whole may be in surplus, some individual utilities are energy-short, and some utilities may need to acquire additional peaking capacity or take action to reduce their exposure to the market.

BPA's 2006 Northwest Loads and Resources Study (BPA White Book) reflects modest regional power surpluses through 2016. However, this forecast also assumes that 3,360 MWa of generation from the region's IPPs would be available to serve Northwest consumers under critical water conditions. This IPP generation represents about 15 percent of the region's total power supply. Absent this supply, the near-term Northwest energy outlook would be about 1,300 MWa deficit assuming critical hydro conditions, according to the BPA White Book.

If the region runs into a supply crisis as it did in 2000 and 2001, this will force the Northwest to compete with other higher-price Western markets for unsubscribed IPP generation, potentially resulting in extreme price volatility and supply shortages. Consequently, even if capacity is available in the region, it may be expensive and/or not accessible.

PGE's Energy Load-Resource Balance

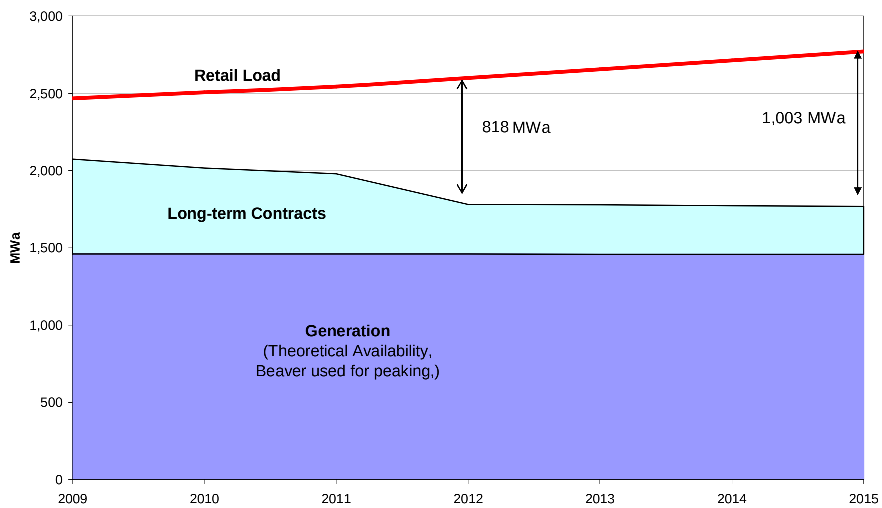
Energy balance in this IRP refers to the average amount of electricity PGE will need over a year under normal hydro and weather conditions. It is computed as the difference between the expected energy capability of PGE's resources (plants, contracts and purchases) and the expected annual average load. Using this approach suggests that when we are in supply/demand balance on an annual average basis, we would be short for about half the hours of the year and long for the remaining hours. Unfortunately the long hours and short hours also vary across the year. As a result, we generally find that when our energy supply and demand are balanced on an average annual basis for planning purposes, we are short during the high-demand, high-price periods and long during times of low prices and reduced demand for PGE and the region. A primary function of PGE's Power Operations group is to make purchases and sales to balance resources to meet loads for all hours.

Figure 3-4 shows a projection of PGE's load and resources. It reveals resource gaps increasing to 818 MWa in 2012, and 1003 MWa in 2015. These forecast deficits are attributed to the expiration of existing long-term resources, the proposed treatment of Beaver (discussed in detail later in this chapter), and load growth of approximately 55 MWa per year at our reference case annual long-term load growth forecast of 2.2%. This annual load growth is net of an assumed average of 15 MWa per year (through the end of the forecast period) of EE savings acquired through the ETO.

By 2025, PGE will face the potential economic obsolescence and full depreciation of our Colstrip, Beaver, and Coyote plants. These plants will likely require either upgrades for efficient ongoing operation or decommissioning and replacement. For modeling purposes only, we assume in this IRP that the Coyote, Beaver, Beaver 8, and Colstrip plants all cease operation beyond 2025.

Boardman will be fully depreciated in 2020. It is a valuable resource because it offers fuel diversity in PGE's portfolio and relies on an abundant domestic source of fuel, Powder River Basin coal. While Boardman will likely require environmental and maintenance upgrades to enable long-term operations, its low dispatch cost continues to provide significant cost savings to PGE customers. For this reason, we keep Boardman in our resource stack for our entire analysis period. Chapter 6 provides a more detailed discussion of the economics of Boardman with the potential cost of environmental upgrades and under different potential CO_2 tax levels.

Figure 3-4: PGE Energy Load-Resource Balance to 2015



PGE's Capacity Load-Resource Balance

Capacity is the amount of electricity a utility needs at the times when customers place maximum demand on the system (i.e., during a peak event). A given resource's capacity value is the amount of electricity the facility is capable of producing in a given hour on demand (i.e., when called for).

Consistent with past IRPs, we evaluate peaking needs by comparing the annual 1-hour maximum 1-in-2 load inclusive of 12% reserves[12] to the capability of our resources. The capabilities of our resources are reported at their August and January peak operating capacities, with the exception of hydro resources, for which we use a more prudent sustained four-hour capability measure. Starting with this IRP, we are reporting both the winter and the summer peak loads because summer peak needs are growing faster and could exceed the winter peak in the future.

Figure 3-5 and Figure 3-6 show PGE's projected capacity needs for winter and summer, respectively. They show a gap that starts at approximately 500 MW, consistent with the resource procurement specified in the last IRP which proposed reliance on the short-term market for 500 MW. The expected gap, absent any baseload energy action, will grow to approximately 1,540 MW in winter and 1,330 MW in summer by 2012.

---

12 Inclusive of 6% operating and 6% contingency reserves.

Figure 3-5: PGE Capacity Load-Resource Balance - Winter

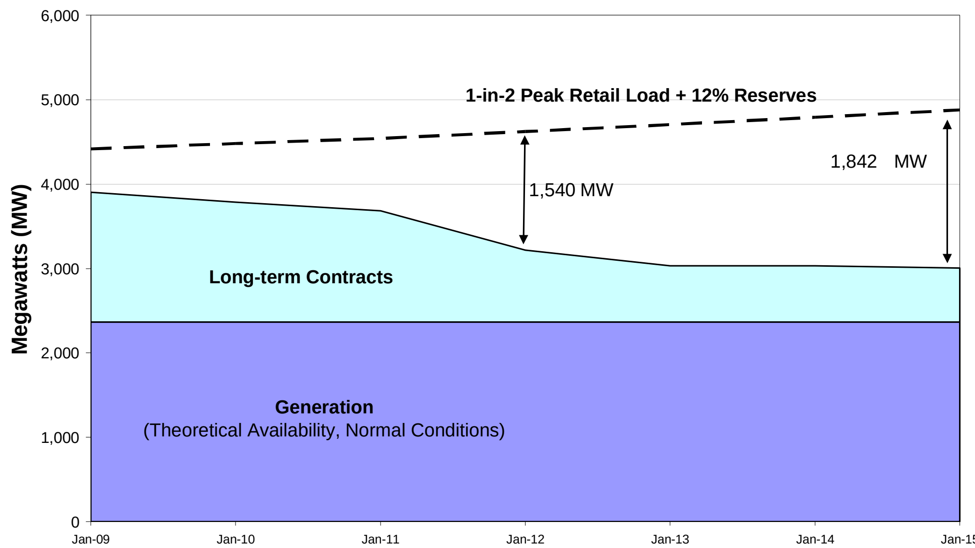
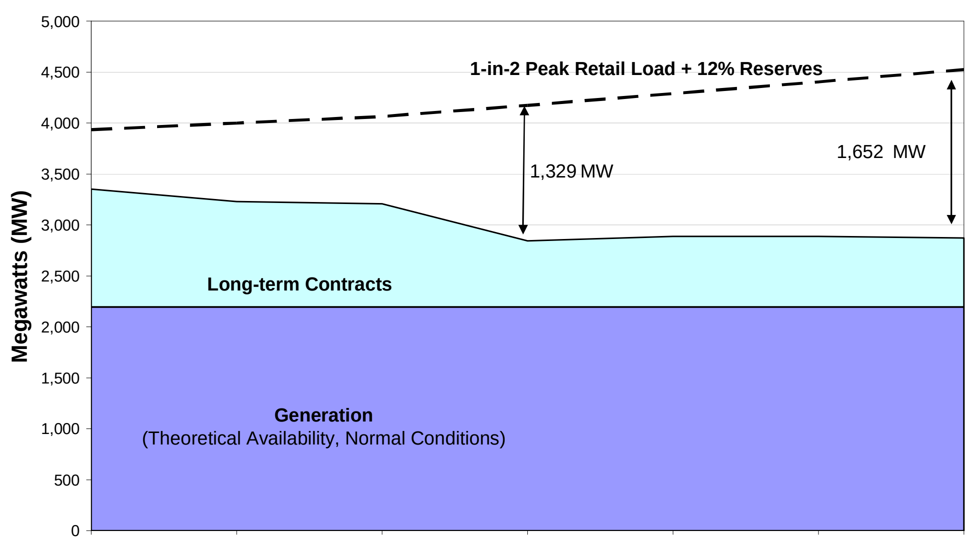


Figure 3-6: PGE Capacity Load-Resource Balance - Summer



Treatment of Beaver

PGE's resource stack indicates a need for additional baseload resources that offer competitive dispatch costs when compared to wholesale market prices. In our resource stack, there is a large dispatch cost step between our high-efficiency gas plants (Port Westward and Coyote) and Beaver, which is an older and less efficient gas plant. See Table 3-2 below.

Table 3-2: PGE Resource Stack in 2012

	PGE Stack	Capacity (MW)	Cumulative Capacity (MW)	Marginal Cost ($/MWh)	Cost Steps ($/MWh)
1	"Must Run" - hydro/PPA/renewable	1,290	1,290	$3	
2	Colstrip	296	1,586	$11	$8
3	Boardman	380	1,967	$21	$10
4	Port Westward	425	2,392	$38	$17
5	Coyote	245	2,637	$43	$5
	Market ===>		Market		
6	Beaver 1-7 (in CCCT mode)	521	3,158	$58	$15
7	Beaver 8	24	3,182	$70	$12
8	DSG	44	3,226	$133	$63

Note: The marginal cost is an annual average estimate based on the expected 2012 fuel price.

Both in recent history and based on our forward curve and post-2011 modeling runs, Beaver's economic dispatch places it firmly as an intermediate resource under normal conditions. Accordingly, we would expect Beaver to provide energy primarily during the high demand hours such as the peak summer and winter months. See Table 3-3 and Table 3-4.

Table 3-3: Beaver Historical Dispatch

		2001*	2002	2003	2004	2005	2006
Capability	MW	524	529	545	545	545	545
Net Generation (MWa)	MWa	378	41	35	40	19	41
Capacity Factor	%	72%	8%	6%	7%	3%	7%

*Notes: * 2000-2001 - Western Energy Crisis*

Table 3-4: Beaver Projected Economic Dispatch

	2007	2008	2009	2010	2011
Beaver Units 1-7	12%	14%	11%	11%	11%
Beaver Unit 8	2%	3%	1%	1%	1%

Data from August 2006 Monet Run

These tables indicate that most of the Beaver generating capability is economically displaced in a normal year. As a result, our current and future expectation is that we would produce power from Beaver only during the peak summer and winter periods, under normal conditions. Based on these expectations we propose to recognize Beaver in this IRP as primarily an intermediate resource and reduce the energy value of our portfolio by up to 370 MWa for the purposes of determining our energy load-resource balance. This will increase our energy gap by up to 370 MWa (to a total of 818 MWa in 2012), and reduce our capacity gap by a like amount, thereby creating a resource acquisition strategy that is more balanced between energy and capacity resources on an annual basis.

In making this change for the IRP, we do not anticipate any operating changes to the Beaver plant. We are simply recognizing the expected energy output of Beaver and reducing our short-term market exposure resulting from the plant's anticipated economic dispatch. Recognizing Beaver as an intermediate resource also helps meet part of our capacity requirement and recognizes that we need to acquire additional baseload resources to meet our customers' energy needs.

PGE's Proposed Planning Reserve

An important assumption included in the capacity graphs in the previous section is the level of reserves that we include in resource planning. We propose to keep the same reserve levels as in the 2002 IRP - a minimum of 12%, which includes a 6% contingency reserve margin and the required approximately 6% operating reserve[13]. The operating reserve is required by regional reliability standards and is meant to maintain supply stability and power quality during unexpected real-time disruptions that occur within the operating hour and must be corrected for within one hour's time, such as a sudden plant trip or unanticipated increase in load. A contingency reserve primarily covers two types of events: 1) extreme weather events and resulting load excursions (beyond a 1-in-2 event); and 2) generator and transmission unplanned outages (or partial outages) that extend for longer periods of time than an operating reserve is meant to cover. Our combined planning reserve is generally sufficient for either of these events alone, but not for both should they happen simultaneously.

To provide perspective, a 12% reserve for our peak winter load at normal weather in 2012 is approximately 500 MW. Moving from normal winter weather in 2012 to 1-in-5 weather conditions increases PGE's forecast one-hour peak load by about 300 MW (see Figure 3-7). Our largest single shaft risk is Port Westward at 425 MW (inclusive of duct firing). Given that half of that 500 MW reserve is required operating reserve, our proposed contingency reserve alone covers about 80% of a 1-in-5 weather event and about 60% of our Port Westward shaft risk.

[13] See 2002 IRP Final Action Plan, March 2004, pages 34 and 35.

Figure 3-7 shows the impact for PGE in 2011, for both winter and summer peaks, of moving from normal weather to 1-in-3, 1-in-5, and 1-in-10 weather. Beyond 1-in-10 weather, incremental load increases diminish rapidly because most electricity consuming devices are already on.

Figure 3-7: Impact of Temperature on PGE Peak Load

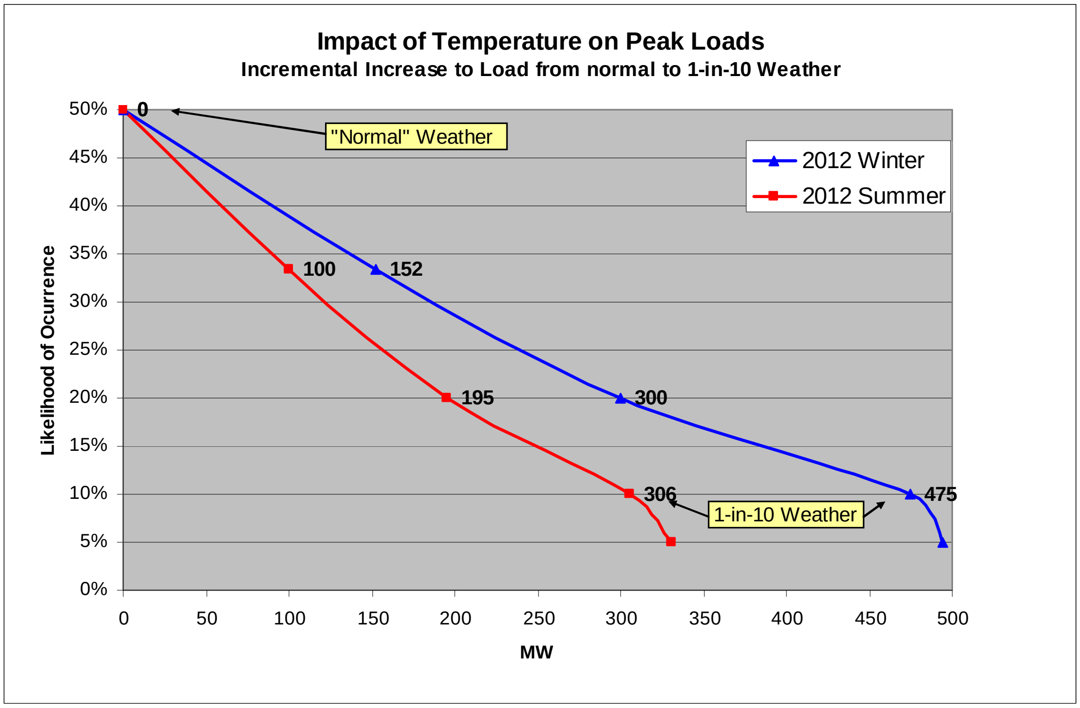
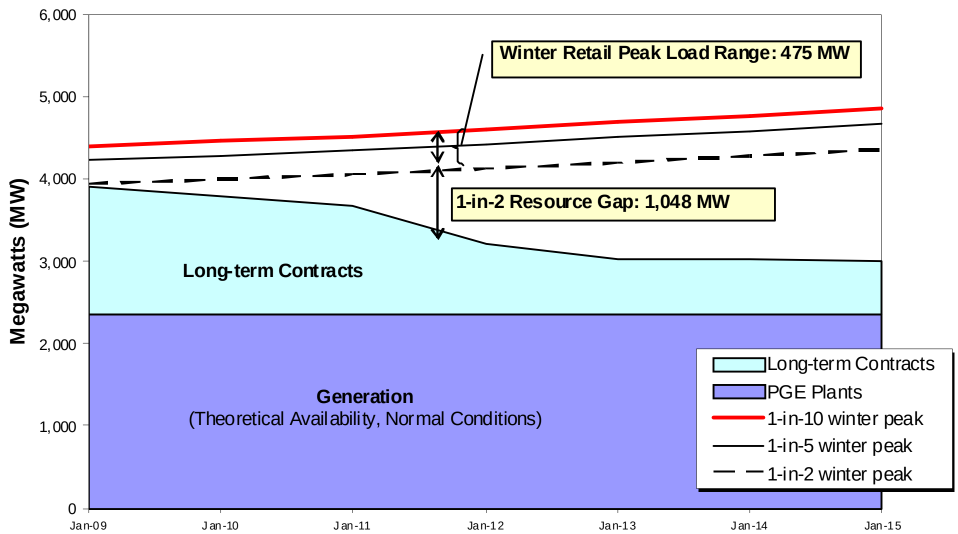


Figure 3-8 shows the impact of temperature excursion on the expected capacity gap. It shows that the proposed 12% reserve margin on the 1-in-2 peak (about 500 MW) load allows PGE to meet a 1-in-10 load excursion, which is 475 MW higher than the 1-in-2 peak.

The WECC region does not have mandatory resource adequacy standards, with the exception of an operating reserve margin of 5% for hydro plants and 7% for thermal plants. Historically, utilities sought reserves that would equal at least the largest generating shaft risk in their portfolio. OPUC Order No. 07-002 generally does not impose prescriptive planning standards. Rather, it requires utilities to identify resources needed to bridge the gap between expected load and resources. It also requires utilities to analyze reliability standards, recognizing that higher reliability typically carries a higher cost.

Figure 3-8: Expected Capacity Gap across Peak Events



Given stakeholder concerns about increased reserve margins expressed in our last IRP process, and in view of developing regional efforts to evaluate common utility reliability standards, we are not recommending a change in our reserve margin requirements for this IRP. However, we also consider 12% to be the minimum acceptable peak reserve margin to use for planning purposes and have retained these levels for the current IRP. As stated above, a 12% reserve margin is not adequate to insulate PGE customers from exposure to supply disruptions in all circumstances. Large plant outages, adverse region-wide hydro conditions and extreme weather events could individually or collectively exceed the capability of our portfolio to meet 100% of our customers' power supply requirements.

Ultimately, during times when contingency events exceed our reserve margins, we will need to rely on voluntary demand reductions and market sources of supply (if available) to maintain system reliability. To mitigate our supply and reliability risk, we are proposing in this IRP to become less reliant upon the short-term markets to provide for our planned (1-in-2) peak needs. Specifically, we believe that in the future with the regional load-resource balance becoming tighter and the transmission system increasingly constrained, it will no longer be prudent to satisfy as much of our capacity need through the short-term markets as we targeted in our last IRP. In our last IRP, we targeted filling 500 MW of our capacity needs through the short-term wholesale electric market. For this IRP we propose filling our planned capacity need through a combination of longer-term and more stable demand- and supply-side sources. See Chapter 12 for additional discussion and analysis of the capacity needs and resources we considered in this IRP.

Impact of Critical Hydro Conditions

Critical hydro is defined as the monthly energy generating capability of Northwest system hydro plants during a critical energy period. The critical energy period is the historical time period of stream flows during which the least amount of load can be served from regional firm resources. Critical hydro for PGE is the year 1944, which was the worst annual hydro generation in the period from 1929 to 1997 for PGE-owned and contract hydro resources. For the Pacific Northwest, the critical hydro year is 1937. The 2012 critical hydro energy adjustment for PGE is about 93 MWa (assuming continued access to the entire output of Pelton and Round Butte).

Risks associated with hydro plants differ from the risks associated with thermal plants in the following ways:

- Reduced water flow, as opposed to forced outages of generating equipment, is the primary risk. However, as our access to existing hydro is reduced over the next 10 years, our exposure to low water flows declines from about 125 MWa now to as little as 84 MWa (if none of the hydro contracts expiring by 2012 are renewed).

- While our plants encompass more than one river drainage system, we remain at risk for a region-wide drought. This risk is relatively high since the climate factors that influence snow pack and precipitation for PGE hydro resources are common to the region. Unlike individual thermal plant risk, and because of the size of the regional hydro system, region-wide low hydro has a very direct and potentially significant effect on regional wholesale electricity prices.

Hydro risk can affect PGE in two fundamental ways:

- First, hydro risk affects our average cost of production. To the extent that PGE-owned and contracted hydro output is below normal, we may replace hydro generation, which has a very low variable cost, with thermal generation which has a substantially higher variable cost. Conversely, above-normal hydro conditions allow us to displace more expensive thermal plants with less expensive hydro resources.

- Second, hydro risk affects PGE's total power costs, because hydro conditions directly affect wholesale market prices. Abundant hydro production tends to depress wholesale prices. Low hydro production tends to increase wholesale prices when the region turns to higher-cost generating units. Therefore, we expect the cost of replacement power in low hydro years to be greater than the value of surplus output in high hydro years. Poor hydro conditions can increase the demand for and cost of natural gas, thereby increasing our overall thermal generation costs. In addition, poor hydro conditions can also contribute to real supply scarcity and reliability problems, as were seen in 2000 and 2001.

While we recognize the unique benefits and risks of hydro in this IRP, we do not propose any adjustments to our supply targets for critical hydro conditions because, for reliability purposes, the risk to PGE from poor hydro conditions is lower than the risk from weather and forced outage events.

3.4 Regional Reliability Standards

The NWPCC is leading an effort to establish a resource adequacy framework and standard for the region. The NWPCC specifies that the standard it proposes is not intended to be a mandatory compliance target or to imply an enforcement mechanism. Rather, the standard is meant to be a gauge to assess whether the Northwest power supply is adequate in a physical sense. It can be thought of as a suggested minimum threshold for resource acquisition.

For energy, the NWPCC proposes to use the annual average load/resource balance as the energy target for the Pacific Northwest. It is defined as the available energy minus the average annual firm load[14], where the available energy total is defined as the sum of:

- The annual energy capability from all non-hydro resources (accounting for maintenance and forced-outage rates and limited by fuel-supply and/or environmental constraints);
- The hydroelectric-system annual energy based on critical water conditions; and
- 1,500 MWa of planning-adjustment energy, which is derived from the NWPCC's current five percent loss-of-load probability guideline.

The average annual firm load is based on average temperature conditions, adjusted for firm out-of-region contract sales and purchases.

[14] Northwest Power and Conservation Council. "A Resource Adequacy Standard for the Pacific Northwest." May 10, 2006, p. 3; see http://www.nwcouncil.org/library/2006/2006-5.pdf.

PGE uses essentially the same energy metric, but assumes normal hydro instead of regional critical hydro conditions. Our definition of resources does include long-term contracts. We do not apply any planning adjustment[15]. PGE's energy load is defined as our system load net of 5-year opt-out customers and energy efficiency achieved by the ETO.

The NWPCC defines the energy target for the Pacific Northwest to be zero on an annual basis for reliability purposes. In other words, available energy (as defined above) should at least match the expected annual load. We are proposing to use the same target.

For capacity, the NWPCC adopted a pilot capacity adequacy standard in December 2006[16]. The capacity metric for the Pacific Northwest is defined as the planning reserve margin, which is the surplus generating capability over expected peak load during the peak load hours for each month (also referred to as the surplus sustained-peaking capability). The pilot capacity target for the Pacific Northwest is 25 percent for winter and 19 percent for summer.

The NWPCC defines sustained peaking capability as the average of the ten consecutive hours per day over five consecutive days that yield the highest average load on a monthly basis. This is the peak heavy load hour week. This standard for regional capacity is materially different from the traditional planning targets for utilities, which have the obligation to serve hourly demand and have therefore focused on the hourly peaking needs with suitable reserves added to reliably meet the highest demand hour.

Table 3-5 and Table 3-6 show the difference between PGE's current methodology and the result of applying the NWPCC's proposed standards for PGE system load for winter and summer 2012, the reference year in our analysis. The NWPCC's pilot standard, as we interpret it, would reduce our capacity gap from 1,541 MW to 1,397 MW in winter and from 1,329 to 1,156 MW in summer.

---

[15] PGE conducted a loss-of-load-probability study – see Chapter 12.

[16] Northwest Power and Conservation Council. "A Pilot Capacity Adequacy Standard for the Pacific Northwest." Dec. 12, 2006; see http://www.nwcouncil.org/library/2006/2006-23.pdf.

Table 3-5: PGE and NWPCC Planning Standards, Winter 2012

		1-hour Peak (MW)	10 Consecutive Hours for 5 Consecutive Days Peak (MW) (NWPCC Capacity Pilot)	
Load (January)				
1-in-2 peak		(4,127)	(3,421)	
Reserves	12%	(495)	(855)	25%
Load Subtotal		**(4,623)**	**(4,276)**	
Resources – Sustained Capability Measured at Average January Temperature				
Dispatchable Stand-by Generation		44	44	
Load Control		-	-	
PGE Thermal		1,891	1,891	
PGE Hydro		457	437	
PGE Mid-C share		281	281	
PGE Wind Plants		19	19	
Long-term Contracts		358	358	
Gross capability		3,050	3,030	
Net Position		(1,573)	(1,246)	
Long-term Opt-out		32	32	
Net Position after Opt-out		**(1,541)**	(1,214)	
Critical hydro adjustment (1937)			(190)	
Hydro flexibility			7	
Net Position after Opt-out w/ critical hydro and hydro flexibility			**(1,397)**	

Table 3-6: PGE and NWPCC Planning Standards, Summer 2012

		1-hour Peak (MW)	10 consecutive hours for 5 consecutive days peak (MW) (NWPCC Capacity Pilot)	
Load (August)				
1-in-2 peak		(3,761)	(3,325)	
Reserves	12%	(451)	(632)	19%
Load Subtotal		(4,212)	(3,957)	
Resources – Sustained Capability Measured at Average August Temperature				
Dispatchable Stand-by Generation		44	44	
Load Control		-	-	
PGE Thermal		1,821	1,821	
PGE Hydro		355	276	
PGE Mid-C share		281	281	
PGE Wind Plants		19	19	
Long-term Contracts		325	325	
Gross capability		3,845	2,766	
Net Position		(1,367)	(1,191)	
Long-term Opt-out		38	38	
Net Position after Opt-out		**(1,329)**	(1,153)	
Critical hydro adjustment (1937)			(11)	
Hydro flexibility			8	
Net Position after Opt-out w/ critical hydro and hydro flexibility			**(1,156)**	

We agree with the NWPCC that peaking needs should be assessed for both winter and summer and we are doing so in this IRP. However, we have not adopted at this time the NWPCC's approach to establishing capacity needs based on the risk of not meeting the weekly average peak. PGE is actively taking part in the regional efforts at the NWPCC and WECC level to assess reliability standards for electric utilities. For this IRP, we propose to retain a 12% reserve margin and allow the regional committees' work and proposals to mature before adopting revised reliability standards.

4. Demand-Side Options

We consider customer-based solutions, both supply and demand response actions, to be an effective way to fill gaps between our loads and resources. Given the continued instability of global energy markets and the future uncertainty associated with many supply-side resources, we further believe that demand-side resources not only can be an economically preferable solution, but also can provide substantial risk mitigation against price volatility and structural shifts in policy or the availability of energy resources. In addition, our customer research and stakeholder dialogue has indicated a clear preference for demand-side solutions to meet our growing energy and capacity needs. Customers and constituents across all areas have expressed a strong interest in PGE seeking demand-side measures whenever feasible. Given these factors, we intend to pursue several new ideas and initiatives to acquire, expand, or enable future customer-based solutions. Below we outline PGE's assessment of demand-side alternatives and a variety of specific measures, programs, and initiatives that we believe offer potential for increased energy savings and capacity opportunities for this IRP cycle.

The following discussion distinguishes between demand-side solutions that primarily bring energy reductions (e.g., energy efficiency savings expressed in MWa) and capacity solutions which primarily reduce or shift peaks with little aggregate reduction in energy consumption (e.g., demand response (DR), such as air-conditioning cycling, expressed in MW).

We discuss energy efficiency (EE) first below. Our customers prefer EE as a resource and expect PGE to help them manage their bills by advising them on actions and end uses that yield greater energy efficiency. In 2002, SB 1149 consolidated funding for EE at the state level by collecting funds from utility customers and disbursing them to several agencies charged with responsibility for running EE programs, primarily the Energy Trust of Oregon (ETO). Funds are also provided to Oregon Department of Energy for use in educational service districts, and to Oregon Housing and Community Services to focus on low income customers.

For nearly five years the ETO has successfully worked with utility customers to implement EE measures, resulting in savings via costs that are lower than the equivalent amount of generation. In 2006, the ETO experienced record participation and some programs are oversubscribed. The ETO's most recent resource assessment indicates there is more cost effective EE available than is currently being captured.

We netted out of our load forecasts the energy efficiency acquisition that the ETO expects to obtain from 2008 through 2012 under current funding levels.

However, we believe that there is additional, cost-effective energy efficiency available that could be achieved with additional support from PGE. We discuss this additional EE potential later in this chapter.

With the exception of EE, most of the potential demand-side resources available to PGE are capacity resources. PGE treats customer-based capacity resources in two categories: firm (usually dispatchable) resources, and non-firm (behaviorally driven) resources. When capacity resources were evaluated, assumptions for demand-side resources, such as residential direct load control, were modeled on an equivalent basis with supply-side capacity resources. Chapter 12 contains a detailed discussion of PGE's capacity requirements and how demand-side resources can help fill those needs.

Chapter Highlights

- The ETO estimates that approximately 85 MWa in total for the five years 2008 through 2012 can be acquired through energy efficiency measures at current funding levels.
- We estimate that there is at least 45 MWa of additional cost-effective EE beyond the ETO's estimates that can be achieved between 2008 and 2012 with additional support from PGE. This represents 25% of PGE's forecasted net load growth of 179 MWa for the same period.
- Our assessment of demand response resources shows there are approximately 138 MW of firm capacity available during winter months, and 148 MW of firm capacity during summer months by 2012.
- An RFP would likely be required to learn precisely how much firm capacity could be acquired through demand-side options.

4.1 Demand-Side Energy Resources

PGE Approach

Energy efficiency is the preferred option for meeting our growing energy needs[17]. EE is a low risk, low cost resource. Market assessments confirm there is more cost-effective EE available than is currently being captured by the ETO with available public purpose charge funding[18]. Our customers also expect PGE to be proactive in helping them become more efficient in their energy use. Therefore, PGE wants to ensure that we enable and capture as much cost-effective energy efficiency as our customers are willing to pursue.

ETO Targets

The ETO estimates that PGE's customers can acquire about 85 MWa for the five years 2008 through 2012 (including customers with greater than 1 MW load) through programmatic EE measures at current funding levels. We support the ETO's work, and are actively facilitating its efforts. PGE and the ETO are currently operating under a written understanding to jointly provide commercial, institutional and industrial customers with information, access and program implementation assistance, and training and education to assure the success of the ETO's energy efficiency programs.

The ETO has been offering programs in the residential customer segment since its inception in 2002. Using a variety of media and customer interaction channels, we have encouraged our customers to take advantage of these resources and incentives. We also prominently feature the ETO on the front page of our Web site and provide a link to the ETO Web site. We also regularly use bill inserts to inform customers of programs available through the ETO.

Opportunity to Engage Actively in Energy Efficiency

Senate Bill 1149 removed PGE from our traditional role of directly implementing EE programs. Research indicates that our customers expect PGE to provide ways to become more efficient in their energy use. Research also shows that customers prefer EE as a resource[19]. Environmental and consumer activists have been looking for ways to accelerate the acquisition of EE, and many have supported

---

[17] See Chapter 8 for more information on customer resource preferences.

[18] Stellar Processes and Ecotope. "Energy Efficiency and Conservation Measure Resource Assessment." Energy Trust of Oregon Final Report, May 4, 2006.

[19] Momentum Market Intelligence. "Customer Preferences for IRP Portfolio Content: Is it Really All About Green Resources?" May 8, 2006, slide 4.

PGE's efforts in this area and encouraged the Company to further increase its involvement.

Energy Efficiency Targets for PGE

As part of the IRP public process, PGE worked with the ETO and other stakeholders to determine ways to capture additional cost-effective EE opportunities that our customers are ready to pursue. PGE worked closely with ETO planners, revising and updating assumptions to the model specific to PGE's service territory and customers. First we adapted the ETO 2006 market assessment of EE technical and achievable potential to our service territory with updates of critical assumptions. The load growth assumptions were updated with PGE's most recent forecast. PGE's EE specialists then worked with ETO staff to fine tune assumptions of customer acceptance rates by sector. As a result of this collaborative effort, the ETO and PGE developed an assessment of the potential EE opportunities with PGE's customers. As a final check, PGE asked staff at the NWPCC to review the process and results for major omissions or corrections.

We updated the ETO's acquisition forecast and removed this from the achievable potential. The remaining EE opportunity is shown in Table 4-1. Because the ETO's forecasted acquisition for customers over 1 MW includes most of the achievable potential from large customers, and because Oregon statutes[20] impose a cap on collecting additional funds for EE resource acquisition from these customers, we have not included further incremental EE opportunities for this class of customer.

To analyze these EE opportunities for this IRP, we compare life-cycle fully allocated costs of EE measures against those of supply-side alternatives. Based on preliminary cost estimates, it appears that PGE can acquire additional EE up to a levelized cost of $64 per MWh (calculated using PGE's discount rate), which includes a 10% EE preference adjustment[21]. We determined that there are approximately 60 MWa of EE available over the amount of EE acquisition funded by the ETO that would otherwise be lost or deferred. This represents additional energy efficiency resource that could be achieved between 2008 and 2012 with additional funding. Table 4-1 shows the estimated total achievable potential in PGE's service area, the projected amount of acquisition currently targeted by the ETO, and the resulting gap.

[20] ORS 757.612 Section 3(f)

[21] ORS 469.631(4) Definitions for ORS 469.631 to 469.645. Residential Energy Conservation Act.

Table 4-1: Potential Energy Efficiency (MWa) for Customers < 1 MW

	PGE Achievable	ETO Forecast Acquisition* 2008-2012	Gap@ PGE Discount Rate
Residential	42	29	13
Business	83	36	47
TOTAL	125	65	60

* Includes free riders[22] and background[23].

Energy Efficiency in the IRP Portfolios

According to IRP guidelines, PGE should pursue the lowest cost resources first, assuming equivalent risk profiles, whether supply-side or demand-side. Based on the societal, environmental and risk mitigation benefits, it is prudent to pursue EE resources up to cost-effectiveness limits. However, attaining incremental EE in the time frame of the IRP planning horizon is challenging because this requires accessing markets that may be more difficult to reach and because programs become more specialized and technologies in the supply curve are more expensive. By focusing on the incremental EE with the highest impact, PGE has determined there are approximately 45 MWa out of the 60 MWa of additional EE savings that are both cost-effective and achievable by 2012. This amount is over and above the forecasted EE acquisition that is included in our load forecast and represents 25% of PGE's forecasted net load growth of 179 MWa between 2008 and 2012.

Opportunities for Achieving More EE

PGE and its stakeholders are working to find ways to accelerate EE acquisition. PGE collaborated with interested parties to advance legislation that removes impediments to utilities' involvement in and funding of EE. That effort culminated in the recent passage of SB 838, which was signed into law by Governor Kulongoski on June 6, 2007. This legislation, which enacts the Oregon RPS, also contains a provision in which the OPUC may authorize an electric utility to include in its rates the costs of funding or implementing cost-effective energy conservation measures (customers greater than one MW are excluded).

[22] Free riders are those customers who would install the measure without assistance, but accept the assistance anyway.

[23] Background refers to the energy efficiency that is installed by customers who do not accept assistance. The amount of background EE is unknown and therefore is estimated.

To pursue and implement initiatives to achieve additional EE savings, PGE does not intend to develop or run its own programs, but instead will work cooperatively with the ETO to expand current initiatives. The additional EE will be achieved primarily by leveraging PGE's marketing capabilities and customer contacts and relationships with those of the ETO to increase participation in existing programs. We will also support ETO programs and program managers with additional PGE staff expertise, and provide funding to the ETO to implement additional cost-effective programs. Another focus for PGE will be transforming markets through new codes, education and promotion of efficient technologies with wide applicability, multi-family retrofit, and commercial lighting. Table 4-2 shows areas most likely to benefit from additional funding.

Table 4-2: Additional Energy Efficiency by Sector and Type

Residential	MWa	Business	MWa
General Measures	4.5	Building Retrofit	4.5
Middle & Low Income	2.0	New Construction	21.0
		Other	8.0
		Industrial < 1 MW	5.0
Total Residential	**6.5**	**Total Business**	**38.5**

This endeavor at incremental funding will result in learning that will inform our future efforts. Programs will likely change over the course of the planning period, technology will advance and adapt, and improvements in funding applications will be made.

Examples of various ways that PGE could work with the ETO to achieve additional EE are discussed below. Current legislation and rules do not clearly state that a utility can recover costs incurred to acquire cost-effective EE, nor are incentives in place. See Chapter 13 for more discussion of the regulatory changes needed to provide incentives and ensure EE cost recovery so that additional EE can fairly compete with other resource opportunities.

Energy Efficiency for Sectors Managed by the ETO

- Provide additional funds to the ETO to expand programming among PGE customers. Some funds could go to enhance existing programs. Much of the funding should go to underserved and hard to reach markets such as renters, multi-family housing, small business or programs such as building retro-commissioning.

- Provide additional mass market media on EE to drive participants to the ETO.

- Provide additional full-time employee (FTE) resources to work as Energy Champions in conjunction with Small/Medium Businesses to encourage EE work and stimulate the ETO's programs. Potential roles these employees could play are as follows:
    - Provide customer outreach and program facilitation;
    - Speak to business associations/chambers/trade groups on EE;
    - Conduct audit/overview services;
    - Provide design review services for vendor proposals;
    - Act as project manager to ensure that upgrade projects proceed; and
    - Conduct training on specific technologies as appropriate.

Energy Efficiency for Low Income Customers

- Provide FTE resources to help counties and community action organizations complete low income weatherization audits funded by existing public purpose charge monies.

- Provide EE training to all households receiving weatherization assistance to ensure that savings are maintained.

- Overcome traditional resistance among landlords to invest in EE for housing units occupied by low-income renters by providing financing for measures taken through energy service charges assessed to the meter and paid back over time, or through interest-free loans payable at the time of property sale.

Energy Efficiency in Schools with the Oregon Department of Energy (ODOE)

- Provide additional funding to school districts in PGE's service territory where identified measures exceed the district's 10-year allotment.

- Supplement school districts having a large proportion of older buildings with funding based on need.

- Provide FTE resources to help educational service districts and school districts implement EE projects. Potential roles these employees could play are as follows:
    - Review and update audit recommendations;
    - Solicit and review contractor bids to perform recommended efficiency upgrades; and
    - Provide project management expertise.

- Provide training to maintenance staff, faculty and students to ensure that EE practices continue in districts and that savings are maintained.

4.2 Order No. 04-375 Demand Response Recommendations

The OPUC made two specific recommendations for this IRP related to demand response (DR) in acknowledging PGE's 2002 IRP Action Plan. We discuss below the steps that PGE has taken to be responsive to these stipulations.

1. PGE should model DR options as portfolio options along with supply-side options.

   In our IRP, we have compared customer-based opportunities with those available from utility or wholesale supply market for cost-effectiveness, reliability, dispatchability, environmental impact and other factors to achieve the best overall results for customers. We have done so for both energy needs and for capacity requirements that can be met with demand response.

   PGE uses the AURORAxmp® model which is primarily an energy resource model. With the exception of EE, most of the demand-side resources available to PGE are capacity resources. PGE assessed capacity needs and alternatives to meet those needs separately from energy resources. In evaluating capacity resources, PGE modeled assumptions for demand-side resources, such as residential direct load control, on an equivalent basis with supply-side capacity resources. More precisely, we calculated the real levelized capital carrying cost per kW and ongoing O&M for each supply and demand-side option as a stand-alone capacity resource (Table 12-2 and Table 12-3 show the results of our analysis). We then assessed each resource's fuel and transmission risk and identified which option to use first to meet our load duration curve shape (see Figure 12-6).

2. PGE's load forecasts should recognize the effects of non-dispatchable DR resources (such as time-of-use pricing).

   Because PGE's load forecasts are based on historical reductions, they implicitly reflect the effects of PGE's time-of-use pricing option. Non-dispatchable pricing options are considered to be non-firm resources. Time-of-use pricing options are considered to be non-dispatchable because they are behaviorally driven, that is, there is no remote or direct control of energy use by third parties, making it difficult to measure load reductions or load shifting. Load forecasting which is based on historical usage includes demand-side reductions from time varying pricing and

EE. It is not practical to project how much incremental demand reduction related to future pricing programs should be included in load forecasts.

4.3 Customer-based Capacity Resources

For several years, PGE has had a strong interest in enabling and implementing cost-effective DR and actively monitors industry players in their efforts to implement various forms of demand-side response to meet peak energy. The Demand Response Research Center at the Lawrence Berkeley National Laboratory defines DR as the action taken to reduce load when contingencies (emergencies and congestion) occur that threaten supply-demand balance, and/or market conditions occur that raise supply costs[24]. DR typically involves peak-load reductions. DR strategies, which are transient, are different from EE, which is generally permanent.

We treat customer-based capacity resources in two categories: firm or resources such as non-discretionary direct load control programs, and non-firm or resources such as non-technology-enabled pricing options and programs or products that are elective and behaviorally driven (instead of requiring a firm commitment). The IRP does not plan for non-firm capacity resources. We used only firm DR resources for planning purposes because of their expected reliability. Such resources are usually dispatchable. We believe we can reliably achieve by 2012 up to 140 MW of incremental resources on a day-of or day-ahead notice from our DSG program with large customers, direct load control, and curtailment tariff. Additional customer-based capacity solutions would further allow us to reduce generation supply costs and offer more options for customers to control their monthly electricity bills.

The following factors influence the feasibility of demand-side capacity:

- Availability of Capacity – the Pacific Northwest historically has been an energy constrained region, unlike most of the rest of the U.S. which is capacity constrained. This is due primarily to our hydro system, which is traditionally used for minute-to-minute load changes. During times of short-term need, hydro resources can deliver on average about twice as much power as they normally generate. However, this situation is changing as hydro availability is decreasing and demand is growing. PGE believes the region is now both capacity and energy constrained. The region's and PGE's evolving capacity situation is discussed in greater detail in Chapter 12.

---

[24] Diamond, Rick and Piette, Mary Ann. "Understanding Customer Behavior to Improve Demand Response Delivery in California." Demand Response Research Center, Research Opportunity Notice, February 2, 2007.

- Low Prices – Utilities in the Northwest are still relatively low cost providers compared to other regions in the West and throughout the country. Until now, customers have had little incentive to practice DR because of the minimal difference in their bills for their efforts. Longer payback periods on the DR investments have also been an economic impediment.

- Market Conditioning – There is a body of evidence indicating that external factors condition the market toward or away from participation in market trends, including utility DR programs[25]. For example, in grid areas that have experienced blackouts, or even rolling blackouts, where the media has brought attention to the causes, people are more sensitized to their role in the cause and therefore their role in the solution. DR programs in those areas are showing some measured success.

- Winter Peaking Programs – Nationally and in the West, the most successful DR programs to date are for irrigation, air conditioning, and pool pump control (i.e., cycling pool cleaning pumps during peak hours) – all programs for summer peaking. PGE does not have much irrigation load; however, air conditioning load is growing. At projected growth rates, in several more years air conditioning load will cause a shift in seasonal peaking from winter to summer. When it does, the summer peak will have a needle peak load shape of very short duration compared to winter peaking.

- Cost Recovery – Because air conditioning peaks are of short duration, it may be more difficult to recover fixed overheads and program costs since air conditioning is used for a limited number of hours per year in the Pacific Northwest. However, when extra-regional weather events occur, such as in late July 2006, even relatively expensive load control programs can have a place in meeting reliability requirements.

In an effort to determine how much capacity PGE customers can likely achieve, we commissioned Quantec, LLC to update the DR Technical Potential report.

PGE's Updated Demand Response Resource Potentials report[26] shows there are approximately 138 MW of firm, physical capacity during winter months, and 148 MW of firm capacity during summer months by 2012, as shown in Table 4-3. For modeling purposes PGE used proxy programs consisting of residential direct load control and DSG.

[25] Energy Information Administration, PowerDat, RMI.

[26] Quantec, LLC. "Update of Demand Response Resource Potentials for PGE." January 31, 2007.

Table 4-3: Demand Response Resource Potential by 2012

	Winter Space Heat	Winter Water Heat	Winter DSG	Summer A/C	Summer Water Heat	Summer DSG
Industrial			38			40
Commercial			72			80
Ag/Utilities			4			5
Residential	10	15		18	5	
TOTAL	**10**	**15**	**113**	**19**	**5**	**125**

PGE intends to explore options for using demand-side resources for extreme event or needle peak circumstances. Several utilities have entered into contracts with vendors to provide demand response peak capacity. We plan to learn if there is enough volume from various controllable appliances such as water heaters, space heat, and air conditioners to motivate vendors to provide estimates and/or proposals for potential quantities and prices for products within our service territory. PGE proposes as part of its Capacity Action Plan to issue a capacity RFP to determine precisely how much firm capacity could be acquired through demand-side options (see Chapter 13). Customer-based resources will also be included in any future RFP solicitation.

Following are descriptions of PGE's existing customer-based capacity resources.

Firm Demand Response – Direct Load Control

Dispatchable Standby Generation

PGE's DSG program uses networked diesel-fueled back-up generators at commercial and industrial customer sites to supply capacity resources for PGE's portfolio and enhanced reliability for the host customer. Customers acquire the generators to provide supply reliability in the event that power from the grid is disrupted, for instance, in a severe ice or wind storm. Through communications and technology enhancements, PGE can remotely start the generators to both displace the generator owner's load and supply excess power to the grid. This program increases customer satisfaction and provides PGE with an economic source of capacity that is distributed within our load, thereby reducing costs and risks associated with transmission, fuel supply and large single shaft exposure.

In the 2002 IRP, we committed to developing by year-end 2007 a 30 MW DSG virtual peaking plant. We attained our goal in June 2006 when we cumulatively brought 30 MW of DSG on-line. Current projections show we may be able to develop as much as an additional 125 MW of DSG. Our Capacity Action Plan assumes that we can achieve 80 MW of additional DSG by 2012. The operation of the back-up generators is limited by operating permit restrictions to 400 hours per year. However, they provide benefit as standby operating reserves for PGE during times of the year when they are not dispatched to meet peak energy needs. To our knowledge, no other electric utility in the U.S. has the capability to dispatch from the utility's system control center this level of energy from customer-owned generation.

Institutional Direct Load Control through Energy Management Systems

PGE has developed a program that builds upon existing DSG infrastructure wherein end-use load in commercial buildings can be remotely curtailed. We are currently in the process of identifying customers who might be interested in participating.

Curtailment Tariff

PGE proposes a curtailment tariff as part of a larger demand-side capacity resource package to help meet system capacity needs. It is generally intended to provide the utility with access to firm capacity.

A curtailment tariff can be customized to provide customers flexibility based on their diverse operations and processes. Customers may choose to reduce lighting levels, ventilation hours, or whole manufacturing processes to provide peak reductions. Customers agree ahead of time to reduce loads to predetermined levels on notice from PGE, for which they are compensated. Load reduction, notification time, and compensation vary from customer to customer depending on a customized agreement which best meets their operational capability. For example, customer compensation could take the form of an up-front reservation payment, or an incentive at the time of reduction. The term of the tariff will be intended to help customers plan their operations for a year ahead.

To minimize customer inconvenience and maximize participation, and given PGE’s steep demand curve, curtailment requests would be infrequent during a normal year and generally only during peak hours. Curtailment requests could be made annually on a test basis to help customers plan how they would make reductions on short notice.

The amount of demand reduction that can be reliably expected from the tariff is unknown until we begin program development with input from interested customers. Based on the response rate from similar customer groups of other utilities and discussions from demand response vendors, it is reasonable to believe that PGE could enroll up to 30 MW over five years, which represents up to1% of our 2012 peak load.

Smart Appliances

PGE is completing its participation in R&D for advanced demand response technology through automated control built into residential white goods appliances[27], and moving forward to the next phase of appliance market transformation. We are an active co-sponsor of the U.S. Department of Energy's GridWise™ test bed's Grid Friendly™ Appliance demonstration project to develop appliance controllers activated at the system level. The research has been accelerated to test direct load control of appliances and pricing controls, with initial favorable results.

PGE is also proceeding with R&D directly with appliance manufacturers to automatically control appliances to respond to under- and over-frequencies and voltages on the distribution grid. When grid frequencies fluctuate out of range, designated appliances would respond by momentarily stopping high wattage uses until grid frequency stabilizes.

The first phase of PGE's involvement in research to examine the feasibility of placing smart chips in major appliances is complete. The research produced positive results, and PGE is actively pursuing next steps in the market transformation of smart appliances in two major ways:

- We are forming a consortium to work directly with appliance manufacturers to place communication devices in major appliances for after-market application of demand response controls.
- We support language for legislation that may be introduced to require appliance manufacturers to place communication capability in home appliances.

Non-Firm Demand Response Pricing Options

Demand Buy-Back Program

PGE currently offers large, non-residential customers a demand buy-back (DBB) program, which can be implemented during critical peak hours. Because DBB is a voluntary program, we do not consider it to be a firm capacity resource. The program typically is triggered under 1-in-5 weather conditions, and has been

[27] "White goods" is a common reference, inside and outside the appliance industry, for large household appliances such as washers, dryers, refrigerators, ranges, etc.

effective in the past for reducing peak demand. While agreeing to conditionally provide over 25 MW of capacity reductions, our customers tell us their ability to respond depends largely on their varied business operating conditions and circumstances at the time.

DBB should help reduce our forecasted capacity needs. During the regional heat event triggered in July 2006, we suggested that PGE could count on approximately 5 MW of capacity through DBB on short notice (intra-day or a few hours in advance) for resource planning purposes. The range of reduction depends on the customers' circumstances at the time PGE requires the resource. The actual reduction may be larger when customers are given longer advance notice about the DBB event. Because of the limited experience with non-firm demand response pricing programs in the Pacific Northwest climate, we do not yet have adequate estimates of the reliable size of these resources when called.

Energy Information Service

All Schedule 83 customers (large non residential customers with greater than 30 kW of demand) are eligible for PGE's energy information services (EIS). A total of 92 customers, representing over 579 meters, have signed up for EIS. EIS provides graphs depicting energy use in 15-minute intervals showing precisely how much energy is being used by a customer facility at a given time. By knowing when peaks occur, customers can analyze their processes and respond accordingly. In some instances, this information has helped customers know which processes they could shift to reduce peaks, or to participate in such programs as DBB, real-time pricing or contract curtailment. EIS can also be used to track the effects of EE initiatives.

Time-of-Day Pricing

Large non-COS customers take service from PGE under time-of-day pricing, with daytime hours designated as peak hours which are priced higher than non-peak hours at night.

Real-Time Pricing

Schedule 87 is our real-time pricing offer. Real-time pricing is a rate option designed to flatten peak load and improve load factor by offering business customers hourly prices reflective of costs. The potential customer benefit is to lower their energy bill. Customers agree to a baseline hourly load shape based on their consumption patterns for their business. Customers are charged higher prices when they go above the baseline, and are rewarded with lower prices reflective of market costs when they go below it.

We offer real-time pricing under a two-part schedule. First, we recover our costs through a fixed customer baseline load charge that is priced using the annual cost-of-service rates of the otherwise applicable rate schedule. The second part of the schedule provides a charge or credit to the customer based on deviations of actual usage from the customer baseline load, priced at marginal cost.

While some customers expressed interest in Schedule 87, none signed up to participate. Potential reasons for this include the availability of other PGE demand-side management programs and fear of market price exposure. It is possible that some customers may also want their entire load purchased at market prices as opposed to only the incremental load.

Time-of-Use Pricing

Among the non-firm programs, we offer a time-of-use pricing option to residential customers and small non-residential customers with less than 30kW of demand. Time-of-use differs from time-of-day in that time-of-use pricing offers on-peak, mid-peak, and off-peak rates. Participants report that they are pleased with the option and the program generally contributes to higher satisfaction with the utility.

Critical Peak Pricing

Rates, including critical peak pricing (CPP) rates, reflect differences in utility climates, resource requirements, and state policies. Because they depend upon customer behavior, the designs of CPP rates also reflect differences among utility customers. The many differences from one utility to another mean that the results of CPP experiences elsewhere can only be taken as a reference point for designing a CPP rate appropriate for Oregon.

California has provided one such reference point[28]. California's notable 2003-2004 Statewide Pricing Pilot (SPP) involved over 2,500 customers in a series of controlled tests across various utility territories, CPP rate designs, customer segments, and customer information and system technologies. While the SPP was a series of tests and was neither designed nor operated to commercial standards, it provided many insights.

Most notably, the SPP demonstrated that price signals can reduce demand. The price-elasticity of electricity demand was significant, reasonably stable over time, and reasonably consistent within customer classes. For example, California Climate Zone 2 (the Inland Coastal zone) constitutes about 48% of California based on geography. PGE identified the SPP Zone 2 as the group of customers

[28] Boice, Craig, memo from Boice Dunham Group to PGE, February 23, 2007.

whose geography more closely matched our service area due to milder temperatures and the moderate level of air conditioning saturation in this zone. In testing the CPP "fixed" version, the SPP confirmed Zone 2 average residential electricity demand reductions of 10% in the summer of 2003.

The SPP indicated that enabling technology (e.g., programmable thermostats and pool pumps) and information (e.g., the online availability of customer usage data) substantially reduced peak demand above these levels. The SPP further revealed that many customers reacted negatively to the complexity and variability of some CPP rates.

Finally, the SPP provided support for the belief that a sufficient set of customers can be recruited into a CPP program, and will remain in a CPP program because they find value in the experience. That is, customers will remain in such a program if they believe the program makes a difference - it either provides savings on their electricity bills, more control over their electricity usage, or a better community. The SPP demonstrated that participants gain an understanding that electricity has become considerably more expensive on certain days, and that they would benefit from becoming aware of these times, and changing their electricity use as they can.

The SPP results were encouraging, but the particular CPP rate designs tested in California were built around particular utilities' aims. The California utilities sought to achieve demand reductions on up to 75 summer hours of their choosing whether or not the temperature was extreme statewide. The utilities selected these "super-peak" days up to 24 hours in advance, and then notified participants they were coming. The rate differentials from off-peak to super-peak periods meant participants faced a difference between 7.8 cents/kWh off-peak to 73.8 cents/kWh super-peak in one test.

These SPP CPP rate design features reflected the particular circumstances of California utilities. The SPP provided substantial insight into how Californians would react to particular versions of CPP rates. However, the results in Oregon may differ. Not only is our CPP design different (e.g., we require a rate to address winter peaks as well as summer peaks), our design cannot depend primarily on air conditioning and pool pump curtailment.

Furthermore, customers in California have been conditioned differently than Oregonians. In the summer, air conditioning is mandatory for many businesses and households in California. California customers are used to an extremely complex inverted tier rate structure, frequent rate shocks, and utilities in financial distress. Californians experienced the SPP immediately after the Western energy crisis and associated electricity supply curtailments and price shocks. Price signals for electricity have a somewhat different context in Oregon.

From similar tests conducted by other utilities (e.g., Puget Sound Energy, Anaheim, Ameren) we can recognize a similar basic pattern of customer interest, participation, and satisfaction. We further note that utilities have designed rates suitable for their own climates, resource requirements, and state policies. Our proposal for a two-year experimental CPP tariff will allow us to identify the particular version of demand response rates most suitable for our circumstances in Oregon.

PGE is planning to issue a tariff upon implementation of our advanced metering infrastructure project to offer critical peak pricing for residential customers. We expect to design the tariff to allow enough events to be triggered to provide measurable data for analysis, including but not limited to the depth of response from customers with and without enabling technologies. Until enough experience with customer response provides a reliable estimate of capacity, it is considered a non-firm resource.

Advanced Metering Infrastructure

For nearly ten years we have been evaluating various advanced metering technologies. In first quarter 2007, PGE filed with the OPUC a request for rate recovery of an advanced metering infrastructure (AMI). AMI is a system that enables the automated collection of meter data via a fixed network. It consists of three main components: solid-state electronic meters, a communication system or network, and a communication server that receives and stores data from the meter. We are planning to implement a two-way system, which will enable us to not only receive register reads and interval data daily but also to send commands to the meter. This capability can, with additional investment, support DR and direct load control programs.

We are pursuing AMI in order to attain operational and economic efficiencies, provide improved services to our customers, and to be able to offer demand response such as CPP and other programs that become more cost effective with AMI. We are preparing for full deployment throughout our service territory by early 2010.

5. Fuels Forecasts

Fuel prices, particularly natural gas, are a major driver of wholesale electricity market prices and the economics of new generation resources. In addition, fuel costs and risks are increasingly influenced by demand and supply drivers and political considerations on a global, national and local level. For this reason, we believe fuels forecasting merits in-depth research and analysis.

Our general approach to projecting fuel prices is to develop a reference-case fuel forecast based on near-term market indications and longer-term fundamentals, as determined by third-party, expert sources. For this IRP, we acquired independent third-party fundamental research and price forecasts for both coal and natural gas. For natural gas, we relied upon research and forecasts from PIRA Energy Group, and for coal we used data and information from the Energy Information Agency (EIA) and Hill and Associates, Inc. In this chapter, we present our long-term forecasts for natural gas and delivered coal prices, along with a discussion of the fundamental drivers for fuel prices going forward. We also include a discussion on the evolving U.S. market for liquefied natural gas (LNG) and the potential impacts of LNG on U.S. and Pacific Northwest gas prices.

For natural gas prices, we model uncertainty around the base case using both stochastic and scenario analyses. Fuel prices are then used to project electricity prices in our AURORAxmp model and to assess the performance and dispatch of power plants. Based on our modeling and fundamental expectations, gas-fired plants remain the marginal resource in most hours of the year. See Chapter 10 for PGE's market electricity prices and a discussion of our stochastic analysis.

Chapter Highlights

- Our base-case natural gas forecast, derived from market price indications followed by PIRA's long-term forecasts, is $6.4/ MMbtu (real levelized in $2006). Our high-case forecast is $9.2, and our low-case forecast is $5.1.
- We used a cost of $0.55 per dekatherm (or MMbtu) for firm gas transportation rights to meet peak gas input needs.
- LNG is expected to become an increasingly important source of gas supply; however, the impact of LNG on U.S. natural gas prices remains uncertain.
- Delivered prices for Powder River Basin 8,400 Btu/lb. low- sulfur coal are $27.6/ short ton in 2007, rising to over $50 in 2025 ($2006). Prices were derived from PGE coal supply contract prices and Hill & Associates, Inc. forecasts.
- For Colstrip (mine-mouth coal plant in Montana), we applied an escalation factor from Hill & Associates to actual commodity costs. The resulting forecast is $13.2/ short ton in 2007, rising to $25.60 in 2025 ($2006).

5.1 Natural Gas

The natural gas forecast used in the base case of this IRP is partly derived from market price indications for three years in the future starting in 2007. We then rely on PIRA's long-term fundamental forecast[29] starting in 2012 for the long-term Henry Hub price and basis differentials to Sumas, AECO and other WECC supply hubs[30]. We transition from the market curve to PIRA's long-term forecast by linearly interpolating for two years (2010 – 2011). For our portfolio analysis, we examine alternative price scenarios based on PIRA's high and low gas price scenarios. An example of the forecasts is shown for Sumas hub in Figure 5-1[31]. For a discussion of the stochastic analysis applied to our reference gas price forecast, see Chapter 10.

In selecting a source for long-term price forecasts, we assessed long-term gas price forecasts from various sources, including PIRA, the EIA, Global Insight and Cambridge Energy Research Associates. While each source is credible and well respected, we chose PIRA because they:

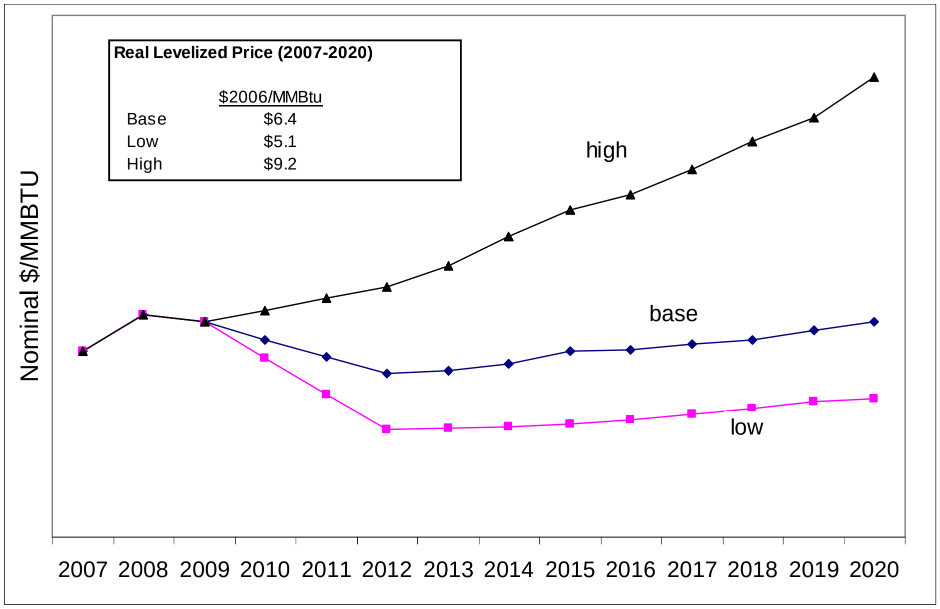
- Include transparent assumptions;
- Identify a reference case and its probability of occurrence;
- Have a strong reputation for both oil and gas fundamental research and forecasting; and
- Project both Henry Hub prices and all main hub basis differentials with Henry Hub in a format that meets our modeling needs.

[29] PIRA Energy Group. Scenario Planning Quarterly Update, May 2007.

[30] Sumas and AECO are the two primary Pacific Northwest natural gas trading hubs from which we fuel our plants. Hub deltas are calculated as an annual percentage difference to Henry Hub prices: e.g. Sumas gas price is 12% lower than Henry Hub in the year 2012.

[31] Due to PIRA license restrictions, PGE cannot show the Y-axis for PIRA forecasts.

Figure 5-1: IRP Long-term Forecast – Sumas Hub Price



Update to PIRA Gas Forecast

PIRA provides quarterly updates of its long-term analysis, the most recent of which was issued on May 15, 2007. In the latest scenario assessment, PIRA revised upward its reference case gas forecast for Henry Hub by $0.80/MMBtu on average from 2009 to 2015[32] over the previous gas forecast discussed in our IRP process. Starting in 2016 prices gradually converge to those in the previous IRP forecast, and the 2020 price is nearly unchanged. Our reference case natural gas price is now $6.40, real levelized $2006. Low and high price gas scenarios were unchanged, at $5.1 and $9.2 real levelized $2006, respectively.

The drivers behind this material increase in the reference case mid-term gas price include:

- A turn for the worse in the oil market, with higher expected oil prices (average of over $60/barrel in $2006) exerting upward pressure on winter gas prices;
- Slower coal penetration in the electric power industry due to increasing capital costs and the higher likelihood of CO_2 regulation in the U.S.; and
- Delay of the Alaska North Slope gas project.

---

[32] For Sumas and AECO, the new PIRA forecast is approximately $0.40/MMBtu higher than our previous reference case forecast (in real levelized $2006) from 2012 to 2020 and $0.20/MMBtu higher thereafter.

PIRA's new reference case scenario suggests that the current high gas prices (around $8.0/MMBtu) are expected to stay for several years. This outlook reinforces PGE's long-term strategy (as detailed in Chapter 13) to invest in renewable and demand-side resources and EE, and to pursue long-term contracts.

Natural Gas Forecast Fundamentals

The main demand drivers behind PIRA's latest reference case gas price forecast include greater industrial demand, increased storage availability, and continued strong power generation growth, with gas accounting for more than 70% of new capacity additions. Increasing up-front capital costs for new coal plants and the perception that the U.S. will impose CO_2 costs via a cap and trade system have dampened expectations for new coal-fired power plants[33]. However, restrictions on CO_2 could be coupled with legislation that encourages greater appliance efficiency or others steps to slow the rate of electricity demand. Thus potential restrictions on new coal plants may not necessarily lead to increased demand for natural gas.

On the supply side, PIRA's reference case assumes no major supply disruptions. Domestic production is expected to increase slightly, due to a sharp increase in non-conventional supply in the Rockies and Texas shale, balanced by very slow progress in Alaska and declining production growth in Canada. LNG imports are expected to increase from approximately two billion cubic feet (Bcf) per day at present to over 15 Bcf/day of capacity by 2010. In addition, PIRA assumes that while substantial re-gasification capacity will be built in North America, primarily along the Gulf and East Coast, expectations for new facilities on the West Coast are not high. At this point the only new terminal that appears likely to be completed on the West Coast is the Costa Azul project, which is currently under construction along the Baja coast in Mexico. Imports from Canada are expected to remain stable at 9-10 Bcf/day. Oil prices are assumed to remain above $60 per barrel (Bbl) in $2006 with no major supply disruptions or confrontation in the Middle East.

For PIRA's high gas price scenario, drivers include declining domestic gas production with disappointing production from Western Canada and from U.S. unconventional sources; no Alaska/McKenzie development; conflicts in the Middle East with major oil price shocks and oil prices above $95/Bbl ($2006). This scenario also presumes slow LNG penetration in the U.S. with LNG prices

[33] The majority of new coal plants are planned for the interior and the East Coast. Recent legislation limiting or prohibiting construction of new coal plants in California, Washington, and other Western states has negatively affected the outlook for coal in the West.

closely linked to high oil prices; higher industrial gas demand due to recovery of gas-intensive industries; less price-elastic demand than expected; and widespread opposition to new coal plants in the electric power industry due to high capital costs and CO_2 legislation.

For PIRA's low gas price scenario, drivers include higher penetration of coal-fired power generation (as compared to the reference case); weaker industrial gas demand; greater, price-resilient non-conventional supply from the Rockies, Western Canada, and Texas shale, which keeps downward pressure on the market by competing with LNG; LNG projects moving forward resulting in development of significant spare re-gasification capacity; expansion of the Canadian coal bed methane industry; and no major confrontation in the Middle East with oil prices below $35/Bbl ($2006).

As seen in Figure 5-1, which shows our three natural gas price scenarios, uncertainty is biased to the upside with more potential for prices to increase in the event of reduced supply and/or increased demand and less opportunity for prices to fall in a weaker supply-demand environment. We consider these structural risks further in our discussion of modeling methods and results later in Chapters 10 and 11.

5.2 Gas Transportation Cost

Estimating the cost of gas transportation without knowledge of the exact location, construction timing, and supply options for a new gas plant is a challenging exercise and requires market insights as well as professional judgment. For planning purposes, we chose a conservative approach and priced gas transport as if every new gas plant in the WECC was fueled from new expansion capacity on the Williams pipeline. We chose Williams because it currently has the highest cost, as there is not sufficient excess pipeline capacity available in the secondary market. Given the proximity of PGE's service territory, we further believe that the Williams pipeline is a reasonable proxy for any future transport requirements. The associated cost is $0.55 per dekatherm[34] for firm gas transportation rights to meet the peak gas input needs (gas plant running at nameplate capacity). We did not estimate alternative gas supply strategies, like storage, non-firm transport, or new pipeline construction. These strategies can be modeled only after identification of a location and site for a new gas plant. Sites are typically identified in the request for proposal stage of the planning process, which follows the IRP filing.

[34] Dekatherm is the heat energy equivalent of MMBtu. This estimate is in nominal dollars, flat across the time frame of our analysis.

5.3 Liquefied Natural Gas

Liquefied natural gas is gas chilled to a liquid state (at -260° F), reducing the volume by 600 times so that it can be shipped by tanker. LNG is stored at or near atmospheric pressure and is lighter than water. LNG will float if spilled onto open water and evaporate completely, leaving no residue. When LNG is unloaded, it is warmed (re-gasified) and shipped by pipeline. LNG is not explosive or flammable under most conditions and has been used safely around the globe for more than 40 years. LNG is not without risks, however. Particularly when import terminals are sited near population centers, thermal hazards from fires and vapor clouds can pose public safety and property hazards within one mile of a spill in the worst-case scenario. As a result of these concerns, permitting and siting of receiving and re-gasification terminals is challenging in many areas, including the U.S. West Coast.

Only five LNG import facilities are operating in the U.S. today, although developers have made multiple applications for new terminals. Decreases in the cost of producing, shipping and re-gasifying LNG (currently $3.50 - $4.00/ MMBtu), coupled with rising U.S. natural gas prices and tightening supplies, have renewed interest in building LNG terminals in North America. As of February 2007, FERC had approved thirteen new LNG terminals and the U.S. Coast Guard had approved five, most of which would be sited in the Gulf of Mexico. PGE is closely monitoring the development of potential LNG import terminals in the Pacific Northwest and Oregon, including proposed facilities at Bradwood, OR (Northern Star LNG), Warrenton, OR (Oregon LNG), Coos Bay, OR (Jordan Cove Energy Project), and Clatskanie, OR (Port Westward LNG) and the British Columbia coast.

The impact of LNG on U.S. natural gas prices remains uncertain. Currently LNG accounts for less than 3% of total U.S. natural gas supplies; however, this amount has been growing over the last few years. If LNG liquefaction projects are further developed in producing regions in the Middle East, Asia and the Caribbean, and if re-gasification capacity expands in the U.S., LNG could serve as another significant source of North American natural gas supply and could help bring down natural gas prices. However, these events, if they come to fruition, may not necessarily translate into lower gas prices. Rapidly growing global LNG demand (in Europe and Asia in particular) is putting considerable competitive pressure on potential LNG supplies. Because the U.S. must compete with other countries for supplies of LNG, U.S. gas prices must remain high enough to prevent LNG shipments from being diverted to European and Asian markets. According to the EIA, recent competition from buyers in Western Europe and Asia for LNG cargoes has resulted in LNG prices exceeding the corresponding natural gas market price in the U.S.[35]. U.S. imports during 2006 were also negatively affected by a lack of long-term contracts relative to other global markets.

However, increasing global LNG supplies will likely ease price pressure in the world market over time, and as a result the U.S. is expected to attract a greater share of available LNG cargoes over time. According to the EIA, LNG imports to the U.S. in 2006 were from a mix of source countries: Trinidad and Tobago (67.6 %), Egypt (18.8 %), Nigeria (10.0 %), and Algeria (3.6 %). Other major exporters of LNG include Indonesia, Malaysia, and Qatar. Global supply is expected to expand with the addition of exports from Equatorial Guinea, Norway, and Yemen. New projects are also expected to come online soon in Russia, Australia, and Egypt.

5.4 Coal Price Forecasts, Supply, and Market Conditions

PGE's approach for developing coal price forecasts is similar to that used for natural gas. We rely on current contracts for coal delivered to Boardman through 2008 and then use Hill & Associates, Inc. to forecast long-term Powder River Basin (PRB) 8,400 Btu/lb. low sulfur coal commodity prices for our reference case[36]. This coal has quality and characteristics comparable to that of our current supply agreement(s).

Rail delivery costs are based on PGE contracts through 2013 with annual real escalation of 5% thereafter. Our current contracts do not include a separate fuel cost adjustment. Starting in 2014, we include a fuel cost adjustment of 15% of the total rail rate, based on Hill & Associates estimates and our judgment. Our underlying rail rates and annual escalation of 5% are also consistent with Hill & Associates' report on costs for new rail agreements[37]. The biggest driver for our expected rail cost increase post-2013 is that we are unlikely to get the same type of rail arrangement that we currently have. The railroads have been clear in their public pronouncements that once legacy agreements expire, they will move to common carrier-type arrangements that include a fuel surcharge. Some arrangements may also include mileage-based costs. Both of these adders are not in our existing agreement.

---

[35] Energy Information Agency. "Short-Term Energy Outlook Supplement: U.S. LNG Imports - the Next Wave." January 2007.

[36] Hill & Associates, Inc. <u>The 2005 Outlook for U.S. Steam Coal Long-Term Forecast to 2024</u>. August 2005.

[37] Hill & Associates, Inc. <u>Powder River Basin Coal Supply, Demand, and Prices.</u> November 2006. p. 4-11 and 4-12.

The resulting forecasts are shown in Figure 5-2. We do not apply stochastic analysis to coal commodity prices because coal represents a small proportion of the overall real levelized cost for coal plants and coal has not historically exhibited the level of price volatility of other energy commodities such as oil, natural gas, and electricity. This is in part attributable to the relatively abundant national and global supply and more limited substitution potential of coal.

For Colstrip (PGE's partial ownership in a mine-mouth plant in Montana), we use actual plant coal commodity costs for 2007 – 2011. For 2012 and beyond, we apply an escalation factor based on Hill & Associates' forecast of costs of production at the Rosebud (Colstrip) mine. The resulting fuel forecast is shown in Figure 5-3.

Figure 5-2: PRB 8,400 Btu/lb. Low Sulfur Delivered Coal, $2006/ Short Ton

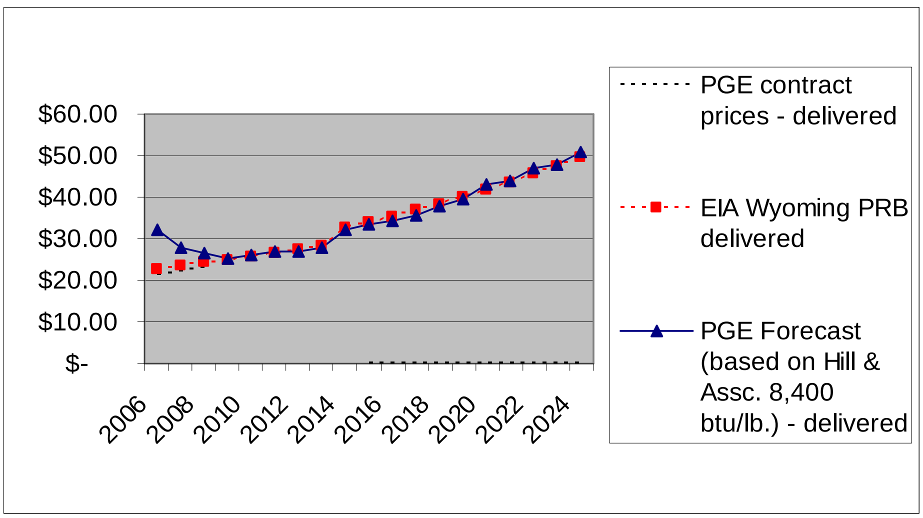
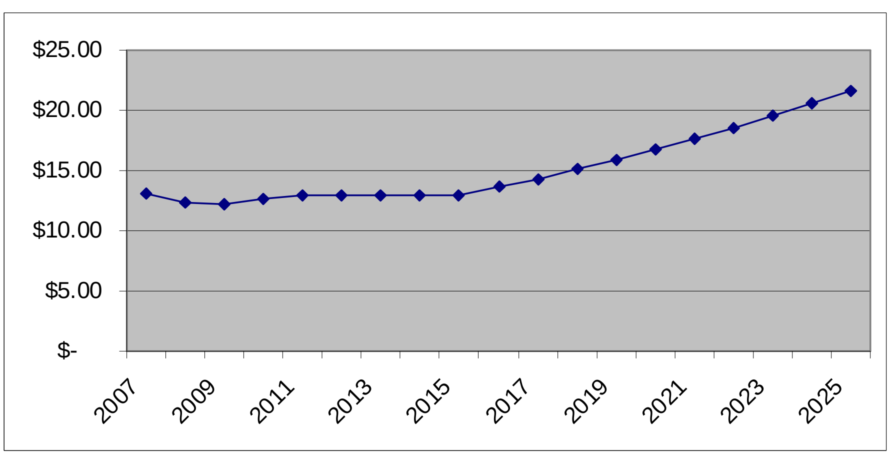


Figure 5-3: Colstrip Commodity Cost of 8,500 Btu/lb. Coal, $2006/ Short Ton



PGE reviewed several sources of long-term coal price forecasts, including the EIA 2007 Annual Energy Outlook (AEO), Global Insight, and Hill & Associates. We chose Hill & Associates because it is widely respected within the industry with its primary focus on the coal industry. In addition, Hill & Associates' reports have very transparent assumptions and fewer restrictions on their use compared to other proprietary forecast sources. We note that Hill & Associates' commodity prices are in line with the EIA's 2007 AEO prices for Wyoming PRB coal, as seen in Figure 5-2.

For WECC coal price forecasts used in AURORAxmp, we used updated delivered coal prices from the EIA's Electric Power Monthly February 2007 Table 4.10a, and applied an escalation factor based on rail escalation costs from Hill & Associates.

Market Conditions and Forecast Drivers

Hill & Associates' reference case is based on the EIA's AEO electricity demand growth and natural gas price and volume forecast. Demand for PRB coal may decline as Eastern coal-fired plants are retrofitted with flue gas de-sulfurization equipment as a result of the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). Once retrofits are in place, eastern companies may return to the Appalachian and interior coal markets if they are more price-competitive on a delivered basis. The main growth area for PRB coal will be in new plant construction and the displacement of lignite in Texas as many of these mines deplete their economic reserves. Hill & Associates' forecast does not include TXU's previously announced (and since canceled) additions of more than 6,000 MW that would have used PRB coal.

According to a recent report dated April 12, 2007, by the National Energy Technology Laboratory, an arm of the U.S. Department of Energy, 151 proposed and new coal plants were identified, representing approximately 90 gigawatts (GW) of coal generation at a cost of $145 billion. Proposals to build new power plants are often speculative and typically operate on boom and bust cycles, based upon the ever-changing economics of power generation markets. As such, it should be noted that many of the proposed plants will likely not be built[38]. Nonetheless, the number of proposed coal plants reflects the growing resurgence of expected new coal generation in some parts of the country. At the same time, renewed concern over environmental impacts, global warming and political uncertainty are also likely to have a dampening influence on investment in new coal resources until public policy and related costs become clearer.

[38] For example, out of a total portfolio of 500 GW of newly planned power plant capacity announced in 2001, 91 GW have already been canceled or delayed.

Potential drivers of downward pressure on prices also include stable to increasing supply from the PRB region. PRB has large reserves of low-sulfur, low-ratio[39] coal and relatively low mining costs compared to other regions, making it very economic relative to other supply sources. In the long term, load growth, new power plant construction and additional switches to low-cost PRB coal are expected to allow PRB coal supply to increase about 3% annually, compared to less than 0.5% in the other regions.

Potential factors placing upward pressure on PRB prices include increased mining costs in Appalachia due to depleting reserves (furthering the relative price advantage of and thus demand for PRB coal); increased short-term steam coal exports to reflect international demand, especially to China for metallurgical coal; and increased rail and transport costs and restrictions (see below).

Delivered Coal Prices

For utilities using PRB coal, transportation costs account for 60-75% of delivered prices of coal due to the long distances from mine to plant. For non-mine mouth plants in the West, approximately 70% of coal shipments are delivered via rail on a system that is at or beyond capacity in many areas, particularly in the PRB. These infrastructure constraints, due to higher demand for coal and surging demand in inter-modal (rail-to-truck) traffic, have caused increased competition for existing track capacity. At the same time, railroad costs have escalated in the areas of fuel, capital equipment, and labor. With rail carriers operating at maximum capacity, disruptions on major supply routes have made it difficult for utilities to make up for missed deliveries. All of these factors are leading to the increases in rail transportation costs that PGE and other utilities will see going forward.

PGE closely monitors coal industry fundamentals and potential drivers of higher or lower coal prices. PGE believes that uncertainties remain around the following key issues:

- The investment in rail infrastructure from terminals to equipment could be slower than expected.
- Proposed new rail line by Dakota, Minnesota and Eastern Railroad Corporation as a third rail carrier in the PRB market to serve Eastern markets.

[39] Low-ratio refers to lower overburden and strip mining costs (as compared to CAPP and other Eastern coals).

- Available capacity of the existing PRB joint rail line to keep up with demand.
- Global demand, particularly the impact of economic development in China and India, could increase demand for Eastern coal.
- Additional Eastern utilities could switch to PRB coal (due to the relative price advantage of PRB coal), even after plant retrofits.
- Impact of CAIR and CAMR and their implications for SO_2, NO_x, and mercury on different emission vintages is still unknown.
- Railroads could place more emphasis on growth of inter-modal traffic, decreasing available cars and track capacity for coal shipments.

6. Environmental Assumptions

We recognize that one of the biggest challenges we face is to meet the growing energy needs of customers while being good stewards of the environment. We also recognize that we are operating in an environment of increasing public awareness of and concern for environmental issues. At the same time, the political and public policy climate related to future energy and environmental issues remains unclear. Consequently, the potential for increased environmental regulations and major shifts in energy policy add a significant element of uncertainty to resource planning.

This section outlines our position on climate change and the environmental assumptions used in our analysis, assesses uncertainties related to potential environment regulation and policy developments, and discusses the potential effects of Oregon's RPS on our resource planning and procurement. The assumptions described here are used in determining the real levelized costs of the generation resources outlined in Chapter 7. Later in Chapter 10 we describe the various RPS and carbon tax futures we used to evaluate resource portfolios under an uncertain future, and in Chapter 11 we describe the results of our portfolio analysis.

Chapter Highlights

- We model a carbon dioxide (CO_2) tax in our base case based on the original CO_2 safety valve price of $7.72 per short ton (in $2010) proposed by the National Commission on Energy Policy
- We also model three CO_2 tax sensitivities in our portfolio analysis: $10/ short ton; $25/ton and $40/ton (in $1990).
- The real levelized costs for new gas, IGCC and SCPC coal generating plants include estimates for offset payments to the Climate Trust.
- PGE's Boardman and Beaver generating plants are subject to an assessment of emissions sources pursuant to the RH BART process.
- PGE is evaluating the installation of emissions controls at Boardman, as required by the RH BART process and Oregon mercury regulations stemming from the Clean Air Mercury Rule. We expect Boardman's useful life to extend to 2040.
- The Oregon RPS legislation requires that 25% of electric utility energy load be served by qualifying renewable resources by 2025, with interim targets of 5% by 2011, 15% by 2015, and 20% by 2020.

6.1 Climate Change Impacts

Climate Change – PGE's Principles for Action

PGE believes responsible protection of the environment and cost-effective business practices are compatible. Further, a corporate policy that ensures that we are addressing environmental issues is in the best long-term interest of the communities we serve, our customers, shareholders and employees.

We believe that global climate change is an issue that requires action. We also believe that it is prudent to pursue affirmative steps to mitigate potential emission impacts that may affect global climate change while we continue to study the issue. At the same time, we acknowledge that there is a spectrum of views on this issue. PGE will use the following framework to make proactive decisions and to take action.

We encourage:

- Steps to mitigate emissions taken at all levels – international, national, state and local – to ensure mitigation is encouraged and achieved efficiently with costs borne fairly across geographic boundaries.
- Creation of national standards and, as these evolve, seeking support in Oregon to implement them while maintaining reasonable costs to provide power to customers.
- Climate-change mitigation actions that apply proportionally to point (generating and manufacturing plants) and mobile (vehicular) sources that are located in or serve Oregon.
- Mitigation measures attributed to power production and consumption should be borne equitably among all types of fuel producers and consumers.
- Mitigation measures attributed to power production should be borne equitably among all retail customers whether they are served by a public or private utility.
- The inclusion of Oregon's business and residential communities in all groups tasked with developing Oregon's policy on climate change.
- Credit for early action in any greenhouse gas mitigation strategy or policy, *e.g.*, 1992 Energy Policy Act USDOE1605b registry, public purpose charge, green power, Climate Trust contributions, and hydro re-licensing.

We will:

Supply Position

- Plan our resource portfolio with standards that reflect the likelihood and magnitude of the project costs over the life of each plant as demonstrated in our IRP process.
- Based on the results of the IRP process, select that mix of resource options that yield, for customer and society over the long run, the optimum combination of expected costs and associated risks and uncertainties.
- Give preference to actions that minimize emissions where emissions would be a deciding factor between otherwise equally viable options in making our final resource choices.
- Evaluate and give preference to innovative approaches to reduce or offset greenhouse gas emissions, while providing the power that our customers need. For example, we will continue our promotion of renewable resources such as wind power and will investigate carbon sequestration and new emission mitigation techniques that optimize fuel usage.

Operational Excellence

- Evaluate and give preference to cost-effective efficiency improvements so that additional power can be produced at our plants without increasing greenhouse gas emissions or with a minimal increase in greenhouse gas emissions.
- Address non-resource planning activities that have emissions effects by eliminating the activity or changing it at a reasonable cost to reduce the emissions.
- Purposefully seek and monitor specific PGE carbon mitigation or offset opportunities/ projects, past, present and projected.

Customer Value

- Be influential, active participants within the local, state, and national climate change arenas and support these principles for the benefit of our customers and investors.
- Continue to work with our customers to improve EE, which ultimately helps to offset power plant emissions, and push for new actions to support EE efforts.

- Continue to solicit input from a cross-section of our customers on climate change and its impacts on them.
- Continue to recognize and support the efforts of our employees, customers and communities that are focused on addressing climate change actions.

Economic Growth

- Support regional efforts to create family-wage jobs by recruiting businesses that manufacture solutions to global climate change.

University of Washington Climate Change Study

In order to better understand the potential regional impacts of global climate change, we engaged the University of Washington Climate Impacts Group to examine 19 scenarios from state-of-the-art climate models and summarize the changes they project for the Pacific Northwest regarding temperature, precipitation, snow pack and resulting stream flows, and wind patterns.

Study results suggest that the average warming rate in the Pacific Northwest in the next century may be in the range of 0.1 to 0.6° C (0.2 to 1°F) per decade with a best estimate of 0.3° C (0.5° F) per decade. The study models also predict a decrease in the number of winter frost days. Beyond beneficial impacts to the growing season, increased temperatures could slightly accelerate an increase in summer air conditioning.

Projected precipitation changes are modest: annual rainfall expectations range from slight decreases to slight increases. Most models have winter precipitation increasing, but with higher freezing elevations for snow, and summer precipitation decreasing. These results suggest that seasonal climate change will most likely produce continued decreases in June – September stream flows in most Northwest rivers (with a corresponding decrease in summer hydro production), with increases in winter flows, as relatively more of the precipitation falls as rain vs. snow and snow-pack melt occurs earlier.

The climate models do not have sufficient granularity to forecast changes to overall windiness or changes to seasonal or diurnal wind patterns. But changes are likely to be small, and information is not sufficient to suggest any major shift in the Pacific Northwest's wind resources.

While useful for giving long-term context to our IRP, we do not propose any specific adjustments to our IRP modeling assumptions based on this climate study. However, we will continue to monitor scientific analysis and predictions for changes in Pacific Northwest weather patterns resulting from global climate change. For more detail, please see *Appendix C: University of Washington Climate Change Study*.

6.2 Carbon Regulation

In December 2006, we announced our intention to reach out to Oregon's Congressional delegation, our customers and other Northwest utilities to advocate for federal climate change legislation based on the original National Commission on Energy Policy (NCEP[40]) recommendations. PGE's CEO, Peggy Fowler, stated in a December 2006 speech, "An issue as broad as global climate change, by definition, cannot be addressed on a utility-by-utility or state-by-state basis." Fowler went on to say that the NCEP approach would:

> "Phase in requirements to slow, stop and reverse the growth of emissions, while placing regulation upstream on carbon-based fuel sources, rather than downstream at the consumer level. It distributes costs equitably to all emission sources, and it links emissions targets to the economy.[41]"

Our IRP base case assumes that any electric power plant in the WECC pays a federal tax based on its CO_2 emissions. For modeling purposes, in our reference case assumptions we set this tax to $7.72 per short ton, starting in 2010, with a 5% annual nominal growth rate from 2010 through 2025. After 2025 the tax escalates at inflation (is flat in real terms).

This assumption is based on the CO_2 safety valve price of $7.72 per short ton (in $2010) originally proposed by the NCEP and reflects the goal of discouraging further CO_2 emissions without forcing premature and costly retirement of existing long-lived assets. The annual growth in nominal dollars of the tax (5% per year) per NCEP assures a progressively higher CO_2 penalty on carbon emissions. After completion of our analysis, the NCEP issued an updated proposal which raises the initial safety valve price from $7.72 ($2010) to $11.03 ($2012) per short ton and raises the cap by 5% per year in *real* dollars. The update also delays implementation from 2010 to 2012. While we have not analyzed the impact of this updated proposal, we note that it still falls below the $10 per ton ($1990) sensitivity prescribed by the OPUC, which we refer to below.

---

[40] The National Commission on Energy Policy. "Ending the Energy Stalemate. A Bipartisan Strategy to Meet America's Energy Challenges." December 2004.

[41] Fowler, Peggy. Introduction. 2006 Energy Summit: Powering the Northwest into the 21st Century. Oregon Convention Center, Portland. December 13, 2006.

To ease the cost impact of the transition, the NCEP legislation also proposes to issue free allowances, or offsets, to electric utilities. These allowances have the effect of offsetting a substantial portion of the costs that otherwise would be incurred by the utilities for their existing CO_2-emitting plants. These allowances are based on plants in service during a given historical year and are thus not a function of new plants that may be built. Hence, these allowances are not relevant to the economics of new resource decisions.

PGE is aware that there is currently no mandatory carbon emission tax in the U.S. However, several factors have convinced us that it is prudent to model a CO_2 tax in our base case: 1) ratification of the Kyoto Protocol by most industrial countries in the world, 2) growing public environmental interest and concern, 3) the existence of several legislative proposals to introduce carbon regulation in the US, 4) a changing federal political landscape and 5) the input received in our public meetings and our dialogue with stakeholders. We chose the NCEP proposal because it distributes costs equitably to all emissions sources, and it links emissions targets to the economy. By incorporating this tax in all of our analyses, we quantify the risk of future costs that may be assessed on long-term investments to which we commit today.

Consistent with OPUC Order 93-695, we also model three CO_2 tax sensitivities in our portfolio analysis: a $10/ short ton CO_2 tax in $1990 ($14.4 in $2006); $25/ton in $1990 ($36 in $2006) and $40/ton in $1990 ($57.6 in $2006).

OEFSC Rules - Climate Trust Offset Payment

In 1997, the Oregon legislature gave the Oregon Energy Facility Siting Council (OEFSC) authority to set CO_2 emission standards for new energy facilities. Under Division 24 of the OEFSC rules, beginning at OAR 345-024-0500, there are specific standards for baseload gas plants, non-baseload (peaking) power plants and non-generating energy facilities that emit CO_2. See Table 6-1.

Table 6-1: OEFSC Carbon Dioxide Emissions Standards

Plant Type	Emission
Baseload gas plants	0.675 lb. CO_2 / kWh
Non-baseload gas plants	0.675 lb. CO_2 / kWh
Non-generating facilities	0.504 lb. CO_2 / horsepower-hour

The standard for baseload plants currently applies only to natural gas-fired plants. The standards for non-baseload plants and non-generating facilities apply to all fuels. The OEFSC has not yet set a CO_2 emission standard for baseload power plants using other fossil fuels (i.e., coal). However, after initial discussion with the Oregon Department of Energy, PGE has made the conservative assumption for this IRP that the baseload gas plant CO_2 emissions standards would apply to future coal plants as well as natural gas plants.

At their discretion, applicants for site certificates can propose CO_2 offset projects that they or a third party will manage, or the applicant can provide funds via the monetary path to the Climate Trust, which has been designated as a qualified organization by the OEFSC. Under the monetary path, the site certificate holder is responsible for two types of payments: 1) offset funds of $.85 per short ton of excess CO_2 emissions; and 2) selection and contracting funds. The real levelized costs for new gas generating plants and new IGCC and SCPC plants shown in Chapter 7 include estimates for these payments to the Climate Trust. In the advent of a federal carbon tax, or an Oregon emissions standard, it is not clear whether the current OEFSC rules would continue. For modeling purposes, we have assumed they would continue.

6.3 Sulfur Dioxide, Nitrogen Oxide and Particulate

In accordance with new federal regional haze rules, the Oregon Department of Environmental Quality (DEQ) is conducting an assessment of emission sources pursuant to the Regional Haze Best Available Retrofit Technology (RH BART)[42] process. Those sources determined to cause or contribute to visibility impairment at protected areas within 300 kilometers of each source will be subject to an RH BART determination. Several other states are conducting a similar process.

The DEQ is working with approximately seven RH BART eligible sources in Oregon, including our Boardman and Beaver thermal generating plants. In January 2006, we volunteered to participate in a DEQ pilot project that will analyze information about air emissions from Boardman to determine their effect on visibility in the region, particularly in wilderness and scenic areas. An exemption modeling analysis for identified sources begun in September 2006 indicated that the Boardman and Beaver facilities may cause or contribute to visibility impairment in several protected areas. The objectives of the RH BART analysis and recommendations include significant reductions of sulfur dioxide (SO_2), nitrogen oxide (NOx), and particulate emissions.

Table 6-2 below summarizes the base case emissions adders we used in our calculations of the real levelized costs of thermal resources. All existing and new

[42] Regional Haze Best Available Retrofit Technology (RH BART) is a requirement under the Environmental Protection Agency's Regional Haze Regulations.

plants meet particulate regulation; compliance costs for particulate are included in the capital costs.

Table 6-2: Regulatory Compliance Costs for Environmental Emissions

	Base Case Emissions Adders					Sensitivities	
	To Investment Cost (for new thermal plants)	To Variable Cost (adders to all thermal plants)					
	Description	Description	Cost ($)	Start Date	Annual Escalation	Cost ($)	Start Date
CO_2	Offset payment to Climate Trust per OEFSC rules	NCEP recommendations	$7.72 per short ton	2010	5% until 2025	10, 25, 40 ($1990 per short ton)	2009
NOx	Cost of BACT[1] included in generic capital cost assumption	NA	-	-	-		
SO_2	Cost of BACT[1] included in generic capital cost assumption	SO2 allowances cost per Title IV of the Clean Air Act	$595 ($2006) per short ton	ongoing	2006 Market quotes: declining from $595 to $255 in 2011	NA	ongoing
Hg	Cost of CAMR compliance[2] included in generic capital cost assumption	NA	-	-	-	NA	NA

1) Best Available Control Technology

2) CAMR rules only apply to new coal plants, not gas plants.

6.4 Mercury

In May 2005, the U.S. Environmental Protection Agency (EPA) established the Clean Air Mercury Rule (CAMR), which regulates mercury emissions from the nation's coal-fired electric generating plants. The CAMR includes a federal cap-and-trade program (scheduled to begin in 2010), that establishes a cumulative total (cap) for mercury emissions from all electric generating plants in the U.S. and assigns to each state a mercury emissions budget. Individual states have the choice of adopting this model or establishing their own programs.

In October 2006, the Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating units, including Colstrip, which set strict mercury emission limits by 2010 and established a review process to ensure that such facilities continue to utilize the latest mercury emission control technology. The rules were submitted to the EPA for review and determination of their compliance with CAMR requirements, but EPA approval has not yet been received.

In December 2006, Oregon’s Environmental Quality Commission adopted the Utility Mercury Rule, which limits mercury emissions from new coal-fired power plants. Beginning in 2018, the Oregon Utility Mercury Rule will limit mercury emissions from all coal-fired plants to a total of 60 pounds per year. The Boardman plant will receive a total of 35 pounds of the cap with the remaining 25 pounds being distributed on a first-come-first-served basis. Once the cap is reached, no new mercury allowances will be available for new coal-fired plants in Oregon. The rule also requires installation of mercury control technology on the Boardman plant and requires the plant to reduce its mercury emissions by 90% or to 0.6 lb/TBTU by July 1, 2012, with a possible 1-year extension. The adopted rules allow limited mercury allowance trading up to 2018, after which time no trading will be allowed.

6.5 Impact of New Emission Rules on Boardman

Once analysis is complete and potential mitigation measures are identified and evaluated, PGE's implementation plan for compliance at Boardman with RH BART will be reviewed by DEQ, EPA, and other state and federal agencies in a public process that is expected to last several months. The current schedule for obtaining regulatory approval (and the start of a 5-year clock to complete installation of controls) is not expected to occur until mid- to late-2008, or possibly not until 2009. Thus, we will not have full regulatory guidance for final technology decisions or be able to firm cost estimates via bids within the time frame of filing this IRP.

Because Boardman is a baseload coal plant, emissions are more significant than at Beaver, which is an intermediate duty resource. While it is not yet known what ultimate impacts the new state and federal regulations on air quality standards and mercury will have on future operations, operating costs, or generating capacity of our Boardman plant, we are engaged in preliminary estimates to assess these issues. Compliance technologies are being evaluated, but we do not have firm cost bids at this point. It is expected that capital costs will be between $165 million and $215 million for our share of Boardman for the most likely compliance cases, depending on the selected emissions control technology. Installation of the new systems is expected to take place during our normally scheduled spring maintenance outages.

At this point, we estimate that fixed and variable O&M will increase between $10 million and $12 million per year, for the existing PGE share of Boardman, of which about two-thirds is variable O&M. The net plant heat rate is expected to increase from between 0.7% and 1.3% for the most likely compliance cases, with a corresponding decrease in PGE's share of plant output. However, the ongoing impacts to the dispatch cost due solely to emissions controls (the variable O&M

and change in heat rate) are fairly modest. In 2013, the dispatch cost is expected to increase by $3 to $4 per MWh, after the installation of emissions controls.

Preliminary economic analysis indicates that, inclusive of the original NCEP carbon tax and assuming a remaining useful life at Boardman until 2040, the plant continues to be a baseload resource that is economically beneficial for our customers. Even with the capital and O&M requirements from new emissions controls, Boardman still creates an NPV benefit for customers of between $240 million to $450 million (for the PGE share), when compared to the projected avoided cost, including a CO_2 tax commensurate with the NCEP assumption of $7.72 per short ton. Much higher carbon taxes could change this outcome.

This analysis is predicated on our cost of capital. Incremental capital requirements for select component replacements (e.g., a stator rewind) are also included in the economic analysis. Tax-favored pollution control bond financing, if available, could improve the economics. This analysis further assumes no extension of the Oregon Pollution Control Facilities Tax Credit program, which currently is set to expire this year.

We currently plan to run our Boardman plant until 2040. This date was used for Boardman in our latest depreciation study, which was accepted in PGE's last rate case. Our Power Supply Engineering Services group and the Boardman plant operations team are comfortable in this assessment. They note that Boardman was not operated heavily in the first decade of its life.

In addition, the plant already has a number of relatively new major components or upgrades, including steam turbines, pulverizers, and boiler tubing. Other scheduled replacements over the next few years include generator components and burners. There are also many instances of thermal plants operating well beyond their original book life; other coal plants placed in service before Boardman are also proceeding with emission controls retrofits.

Impact of Carbon Tax on Boardman

We evaluated the impact of a carbon tax on Boardman, in conjunction with the potential RH BART related emission controls. We further modeled sensitivities based on our current set of potential futures: a $7.72 per short ton tax (in $2010) per proposed NCEP legislation as the base case and a tax of $10, $25, and $40 per short ton (in $1990) per OPUC rules. NCEP legislation would provide allowances for approximately 90% of Boardman's output. The preliminary estimate for the break-even CO_2 tax (the CO_2 tax at which the NPV of Boardman is $0 when compared to an avoided cost of a CCCT with the same CO_2 tax rate) ranges from $21 to $30 per short ton in $2010, depending on the scrubber configuration and price of natural gas.

6.6 Renewable Portfolio Standard

PGE supports the implementation of an effective RPS for Oregon that is achievable, provides for clean and environmentally responsible future energy supply, and includes measures to ensure that Oregon electric consumers are protected from unreasonable price increases and detrimental impacts to overall economic prosperity for the state. We, along with many of our consumer groups and stakeholders, have worked cooperatively over the last several months to pursue these objectives. On June 6, 2007, Renewable Portfolio Standard (RPS) legislation in Oregon was signed into law and became effective immediately. The Oregon RPS legislation requires that 25% of our retail energy load be served by qualifying renewable resources by 2025, with interim targets of 5% by 2011, 15% by 2015, and 20% by 2020. Qualifying resources include generating facilities placed into operation on or after January 1, 1995, and their incremental improvements.

Qualifying resources include:

- Wind;
- Solar photovoltaic and solar thermal;
- Wave, tidal, and ocean thermal;
- Geothermal;
- Certain types of biomass;
- Biogas from organic sources such as anaerobic digesters and landfill gas;
- New hydro facilities not located in federally protected areas or on wild and scenic rivers, and incremental hydro upgrades; and
- Up to 50 MWa per year of energy generated from a certified low-impact hydroelectric facility.

Such facilities placed into operation by January 1, 1995, and subsequent efficiency improvements to such facilities are included.

The legislation further provides that Tradable Renewable Energy Credits (TRCs), commonly known as Renewable Energy Credits (RECs) or Green Tags, may be used to fulfill the RPS targets if independently verified and tracked. Bundled RECs[43] must physically reside within the U.S. portion of the WECC. For unbundled RECs, the facility that generates the qualifying electricity must be located within the geographic boundary of the WECC. RECs obtained by utilities through voluntary green power programs would not apply toward meeting the RPS compliance targets.

[43] A bundled tradable renewable energy certificate includes both the underlying qualifying electricity along with the renewable certificate that was issued for the electricity.

The legislation also includes an annual cost cap of 4% of the utility's retail revenue requirement. The cost cap is met by applying the incremental cost of development of a renewable resource over an equivalent nonrenewable resource[44]. Thus, for PGE, if our annual revenue requirement is $1.5 billion, then the annual cost cap would be 4% or $60 million. If subject utilities fail to meet the compliance target for reasons other than reaching the cost cap, then they may be subject to a penalty imposed and determined by the OPUC. All prudently incurred costs associated with RPS compliance are recoverable under the RPS legislation, including those associated with transmission and development.

In March, 2007, PGE's Pelton Round Butte hydro project was certified by the Low Impact Hydropower Institute. This makes Pelton Round Butte the second largest hydro project in the U.S. to receive the designation. A 50 MWa portion of the project will count as a qualifying renewable toward the RPS target.

Banking vs. Sales of Tradable Renewable Energy Credits

On March 5, 2007, the OPUC issued Order No. 07-083 (in Docket UP 236) in response to PGE's application to sell TRCs. TRCs, or RECs, are the separable renewable attribute associated with energy generated by renewable power resources. RECs have a market value which, if sold, reclassifies the green energy into undifferentiated energy as though it were generated from a non-renewable power source. Typically, one REC equals one MWh of generation from a qualifying renewable project. These can be sold into the market over various time periods. For example, a 10 MWa wind project which sold its RECs for one year would generate (10 MW * 8,760 hours) = 87,600 RECs during that time period.

Condition 8 of OPUC Order No. 07-083 directs PGE to

> "Analyze, in its [IRP] process, the valuation and risks associated with the disposition of TRCs, including their value for compliance with a potential [RPS] or regulations on greenhouse gas emissions."

The condition also stipulates that value from the sale of TRCs flow back to customers, either in the form of rate credits or funding to develop new resources.

We currently have regulations on greenhouse emissions in place in Oregon via the Climate Trust offset payment (see Section 6.2 above). Given that an Emissions Portfolio Standard is only in the early stages of consideration, it is not clear how such emissions legislation would interact with an RPS, particularly

[44] The incremental levelized cost difference between nonrenewable and renewable resource choices is applied evenly towards the cost cap throughout the life of the project.

regarding the valuation of RECs. The potential effects of a future state or federal carbon tax on the value of RECs are discussed below.

The RPS legislation provides for indefinite banking of utility-owned or generated RECs for the purpose of future RPS compliance. The RPS legislation also allows for RECs generated from existing PGE projects to be bankable and tracked via the Western Renewable Energy Generation Information System (WREGIS) or other regional system or trading program. The legislation specifies that the Oregon Department of Energy shall establish a system of renewable energy certificates, after consultation with the OPUC, but it does not specify when banking of RECs will begin. For purposes of our IRP analysis here, we assume that banking of RECs will begin January 1, 2008.

An important consideration with respect to PGE's RECs is whether excess RECs that we generate in advance of RPS requirements will have more value if banked for future use towards RPS targets, or if they will have more value when sold in the marketplace. Reasons for selling excess RECs may include providing immediate cost reductions for our customers, or using funds generated by the sale of RECs to acquire additional renewable resources.

We may choose to sell RECs generated before WREGIS is formed and REC banking goes into effect. PGE recently sold, pursuant to the other conditions in Order No. 07-083, some of the previously generated RECs associated with the output of the Klondike II wind plant. We currently estimate that if RECs were sold over the entire life of the plant, they could reduce the plant's lifecycle costs by $0.50 to $5.00 per MWh, based on market indications of the current value of RECs. Our decision to retain or sell RECs in the future for the benefit of our customers will ultimately be based on many factors (many of which are not currently known), including market conditions and prices for environmental attributes, federal and state energy and environmental policy developments, and our evolving renewable energy supply to meet RPS standards.

Table 6-3 compares PGE's load-based renewable resource requirement by year versus RECs that we generate from existing renewable resources and from IRP renewable acquisitions recommended in this IRP to achieve the 2015 target.

Table 6-3: PGE Estimated RPS Position by Year (in MWa)

	2008	2011	2015	2020
Calculate Renewable Resource Requirement:				
PGE retail bus bar Load	2451	2574	2802	3120
Remove incremental EE	-9	-36	-45	-45
Remove Schedule 483 5-yr. load	-27	-29	-31	-34
A) Net PGE load	2424	2545	2770	3086
Renewable resources target load %	0%	5%	15%	20%
B) Renewable Resources Requirement	**0**	**127**	**416**	**617**
Existing renewable resources at Bus:				
Vansycle Ridge	8	8	8	8
Klondike II	27	27	27	27
K2 dedicated to PGE green tariff	-5	-5	-5	-5
Sales of RECs	0	0	0	0
Biglow Canyon Phase I (year-end 2007)	46	46	46	46
Biglow Canyon Phases II and III (year-end 2008, 2010)	0	105	105	105
Biomass (assume 20 year deal at year-end 2008)	0	12	12	12
Post-1999 Hydro Upgrades	9	9	9	9
Pelton Round Butte LIHI Certification	50	50	50	50
C) Total Qualifying Renewable Resources	**136**	**253**	**253**	**253**
Compliance positions & RECs banking:				
D) Excess/(deficit) RECs B4 new IRP Actions (C less B)	136	126	-163	-364
E) IRP Action Plan -- additional compliance by 2015*	0	0	213	213
F) Total PGE renewable resources (C plus E)	136	253	466	466
G) % of load served via RPS renewables (F divided by A)	5.6%	9.9%	16.8%	15.1%
H) Excess/(deficit) RECs w/ IRP Actions (D plus E)	136	126	50	-152
I) Cumulative Banked RECs after IRP Actions	**136**	**644**	**1265**	**1221**

With the sharp rise in the renewable resource requirement from 5% of load in 2011 to 15% by 2015, banking RECs from early renewable resource actions could provide a significant source of renewable supply toward future RPS compliance. We expect that our existing actions, combined with our proposed renewable actions, provide sufficient RECs to meet the RPS requirement through 2020, assuming no sales of RECs (see line I of Table 6-3). Thereafter, however, large new renewable resource acquisitions are required to meet the 25% target.

Estimating the future costs for renewable resources and the future market for RECs would be speculative. However, if the value for RECs continues to vary within a range of $.50 to $5.00 per MWh, then it appears that banking RECs could provide an effective hedge against future renewable resource cost increases. The relative value of RECs may be estimated by comparing the market price for traded RECs to the cost difference between renewable resources and thermal alternatives. If a carbon tax or other emissions regulations increase the cost of thermal alternatives, then this cost difference may decrease, possibly making RECs less valuable.

In addition to financial flexibility, banking RECs provides flexibility in timing of renewable resource acquisitions. Flexibility may be particularly important for our customers given the 5-year MACRS depreciation for all renewable resources, which provides tax depreciation for 38% of the property in-service basis in its second year of service. This creates challenges in having a sufficient tax liability to use all the depreciation associated with qualifying renewable resource investments in the year generated. While tax losses can be carried forward, their value diminishes over time. Flexibility in timing of adding new renewable resources would allow us to maximize the benefit to our customers of the tax depreciation while minimizing potential tax loss carry-forwards.

Several other factors beyond the ability to bank RECs favor early action over later action to acquire renewable resources. These include reduced access to and quality of remaining wind sites, possible expiration or limitation of the PTC, scarce transmission access, and increasing costs per kW for wind plants based on commodity and construction costs and higher demand. Factors that may suggest later development include larger turbine sizes for wind plants and possible cost and efficiency breakthroughs in non-wind renewable resources such as wave and solar generation.

It is difficult at this time to know whether the market price of RECs will favor selling some portion of the RPS bankable RECs that PGE generates vs. retaining REC inventory for future RPS compliance. However, our early renewable resource acquisitions provide flexibility to both PGE and our customers to bank or monetize RECs as future circumstances dictate. Going forward, given the preceding considerations, we will do what is most beneficial for our customers.

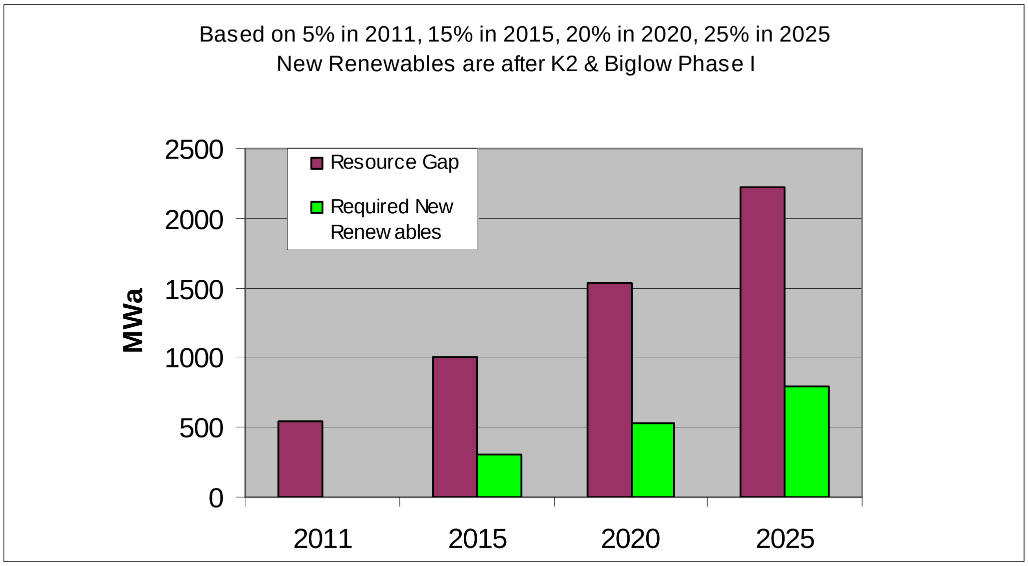
Impact of the RPS on PGE's Future Resource Mix

Meeting the RPS target requires that about one-third of our cumulative energy additions be met via incremental (new) renewable resources through 2025 (see Figure 6-1)[45]. Given the sharp increase in the requirements of the Oregon RPS targets between 2010 and 2015 as well as a preference for pursuing a measured implementation strategy, we propose taking additional actions beyond Biglow Phase I in this IRP in order to reach the 2015 goal, if economic resources are available.

---

[45] Assuming no use of banked Renewable Energy Credits towards RPS requirements.

Figure 6-1: Oregon RPS Requirements vs. Resource Need



If met entirely by wind, 788 MWa, or about 2,400 MW of new wind would be required by 2025. At current estimated costs, the bus bar investment required to achieve the RPS by 2025 with all wind is estimated at $5.0 billion (including capacity from incremental SCCTs and additional transmission investment), versus $2.1 billion for traditional coal and $1.0 billion for CCCTs for similar amounts of energy. Nevertheless, initial rate impact differentials are less than capital investment differentials might imply due to incremental fuel and carbon costs of the thermal alternatives (and no such costs for wind) and spreading of the wind investment recovery over more than 25 years. See Table 11-1 for comparative detail on estimated initial rate impacts. Chapter 7 (Supply-Side Options) provides a fully-allocated cost comparison, inclusive of substantial fuel costs for the coal and natural gas alternatives.

Substantially increased penetrations of wind are expected throughout the WECC due to state RPS requirements. In Chapter 10 we discuss our modeling approach to resource expansion in the WECC. Table 10-1 lists RPS requirements for states in the WECC, and Figure 10-5 highlights the significant build-out of renewable energy resources due to state RPS requirements. After these resource additions, 25% of the WECC resource mix in 2031 will be composed of non-hydro renewable resources, the majority of which is expected to be wind generation. Increased demand for wind has created uncertainty about future site availability, turbine supply, and integration capabilities and costs. These issues are discussed in more detail in the following chapter. All of these factors will impact PGE's ability to obtain cost-effective wind generation to meet the resource targets proposed in our Energy Action Plan.

7. Supply-Side Options

The following sections outline the energy supply-side alternatives we examined for this IRP to meet our customers' future needs. Each section includes a description of the technology, expected economics, potential locations and energy available to PGE, and any challenges associated with future development. Capacity resource alternatives and needs are discussed in Chapters 4 and 12.

The primary supply-side resources that we evaluated to meet our energy needs in this IRP cycle included traditional and gasified coal plants, new G-class CCCTs similar to our Port Westward plant, wind, biomass, and geothermal plants. We also evaluated the potential reliability and cost volatility risks of relying on short-term market purchases. These resources, along with energy efficiency (EE), are included in the candidate portfolios that we tested. We describe the reference case capital and operating costs and underlying assumptions for all resources included in our portfolio analysis, taking into account advances in technology.

We reviewed solar photovoltaic and solar thermal plants, nuclear, wave energy, and other emerging technologies. However, we do not include these in our portfolio analysis because they are expected to be either not commercially available or economically uncompetitive through our target resource acquisition period of 2012.

Chapter Highlights

- We included in our analysis only those supply-side alternatives that are expected to be commercially available and cost competitive on a utility scale.
- These include combined- and simple-cycle gas turbines, super-critical and IGCC coal, and utility-scale renewables (wind, geothermal, and biomass), as well as reliance upon market contracts.
- We reviewed developing technologies such as nuclear, solar and wave energy for inclusion in future IRPs.
- We do not project any learning effect on costs for all baseload energy resources, with the exception of IGCC plants, whose costs should decline because of advances in technology.
- We included two categories of wind costs to reflect the decreasing availability of optimal wind sites and increasing integration costs.

7.1 Renewable Options

Wind – Tier I (Biglow Canyon Expansion)

For wind, we are evaluating performance based on two tiers for expected capital costs and capacity factors. An expansion of PGE's Biglow Canyon project (to full site build-out) represents Tier I due to its relatively high forecast capacity factor of 35% and its anticipated scale economies due to shared facilities deployed in connection with Phase I of the project. Tier II wind includes all other wind resources available to PGE. For Tier II wind we are using modestly higher capital costs, under the expectation that most new wind farms would not benefit from savings based on common facilities. We are also using a slightly lower capacity factor that is more reflective of the actual operating experience, on average, of existing Pacific Northwest wind farms.

Phase I of the Biglow Canyon wind project is currently under construction pursuant to the wind energy requirements from our acknowledged 2002 IRP Final Action Plan and is expected to achieve commercial operation by December 31, 2007. Further expansion of the project will provide economies of scale by utilizing common facilities constructed in Phase I, including roads, substation, transmission interconnection and operations and maintenance infrastructure. Expansion of Biglow Canyon will better position us to meet Oregon RPS requirements, as well as ongoing customer energy needs with a relatively stable cost renewable resource. We propose to begin expansion of Biglow Canyon by 2009, and complete the entire project build-out with up to an additional 250 to 325 MW beyond Phase I, depending on turbine size, by the end of 2010.

New Wind Resources

With the extension of the Production Tax Credit (PTC) until December 31, 2008, and the continued expansion of state RPS requirements, we expect the recent rapid growth in new wind generation projects to continue well into the future. Record U.S. installations of over 3,000 MW of turbines are projected for 2007. Key growth drivers include increasing public awareness of and concern for environmental issues, high and unstable fossil fuel prices, maturation and scaling of wind generation technology, an influx of capital to the industry, market evolution, and supportive state and federal policy for renewable resources.

Oregon and Washington have modest wind resource potential compared to many other regions of the country. Most of the identified sites in the Pacific Northwest with strong wind potential are located along the middle and lower Columbia River Gorge from central and southeast Washington to northeast and north-central Oregon. Montana and Wyoming offer significant wind resource opportunities; however, transmission and distance from load centers present considerable barriers to our access to these resources.

As technological advances continue, bigger is better. Turbines, towers, rotors and total project size are all increasing in scale. The typical project size for a new utility scale wind project is now 100 – 400 MW. The typical turbine size is 1.5 MW to 3 MW. Increased scale is improving both wind project efficiency and economics. As a result, geographically advantaged wind sites that have higher wind speeds and lower interconnection costs remain cost-competitive (with the PTC) compared to fossil-fueled generation alternatives.

However, while Pacific Northwest wind development activity is vibrant, structural impediments remain. The PTC-driven boom–bust cycle hampers wind turbine manufacturing investment and stability. The current PTC benefit is approximately $20/MWh nominally (indexed to inflation), with an estimated after-tax value for entities that can fully utilize the tax credit of as much as $30/MWh[46]. Given this substantial economic benefit, the PTC remains critical to the competitiveness of wind for the Pacific Northwest. The importance of the PTC to the economic viability of wind can be seen in the boom and bust cycle that has occurred as a result of PTC expiration and renewal in the past. Annual wind installations have declined by as much as 75 to 85 % (year-over-year) in years with PTC expiration and renewal uncertainty. In addition, despite the number of wind turbine suppliers opening new manufacturing plants in North America, turbine shortages are expected to continue for the foreseeable future due to anticipated U.S. and global demand-supply tightness. Turbine costs are also expected to increase in part due to increases in commodity costs for steel, oil and related materials.

Beyond turbine availability, potential uncertainties and barriers for increased adoption of wind power include transmission availability and integration costs. The most viable Pacific Northwest wind sites are on the east side of the Cascades. Incremental firm transmission from these areas in the mid and lower Columbia River Gorge area is limited or not available. In addition, integration costs and system impacts at high penetration levels are still not known. Regional groups including the NWPCC and the BPA are currently studying the costs and transmission requirements of integrating up to 6,000 MW of developable wind power in the Northwest[47]. Preliminary indications from the regional wind integration initiative point to a range of wind integration costs, based on a survey

---

[46] Western Governors' Association Clean and Diversified Energy Initiative. "Wind Task Force Report." March 2006. http://www.westgov.org/wga/initiatives/cdeac/Wind-full.pdf.

[47] For more information, see the "Northwest Wind Integration Action Plan," March, 2007. http://www.nwcouncil.org/energy/Wind/library/2007-1.htm

of individual Pacific Northwest utility studies, of approximately $2/ MWh (for penetration levels of 5% and under of nameplate wind to peak load) to over $16/ MWh (for penetration levels of 30%).

We are conducting our own study to assess the cost of wind integration in our system at increasing penetration levels of wind. The cost range for wind integration used in our analysis for this IRP is $6/MWh for Tier I wind and $10/MWh for Tier II wind. The application of these costs with respect to the reference case for wind and for the purpose of portfolio modeling is further discussed below.

PGE Wind Integration Assessment

Study Scope & Description

We currently receive third-party integration services for our contracts for the output of the Vansycle Ridge and Klondike II wind farms. With the completion of Biglow Canyon Phase I later this year, we will operate and self-integrate our first wind project. While we believe that our existing system capability is sufficient to integrate the first phase of the Biglow Canyon project, we expect costs to rise as we add increasing levels of wind to our resource portfolio. We further expect that as we add more wind to our portfolio over time, our system capability to integrate will deteriorate due to a declining hydro resource base (both in aggregate and in proportion to our expected load).

In the late fall of 2006 we selected EnerNex Corporation to perform a wind integration study. The scope of the initial study was for integration of wind resources located in the Klondike/Biglow Canyon area for an amount equal to the full Biglow Canyon build-out. A subsequent phase of the study, which was recently engaged, assesses the impact of up to an additional 500 MW of wind output in the same geographic area, but with special diversity across an expected land area that would be necessary for that amount of additional wind. In addition to assessing the costs for system integration, which commonly include direct and opportunity costs associated with incremental ancillary services requirements as well as shaping considerations and forecast error over various time horizons, our study scope also includes an assessment of the capacity value associated with wind generation. Assessing the capacity value of wind generation will allow us to make a more meaningful comparison to thermal alternatives of equal energy value.

Because hydro is currently used for system load following, the study scope further assesses impacts when moving from normal to low and high water years. Because integration costs are a function of the net impact of intermittent wind generation on more predictable but also dynamic system demand and capabilities, we have provided EnerNex with high resolution historical data on our control area demand, as well as high-resolution chronological, historical wind speed data for the Klondike/ Biglow area. We have provided additional information regarding assumed wind turbine size and density, as well as the operating characteristics of our thermal plants. We expect to receive preliminary study results to review by July 2007. Upon completion of the wind integration study, we intend to update our IRP analysis, if necessary, and also provide a supplement to our IRP.

Assumptions Used in our Analysis

As we did not have a PGE-specific wind integration study available when we performed our resource cost evaluations and portfolio analysis, we assumed a cost for wind integration in two blocks. We assume a cost of $6/MWh for the average cost of the first block, Tier I wind (which is the entire build-out of the Biglow Canyon project). We determined the $6/MWh cost by surveying other wind integration studies and other regional utility IRPs, as well as market indications for such services. For subsequent wind projects, we assume an average cost of $10/MWh (integration costs are in $2006 and increase with inflation). These assumptions are consistent with recent estimates by the NWPCC[48].

Biomass

Biomass is a renewable energy resource fueled by the combustion of organic materials. Although numerous materials can be converted to energy using various technologies, wood is the primary source for biomass fuels. Feed stocks generally include residue from forest thinning, logging residue, lumber mill byproducts (bark, mill ends, saw dust, planer shavings), and urban wood waste (tree pruning, used packing materials, and demolition, construction and urban renewal waste). The collected wood waste is converted to chips or pellets and used to fire boilers, producing steam to power electric generators. Typically, biomass facilities also sell excess, process steam to an adjacent industry host facility, e.g., saw mill. Due to the combined heat and power generation, biomass power plants are generally baseload and not dispatchable.

We estimate that approximately 40 MW of urban wood waste projects could be developed within areas that may be accessible to PGE, depending upon transmission availability, at competitive prices with the PTC and ETO

[48] Northwest Power and Conservation Council. "Biennial Monitoring Report on the 5th Power Plan." Appendix D, p. D-3. January 5, 2007. http://www.nwcouncil.org/library/2007/2007-4.pdf

subsidies[49]. However, our compact and more urban service territory and customer base limit most biomass opportunities to resources that are remote and would be dependent on obtaining firm transmission from a third-party transmission provider

Geothermal

Geothermal generation captures heat and/or steam naturally produced by sub-surface geologic or volcanic processes and directs the thermal energy through a turbine to produce electricity. The use of geothermal energy to produce electricity is over a century old. The history of commercial-scale geothermal energy in the U.S. has been sporadic as government subsidies have varied over the last three decades. Rarer dry resources (steam only) are the easiest to develop and became the first commercial-scale projects (e.g., the California Geysers in 1960). The more prevalent secondary wet sources (hot water with steam) were developed later. Dry resources have the benefit of not requiring the additional capital costs of piping and separation tanks needed to separate hot water from steam.

Geothermal resources are typically baseload and historically have had high reliability. Generation is only limited by the routine maintenance of the turbine and associated machinery, resulting in an average 85% mechanical availability factor, including planned maintenance.

Potential geothermal resources exist in Oregon's Cascade Range and its associated volcanic thermal sources. However, most of Oregon's geothermal resources are wet resources with lower heat intensity and are used in flash generation. Newberry Crater is the best known and largest potential project site in Oregon. A developer at Newberry Crater recently sold 120 MW of its project under a long-term power purchase agreement to Pacific Gas & Electric with the intention to serve California load. A total of 240 MW of expected production may still be available at Newberry Crater. Idaho Power also is evaluating a potential development site in Oregon near the Idaho-Oregon border.

Identified native Oregon geothermal resources are listed in Table 7-1.

---

[49] Based on estimate from the Biomass Task Force Report issued by the Western Governors Association Clean and Diversified Energy Initiative, January 2006. See http://www.energytrust.org/RR/bio/faq.html for more information on ETO subsidies for biomass.

Table 7-1: Potential Oregon Geothermal Resources

Top Known Oregon Locations	Expected Production	Recommended Generation Type	Development Stage
Newberry Crater	240 MW	Flash	Phase 3 (PPA executed)
Crump's Hot Springs	20 MW	Flash	Phase 1 (identified)
Mickey Hot Springs	25 MW	Flash	Unconfirmed
Neal Hot Springs	25 MW	Flash	Unconfirmed
Other Sites<=20 MW	70MW	Flash	Unconfirmed

Total expected Oregon potential geothermal generation is 380 MW (including Newberry Crater)[50]. Some of the challenges to development include permitting (as many of the best resources are on U.S. Forest Service, Bureau of Land Management or National Park lands), and the risk that test wells will not produce economic energy and may discourage development investment (the latter risk is also commonly referred to as dry-hole risk).

Commercial-scale geothermal energy may be a competitive but limited generation alternative for PGE. Current subsidies under the federal PTC and from the ETO[51] may make some projects cost-competitive, if developed and if transmission is accessible. Actual project costs can vary significantly, based on the hydrothermal reservoir quality and location relative to transmission.

7.2 Thermal Options

Combined Cycle Combustion Turbines (CCCT)

Combustion turbines (CT) have been used by PGE since the mid-1970s to provide energy to our customers. CTs can be fueled via a variety of hydrocarbon sources, including natural gas, synthetic gas (syngas), and No. 2 diesel fuel oil. They can be run in simple cycle, where the expended exhaust gas is vented, or in combined cycle, in which the waste heat in the exhaust gas is used to produce steam in a heat recovery steam generator (HRSG). The steam from the HRSG is used to drive a conventional steam turbine to generate additional electricity without burning additional fuel.

---

[50] Source: Western Governor's Association Clean and Diversified Energy Initiative. "Geothermal Task Force Report." January 2006. http://www.westgov.org/wga/initiatives/cdeac/Geothermal-full.pdf

[51] See http://www.energytrust.org/RR/os/faq.html for more information on ETO subsidies available for geothermal projects.

Improvements in CT technology, such as forced cooling of the combustion parts, have resulted in increased efficiency, producing more energy from the same amount of fuel. CCCTs can also be equipped with duct firing to provide added generation capacity (but with somewhat reduced overall efficiency).

We used estimated costs from Port Westward, our newest gas-fired plant, as the basis for the real levelized costs of CCCT generation in our portfolio analysis.

Pulverized Coal

Coal is the most widely used fuel for the production of power in the U.S. and most coal-burning power plants use pulverized coal (PC) boilers. PC units utilize a proven technology with a very high reliability level. New-generation super-critical pulverized coal (SCPC) boilers can be designed for supercritical steam pressures of 3,500 to 4,500 pounds-force per square inch gauge (psig), compared to the steam pressure of 2,400 psig for conventional subcritical boilers. The increase in pressure from subcritical to supercritical generally improves the net plant heat rate by about 200 Btu/kWh (HHV), assuming the same main and reheat steam temperatures and cycle configuration. This increase in efficiency comes at a higher initial cost, however, and the economics of the decision between subcritical and supercritical design depend on the cost of fuel, expected capacity factor of the unit, environmental factors, and the cost of capital.

The political climate in the Northwest, and Oregon in particular, is currently not favorable for new PC plants. At this time there are no new PC plants being considered or permitted for Oregon or Washington. As mentioned in Chapter 6, once the cap on mercury emissions imposed by the Oregon Utility Mercury Rule is reached, no new mercury allowances will be available for new coal fired plants in Oregon. Elsewhere in the West, Nevada Power's 2006 IRP for 2007 to 2026 contains information on their proposed coal complex at Ely, NV, which includes a 750 MW SCPC unit for Phase I[52].

In 2014, we have an option to repurchase the 15% of the Boardman plant and AC Intertie transmission rights currently held by General Electric Capital Corporation (GECC). Until then, the GECC share is sold under a power purchase arrangement with San Diego Gas & Electric (SDG&E). We also have a right to lease the GECC share in lieu of exercising purchase rights. If the purchase or lease rights are exercised, we could acquire about 88 MW of capacity from the Boardman plant along with 75 MW of transmission rights to the California-Oregon border. The purchase would be based on the market price for the asset at the time.

[52] See http://www.nevadapower.com/rates/filings/.

Advantages to acquiring this share of the Boardman plant include that it does not create incremental emissions for the region. It would also provide a stable-priced, secure source of fuel and additional baseload energy and associated capacity. Disadvantages include increased single-shaft concentration and uncertainty regarding transmission availability and emissions cost risk.

At this time, we neither recommend nor reject the option of pursuing our rights to acquire the GECC share of Boardman as part of our Energy Action Plan. Any determination with regard to this option is premature until more is known about several important considerations including, the transfer price, disposition of Boardman scrubbers for new emission compliance standards, potential state and national CO_2 and greenhouse gas policy, and availability of transmission to PGE's service territory.

Integrated Gasification Combined Cycle Coal (IGCC)

IGCC is an evolving technology for coal-fueled generation that offers the potential for significantly lower environmental emissions compared to conventional pulverized coal technology. The capabilities of IGCC to produce lower non-CO_2 emissions, separate and capture CO_2, and produce pipeline quality synthetic natural gas and hydrogen, as well as power have led it to be considered as a possible core technology for the future in the U.S. Department of Energy's Vision 21 program and the Electric Power Research Institute (EPRI) roadmap.

Coal gasification alone is a mature technology with a history that dates back to the 1800s. Currently, there are four main types of gasifiers: entrained flow, fixed bed, fluid bed, and transport bed. Gasification consists of partially oxidizing a carbon-containing feedstock (solid or liquid) at a high temperature (2,500 to 3,000° F) to produce a syngas consisting primarily of CO and hydrogen. A portion of the carbon is completely oxidized to CO_2 to generate sufficient heat required for the endothermic gasification reactions. The CO_2 proportion in the syngas ranges from one percent for the dry feed Shell gasifier to over 15% for the slurry feed ConocoPhillips and GE gasifiers. The gasifier operates in a reducing environment that converts most of the sulfur in the feed to hydrogen sulfide (H_2S). A small amount of sulfur is converted to carbonyl sulfide. Some sulfur remains in the ash, which is melted and then quenched to produce slag.

The cooled, raw syngas is cleaned by various treatments, including filtration, scrubbing with water, catalytic conversion and scrubbing with solvents. The clean syngas containing hydrogen, CO, CO_2, water, and low concentrations of H_2S and carbonyl sulfide is used to fuel a combustion turbine. The combustion turbine and steam turbine drive generators to produce energy.

In the near term, reliability is expected to be lower for an IGCC plant than for a traditional or supercritical PC plant. IGCC plants without spare gasifiers are expected to achieve long term annual availabilities in the 80 to 85% range, which is substantially the same as a traditional coal plant. However, the increased reliability of a spare gasifier also comes with increased cost. IGCC availability during initial startup and the first several years of operation is expected to be significantly lower. However, power generation availability can be increased by using natural gas as a back-up when syngas is not available from coal gasification.

As of this writing, there are three known IGCC plants being considered in the Pacific Northwest:

- Westward Energy LLC has submitted a notice of intent to submit a site certificate application for the proposed Lower Columbia Clean Energy Center Project at the Port Westward Industrial Area near Clatskanie, Oregon. The facility would have a peak generating capacity of 520 MW.

- Energy Northwest, a joint operating agency comprised of 20 public utilities, submitted an application to the Washington State Energy Facility Site Evaluation Council (EFSEC) to site the Pacific Mountain Energy Center. This project is proposed as a 600-MW electrical generation facility located on 95 acres at the Port of Kalama, about eight miles south of Longview, Washington. The Pacific Mountain Energy Center plan includes two IGCC units, each producing about 300 MW. In response to recent legislation in the state of Washington intended to curb CO_2 emissions from electric generation, Energy Northwest has announced plans to delay its application with state regulators to site and permit the Kalama IGCC project.

- Quigg Bros., Inc. proposes building an IGCC plant with sequestration at Wallula, WA (south of the Tri Cities area on the Columbia River); the proposal is in very early stage development.

Because IGCC is a new and developing technology, we felt it was important to retain a third-party expert, Black & Veatch, to compare SCPC and IGCC technologies for this IRP. Black & Veatch developed performance and cost estimates of two baseload generation technology options: an 850 net MW advanced SCPC unit and a 507 net MW IGCC unit. The cost estimates assume that the project would be co-located at our existing Boardman site. Data from the Black & Veatch report served as the basis for our IRP generic resource cost estimates for both SCPC and IGCC coal. Summaries of Black & Veatch's performance estimates and total project costs are included in *Appendix D: Black & Veatch Coal Technology Study – Executive Summary*.

Carbon Sequestration

We commissioned a study by Cornforth Consultants, Inc. to examine the feasibility of subsurface or geologic carbon sequestration for an IGCC plant at our Boardman site and at a hypothetical mine-mouth coal plant in Wyoming or Montana. Cornforth found good potential for sequestration in the deep saline aquifers located in basalt formations near Boardman. Based on the geologic criteria, a conceptual facility at Boardman might include five injection wells and 12 monitoring wells over a minimum area of about 30 square miles. While costs are highly uncertain, the study estimated that such a project would cost in the range of $35 million in $2006. Carbon sequestration in basalt is currently only a theoretical concept. A pilot test is planned for demonstration in summer 2007.

Based on the geologic criteria, a conceptual facility at a coal mine-mouth plant in Montana or Wyoming might include 90 injection wells and 20 monitoring wells in thin coal beds over a minimum area of one square mile, at an order of magnitude cost estimate about $124 million ($2006). The large cost difference in comparison to basalt is primarily due to the greater number of injection wells that would be necessary for the thin coal beds.

Sequestration requires substantial load for pumping and compression, perhaps as much as 20% of the energy output of a plant. Due to required testing and development, large-scale geological sequestration is likely well over a decade away.

For more information regarding carbon sequestration please see *Appendix E: Cornforth Geological Carbon Sequestration Study – Executive Summary*.

Carbon Solar/Biological Recycling

Emerging technology may allow photosynthesis of algae in which CO_2 from traditional fossil fuel combustion would become a biological energy feedstock. The algae would subsequently be converted to generate commercially viable byproducts such as ethanol or biodiesel, thereby dramatically increasing the energy produced per pound of CO_2. This approach may be safer than underground storage, which has unknown long-term consequences. This new technology has not been commercialized at a utility scale, and capital and operating costs are not well understood at this time. A test project is currently planned in New York.

7.3 Contracts

Contracts represent a viable source of supply for terms of three to 20 years, depending on market depth and liquidity and the availability of unsubscribed generation resources in the region. After a temporary overbuild of capacity following the 1999-2001 energy crisis, development of generation projects aside from wind has slowed dramatically across the West. Today, new generation is dominated by renewable resources, primarily wind. However, the short-term market for energy trading in the Northwest remains robust, albeit volatile.

One of the consequences of the Western energy crisis and subsequent resource overbuild is the deterioration of financial capability and, in some cases, insolvency or retrenchment within the merchant and Independent Power Producer (IPP) sector. Many of the prominent IPPs and merchants that were operating in the Pacific Northwest during our last IRP cycle have gone bankrupt or have pursued restructuring plans that caused them to exit many western markets, including the Northwest. In some cases, financial speculators such as hedge and private equity funds have taken over IPP investments. However, it is still not clear if some of the acquired development rights or projects will ultimately be completed by these entities. In other cases, banks have provided distressed or undercapitalized developers credit enhanced structures to enable these entities to make short- to mid-term sales to wholesale market purchasers and utilities.

Despite the fact that the market has evolved and participants have changed since we last issued an RFP in 2003, we believe that the market remains a viable source of supply and we expect contractual products, including PPAs and tolling arrangements, to remain available to meet a portion of our future needs. However, validating these expectations will require market discovery through bi-lateral solicitation or competitive bidding. Potential market products are further discussed below.

Power Purchase Agreements

PPAs are longer-term contracts to provide physical power. They have a variety of terms and conditions, which typically fall into a few basic categories: 1) firm or unit-contingent power delivery, 2) fixed or index price, and 3) delivery location (at PGE system, unit bus bar, or at a market hub such as Mid-Columbia). The term of these contracts can range from 5 to 20 years. They are typically take-or-pay contracts whereby the buyer must take the energy or pay the seller for any liquidated damages incurred from liquidating the energy at market.

Tolling Agreements

Tolling agreements are typically take-and-pay contracts where the buyer must pay a fixed demand payment or option premium for the right to call on the energy or dispatch a plant. When these demand rights are exercised, the buyer must make an additional payment for the fuel and/or operating expense to generate electricity. The demand payment is typically paid on a monthly basis.

Tolling agreements can have a financial fuel index or a physical delivered fuel clause. The former allows simplified accounting and administration of the contract, whereas the latter may involve acquisition, delivery logistics, and nomination of fuel to the generator associated with the contract. Additional terms in a tolling agreement may include O&M charges, start-up charges, limit on the number of start-ups per year, transmission charges, etc. Further, this type of contract can have other features mentioned for a PPA above, such as unit availability and point of delivery.

Other Market Solutions

PPAs and tolling agreements are the two primary market alternatives for supplying mid- and long-term electricity today. However, there is some opportunity for more structured contracts such as seasonal exchanges and energy or capacity swaps. The advantage of this type of contract is the ability to monetize any excess capacity or energy resulting from seasonally driven load variations and receive energy during peak periods when it is most needed.

Seasonal exchanges involve the creation of a virtual bank that allows each party to the contract to draw and return energy. In the past, such exchanges were commonly used to take advantage of seasonal, regional diversity (summer peaking in California and winter peaking in the PNW). Such seasonal differences are now less pronounced and supplies are less surplus, making seasonal exchanges less economic.

7.4 Potential Future Technology Advances

The technological advances in electricity generation in the past twenty years have been impressive and have led to the increasing market penetration of natural gas CCCT plants and wind turbines. Going forward, clean coal, solar thermal and photovoltaic, wave energy, and advanced nuclear technologies could play a significant role in meeting future energy needs. For this IRP, however, we narrowed our analysis to those supply-side technologies that are commercially available and cost competitive. These are:

- Gas plants: SCCTs and CCCTs;
- Coal plants: super critical pulverized coal boiler and IGCC coal with and without carbon sequestration;
- Utility-scale renewable resources: wind, biomass, and geothermal.

For these technologies, we projected anticipated efficiency and/ or cost advances using the following main sources: the NWPCC 5th Power Plan[53] and the 2006 EIA Annual Energy Outlook (AEO)[54], as well as the AURORAxmp® database (which is also primarily based on the 2005 AEO). Advances in technology are usually quantified by a combination of a decline in real cost per kW, due to learning effects and economies of scale, or a decline in heat rates for thermal plants (or, alternatively, increases in efficiency for renewable resources) due to actual technology improvements.

Expected Cost per kW

For new WECC resources added in our production cost and resource expansion model, AURORAxmp, we applied the construction and operating parameters and capital and operating costs shown in Table 7-2. Variable O&M includes integration costs for wind.

Both the AEO and the NWPCC publications project capital costs well below our current estimates shown in Table 7-2. We believe that these disparities are explained primarily by timing differences. Both the AEO and NWPCC based their assumptions on publications and market assessments that are now dated, and thus not appropriate for this scope. In January 2007, the NWPCC updated its estimates. Overall, they validate our current assumptions. The NWPCC is now advising a material cost increase for at least two technologies, wind and IGCC plants. The 2006 AEO projects cost declines per kW that we could not validate with any other source.

[53] See Appendix I "Bulk Electricity Generating Technologies", May 2005.

[54] See Table 48 of the Assumptions to the 2006 Annual Energy Outlook, March 2006.

Table 7-2: New WECC Resource Costs ($2006)

	Typical Size MW	Date Avail. years	Expected Availability %	Overnight Capital $/kW	Fixed O&M[1] $/kW-yr	Variable O&M[2] $/MWh	Heat Rate BTU/kWh
WECC Options for Resource Expansion							
Coal - Super Critical	850	>2012	86%	1,596	17.1	2.2	9,100
Coal - Integrated Gasification Combined Cycle	525	>2012	86%	2,337	28.9	5.2	8,600
Coal - Integrated Gasification Combined Cycle with Sequestration	525	>2012	86%	3,037	28.9	5.2	10,320
Tier I Wind	100	2008	35%	1,739	11.3	12.4	N/A
Tier II Wind	100	2008	32%	1,841	11.3	16.4	N/A
Natural Gas Combined Cycle - (G Class)	392	2008	93%	710	8.9	2.3	6,653
SCCT - LM6000	47	2008	92%	638	0.0	4.5	10,050
SCCT - 7A[3]	164	2008	92%	345	0.0	2.5	10,809
Incremental Options for PGE Portfolio Analysis							
Generic Geothermal - Flash	30	2010	92%	4,092	0.0	26.7	N/A
Biomass	16	2008	90%	2,061	71.8	6.9	12,446
SCCT - LMS100	96	2008	90%	555	2.2	7.2	9,310

Notes: [1]) Fixed fuel costs not reported in the table.
[2]) Variable O&M includes integration costs for wind.
[3]) We assume secondary market pricing for the 7FA SCCT.

Table 7-3 shows the NWPCC cost assumptions and revisions compared to PGE's assumptions. We are still overall more conservative, likely because our estimates are driven by mid-term implementation needs and are therefore more influenced by current market conditions. The NWPCC's estimates are representative of longer-term market conditions, assuming long-term demand and supply equilibrium. Also, our estimates include Climate Trust offset payments (see Chapter 7 for more information) and owner's costs[55]. Finally, cost assumptions tend to be site- and risk-specific, i.e., they depend on contingencies embedded in capital costs estimates according to perceived development and construction risks of the estimating entity. A comparison of average estimates can only be used for indicative order-of-magnitude validation.

[55] Owner's cost represents all those costs that are not typically included in the overnight capital cost estimate. These include expenses for oversight and management during construction, as well as project development costs, access road, water supply, etc. In our estimates, owner's cost does not include interest during construction and fuel supply, which are added as separate components.

Table 7-3: PGE vs. NWPCC Overnight Capital Cost Assumptions ($2006/kW)

	NWPCC		PGE
	5th Plan	January 2007 Assessment	2007 IRP
Natural Gas Plants			
CCCT-G	$586	unchanged	$710
SCCT			
- frame	$420	unchanged	$345
- LM 6000	$673	unchanged	$638
- LMS 100	N.A.	$708	$555
Coal			
Super Critical Pulverized	$1,457	unchanged	$1,596
IGCC w/o seq.	$1,617	$1,817	$2,337
IGCC with seq.	$2,079	$2,279	$3,037
Renewable Resources			
Wind	$1,160	$1,500	$1,739
Biomass	$2,292	unchanged	$2,061
Geothermal (Flash)	$2,098	unchanged	$4,092

Since supply-demand drivers for manufacturing inputs (e.g., steel, oil) and construction costs have been dynamic, we have relied on market evidence of a sustained and material ongoing increase in capital costs for most technologies. For this reason, we do not project any cost decline per kW for our primary supply-side alternatives, with two exceptions: IGCC plants and SCCTs. The IGCC technology is relatively new and, as a result, increased deployments will reduce project costs over time. Thus we assume that by 2020, the cost of a new IGCC plant will equal that of a supercritical coal plant ($1,782 per kW, down from the current $2,497 per kW, total installed cost.) Simple-cycle technology is both mature and, when fueled with natural gas, has negligible new environmental requirements going forward. Also, while for CCCTs we expect further technological improvements and more mechanical complexity (i.e., from G technology to H technology, etc.), we anticipate no major technological break-through implying higher costs for SCCTs. For these reasons we input a modest decline in real cost per kW (about 1% a year.)

Estimating the impact of learning effects on the cost of wind turbines is particularly challenging. For modeling purposes, we assume that we have already reached the peak of the learning curve and that any future cost decreases per kW due to improved technology will be offset by increasing global demand for wind turbines, along with the offsetting effect of a possible reduction of tax-driven benefits over time. For this reason, we do not model any capital cost decline for wind projects.

Heat Rate Decline

We used the AEO estimates of decreasing heat rates to measure foreseeable improvement in efficiency for thermal plants. Decreasing heat rates for the generic CCCT, super critical pulverized coal and IGCC plants mean that plant efficiencies for these technologies are improving. However, expected improvements are modest. We used relative heat rate improvements from the 2006 AEO for our analysis. Absolute values may not be relevant for plants in the Pacific Northwest because observed heat rate values in the Northwest are higher than the AEO starting values.

The AEO data gives a relative heat rate improvement for the generic CCCT plant of 419 Btu/kWh (0.9%) through 2020. This change includes both improvements in the G-class technology and migration to a future H-class technology. However, plant efficiency improvements could also be lost to additional emission control requirements.

The AEO looked at a supercritical coal plant similar to the Black & Veatch design and projected a relative heat rate improvement of 2.3% from 2005 to 2015. We based the current heat rate of 9,100 Btu/kWh on the Black & Veatch study (which assumes a commercial operation date of 2012) and applied the AEO relative improvement of 2.3% from 2012 to 2015. We then kept the resulting 2015 heat rate of 8,890 Btu/kWh constant, assuming no further improvements in efficiency, for the rest of the study. As with the CCCT, plant efficiency improvements for the SCPC plant could be lost to additional emissions control requirements.

We assumed that IGCC heat rates will stay at current levels, about 8,700 Btu/kWh until 2012, per the Black & Veatch study. We modeled efficiency improvements starting in 2013, with the next generation of plants. We assumed improved efficiency in the gasification process of 10% vs. the current level (following the advice of our consultant) and an improvement in combustion efficiency similar to that assumed for the CCCT. This results in a decrease of 933 Btu/kWh by 2020.

SCCT plants are not assumed to have heat rate improvements because of the maturity of the technology and unlikely improvement in the combustion process. Table 7-4 shows the merging of PGE's assumed heat rates with declining AEO values.

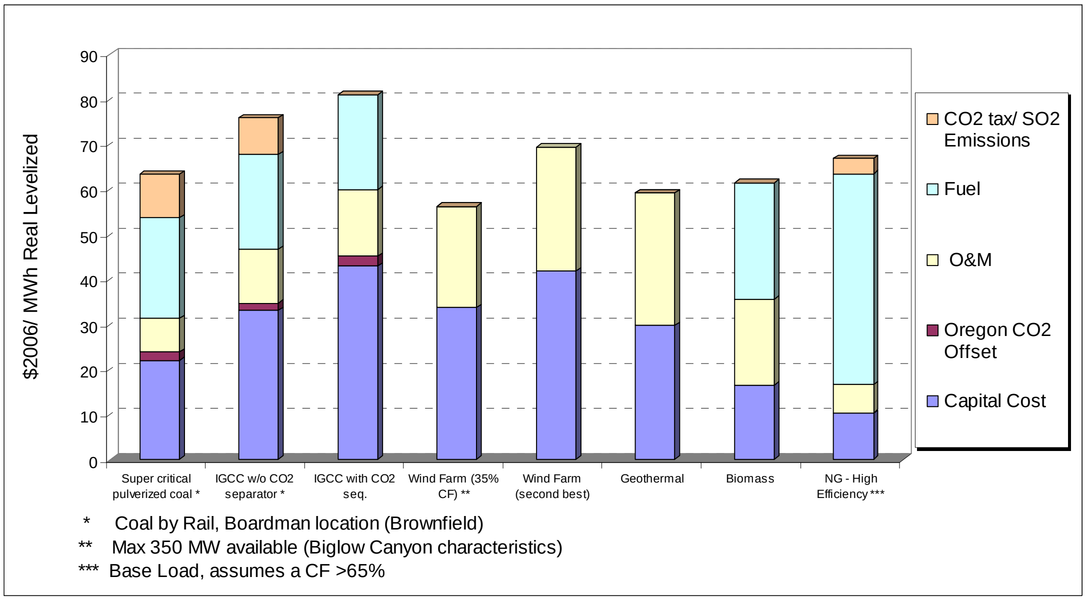
Table 7-4: Projected Heat Rates - PGE Estimate (BTU/kWh)

	CCCT	IGCC	Super Critical Coal	SCCT LM 6000	SCCT LMS100	SCCT 7A
2008	6,786	8,667	9,100	10,050	9,310	10,809
2009	6,786	8,667	9,100	10,050	9,310	10,809
2010	6,615	8,667	9,100	10,050	9,310	10,809
2011	6,615	8,667	9,100	10,050	9,310	10,809
2012	6,500	8,667	9,100	10,050	9,310	10,809
2013	6,500	8,379	9,081	10,050	9,310	10,809
2014	6,500	8,092	9,062	10,050	9,310	10,809
2015	6,441	7,804	8,890	10,050	9,310	10,809
2016	6,427	7,797	8,890	10,050	9,310	10,809
2017	6,413	7,790	8,890	10,050	9,310	10,809
2018	6,399	7,783	8,890	10,050	9,310	10,809
2019	6,385	7,776	8,890	10,050	9,310	10,809
2020	6,371	7,734	8,890	10,050	9,310	10,809
2021	6,371	7,734	8,890	10,050	9,310	10,809
2022	6,371	7,734	8,890	10,050	9,310	10,809
2023	6,371	7,734	8,890	10,050	9,310	10,809
2024	6,371	7,734	8,890	10,050	9,310	10,809
2025	6,333	7,734	8,890	10,050	9,310	10,809

7.5 New Resource Cost Summary

Fuel costs, emissions taxes, and transmission costs were added to the capital and operating costs summarized in Table 7-2 to determine real levelized, fully-allocated energy costs for PGE (based on a levelized annual revenue requirement). Capital costs include depreciation, property tax, return on undepreciated capital, income tax, and similar costs for ongoing capital additions (see Table 10-2 for a summary of our financial assumptions). To calculate a real levelized cost of energy, a traditional life-cycle revenue requirements model was used, in conjunction with our production cost model (AURORAxmp). We also applied PGE's incremental cost of capital and widely accepted assumptions about plant book life and tax depreciation in making the calculations. The reference case total levelized costs of energy for our primary supply-side resource alternatives are shown in Figure 7-1.

Figure 7-1: Real Levelized Costs for New PGE Resources



Sources and Assumptions for PGE Real Levelized Costs

Figure 7-1 does not attempt to modify the per MWh costs for differing amounts of capacity that the competing technologies bring. However, our portfolio analysis does take capacity contribution variances into account by adding capacity resources (SCCTs) to calibrate all candidate portfolios to the same overall capacity level.

We applied the following key assumptions in estimating the reference case resource costs shown in Table 7-3 and Figure 7-1:

Wind

- We included two categories of wind costs (Tier I and Tier II) to reflect the decreasing availability of optimal wind sites and anticipated increases in integration costs at higher wind penetration levels.
- Capacity factor of 35% for Tier I wind (the first 325 MW that PGE acquires) and 32% for Tier II wind (all wind analyzed beyond Tier I volume).
- Ongoing PTC renewal at current levels (approximately $20/MWh in 2008).
- Integration costs of $6/ MWh included in O&M for Tier I wind and $10/ MWh for Tier II wind.

Geothermal

- Costs are indicative of the high range of greenfield development costs from the Western Governors' Association geothermal task force report.

- Ongoing PTC renewal at current levels (approximately $20/MWh in $2008).

Biomass

- Costs are based on our assessment of potential Northwest projects; actual biomass project costs may vary significantly depending on fuel type and availability, as well as particular site and host characteristics. We assume a steep supply curve due to limited fuel supply.

- Typically a combined heat and power configuration is required to achieve favorable economics.

- PTC at current levels of $10/MWh (represents 50% of the PTC available for wind and geothermal).

High Efficiency Natural Gas

- We used capital and operating costs estimated based on Port Westward, escalated for changes in market conditions and adjusted to reflect a green-field site.

- We used a long-term real levelized fuel forecast of $6.4/ MMBtu (from the PIRA reference case, baseloaded dispatch; see Chapter 5).

- Costs include CO_2 offset payment to the Climate Trust of approximately $5 million, based on current requirements (see Chapter 6).

- A carbon tax using the NCEP/ Bingaman approach: $7.72 per short ton of CO_2 in 2010 with a 5% annual increase, rising to $16.04 per short ton by 2025 (see Chapter 6).

IGCC and SCPC

- Cost data for a new coal plant at the Boardman site comes from the Black & Veatch study commissioned by PGE (see *Appendix D: Black & Veatch Coal Technology Study – Executive Summary*).

- Owner's cost is 15% of the total capital cost of the plant, based on PGE's estimate of the Black & Veatch study.

- Cost of additional rail build-out is not included.
- For IGCC, we assumed no federal investment tax credit.
- The capital cost includes a carbon offset of $109 million for SCPC and $58 million for IGCC (paid to the Climate Trust), estimated per OEFSC rules.
- Equipping an IGCC plant for carbon capture and sequestration would add at least 30% to the cost of electricity from an IGCC plant[56]. Using our professional judgment, we also modeled a 20% efficiency loss due to increased station services for the CO_2 sequestration (the resulting heat rate of an IGCC with sequestration is 10,320 Btu/kWh.) In general, however, cost and performance assumptions on IGCC plants with or without sequestration are highly uncertain. Better estimates would require site-specific feasibility studies.
- A carbon tax uses the NCEP/ Bingaman approach: $7.72 per short ton of CO_2 in 2010 with 5% annual increase, rising to $16.04 per short ton in 2025.

7.6 Distributed Generation Options

Customer-Sited Combined Heat and Power (CHP)

CHP is a proven application that simultaneously produces electric power and useful thermal energy from a single fuel source. The resulting waste heat or steam may be used for industrial processes or heating and heat-activated cooling, such as absorption chillers. CHP systems are scalable and, under the right conditions, can be a valuable resource to utilities and their customers.

Market Potential

In Oregon, the greatest technical potential for utility-scale CHP projects exists in the industrial sector, specifically the paper and forest products industries. Targeted applications in the commercial/institutional sector, such as colleges and universities, hospitals and healthcare, also appear viable.

While the technical potential remains promising, the actual market potential is contingent on several factors. CHP economics continue to be challenging in the Pacific Northwest, with the region's moderate climate conditions and relatively

[56] Source: Big Sky Carbon Sequestration Partnership.

low overall electricity prices and spark spreads. Customer payback requirements of 2 to 5 years also present a significant challenge.

Project economics and the risk/return requirements of host candidates are perhaps the biggest obstacle to regional CHP expansion. To maximize efficiencies and economics, CHP must be used in applications where electrical consumption and onsite thermal loads are relatively consistent – this balance is difficult for customers to achieve, leading to a relatively small pool of economically viable CHP candidates.

Potential Host Customers' Current Situation

CHP can be a complex alternative to utility electrical supply. Prospective CHP host customers cite the following issues and barriers:

- Project economics (including high up-front capital requirements) and objectionably long payback periods, when considering electricity and natural gas prices, utility interconnection costs, standby charges and project financing.
- Lack of host site thermal load to maximize use of waste heat; highly coincident electric and thermal loads are needed to meet economic thresholds.
- CHP is a non-core activity for most customers, who lack trained onsite technical staff; CHP projects compete in the same budget pool as higher priority core business activities.
- Staffing for O&M.

Regulatory Environment for CHP

Regulatory agency interest in CHP has increased since our 2002 IRP. On the national level, the Energy Policy Act of 2005 established uniform technical standards for interconnection of a consumer's on-site generation (IEEE 1547). It also required that state regulatory authorities develop best practices of interconnection for distributed generation.

In Oregon, OPUC staff has identified several regulatory barriers perceived to hinder CHP development and proposes several recommendations that could serve to improve the CHP outlook:

- Explore mechanisms to remove potential utility disincentives so that utilities are encouraged to pursue competitive CHP opportunities.

- Consider approval of a utility's request for accounting treatment allowing a return on capital invested in new customer-sited generation, regardless of ownership.

- Investigate how CHP should be treated in utility planning and acquisition processes to meet combined energy, capacity, distribution and transmission system needs at the lowest cost.

- Explore issues related to CHP hosts selling power to retail customers or third parties, including access to the utility distribution system at cost-based rates.

- Implement uniform technical standards, procedures and agreements for interconnecting small generators.

The ETO approved policy changes in 2006 that could lead to financial incentives for large onsite CHP projects 500 kW and above. Prior ETO policy provides incentives for small CHP, defined as less than 500 kW based on the efficient use of waste heat. ETO's policy aim is to fund efficient CHP from existing EE programs and budgets presently funded by the electric public purpose charges. Northwest Natural's industrial customers do not pay public purpose charges, which complicates this policy, as these are the most likely CHP prospects.

Current ETO policy includes:

- Eligibility limited to PGE and PacifiCorp customers.

- Incentive to be calculated by comparing increased total system heat rate efficiency to a baseline case.

- Choice of selecting standard efficiency incentives for gas or electric waste heat recovery, or new CHP incentives, but not both and no blending.

- Fixed incentives up to $500,000 per project; negotiated incentives if over $500,000. The total CHP incentive pool capped at $4.5 million per year.

Conclusions

Many assessments have been made regarding the overall benefits and value of CHP to society. The economics work well for customers with key success characteristics such as project scale, coincidence of thermal loads to electric needs, and supportive risk and investment appetite. We will continue to work with customers who are pursuing projects to better understand the financial and technical hurdles. We also plan to continue working with the ETO to clear barriers that currently limit CHP potential for both host customers and utilities. Meanwhile, we will remain open to new CHP opportunities and evaluate CHP projects from a cost/benefit perspective on an equivalent basis to other supply-side and demand-side options

Net Metering

Net metering provides customers with an incentive to install renewable generation. Under this program, customers with renewable power sources may offset part or their entire load. Generation size is currently capped at 25 kW. New OPUC rules, expected in 2007, will likely allow commercial customers to install up to 2 MW of generation. Participating customers' energy bills are reduced by the amount of power they generate.

Although net metering is currently used by a small fraction of our customers, the new rules combined with OPUC streamlined grid interconnection rules (currently under development) are expected to increase participation, especially in the green-conscious commercial sector. The larger limit (2MW) could also impact the amount of distributed solar and wind in our service territory.

Under our net metering program, the customer handles all installation arrangements and its system must meet all applicable codes. We provide a bidirectional meter to allow measurement of energy flowing both to and from the customer's site. We also provide an inspection at the time of the net meter installation.

The program is marketed through the PGE Web site and various publications. Customers installing renewable energy systems for net metering can receive incentives from the ETO, as well as state and federal tax credits. Recently, PGE also proposed language for the draft House Bill 3488 which would authorize public utilities to use moneys obtained through cost-of-service rate to provide renewable energy generation facilities to property owners or customers.

7.7 Emerging Technologies

The supply-side resources listed above which we modeled within the IRP represent those technologies that are commercialized at an economic, utility scale, or nearing commercialization. A number of other evolving technologies may become more attractive as they mature and wholesale energy market conditions change. We believe that the emerging or evolving technologies discussed here may present significant potential sources of new supply for future resource plans.

Solar

Solar energy, including both central station and distributed solar, may be the largest potential renewable energy source worldwide. The majority of central station solar projects underway are concentrating solar power technologies (CSP). CSP plants are utility-scale generators that use mirrors or lenses to concentrate the sun's energy to drive turbines, engines, or high-efficiency photovoltaic (PV) cells. Primary CSP technologies include parabolic troughs, dish-Stirling engine systems, power towers, and concentrating PV systems. Parabolic trough plants from 30 to 80 MW in size have been in commercial operation in California since 1985. Dish-Stirling systems are currently entering commercial production. However, CSP systems currently have high up-front capital costs compared to traditional fossil-fired plants and other commercially available renewable resources such as wind.

Distributed solar includes photovoltaic and solar water heating systems on residential, business, and government buildings. Market penetration of solar water heating has slowed to a trickle since its heyday two decades ago, but photovoltaics have been gaining momentum. A potential breakthrough for solar could come through efforts to develop integrated solar PV roofing tiles. We expect the deployment of photovoltaics to grow dramatically. Current installed capacity is under a megawatt in PGE's service territory. This could increase by an order of magnitude over the next five years.

We estimate the potential for up to 120 MW from distributed solar generation exists in Oregon[57]. PGE's net metering program will help foster the growth of photovoltaic systems. The OPUC is currently expanding net metering to include commercial customers up to 2 MW per site. The current federal and state tax credits and subsidies are supportive of the development of distributed solar projects and significantly improve their net economics. Incentive and rebate programs will continue to play an important role in the future adoption of distributed solar.

The market development of photovoltaic systems in PGE's service territory may be accelerated by manufacturing interests. SolarWorld and Solaicx could represent the anchors of an economic cluster whose presence would further stimulate the market through material contributions and preferred pricing (e.g., SolarWorld's commitment to donate $1 million in equipment to the school children of Oregon and offer the lowest distributor pricing to State of Oregon projects).

[57] Source: Western Governors Association Clean and Diversified Energy Initiative. "Solar Task Force Report." January 2006. http://www.westgov.org/wga/initiatives/cdeac/Solar-full.pdf

We are currently in discussions with several large customers interested in projects approaching one MW in size. In addition, our DSG program may enhance potential for distributed solar systems. DSG participants could potentially provide lower cost solar sites because most of the required facilities for utility interconnection, metering, communications and control are already in place. We are currently analyzing the impacts and costs of these potential supply options and expect to have more information in the near future.

Benefits of solar power include no fuel cost, pollution or CO_2 emissions and coincidental summer peak period production benefits. Some CSP technologies (tower and trough) can be dispatchable by using thermal storage to deliver firm power during peak demand periods. Distributed solar may also provide relief of transmission and distribution congestion, if located in areas of high localized demand.

The chief disadvantage of solar systems is availability. In Oregon, the length of the day varies considerably from summer to winter, with winter peak load periods receiving the least amount of insolation. Due to reduced cloud cover, projects east of the Cascades (with transmission to our load) are a more economic alternative for central station solar projects. Locations such as Arizona and Southern California, where insolation is higher, summer demand is greater, and load is more costly to serve are leading the way in the development of next generation solar technologies.

PGE will continue to monitor developments in both central station and distributed solar power. This IRP action plan calls for achieving the 2015 targets from the Oregon Renewable Portfolio Standard. While initial RPS targets are expected to be achieved primarily from wind, we remain interested in evaluating opportunities with solar and other renewable resource technologies which can bring diversity within our renewable resource portfolio.

Wave Energy

It is estimated that only 0.2% of the ocean's wave and tidal energy could provide sufficient electric power for the entire world. EPRI, in partnership with Oregon State University (OSU), concluded a study in 2005 assessing the wave energy potential off the U.S. coastline. The Pacific Ocean has the most potential, with higher energy levels in the north. The Oregon coastline in particular has vast potential. OSU estimates that the wave energy harvested from about 10 square miles of ocean off the Oregon coast could produce enough electricity to power the entire state. Should planned demonstration projects and R&D efforts move forward in Oregon, it is possible that early commercial development could occur here as well.

Wave energy technology is at an early stage of development, similar to where the wind power industry was 15 to 20 years ago. Early designs and demonstration projects fall into three broad categories: floating devices, oscillating water columns and wave surge devices. Most current floating (or pitching) designs use hydraulic or pneumatic mechanisms to convert wave action into electrical power. OSU has demonstrated direct conversion using a linear generator.

Wave energy has distinct advantages over intermittent renewable resources such as wind or solar. These advantages include significantly higher energy density (resulting in lower materials requirements per kWh) and greater predictability. Wave energy also provides significantly higher capacity value than wind energy and is more consistent with PGE's load profile. Transmission access is also good due to the location of the wave potential off the coast, west of most current generation resources and our service territory.

While there are no U.S. Government R&D programs yet, OSU has applied to the U.S. Department of Energy to become the nation's research center for wave energy. In addition, OSU, ODOE, and a number of stakeholders have formed POWER, a group facilitating information exchange on siting a wave energy demonstration plant and R&D facility in Oregon by 2008.

On the local development front, Ocean Power Technologies, Inc (OPT) and Pacific Northwest Generating Cooperative have signed an agreement to work cooperatively on the development of the Reedsport OPT Wave Park in Douglas County, Oregon. OPT expects to install buoys initially generating a total of 2 MW approximately 2.5 miles off the coast at a depth of 50 meters. OPT has been issued a preliminary permit by the FERC for up to 50 MW of capacity at the site. Several other projects along the West Coast have also filed permit applications with FERC.

Utilities along the West Coast are uniquely positioned to take advantage of this resource when it matures sufficiently for economic utility-scale development. We are genuinely excited about the future potential for wave energy; however, it is not an alternative we considered in our portfolio analysis since economic, utility-scale commercialization will likely occur after the target resource acquisition timeframe for this IRP. In our efforts to remain proactive with respect to enabling the development of new, indigenous renewable energy sources, we contributed to the EPRI Study and provided additional direct funding toward OSU's research and development efforts. We will continue to monitor and support the development of wave energy in Oregon.

Next Generation Nuclear

Existing U.S. nuclear power plants were largely custom-built - a one-at-a-time process that caused delays in approval and construction along with large cost overruns. Today, with several standard designs already approved by the Nuclear Regulatory Commission (NRC), builders of nuclear power plants assert that they are much better able to manage costs and maintain quality control for new projects.

New designs include passive safety features such as gravity-fed water supplies to cool a reactor core if it overheats. The design simplifications result in a reduction in the number of components and have reduced both risk and cost. Large, standardized components are expected to be built off-site and then delivered and assembled at the plant. The Westinghouse active passive (AP) 600 and AP 1000 configurations are NRC-approved standard designs.

In addition, federal policy and national concern over energy security are contributing to new nuclear project development. The Energy Policy Act of 2005 outlined the following federal assistance for the nuclear industry:

- Over $3 billion in construction subsidies for new nuclear power plants
- Nearly $6 billion in operating tax credits
- More than $1 billion in subsidies to decommission old plants
- A 20-year extension of liability caps for accidents at nuclear plants
- Federal loan guarantees for the construction of new power plants
- $3 billion in research subsidies

Barriers to the construction of next generation nuclear plants include concerns from the financial industry about cost estimates and overruns. In addition, a permanent nuclear spent fuel repository site has not been approved. With respect to potential timing of new nuclear development in the U.S., we believe that the new designs discussed above will not be commercially available by 2012.

Some environmental organizations and utilities are now calling for new nuclear supply to reduce dependence on polluting fossil fuels and reliance on non-domestic energy sources. While near-term project development in the Pacific Northwest appears unlikely, some proposals have been discussed, including a new nuclear plant proposed at the site of the Idaho National Laboratory. Idaho Power also proposed a nuclear plant in the early 2020s in its latest IRP. We will continue to monitor developments in next generation nuclear for future resource plans.

Canadian Tar Sands

Extraction of oil products from Canadian tar sands requires a significant amount of heat, which could potentially be supplied by cogeneration plants with existing CT technology. Such plants could have an overall efficiency of up to 80%, thereby producing a sufficiently high kWh output per pound of CO_2 to meet even the strict California carbon emissions standard. Prices for such projects may prove to be competitive with conventional natural gas.

Although project sponsors are already approaching potential participants, the largest impediment for PGE and other regional entities to pursuing cogeneration from the Canadian tar sands is transmission. Currently, Alberta's transmission grid only has limited export capability which is already exhausted and insufficient to move significant amounts of new power to the Northwest and beyond. Accordingly significant new transmission infrastructure would need to be financed and built to realize the benefits of Alberta tar sands cogeneration opportunities. Potential investors are currently investigating the technical and financial feasibility of such a venture including a possible 1,100 mile transmission line from Alberta to the head of the Pacific Northwest AC Intertie.

We will continue to monitor these activities for potential opportunities to pursue competitive energy from Alberta.

Recent Developments with IGCC

Due to transmission constraints, we limited our IGCC considerations to announced, local proposals. These proposals require fuel transportation to the plant. More recently, the potential for mine-mouth gasification has come to our attention. In addition to the advantage of not transporting coal via rail or barge, the CO_2 emissions can be piped a comparatively short distance for enhanced oil recovery in existing fields. The operators of these fields purchase the CO_2, creating a revenue stream. The syngas could potentially be enhanced to pipeline quality synthetic natural gas and sold rather than converting it onsite to electricity. In addition, gasifier technology is evolving to better handle Western coals. Gasification processes would use a greater number of smaller gasifiers (e.g., six gasifiers plus a spare rather than one plus a spare), thus significantly improving the capacity factor.

Such an approach could, in concept, provide PGE and other utilities with a secure, stable-priced, long-term supply of syngas from domestic coal for use in local CCCTs. Economics could improve over the IGCC configuration that we considered due to the combination of elimination of coal transportation, realization of revenue from CO_2 sales, use of existing gas pipeline capacity (rather than new transmission investment), and a significantly improved gasification capacity factor.

While this approach holds much promise, it is still in the development stage. We have not modeled this gasification approach within our IRP. However, we would welcome creative bids within the proposed RFP for baseload energy (see Chapter 13) that have reduced emissions footprints but continue to use an abundant domestic fuel.

Hybrid Technologies

Hybrid technologies such as compressed air energy storage (CAES) may offer potential to address the intermittent nature of wind. CAES stores compressed air underground. The compressed air is used in the combustion stage of an ordinary CCCT, where compression of air requires almost two-thirds of the energy from the combustion. The effect is to dramatically increase the efficiency of the CCCT by using less gas to produce more electricity. Such a facility has high capital costs and efficiency losses in pumping and compression. It also requires a site that has a gas pipeline, transmission, wind, water, and suitable underground storage.

A similar hybrid technology involves using wind energy to create and store hydrogen, which is then burned in a CT. This could potentially convert intermittent wind into a dispatchable resource, but current estimates project high capital costs and reduced efficiency.

PGE Research Projects

We have provided support to or participation in the following research and demonstration projects:

Capstone Microturbines at Columbia Boulevard Wastewater Treatment

Located in Portland and built in 1952, the Columbia Boulevard Wastewater Treatment Plant is the largest in the state. In 2003, four 30 kW Capstone generators were installed by City of Portland Environmental Services as an additional internal power supply with no export capability. The City helps reduce the cost of the facility by selling fertilizer produced from digesters to local farms and pastures around the state. Digester gas is used to fire the turbines. Reusing the heat from the exhaust of the microturbines helps regulate the temperature of the digester. We provided remote monitoring of the Capstone units to explore the performance of the microturbines over time. Further research was planned to explore the potential of synchronizing the microturbines with an existing fuel cell that was in operation at the facility at that time (2003). Unfortunately, problems with the fuel cell and its eventual decommissioning caused this part of the project to be canceled.

Kettle Foods Solar Array

In late 2003, Advanced Energy Systems completed the installation of a 114 kW solar array at Kettle Foods in Salem, Oregon, for the potato chip plant. PGE provided remote monitoring for this project in order to explore Ethernet radio as a potential lower cost means to collect data and to evaluate the potential of utilizing this form of distributed resource.

Calgon Biogas Facility

In December of 2001, construction was completed and digester gas production was initiated at the biogas pilot project at Calgon Farms, a dairy in Salem, Oregon. In March of 2002, export power was sent to the grid and delivered to PGE customers.

Dairy waste at the project is run through a digester, after which the remaining solids are separated from a relatively clear effluent and sold as a soil amendment. Much of the phosphorous and potassium that would otherwise overload the soil where the waste would be spread is shipped off-site with the solids. The nitrogen that remains in the effluent is ammoniated for better plant uptake and reduced run-off when used on crops as fertilizer/irrigation. The project thus allows the dairy to potentially have more efficient land utilization.

We provided most of the biogas development equipment, gas reciprocating engine and remote monitoring for the project. We have been collecting information and assessing techniques on this form of small scale energy production. The purpose of the research was to determine the economic viability of this type of resource for PGE and dairy farmers.

8. Customer Research and Preferences

We believe that the views and preferences of our customers should be considered in determining future resource choices to serve their needs. To assess customer views and preferences with respect to energy supply, we engaged independent market research firms to conduct qualitative and quantitative evaluations of the perceptions and receptivity of our customers to a variety of potential energy resources.

The research was conducted through a combination of techniques including focus groups, Internet- and telephone-based surveys, and interviews with representatives of our large customer accounts. The research indicates that all customer groups prefer energy supply sources that are sustainable and have a low impact to the environment, including renewable resources and EE, even at a somewhat higher cost. At the same time, most customers displayed negative views of certain thermal resources, such as traditional coal and nuclear generation. Finally, customers generally prefer a portfolio approach that provides diversity of resource types. In this chapter, we further describe our approach to assessing customer resource preferences as well as the results of this research.

Chapter Highlights

- Most customers are not very aware of PGE's current generation mix and tend to overestimate the amount of hydro generation in our existing portfolio.
- Most business and residential focus group participants preferred a diverse mix of generation to meet PGE's future resource gap by 2012.
- Wind and energy efficiency were the most preferred resources for all customer classes, while coal and nuclear were the least preferred.
- Business focus group participants were willing to pay more for a specific resource or mix of resources if it would help assure long term price predictability, whereas residential customers were more resistant to cost increases.
- In general, surveyed customers suggested that renewable resources and conservation should supply 50-65% of our incremental energy needs.

8.1 Qualitative Customer Outreach Study

We engaged the market research firm KEMA to conduct four focus groups (two with residential customers, and two with business customers) in August 2005, as well as in-depth interviews with ten of our key customers (large business customers with assigned key customer managers). These focus groups and interviews were conducted in the fall of 2005 to identify customer perspectives with respect to a wide range of future resource options.

Focus Group and In-depth Interview Objectives

The objective of the focus groups and in-depth interviews with key customers was to assess perceptions and receptivity of our customers to a variety of energy resources, including:

- Assessing customer understanding and perceptions of PGE's actual current resource mix;
- Understanding customer perceptions and views with respect to electricity supply alternatives;
- Identifying factors that would make a variety of energy supply options more vs. less preferable;
- Evaluating customer understanding of utility reliance on traded wholesale electric markets to meet electricity needs;
- Understanding participant concerns about environmental issues and global climate change;
- Exploring perspectives about the economic and national security implications of various energy supply options;
- Identifying customer preferences for price predictability; and
- Assessing the strength and elasticity (i.e., willingness to pay more for preferred resource options) of customer resource preferences.

Study Methodology

Each focus group had either ten or eleven participants in attendance. Participants for each group were randomly recruited from our customer database. Customer participants encompassed a broad demographic range and included a variety of employment titles, as well as diverse economic and educational backgrounds. The focus groups reflected an equal gender distribution. Most participants were older than 45, with a mix of participants who had been PGE customers for periods of more than 10 years, 5 to 10 years, and less than 5 years.

For the key account interviews, KEMA randomly drew a sub-sample of 53 customers from an initial pool of 163 large business customer accounts provided by PGE. KEMA developed an interview guide with supporting documents, which served as the basis for discussion with key customers.

The ten completed interviews averaged 40 minutes in length. All ten of the PGE customers interviewed requested that their responses be kept anonymous. Results were aggregated to ensure that we are responsive to our customers' requests. Eight of 28 market segments were represented among the ten completed in-depth interviews[58].

Key Findings

Generation Sources

A majority of both residential and business participants were able to identify at the beginning of each focus group most of the fuel categories (hydroelectricity, coal, natural gas, wind) that comprise PGE's electricity supply. However, when presented with our 2004 resource mix, many participants across all four focus groups were surprised that hydroelectricity was not a larger percentage of PGE's generation mix[59]. Several business and residential participants said they were surprised that PGE's contract purchases (19%[60] in 2004) were such a high proportion of the supply portfolio. Several residential focus group participants also noted that the percentage of coal (26%[61] in 2004) was significantly higher than they thought.

Desired Resource Attributes

Supply reliability and price predictability were most critical to both business focus group and key customer interview participants. Five of ten key customers cited the long-term sustainability of resources as one of the top factors PGE should consider in making future resource decisions. The majority of all

[58] The market segments represented among the key customer accounts interviewed included: Assembly/Fabrication, High Tech (2), Major Account, Miscellaneous Commercial (2), Warehouse, School, Utility, and Residential Housing.

[59] Participants expected hydro to be as much as 50% - 80% of PGE's generation resource mix.

[60] Percentage does not include contract hydro or contract coal.

[61] Includes both PGE-owned and contract coal.

residential and business focus group participants indicated that PGE should fill future resource gaps with sustainable generation sources located within the U.S. Many thought we should not include new resources in the supply portfolio that have a risk of being depleted in the next 20 to 30 years.

Cost and Willingness to Pay

Business focus group participants expressed a strong preference for cost predictability and indicated that they would be willing to pay more for a particular resource or mix of resources if they could be assured long-term price predictability. Residential focus group participants were more resistant to price increases, even if those increases were for resources they later said they preferred (such as wind). Key customers had mixed responses about the relative importance of price predictability and higher costs.

Energy Supply Option Preferences and Trade-offs

A diverse supply mix was important to all focus group participants. Most business and residential focus group participants preferred a diverse mix of generation to meet PGE's 2012 resource gap. Six of ten key customer respondents indicated that the fuel sources of their power generation did not matter to their company. Price predictability and reliability were the most critical attributes of generation sources. However, when given a choice among resource options, these customers also preferred greener alternatives, as described below.

As seen in Table 8-1, wind and energy efficiency ranked highest among preferred supply-side resource alternatives for all customer classes. Energy efficiency was preferred because of its perceived low costs and the view that it is a resource that customers can personally affect and control. Conventional coal and nuclear energy were the least preferred energy resource options among all customer classes. Most focus group participants expressed concern regarding safety precautions for nuclear generation or waste storage. Six of ten key customer respondents ranked conventional coal as their lowest preference, citing emissions and pollution from the generation process.

For more information on the KEMA study, see *Appendix F: KEMA Customer Research – Executive Summary*.

Table 8-1: Summary of PGE Customer Feedback

PGE Customer Class/Format	Feedback Consensus by PGE Customer Type						
	Key Generation Attributes	Should PGE own more generation or contract?	Should generation be located in or out of Oregon?	Willing to Pay More under some circumstances ?	Energy Supply Option Preferences and Trade-offs		
					Most-preferred Supply Options	Least-preferred Supply Options	Key Considerations
Residential Focus Group Participants (n=20)	Long-term sustainability , minimum price increases	PGE-Own	In Oregon (out of state if it has waste or risk associated)	No	Energy Efficiency/Load Management; Wind	Nuclear; Conventional Coal	Initial cost to develop is high (might translate to rates); long-term sustainability, environmental impacts
Business Focus Group Participants (n=21)	Reliability, price predictability	PGE-Own	No strong preference	Yes (for price predictability)	Energy Efficiency/Load Management; Wind	Conventional Coal; Nuclear	Long term price predictability; long-term sustainability; environmental impacts
Key Account (Business) Respondents (n=10)	Reliability, price predictability	Divided responses	No strong preference	Mixed responses	Wind; Energy Efficiency/Load Management	Conventional Coal; Nuclear	Long term price predictability; reliability; environmental impacts

8.2 Quantitative Customer Outreach Study

In order to further understand customer views regarding future portfolio choices, we engaged Momentum Market Intelligence to research and quantify customer preferences for different resource options being considered in this IRP. One challenge that we identified prior to launching the study is that customers tend to overstate their preferences for some resources (based on current societal trends and their overall world view), and typically are not familiar with utility resource planning processes. Operating under this challenge, Momentum endeavored to answer the following basic questions: Do customers care about utility energy supply choices? If so, how much more do they prefer some choices over others?

Study Methodology

Momentum designed an online survey to query customers about resource preferences. Sample sizes were 507 residential customers, 200 general business customers, and 34 key customers. Residential and small business customers were screened by telephone and, if they qualified, were invited to participate in an online survey. Large business customers qualified themselves online in response to an e-mail invitation. Research was conducted in December 2005 and January 2006.

The survey was designed around the following primary questions:

- What do customers see as the current situation, in terms of current energy resources and environmental concerns?
- What is their initial reaction to alternative sources of electricity production?
- What do customers believe is the right path for PGE to take in constructing an electricity resource mix for the future?
- What should we take away from these perceptions?

Key Findings

Customer Knowledge of Energy Resources

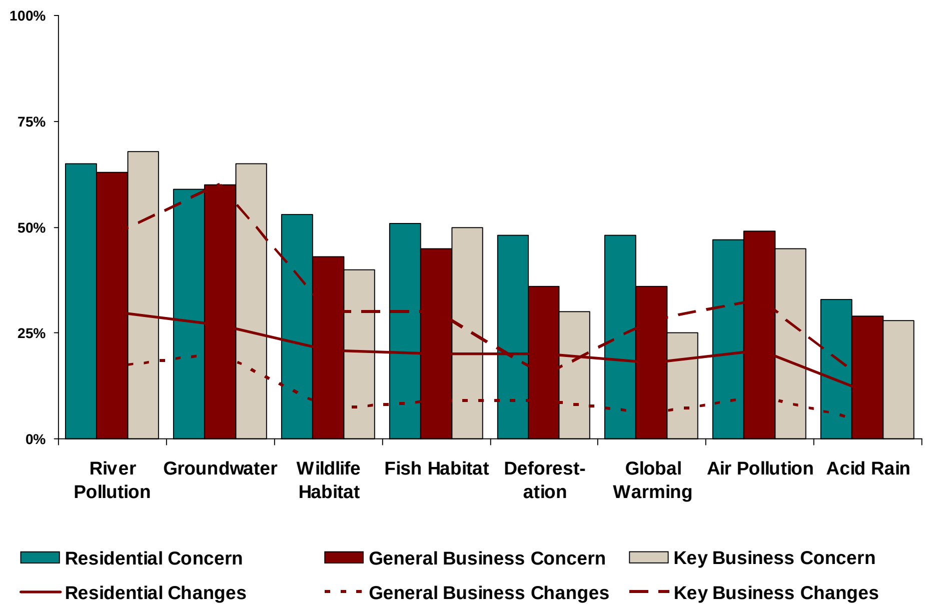
Overall, PGE customers did not demonstrate a high degree of knowledge about energy resources. All customer classes were most familiar with energy efficiency and least familiar with next-generation nuclear and next-generation coal (IGCC) plants. Key business customers were more familiar than either residential or general business customers with all resource categories except nuclear, where familiarity was equally low across all customer groups.

Customer uncertainty about energy resources was reflected in their assumptions about current power supply. Over 75% of all customer groups reported that hydro, followed by natural gas, renewable resources, and conventional coal, has the greatest or second greatest role in current PGE power supply. In reality, natural gas (20% of energy based on economic dispatch), owned and contract hydro (23%) and conventional coal (23%) will supply relatively balanced proportions of our projected 2008 resource mix. Renewable resources account for a much smaller proportion of PGE's projected 2008 resource mix at 4% when calculated on an energy basis (see Chapter 2).

Environmental Concerns

Customers displayed the greatest levels of concern for those environmental issues that have local impacts (river pollution, groundwater quality, and wildlife habitat). However, changes in behavior lagged concern for environmental issues – especially for general business & residential customers. In other words, many customers are concerned with environmental issues, but are not yet taking actions themselves based on these concerns - see Figure 8-1.

Figure 8-1: Customer Environmental Concerns and Changes in Behavior



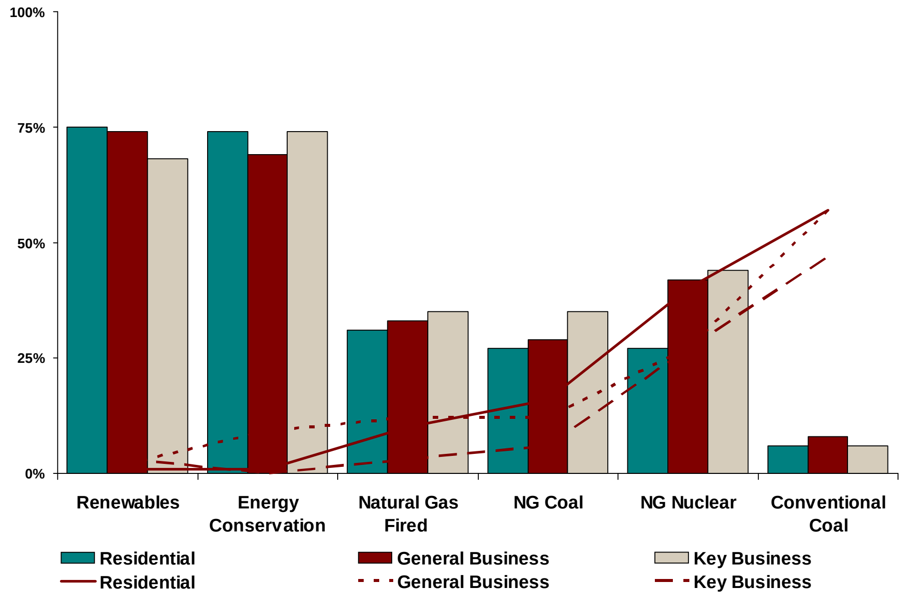
Customer Views on Future Supply Portfolios

Identifying the strength of positive or negative resource perceptions further helps us understand customer preferences for future supply choices. All customers expressed strong preferences for the inclusion of renewable resources and EE in future supply portfolios, regardless of cost. In addition, less preferred resources were not just "less preferred," but actively disliked. For example, more residential customers actively dislike nuclear than prefer it. All customer groups actively dislike conventional coal more than they prefer it. See Figure 8-2.

Approximately 60% of customers said that it is appropriate for all customers to pay more for renewable resources. However, key business customers who exhibited overall support for paying more for renewables displayed a higher degree of price elasticity; that is to say they exhibited less support at higher price increase levels (above 15%) than did residential or general business customers.

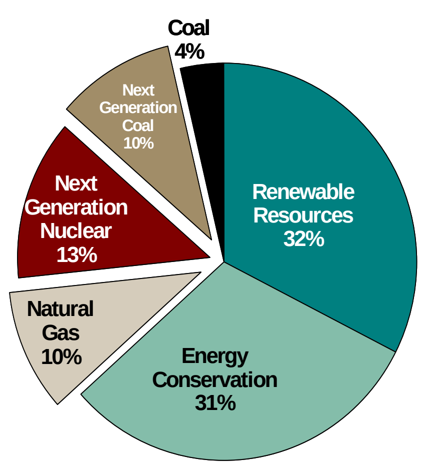
Momentum then asked customers to construct their preferred incremental resource portfolio for PGE. Respondents were provided a description of each resource's relative cost, price stability, environmental impact, and reliability. Then they were asked to design a series of energy resource plans indicating their preferred mix of resources. Respondents were shown dollar impacts on all customers' bills of the choices they made, i.e., cost increases/ decreases resulting from the respondents' choices affected all PGE customers.

Figure 8-2: Customer Resource Preferences



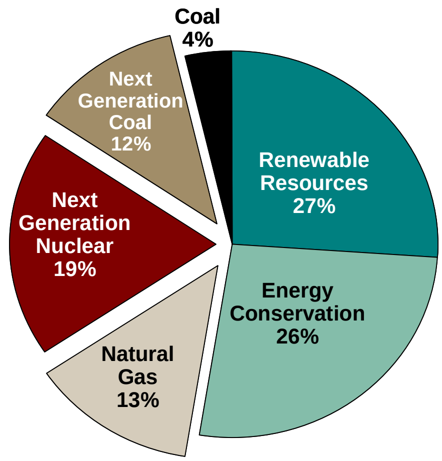
Given equal prices and availability, residential customers preferred a resource mix heavily weighted to renewable resources and energy efficiency (see Figure 8-3), though not to the complete exclusion of fossil fuel generation.

Figure 8-3: Residential Customers Average Desired Portfolio Mix



Business customers in the aggregate preferred a more diverse mix of green energy options and fossil fuel generation sources – again, given equal prices and availability (see Figure 8-4).

Figure 8-4: Business Customers Average Desired Portfolio Mix



The study then tested customer portfolio mix preferences across a variety of resource cost ranges (i.e., increasing and decreasing costs for each resource alternative). Neither residential nor business customers' resource mix preferences changed substantially across the cost ranges tested.

Key Conclusions from Momentum Research

- Most customers are not very aware of PGE's current generation mix.
- Support for renewables is strong, and remains strong even if all customers are required to pay somewhat more (up to 5%). Wind is viewed as a key option and is frequently considered as a category of its own.
- Support for renewables is less strong among key customers, but there is still significant support at up to 5% cost increases.
- Customers exhibited a generally negative preference for nuclear and an even stronger dislike for conventional coal.
- In general, surveyed customers suggested that renewables and conservation should supply 50-65% of new energy needs. Natural gas, gasified coal, and next-generation nuclear are essentially tied as the next preferred options. However, most customers also believe that a diverse resource supply is desirable. These positive preferences are relatively resistant to cost differences. Negative preferences (particularly for conventional coal) were also resistant to cost differences.

In general, the findings from the qualitative focus groups and the broader sampling of the quantitative customer study yielded remarkably similar results in overall customer views about resource choices and preferences exhibited for renewable resources and energy efficiency. These results are supported by the high response by our customers to our green retail product offerings. PGE ranks second in the nation for renewable energy sales to retail customers, and has the third largest customer participation rate per capita in voluntary renewable energy purchases[62].

[62] See http://www.eere.energy.gov/greenpower/resources/tables/topten.shtml.

9. Transmission

The Energy Policy Act of 1992 launched the electric utility industry down a long path of restructuring that created uncertainty in an industry that was formerly highly structured and locally regulated. The transition to federal oversight of transmission access and rate authority created new risks for traditional transmission investors. Due to the significant costs required for new transmission investment and the regulatory uncertainties associated with recovery of those costs, there has been a significant reduction in investments made in the bulk power transmission system over the past 20 years. At the same time, loads have continued to grow and generation supplies have generally increased to serve the loads. Here in the Pacific Northwest, a number of transmission constraints have emerged that have made delivery of new remote power resources challenging[63].

In this chapter we examine the transmission constraints that make access to new resources challenging for PGE. We also present studies that our power supply staff conducted to evaluate potential transmission solutions and related cost impacts for meeting future resource needs.

Chapter Highlights

- Transmission constraints in the Pacific Northwest present challenges to the delivery of new geographically remote power supply resources.
- PGE currently has sufficient transmission via its BPA transmission agreements to meet current customer demand up to 1-in-2 peak levels through 2012.
- For IRP modeling purposes, we use the standard BPA transmission tariff rates (escalated for inflation) to estimate the cost of delivering power to PGE's system for all remote resources.
- Going forward, we are concerned about the availability of transmission to meet our growing energy needs.
- During the summer of 2005, PGE investigated some possible options for increasing capacity across the South of Allston cutplane.
- During the summer of 2006, we conducted a subsequent study to determine the technical feasibility of an expansion of PGE's transmission system all the way to BPA's McNary Substation to access new potential resources east of the Cascades.

[63] PGE also identified the critical nature of transmission in its 2002 Integrated Resource Plan.

9.1 Current State of the Transmission System

In today's regulatory environment, developers of most new generation resources opt to participate in special remedial action schemes[64] to assure firm transmission rather than participating in large new transmission projects that risk being under funded and not built. For example, BPA cancelled the proposed McNary – John Day 500kV line project in 2004 when it was unable to reach adequate funding participation. As a result of the lack of new transmission facilities, combined with increasing generation and load, the Pacific Northwest region is fast approaching transmission capacity limits in many areas. To address these constraints, it will not be sufficient for PGE or the region, to develop solutions for just one or two constraints. Many parts of the transmission network can be impacted by any given event or new resource and thus substantial investments in many locations may be required to relieve constraints and assure delivery of future resources to our customers.

In April 2006, the BPA published a white paper, "Challenge for the Northwest – Protecting and managing an increasingly congested transmission system." This document[65] describes the complex challenges that BPA faces in maintaining system reliability. In short, persistent congestion manifests itself in three ways: 1) reliability is put at risk, 2) lack of compliance with applicable tariffs and reliability standards, and 3) reduced economic efficiency.

Given the compact and urban nature of our service territory combined with the geographically remote location of most regional generation sources, we depend on BPA to deliver approximately three-quarters of our existing power supply. Our current coal and contractual hydro resources, as well as new and potential future renewable resources (wind, biomass, geothermal, etc.), are all located well outside of PGE's service territory.

For PGE, the Pacific Northwest transmission system is a vital component for meeting our customers' future power requirements. The availability of firm transmission is a critical consideration when evaluating and selecting new resource options to meet future load. For several years, we have been unable to obtain new transmission service on BPA's system. The cost and uncertainty associated with obtaining new firm transmission from BPA was an important factor in our decision to proceed with the construction of the Port Westward plant, which is located close to our load center and within our control area. More recently, we have re-directed a portion of our existing BPA transmission rights to

---

[64] Remedial action schemes are pre-planned actions which automatically respond to certain system problems as they develop.

[65] Available at www.bpa.gov/corporate/pubs/Congestion_White_Paper_April06.pdf

enable us to deliver energy from the Biglow Canyon Wind Project to our customers. However, over the longer term, we will likely require new transmission to our service territory to allow us to access future remote resource options.

The Pacific Northwest transmission system is depicted in Figure 9-1. The green lines show Inter-regional Interties. Power transfers on these paths are commercially traded and these systems were designed and built for a given transfer capability. The red lines show the major internal cutplanes (system constraints) that BPA manages daily. The heart of the system, the circular network encompassing Seattle and Portland, is where the cutplanes are mainly located.

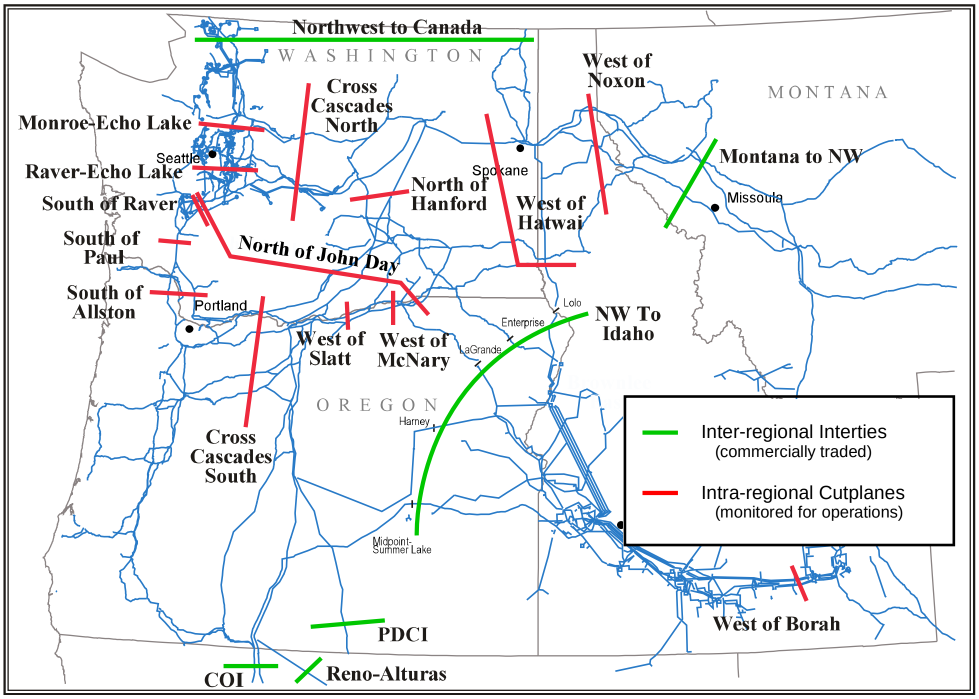
The capacity of the Montana and Idaho Interties has remained unchanged for about 25 years. Approximately 15 years ago, the capacities of the AC and DC Interties to California and the Canadian Intertie were increased by approximately 50 percent. This increased north-south transfer has put additional stress on the system, mainly in the summer as Northwest hydro generation flows south to serve California demand. At the same time, increasing loads and new generation sources along the I-5 corridor between Seattle and Portland have also placed more stress on the system. Very little new transmission has been built, particularly along the I-5 corridor, to support the increased demand. As a result, BPA has relied extensively on remedial action schemes and reactive compensation to maximize existing transmission capacity. The overall impact is that a very complex constraint management system is required to ensure reliability. In addition, because an outage on any one part of the system may affect deliveries over other parts of the system, an outage can cause unexpected market impacts.

As seen in Figure 9-1, the transmission system is divided into four sections, or quadrants. The North of John Day cutplane splits the system in half and is the main indicator for managing the Southern Interties to California. The Cross-Cascades cutplanes, both North and South, also cut the system in half, and are the main indicators that define the ability to serve west-side load centers from east-side resources. The stress on the system is primarily north-to-south in the summer and east-to-west in the winter.

The cutplanes in the I-5 corridor and the east-side Slatt and McNary cutplanes are significantly affected by inter-regional north-to-south summer transfers. In the last two years, BPA has completed two transmission additions that have diminished or temporarily mitigated limitations on the West of Hatwai (east-to-west from Montana) and the North of Hanford cutplanes.

This characterization of the regional transmission system is the basis for the transmission model that we used in the AURORAxmp program and is further discussed in Chapter 10.

Figure 9-1: Pacific Northwest Transmission System

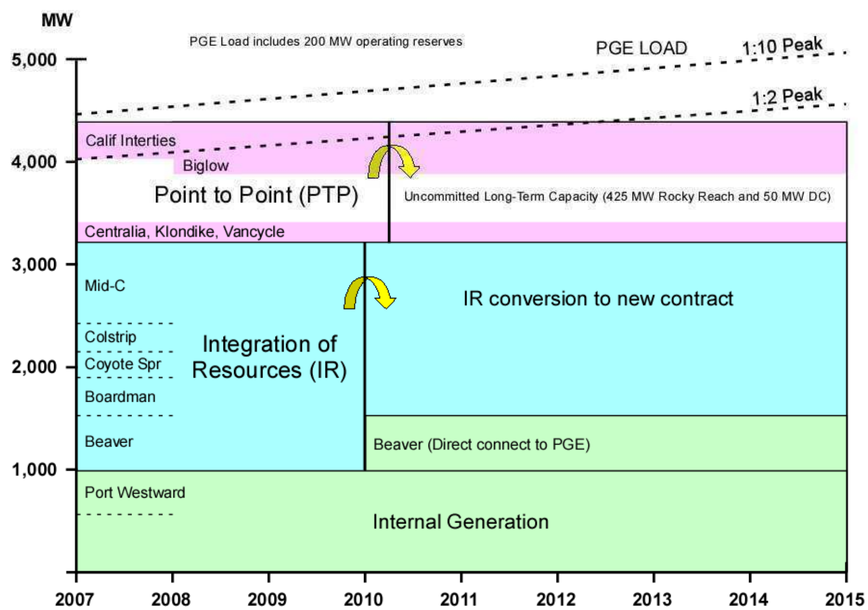


9.2 PGE's Transmission Balance

The majority of our current power supply portfolio (and likely sources of future new supply) is outside of our service territory. It includes hydro sources in the Mid-Columbia area, thermal and renewable generation sources east of the Cascades (as far away as eastern Montana), and thermal generation sources between Portland and the Puget Sound area. Additionally, we have long-term contracts that are delivered through the Southern Interties and we acquire additional energy supply to balance our loads from the Mid-C market hub. In all cases, there are transmission constraints that separate PGE from our power supply. This has created a challenge in both managing our existing resources, as well as planning for new additions to our portfolio.

We deliver power from our remote resources primarily through the use of BPA transmission agreements. Most of our owned and long-term contract resources use the Integration of Resources (IR) agreement. We also hold several Point-to-Point (PTP) agreements that are used to deliver our wind resources and access the regional market hubs. Figure 9-2 is a composite chart showing PGE's overall transmission holdings and use.

Figure 9-2: Transmission Balance



The green area represents internal generation for which third-party transmission to our service territory is not required. The blue area represents IR transmission rights. The pink area represents PTP transmission. The white area within the pink area represents long-term uncommitted transmission capacity that is used for short-term market purchases and to balance our supply to load.

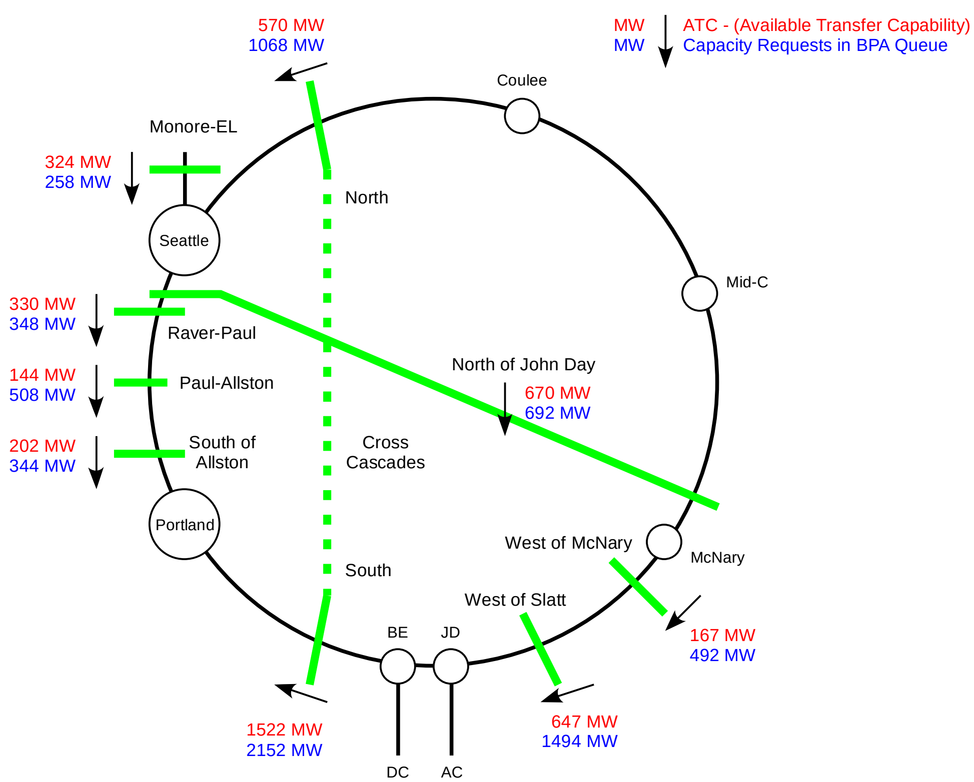
At the top is PGE's peak load requirement for 1-in-2 and 1-in-10 weather conditions inclusive of 200 MW for required operating reserves associated with the transmission of remote resources. The solid vertical lines in the year 2010 represent the expiration of the existing transmission contracts. One benefit of the new Port Westward CCCT project is that it delays the need for us to obtain additional transmission until approximately 2012. We can transmit Port Westward power to our service territory without using BPA transmission lines. This is significant because there is no new transmission planned to Portland in the near term. In addition, because Port Westward did not consume our uncommitted long-term transmission rights, we continue to have the ability to use these remaining rights to provide transmission service to the undeveloped portion of Biglow Canyon or other resource options in this geographic area.

In summary, we have sufficient transmission to meet current customer demand up to 1-in-2 peak levels through 2012. Looking forward, we are concerned about transmission availability to meet growing energy needs on an increasingly constrained regional system. New external generation resources may require new transmission all the way to PGE. Getting new transmission into service will likely take much longer than acquiring or building the generation it serves.

9.3 Available Transmission to Portland

As discussed above, congestion in the Pacific Northwest grid prevents us from securing new transmission service unless new and costly transmission facilities are built. The transmission map shown in Figure 9-1 can be simplified to show the long-term available transmission capacity (ATC) that is posted on BPA's Open Access Same-Time Information System (OASIS). Figure 9-3 depicts the main cutplanes that affect PGE.

Figure 9-3: Cutplane Capacity Availability, February 2007



The amount of long-term firm ATC as of February 2007 is identified in red. The amount of new transmission capacity requested on the BPA system is identified in blue. The requested capacity exceeds the available capacity for all but one cutplane. Table 9-1 lists the same information but in order of largest to smallest deficit, where a deficit is defined as the available capacity minus the currently requested capacity.

Table 9-1: PNW Cutplane ATC and Queued Requests

Cut-Plane	ATC (MW)	Queue (MW)	ATC – Queue (MW)
West of Slatt	647	1,494	-847
Cross Cascades - South	1,522	2,152	-630
Cross Cascades - North	570	1,068	-498
Paul - Allston	144	508	-364
West of McNary	167	492	-325
South of Allston	202	344	-142
North of John Day	670	692	-22
Raver - Paul	330	348	-18
Monroe - Echo Lake	324	258	66

The largest deficit is on the West of Slatt cutplane, followed by Cross-Cascades, both South and North. Although substantial capacity is currently available on the Cross-Cascades South cutplane, the requests for new capacity are over 2,100 MW, greatly exceeding the remaining availability. Much of the requested capacity stems from proposed wind projects that are located roughly between BPA's John Day and McNary Substations. The proximity of the wind generation to Portland, relative to Seattle, helps to explain the large demand across the southern portion of the Cross-Cascades transmission system. To meet all of these requests, substantial transmission facility additions will be required throughout the Pacific Northwest grid.

It should also be noted that there is a coordinated and concerted effort underway by many of the Pacific Northwest utilities and regional stakeholders to address the integration requirements of as much as 6,000 MW of wind power in the region, as identified by the NWPCC Fifth Power Plan. This effort, the Northwest Wind Integration Action Plan[66], is co-chaired by the NWPCC and BPA. We are participating in this region-wide effort.

[66] More information on the Fifth Power Plan and the Northwest Wind Integration Action Plan can be found at http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf.

9.4 New Transmission to Portland General Electric

As stated earlier, BPA currently has no firm plans to increase the transmission capacity to our service territory. BPA manages its long-term transmission service by using its Long-Term ATC Methodology[67]. This methodology is a flow-based calculation to determine if capacity is available on its system to serve new requests. In assessing new external resource options, typically most or all of BPA's flowgates are negatively impacted. Given the small amounts of ATC on these flowgates relative to BPA's request queue, we believe that many or most of the flowgates on the Pacific Northwest grid would require facility additions to accommodate a large new service request.

We use the standard BPA tariff to estimate the cost of delivering power to PGE for all new potential resources that we model in this IRP. Since BPA uses a postage-stamp type of rate structure, this approach does not differentiate the real transmission cost or risk of various resource choices. Only BPA or other transmission providers can determine the transmission upgrades necessary to support our future resource choices that are remote to our system. We further expect that any new transmission facility additions will likely be required to be fully subscribed before proceeding. Further, any facility additions determined to be required will also have to be fully funded, even if only a portion of the additions are used for PGE's resource delivery.

However, it is possible to use publicly available transmission information to perform system studies outside the normal transmission request process for resource planning purposes. Although the time horizon of the current IRP is mid-term (2012), and in that time-frame our existing transmission contracts with BPA may be sufficient to accommodate resource requirements (up to 1-in-2 peak levels) through 2012, we will require better estimates of transmission impacts related to longer-term resource needs. For these reasons, our IRP team initiated a series of transmission studies in 2005 and 2006 to assess those system upgrades and impacts that may be necessary to support future access to remote power supply resources. While it is impracticable to assume a system wide fix to deliver a single remote resource, we can attempt to determine the incremental transmission infrastructure upgrade costs required to bring power from a single resource in north-central Oregon to our loads by taking actions to mitigate the most significant system constraint and by adding transmission capacity directly from source to load.

First, we must recognize that the South of Allston cutplane is immediately north of PGE's service territory, and any incremental use of the Pacific Northwest grid

[67] More information on BPA's ATC Methodology can be found at www.transmission.bpa.gov/Business/Customer_Forums_and_Feedback/ATC_Methodology.

will likely require available capacity on this constraint. During the summer of 2005, we investigated the possibility of increasing capacity across this cutplane. To do this we identified potential solutions with a range of capacities and costs. At the low end of the cost spectrum, modest amounts of capacity could be made available by increasing capacity on lower-voltage transmission lines which tend to constrain the cutplane. At the mid level, there are several options that reinforce the grid through additions of mid-voltage transmission facilities to achieve increased capacity. At the high end for both cost and capacity, BPA has proposed a new high-voltage line addition that will solve several constraints north of Portland and provide substantial new capacity, provided it can be fully subscribed.

During the summer of 2006 we also looked at constraints east of our system. From Figure 9-1, these constraints include the Cross-Cascades South, the West of Slatt, and the West of McNary cutplanes. PGE has several resources and transmission contracts in the John Day to McNary area. As previously noted, there is also much renewable wind development in this area, including our Biglow Canyon Project. We also used publicly available information to investigate the possible expansion of our transmission system all the way to BPA's McNary Substation. The purpose of that study was to determine the technical feasibility of such an expansion. The goal of any such expansion would be to increase the transmission capacity to PGE to service future load requirements, mitigate the system constraints that limit our use of the transmission system in that area, and provide a direct connection to our new and existing resources. The study has been completed and shows that the project is technically viable, i.e., models indicate that power flows would occur at the desired level and direction. We are currently studying the project's economic feasibility. We refer to this potential transmission expansion project as the Southern Crossing.

Based on our work with regional transmission planning groups in the West, we believe that synergies may exist between the Southern Crossing concept and several proposed large-scale inter-regional transmission projects. The value of the Southern Crossing will be higher to the extent that the project provides additional regional benefits and synergies with these other projects. Most of these other potential projects would include anchor resources, and more rigorous analysis is needed to define and determine the benefits of moving forward with the Southern Crossing option.

9.5 Order No. 04-375 Transmission Conditions

The OPUC's acknowledgement of our 2002 IRP Final Action Plan was conditioned on PGE taking a number of actions related to developing transmission capacity over the Cascades. Specifically, the acknowledgement stipulates that the following three conditions be met:

1. PGE must initiate discussions with Staff, renewable developers, BPA, ETO and other stakeholders to discuss constraints to competitive renewable development in the region.

2. PGE must include an action item in its 2005 IRP to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional resources are accessible to PGE at a reasonable price.

3. PGE must demonstrate that it has made reasonable efforts to acquire, retain or option cost effective transmission capacity over the Cascades before issuing its next RFP.

On March 23, 2006, PGE provided its Final Action Plan Update to the OPUC. A section of that report discusses the actions we have taken to meet these conditions. As explained earlier, we have already met the first and third conditions by participating in BPA's McNary Open Season and redirecting a portion of our BPA PTP transmission rights to accommodate east-side resources such as the Biglow Canyon wind project.

The March 23, 2006 Final Action Plan Update also discussed our work with BPA and others to address the second condition, as well as earlier mentioned studies to assess possible solutions to existing transmission constraints such as the Southern Crossing transmission concept. We have now completed the technical studies of the Southern Crossing, as described above. Economic evaluations are on-going.

In addition to the Southern Crossing study work, we are actively engaged with the joint BPA/NWPCC Wind Integration Action Plan. One of the goals of this initiative is to determine both the short-term and long-term transmission requirements associated with high levels of wind development. Depending on project economics, the Southern Crossing concept may play a role in identifying solutions for PGE and others to have better access to these important new supply sources. Since acknowledgement of our 2002 IRP Action Plan, we have also actively worked with BPA and others to develop transmission capacity over the Cascades so that additional resources are accessible to us at a reasonable price. We have included the continued evaluation of Southern Crossing and ongoing work with BPA and others to develop transmission options as an action item in our Final Action Plans in this IRP.

9.6 Regional Transmission Organization Development

Since filing the March 23, 2006 Final Action Plan Update, the Pacific Northwest Regional Transmission Organization (RTO) development as described in the Update has taken yet another turn. Two new organizations have emerged that are concerned with transmission planning and expansion. Columbia Grid[68] seeks to combine the potential benefits of Grid West and the Transmission Improvements Group. Another organization, Northern Tier Transmission Group[69] extends the geographic scope into the Mountain West States. While we are not a member of either group, we participate in many of the meetings and activities of both groups.

On February 16, 2007, the FERC issued Order 890, Preventing Undue Discrimination and Preference in Transmission Service. The Order includes significant reforms to the provision of open access transmission service by transmission providers, including PGE. Among the reforms are new requirements related to transmission planning. Each public utility transmission provider is required to submit as part of a compliance filing a proposal for a coordinated and regional planning process that complies with the planning principles and other requirements in Order 890. The planning principles include requirements for coordinated, open and transparent planning processes and the inclusion of customers early on in the development of transmission plans. Transmission planning processes must be filed by October 11, 2007. Although it is too early to determine how the planning reforms adopted in Order 890 might affect this IRP, we intend to fully comply with the new requirements and to actively participate in the new planning processes which will develop as a result of the Order.

---

[68] More information on Columbia Grid can be found at www.columbiagrid.org

[69] More information on Northern Tier Transmission Group can be found at www.nttg.biz

10. Analytical Approach

The goal of the IRP is to identify a mix of new resources that, considered with our existing portfolio, provides the best combination of cost and risk for PGE and our customers. In order to achieve this goal, we must first examine the relevant types of risk and cost that can be forecast and measured through the IRP process, as well as how those results should be interpreted and applied to resource decision-making. Given the many uncertainties facing the energy industry today, our analysis and risk evaluation approach must be broad and flexible enough to identify and describe the many possible conditions that may be encountered over a long-term planning horizon. In this chapter we provide both a conceptual overview of how we think about and assess risk and value for the IRP, as well as a detailed description of our analytical methods, tools and metrics.

Resource planning analytics primarily involve estimating future expected costs for various potential portfolios of resources along with an assessment of the range of possible variations in outcomes around those expected costs. IRP analysis also requires making point estimates and risk assessments that extend well beyond the current timeframe. Given the potential for significant timing differences between planning and implementation, we must consider the possibility that current circumstances may change, perhaps dramatically, over time. History in the energy markets has consistently demonstrated that supply-demand equilibrium can fluctuate, sometimes drastically, and structural changes and market evolution that can significantly impact price and availability do occur.

As a result, we believe that it is most effective to apply a broad set of tools and techniques to assess resource and portfolio performance across a wide range of potential future environments. In addition, we believe that it would not be wise to rely on any single performance metric or analytical method. There is simply no single right answer when evaluating an uncertain energy supply future. Rather, the collective insights derived from quantitative and qualitative performance measures instruct and guide our business judgment and strategic decision-making with respect to the selection of a preferred future portfolio.

Our analytical tools and techniques have continued to evolve. Since our last IRP we have implemented a new model, AURORAxmp® by EPIS, Inc., that allows us to assess western electricity supply and demand, as well as resource dispatch costs and resulting market prices on an hourly basis for the entire WECC region across our planning horizon. In addition to the increased scope and granularity that the new model provides, we are also able to gain better insights into the impacts of different potential future resource choices, both by PGE and other regional participants, through more advanced sensitivity and scenario testing capabilities.

We have also refined our risk metrics. We continue to use net present value of revenue requirements (NPVRR) and rate variability index (RVI), which are derivations of basic financial and statistical measures, to assess cost and risk. We now also apply alternative versions of these concepts that allow us to better understand the magnitude of potential cost changes under adverse conditions, as well as the potential for large rate increases over time for a given portfolio. These metrics include TailVaR90 of NPVRR and TailVaR90 of RVI. We regard these additional risk measurement techniques as evolutionary, not revolutionary. They build on widely accepted concepts originally developed for the financial markets in connection with asset valuation and portfolio theory, and have been applied by PGE and others in previous IRPs. We continue to evaluate risk according to three primary categories: stochastic risk, scenario risk and paradigm risk.

More detail regarding our specific risk metrics and modeling methods are presented later in this chapter.

Chapter Highlights

- We use AURORAxmp® to conduct fundamental supply-demand analysis in the WECC, dispatch existing and potential new resources, and project hourly wholesale electricity market prices.
- We constructed 13 discrete portfolios representing either predominantly a single resource or a diverse mix of resources. We then calculate the total long-term variable power cost and fixed revenue requirement of each portfolio.
- We assess the total portfolio cost (measured as the NPVRR) and related risk (as measured by changes in cost and TailVaR90 of NPVRR) for each portfolio using both scenario and stochastic analyses.
- We test these portfolios using 19 different futures representing various potential risks and uncertainties.
- Our stochastic analysis includes changes in load, hydro generation, natural gas prices, and unplanned thermal generating resource outages.

10.1 Modeling Process Overview

Our modeling process is composed of three primary steps:

1) We conduct fundamental supply-demand analysis in the WECC using AURORAxmp with the goal of projecting hourly wholesale electricity market prices for all areas in the WECC.

2) We then estimate expected variable and fixed costs of our new resource alternatives. This process includes:

    - Dispatching existing and future alternative resources available to PGE in AURORAxmp, using AURORAxmp's projections of hourly electric market prices and resource availability (subject to transmission constraints) for all areas in the WECC;

    - Grouping alternative resource mixes in different portfolios and calculating the total long-term variable power cost of each portfolio in AURORAxmp;

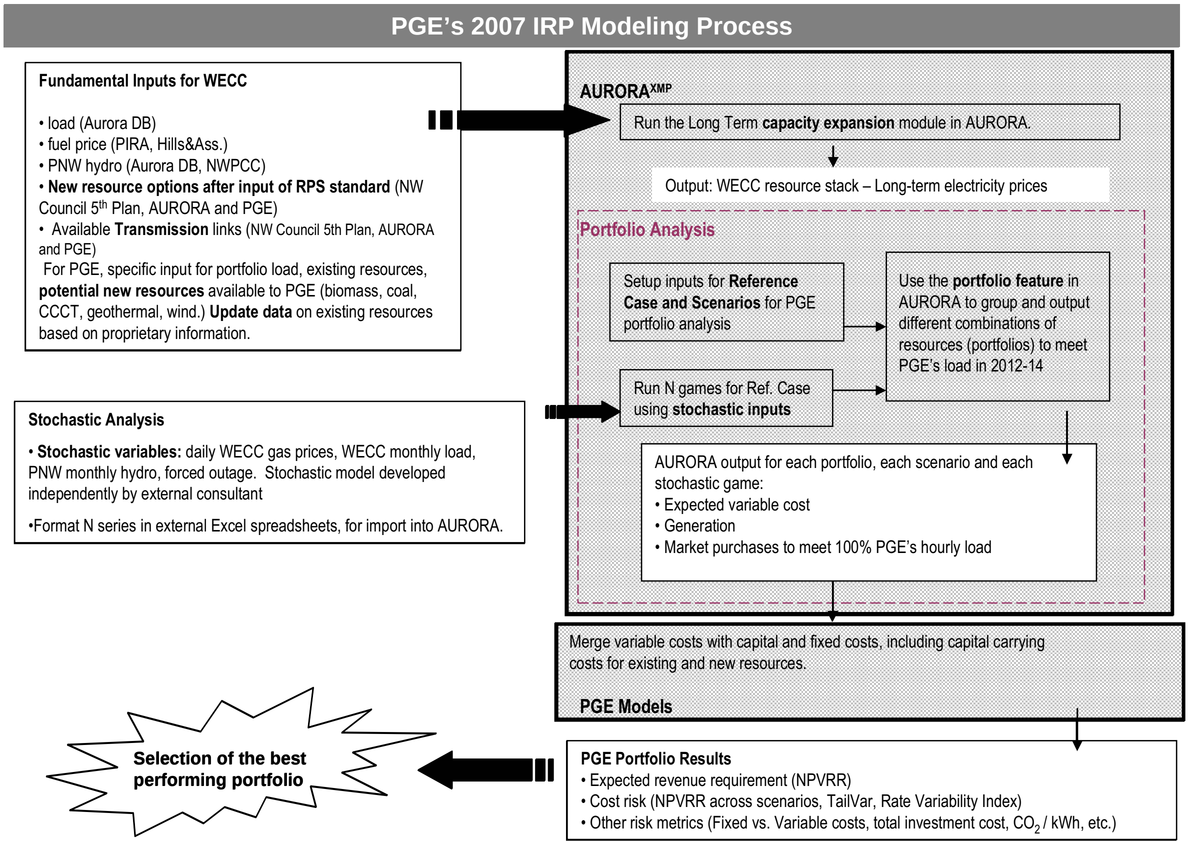
    - Combining the variable power cost from AURORAxmp with the fixed revenue requirement (capital and fixed operating costs), determined using our spreadsheet-based revenue requirement model, for each of the alternative portfolios; and

    - Calculating the NPVRR over the planning horizon (from 2009 to 2031). The NPVRR is our primary long-term cost metric.

3) Using scenario (or deterministic) analysis, we then assess portfolio risk performance for each portfolio based on change in portfolio costs under varying future conditions (i.e., changes in fuel prices, emissions costs, etc). We also consider emissions risk, rate impacts, financial commitment, and other criteria for each portfolio. We performed stochastic analysis for all portfolios using only the reference case future.

Figure 10-1 summarizes PGE's modeling process.

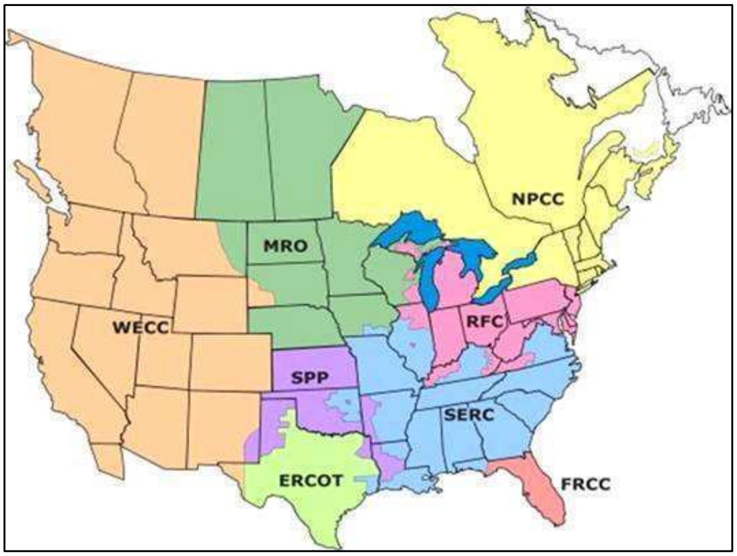
Figure 10-1: Modeling Process for the 2007 IRP



10.2 WECC Topology

We paid particular attention to EPIS-supplied transmission topology and constraints and WECC loads and resources to estimate WECC market prices. The key components of the AURORAxmp topology are areas, zones, and transmission links. AURORAxmp has an extensive database that includes existing resources, new resource costs, electric loads, and fuel costs for North America. Our modeling focused on the WECC region (see Figure 10-2), which includes British Columbia, Alberta, the Pacific Northwest, California, the Southwest, Idaho, Colorado, Utah, Montana, and Wyoming.

Figure 10-2: WECC Region Map



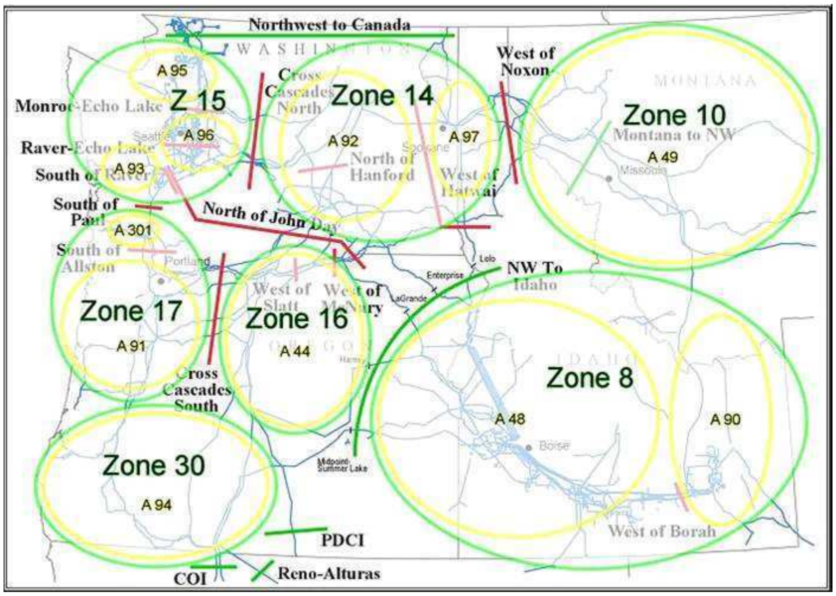
The database is subdivided by region, defined as a geographical area with no internal transmission constraints. Transmission links connect the different areas, define the import-export capability between them, and set related wheeling costs and losses.

AURORAxmp areas are further consolidated into zones, which represent markets. AURORAxmp calculates the dispatch cost of all WECC resources each hour and, for each zone, selects the least cost incremental resource available to meet load by choosing to generate within the zone or import electricity from other less expensive zones. Intra-zone transmission is ignored in the dispatch logic because AURORAxmp assumes that intra-zone transmission does not constrain plant operations within a zone. Inter-zone transmission sets the maximum import-export capability between zones.

We modified the default topology of AURORAxmp to better represent transmission constraints affecting PGE. We also updated transmission capability, expected losses, and wheeling to current path ratings and adjusted default database import/export capability between zones. We configured the WECC with 20 total zones and divided Oregon and Washington into five zones as listed below and shown in Figure 10-3:

- Zone 14: East of Cascades, North of South-of-Paul cutplane
- Zone 15 (Mid-C): West of Cascades, North-of-John Day cutplane
- Zone 16: East of Cascades, South of South-of-Paul cutplane (includes PGE's system)
- Zone 17: West of Cascades; South-of-John Day cutplane
- Zone 30 (COB/COI): South of Grizzly

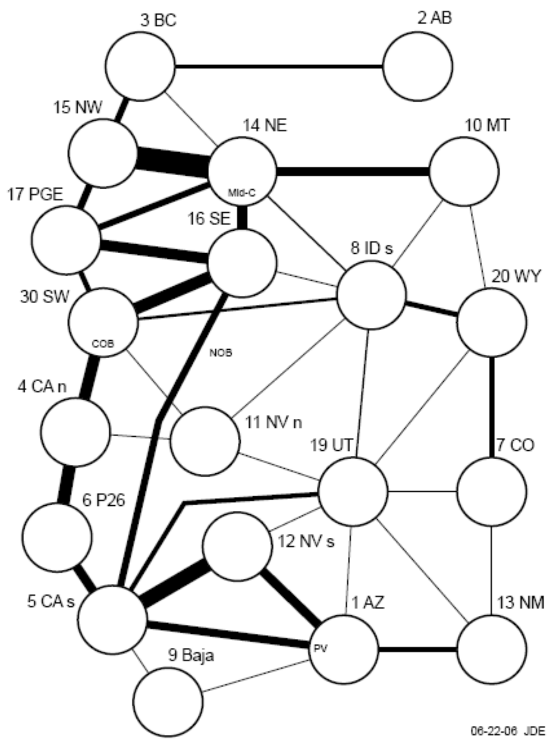
Figure 10-3: WECC Zones



We also changed the inter-area transmission capability within the default topology. We relied mainly on three sources to update transmission link capabilities: 1) inputs to the NWPCC's version of AURORAxmp in the 5th Plan, 2) the WECC path rating catalog; and 3) the professional judgment of our IRP team.

Figure 10-4 shows our final topology. Thickness of the lines in the figure indicates the relative transfer capability between two zones.

Figure 10-4: 2007 IRP Topology: 20-Zone WECC Configuration



Legend	
1 AZ	Arizona
2 AB	Canada-Alberta
3 BC	Canada-British Columbia
4 CA n	Northern California
5 CA s	Southern California
6 P26	California -ZP26+
7 CO	Colorado
8 IDs	Idaho South
9 Baja	Mexico-Baja California North
10 MT	Montana
11 NV n	Nevada North
12 NV s	Nevada South
13 NM	New Mexico
14 NE	Washington - Northeast
15 NW	Washington - Northwest
16 SE	Oregon - SE and Idaho North
17 PGE	Oregon – West (and PGE System)
30 SW	Southwest Oregon / COB
19 UT	Utah
20 WY	Wyoming

10.3 WECC Long-Term Wholesale Electricity Market

In the 2002 IRP, we did not perform a WECC-wide market price simulation; instead we used PGE's avoided cost as an estimate of future electricity market prices[70]. For this IRP, we used AURORAxmp to simulate the long-term build-out of WECC resources to meet future electricity demand and generate hourly electricity prices to be used in our portfolio analysis.

The AURORAxmp database specifies load, expected load growth over time, resources, transmission capability, fuel prices, hydro potential and generation, and generation resource emissions for each zone in Figure 10-4. AURORAxmp simulates the WECC markets every hour by calculating the electricity demand of each of the 20 zones and stacking resources to meet demand and reliability standards with the least cost resource, given operating constraints. The variable cost of the most expensive generating plant or increment of load curtailment

[70] For this IRP, the avoided cost is used to validate AURORAxmp® generated prices. We also compare projected new resource costs to our avoided cost to evaluate stand-alone projects.

needed to meet load for each hour of the forecast period establishes the marginal price.

We relied on the advice and expertise of the NWPCC and on the assumptions in Appendix C of the 5th Plan, with a few exceptions. Following are highlights of the main assumptions we used and a description of the results. *Appendix G: AURORAxmp® WECC Resource Expansion* provides additional detail.

Regional Resource Modeling Assumptions

We imposed the following criteria on the WECC long-term wholesale electricity market:

1. A reliability standard that adds sufficient resources in the WECC to meet the 1-in-2 peak load plus operating reserves of about 7%. Like the NWPCC, we allow utilities within the Northwest Power Pool and California to share their reserves (so that, for example, the west side of the Pacific Northwest takes advantage of the surplus capacity of the east side).

2. A carbon tax of $7.72 per short ton of CO_2 starting in 2010.

3. We keep fuel costs constant in real dollars after 2020 (because forecasts become increasingly uncertain and speculative beyond that point).

4. Implementation of all approved state RPS targets as of year-end 2006. We also modeled the RPS for Oregon as follows: 5% of 2011 retail load met by renewable resources, 15% by 2015, 20% by 2020, and 25% by 2025.

Table 10-1: RPS Requirements in WECC

	2010	2015	2020
Arizona	2.5%	5%	15%
California	20%	27%	33%
Colorado	3%	10%	10%
Montana	10%	15%	15%
Nevada	12%	20%	20%
New Mexico	9%	10%	10%
Oregon		15%	20%
Washington		8%	15%

5. We applied PGE's after tax nominal cost of capital of 7.59% as a proxy for the long-term cost of capital in the WECC. Table 10-2 contains our other financial assumptions.

Table 10-2: Financial Assumptions

	Percentage
Income Tax Rate	39.29%
Inflation Rate	2.30%
Capitalization:	
Preferred Stock	-
Common Stock (50% at 11%)	5.50%
Debt (50% at 6.87%)	3.44%
Nominal Cost of Capital	8.94%
After-Tax Nominal Cost of Capital	7.59%
After-Tax Real Cost of Capital	5.17%

6. For modeling purposes only, we did not allow AURORAxmp to make plant retirements prior to the end of their original book lives.

Resource adequacy standards and RPS implementation are key drivers of long-term resource additions in the WECC. Figure 10-5 highlights the significant build-out of renewable energy resources due to approved RPS targets in the WECC. After these projected resource additions, the WECC resource mix in 2031 is composed of 32% gas-fueled plants, 23% non-hydro renewable resources, 23% hydro, 18% coal, 3% nuclear, and 1% other. See *Appendix G* for more details.

Figure 10-5: WECC Resource Additions

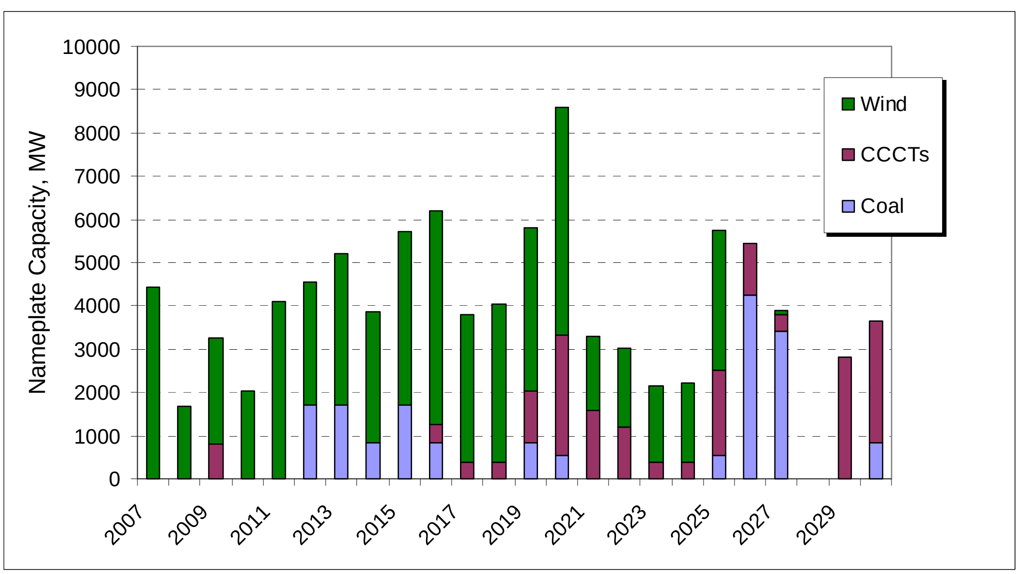
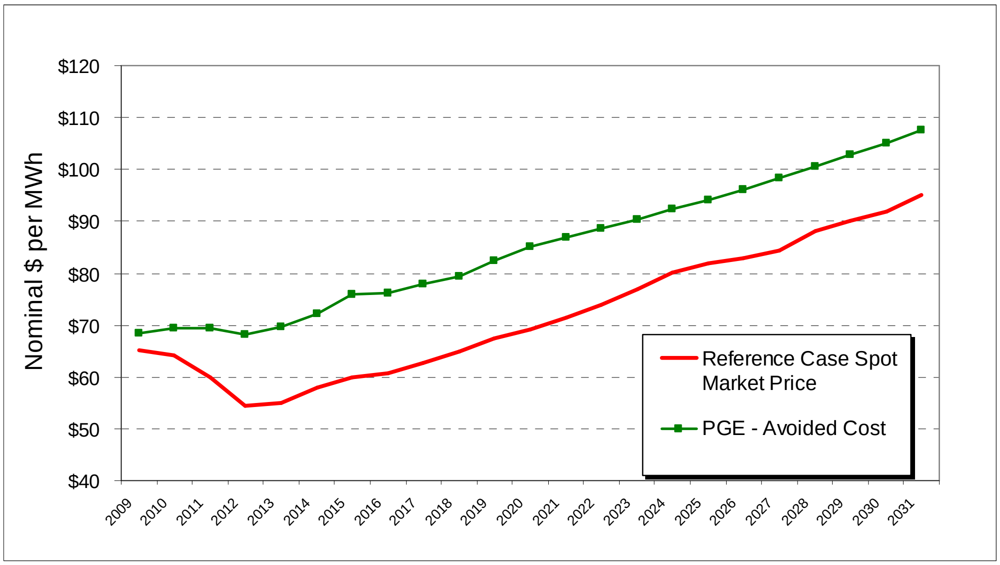


Figure 10-6 shows the resulting average annual electricity market price projection for PGE using the reference case assumptions described above. See *Appendix H: Portfolio Analysis* for the full range of prices used in our analysis.

Figure 10-6: PGE Projected Electricity Price – Reference Case



Once we developed a forecast reference case market price for electricity in AURORAxmp, we compared it with the fully allocated cost of the avoided resource for PGE, which we currently assume to be a new CCCT. We do this to validate AURORAxmp's output and understand the potential consequences of using AURORAxmp's endogenous prices for portfolio analysis. AURORAxmp projects lower prices than the CCCT ($51.8 vs. $61.3 per MWh in $2006, real levelized) for the following reasons:

1. AURORAxmp assumes that surplus power will be priced at short-term marginal cost and will be traded, if economic, until transmission limits are reached.

2. Reserve margins imposed to assure reliability and resource adequacy cause the WECC to be in surplus for most hours of the year.

3. New generating plants are added to maintain the minimum reserve requirement[71] (7% for states with primarily thermal generation, 6% for the Pacific Northwest, which has a mix of thermal and hydro resources). New resource additions, which are typically large, thus cause temporary over-supply conditions until load growth catches up to new lumpy resource additions.

[71] Operating reserves are 7% generation resources for thermal plants and 5% for hydro and wind.

4. Given these assumptions, the AURORAxmp forecasted electricity price is generally not adequate to achieve a positive return of and return on invested capital. Therefore, it is assumed that fixed costs, particularly for capacity, would need to be recovered through regulation or a separate capacity market.

The assumptions we impose on AURORAxmp, while reasonably constraining the model to meet reliability standards over the long haul, do not reflect the discretion of individual utilities and market participants to deviate from these norms nor do they recognize that, in the short-run, supply imbalances have occurred and can cause reserve margins to shrink until new supply is added. A simplified modeling world that always has adequate resources and market prices that are below avoided cost may unwisely suggest a deliberate short-supply strategy in which a utility ignores recommended resource adequacy standards. This simplification ignores real-world supply, price, and reliability risks and may also be inconsistent with emerging resource adequacy standards as described in Chapter 3. To offset this potential bias in favor of a deliberately short strategy, we designed scenarios that describe potential market shocks such as a high CO_2 tax or higher than expected load growth. These scenarios reveal the risks of such a short strategy.

The WECC resource mix and resulting market price forecast created in this step are used in our portfolio and stochastic analyses. Changes in fundamental assumptions for portfolio analysis, such as natural gas prices, potential CO_2 tax, and load growth rates, do not cause any adjustments to the WECC resource mix in our modeling. That is, we do not re-run the AURORAxmp WECC capacity build-out in response to different future scenarios such as a high CO_2 tax. Changes in fundamental assumptions do, however, affect resource dispatch cost and order and lead to differing spot electricity prices.

10.4 Portfolio Analysis

The next step of our analysis is to identify the combination of resources that, when added to the existing PGE portfolio to meet expected future load, achieves the best combination of cost and risk. In creating, selecting and analyzing our portfolios, we:

1. Identified expected future resource needs (see Chapter 3: Resource Requirements).

2. Constructed alternative portfolios with different mixes of resources to meet the expected load-resource gap in 2012. Each incremental portfolio

contains the same amount of energy generating capability on an annual average basis.

3. Froze long-term resources additions after 2012 to avoid skewing results with post-2012 resource actions. We chose 2012 as the target year for our actions because the magnitude of the gap in 2012 (818 MWa) implies that actions cannot be postponed further. We will evaluate post-2012 resource procurement in the next IRP. We also froze PGE load after 2014, which represents the target end date for our actions. This approach allows us to focus our resource evaluation efforts in this IRP on those actions that we would expect to implement in the next few years. We also avoid biasing the selection of the best portfolio by the performance of resource additions in an increasingly uncertain distant future.

4. Added capacity resources to achieve equivalent capacity value for all portfolios. We did this to ensure that we fairly compared the overall value that each portfolio provides. The value of a portfolio depends, in part, on the ability of the resources to respond to customer needs during peak events and critical hours. All portfolios were constructed to have the same annual average energy generation (818 MWa) and one-hour peaking capability (1,016 MW)[72], and thus provide a comparable level of reliability.

5. Dispatched the portfolios, including existing and new resources, from 2009 to 2031.

6. Added capital and fixed costs for both existing and new resources.

7. Compared the expected cost and risk performance of portfolios across different futures and stochastic iterations. Futures were constructed with input from OPUC staff and other stakeholders. See the Section 10.6 for a description of the various futures we used.

Our approach to portfolio analysis focuses primarily on baseload energy resources, along with the capacity value they bring. Once this annual baseload energy gap was met, we added capacity resources where necessary to reach a common capacity target of 1,016 MW for all portfolios. For wind, we modeled a capacity value equal to 15% of the nameplate capacity, which is commonly used by the WECC and NWPCC in their regional load resource assessments. We consider this assumption a placeholder, subject to revision once we gain a better understanding of wind behavior in the Pacific Northwest during peak events.

[72] 1016 MW represents the capacity of the coal portfolio, which has the highest capacity of all portfolios.

The NWPPC is coordinating a multi-utility effort[73] to estimate a reasonable capacity value for wind to use in the Pacific Northwest for long-term planning purposes. We are actively helping the NWPCC in its effort.

These capacity additions still fall well short of our forecast 1-in-2 annual peak need, inclusive of contingency and required operating reserves. The additional capacity needed to meet the 2012 peak load and reserves of 1,540 MW is analyzed separately in Chapter 12.

We included in candidate portfolios those resources that are considered commercially available on a utility scale in 2012, including wind, biomass, geothermal, energy efficiency, SCPC, IGCC, SCCTs, and CCCTs. To assess the performance of each resource alternative, we first used a bookend or pure play approach, whereby we created portfolios relying primarily on one long-term resource type (i.e., all wind, IGCC, CCCT, SCPC, and all spot market). With input from stakeholders, we then constructed a number of diverse portfolios to test the performance and risk mitigation potential of various combinations of potential resources. All diverse portfolios were constructed to meet the 2015 Oregon RPS standard. See Table 10-3 and Figure 10-7 for the composition of our portfolios.

All portfolios contain about 180 MWa of short- and mid-term market purchases to provide supply flexibility and responsiveness in serving uncertain commercial and industrial load. As described in Chapter 3, all of our commercial and industrial customers have the option of choosing an alternative energy provider with one year notice. Large customers can make this election for up to 5 years. In aggregate, 300 MWa of customer load is eligible for these programs. We are proposing to manage this uncertainty in annual load by meeting about 180 MWa of the expected load in 2012 through a mid-term procurement strategy. An additional 66 MWa is associated with renewal of an expiring hydro contract.

Our portfolio analysis is conducted from 2009 to 2031, over 20 years of hourly dispatch of new resources. For stochastic analysis, we use an hourly sampling method (every 8th hour); each portfolio is run against 100 stochastic iterations. The stochastic futures are based on the reference case and not on the long-term scenario futures. We tested hourly sampling and compared it with the results obtained without sampling. We verified that there are no material differences in the relative long-term performance of the different portfolios. In addition, sampling allows for faster data processing.

End-of-life effects are addressed by using the real levelized fixed revenue requirement calculated over the life of the plant. The alternative accounting

[73] Wind Task Force of the Resource Adequacy Forum

approach of front-loaded costs (typical of rate-making) ignores the remaining years of low fixed costs for resources with an expected useful life beyond 2031. Such an approach would bias our analysis against those resources that have relatively high fixed costs and a long life. Using real levelized fixed costs allows us to truncate the analysis at the end of 2031 without the need for end-effect adjustments.

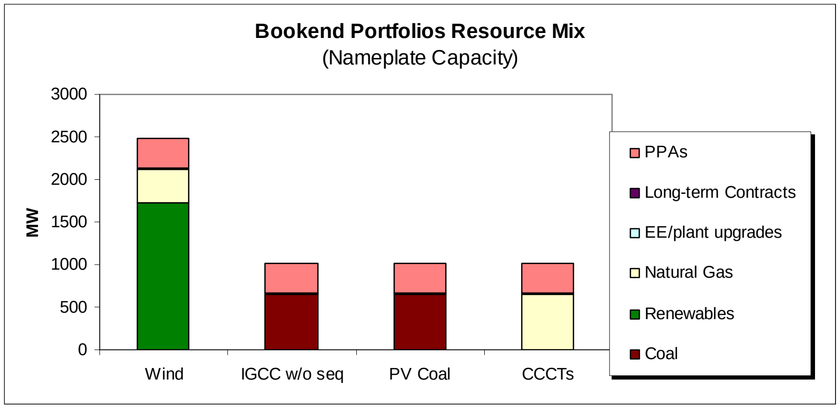
Table 10-3: Portfolios Composition

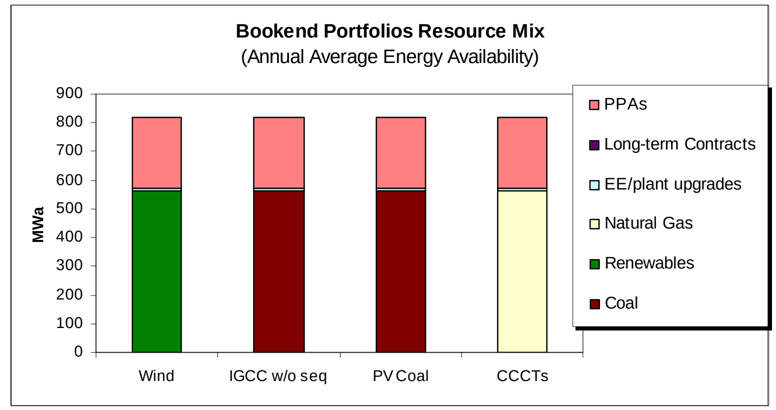
Resource added:	Wind+SCCT		IGCC w/o seq		IGCC with seq		PV Coal		CCCTs		Market	
	MW *	MWa	MW *	MWa	MW *	MWa	MW *	MWa	MW *	MWa	MW *	MWa
SCP Coal w/o seq.							653	562				
Wind - Tier I	45	105										
Wind - Tier II	214	457										
CCCTG									604	562		
Energy Efficiency												
Geothermal												
Biomass												
IGCC w/o CO2 seq.			653	562								
IGCC with CO2 seq.					653	562						
5-to-10 yr Contracts												
Plant Upgrades	16	10	16	10	16	10	16	10	16	10		
ST and MT purchases	347	246	347	246	347	246	347	246	347	246		
<u>Capacity Resources</u>												
CCCTG, HR 6500												
SCCT 7a frame, HR 10050	394								49			
Total	1,016	818	1,016	818	1,016	818	1,016	818	1,016	818	-	0

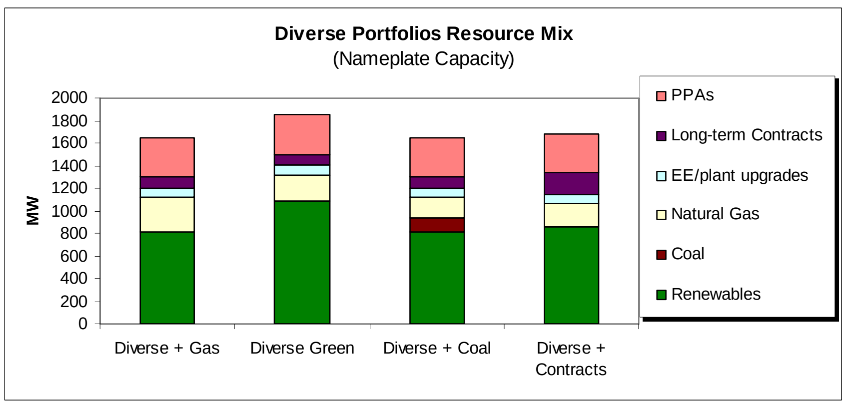
Resource added:	Diverse + Gas		Diverse + Coal		Diverse Green		Diverse + Contracts		Diverse Coal w/CCCTs		Diverse Green w/CCCTs		Diverse + Contracts + CCCTs	
	MW *	MWa	MW *	MWa	MW *	MWa	MW *	MWa	MW *	MWa	MW *	MWa	MW *	MWa
SCP Coal w/o seq.			122	105					122	105				
Wind - Tier I	45	105	45	105	45	105	45	105	45	105	45	105	45	105
Wind - Tier II	67	142	67	142	102	217	73	156	67	142	102	217	73	156
CCCTG	113	105												
Energy Efficiency	59	45	59	45	59	45	59	45	59	45	59	45	59	45
Geothermal	54	50	54	50	49	45	54	50	54	50	49	45	54	50
Biomass	17	15	17	15	56	50	13	12	17	15	56	50	13	12
IGCC w/o CO2 seq.														
IGCC with CO2 seq.														
5-to-10 yr Contracts	100	100	100	100	100	100	194	194	100	100	100	100	194	194
Plant Upgrades	16	10	16	10	16	10	16	10	16	10	16	10	16	10
ST and MT purchases	347	246	347	246	347	246	347	246	347	246	347	246	347	246
<u>Capacity Resources</u>														
CCCTG, HR 6500									189		243		214	
SCCT 7a frame, HR 10050	199		189		243		214							
Total	1,016	818	1,016	818	1,016	818	1,016	818	1,016	818	1,016	818	1,016	818

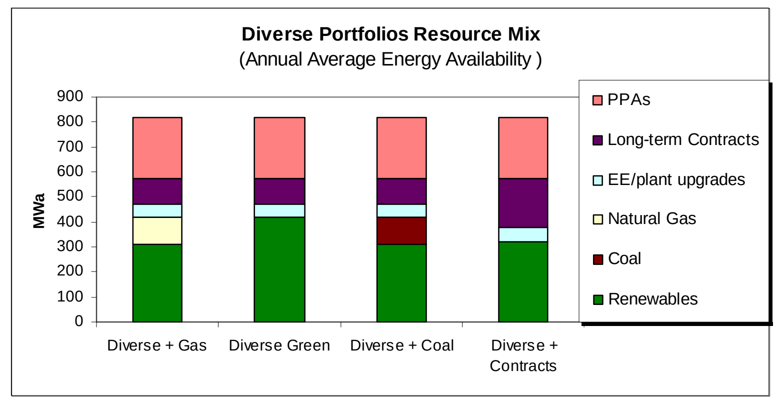
** January peak capability: 15% of nameplate capacity for wind, nameplate capacity for other resources.*

Figure 10-7: Portfolios by Resource Type









For modeling purposes only, existing PGE resources that expire or reach the end of their original book life before 2031 are generally not extended beyond their term, and are therefore replaced by spot market purchases upon expiry. There are two exceptions: 1) Boardman, for which we expect to install emissions controls to enable its efficient long-term operation (see Section 6.5 for a discussion of the useful life of Boardman), and 2) a long-term hydro contract expiring in 2011, for which we anticipate renewal.

10.5 Reference Case

The reference case is a deterministic study based on the expected assumptions regarding resource, market, and internal and external conditions associated with the candidate portfolios described earlier. The reference case is also the basis against which we test portfolio performance. The following section summarizes the key inputs used in our reference case.

- **Commodity fuel price** - Natural gas prices are approximately $6.4 per MMBtu (real levelized $2006). Commodity coal prices are based on prices for PRB coal. Both forecasts rely on independent third party fundamental research and market quotes. More details regarding fuel prices are in Chapter 5. Fuel prices are constant in real dollars after 2020.

- **Fuel transportation cost** - Fixed fuel supply costs are $ $0.55 per dekatherm for gas. Coal rail transportation and handling costs are based on costs at Boardman.

- **Resource costs** - We used the cost assumptions detailed in Table 7-2.

- **Renewable Energy Production Tax Credit** - We assume renewal of the PTC in its current form after 2008.

- **Transmission cost to PGE's system** - We use BPA's transmission tariff rates (escalated at inflation) for all new generation resources.

- **PGE load** – We used the base case long-term load growth of 2.2% per year, as described in Chapter 2. The reference case load growth varies between 1.5% and 2.2% in the mid-term and is 2.2% from 2012 forward. For modeling purposes, we freeze our load growth (in all scenarios) in 2014, as explained in Section 10.4.

- **Environmental assumptions** - We used the assumptions detailed in Table 6-2. A CO_2 tax of $7.72 per short ton is imposed on all WECC thermal plants starting in 2010.

- **Renewable portfolio standard (RPS)** - We input an RPS standard in all WECC states that currently have an RPS. In addition, we applied an RPS in Oregon based on the new legislation. See Table 10-1 for details.

10.6 Futures

In order to stress-test portfolio performance against an unknown future environment, we constructed several discrete futures based on feedback from our stakeholders received throughout our IRP workshops. While the use of these scenarios may not include the full range of possible conditions, we believe that it is possible to develop a broad set of futures that reasonably reflect the types of changing circumstances that could be encountered and the resulting impact to the cost and risk of future portfolio choices. In particular, we wanted to ensure that our futures tested the durability of each candidate portfolio against possible changes in underlying fundamentals that could, if they came to fruition, result in large changes in prevailing energy market prices or significant impacts to the cost or value of the resources within the portfolio. In addition, we wanted to understand the impacts of pursuing portfolios that had more or less exposure to variable costs and prevailing market conditions vs. those candidate portfolios that included higher proportions of fixed costs and would thus be less responsive to changing external factors. We evaluated portfolios across the following future scenarios, which we created by modifying the reference case assumptions with input from stakeholders:

1. CO_2 tax at $10, $25, and $40 per short ton (in $1990), as prescribed in Order No. 07-002. In addition, we modeled a scenario with no CO_2 regulation, which represents the current status.

2. High gas price future ($9.2 per MMBtu, an increase of $2.8 per MMBtu over the reference case in real levelized $2006). See Figure 5-1 for more detail.

3. Low gas price future (decrease of $1.3 per MMBtu below the base case in real levelized $2006). This scenario projects real gas prices less than $5.1 per MMBtu, which are substantially higher than the average actual gas prices of the past 10 years. This means that we do not assume a return to historical prices in our IRP.

4. A combination of $25 per short ton (in $1990) carbon tax with the high gas price. This scenario combines two of the risk factors that concern us most: fuel price and environmental risk. Both factors primarily affect thermal plants.

5. Low and high long-term PGE load growth (low growth is 1.2% per year, high growth is 3.1% per year), as required by Order No. 07-002.

6. Lower WECC market electric price due to technological advances in generation of electricity. We assume that a new (yet unknown) technology allows for the generation of electricity with renewable resources and low capital investment.

7. Phase-out of the federal PTC. This scenario assumes that the PTC is not renewed after its expiration in 2008.

8. 25-year economic life for new coal generation; this sensitivity captures the risk of premature obsolescence of coal plants because of the emergence of a new, cleaner technology or restrictive carbon regulation.

9. $15 per MMBtu gas for the next 10 years, reverting to the reference case thereafter. This scenario was suggested in the public process and captures severe turmoil in the oil and gas industry.

10. $15 per MMBtu gas for the next 10 years, reverting to the reference case thereafter, and low WECC load growth. Similar to the scenario above, this is a future where severe turmoil in the oil and gas industry triggers a recession. Demand for electricity stagnates and investments in new plants made assuming future load growth become redundant.

11. High WECC (2.8% per year) and PGE (3.1% per year) load growth. This scenario captures strong economic growth across the WECC and/or an ongoing inflow of new immigrants, which increases the demand for new homes and residential energy use. This scenario is particularly useful in our analysis because it is the only scenario that progressively erodes the surplus of generation over demand in the WECC that we input by imposing reliability standards in the WECC capacity expansion model.

12. Combined RPS and gas price scenarios[74]:

    - Gas 10% cheaper than reference case, renewable resources 10% more expensive;
    - Gas 20% cheaper, renewable resources 20% more expensive;
    - Gas 20% cheaper, renewable resources 20% more expensive; PTC at 50% of reference case;
    - Gas 10% more expensive, renewables 10% more expensive;

[74] These futures with less expensive gas were created in response to stakeholder requests. We added the two futures with higher gas prices for a more detailed portfolio performance comparison.

- Gas 20% more expensive, renewables 20% more expensive.

10.7 Performance and Risk Metrics

We use two primary metrics to assess the performance of a portfolio: expected cost, and risk as measured by change in cost. These metrics are explained below.

Cost Definition

The cost definition used in our portfolio analysis is the NPVRR in the reference case, or the average NPVRR across scenarios or stochastic iterations. The total revenue requirement is composed of variable power costs and fixed costs. We use an Excel spreadsheet to model the fixed component of the revenue requirement, which includes investment return and recovery, current and deferred income taxes, property taxes, decommissioning, ongoing capital additions, fixed O&M, fixed fuel costs, wheeling and transmission costs[75]. The variable power cost is computed in AURORAxmp using hourly dispatch. It includes fuel cost, variable O&M, start-up costs, and environmental emissions costs.

For deterministic risk analysis, we compare portfolio costs under alternative futures or scenarios defined in Section 10.6 against the cost under reference case assumptions. For stochastic risk analysis, we measure cost variances statistically through 100 AURORAxmp iterations, using probabilistic inputs for loads, hydro, forced outages, and natural gas prices.

Scenario and Stochastic Risk Definitions

We use both scenario analysis and stochastic simulations to analyze the uncertainty of certain variables and their impacts on portfolio performance. We categorize uncertainty according to the extent that its statistical attributes can be measured. Uncertainty generally falls into one of three categories: stochastic, scenario, and paradigm risk.

Stochastic Risk

For planning purposes, the most tangible form of uncertainty is the short-term variability we experience with weather, loads, and fuel prices. Some of these

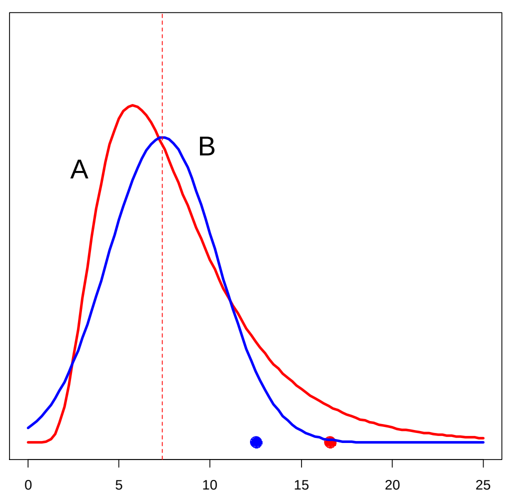
[75] The spreadsheet-based revenue requirement model also has a dispatch engine with monthly on-off peak granularity. We use the calculated dispatch in this model for financial analysis of stand-alone plants (for example, calculation of the expected real levelized cost of a new coal plant).

uncertainties can be assessed accurately with the large amount of historical data available. For example, weather forecasts generated by sophisticated meteorological models are very accurate over the short term. With hydro, knowledge of total system capacity and seasonality allows us to establish a confidence band on expected monthly energy with reasonable precision. We call this kind of short-term uncertainty the stochastic risk of a variable.

The stochastic risks of many of our environmental variables share several common characteristics. For example, fuel prices and weather, although highly volatile, tend to revert to the mean across 100 iterations. Fuel prices exhibit lognormal distributions. Regional loads are also highly predictable when they are conditioned only on weather.

The stochastic risk of a portfolio can be measured by several metrics. We choose TailVaR90[76] as our main measure of risk for this IRP. The TailVaR90 of a stochastic variable is the average value of the worst ten percent outcomes. The advantage of TailVaR90 over other risk measures is illustrated in Figure 10-8, in which we plot the probability distribution of the cost of two portfolios.

Figure 10-8: Graphic Representation of TailVaR90



Portfolios A and B have the same average or expected cost, indicated by the vertical dotted line, and nearly the same standard deviation. The large dots at the bottom of the graph represent the TailVaR90. According to the traditional risk measure of standard deviation, a decision-maker would be essentially indifferent

[76] Tail means tail of the probability distribution, specifically the tail on the high cost side; VaR means Value at Risk; 90 means 90%.

between the two portfolios, as the statistically measurable risk of not achieving the expected outcome is the same. However, Portfolio A has a longer tail to the right, which suggests a higher probability of extreme outcomes. Using TailVaR90 thus helps us better understand the exposure that a candidate portfolio has to particularly adverse results. With this example, Portfolio B should be selected if reduced exposure to extreme adverse results is preferred.

We calculate the TailVaR90 for the NPVRR over a large number of stochastic runs. Typically, 100 runs are carried out, which is generally accepted as sufficient to describe the underlying statistical characteristics of a portfolio. The TailVaR90 is also calculated for the rate variability index, or RVI. The RVI, which measures the year-over-year change in rates, provides a gauge of the potential volatility of rates seen by our customers. It is calculated by taking the percentage difference of rates from one year to the next. We compute a series of rate changes for every stochastic iteration. The TailVaR90 of RVI is based on the aggregate of all the years' rate changes for the timeframe 2013 to 2031[77] in all the iteration runs. Thus, a higher TailVaR90 of RVI implies a greater chance of experiencing large annual rate increases (i.e., upward rate shocks).

We have chosen to perform stochastic risk analysis by looking at weather-related load variation, hydro conditions, natural gas price volatility, and plant forced outages. We turn to scenario analysis to consider a broader set of risks, such as those associated with imposition of carbon regulation. In our deterministic analysis, all of our futures described in Section 10.6 are considerations of scenario risk.

Scenario Risk

The second kind of uncertainty arises from fundamental or structural changes in the relationships among the fundamental drivers in power costs over time. We call this scenario risk, as the form it takes and the way it occurs can be described in specific, deterministic terms. For example, carbon legislation, whether at the state or federal level, is plausible within the 20-year study horizon of our portfolio analysis. The timing and the cost of such legislation, however, is difficult to assess due to the fact that the U.S. has no direct experience in enacting greenhouse gas legislation. A knowledgeable observer may assign a probability to the $25/ton CO_2 tax scenario, for example. Yet this assessment is subjective in nature, and does not come from statistical analysis of actual observations.

[77] In order not to overly burden the portfolio performance with the initial rate impacts of the new resources, we excluded the 2012 rate impact from our analysis. In addition, since the portfolios contain the same resource mix prior to 2012, we restrict our attention to 2013 to 2031 rate changes.

Paradigm Risk

The last category of uncertainty concerns paradigm risk. A paradigm risk is the occurrence of an event that radically changes one or more of the fundamental assumptions of our analysis. For example, a major breakthrough in generation technology, such as cost-effective wave power or a new form of solar photovoltaic, could alter the balance of resources and introduce new opportunities for energy supply that are not currently available. This type of risk is the most difficult to assess because the high degree of uncertainty makes it difficult to formulate a concrete description of the event. For this reason we do not separately model paradigm risk, aside from insights gained through the sensitivities performed in connection with our scenario analysis[78].

10.8 Other Quantitative and Qualitative Portfolio Considerations

In addition to the cost and risk metrics described above, we considered several other quantitative and qualitative portfolio characteristics that help us understand overall portfolio composition, and thus potential exposure to adverse events or changing conditions. They are as follows:

- CO_2 intensity, which measures for a given portfolio the sum of CO_2 emissions in tons per MWh generated by our fossil fuel plants and the CO_2 associated with purchases. All else being equal, portfolios with a smaller CO_2 footprint are preferable;

- Total capital required for new long-term resources. Capital intensity also provides insights into how fixed or tractable a resource portfolio would be in the event that circumstances change, substantially impacting the value of the contained resources. Financing and capital constraints are also considered for new resources in which we may take an ownership position;

- Estimate of initial rate impacts. Projects with equal lifecycle levelized costs may have differing initial rate impacts, usually due to the relative capital intensity of varying technologies;

- Variable cost as a percentage of total energy cost for the portfolio (i.e., variable revenue requirement divided by the total revenue requirement). Similar to capital intensity, this measure provides insights into the

[78] We modeled a simplified version of paradigm risk. We include a scenario that assumes that a new technology will lead to low electricity prices in the WECC in the near future.

responsiveness or exposure that a portfolio has to changing external factors;

- Number and size of shafts (all else being equal, we would prefer to have more shafts with smaller sizes);
- Ratio of a portfolio's adverse outcomes across various scenarios.
- Ratio of a portfolio's positive outcomes across various scenarios.

Portfolios that perform well under some of the above criteria and cost and risk definitions described in the previous section may fare poorly under others. These quantitative measures provide further indications regarding the tradeoffs associated with various portfolios. Combined with stochastic and scenario analysis, we believe these additional metrics enhance our overall understanding of the potential future performance of our candidate portfolios. Table 10-4 and Table 10-5 summarize other criteria we considered.

Table 10-4: Other Considerations for Thermal Resources

Consideration	CCCT	IGCC	SCPC
Technology Maturity	High	Low*	Medium
Time to Develop	Medium	High	High
Economic Life	Medium	High	High
Capital per kW	Low	High	Medium
Emissions	Medium for CO2; Low for NOx, SO2, and HG	High (CO2, without sequestration); Medium (other)	High (without sequestration)
Fuel Cost Stability	Low	Medium - commodity; transport uncertain	Medium - commodity; transport uncertain
Distance from Load - Transmission	Medium to Low	Depends on location	High
Distance from Fuel Source	Medium to Low (from pipeline)	Low (mine mouth); high at Boardman High (coal by rail)	Low (mine mouth); high at Boardman High (coal by rail)
Dispatchability	High	Normally baseload	Normally baseload
Local Acceptance**	Medium	Medium	Low
Single Shaft Risk	Medium to Low	High	High

** While gasifiers and combined-cycle turbines have been used for years, the commercial use of integrating the two is new.*
*** Local acceptance refers to support or opposition to the energy resource from community members.*

Table 10-5: Other Considerations for Renewable Resources

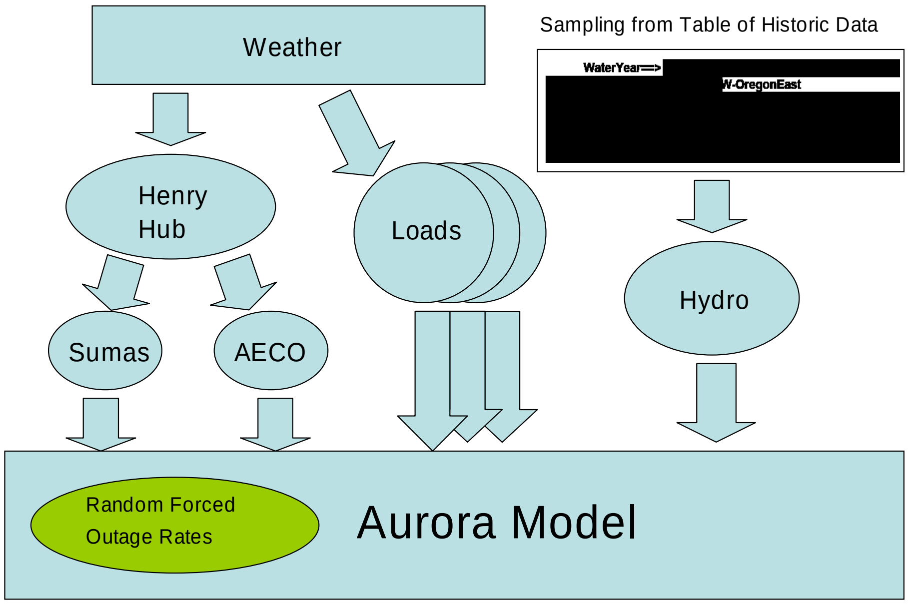
Consideration	Wind	Geothermal	Biomass
Technology Maturity	Medium	High	High
Time to Develop	Low	Medium	Low
Economic Life	Medium	Medium	Medium
Capital per kW	Medium	High	Medium
Emissions	None	Low	Low*
Fuel Cost Stability	NA	NA	Depends on project
Distance from Load-Transmission	High	High (for Oregon)	Depends on location
Distance from Fuel Source	NA	NA	Depends on location
Dispatchability	None	Normally baseload	Low (assuming cogeneration)
Local Acceptance	High	Medium to High	Medium to High
Single Shaft Risk	Low	Low (due to small plant size)	Low (due to small plant size)

** High absolute emissions for CO2, NOx and particulate; low compared to alternative disposal of fuel sources.*

10.9 Stochastic Modeling Methodology

Our uncertainty analysis employs four stochastic risks. The first three come from the stochastic behavior of load, hydro generation, and the price of natural gas. The fourth source of uncertainty is unplanned generating resource outages, which have the effect of reducing available supply in the region. Figure 10-9 depicts the relationship between these variables.

Figure 10-9: Stochastic Inputs



Gas Price

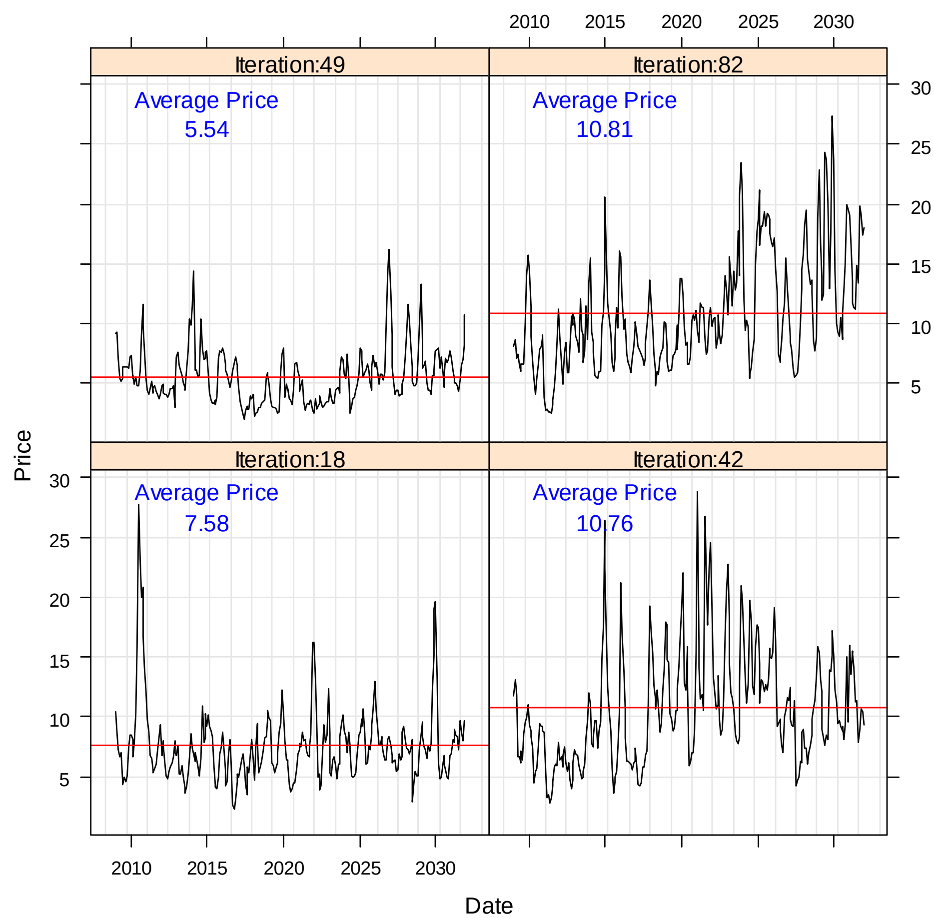
As modeled in our IRP stochastic analysis, natural gas prices follow a mean-reverting process in such a way that their average over all iterations and across the 23-year study horizon is approximately equal to the long-term forecast[79]. We developed separate statistical distributions for the Henry Hub, Sumas, and AECO trading hubs, where the latter two are a function of the first. Daily prices are generated for the entire study horizon, totaling 8,400 observations per hub. The stochastic hub prices were applied to the entire WECC to perform economic dispatch.

All three natural gas hubs use weather as a common driver, allowing the effect of seasonal variation in climate to impact daily price changes. To generate the weather component, we sampled a time series of error terms from the historic deviations from normal temperature. Figure 10-10 illustrates four monthly series of simulated Sumas prices.

---

[79] Our model, however, allows for substantially higher and lower price scenarios to take place within any single iteration. For example, given an average forecast natural gas price of $8.00/MMBtu from 2009 to 2031, we might have one iteration that shows an average price of $15.00/MMBtu over this period, while another iteration may show an average price of $4.00/MMBtu for the same period. The term "mean-reversion" as we use it here describes the entire collection of prices generated by our simulation, not any individual stochastic future.

Figure 10-10: Sumas Prices



Load

Our statistical simulation model uses weather, an independent variable randomly selected from a data set of temperatures measured at the Portland airport, to influence demand for electricity. Demand for electricity is thus correlated with the price of natural gas, which is also driven by weather in our stochastic analysis. We also allow for independent random effects unrelated to the weather. The aggregate load in the Pacific Northwest outside PGE's service territory is simulated in a similar fashion, as a single component. Finally, load in the remainder of the WECC is also modeled stochastically.

While the statistical models for load generate data in a daily time step, these are aggregated into monthly factors and are fitted to an annual average energy profile for the three demand series (PGE, the rest of the PNW, and WECC outside of the Pacific Northwest). The final input into AURORAxmp consists of a vector of 12 monthly shape factors and average annual energy in MWa for each of the 23 years and each AURORAxmp area. Notice that load exhibits strong autocorrelation because of the effect of seasonality. Table 10-6 shows monthly factors from six iterations of the simulator.

Table 10-6: Monthly and Annual Load Factors

Iteration	1	2	3	4	5	6
Jan	1.14632	1.14217	1.15767	1.14039	1.13807	1.13527
Feb	1.09207	1.07479	1.10233	1.11923	1.09355	1.07016
Mar	1.00574	1.01800	0.99378	1.00110	0.99711	1.00640
Apr	0.94441	0.93820	0.92720	0.93740	0.94366	0.93907
May	0.89748	0.89038	0.88974	0.89499	0.89520	0.89459
Jun	0.90166	0.91003	0.91306	0.91565	0.91856	0.89926
Jul	0.97633	0.96975	0.96181	0.97350	0.98440	0.98356
Aug	0.98213	1.01206	0.98921	0.98598	1.00124	1.03513
Sep	0.93677	0.92506	0.92691	0.91370	0.91329	0.92251
Oct	0.93082	0.92622	0.92866	0.92911	0.92639	0.93078
Nov	1.02945	1.06615	1.04186	1.03804	1.04251	1.04736
Dec	1.15967	1.12924	1.17152	1.15615	1.14921	1.13651
Annual	2,544	2,551	2,567	2,554	2,551	2,558

Hydro Generation

Hydro year generation is a random process independent of both electricity demand and the natural gas price. Since hydro exhibits significant monthly serial correlation, it is simulated by random sampling of the 50 historic water years starting in 1929[80]. We input these water years into the twelve AURORAxmp areas covering the Pacific Northwest and western Canada. Each area is described by twelve monthly factors and one annual factor, representing the hydro condition of one actual year in the past.

The sampling is made independently, thus there is no serial correlation across the years. Similarly, the hydro condition is independent within each stochastic iteration and between any two stochastic iterations. As a result, each of the 50 hydro years has an equal chance of being selected. Table 10-7 shows the result of our random sampling, where the numbers in the table represent the water year, from 1 to 50, that was chosen for the given year and iteration.

[80] In the stochastic analysis we use 50 hydro years to simulate hydro uncertainty in the Pacific Northwest because this data is readily available from the NWPCC and is still commonly used by the NWPCC in its regional studies.

Table 10-7: Random Sampling of Historic Water Years

Iteration	2007	2008	2009	2010	2011	2012	2013	2014
1	43	24	19	7	16	17	44	13
2	3	25	5	33	22	16	30	7
3	49	29	47	23	22	33	49	22
4	29	5	34	34	50	17	5	2
5	4	36	48	27	11	43	30	34
6	41	4	7	14	34	20	26	34
7	41	1	1	16	42	7	7	39
8	33	13	6	22	49	45	5	34
9	50	15	6	18	11	46	25	44
10	33	46	36	47	32	27	8	29
11	49	15	22	30	36	17	7	20
12	23	30	1	3	12	25	18	24
13	19	28	6	8	12	25	16	27

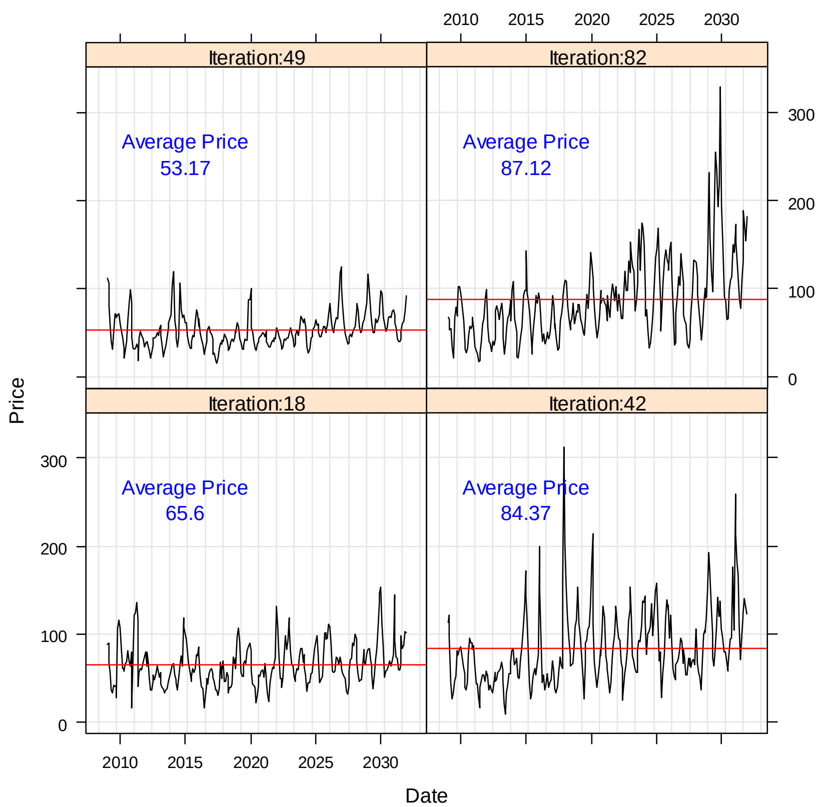
Forced Outage

Strictly speaking, forced outages are not random variables in our model. However, to make our model more reflective of actual plant operations, we use the AURORAxmp built-in risk function to simulate thermal plant outages that occur randomly across the year. All resources in the WECC are modeled in the risk study, excluding hydro plants and wind farms. For each resource we used the same annual expected forced outage rate used in the scenario analysis and a Mean-Time-to-Repair (MTTR) in unit of hours according to its fuel type. The MTTRs are calculated from North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS) database. We also use historical forced outage data from PGE's plants. For new coal plants, we use data from the Black & Veatch report.

Electricity Price

Using the three stochastic input variables and plant outage parameters described above, AURORAxmp is run to produce a market clearing electric price in each hour of the year for each zone of the AURORAxmp topology. A large number of iterations are performed, each with a different time series of gas prices, loads, resource availability reflecting plant forced outages, and hydro production, leading to a differing series of electric prices. Electric prices are thus determined as a function of the stochastic variables: gas, load, hydro generation, and other resource availability reflecting plant forced outages. Figure 10-11 illustrates four iterations of resulting AURORAxmp electric prices.

Figure 10-11: PGE Electric Price Series from AURORAxmp®



While we continue to believe that both stochastic and scenario analyses (and related sensitivities) provide important insights for assessing the performance and durability of a portfolio over time, it appears evident that the most substantial risks that we face in connection with making future resource choices are those associated with potential large fundamental or structural shifts, the types of risk best described through scenario analysis. As a result, we believe that scenario analysis should be given increased emphasis in our overall portfolio risk evaluation. This does not mean that we ignore or minimize the instructive value of stochastic analysis. Rather, stochastic analysis must also remain an important part of our risk assessment, as cost impacts driven by short-term variations in supply and demand can be considerable. Even routine or expected volatility, if high over time, can result in ongoing price instability.

Ultimately no degree of modeling and analysis can account for all possible future uncertainties. Modeling by its nature only provides an estimate or range of estimates of future results. However, we believe that a well-reasoned and complimentary application of both scenario and stochastic analysis techniques can provide useful insights about how a candidate portfolio is likely to perform in the future.

11. Energy Portfolio Analysis and Results

The following chapter presents the results of our analysis and modeling, as well as our conclusions regarding those results. As discussed in Chapter 10 regarding our analytical approach, IRP models do not provide incontrovertible answers to future resource needs, as they merely represent an estimate of future performance or a range of potential results, given a set of assumptions. However, they do provide important insights and guidance that enhance business judgment and strategic decision-making with regard to selecting future resources that are most likely to perform well under various conditions. More specifically, the results described in this chapter do not provide a single, clear-cut answer as to which combination of potential resources provides the optimal balance of cost and risk. Rather, the results indicate that the relative performance of various resource alternatives can differ widely depending upon varying future circumstances. Accordingly, our objective is to identify a robust portfolio that performs better than the alternatives under a wide range of credible futures.

To assess the performance of each candidate resource portfolio, we calculated the NPVRR for each portfolio described in Chapter 10 , along with existing PGE resources, across each distinct, deterministic potential future and then examined the results using several alternative views of risk. We also examine portfolio performance on other quantitative metrics such as CO_2 intensity, investment, initial rate impacts, number of shafts, and variable percentage of generation costs. In addition, we analyze portfolio performance under different levels of carbon tax and load growth. In response to stakeholder requests, we also looked at the effects of various RPS scenarios as well as a potential low fixed and variable cost new technology that significantly decreases the market price for electricity. In our stochastic analysis, we examined the TailVaR90 of the NPVRR, of variable costs only, and of annual rate changes.

The Diverse + Contracts portfolio (our preferred candidate action plan) performed consistently well both on an expected case basis and under uncertainty in both scenario and stochastic analyses. The Diverse + Contracts portfolio performed well on an expected-case basis by capturing the potential benefits of a temporary surplus in the market through acquisition of fixed-price contracts. Based on our modeling it also provides considerable risk mitigation against market/fuel price fluctuations due to the inclusion of significant amounts of long-term, stable cost renewable resources. Furthermore, a strategy that meets our energy needs through both mid-term contracts and longer-term stable resources provides flexibility to commit to new resources at a later time, allowing for technology and policy developments to mature (e.g., IGCC and greenhouse gas regulations). This portfolio also meets the 2015 Oregon RPS target.

Chapter Highlights

- Several candidate portfolios, including Market, Diverse + Contracts, Diverse Coal, and Diverse Green all lie on the efficient frontier in the scenario analysis.
- Wind + SCCTs and IGCC with Sequestration are also on the efficient frontier but have significantly higher expected costs.
- The Market portfolio performs well with regards to expected cost, but poorly on risk in both scenario and stochastic analyses.
- Coal portfolios perform well with regard to annual rate changes. However, they do not perform as well as diversified portfolios in our stochastic analysis using the TailVaR90 of variable costs only, and they perform poorly under carbon tax scenario analysis.
- We select the Diverse + Contracts portfolio as our preferred candidate action plan because it performs consistently well on an expected case basis and under uncertainty using both scenario and stochastic analyses. This portfolio also provides greater future supply flexibility.

11.1 Deterministic Portfolio Analysis Results

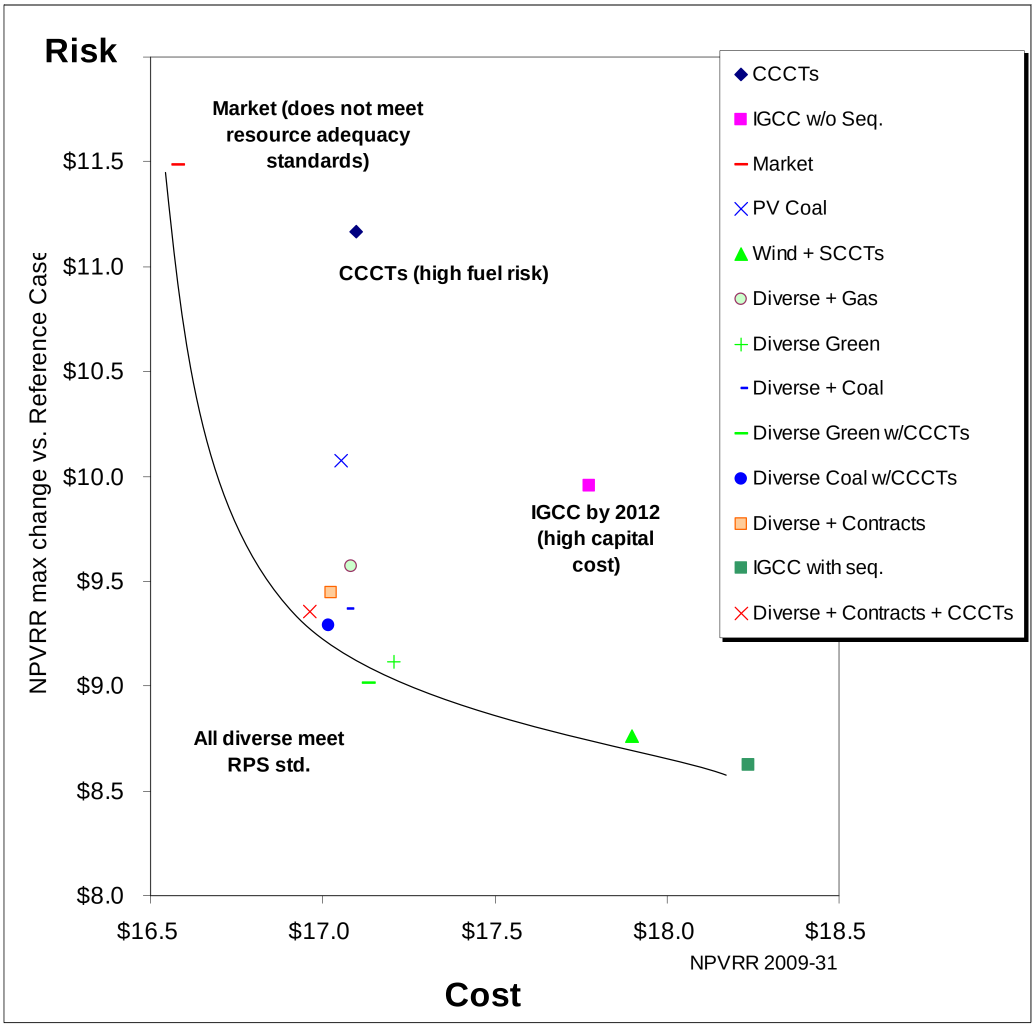
The purpose of portfolio analysis is to identify the combination of resources that consistently performs well across different potential future environments. Future scenarios serve as a good proxy for the kinds of risk that we could encounter. To assess the performance of each candidate portfolio, we calculated the NPVRR for each combination of incremental resources in Table 10-3, along with existing PGE resources, across each discrete potential future described in Chapter 10. We then examined several alternative views of risk and performance, which are described below.

Efficient Frontier

The first and most direct insight from our portfolio analysis is the identification of the expected cost and associated risk for each portfolio. Figure 11-1 shows on the horizontal axis the expected cost of each of the portfolios, defined as the NPVRR of the reference case future, i.e., the future that contains all of our base case assumptions about CO_2 costs, fuel prices, load, capital costs, etc. The vertical axis shows risk, defined as the difference between the maximum NPVRR across all futures and the NPVRR of the reference case. For all portfolios, the scenario that leads to the maximum cost outcome is the combination of high gas prices with a $25 per short ton CO_2 tax.

Traditionally, an efficient frontier graph is interpreted by examining the proximity of the portfolio value to the graph origin (the point where the X and Y axis meet). Portfolios closer to the origin perform more efficiently relative to the cost/risk tradeoff. The efficient frontier plotted in Figure 11-1 is the curve that connects those portfolios that for a given level of risk have the lowest cost, or for a given cost have the lowest risk. Theoretically, an investor (in this case, the utility and its customers) should be indifferent among portfolios that lie on the efficient frontier. Risk tolerance allows the investor to differentiate among portfolios on the efficient frontier and to ultimately select a preferred option. In Figure 11-1, the portfolios labeled Market, Diverse + Contracts + CCCTs, Diverse Coal + CCCTs, Diverse Green, and Diverse Green with CCCTs all lie on the efficient frontier. Wind + SCCTs and IGCC with sequestration are also on the efficient frontier but have a higher expected cost.

Figure 11-1: Efficient Frontier – Risk vs. Cost



We note the following key insights from Figure 11-1:

- *Steepness of the efficient frontier is relevant*. Risk deltas are generally larger than cost deltas. As an example, diversified portfolios are 20% less risky on average than the most risky alternative, Market, while the cost of the most expensive diversified portfolios is just 5% higher than the lowest expected cost option, which is also Market. This suggests that we can influence risk more than cost, given our alternatives, and a comparatively large amount of risk can be eliminated for a fairly small change in expected cost. However, the curve also reaches a point of diminishing marginal returns, where it becomes increasingly costly to further reduce risk.

- *Diverse portfolios generally outperform the single-resource portfolios*. Most single-resource portfolios are not on the efficient frontier.

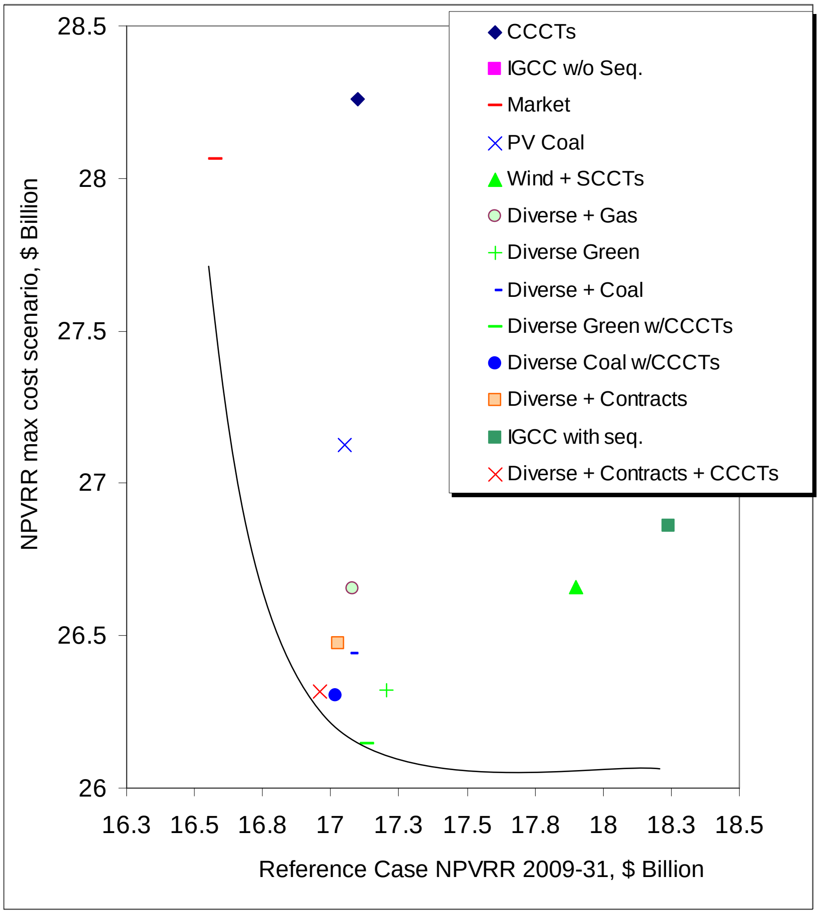
- *Diverse portfolios are tightly clustered*. Given the rather small differences in both risk and cost, the relative performance of these diverse portfolios could easily switch places with relatively small changes to the reference case assumptions.

- *Diverse Gas, Coal, and Green portfolios are modeled in two versions*: one with SCCTs as a capacity back-up resource (mainly to back-up wind) and one with CCCTs. In all cases, and in both the scenario and stochastic analysis, CCCTs add more value to the portfolios (i.e., they reduce both expected cost and expected risk.) SCCTs, however, would be a better operational fit for wind because they are capable of load following. This is an instance in which the analytical evidence needs to be validated once we identify actual projects or capacity options that may emerge from an RFP.

Alternative Perspectives of the Efficient Frontier

Figure 11-2 shows a different plot of the same portfolio results that was suggested during our public process. The horizontal axis measures the NPVRR of the reference case. The risk metric on the vertical axis is now the NPVRR of the highest cost scenario for each portfolio. The main insight from this alternative view is that the Wind + SCCTs and IGCC with Sequestration portfolios no longer lie on the efficient frontier because of their high fixed costs. Market is still the least cost and riskiest strategy. The performance of the diverse portfolios is substantially the same as described above.

Figure 11-2: Efficient Frontier Using the Highest Cost Scenario



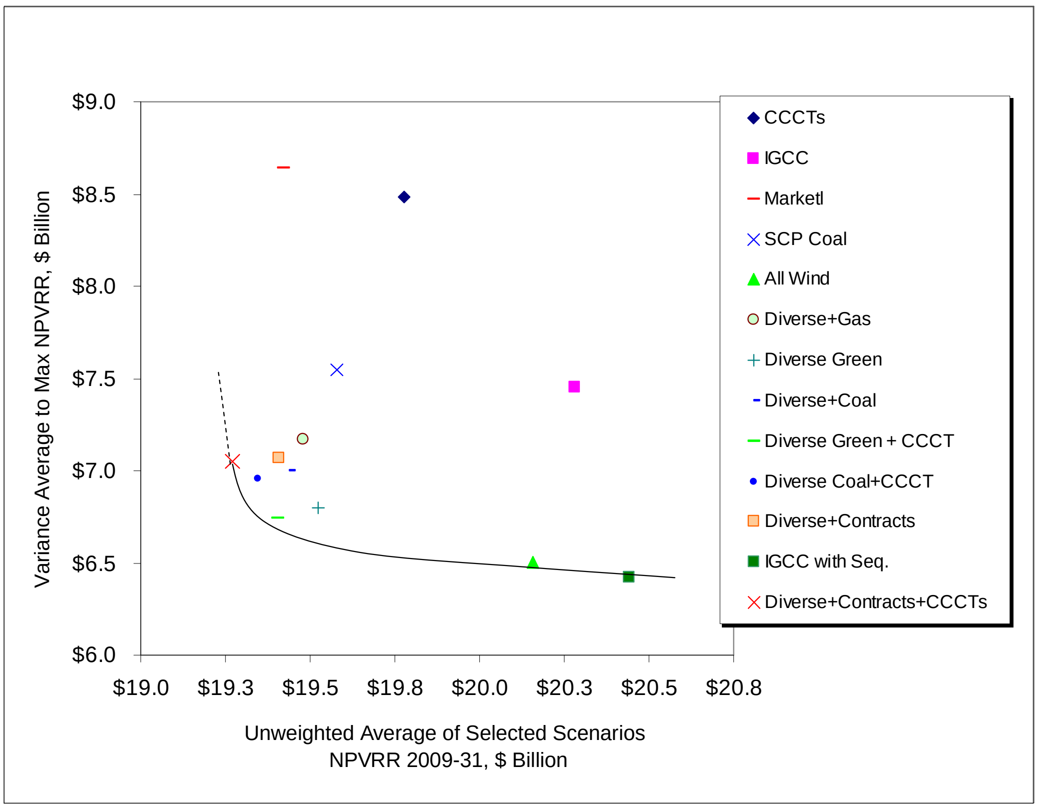
In order to better understand the trade-off between cost and risk, we constructed another alternative view of the efficient frontier depicted in Figure 11-1 in which we do not use the reference case scenario as the basis for measuring performance. Instead, we estimate the cost vs. risk trade-off using the average of a subset of selected futures, inclusive of the reference case. Our goal in choosing this subset is to define a representative sample of distinct futures, with equal weight assigned to scenarios that stress environmental risk, capital cost, fuel, and load uncertainty. Cost is defined as the unweighted average NPVRR of the following subset of futures:

- Reference case
- No CO_2 tax
- Low gas price (real levelized price of $5.1 per MMBtu in $2006)
- Low long-term portfolio load growth (1.2% per year)
- Gas 10% cheaper, renewable resources 10% more expensive
- Coal with 25-year life
- No Production Tax Credit
- $15 gas and low WECC load growth

- High WECC and PGE load growth (3.1% per year)
- High gas price (real levelized price of \$9.2 per MMBtu in \$2006)
- \$40 per short ton CO_2 tax
- High gas price and \$25 per short ton CO_2 tax

We define risk as the difference between the maximum NPVRR and the average cost over the above futures for the candidate portfolios. The graph in Figure 11-3 demonstrates that diversified portfolios continue to perform well using the alternative methodology. While some portfolios changed relative positions, this alternative view further validates the results shown in Figure 11-1, and suggests that diversification offers strong risk mitigation benefits.

Figure 11-3: Efficient Frontier Using Unweighted Average of Select Futures



Probability of High Expected Costs

We further examined each portfolio's probability of being among the worst four performers under various futures with respect to cost. Under this methodology, the probability of poor performance equals the number of times that a given portfolio ranked among the worst five out of the 13 portfolios we tested against all 19 futures. Any portfolio that exhibits a high number of high cost outcomes may be viewed as more likely to perform poorly under conditions that vary from the reference case.

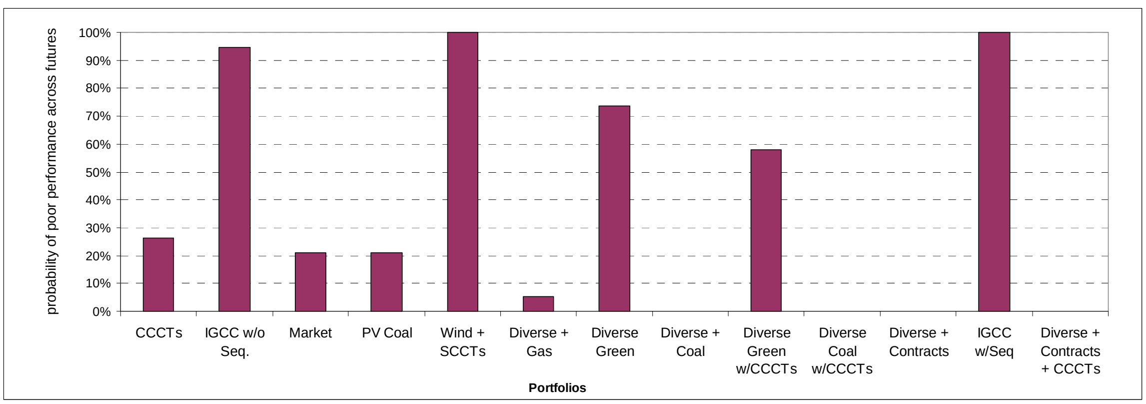
Results shown in Figure 11-4 yield these insights:

- IGCC with and without sequestration performs poorly, due to the high investment cost of this technology, relative to other generation resources.

- The Wind + SCCTs strategy is a consistently high-cost portfolio. This result is driven, in part, by our assumption that increasing amounts of wind will have increasingly higher capital costs and lower capacity factors. This is due to increased competition for turbines and good locations and a likely lower average wind speed for later projects, based on an expectation that the best sites will be developed earlier.

- Diversified portfolios typically avoid high-cost outcomes under conditions that vary from the reference case, as they are generally not overexposed to any single risk factor.

Figure 11-4: Portfolio Probability of High Expected Costs

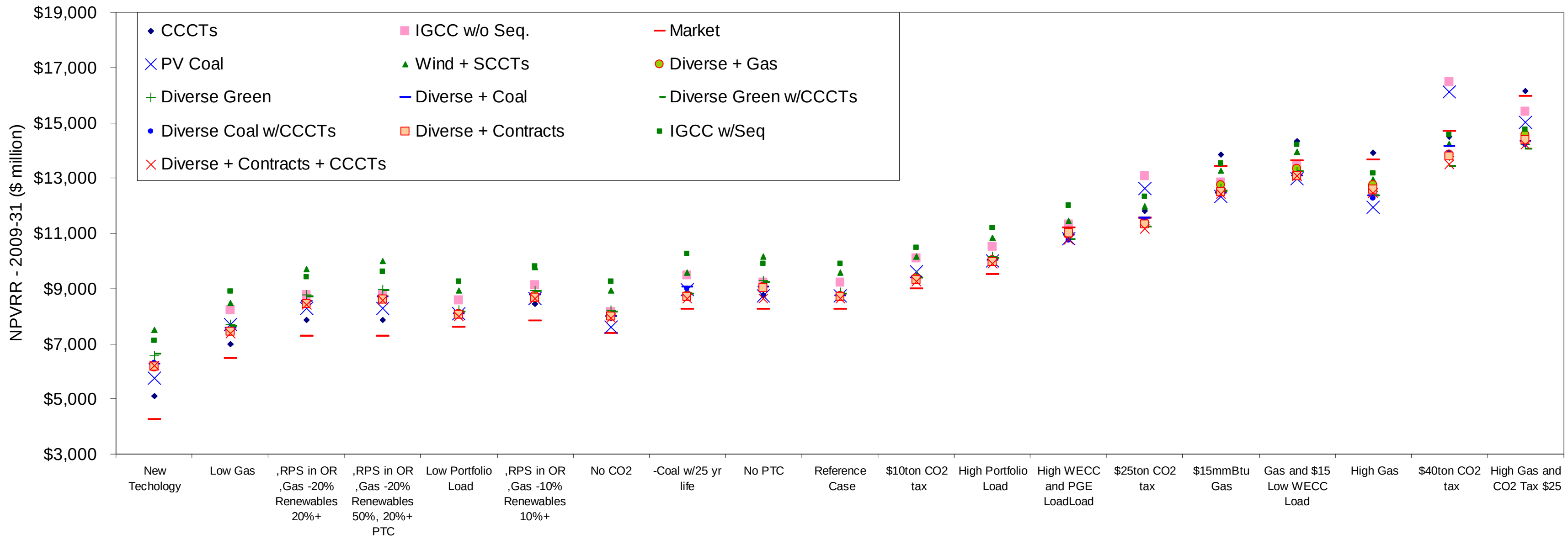


Relative Cost across All Futures

We also wanted to better understand the analytical relationship between scenario results and the underlying portfolios and futures. In other words, we wanted to find out whether the particular mix of new resources selected, or the futures to which they were subjected, had the larger impact on portfolio costs. To understand this, we assessed the incremental cost for each portfolio, defined as the NPVRR of the new resource additions without existing resources, against all futures. Figure 11-5 below shows that portfolio cost results are generally tightly clustered within each future. The results also indicate that portfolios generally tend to increase or decrease in cost depending upon the prevailing future conditions. In very costly future environments (e.g., high carbon tax and high gas costs), all portfolios exhibited higher cost results. Likewise most portfolios exhibited lower cost returns in prevailing lower cost environments, such as low gas prices. In addition, different futures tend to increase or decrease the cost differentials across portfolios. Relative cost differences are also more pronounced in the more extreme futures. However, varying the futures (particularly using extreme, high cost futures) also changes the rank order of portfolios on a cost basis. Figure 11-5 shows that diversified and greener portfolios perform more consistently across various futures but that the ability to hedge against futures by selecting one optimal portfolio is relatively limited.

Appendix H: Portfolio Analysis Results shows the NPVRR associated with each portfolio and scenario shown in Figure 11-5.

Figure 11-5: Relative Cost Across Futures of the Incremental Portfolios



Other Quantitative Performance Metrics

Our evaluation of portfolio performance under other important metrics which have direct bearing on the selection of our action plans are summarized in Table 11-1 below. The table provides a snapshot of portfolio performance as of 2012.

The first metric is ***CO_2 intensity***, which is defined by the carbon content per MWh generated and/or purchased to meet our load. We assumed a CO_2 content of 1,100 lb/MWh (a commonly used emission rate, about equal to the carbon content of existing CCCTs) for market purchases. Not surprisingly, Wind + SCCTs and the IGCC with Sequestration portfolio rank best using this metric.

The ***investment*** metric measures the total investment cost of procuring new long-term resources. For modeling purposes we assume that all resources are added in 2012. The range of investments required for procuring 1,016 MW of capacity and 818 MWa of energy is wide, ranging from $0.5 billion for the CCCT portfolio, to $3.1 billion for Wind +SCCTs. New wind resources are very capital intensive, as are new coal plants. However, high fixed-cost resources (such as wind or coal) typically have low variable and fuel costs.

The ***initial rate impact*** metric is calculated as the ratio between the total revenue requirement for a given new resource portfolio and our estimate of overall PGE revenue requirements in 2012 prior to new resource actions. All revenue requirements associated with the generating plants, including fuel and environmental taxes, are included in the rate impact calculations. Again, we assume that we add 818 MWa of energy and 1,016 MW of capacity in 2012 (as opposed to staging procurement over a longer time-frame). Based on this metric IGCC and Wind + SCCT perform relatively poorly due to high capital costs which, under current regulatory practices, are front loaded, resulting in larger initial rate impacts. However, the higher capital intensity and lower variable costs associated with these resources also contribute to increased expected rate stability over time. Diversified portfolios have reduced initial rate impacts compared to single-resource IGCC and Wind portfolios, but higher initial rate impacts compared to the much riskier Market and CCCT portfolios.

The ***variable percentage of generation revenue requirement*** metric measures fuel, variable O&M, and short-term market purchase costs as a percentage of the total generation cost. Portfolios with higher percentages of variable costs are typically more exposed to fluctuations in energy market prices, therefore increasing the risk of volatile rates. The worst performing portfolios, based on this metric, are CCCTs and Market. Diversified portfolios are among the best performing portfolios using this metric.

The ***number of shafts*** metric counts the number of generating units that the portfolio adds. A higher number of shafts reduces the risk of losing a large unit and being incapable of serving load, or needing to replace power generated by that unit at a potentially high cost. The Wind + SCCTs and diverse portfolios perform best on this metric, assuming that the renewable resource portion of the diverse portfolios is dominated by wind. This metric only measures generator risk and does not account for other single contingencies such as substation and transmission facilities.

Table 11-1: Evaluation of Other Portfolio Metrics

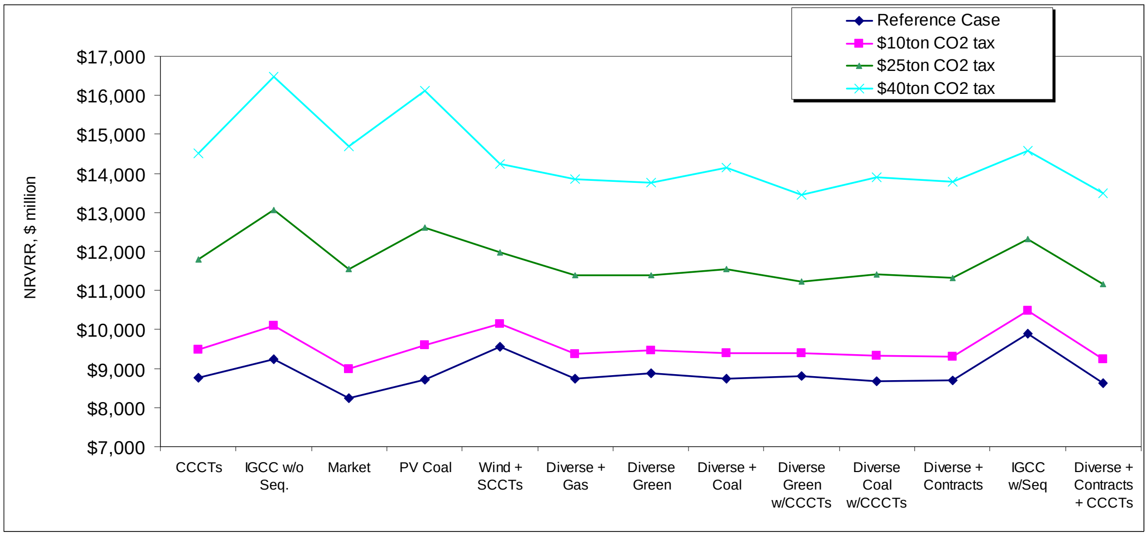
"Pure Play" Portfolios ==>	CCCTs	IGCC w/o Seq.	IGCC with Seq.	Market	PV Coal	Wind + SCCTs	
CO_2 Intensity - Tons per GWh	479	582	389	507	592	386	
Investment, $ billion	$0.5	$1.9	$2.5	none	$1.3	$3.4	
Estimate of Initial Rate Impact, '	4%	12%	17%	0%	6%	15%	
Variable % of Gen. Rev. Req.	64%	56%	52%	69%	58%	47%	
Number of Shafts	2 to 4	2	2	-	2	> 100	
Diverse Portfolios ==>	**Diverse + Gas**	**Diverse Green**	**Diverse + Coal**	**Diverse + Contracts**	**Diverse Green w/CCCTs**	**Diverse Coal w/CCCTs**	**Diverse + Contracts + CCCTs**
CO_2 Intensity - Tons per GWh	425	407	446	427	397	438	418
Investment, $ billion	$1.8	$2.3	$2.0	$1.8	$2.4	$2.1	$1.9
Estimate of Initial Rate Impact, '	11%	13%	11%	11%	13%	11%	11%
Variable % of Gen. Rev Req.	49%	46%	48%	46%	46%	47%	45%
Number of Shafts	>100	>100	>100	>100	>100	>100	> 100

In examining these metrics, it becomes clear that no one resource type dominates the others in performance across all metrics. Overall, the Diverse + Contracts portfolio performs well, in particular based on estimates of initial rate impacts and shaft risk.

11.2 Carbon Tax Performance

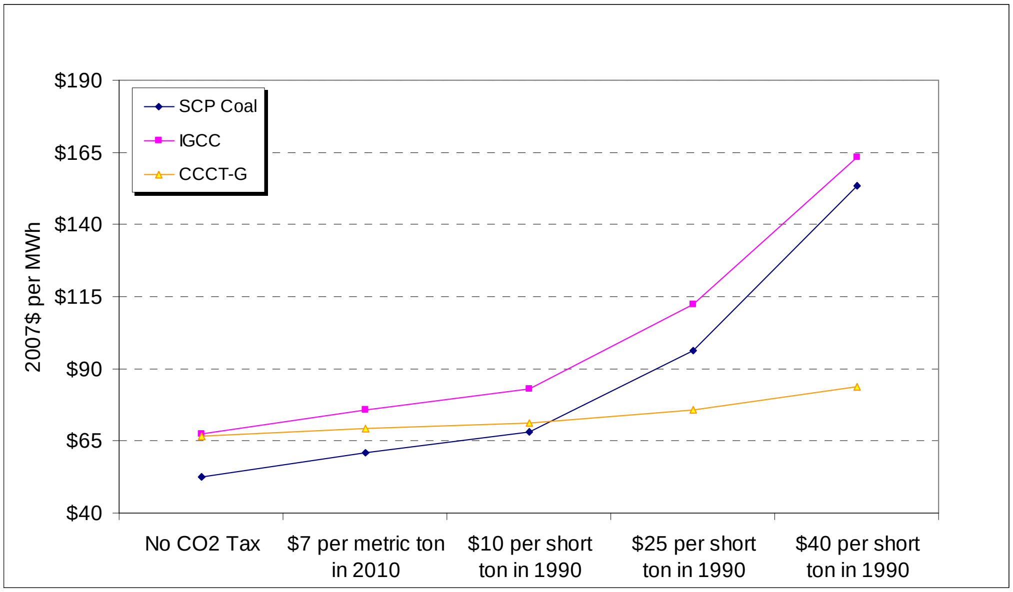
Following Guideline 8 of Order No. 07-002 governing integrated resource planning, we analyzed the impact of potential CO_2 regulatory costs from zero to $40 per short ton (in $1990) on each of our portfolios. Our reference case assumes a CO_2 tax of $7.72 per short ton in $2010, based on the original NCEP legislation. In Figure 11-6 below, we assess the NPVRR of each portfolio under different CO_2 tax levels. Results show that low carbon portfolios hedge against increasing carbon risk. According to this analysis, the Market portfolio appears to perform well due to its low expected case cost, not due to its emissions levels.

Figure 11-6: Carbon Tax Performance of the Incremental Portfolios



One outcome of this analysis is portrayed in Figure 11-7. As the carbon tax increases, the cost per MWh of power generated by coal plants increases significantly, while the cost per MWh of CCCT generation remains relatively flat, despite the fact that gas also has the same carbon tax based on dollars per ton of CO_2. This is because new CCCTs produce only about 40% of the CO_2 per kWh produced by a new coal plant. As the carbon tax rises, the dispatch cost of a coal plant increases proportionally more than the dispatch cost of other resources, increasing the overall market price of electricity. As a result, the dispatch value of a baseload gas unit goes up, even though it also experiences increased CO_2 costs. In effect, coal and gas swap places in the resource stack at a high enough carbon tax. Where that intersection lies is also a function of the prevailing price of natural gas. This analysis further suggests that a high carbon tax would have the effect of reducing demand for resources that have high CO_2 emissions.

Figure 11-7: Levelized Revenue Requirements of Fossil Fuel Resources across Carbon Tax Scenarios and Reference Case Gas Price



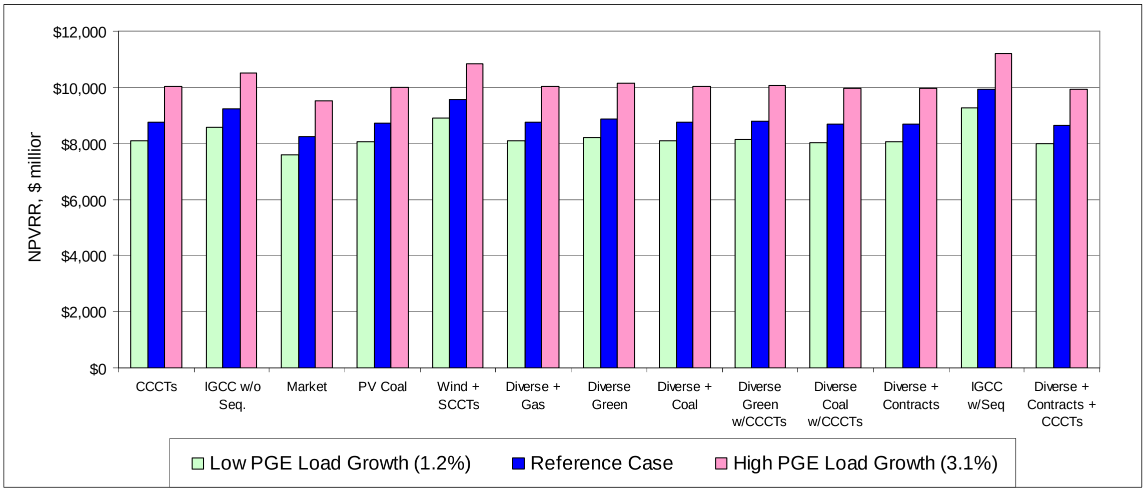
11.3 Other Portfolio Performance Stress Testing

Load Growth Stress Testing

Guideline 4b of Order No. 07-002 requires an analysis of high and low load growth scenarios. The analysis provides insights into the potential impacts of fundamental shifts driven by the economy, population growth, or unforeseen changes to electric end uses. In addition, the order requires a stochastic load risk analysis with an explanation of major assumptions. Stochastic load risk in our analysis is driven purely by weather. We further address stochastic load risk later in this chapter.

Figure 11-8 shows portfolio performance under the reference case load growth (2.2% per year), high load growth (3.1%), and low load growth (1.2%). All portfolios are affected similarly: they all add the same amount of market purchases when load is systematically higher than forecasted. When PGE load is lower than forecasted, all portfolios reduced market purchases by the same amount. The resulting risk is being overly long with commitments to longer-term resources when loads do not meet expectations, or conversely, of being too market-dependent in the instance where load growth exceeds expectations.

Figure 11-8: Incremental Portfolio Performance under Load Growth Stress Testing



Given our focus on 2012 actions and the consequent decision to freeze load growth after 2014, these sensitivities offer limited insights because an unexpected short or long position, with respect of our actual need, could be adjusted after 2012.

Electricity Price Sensitivities

At the request of our stakeholders, we looked at a scenario in which a new (currently unknown) generation technology would enter the market with both low fixed and low variable costs. This scenario was meant to assess the uncertainty in long-term resource planning introduced by technological innovation. It is an examination of one possible paradigm risk.

We assumed, per the stakeholder suggestion, a new technology plant (NewTech) that has capital and fixed costs similar to that of a combined cycle plant, but with no fuel costs (similar to a wind plant) and low variable O&M costs. We ran long-term capacity expansion in AURORAxmp, where the NewTech plant is among the available resource choices. We also assumed that PGE had already built its new portfolio just prior to emergence of the NewTech option, so that we could see how our portfolios performed under this unique future. The resulting electricity prices are shown in Figure 11-9.

Figure 11-9: Low Electricity Price Scenario vs. Reference Case

Given the aggressive cost assumptions for the NewTech plant, the impact on portfolio cost could be dramatic, as seen in Table 11-2. Not surprisingly, the portfolio that is most exposed to prevailing market conditions, the Market portfolio, experiences the greatest reduction in cost, while the portfolios that are most insulated from changes in energy market prices such as Wind + SCCT experience the least change in cost.

Table 11-2: Portfolio Cost in a Low Electricity Price Scenario, $Billion

	CCCTs	IGCC w/o Seq.	IGCC w/Seq.	Market	PV Coal	Wind SCCT	Div. + Gas	Div. Green	Div. + Coal	Div. + Contracts
Reference Case										
NPVRR	$17.1	$17.8	$18.2	$16.6	$17.1	$17.9	$17.1	$17.2	$17.1	$17.1
% Delta vs. Market	3.1%	7.2%	10.0%	0.0%	2.9%	8.0%	3.0%	3.8%	3.0%	3.3%
New Technology Case										
NPVRR	$9.6	$10.9	$11.6	$8.8	$10.2	$12.0	$10.7	$11.1	$10.8	$10.7
% Delta vs. Market	9.8%	24.1%	32.7%	0.0%	17.0%	37.1%	21.6%	26.5%	23.0%	22.0%

The lessons from this scenario are two-fold. First, portfolios that are best hedged against adverse changes in the prevailing market, i.e., those with higher fixed costs and low variable costs, are less able to benefit if overall market prices decline. Second, to maintain our ability to take advantage of the potential benefits from such a paradigm shift, we should maintain capital flexibility to pursue new future opportunities that do not currently exist. While our preferred resource plan is more fixed-cost intensive due to a relatively high proportion of wind, we also propose inclusion of a significant amount of mid-term contracts. Doing so provides the additional potential benefit of bridging and retaining partial flexibility to respond to emerging technology opportunities. However, we must also remain cognizant that changing external factors could have the opposite impact of higher market prices, and if signals suggest such a future environment, we will need to be prepared to respond by reducing our exposure to market.

11.4 RPS Sensitivities

In response to another stakeholder request, we performed five sensitivities to determine the performance of our portfolios under different specific futures which could result from the implementation of an RPS in Oregon.

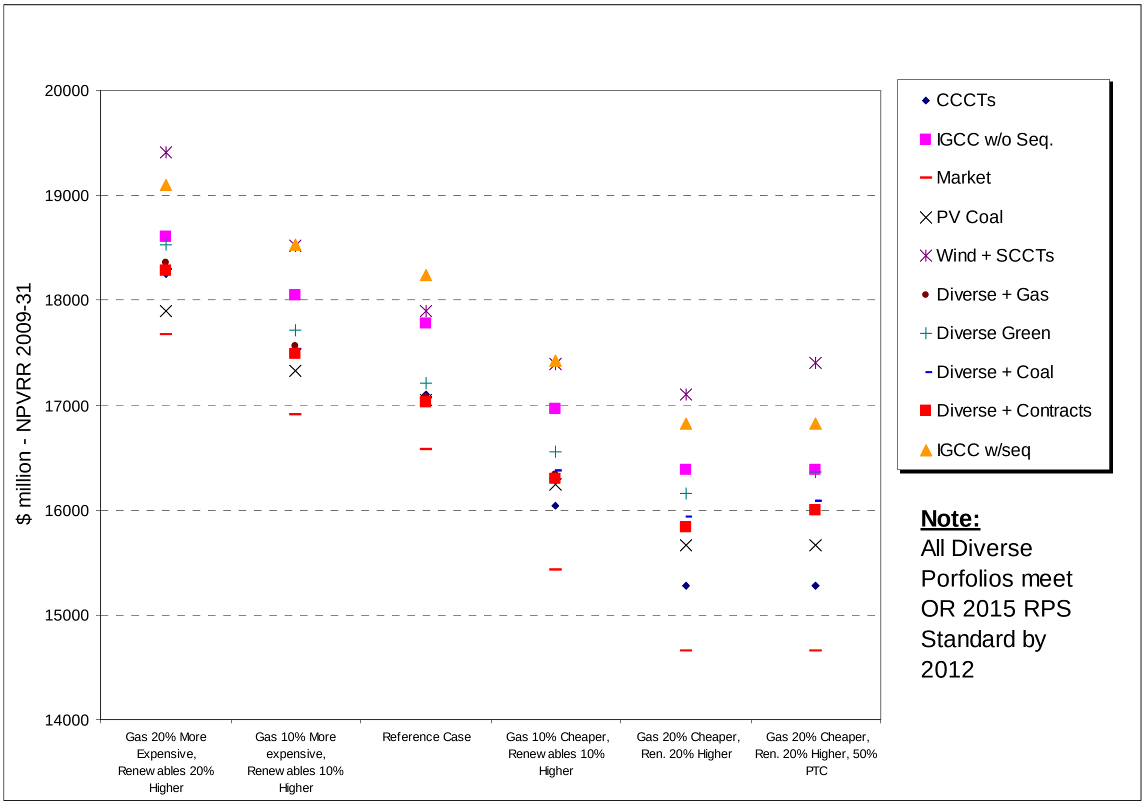
More precisely, these scenarios assume that an RPS would lead to increased demand for wind turbines and would inflate their relative capital costs by 10% and 20% vs. the reference case. The impact of an RPS on natural gas prices is less predictable, so we test both an increase and a decrease in gas prices.

We tested portfolio performance across the following RPS sensitivities:

- Gas price decreases10%, capital cost of renewable resources increases 10% (both from the reference case costs)
- Gas price decreases 20%, capital cost of renewables increases 20%
- Gas price decreases 20%, capital cost of renewable resources increases 20%, PTC at 50% of the current rate
- Gas price increases 10%, capital cost of renewables increases 10%, and
- Gas price increases 20%, capital cost of renewables increases 20%

The results of these sensitivities are shown in Figure 11-10. Changes in capital cost and the PTC benefit have significant impacts on the cost of renewable resources. It is also clear that the costs of all portfolios rise or fall with significant changes in gas prices. Cost differences among portfolios become larger under higher cost renewable resource futures combined with low gas prices. An exception to this is that natural gas-based resources perform better on a relative basis under low natural gas price conditions. It should also be noted that the relative portfolio rankings under the above RPS sensitivities generally do not change greatly from the reference case rankings.

Figure 11-10: Portfolio Performance under RPS Scenarios



11.5 Stochastic Analysis Results

The results of our stochastic analysis, in which we tested our portfolios against stochastic inputs for loads, gas prices, forced outages, and hydro, are summarized in the following three graphs.

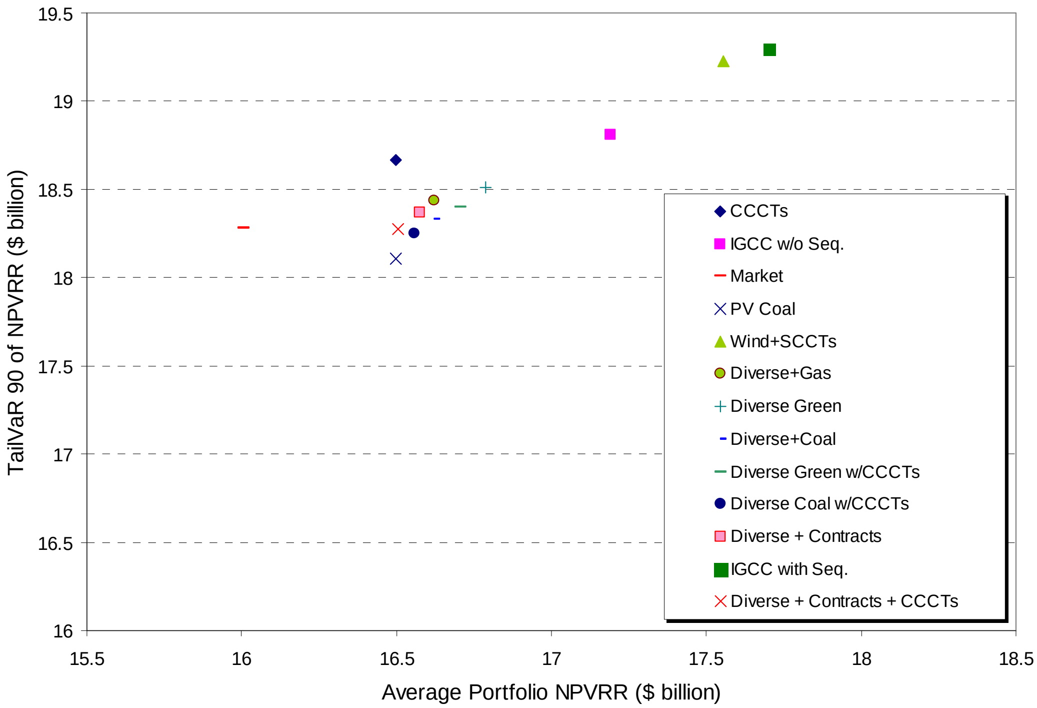
The defining characteristics of our stochastic runs are captured by the average prices of gas and electricity and their respective volatilities and correlations. Table 11-3 shows the average prices of Sumas and AECO (two primary Pacific Northwest natural gas trading hubs from which we fuel our plants) in the deterministic case compared with the prices in the stochastic case. Averaging in the deterministic case covers the 23-year period, while averaging in the stochastic case is calculated for all years and across all iterations (23 years multiplied by 100 iterations.) For natural gas, the two prices at Sumas and AECO are very close. The average electricity prices generated by AURORAxmp in the stochastic analysis show a modest difference of $1.6 per MWh (or 3%) because the average hydro generation across the 100 stochastic iterations is somewhat higher than the reference case. The standard deviations and volatilities of gas and power are calculated from their monthly data. The correlations between power and gas are around 49 percent, suggesting that simulated correlations are lower than historically observed. This is in part because the electricity prices determined by a model like AURORAxmp do not account for all the exogenous influences that exist in the real world.

Table 11-3: Stochastic Price Summary 2009-31 ($2006)

	PGE Electricity Prices $/MWh			Sumas Gas Prices $/MMBtu		AECO Gas Prices $/MMBtu	
	Base Case	Stochastic		Base Case	Stochastic	Base Case	Stochastic
Mean	$51.8	$49.1		$5.9	$5.9	$5.7	$5.8
Standard Deviation	NA	0.3		NA	0.2	NA	0.2
Annualized Volatility (%)	NA	93.6		NA	67.9	NA	62.8
Correlations :							
		Maximum	Mean	Minimum			
PGE Electricity Prices vs. Sumas		0.64	0.48	0.18			
PGE Electricity Prices vs. AECO		0.64	0.48	0.18			

In Figure 11-11, we present a view of the tradeoff between cost, as measured by the NPVRR of the total revenue requirement over the 23-year study horizon, and risk, as defined by the TailVaR90 of this measure (see Chapter 10 for an explanation of TailVaR90). Using this methodology, which does not reflect deterministic scenario shocks, the Market portfolio appears to be the lowest cost and one of the lowest risk options. Since this portfolio does not have a fixed cost component, the TailVaR90 risk is low despite the more volatile nature of its revenue requirements. Pulverized Coal, CCCTs, and most diverse portfolios are closely clustered together. There is no material statistical difference between these portfolios, and thus a decision maker should be indifferent among them when considering only the stochastic risks mentioned above. Some portfolios, however, are clearly less desirable because they are more costly with no decrease in risk. These include both the IGCC and Wind +SCCTs portfolios.

Figure 11-11: TailVaR90 of NPVRR vs. Average Portfolio NPVRR

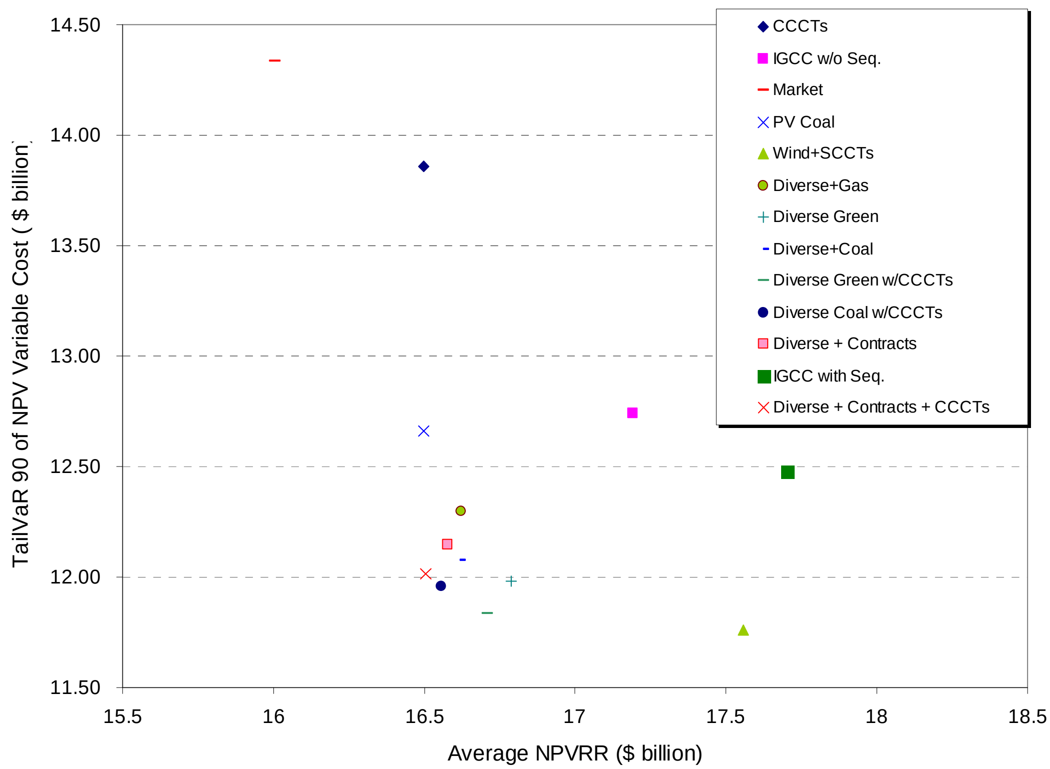


Another view of portfolio stochastic performance is found in Figure 11-12, where the Y-axis represents risk as measured by the TailVaR90 of a portfolio's variable cost only. This approach allows us to identify variable cost risk, which is estimated annually and assigned to customers in our annual net power cost updates. More precisely, once we invest in a new plant, its fixed cost is accounted for in rates. However, customers remain vulnerable to fluctuations in fuel cost and power purchase prices (i.e., variable costs). The X-axis is the same as in Figure 11-11, showing the sum of both variable and fixed costs.

While the Market portfolio remains the best portfolio in terms of cost, it now has the highest risk level, far higher than the risk of the diverse portfolios. The bookend portfolios CCCTs and Traditional Coal now are also more risky. The CCCTs portfolio yields a similar outcome. Several of the diverse portfolios now define the efficient frontier in this view.

The predominantly single-resource portfolios that fall on a straight line in the previous graph have moved apart. All single-resource portfolios, with the exception of Market, are less efficient as they are higher risk for a modestly lower cost than are diverse portfolios. The IGCC and IGCC with Sequestration portfolios, however, remain on the right side of the graph but have moved away from the efficient frontier. This leads us to rule them out as optimal choices because they are less attractive than the six diverse portfolios.

Figure 11-12: TailVaR90 of NPV Variable Cost vs. Average Portfolio NPVRR

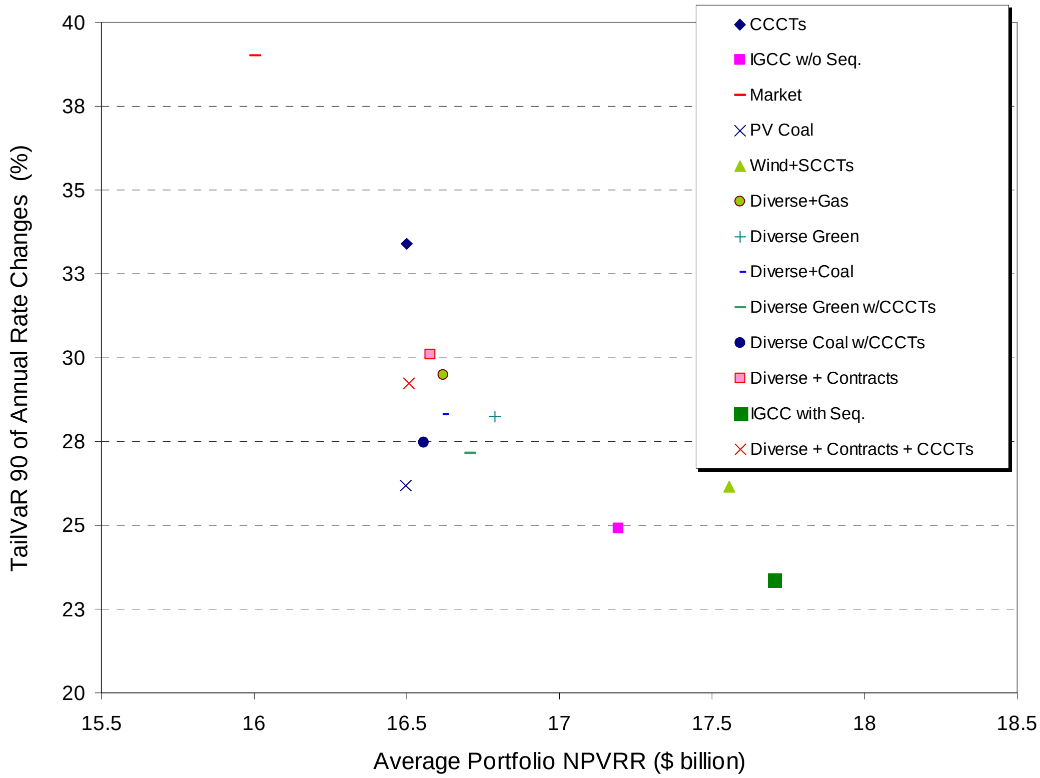


Finally, we present a view that determines risk from the perspective of potential customer rate changes. In Figure 11-13, the Y-axis is the TailVaR90 of the annual changes in rates during the period 2013 to 2031. It measures the average of the highest 10% annual rate increases across 100 iterations that our customers could experience with each portfolio.

As in the previous graphs, the Market portfolio performs the worst in terms of rate increase risk, as expected. It has by far the highest average rate change of all portfolios considered. The IGCC with Sequestration portfolio has the lowest rate increase risk. This portfolio is better insulated against variable cost risk than even an all wind portfolio, which requires incremental gas resources for firming and capacity augmentation. The efficient frontier in this view (which does not contain CO_2 tax scenario risk) is defined by a traditional coal plant that has low costs and is well insulated from price risk.

The diverse portfolios again tend to cluster and are both more costly and riskier than the traditional coal-only portfolio. However, they outperform most other portfolios.

Figure 11-13: TailVaR90 of Rate Changes vs. Average Portfolio NPVRR



Some participants in our IRP public meetings have correctly observed that long-term future/scenario analysis is more insightful than stochastic analysis, as scenario analysis considers a wider range of risk factors. Nevertheless, stochastic analysis is valuable in its own right, and both types of modeling methods are necessary to fully examine portfolio performance and durability. They answer different questions, and thus contribute to a broader, more informed set of insights for our decisions.

11.6 Summary of Portfolio Performance and Uncertainties

The deterministic and stochastic portfolio analyses described above reveal both strengths and weaknesses of the different procurement strategies. Below, we describe and summarize performance for each of our candidate portfolios. All of them, except the Market portfolio, have three resources in common: 16 MW of ongoing plants efficiency upgrades, 167 MW of contract renewals, and a reliance on short-to-mid term contracts for 180 MW to provide supply flexibility against future load uncertainty (see Chapter 3 for a description of load forecasts and opt-out options for our customers). The Market portfolio represents an aggressive short strategy, where we do not pursue plants upgrades, EE, or contract renewals, and rely instead entirely on spot purchases to meet customer load.

Market

This strategy does not add any long-term resources and would thus offer benefits only during times of expected regional over-supply and relative stability in energy markets. This strategy has the least expected cost across all futures that assume no resource scarcity-related market shocks, such as sustained poor hydro conditions, delays in the addition of new resources to meet expected WECC load growth, high gas prices, and higher than expected load growth. An example of a future in which Market performs poorly is the high PGE and WECC load growth future, which projects resource deficits instead of perfect supply-demand equilibrium. In this scarcity future, Market ranks second to worst. This portfolio also ranks worst when we assume that a high CO_2 tax and/or high gas prices will increase wholesale electricity market prices. This portfolio also is the worst performer in customer rate stability as measured by the TailVaR90 of rate changes metric (see Figure 11-13). Finally, this strategy does not meet regional resource adequacy standards and has by far the highest likelihood of load curtailment (see Loss of Load Probability in Chapter 12). Paradoxically, however, the low expected cost of this strategy depends on other WECC participants building new resources to meet reliability standards.

CCCTs

This strategy assumes the construction of 604 MW of G-class CCCTs and 49 MW of SCCTs. The strength of this portfolio is the low capital commitment required for implementation and low incremental CO_2 production. A baseload natural gas portfolio performs well under low gas price scenarios and does not cause initial high rate impacts due to its relatively low front-loaded capital costs. However, because around two-thirds of its revenue requirement is fuel, its performance is the worst in all scenarios with gas prices above $6.4 per MMBtu (in real levelized $2006). This portfolio also increases aggregate reliance on gas-fueled resources to meet our load and would therefore reduce the overall diversity of our resource portfolio.

Pulverized Coal

This strategy adds 653 MW of supercritical pulverized coal in 2012. It is among the best performing portfolios in many futures and based on stochastic analysis. It also relies on a domestic, relatively stable-priced, and secure source of fuel.

However, this portfolio is the worst performing plan in high CO_2 cost futures and increases the CO_2 intensity of our overall portfolio. It has high shaft risk, very high capital costs, a long construction period, and a high first-year rate impact. Pursuit of this portfolio would also require an investment of $1 billion or greater (for a 100% share of the plant), and the five-year permitting and construction cycle adds substantial interest expense to the investment basis. Uncertainty also exists in the area of capital costs, as projected costs for new coal plants have increased steadily over the last few years. Further uncertainty exists related to transmission for such a large and typically remote central station generation resource. Transmission to potential new mine-mouth coal plant sites in Montana or Wyoming is currently not available and other potential sites would likely require incremental cost for rail transport for coal.

IGCC With and Without Sequestration

This strategy is similar to the one above with the exception that the coal technology of choice is gasification combined cycle CT, which would increase efficiency (reduce heat rate), reduce certain emissions, and allow CO_2 to be more easily isolated and captured. We modeled IGCC with and without sequestration assuming underground storage. This portfolio performs poorly according to most measures; it is the worst of all portfolios based on both scenario and stochastic analyses. This portfolio is penalized by very high and uncertain fixed costs, as well as reduced efficiency in the case with sequestration due to the energy requirements for compression and pumping of CO_2. IGCC does not appear to be a viable near or mid-term option for PGE, as it has not been widely commercialized. Some stakeholders have also suggested that such a plant would be expected to sequester a substantial portion of its CO_2 upon operation. Underground storage in the Boardman area basalts appears to be technically feasible, but pilot test holes have not yet been drilled or monitored. Unlike areas where enhanced oil and gas recovery can be leveraged, sequestration in the basalts would not provide a revenue stream to offset the additional costs.

Wind + SCCT

This portfolio adds 1,728 MW of nameplate wind[81] by 2012, and 394 MW of SCCTs. Though free from emissions and fuel risk (except for the SCCTs), two primary risk factors, this strategy is very capital intensive and leads to the highest initial rate impact among our portfolios. On the other hand, this portfolio remains on some views of the efficient frontier because it minimizes risk based on its reduced exposure to changes in external factors such as fuel prices.

[81] As a reminder, we assigned a 15% capacity value to wind. A 1,728 MW nameplate capacity is therefore equal to 1,728 MW * 15% = 259 MW usable capacity, which is the number reported in Table 10-3.

The addition of SCCTs to provide backup capacity also leads to additional fixed costs. Our assumed Tier II wind also has a higher capital cost and a lower capacity factor. The IRP public process highlighted the difficulties in modeling the capacity value of wind and comparing it to other resources (see Chapter 12 for information and analysis). We opted for a simplified approach that assumed that SCCTs are the primary option to serve as backup capacity for wind. We use the least expensive CTs available for this purpose, the 7FA frame machines.

Diverse + Gas

As with all of our diverse portfolio candidates, this portfolio meets the 2015 Oregon RPS target with a mix of mostly wind, with smaller amounts of biomass and geothermal. The remaining resource need is met by 113 MW of CCCTs, 45 MWa of incremental EE, 100 MW of long-term contracts, and 199 MW of SCCTs for capacity. It has similar weaknesses to the all-CCCT portfolio (exposure to fuel price volatility). However, these weaknesses are partially offset by the large amount of more stable cost renewables. Though more balanced than the preceding portfolios, it performs slightly worse than the other diversified portfolios across all futures.

Diverse + Coal

This portfolio meets Oregon's 2015 RPS target and is different from Diverse + Gas in that it replaces gas fired resources with 122 MW of supercritical pulverized coal. The additional coal is a modest enough amount that carbon tax impacts are not severe until the upper end of the carbon tax range is approached. We modeled two versions of this portfolio - one in which SCCTs provide additional capacity, and another in which CCCTs meet this need. Overall, Diverse + Coal performs well, especially when we use CCCTs for capacity, as baseload gas units provide an economic benefit by selling excess energy into the market when not needed for capacity. To pursue this strategy, we would need to buy a share in an existing or new coal plant.

Diverse Green

This portfolio is similar to Diverse + Coal, but with additional renewable resources added in place of coal. This portfolio is on the efficient frontier and ranks among the best in both scenario and stochastic analyses. It adds 1,083 MW (nameplate) of diversified green energy in the form of wind, biomass, and geothermal. It also adds more SCCTs for capacity (243 MW). The big advantage of this portfolio over the Wind + SCCTs portfolio is the inclusion of biomass and geothermal, which have less need for capacity back-up, and 45 MWa of EE, which has an expected lower cost for customers than a Tier II wind plant. The main weaknesses and risks of this portfolio are the capital requirement and uncertainty surrounding availability and cost of acquiring such a large amount of wind, biomass, and geothermal resources over a relatively short timeframe (by 2012).

Diverse + Contracts

This is our recommended portfolio. The mix includes 855 MW (nameplate) of renewable resources by 2012, 45 MWa of incremental energy efficiency, 194 MW of long-term contracts, and 214 MW of SCCTs (for capacity back-up). We also modeled a version with CCCTs providing capacity back-up. One advantage of the Diverse + Contracts portfolio is that it captures the potential benefits of a temporary surplus in the market through acquisition of fixed-price contracts. It also provides considerable risk mitigation against market/fuel price fluctuations by inclusion of significant amounts of long-term, stable cost renewable resources.

This portfolio performs consistently well across all scenarios relative to the other portfolios. This strategy also provides us with flexibility to commit to new resources at a later time. It could thus be referred to as a bridging strategy because it allows time for current technologies (IGCC, CO_2 sequestration, solar, ocean wave, nuclear, etc.) to further mature and commercialize, while allowing public policy (CO_2 tax, etc.) to develop. However, the plan carries some risk that market electricity prices could be much higher when new contracts expire and need to be replaced. This strategy has slightly higher risk than the other diversified portfolios but lower expected cost and increased flexibility.

12. Capacity Analysis and Results

In this chapter we analyze an emerging issue for PGE and the entire region. Traditionally, due to a significant hydro resource base, the Pacific Northwest has had been energy constrained, not capacity constrained. This is due to the relatively low capacity factors of the regional hydro system, typically on the order of 50% and sometimes significantly less in dry years, and the highly usable capacity at many of the regional hydro plants. Much of this hydro capacity can be used for load factoring, automatic generation control, load following, regulation, and spinning and standby operating reserve. Regional planning has focused on having enough firm energy capability in dry years, adding thermal plants as required. This practice of building for energy requirements generally resulted in significant capacity surpluses. Our region is unique in this regard as most areas of the U.S. have required incremental energy and capacity to meet changes in load over time. As a result, planning for PGE and most regional utilities historically focused on acquiring baseload energy resources, with little attention paid to capacity beyond the amount brought by new energy resources.

The energy actions described in our Energy Action Plan (see Section 13.1) will bring approximately 904 MW of capacity, on an annual average basis. This leaves about 748 MW of capacity need to be filled to meet our winter need and 536 MW to meet our summer peak. In the sections below we take a more detailed look at the capacity situation for PGE and the region and examine various resource alternatives to meet this need, including customer-sited demand response alternatives, dispatchable resources, and potential market products.

Chapter Highlights

- Unlike in past IRPs, we no longer believe that we can rely on spot markets to supply the last 500 MW of peak demand. This is due to expected tighter regional load/resource balance over time, increased utilization of the hydro system to balance higher levels of wind, and increasing transmission grid constraints that may limit our ability to import power from distant sources during future peak events.
- Our analysis of the correlation of market prices to peak loads indicates that market reliance is increasingly more expensive, more volatile, and riskier in terms of adequacy as loads increase.
- Due to decreased Mid-C access, we may not have sufficient hydro load following capabilities by 2012 to entirely meet the daily average peak hour load variability after inclusion of new wind resources.
- Our loss of load probability analysis validates our 12% reserve margin (capacity reserve margin of approximately 500 MW) as a minimum reliability standard.
- Customer-sited demand alternatives are a low-cost resource to meet the highest incremental peak loads during the year; however, they are not currently available in sufficient quantity to meet all of our peak needs.
- Dispatchable supply resources may provide a cost-effective alternative to meet the remaining peak demand.
- While CCCTs reduce both expected cost and risk when compared to an equivalent amount of SCCTs, they do not have the dispatch flexibility of SCCTs. SCCTs can serve the dual purpose of both integrating wind and providing incremental capacity.

12.1 Current and Future Ability to Meet Peak Demand

Supply-Side Factors

On the supply side, we forecast a reduction in high capacity hydro resources for our system, both in aggregate and in proportion to our load. This is due to expected reductions in contract hydro resources over time[82]. At the same time, we are projecting significant wind resource additions for both PGE and the entire WECC, which have a low capacity-to-energy contribution (5 to 15% of nameplate capacity is usable for capacity purposes, per NWPCC's current assumptions). To illustrate, 35 MWa of hydro might bring 70 MW of capacity. However, 35 MWa of wind (100 MW name plate) would bring a capacity contribution of between 5 and 15 MW (i.e., up to a 14-fold difference). A thermal plant with a 100 MW nameplate or rated capacity is generally expected to provide 100 MW when needed (assuming that there are no forced outages or maintenance occurring).

The current amount of wind on our system is about 100 MW (nameplate, including Vansycle and Klondike II). However, both of these resources are being integrated by third parties through contract shaping and firming arrangements. As a result, we are not exposed to the short-term impacts of the resource variability. The nameplate total of wind on our system is projected to increase to approximately 225 MW with the addition of Phase I of Biglow Canyon. Our preferred Energy Action Plan, presented in the following chapter, and the Oregon RPS would increase our wind supply substantially - to almost 1,000 MW by 2015. We expect a similar trend toward increased reliance on wind throughout the entire WECC. The combined reduction of our most flexible and dispatchable, high capacity value hydro resource and increased penetration of low capacity value wind is expected to increase the strain on our portfolio to meet ancillary services and peaking needs in the future. Our forthcoming wind integration study should provide more specific details regarding the impact of these changes on our projected future portfolio.

Demand-Side Factors

On the demand side, due to rapidly increasing residential central air-conditioning saturation (from 17% in 1989 to 52% today, with no signs of slowing), we are becoming a dual peaking utility. Current expectations are that, under normal weather conditions, our summer peaks will surpass winter peaks toward the end of the next decade. This has been an ongoing trend caused by

---

[82] The potential for environmental and recreational requirements to increase restrictions on hydro operations also exists, however we did not attempt to model these effects because they are highly uncertain and we have no quantifiable basis on which to model them.

falling prices for central air-conditioning and growing single-family adoption of air-conditioning.

Seasonality Considerations

Increasing summer peaks have also caused us to reexamine the types of resources that we need to meet our peak load requirements. Historically, PGE and other regional utilities have focused on winter peaking needs as our forecast winter peak sets our annual maximum load. As summer peaks continue to increase, the difference between our winter and summer capacity deficits has declined. PGE also has reduced resource capability (both thermal and sustained hydro) during summer months and reduced import capability over transmission lines. Reduced capacity availability for thermal units and transmission is due to lower operating limits for both at higher ambient temperatures. In the summer, our expected sustained peak energy capability for hydro is reduced because rivers in the Pacific Northwest normally have a lower flow in summer. The unusual heat wave that occurred in July 2006 also demonstrated that extra-regional weather events can occur and, when they do, resources quickly become scarce. As a result, energy may not be available or may be available only at very high prices. The NWPCC suggests that we cannot rely on any spot imports during region-wide summer peak events and only limited imports during extreme winter weather conditions.

Regional Outlook

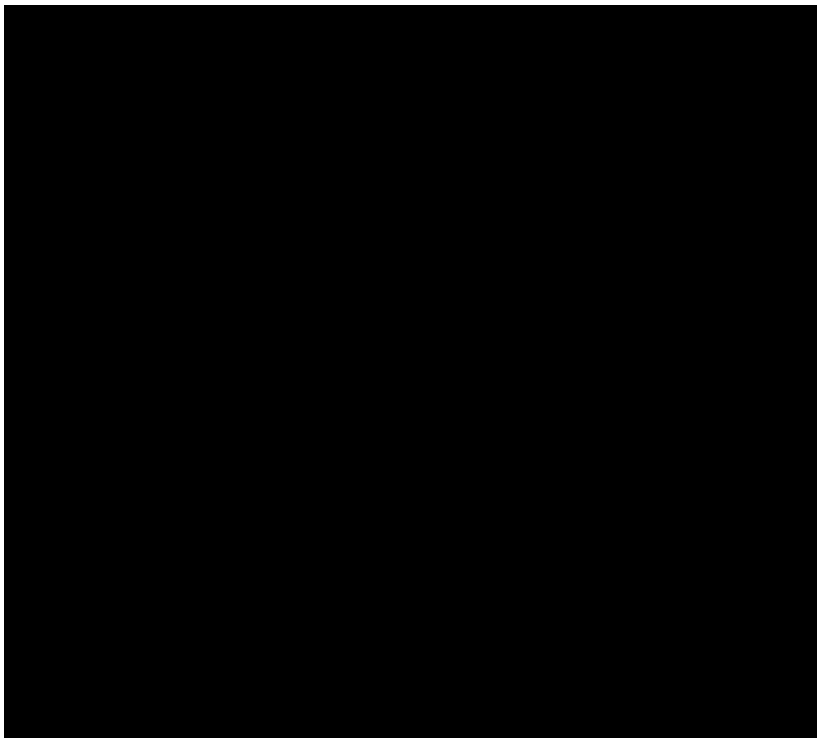
At the time we presented our last IRP, a regional surplus was forecast and, as a result, we targeted supply from the short-term markets to fill the highest 500 MW of our annual peak demand. However, the region is now expected to be more tightly balanced by the end of this decade. PGE and the region are unlikely to have incremental access to high capacity value hydro resources, as we do not expect any significant hydro additions in the region. And as described earlier, the region is anticipated to substantially increase penetration of lower capacity value wind resources to meet incremental energy needs. Given these factors, combined with projected changes to our own portfolio composition over time, we believe that it will no longer be wise to meet our future capacity needs through short-term markets. More detail on this topic is found in Chapter 3.

12.2 Risk of Reliance on Spot Markets to Meet Peak Demand

Unlike our prior IRP, we do not believe it will be physically or financially prudent to rely on future spot markets to supply the last 500 MW of our peak needs. To test our premise, we conducted an investigation into the correlation of our loads to market prices. Our analysis, as described below, indicates that relying on spot markets during times of peak need poses significant risk.

Historically, market prices have been positively correlated with our loads. To assess this risk, we analyzed three and a half years of hourly price-load data (going back to April 2003). The result is shown in Figure 12-1. The X-axis represents the hourly net system load during the on-peak hours, while the Y-axis is the hourly Mid-Columbia spot market price of one MW of electricity as reported by Dow Jones.

Figure 12-1: Mid-C Hourly Price vs. On-Peak Load, 4/2003 – 1/2007

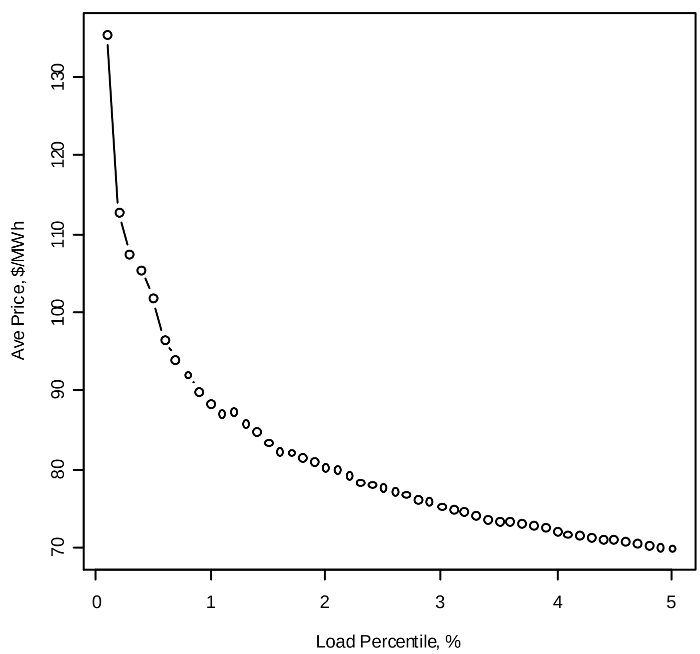


Each point on the graph is a pair of matching observations, measuring the cost of serving one incremental MW of load for that hour of load. The straight line in blue is a simple linear regression fit of the entire data set. The beta, or the slope of the line, is 0.0273, meaning that for every additional MW of load served, the price would increase on average by 2.7 cents.

This relationship, however, is not constant, as seen by the red line as it bends upward on the right hand side of the graph. The red line is a loess fit, or a locally weighted polynomial regression. It is a better way to describe non-linear functions, as it more accurately reflects changing relationships among the factors. The red line diverges from the blue line as load increases. At approximately 3,700 MW, the slope of the red line, and thus the correlation between price and load, is markedly higher than the blue line. The dozen or so outliers in the upper right hand corner of the graph are all recorded in July of 2006 when the Pacific Northwest and the entire WECC, experienced very hot weather conditions.

Figure 12-2 is another view of this positive price/load correlation. This graph shows the average price at each percentile of load. For example, the average price for the highest one percent of load is about $88/MWh. If there is no correlation between the two variables, the line would be flat. The fact that we see a concave curve declining from the left indicates that when loads are high, we are more likely to see higher than average market prices.

Figure 12-2: Average Hourly Price vs. Extreme Load Quantile

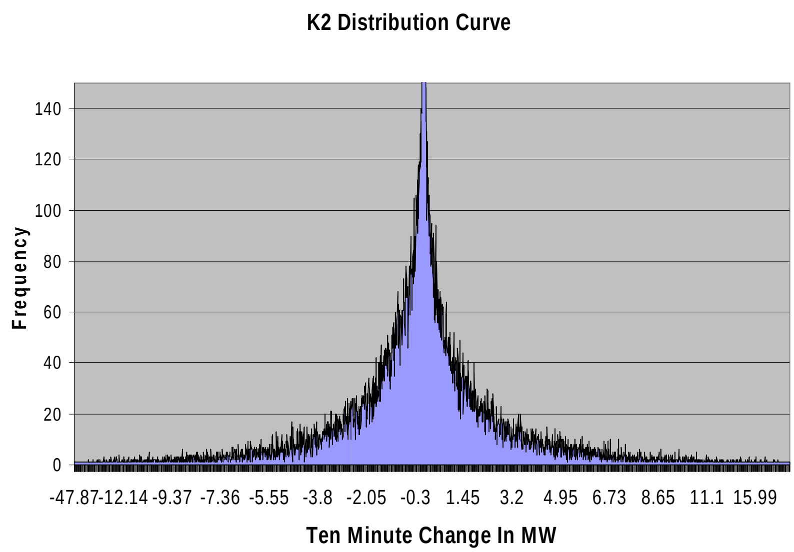


We conclude that market reliance to meet peak needs is both increasingly more expensive as higher peak events occur and a potentially volatile approach. Market reliance is also riskier from a resource adequacy/reliability perspective.

12.3 PGE System Flexibility to Follow Loads and Wind

We initiated a study of our hydro system flexibility to follow loads and wind. We conducted this study in response to a stakeholder question as to whether our existing hydro base is adequate to accommodate the wind resource additions anticipated in this IRP. To test this premise, we analyzed measurements of intra-hour wind variability at Klondike II during 2006. Generation changes, as measured in 10-minute increments, are symmetrically distributed with a mean of zero and most deviations falling within +/- 10 MW out of the 75 MW nameplate total. However, for a portion of the hours of the year, 10-minute changes of 10 MW or greater of the nameplate capacity of Klondike II occur (see Figure 12-3). For those hours, this represents a 10-minute change of 13% or greater of the nameplate capacity. The change as a ratio of actual energy production is actually much higher for most hours, since the project produces on average at 36% of its maximum capability.

Figure 12-3: Ten-Minute Generation Changes at Klondike II



Forecast Biglow Canyon generation data, based on wind speed data, is very similar to Klondike II. For 340 MW of generation at Biglow Canyon, we estimate an *average* daily hourly variability of just 24 MW, but an annual *maximum* hourly change of 330 MW.

Due to expiration of Mid-C hydro contracts, combined with the increased need for regulation and ramping associated with wind, we may not have sufficient load following capabilities by 2012 to entirely meet the daily average peak hour load variability (forecast for 6:00 a.m.) after inclusion of high levels of new wind resources. See Table 12-1.

In short, our examination of PGE's system flexibility to follow loads further indicates that we have a future need for additional flexible capacity resources over an increasing number of hours during the year. Further investigation is required during the spring run-off period, where the load-following capability of the hydro system is reduced. In addition, we have not explored changes within the 10-minute periods.

Table 12-1: PGE Intra-Hour Load Following Capability (Average Hydro)

	Forecast 2008			Expected 2012		
	24 Hr. Avg.	6:00 a.m. Avg.	Annual Intra-hour Max	24 Hr. Avg.	6:00 a.m. Avg.	Annual Intra-hour Max
Hydro available for load following:						
PGE retail load ramp rate before wind	-102	-302	-655	-108	-320	-712
Ramping available from Mid-C or Round Butte	303	443	443	244	355	355
Net Surplus / (Deficit) before wind	201	141	-212	136	**35**	-357
Thermal capability to follow wind:						
Wind intra-hour variability @ 900 MW nameplate[1]				-64		-876
PGE gas-fired thermal ramping from existing units.[2]				571		571

Notes: *1. No correlation of wind intermittency to load is implied.*
2. Assumes Beaver in simple cycle mode; addition of AGC to thermal units.

To meet these growing requirements, our thermal system may need to be adapted, at additional cost and reduced operating efficiency, to augment hydro for following loads and regulating variable resources. Adapting our thermal units to load follow will require further technical assessments to determine potential upgrades and, if implemented, could result in additional operating costs and reduced efficiencies. Should potential upgrades to existing plants be insufficient to meet our future requirements, we would need to consider the addition of new flexible thermal units designed to handle load following and regulation, such as the LMS 100 MW aero-derivative gas turbine. It should also be noted that currently, excess hydro capability is monetized, so its alternate use for wind following also carries an opportunity cost.

PGE must balance the need for dispatch flexibility to meet load requirements (net of wind) with the acquisition of incremental gas-fired capability at the lowest possible heat rate (see also section 12.7 below). In addition to seeking new capacity resources, we intend to more fully explore the capability of our existing dispatchable thermal generating plants to ramp up and down, as well as the resulting impacts to efficiency and maintenance and any required modifications, such as addition of Automated Generation Control (AGC). The goal is to provide a more detailed assessment of the appropriate resource type and size to meet capacity needs in 2012 and beyond.

12.4 Loss of Load Probability (LOLP)

OPUC Order 07-002 requires PGE to analyze supply reliability within the risk modeling of the supply portfolios we consider. To do this, we assessed traditional loss of load reliability metrics under various planning reserve margins as outlined below. The purpose of this work was to independently validate our other quantitative and qualitative approaches to assessing resource adequacy (covered in Chapter 3).

LOLP Modeling Methodology

We used AURORAxmp to assess our risk (probability) of being unable to serve our customer energy needs and the resulting amount of expected unserved energy. For this purpose, we created a new AURORAxmp topology in which we isolated our service area from the rest of the WECC by restricting its import/export capabilities. The Diverse + Contracts portfolio, our recommended energy portfolio, was the basis for the study, along with our existing resources. We chose year 2012 for the analysis as a simplifying assumption, as this is the target time frame of our resource additions for IRP modeling purposes. In 2012, our recommended energy portfolio brings sufficient capacity to meet our annual 1-in-2 peak need before consideration of operating and contingency reserves. However, the projected future portfolio inclusive of our recommended energy actions does not supply adequate capacity to meet our 1-in-2 peak need and provide required operating reserves or suggested contingency reserves.

We chose three parameters to model resource adequacy uncertainty and test the potential stress imposed on our system:

1. *Load* – We used the build-in Risk Study functionality of AURORAxmp to simulate variations in load. A risk factor is generated for each month of the study period from either a normal or a lognormal distribution. The type of distribution and its parameters (i.e., its mean and standard deviation) are determined from the stochastic models described in Chapter 10, ensuring overall consistency in methodology. All the monthly distributions have a mean of zero, and a standard deviation ranging from 4% to 6.2%.

2. *Hydro Generation* – We simulated hydro generation as a random process independent of load. Since hydro exhibits significant monthly autocorrelation, each of the 100 risk iterations used 12 monthly factors and one annual factor, representing a hydro condition randomly selected from 50 historic water years. Annual iterations were independent of each other; thus each of the 50 analog years (1929-1978) had an equal chance of being selected.

3. *Forced Outages* - To make our model consistent with actual plant operations, we simulated random forced outages using the AURORAxmp built-in risk engine. For each of our gas- and coal-fired resources, we used the same annual expected Forced Outage Rate (FOR) used in the

scenario analysis, based on historical performance and our professional judgment. We then imposed a random occurrence of the outage by inputting a Mean-Time-to-Repair based on historical NERC data. AURORAxmp's risk engine generated random forced outages, which then impacted the amount of energy available to serve our load.

Since the main goal of the LOLP study was to assess PGE's reliability at our recommended reserve margin, we tested performance at a variety of capacity levels, increasing from the projected capacity of our recommended future portfolio. Initially, our portfolio has just sufficient supply to meet our 1-in-2 peak demand, assuming no contingency reserves but including required operating reserves. We then added 100 MW increments of capacity (using SCCTs) to our proposed energy portfolio in 2012, starting from 0 MW (i.e., no additional capacity resources) and increasing up to 1,000 MW of additional capacity. Each increment of 100 MW also had a forced outage rate and a mean time to repair. We ran the model 100 times at each level of added capacity reserve (from 0 to 1000 MW) and allowed the loads, hydro production, and plant forced outages to vary stochastically, while maintaining operating reserves.

Loss of Load Probability Analysis Metrics and Results

We chose three metrics to describe our reliability modeling results:

Loss of Load Probability – We calculated the loss of load probability (LOLP) as the average (expressed as a percentage across 100 risk iterations) of the ratio between the number of hours of load curtailment and the total number of hours included in the study. We excluded May from the study because it is the month in which we assumed most thermal maintenance would occur.

FORMULA: For each risk iteration i, let h_i represent the number of hours across the year when load is curtailed. The loss of load probability is calculated as

$$\frac{1}{100}\left(\sum_{i=1}^{100}\frac{h_i}{8784-744}\right)$$

This metric measures the percentage probability that customer load will exceed PGE's generating capacity. For example, a 0.1% LOLP indicates that PGE, on average, would expect to not be able to serve some portion of its load requirement 8.7 hours per year. This metric alone does not address the frequency of loss of load or the amount of load that was not served.

Expected Unserved Energy – We calculated the expected unserved energy (EUE) as the average (across 100 risk iterations) of the amount of unserved customer load (or load involuntarily curtailed) expressed in MWa.

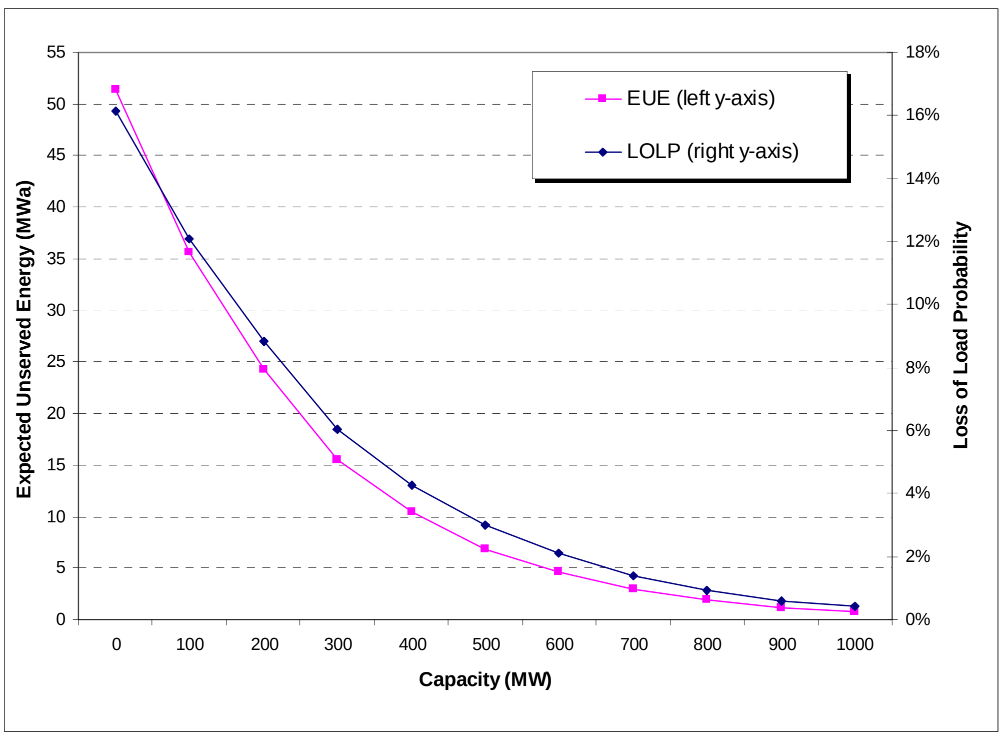
FORMULA: For each risk iteration i, let l_i represent the total amount of unserved energy load during the year. The expected unserved energy is calculated as

$$\frac{1}{100}\left(\sum_{i=1}^{100}\frac{l_i}{8784-744}\right)$$

This metric measures the average amount of load curtailed. This statistic is a better indicator of the expected magnitude of the problem. However, because it is the average of 100 iterations, it doesn't provide direct information on the magnitude of bad outcomes within individual iterations.

Figure 12-4 below shows results for the LOLP and EUE metrics for our system in 2012 with our recommended energy action plan.

Figure 12-4: LOLP and Expected Unserved Energy



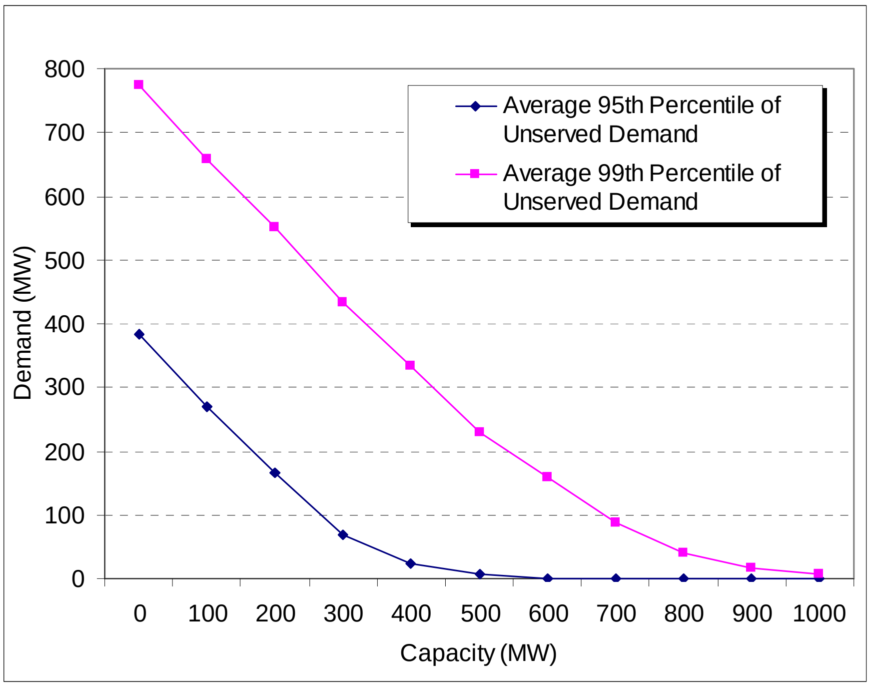
The Average of the 95th and the 99th Percentiles of Unserved Load – We calculated these metrics, measured in MW, as the average across 100 risk iterations of the 95th and 99th percentiles of unserved load.

FORMULA: For each risk iteration i, let p_i^{95} represent the 95th percentile of the curtailed load[83] (that is, roughly 95% of the data will be less that p_i^{95} and 5% of the data will be greater than p_i^{95}). The metric is calculated as

$$\frac{1}{100}\left(\sum_{i=1}^{100} p_i^{95}\right).$$

The formula for the average 99th percentile of unserved customer load is derived similarly. These metrics measure how high the unserved load could be during the year. For example, where EUE may yield a result of 0.01 MWa (88 MWh) for the entire year, if this took place entirely in one hour of one day, it would be a curtailment of 88 MW of demand in that hour. Figure 12-5 shows how we fare at the 95th and 99th percentile of unserved demand.

Figure 12-5: Average 95th and 99th Percentile of Unserved Load



We conclude from the graphs above that a capacity reserve margin of 500 MW or greater is a prudent amount for reserves. From inspection of the graphs from the standpoint of utility-only costs, the region between 500 and 700 MW is where an inflection point can be observed. Prior to 500 MW, the curve is steep, implying large reliability increases for each 100 MW of additional capacity. After about 700 MW, the curve becomes much flatter. Hence, somewhat higher amounts of

[83] All load curtailed data is used in the calculations of the percentiles, including the instances when the unserved load is 0 MW.

capacity reserve (700 to 800 MW) would further reduce risk, but at diminishing marginal reliability gains. This analysis further supports the implementation of a minimum 12% reserve margin as an appropriate reliability standard.

12.5 Capacity Resource Availability and Cost

Now that we have examined financial and physical risk related to capacity and reserve margins, further demonstrating our need for securing additional capacity, we examine the alternatives to fill that need. For the purposes of IRP, we have divided capacity resources into three broad categories: 1) customer-sited resources with constrained operations, both supply and demand actions; 2) year-round supply-side resources with unlimited dispatch; and 3) potential market product alternatives. Demand-side capacity resource options were described in detail and quantified in Chapter 4.

Customer-Sited Capacity Alternatives

Table 12-2 details capacity options that are customer sited with limited operations. Options include dispatchable standby generation (DSG), various tariff-based pricing programs such as demand buy-back and interruptible load tariffs, and residential/commercial direct load control (DLC) of space and water heat and air conditioning. DSG is a flexible source of capacity that is ultimately limited by the number of potential sites. Demand buy-back programs typically require at least day-ahead notice and, as currently structured, are not a firm resource. To be most effective in terms of ongoing customer acceptance, utilities must strictly limit the number of hours or instances in which space conditioning DLC is called upon. Costs for both DSG and DLC are primarily fixed costs.

According to our forecasts for technical availability and cost, we expect that the combined potential of these alternatives can only partially address our future capacity needs. Because these actions occur at the customer site, they have the distinct advantage of mitigating incremental transmission and distribution risk and cost. An RFP will be required to understand the true market potential and costs of DLC.

Table 12-2 outlines our current estimate of the potential quantity, costs, and key characteristics for customer-based capacity alternatives. In addition to these pure capacity alternatives, distributed photovoltaic solar, while not listed in the table below, could in time provide customers with the ability to meet a portion of both their energy and capacity needs.

Table 12-2: Customer Sited Capacity Alternatives

Resource	Potential by 2012	Real Levelized Capital Cost 2006 $/kW-yr	O&M (2006 $/kW-yr)	Fuel Risk	Transmission Risk
DSG	125 MW (max. potential; typically contracted for 400 hours per year)	$24	$5	Yes	No
Demand Buy-Back	Depends on program design & firmness.	NA	Market	No	No
DLC – Res. Water Heat	15MW 43 h/winter; 5MW 43 h/summer	$132	Included in capital cost	No	No
DLC – Res. Space heat	10 MW, max 43 h/yr	$108		No	No
DLC – Res. Air Conditioning	19 MW, max 43 h/yr	$86		No	No
DLC – Non Res.	unknown	unknown	unknown	No	No

Dispatchable Capacity Supply Options

Table 12-3 outlines year-round, dispatchable capacity supply options. Variable costs for these options depend primarily on the cost of natural gas. Fixed O&M is highly dependent on pipeline cost and availability of gas transportation and fuel storage. Supply-side options provide the additional potential advantage of providing regulation and integration for wind, as well as helping to meet our peak needs. Their year-round availability also offers significant economic and risk mitigation benefits in the event of a protracted supply disruption or extended periods of high market prices as occurred during the Western energy crisis. However, if utilized for only a few hours per year, supply-side resources may be less economic in meeting our capacity needs.

Table 12-3: Year-Round, Unlimited Dispatch Capacity Options

Resource	Potential by 2012	Capital Cost (2006 $/kW-yr)	Fixed O&M (2006 $/kW-yr)	Fuel Risk	Transmission Risk
SCCT :					
– LM 6000	47MW per unit	$68	$18-50	Yes	Yes
- Frame (7Fa)[1]	170MW per unit	$41	$18-60	Yes	Yes
- LMS 100	100MW per unit	$69	$18-55	Yes	Yes
Natural Gas Reciprocating Engines	8 MW per unit	$77	$18	Yes	Yes

1) We assume secondary market pricing for the 7FA SCCT.

Market Capacity Alternatives

Possible market alternatives include heat rate contracts (financial derivation of a tolling contract); fixed-strike call options; and tolling arrangements. Although we have previously considered seasonal exchanges to be a viable source of shaped energy and capacity, they may no longer be feasible as traditional seasonal, geographic price diversity no longer reliably exists. Current cost and availability for these market alternatives is not known. An RFP is necessary for price discovery and to determine if these products are available and cost-competitive.

These market alternatives have other limitations. Contracts create fixed obligations which rating agencies impute as debt against the purchasing utility's balance sheet. They also may create additional credit or collateral obligations that may adversely impact working capital and financing costs. In addition, costs for capacity contracts that do not dispatch or produce energy on a forecast basis may be disallowed or have a value imputed for ratemaking purposes, thereby monetizing the capacity value. This can result in either unfairly shifting the entire cost burden for incremental capacity to the utility or forcing us to liquidate the contract on a forward basis to offset the increased costs. Such liquidation would render the capacity associated with the monetized contracts unavailable to meet our customers' peak demand, as intended. A similar regulatory risk exists with plants that PGE owns. For instance, if rates are set with Beaver dispatching economically, then Beaver's power may not be available for peak load when needed.

Finally, while PGE plants have forced outage risk, contracts have similar non-delivery risks. From a reliability perspective, it would be misleading to assume 100% delivery reliability. Such contracts may pay liquidated damages in lieu of physical delivery; however, monetary compensation will not reduce the risk of unserved load. Such payments are unlikely to cover the full economic costs for replacement power or unserved load.

Pumped Storage

With the installation of significant wind generation in the PGE portfolio, there will be increased demand for ancillary services during on-peak hours including spinning operating reserves, standby operating reserves, load following, regulating margin, and automatic generation control. We have undertaken a very preliminary assessment of the technical and financial feasibility of adding pumped-storage generation to the Pelton Round Butte hydro project. Water could be pumped up on a daily basis off-peak and stored for release during the daily super-peak. The amount of energy that can be stored depends on the size of the upper reservoir. An upper reservoir could be sized to provide up to 8-10 hours of on-peak energy each cycle.

In 2006, we reviewed potential sites, as well as project size, capital cost, and project economics. We targeted a facility sized at approximately 250 MW, which could pump off-peak and return energy on-peak with overall cycle energy efficiency of about 74%. Our preliminary review determined that such a project is not economic at this time. If such a project were deemed to be economic in the future, it would require an amendment to the FERC license and could take up to 10 years before it is on line and available for use.

12.6 PGE's Demand Curve

Not unlike most utilities, our highest peak demand occurs over a relatively few number of hours in a year. A resource-duration matching strategy appears to make sense to efficiently meet this relatively steep demand curve. Under such a strategy we would pursue dispatch-limited resources (both demand and supply-side) that may be more expensive on a dollars per MWh basis, but relatively inexpensive in aggregate annual cost, to meet our highest demand hours. We would then seek seasonally or annually available resources to meet more sustained demand farther down the curve. Availability and cost of resources associated with such a strategy would need to be further explored through bilateral negotiations or competitive bidding. Figure 12-6 illustrates the steepness of PGE's demand curve and where various supply and demand resource actions might meet the demand. We use customer-sited supply and demand options to meet the very top of the curve, where the number of hours in which they are called upon would be very limited.

Figure 12-6: PGE's Demand Curve

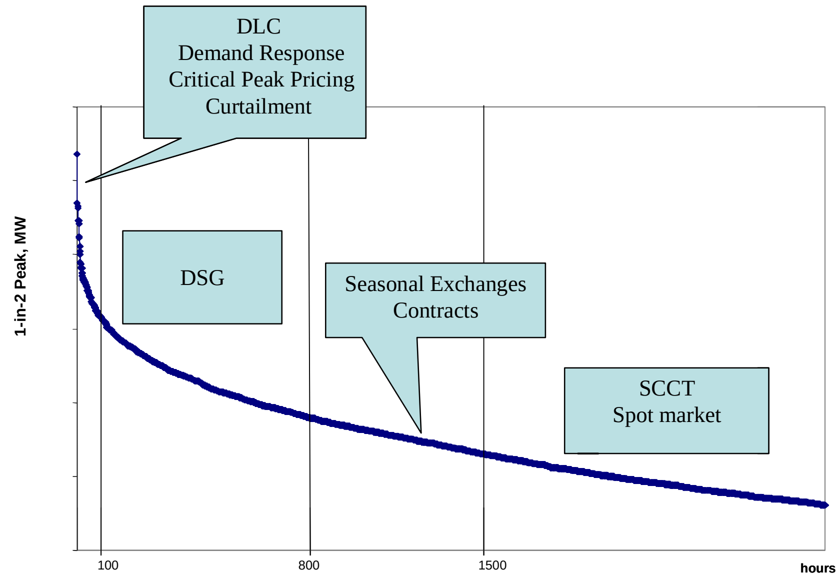


Table 12-4 stratifies PGE's forecast demand curve in 2012 at normal weather:

Table 12-4: PGE's 2012 Peak Load before Reserves

	Load	Reduction from Highest
At Highest Hour	4107	
5th Highest Hour	3841	266
10th Highest Hour	3740	367
20th Highest Hour	3696	411
30th Highest Hour	3667	440
40th Highest Hour	3633	474
50th Highest Hour	3606	501
100th Highest Hour	3506	600

The highest 10% of our annual loads occur in only 20 hours (0.23%) of the year. While loads decrease 500 MW from the highest hour of the year to the 50th-highest hour, loads decline only an additional 100 MW over the next 50 hours. Accordingly, we believe that demand reduction and other low fixed-cost resources are an efficient way to help meet the highest peak loads during the year. Under normal circumstances (excluding protracted periods of supply-demand tightness as in the Western energy crisis), curtailment tariffs, demand response programs, and other low fixed-cost resources which bring firm reductions can be less expensive than SCCTs to help meet these peak needs, based on aggregate cost.

Table 12-5 uses the cost information from Table 12-6 (next section) to show the costs per MWh of using a SCCT to meet limited duration capacity needs. Spreading substantial fixed costs over a limited number of operating hours makes such an approach relatively expensive on a fully allocated cost basis. For example, the costs of using a SCCT to meet load requirements during only ten hours per year are approximately $10,600 per MWh, but the costs fall to $190 per MWh when used for 1,000 hours per year[84].

Table 12-5: SCCT Costs to Serve Limited Duration Incremental Loads

Hours	Total Cost ($/MW)	Unit Cost ($/MWh)
10	$106,377	$ 10,638
100	$114,011	$ 1,140
1000	$190,353	$ 190
8760	$848,587	$ 97

To derive the amounts in Table 12-5, we take the fixed annual revenue requirement for a SCCT and divide by the number of hours it is called upon. We add to this figure fuel costs and variable O&M, which explains why the total cost per MW rises as the facility is used more.

Demand reduction alternatives could be much less expensive, if needed only over a few hours per year. For example, payments to attract demand response program participants can be structured at prices below the high SCCT costs per MWh shown in Table 12-5. Some demand reduction strategies require information technology, but this technology may be available at a relatively low incremental cost after our expected deployment of an advanced metering infrastructure (AMI).

While it is premature to fully quantify customer demand response potential for 2012, particularly in light of the emergence of AMI and the gradual transformation to the smart grid, we understand the importance of laying the groundwork now. Demand response activities and proposals are described in Chapter 4 and included in our capacity action plan in the next chapter.

Unfortunately, demand response and other customer solutions alone do not appear at this time to exist in sufficient quantity to entirely satisfy our capacity need, given that 500 MW are needed for the highest 50 hours of demand per year. Additional dispatchable peaking may also be needed. Thus we turn to an analysis of SCCTs vs. CCCTs to meet our remaining peak needs.

[84] This analysis does not include the possible dispatch benefits from an SCCT when it is not needed to meet extreme peak requirements. However, these benefits would not change the analysis significantly.

12.7 SCCTs for Peaking vs. CCCTs for Energy and Capacity

Once available amounts of economic DSG and other customer-side resources are exhausted, remaining choices appear to be limited to year-round CT capability, or seasonally-tailored capacity contracts, if available from the market. Although the number of hours of need is relatively small, it is not possible to identify in advance, due to unpredictability of weather and plant contingencies, precisely which hours the capacity will be needed (aside from generally narrowing the need to peak winter and summer months). Hence, supply actions must be available to cover a broad range of on-peak seasonal hours.

We do not know availability and pricing of seasonal capacity contracts in 2012 and beyond. However, given an expected regional tightening of the load-resource balance and increased WECC-wide penetration of intermittent wind, it is likely that availability will be less and costs higher. Thus, we evaluated costs and capabilities of SCCT vs. CCCT configurations.

We compared the costs of running a 7FA SCCT vs. a CCCT G-class combustion turbine to cover capacity needs. Results are summarized in Table 12-6 below.

Table 12-6: Comparison of a 7FA SCCT vs. CCCT-G

	7FA	CCCT-G	Delta
Fixed Revenue Req.			
Overnight Capital $ / kW ($2005)[1]	$337	$726	215%
Assumed Life (Years)	20	30	
Levelized Fixed Rev Requirement ($2006)	17,349	48,046	
Capacity (MW)	164	400	
Levelized Fixed Rev Req. $ / kW	$106	$120	114%
Levelized Annual Rev Req. / MW	$105,529	$120,115	$14,586
Variable Cost:			
Heat Rate (MMBTU / kWh)	10,809	6,786	63%
Fuel Cost per MWh at $6.4/MMBtu	$69	$43	$(24)
Variable O&M per MWh	$20	$2	$(18)
Avg. CCCT-G margin required to recover incremental fixed cost ($/MWh)			**$2.4**

[1] *We assume secondary market pricing for the SCCT.*

[2]*We assume a shorter life for the SCCT due to high cycling.*

Due to the substantial variable cost advantage of the CCCT, market prices that average $2.4 per MWh above the variable cost of the CCCT, assuming a 70% capacity factor for the CCCT, will provide a net value due to the increased dispatch when compared to the SCCT. AURORAxmp model runs consistently demonstrate in all portfolios tested and against all futures that CCCTs reduce both expected cost and risk when compared to an equivalent amount of SCCTs, based on reference case assumptions for gas prices and resulting electric market prices.

Despite higher initial costs, CCCTs bring net benefits due to much higher economic dispatch. Hence, we may wish to close the capacity gap in part by increasing our energy balance via dispatchable CCCTs, i.e., having more than enough resources to meet our annual average energy load target. However, we must also consider the limited duration of our peak needs and the potential risk associated with exposure to increased fixed costs. Also, CCCTs are not designed to have the dispatch flexibility of SCCTs and would thus not directly be able to support the integration of variable wind resources or load following. Finally, a long energy position would change overall power cost risks and could require a change in current regulatory mechanisms in order to be effective.

Dual-Purpose Use of SCCTs

Another potential capacity solution is using one or more SCCTs for the dual purpose of integrating wind and providing incremental capacity. The 100 MW LMS[85] units have lower heat rates compared to traditional SCCTs and can load follow, making them potentially attractive for this use. Our Power Supply Engineering team is looking at the possibility of incorporating these at existing plant sites such as Beaver. For non-baseload plants, the high cost of fixed gas transportation is also an issue that must be addressed, possibly via on-site storage or a mix of firm transport and storage.

Using SCCTs to Firm Wind

Following one of our IRP public workshops, we received a letter (dated March 9, 2007) from Renewable Northwest Project (RNP) and the Northwest Energy Coalition (NWEC), addressing concerns over using SCCTs for the purpose of firming wind. The stakeholders correctly observed that we were adding SCCTs in our analysis to the diversified portfolios but not to thermal-based, predominantly single-resource portfolios. We rectified this by adding SCCTs, as needed, to the other portfolios to bring all portfolios to parity with respect to capacity value. All portfolios in our analysis now contain a commensurate amount of both energy and capacity. We assigned a capacity value of 15% to wind for IRP modeling purposes, but we are also continuing to evaluate the capacity contribution of this resource. Recent ongoing regional work shows that, absent a multi-area physical wind-sharing approach, the actual capacity value of wind may be 5% or less.

---

[85] The LMS100 uses an intercooled, aeroderivative gas turbine technology to increase output. The intercooling process between the low and high pressure compressors allows a higher air mass flow rate to increase efficiency without impacting the maintenance costs. These units are able to be at 100% capacity in 10 minutes from start, while maintaining high availability and reliability.

The RNP and NWEC letter asserted that an all-wind portfolio did not perform well because of the associated SCCTs. In response to this assertion, we noted that: the all-wind portfolio is also on the efficient frontier and that the proportional amount of SCCTs added to the all-wind portfolio is exactly the same as in the diversified portfolios. Thus on a cost-per-kW basis, the all-wind portfolio with associated CTs is the exact same cost as the wind plus CTs embedded into our diverse portfolios. Our assumption of higher costs for what we have referred to as Tier II wind drives the higher cost for the all-wind portfolio. Tier II wind is assumed to have a lower capacity factor, higher capital costs, and higher integration costs.

RNP and NWEC suggested combining wind with resources that are more cost-effective than a SCCT, such as a CCCT. We agree that from the standpoint of point estimate analysis, use of CCCTs to provide incremental capacity appears to offer an economic advantage. However, meeting capacity needs and following both variable load and wind (after using existing hydro capability) may require a flexible thermal unit designed for this task, such as the LMS 100 MW aero-derivative gas turbine. Our preliminary analysis, described in this chapter, suggests that incremental, flexible thermal-based load following may be required in the future.

Because capacity needs tend to occur over a relatively small number of hours per year, and because when needs will occur is largely unpredictable as determined by weather and plant performance, it is more difficult to perform an analytical assessment of preferred demand and supply solutions for capacity needs. Our recommended Energy Action Plan fills our capacity needs for most hours of the year. Customer-sited and demand response programs are an attractive solution for peak-hour needs. For the remaining capacity needs, we will continue to explore whether a dual-purpose CT is a viable and economic option to provide both peaking and wind firming as needed. We also propose to issue an RFP for seasonal reserves.

13. Energy and Capacity Action Plans

Based on our cost analysis and assessment of potential future uncertainties, we believe that an effective resource action plan should address the following factors, in addition to meeting the overall cost and risk objectives for the IRP:

- The plan must be achievable and acknowledge any practical internal or external drivers or limitations to implementation with regards to timing, resource availability, and regulation or policy that either prohibits or requires certain resources;

- It should recognize that considerable structural risks remain with respect to global energy supply and demand, as well as significant uncertainty regarding environmental and energy policy. Given the substantial impact of these potential paradigm shifts, a candidate action plan should avoid over-exposure to extreme adverse outcomes;

- Where possible, the plan should provide some level of flexibility to adapt to changing future conditions, including changes in load or customer choice, as well as technology developments and market transformations resulting from public policy regarding energy and the environment.

Based on our portfolio analysis and consideration of future potential cost and risk drivers, we have developed an overall action plan – consisting of an Energy Action Plan and Capacity Action Plan – that we believe meets the primary objectives of the IRP to provide the best combination of expected cost and risk and that addresses the above strategic considerations. Our Action Plan further enhances the overall diversity of our portfolio and reduces exposure to large structural shifts in market conditions. In addition, the Energy Action Plan recognizes the passage of an RPS in Oregon, and addresses continued uncertainty with respect to emerging energy and environmental policy and potential related technology developments.

Energy Action Plan - Our Energy Action Plan is composed of 36% renewable resources; 21% intermediate-term PPAs; 20% short-term PPAs; 14% energy efficiency; 8% hydro (contract renewals); and 1% plant upgrades. It includes no new thermal energy resources, thereby minimizing fuel cost and greenhouse gas emissions risks. Our Energy Action Plan is similar to the plan recommended for the region in the NWPCC's 5th Power Plan in that it relies heavily on energy efficiency and renewable resources to meet load growth.

Capacity Action Plan - Unlike in past IRPs, we no longer believe that it is prudent to rely on the short-term markets to meet our customers' peak demand. Instead our Capacity Action Plan proposes to fill our peak needs by securing long-term or mid-term resources. To do this we will focus on acquiring and enabling limited, customer-based solutions, such as demand response programs and DSG, to meet our highest peak hours. However, given the aggregate size of our capacity need, it is not feasible to rely solely on customer-sited actions to meet peak demand. To meet more sustained peaking requirements, we will also need to acquire either seasonally targeted capacity contracts or CTs that are available on a year-round basis. Our Capacity Action Plan calls for roughly equal parts of customer-based, limited dispatch programs, year-round peaking capacity in the form of simple-cycle combustion turbines, and seasonal peaking capacity from the market.

We also recognize the importance of transmission needed to acquire new resources east of the Cascades. Accordingly, we propose to continue to evaluate the Southern Crossing project and like concepts, and to maintain our proactive approach to working with BPA and others to develop new transmission capacity over the Cascades and north-to-south through the I-5 corridor.

All of these actions are dependent upon a supportive regulatory and legislative environment at both the state and federal levels. The final section in this IRP discusses specific regulatory and legislative actions necessary to fulfilling our action plans.

Chapter Highlights

- Our Energy Action Plan proposes that we acquire 903 MWa of additional energy resources including: incremental energy efficiency; plant efficiency upgrades; hydro contract renewals; new biomass; the expansion of Biglow Canyon; short- and intermediate-term power purchase agreements to meet load uncertainty; and additional renewable resources to meet the 2015 Oregon RPS target.
- Our Capacity Action Plan suggests reduced reliance on the short-term market to meet peak customer demand by acquiring over 700 MW of incremental capacity resources (beyond the energy resources), including: economic direct load control; interruptible tariffs and critical peak pricing; continuation of our dispatchable standby generation program; new SCCTs; and contracts for seasonal supply.
- To ensure that we address transmission requirements, we propose to continue to evaluate the Southern Crossing project and active collaboration with BPA and others to develop transmission capacity over the Cascades and through the I-5 corridor.
- A supportive legislative and regulatory environment is needed to fulfill these actions.

13.1 Energy Actions

Our Energy Action Plan, based on the Diverse + Contracts candidate portfolio (as outlined in Chapter 11), proposes a diverse bridging approach to meeting our customers' future energy needs (see Table 13-1). The Energy Action Plan consists of a diversified mix of owned resources plus contracts that provide a balanced portfolio of resource types and durations. The Plan includes sufficient renewable resources to meet the 2015 Oregon RPS standard. To achieve this level of renewables our Plan focuses on new wind, but also includes biomass and the potential for geothermal, if economic. We also recommend acquiring all additional cost-effective EE in our service territory, including amounts beyond what the ETO has targeted with its existing funding level. Our Energy Action Plan recognizes the economic dispatch of our Beaver plant and our resulting need for replacement baseload energy. Furthermore, the Energy Action Plan contains a significant amount of medium-term power purchase agreements, thereby providing flexibility in meeting future loads. It also serves as a bridging strategy to allow emerging resources such as IGCC to further develop and to permit important policy issues such as carbon regulation to become clearer.

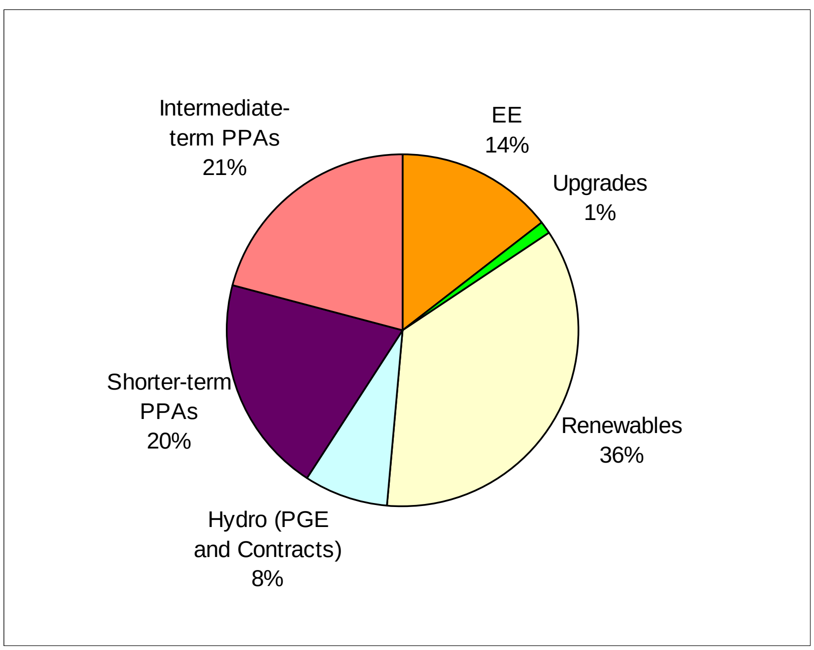
Finally, we believe that the Energy Action Plan is responsive to feedback, preferences and concerns expressed by our stakeholders throughout the IRP process. We remain committed to maintaining an open and robust dialogue about our resource choices and approaches to implementing our Energy Action Plan as we move forward with completing the planning process and transitioning to the implementation phase of the IRP.

Table 13-1: 2012 Resource Need and Potential Energy Supply Actions

	Energy MWa @ Normal Hydro	% of Target	*Capacity* MW @ Normal Hydro
PGE system load at normal weather (net of ETO EE)	2,630		
Remove assumed 5-yr. opt-out load	(30)		
Existing PGE & contract resources in 2012	(2,150)		
Add back implied ETO EE savings 2008-2012	85		
Recognize Beaver as an intermediate resource	368		
PGE 2012 Resource Target	**903**		
Expected & Potential Resource Actions:			
ETO EE savings target 2007-2012	85	9%	111
Additional cost-effective EE 2008-2012	45	5%	65
Plant efficiency upgrades	7	1%	13
Partial contracts renewals (hydro)	70	8%	170
Biglow Canyon 2 & 3 (300 MW nameplate, by 2010)	105	12%	45
PPAs of up to 5-year terms for load uncertainty	180	20%	180
PPAs of 6 to 10-year terms for bridging	192	21%	192
Required added renewables to meet 2015 Oregon RPS	218	24%	133
Total of Recommended Actions	**903**	**100%**	**904**

Figure 13-1 shows our proposed Energy Action Plan by resource type.

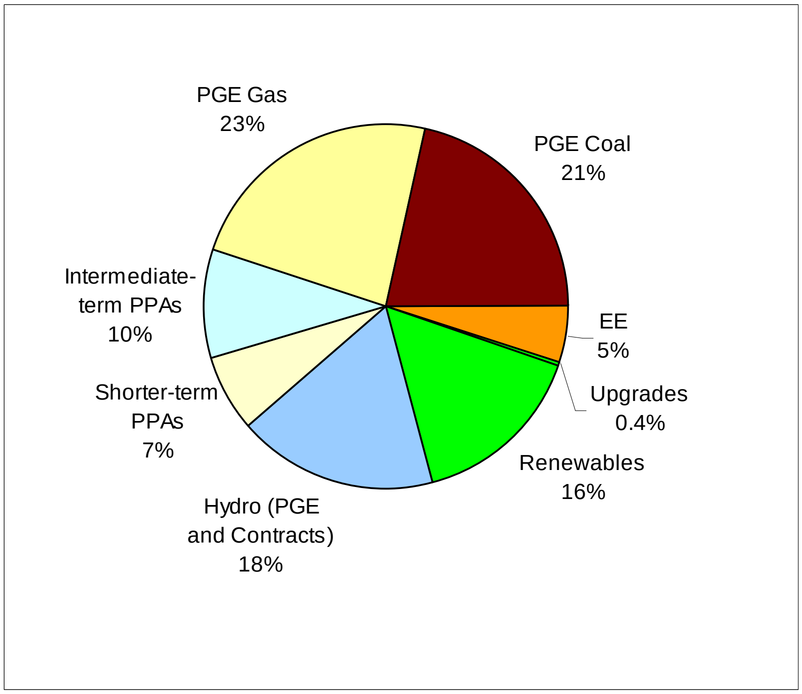
Figure 13-1: Energy Action Plan by Resource Type (MWa)



Our incremental energy actions focus on renewable resources and energy efficiency. PPAs are driven by a combination of economic displacement of our

Beaver plant and a desire to retain flexibility in meeting long-term needs. Figure 13-2 shows PGE's total resource portfolio in 2012, including both existing and proposed energy resources:

Figure 13-2: PGE Total Energy Resource Portfolio in 2012



While we show these actions as though they all take place in 2012, many actions (e.g., Biglow Canyon, EE) will likely precede 2012. A few others (a portion of the renewables needed to reach a 2015 RPS) may come after 2012. We expect to implement new resources between now and 2012 in a measured fashion and as dictated by RFP economics. However, a more gradual or rapid implementation could occur if circumstances warrant.

Description of Energy Action Plan Items

- **End-Use Energy Efficiency -** We show planned ETO targets based on utilization of our customers' public purpose funds as an action item in order to specifically acknowledge this ongoing work. Because our load forecast incorporates the effect of the ETO savings, we have grossed up our loads to show the impact of the ETO programs. We also include additional, projected cost-effective EE that current ETO funding is not sufficient to reach. These two actions combined, from now through 2012, would supply 130 MWa of energy savings, which is about 50% of our expected load growth during that period.

- **Generation upgrades –** We have planned efficiency upgrades at the Pelton Round Butte and Sullivan hydro plants and the Coyote gas plant which will deliver more energy for no additional fuel.

- **Hydro -** Some of our long-term hydro contracts expire by 2012. For IRP planning purposes we assume that a portion of these resources can be renewed upon expiration.

- **Biglow Canyon -** The Biglow Canyon wind project was evaluated, short-listed and accepted in our last all-source RFP. The first phase of this project was also acknowledged in fulfillment of our 2002 IRP Action Plan. This IRP requests acknowledgment of the subsequent two phases of the project. We have development rights for Phases II and III and will have a substation capable of serving the entire project by the end of 2007 as part of Phase I. The Biglow offers an attractive wind resource and is geographically well-suited to meet our future needs.

- **Mid-Term Power Purchase Agreements** - These PPAs are targeted for up to 5 years in duration. They act as a hedge against the load uncertainty and fluctuations in customer energy needs stemming from direct access programs.

- **Intermediate-Term Power Purchase Agreements** – Intermediate-term PPAs are targeted at 5 to 20 years. Securing intermediate term contracts will help us better meet our energy supply needs resulting from the economic dispatch of our Beaver plant. Beaver is currently being displaced much of the time via purchases on the spot and forward markets. Beaver remains available as before for economic dispatch and capacity requirements. This action reduces our physical and financial reliance on short-term volatile markets and provides a bridge to allow technology developments to mature (e.g., IGCC) and energy and environmental policy implications to become clearer.

- **Additional Renewable Resources -** The results of our portfolio analysis support acquiring additional renewable resources to achieve the 2015 Oregon RPS target of 15% of our annual energy requirements. Based on current assumptions about cost and risk exposures of competing resources, and based on our existing resource mix, our analysis concludes that acquiring renewable resources is preferred. This Action Plan recommendation is, however, predicated on continuance of the PTC in substantially its same form. It also assumes that sufficient viable projects exist to fill the demand at competitive prices. While we anticipate that the additional renewable resources will be predominantly wind, biomass offers the potential for adding diversity within our renewable resource mix and provides many of the reliability characteristics of more traditional thermal generation types.

Investment Requirement and Rate Impact of Recommended Energy Action Plan

The financial and rate impacts of this plan relative to alternative portfolios are difficult to assess and largely dependent on future conditions. These impacts also depend in part on whether new renewable resources are acquired via PPA or ownership. However, it is clear that wind resources recommended in this plan require substantial capital investment by PGE or others (and subsequently have no fuel cost). If owned by PGE, the addition of a large amount of capital intensive resources with traditional front-loaded revenue requirements could result in initial rate increases, even though overall life-cycle costs may be lower.

However, the preferred plan partially offsets the capital impacts of increased wind penetration through the targeted acquisition of PPAs and by increased acquisition of cost-effective EE. Table 11-1 shows the capital investment requirement and initial rate impact of the various portfolios, including the recommended Diverse + Contracts portfolio. In absolute terms, the proposed actions require projected new investment of $1.7 billion between now and 2015, and could result in a 12% rate increase for new fixed resource costs if all resource actions were placed in service at once in 2012. As discussed in Section 13.4 below, these actions are ongoing from 2008 through 2015. The rate increase cited above would actually be spread in smaller increments over seven years. These increases represent only the fixed-cost component of the resource actions. Actual rate increases will also be determined by future fuel costs. Capital investment and the initial rate impacts of our preferred plan are only moderately higher than for a traditional coal alternative.

13.2 Capacity Actions

We suggest reducing our short-term market reliance for peaking needs in this IRP to better align with NWPCC resource adequacy recommendations and to recognize the changing internal and external risk factors described in Chapter 12. Rather than rely on short-term markets to supply our highest 500 MW of demand, as acknowledged in our prior resource plan, we now propose to seek intermediate and longer-term supply sources for all forecast demand under normal weather.

Our proposed Energy Action Plan alone brings sufficient capacity to fill about 55% of our peak need. While this leaves a remaining gap in 2012 of about 748 MW in winter and 536 MW in the summer, the highest 500 MW of this demand takes place in no more than 50 hours of the year, as shown in Table 12-4 in the previous chapter. In addition, the last 248 MW of the 2012 resource gap is the contingency reserve for supply reliability. Thus the actual physical operating peaking gap in winter is about 500 MW. Notwithstanding the relatively short duration of peak conditions, the capacity shortfall remains challenging to fill. Our Capacity Action Plan recommends resource actions to meet our customers' remaining capacity needs, as summarized in Table 13-2 below.

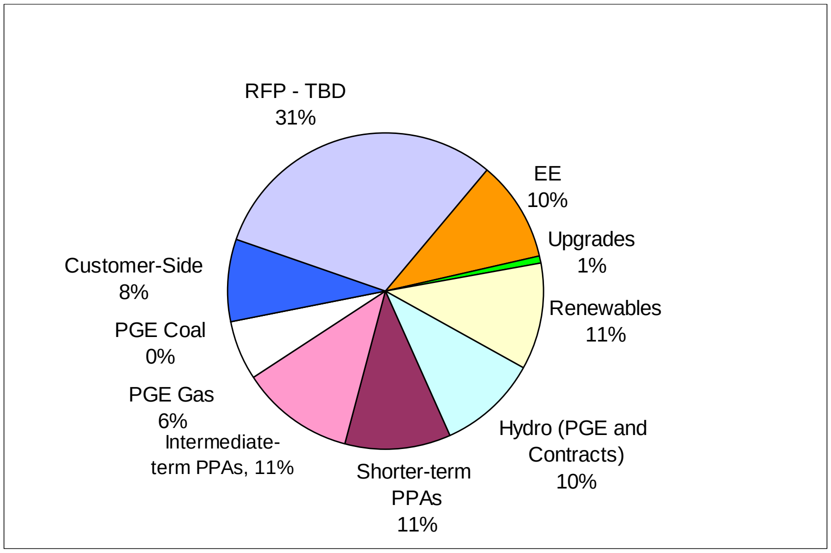
Table 13-2: 2012 Resource Need and Potential Capacity Supply Actions

	Capacity Winter MW @Normal Hydro	% of Target	*Capacity Summer* MW @Normal Hydro	% of Target
PGE system peak at normal weather (net of ETO EE)	4,127		3,761	
Add required operating reserve at 6% of peak load	248		226	
Add weather / plant contingency reserve at 6% of peak load	248		226	
Remove assumed 5-yr. opt-out load (w/reserves)[1]	(32)		(38)	-
Existing PGE & contract resources in 2012	(3,050)		(2,845)	
Add back implied ETO EE savings 2008-2012	111	-	111	
PGE 2012 Resource Target	**1,652**		**1,440**	
Year-round Resource Actions:				
Capacity value from proposed Energy Actions	904	55%	904	63%
Dual-purpose (capacity and wind following) SCCTs	100	6%	100	7%
Customer-based Solutions:				
Direct Load Control, if economic (space & water heat, A/C)	25	2%	23	2%
Curtailment tariff, critical peak pricing	35	2%	35	2%
Continuation of DSG program @ 13.5 MW / Yr.	80	5%	80	6%
Seasonally Targeted Resources:				
Bi-seasonal via demand and supply RFPs	299	18%	299	21%
Winter-only via supply RFP	210	13%	0	0%
Total of Potential Actions	**1,652**	**100%**	**1,440**	**100%**

[1] We do not plan long-term capacity resources for 5-year opt-out customer load; however, we recognize that we remain provider of last resort and could be required to serve all loads within our system.

This proposed approach relies on year-round, dual-purpose SCCTs to provide incremental capacity and supplemental wind integration, customer-sited demand response opportunities, and seasonal market products, if available.

Figure 13-3: Capacity Action Plan by Resource Type (MW)



We make the following observations regarding our proposed Capacity Action Plan:

- Our Capacity Action Plan, after the capacity brought by the Energy Action Plan, calls for roughly equal parts of customer-based, limited hour solutions, year-round peaking capacity (which will also help follow loads and wind), and seasonally targeted peaking capacity from the market.

- Unlike our prior IRP, we no longer believe it will be prudent, either physically or financially, to rely substantially on spot markets to meet our customers' peak demand.

- Our first priority will be to focus on demand response programs to the extent possible. These solutions offer the potential for material reductions in peak demand while providing customers a more active role in controlling their energy costs and consumption. However, we do not believe sufficient DR capability exists to rely solely on customer-based actions to meet peak needs.

- We intend to continue our industry-leading DSG program. This program provides flexible peak capacity located in close proximity to load, and increases reliability and satisfaction for host customers.

- A seldom recognized benefit of EE is that it has a load factor similar to (although somewhat higher than) our system load factor and thus brings capacity in excess of annual average energy savings.

- Upon approval of our advanced metering infrastructure, PGE is planning to issue a tariff to implement critical peak pricing for residential customers.

This program will provide insights about available capacity, allowing us to further refine this estimate.

- Supply and demand RFPs are needed to validate and better inform our choices. Similar to what we did in the last IRP with Port Westward, we intend in the coming months to develop one or more internal benchmark candidates to meet that portion of our capacity gap that is needed for a larger portion of the year. The benchmark resource(s) will be based on actual sites and third party component and construction bids. As with Port Westward, we would submit a sealed bid into the RFP in advance of other bids. We hope this will provide competitive discipline to the proposals. Should we determine that some portion of the capacity need could be more beneficially supplied via a CCCT, our internal alternative could also serve as a benchmark for assessing the medium-term PPAs we propose in the Energy Action Plan, thus potentially reducing our reliance on PPAs.

- In order to better understand the type and size of year-round incremental peak resources that will best meet customer needs, we intend to further investigate prior to securing new supply-side capacity resources the ramping and load-following capabilities of our existing dispatchable thermal plants. This includes understanding impacts to efficiency and maintenance cycles, as well as the need for any additional control equipment, such as AGC. We will balance our need for load following flexibility with the benefits of acquiring the lowest possible incremental heat rate capacity.

The recommended Capacity Action Plan is less specific than the recommended Energy Action Plan. This is due to greater difficulty of conducting capacity cost/benefit analysis, which can be attributed to reliability vs. economic considerations and the fact that capacity does not lend itself to the traditional asset valuation and portfolio modeling techniques used for energy resources. There is also less market activity and reduced transparency with respect to capacity resource availability and cost. As a result, we expect to validate and further refine our proposed capacity action plan as we move forward with resource solicitations, determining an internal benchmark resource, and developing demand-side programs with our customers.

13.3 Transmission Actions

Based on our work with regional transmission planning groups in the West, we believe that synergies may exist between the Southern Crossing and several proposed large-scale, inter-regional transmission projects. The value of the Southern Crossing will be higher to the extent that the project provides enhanced regional benefits and synergies with these other projects. Most of these other potential projects would include anchor resources. More rigorous analysis is needed to define and determine the benefits of moving forward with the Southern Crossing concept.

In addition to the Southern Crossing work, we are actively engaged with the joint BPA/NWPCC Wind Integration Action Plan as described in Chapter 1. Part of that undertaking is to determine both the short-term and long-term transmission requirements associated with high levels of wind penetration for the region. Depending on project economics, the Southern Crossing project may play a role in identifying solutions for PGE and others to have better access to these important resources. In our Action Plan, we propose to continue to evaluate the Southern Crossing project and to actively work with BPA and others to develop transmission capacity over the Cascades so that additional, competitive resources are accessible to PGE.

13.4 Resource Acquisition Timing

In order to enable consistent analytical comparisons and due to timing uncertainties related to implementation, we staged new resources for portfolio analysis as though they would all be placed in service in 2012. Actual resource acquisition results will differ, with several actions likely occurring sooner, and others potentially later than 2012:

- Both ETO EE acquisitions and DSG are ongoing programs.
- Incremental EE begins in 2008, assuming OPUC approval, and then continues.
- Plant efficiency upgrades are ongoing.
- Biglow Canyon Phase II is currently targeted for 2008 to 2009; Biglow Canyon Phase III is targeted for year-end 2010.
- The timing for additional renewable resources in the Energy Action Plan would be based on a variety of factors such as market conditions, turbine and site availability, PTC extensions, etc.
- New customer demand response and direct load control programs would begin upon implementation of advanced metering infrastructure, in 2009 - 2010.
- Power purchase agreements for various amounts and durations could take place at any time, but will likely become more extensive after the expiration of existing resources, shortly after the end of this decade.

13.5 Required Policy and Regulatory Support

Several of the actions we propose depend on supportive regulatory and legislative actions. In this section, we discuss how certain elements of the Energy and Capacity Action Plans depend on policy developments at the OPUC and the Oregon State Legislature.

Energy Efficiency

Energy efficiency is an important element of our Action Plan. Prior to Senate Bill 1149, the Save all Value Equitably program provided incentives and cost recovery (including consideration for lost revenue) for our EE acquisition. However, implementation of Senate Bill 1149 transferred primary responsibility for EE acquisition to the ETO. Given its budget, the ETO is not able to acquire all of the projected cost-effective EE available in our service territory. We would like to enable the ETO to acquire all economic EE. Appropriate changes are needed to provide incentives and ensure EE regulatory cost recovery so that this resource can compete fairly with other resource options.

Power Purchase Agreements

Possible renewable portfolio standards, CO_2 emissions regulation, and the resource development decisions of other entities all introduce major uncertainties to the power markets. Use of PPAs is part of our overall bridging strategy to hedge against these uncertainties while remaining adaptable to changing future conditions. We propose medium rather than long-term resource actions while the energy industry is in a period of transition. In our Energy Action Plan, we propose to fill about 40 percent of the projected 2012 energy gap of 903 MWa with PPAs. However, our bridging strategy also poses increased operating leverage and the risk that debt imputed by rating agencies for contracts will reduce our financial flexibility or increase our borrowing costs. As a result, this portion of our plan depends on a supportive outcome in the UM 1276 docket, which focuses on build vs. buy decisions. Specifically, we need a structure that recognizes and addresses the risk and potential cost associated with PPAs.

Order 07-002 directs us to assess the advantages and disadvantages of owning a resource instead of purchasing power from another party. Our Energy and Capacity Action Plans call for a mixture of PPAs, ownership of Phase II and III of Biglow Canyon, and other supply actions for which we have not specified purchase vs. ownership. Our goal is to provide customers with the most competitive resources on a real-levelized cost basis, also taking risk into account, while providing a reasonable return to our shareholders. Accordingly, we believe that the determination of purchase vs. ownership must be made on a case-by-case basis by comparing results of market alternatives to PGE development opportunities.

Currently, ownership can bring both income to equity investors and greater financial stability to our customers through long-term access to resources. Ownership also provides advantages to customers via lower expected utility debt and equity costs. Conversely, too high of a concentration of PPAs can bring debt obligations that can ultimately increase costs to our customers. If there is a level playing field, as UM 1276 seeks to achieve, then PGE, our customers, and our equity investors should be made indifferent as to who owns the underlying asset.

Production Tax Credits

In our modeling, we assume that the federal PTC for renewable resources continues in its current form past 2008. However, Congress must periodically renew (or revise) this credit. For example, the current credit only covers renewable resources completed by December 31, 2008. Given the amount of wind acquisitions in our Energy Action Plan and the high overall demand for wind turbines, our least-cost resource acquisition strategy could include commitments to purchase turbines before Congress has passed PTC renewal legislation. Acknowledgement of this Plan should include the recognition of this risk and contain an explicit conclusion that it is prudent to proceed notwithstanding the PTC uncertainty. The proliferation of renewable portfolio standards increases this concern, as we will likely be competing with other utilities for future turbines well in advance of actually building new wind projects.

Renewable Site Acquisition

The need of many utilities throughout the WECC to meet RPS energy targets puts pressure on utilities to acquire sites with attractive wind characteristics. For biomass and geothermal, the pressures are similar because the supply of these resources is more limited. Many such sites are no longer available. Given the increasing demand for wind resources, acquisition of wind sites in advance of our actual resource needs might represent the best combination of expected costs and associated risks and uncertainties. However, implementation of this approach would require changes to the current legislative restriction against recognizing in ratemaking the costs of property held for future use. Specifically, ORS 757.355 excludes property from the rate base that is not presently used to provide utility service. Acquisition of sites in advance of needs would also require appropriate risk allocation policies and cost recovery. Both customers and PGE should know in advance the allocation of any gains or losses in value during the holding period.

Capacity Contracts

As was the case in our 2002 IRP Final Action Plan, we may find that it is most economic to meet part of our capacity needs through seasonal contracts that are targeted to our peak periods. Rate-making treatment for capacity contracts is, however, presently unclear. Ultimately we need assurance of cost recovery if we are to enter into future capacity contracts.

Combined-Cycle Combustion Turbines to Meet Capacity Requirements

Some stakeholders have suggested that we meet capacity requirements with CCCTs, rather than SCCTs, because the additional dispatch benefits of CCCTs provide enhanced economics on an expected-case basis. Our analysis and modeling support the premise that CCCTs provide lower expected net overall costs (see Table 12-6 and the related discussion). However, their dispatch benefits can change from year to year, adding to variability in net variable power costs. In addition, a large structural shift that impairs dispatch economics could result in unnecessary exposure to increased fixed costs. This variability would impact PGE's Annual Update Tariff filings and implementation of the Power Cost Adjustment Mechanism (PCAM) instituted in Order No. 07-015. Therefore, implementation of a strategy of pursuing additional CCCTs to meet remaining capacity requirements could require modification of current OPUC rate-setting policies to maintain an appropriate allocation of risk between PGE and customers.

Support for Local Emerging Generation Technology Opportunities

While not a discrete element of our Action Plans, we believe it is important to find ways to engage in local efforts to develop future renewable and other generation technologies. One possible method is to identify and select promising demonstration projects or other similar generation opportunities and to provide technical and financial support. For instance, wave energy off the Oregon coast (as discussed in section 7.7) presents a unique opportunity. Other opportunities may include solar applications, carbon recycling at the Boardman plant, integration of plug-in hybrids, etc. The benefits of early participation in local demonstration projects are threefold:

1. We help stimulate innovative, greener solutions for our customers' energy needs;

2. We gain experience with these technologies, which will in turn better inform later deliberations for possible commercial-scale application; and,

3. Support of demonstration projects allows PGE to preserve a favorable supply position on behalf of our customers by building relationships and enabling access to promising new technologies and resources as they mature.

PGE proposes discussions in connection with this IRP with OPUC staff, the ETO, the NWPCC, and other stakeholders regarding an appropriate regulatory and financial construct to support such local initiatives.

13.6 Proposed RFPs and Timing

We propose RFPs in our Action Plan to seek proposals for the following resource types:

1. Additional renewables to meet our 2015 RPS target;
2. Fixed-price PPAs with staggered terms of between 3 and 10 years;
3. Third-party delivery of customer-sited demand response actions;
4. Seasonal and/or year-round capacity resources.

Actual RFP(s) will be somewhat dependant on stakeholder feedback and response to this IRP upon filing. Recognizing that there is increased competition for attractive renewable resources, we propose exploring ways to expedite competitive bidding by initiating the process prior to final acknowledgement of this IRP. We believe that opportunities for renewable resources and market products are time-sensitive and thus demand a sense of urgency and a flexible approach.

Conclusion

We find ourselves in a planning environment that is changing and unpredictable. During the post-filing, six-month data discovery and review period of this IRP process, new information or insights may emerge which could cause modifications to our recommendations. Subsequent market solicitations could also cause minor course alterations, but we expect the central elements and strategic emphasis of the plan to remain to:

- Maintain an adequate, reliable, and economic supply of power to our customers;
- Focus on overall portfolio diversity and flexibility;

- Acquire cost-effective renewable resources to achieve the Oregon RPS targets;
- Acquire all cost-effective EE;
- Expand on our industry-leading DSG program;
- Actively develop and pursue customer DR opportunities; and
- Enter into mid-term PPAs as a bridge to the future.

We believe that these proposed actions are both progressive and cautious. They position PGE to continue to reliably serve customers for the future while being wise stewards of natural resources and the environment. As we move forward to complete our current IRP process, we continue to welcome suggestions regarding effective ways to provide our customers the best possible electricity solutions, while remaining responsive to the interests of our investors and other constituents.

14. Appendices

A. Order No. 07-002 Compliance Checklist

B. Agendas of IRP Public Meetings

C. University of Washington Climate Change Study

D. Black & Veatch Coal Technology Study – Executive Summary

E. Cornforth Geological Carbon Sequestration Study – Executive Summary

F. KEMA Customer Research – Executive Summary

G. AURORAxmp® WECC Resource Expansion

H. Portfolio Analysis Results

A. Order No. 07-002 Compliance Checklist

Guideline Number	Description of Requirement	Addressed in Draft IRP	PGE Fulfillment of Requirement
Guideline 1: Substantive Requirements			
1a	All resources must be evaluated on a consistent and comparable basis.	Chapters 4 & 7	Supply-side are evaluated in Chapter 7and demand-side resources in Chapter 4.
	All known resources should be considered, including supply side and demand side options	Chapters 4 & 7	We assess all commercially available generation sources, including thermal technologies (SCPC and IGCC coal with and without sequestration, CCCT and SCCTs), hydro, and renewables (biomass, geothermal, and wind), as well as emerging technologies such as next-generation nuclear, solar, wave power, and combined heat and power. We also assess contracts (PPAs) and consider demand-side resources (see comments to Guideline 7, below).
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	Chapters 10, 11, and 12	We consider differing fuels and technologies. Our Action Plans include differing durations and in-service dates. We are waiting for the RFP stage to address varying contract terms and resource location considerations.
	Consistent assumptions and methods should be used for evaluation of all resources.	Chapters 5, 6, and 10	We use consistent fuel and environmental cost assumptions across all resource types. We also use consistent discount rates, PTC, income tax, and other financial assumptions. All portfolios are subjected to the same futures and use the same modeling approach.
	The after-tax WACC should be used to discount all resources	Section 10.3	We use our after tax nominal cost of capital of 7.59% - see Table 10-2.
1b	Risk and uncertainty must be considered. Electric utilities should address the following sources of risk and uncertainty: load requirements, hydro generation, plant forced outages, fuel prices, electricity prices, and costs to comply with regulation of greenhouse gas emissions.	Sections 10.4, 10.5, 10.6, and 10.9	We test all portfolios under four stochastic risks: natural gas prices, hydro generation, forced outages, and load. These input variables are used to produce a series of electricity prices. We also test all portfolios under carbon tax at $10, $25, and $40 per ton (in $1990); high and low gas price futures; high and low load growth futures, and various RPS scenarios.
	Utilities should identify in their plans any additional sources of risk and uncertainty.	Sections 10.6, 10.7 and 10.8	We address an uncertain future and potential for paradigm shifts by testing portfolios across various futures. We also consider qualitative, along with quantitative, measures of risk.
1c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.	Chapters 12 and 13	We select the portfolio "Diverse + Contracts" which offers the best combination of expected costs and associated risks. This portfolio is the basis for our action plans presented in Chapter 13.

	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	Section 10.4	We calculate the Net Present Value of Revenue Requirements (NPVRR) from 2009 - 2031 (over 20 years of actual dispatch of new resources.) End of life effects are taken care of by using real levelized fixed revenue requirements.
	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs of all long-lived resources such as power plants, gas storage facilities and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	Sections 10.4 and 10.7	The cost of a portfolio is measured by the net present value of the total revenue requirement (present value of revenue requirement net of sales) across the time frame of the analysis (NPVRR). The revenue requirement is composed of the net variable power cost (costs for purchases or generation net of revenues from sales) and the fixed cost. We use an excel spreadsheet, the transition cost model (TCM), to model the fixed component of the revenue requirement: investment, ongoing capital additions, fixed O&M, wheeling and transmission costs. The net variable power cost is computed in AURORAxmp using hourly dispatch. We assume that all short-term purchases are priced at the spot market price. Whenever a portfolio does not add enough long-term resources to meet the energy and capacity need in a given year, we meet load by buying spot energy.
	To address risk, the plan should include at a minimum: 1) Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes. 2) Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	Chapter 3, Sections 10.7, 11.1, 11.5, 12.4, and 12.5	The risk metrics we use include: worst NPVRR across deterministic scenarios, TailVar90 of NPVRR across 100 stochastic games, and TailVar90 of annual rate increases across 100 stochastic games. Financial hedges are discussed in Section 12.5. Chapter 3 and Section 12.4 address reliability (physical hedges).
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapters 11 and 12	We analyze in detail the trade-offs between cost and various risk measures, both for energy and for capacity resource options.
1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	Chapters 10, 11, 12, and 13	We examine all major policy issues which impact the action plan. These include the Oregon RPS and possible CO_2 taxes.
Guideline 2: Procedural Requirements			
2a	The public, including other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan.	Chapter 1 and Appendix B	PGE has conducted 7 public meetings (attendance included other utilities, including PacifiCorp, NW Natural and Avista), as well as several other workshops and 1:1 meetings with stakeholders. Stakeholder suggestions have been incorporated into analysis and modeling.

	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan	Chapters 4 - 9	In addition to internal analysis and review, PGE has made public (both in its public meetings and in the written IRP) the results of all studies conducted for this IRP, including customer resource preferences, energy efficiency analysis, climate change impacts study, and many more. All public meeting presentations were posted on our website.
	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	Draft filed June 5	
Guideline 3: Plan Filing, Review and Updates			
3a	Utility must file an IRP within two years of its previous IRP acknowledgement order.	PGE received acknowledgment from the OPUC in UM 1056 that we must file our IRP by second quarter 2007;	
3b	Utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment	PGE plans to present to the OPUC at a public meeting; date: TBD.	
3c - g	These guides discuss Commission comments and acknowledgement and the IRP annual update.	NA	NA
Guideline 4: Plan Components			
	At a minimum, the plan must include the following elements:		
4a	An explanation of how the utility met each of the substantive and procedural requirements	Chapter 1 and Appendix A	
4b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions	Chapter 10, Sections 11.3 and 11.5	We tested all portfolios against a scenario of high (3%) and low (1%) load growth. We also included load as a variable in our stochastic analysis.
4c	A determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested.	Chapters 3, 9, and 10	We compute the energy balance in this IRP as the difference between the energy capability of our resources (plants, contracts and purchases) and the annual average load under normal weather and hydro conditions. Our candidate energy & capacity action plans identify resources needed to bridge this gap. PGE changed the default topology of AURORAxmp to better represent PGE's specific constraints and to update transmission capability, expected losses, and wheeling to current path rating and/or to adjust unrealistic import/export between zones. For future transmission additions required for new resources, we assumed that all resources would incur the standard BPA tariff for transmission.
4e	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology	Chapters 4, 7 (sections 7.4 & 7.5), and 12	We identify and estimate costs for all supply side and demand-side resources, taking into account advances in technology.

4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	Sections 12.4 - 12.7	We performed a LOLP study to determine LOLP and expected unserved energy. We also conducted a capacity analysis to determine the trade-off between capacity additions and reliability.
4g	Identification of key assumptions about the future (e.g. fuel prices and environmental compliance costs) and alternative scenarios considered.	Chapters 5, 6, 7, and 10	We address fuel price assumptions in Chapter 5, new resource costs in Chapter 7, and environmental assumptions in Chapter 6. We test all portfolios against various futures, as described in Section 10.6.
4h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations - system-wide or delivered to a specific portion of the system	Section 10-4	We created thirteen different portfolios consisting of a mix of pure-play (i.e. single resource) and diverse resources representing different fuel types, technologies, lead times, etc.
4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties	Chapter 11	See Chapter 11 - Energy Portfolio Analysis & Results
4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results	Chapter 11	See Chapter 11 - Energy Portfolio Analysis & Results
4k	Analysis of the uncertainties associated with each portfolio evaluated	Chapter 11	Section 11.6
4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers	Chapter 11	Section 11.6
4m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation	Chapter 13	Given its budget, the ETO is not able to acquire all of the projected cost-effective EE available in our service territory. We would like to enable the ETO to acquire all economic EE. Appropriate changes are needed to provide incentives and ensure EE regulatory cost recovery so that this resource can compete fairly with other resource options. Our bridging strategy depends on a supportive outcome in the UM 1276 docket, which focuses on "build vs. buy" decisions. Specifically, we need a structure that recognizes and addresses the risk and potential cost associated with PPAs, and where utilities do not suffer rating agency downgrades or other penalties because of decisions to enter into contracts rather than building new resources. See also other issues in Section 13.5.
4n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Chapter 13	We identify our candidate energy and capacity action plans in Chapter 13.
Guideline 5: Transmission			

5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	Transmission - Chapter 9, (Section 9.4); Fuels - Chapter 5	For transmission, we use the standard BPA tariff to determine the cost of delivering power to PGE. For fuels transportation, we include the cost of transportation (rail for coal, and pipeline delivery charges of $.55/dkt for gas) in the cost of fuels used to forecast our electricity prices and determine the real levelized cost of new resources.
Guideline 6: Conservation			
6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	Chapter 4	We adopted the Energy Trust of Oregon's study of available energy efficiency in our service territory (issued May 2006). We will continue to work with ETO to implement EE measures in our service territory.
6b	NA- for utilities that control the level of funding for conservation programs in their service territories.	NA	NA
6c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1) determine the amount of conservation resources in the best cost/ risk portfolio without regard to any limits on funding of conservation programs; and 2) identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition	p. 61	PGE worked with ETO to determine that there are 44.9 MWa of additional EE potential. We included this amount in our diverse portfolios, and in our candidate action plan.
Guideline 7: Demand Response			
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs	Chapter 4	PGE evaluated demand-side resources, including energy efficiency, dispatchable standby generation, direct load control and load curtailment contracts, demand buy-back, critical peak pricing, and others. We contracted with Quantec to conduct a detailed study of the potential for demand response. We treat demand response resources on par with other capacity resources.
Guideline 8: Environmental Costs			

8	Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for CO2, NOx, SO2, and Hg emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from $0 - $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for NOx, SO2, and Hg, if applicable	Chapter 6	We included in the cost of coal and natural gas the offset payments to the Climate Trust per OEFSC rules. Our base case assumptions include a CO_2 tax of $7.72/ short ton starting in 2010 per the NCEP recommendations. We also test all portfolios under a CO_2 tax at $10, $25, and $40 per ton (in $1990), and under a scenario with no CO_2 tax. For mercury, the Cost of CAMR compliance is included in generic capital cost assumptions. We also evaluate the cost of adding emissions controls to Boardman in order to comply with Oregon's RH BART process. For SO_2 we model the cost of allowances in coal plants.
Guideline 9: Direct Access Loads			
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier	Section 3.2	We do not plan for 5-yr opt-out customers (currently about 30 MWa). For the remaining 270 MWa of customers potentially eligible for 3 and 5-yr opt-out, we acquire long-term resources for two thirds of this load, and shorter-term resources (as required) for the remaining one third.
Guideline 10: Multi-state utilities			
10	NA - PGE is not a multi-state utility.	NA	NA
Guideline 11: Reliability			
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. LOLP, expected planning reserve margin, and expected worst-case unserved energy should be determined by year for top-performing portfolios. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	Section 12.4	We performed a LOLP study on our preferred portfolio (Diverse + Contracts). Three parameters (load, hydro generation, and forced outages) were chosen to model uncertainty in our environmental variables and the stress they impose on our system. We used AURORAxmp to determine how our resource mix will respond to the variability of the stochastic parameters in terms of loss of load probability, and expected and worst-case unserved energy.
Guideline 12: Distributed Generation			
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	Section 7.6	
Guideline 13: Resource Acquisition			

13a	An electric utility should: identify its proposed acquisition strategy for each resource in its action plan	Chapter 13	Energy and Capacity Action Plan. Resource acquisition and timing is specified in section 13.4.
	Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party	Section 13.5	We have identified the risk and advantages associated with PPAs.
	Identify any Benchmark Resources it plans to consider in competitive bidding	Section 13.2	Similar to what we did in the last IRP with Port Westward, we intend in the coming months to develop one or more internal benchmark candidates to meet a portion of our energy and capacity gaps. The benchmark resource(s) will be based on actual sites and third party component and construction bids. As with Port Westward, we would submit a sealed bid into the RFP in advance of other bids.
13b	NA - applies to natural gas utilities.	NA	NA

B. Agendas of Public Meetings

The content of our public meetings is summarized below. The actual presentation material can be found by clicking on the "Resource Planning" menu item at **www.portlandgeneral.com/about_pge/current_issues.** In many instances, the public meeting material contains additional detail not presented in this IRP document. However, please note that these presentations were descriptions of our work in progress as of the publication dates and were intended solely for discussion purposes. These are not intended to be final policy or position pronouncements by PGE. In several instances, this IRP reflects newer data and assumptions. Where data or assumptions are not consistent, this document supersedes the public meeting material.

Public Meeting No. 1 - April 12, 2006
PGE's Load-Resource Balance, Scope of IRP

- Introduction: cost, reliability, price stability, environment
- IRP Update *vs*. Action Plan
- Regional load-resource balance and Resource Adequacy Forum – John Fazio, NWPCC
- LRB jaws - loads and load uncertainties, resource expirations, resource margins, hydro planning – normal and critical hydro
- Detailed plan for evaluating the portfolio for least cost, risk, and diversity
- IRP studies
- Stakeholder dialogue agendas
- Outline of 2006 IRP

Public Meeting No. 2 – May 8, 2006
Customer Outreach Studies, Demand-Side Management, Potential Federal and State Legislation

- Follow-up, open items from previous meeting
- Customer outreach studies, qualitative
- Customer outreach studies, quantitative – David Lineweber, Ph.D., Momentum
- ETO energy efficiency forecasts – Fred Gordon, Energy Trust of Oregon
- PGE's position on energy efficiency
- Demand Response
- Combined heat and power
- Net metering
- Dispatchable standby generation
- PGE climate change principles
- Federal climate legislation

- RPS potential
- What's coming up next meeting

Public Meeting No. 3 - June 12, 2006
Fuels Fundamentals and Forecasts, New Generation Options and Costs

- Welcome & Follow-up on open items from previous meeting
- Fuels fundamentals and forecasts – natural gas, LNG, coal
- Generic generation plant choices & costs – base case & high confidence estimates; CO_2 and other emissions costs
- Commercial-scale renewables – wind, bioenergy, geothermal
- Thermal technologies - IGCC vs. SCPC, Black & Veatch study, CO_2 sequestration
- Generation resource qualitative considerations summary
- Emerging technologies – next generation nuclear, wave energy, utility-scale solar, and special projects (biogas, microturbines, fuel cells)
- What's coming up next meeting

Public Meeting No. 4 - July 25, 2006
Modeling Approach, Transmission Constraints and Capacity Resource Costs

- Follow-up, open items from previous meeting
- Open discussion with stakeholders on 3rd IRP meeting content
- Suggested risk metrics - expected value, TailVaR90, RVI, environmental metrics
- Volatilities, distributions and correlations of stochastic inputs
- Scenarios – i.e. high gas, poor hydro, CO_2 sensitivities, etc.
- Transmission constraints and solutions, OSU studies
- Reserve margin assumptions for 2006 IRP
- Capacity resource costs – SCCT, contracts, demand response, DSG

Public Meeting No. 5 – December 8, 2006
Updates & Analysis of Trial Portfolio Scenarios

- Updates:
  - EE Initiative
  - Demand Response Update
  - Potential Impact of Oregon RPS on PGE
  - Wind Integration Study Status
  - Customer Green Power Status
- Load Resource Balance:
  - Load forecast: discuss Opt-out assumption
  - Projected Energy Gap in 2012
- Portfolio Analysis Insights:
  - Trial portfolios: Performance Across Futures

    - Stochastic Inputs and Results
- Regional Resource Adequacy Update
- PGE's Proposed Approach to Capacity Planning

Public Meeting No. 6 – February 27, 2007
Analysis Updates and Proposed Action Plan

- Load resource balance:
    - Treatment of Beaver as an intermediate resource for energy
    - Revised projected energy and capacity gaps in 2012
- Update on portfolio analysis insights:
    - Trial portfolios: performance across futures
    - Stochastic inputs and results
- Energy action plan and remaining capacity need
- Loss of Load Probability analysis – preliminary results
- Capacity analysis – preliminary results
- Timeline for filing draft IRP/ Resource Action Plan

Public Meeting No. 7 – April 9, 2007
Final Updates and Capacity Analysis and Action Plan

- Follow-up, open items from previous meeting
- Updated portfolio analysis
- Energy efficiency update
- Capacity analysis
- Preliminary results of wind integration study
- Updated loss of load probability analysis
- PGE system flexibility to meet resource adequacy
- Boardman and RH BART
- Timeline for filing draft IRP

C. University of Washington Climate Change Study

(Next Page)

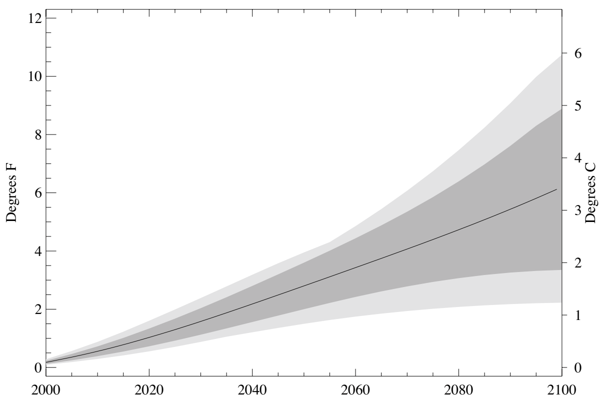
Energy-relevant impacts of climate change in the Pacific Northwest

a report by

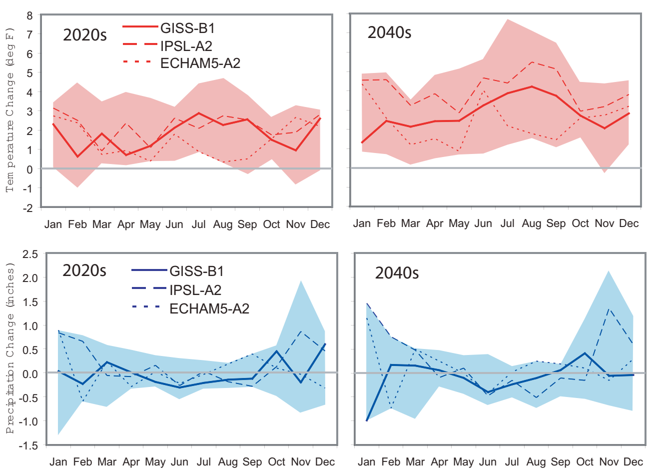
Philip Mote, Eric Salathé, and Cynthia Peacock

Climate Impacts Group, University of Washington

July 2006



A range of warming scenarios for the Northwest from 20 simulations by global climate models. Average shown as thick line, lowest and highest shown by light gray shading, and dark gray encloses about 70% of the model results.



Changes in temperature (top) and precipitation (bottom) month by month, for all scenarios (shaded envelopes) and for three specific scenarios.

Summary.

Observations show substantial warming (1.5°F) in the Pacific Northwest, and indeed the entirety of western North America, over the past 50-100 years. Concomitant hydrologic changes toward earlier peak flow, reduced summer flow, and increased winter flow have also been observed and are several lines of evidence show that warming is responsible.

Continued warming in the region is extremely likely because greenhouse gases are rising. We have examined 20 scenarios from state-of-the-art climate models and summarize here the changes they project. The average warming rate in the Pacific Northwest during the next century is expected to be in the range 0.1-0.6°C (0.2-1.0°F) per decade, with a best estimate of 0.3°C (0.5°F) per decade.

Present-day patterns of greenhouse gas emissions constrain the rate of change of temperature for the next few decades: humans are committed to some degree of additional climate change. Beyond mid-century, the projections of warming depend increasingly on emissions in the next few decades and hence on actions that would limit or increase emissions.

Projected precipitation changes are modest, and are unlikely to be distinguishable from natural variability until late in the 21st century. Most models have winter precipitation increasing and summer precipitation decreasing. The aggregate changes in climate will likely produce continued decreases in June-September flow in most rivers in the Northwest, with increases in winter flow. However, changes in wind energy potential will probably be small.

2020s*	temperature	precipitation
low	0.4°C (0.7°F)	-4%
average	1.1°C (1.9°F)	+2%
high	1.8°C (3.2°F)	+6%

2040s*	temperature	precipitation
low	0.8°C (1.4°F)	-4%
average	1.6°C (2.9°F)	+2%
high	2.6°C (4.6°F)	+9%

---

* In this document, "2020s" means the 2010-2040 average minus the 1970-2000 average, similarly for 2040s and 2080s.

1. Introduction: global and Northwest climate change

Weather and climate affect different economic sectors in different ways, but in the Northwest, the importance of hydropower plays a special role in connecting the energy industry with climate. For this reason, and because the energy industry is technically and analytically advanced, for example in the capabilities for quantitative risk assessment, many energy companies are asking important questions about climate change.

This report arose because Portland General Electric asked such questions. In particular, PGE asked the Climate Impacts Group (CIG) at the University of Washington to provide the latest, most defensible scenarios of future climate change in the Northwest, and to describe how it would change the hydropower and wind generation capabilities upon which PGE relies for a portion of its generating capacity.

1a. Global climate change

The air in Earth's atmosphere includes certain "greenhouse gases", e.g., water vapor, carbon dioxide, and methane, which, by preventing infrared energy from escaping to space, keep the planet warm and habitable. Without them, Earth's average temperature would be well below 0°F. Human activities like the burning of "fossil" fuels – coal, oil, and natural gas – raised concentrations of these gases substantially over the past 150 years (mostly during the last 30 years), to values not seen in millions of years (Prentice et al. 2001).

The "greenhouse effect" refers to a natural process in which certain gases (water vapor, carbon dioxide, and methane are the most important) allow the sun's radiant energy to pass through the atmosphere, but absorb the radiant energy that Earth emits at lower wavelengths. This leads to a natural warming of the Earth. Fluctuations in the composition of the Earth's atmosphere on geologic timescales have produced vastly different climates – 100 million years ago, Earth was so much warmer that alligators lived in what is now Siberia, and the carbon dioxide content of the atmosphere was probably 4 to 8 times present levels (Kump et al., 1999; Prentice et al., 2001). Throughout Earth's history, the natural warming of the greenhouse effect has kept the planet warm enough to sustain life. What is unusual now, however, is the rate at which CO_2 and other greenhouse gases are now increasing.

In the last 150 years or so, humans have enhanced the natural greenhouse effect by increasing the quantities of key greenhouse gases. Carbon dioxide has increased 36% because of burning fossil fuels and reducing forested area, and methane has increased by 151% through agriculture (chiefly cattle and rice paddies) and other human sources (Prentice et al., 2001). Other greenhouse gases have also increased, including some (CF_4, C_2F_6, and SF_6) whose human sources exceed natural sources by a factor of 1,000 or more, and some (e.g., the chlorofluorocarbons) that have no natural sources at all (Prather et al., 2001). In the global mean, carbon dioxide accounts for 60% of the radiative forcing by greenhouse gases, and methane 20% (Ramaswamy et al., 2001). Water vapor is also a greenhouse gas, but its influence is considered a response (positive feedback) of the climate system rather than as a separate forcing.

Two key questions arise from the increase in greenhouse gases: (1) is the planet warming? and (2) can we rule out natural causes for recent climate change? These two questions are answered in this section, drawing heavily on the assessment reports by the "Intergovernmental Panel on Climate Change", or IPCC. The IPCC was created in 1988 and has issued major reports in 1990, 1996, and 2001 (the First, Second, and Third Assessment Reports). Much of what is presented in this section comes from the first volume of the IPCC's Third Assessment Report (TAR). This comprehensive report (884 pages) was written by over 650 scientists who volunteered considerable time over a period of three years to write the report, and was reviewed by 300 additional scientists (IPCC, 2001). The IPCC assessments constitute the most comprehensive, authoritative statement about the state of the science of climate change. The interested reader is strongly urged to consult the IPCC "Summary for Policymakers" (see references).

The IPCC answered affirmatively to both of the questions posed in the previous paragraph.

In answering yes to the first question, whether Earth is warming, the IPCC stated that "An increasing body of observations gives a collective picture of a warming world and other changes in the climate system." Evidence marshalled included the following:

- global average surface temperature has increased by 0.6°±0.2°C during the 20th century;
- Northern Hemisphere snow cover has decreased by about 10% since the late 1960s;
- most mountain glaciers retreated during the 20th century;
- sea ice extent and thickness have decreased since the 1950s; and
- in addition (Cayan et al., 2001), since about 1950 the timing of spring, as marked by blooming or leafing-out dates of various plants, has advanced in much of North America.

Urbanization (the growth of cities around weather stations), though a factor at some locations, has barely affected the estimation of global average temperatures (Peterson, 2003). Additional evidence that Earth's surface is warming has accumulated since the IPCC TAR, including, thinning and contraction of Arctic sea ice, disintegration of Antarctic ice shelves, earlier spring melt on lakes and rivers, earlier snowmelt runoff in the West (Stewart et al. 2005), poleward movement of numerous species, earlier bloom dates of various flowering plants, warming of the ocean's interior in a pattern consistent with the pattern of atmospheric warming (Barnett et al. 2005). Although a few carefully selected observations might show a contrary pattern, the vast weight of evidence clearly points toward a warming world.

What about satellite records that supposedly show no warming? The satellite records have several difficulties, with which climate researchers have been grappling. First, these satellites measure the temperature not of the (unquestionably warming) surface, but of a thick layer of the atmosphere. Second, the satellite record, which began only in 1979, consists not of a single well-calibrated satellite but a patched-together history of nine different satellites. In order to account for inter-satellite differences and other effects like orbital changes and the cooling of the stratosphere, scientists have had to apply various complicated corrections and different groups use different approaches. When most groups apply such corrections, they find a trend 1979-2003 of 0.1-0.2 K/decade; the surface warming is 0.17 K/decade (e.g., Fu et al., 2004).

The warming in the 20th century did not proceed smoothly, but rather in two stages: one from 1910 to 1945 and one since 1976, with temperatures relatively constant at other times. This fact prompts a crucial question: was the warming natural or man-made?

Natural causes of climate change include solar variations, volcanic eruptions, and the redistribution of heat by the oceans. In answering this more complicated question about the cause of warming, scientists have taken different approaches. One approach is to examine past climate and determine whether the warming of the late 20th century is unusual. Scientists have carefully reconstructed temperatures in the Northern Hemisphere back to A.D. 1000 (Mann et al., 2003) from tree rings and corals and other "proxy" data, and two things about recent climate stand out: (1) the 20th century warming appears to be the largest of the millennium and (2) the 1990's are likely the warmest decade of the millennium.

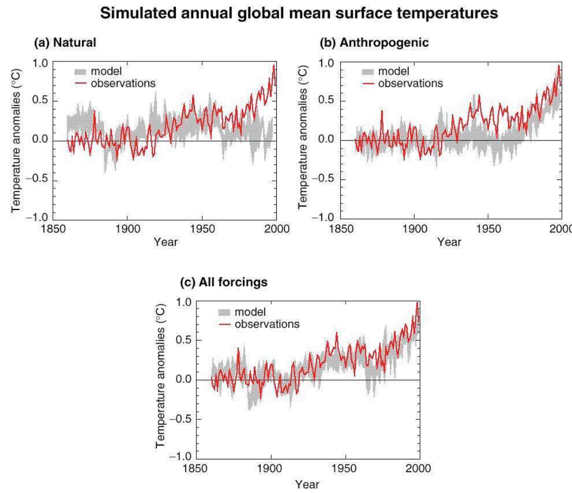


Figure 1. Global average temperature as observed (red) and as simulated using a climate model that was run with (a) natural (solar, volcanic) forcings; (b) anthropogenic (greenhouse gas, sulfate aerosol) forcings; and (c) all forcings. The results clearly show human cause for the warming of the last 40 years, and the remarkable agreement between observations and model in panel c underscores the value and complexity of climate models. From IPCC (2001), used by permission.

The second approach (Mitchell et al., 2001) is to simulate global temperatures (**Figure 1**) with a climate model while introducing various forcings, typically solar variations, volcanic eruptions, and human contributions (greenhouse gases and aerosols). When forced by natural causes alone (Figure 1a), climate models can generally reproduce the warming from 1910 to 1945, but they cannot reproduce the warming since the mid-1970's. In fact, satellite observations of solar output since 1979 show some variability associated with the 11-year solar cycle: a fluctuation of 0.1%, mostly in ultraviolet light absorbed by ozone in the stratosphere. Only when the increase in greenhouse gas concentrations is included (Figure 1b, 1c) can the models reproduce the late-20th century warming. That human influence on climate would emerge later in the century is consistent with the observation that CO_2 and most other greenhouse gases have risen far more in the last 40 years than in the previous 100 years (Prentice et al., 2001; Prather et al., 2001).

A third approach (Mitchell et al., 2001, and references therein) is to compare the spatial pattern of warming as observed and as simulated by climate models with the observed increase of greenhouse gases. The pattern early in the century does not resemble the pattern expected from increasing greenhouse gases, and hence was probably natural. By contrast, the pattern of warming late in the century does resemble the pattern expected from increasing greenhouse gases. This underscores the difference between the (probably natural) early-century warming and the (probably unnatural) late-century warming. Taken together, these pieces of evidence support the view that "There is new and stronger evidence that most of the warming observed over the last 50 years is attributable to human activities."

1b. Regional climate change

At nearly all stations in the Northwest, the temperature trends (**Figure 2**) have been positive over the 1930 to 2005 period of record (the same is true for other starting years: Mote, 2003b). Most trends are between 0.1° and 0.4°F per decade and minimum temperatures rose faster than maximum temperatures. Consistent with the global importance of rising greenhouse gases, there is little systematic difference between trends in urban areas and trends in rural areas (see also Peterson 2003). Warming rates are substantially larger when calculated since 1960, consistent with global results.

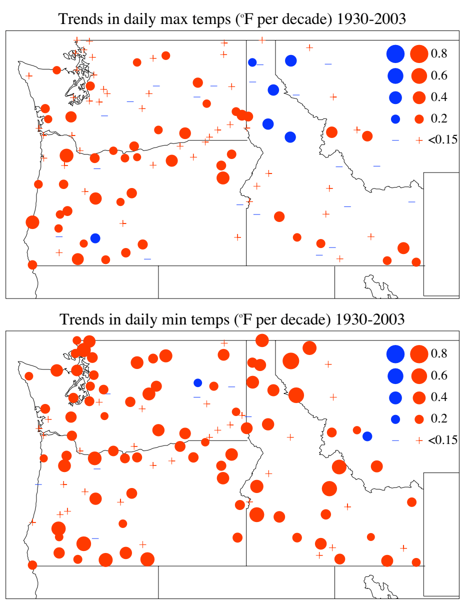


Figure 2. Linear trends in annually averaged daily maximum (top) and minimum (bottom) temperature. Red circles indicate positive trends, blue circles negative trends.

Combining the stations into climate divisions and then area-weighting them to form a regional average (as in Mote et al. 1999, updated) produces

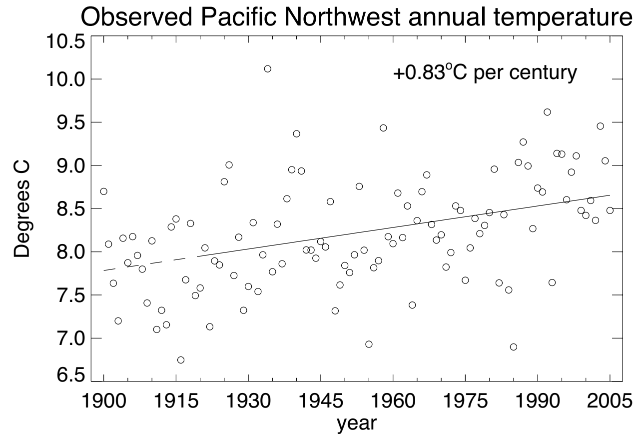


Figure 3. Regionally averaged temperature with linear trend for the 1920-2005 period (extrapolated back, dashed line).

a regionally averaged time series of temperature (**Figure 3**). The warmest single year was 1934, but the warmest 5, 10, and 20 years of the record are the last 5, 10, and 20 years. The regional warming trend of 0.83°C over the 20th century slightly exceeds the global average (0.6°C) but is about the same as the global land average.

Precipitation trends depend more on the period chosen for analysis (**Figure 4**) than do temperature trends. Indeed, a straight-line fit is a poor way to characterize precipitation variability. Part of the variability in precipitation is related to fluctuations in the atmosphere and ocean in the Pacific Basin, including El Nino-Southern Oscillation (ENSO) and the Pacific Decadal Oscillation (PDO), which partly explains the slight decline in precipitation in the past 50 years.

What role, if any, did rising greenhouse gases play in 20th century warming in the Northwest? The original pattern-detection studies (see section 1a) attributed causes of temperature trends on the scale of continents, but recent work (Karoly and Wu 2005) indicates that the signal of human influence on climate is now detectable on the scale of the Northwest. However, for precipitation, no anthropogenic signal has yet emerged even on the global scale (Gillett et al. 2004).

Hydrologically important consequences of regional warming have already emerged in the Northwest. During the past 50 years, peak streamflow in unregulated snowmelt-dominated basins has shifted earlier by 1-3 weeks, winter flow has increased and summer flow has decreased (Stewart et al. 2005). Spring snowpack has declined by about 35% (Mote 2003a, Mote et al. 2005a, Hamlet et al. 2005).

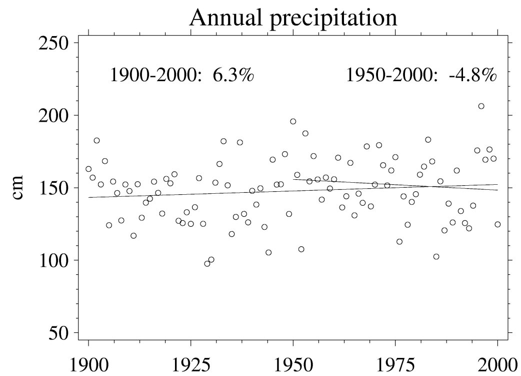


Figure 4. Regionally averaged precipitation with linear trends calculated separately for the periods indicated.

2. Global climate models

Over the decades, more than 20 research centers around the world have developed and used very sophisticated simulation models of the global climate. These models typically resolve the atmosphere with between 6,000 and 15,000 grid squares horizontally, with about 20 atmospheric layers. By calculating energy fluxes between the sun, atmosphere, and surface, they compute surface temperature distributions that compare surprisingly well with observations. In the past 6-8 years climate models have used increasingly sophisticated representations of the ocean, land surface, and sea ice.

As part of the global effort to quantify past and future changes in climate, these research centers have performed a coordinated set of experiments using different scenarios of change in greenhouse gas and in sulfate aerosols (which promote cloud formation in certain regions and hence partly offset greenhouse warming). These new scenarios have been provided as part of the assessment efforts of the Intergovernmental Panel on Climate Change (IPCC), which is in the process of producing a major assessment report due out in early 2007. We chose to use two scenarios, A2 and B1, that lie near the upper and lower limits of future greenhouse gas changes especially beyond 2050 (**Figure 5**). The climate forcing of all scenarios is similar until mid-century.

For this study, we chose a total of ten climate models that had each performed simulations of the A2 (yellow) and B1 (green) scenarios as well as simulations of the 20th century using observed changes in greenhouse gases and sulfate aerosols. We evaluated the models' global climate sensitivity (reported below in this section) and their ability in the 20th century simulations to reproduce observed seasonal variations in Northwest climate (reported in section 2 below). Model output was obtained from https://esg.llnl.gov:8443/index.jsp as monthly values, and analyzed at the University of Washington by the authors of this report.

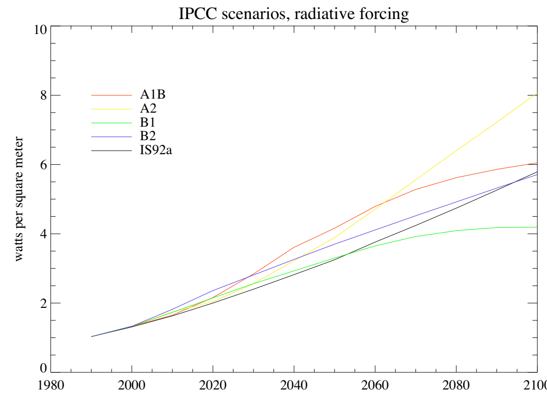
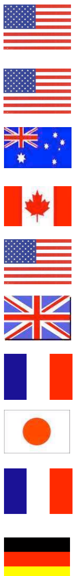


Figure 5. Radiative effects of rising greenhouse gases using several scenarios of socioeconomic change. In this report we use A2 and B1.

The new set of models has not been extensively evaluated and compared by the climate science community, and in particular, the models' global sensitivity to greenhouse gas increases has not been calculated. Formerly, this was calculated either as the "equilibrium climate sensitivity" or the "transient climate response" (TCR). The climate sensitivity is defined as the equilibrium temperature change in a simulation with a doubling of carbon dioxide; because the climate system takes a long time to come into equilibrium, the calculation of the effective climate sensitivity was typically performed only in models with a very simple ocean component, which was standard before the mid-1990s. By the late 1990s most models included a sophisticated ocean, and the TCR was a more economical metric of models' sensitivity. The TCR is defined as the global mean temperature change at the time of CO_2 doubling in a simulation in which the CO_2 increased at 1%/year (roughly IS92a, the black curve in Figure 5). The range of values of TCR reported in IPCC 2001 was 1.1-3.1°C (their Table 9.1).

The new IPCC model simulations included a 1%/year scenario, and we could have obtained those simulations and calculated a TCR since no one else seems to have done so. However, those runs were not otherwise of interest to us, so instead we calculated the rate of warming (globally averaged temperature increase) in each model's A2 scenario as a linear fit during the 2000-2050 period, and compared these to the TCR values reported in IPCC 2001 (Table 1). This method



model	TCR-A2 (2005)	TCR (2001)
PCM1	0.80	1.27
GISS-ER	1.06	1.45
CSIRO-MK3	0.86	2.00
CGCM3.1	1.35	1.96
CCSM3	1.36	1.58
HadCM3	1.36	2.00
CNRM_CM3	1.07	--
MIROC_3.2	1.37	--
IPSL_CM4	1.22	1.96
ECHAM5	1.21	1.4

Table 1. Estimated TCR from the A2 simulations (°C) and reported by IPCC 2001 for each model's predecessor. In some cases the 2005 version of the model is substantially different and not comparable; models indicated by -- had no predecessor represented in IPCC (2001). Lower TCR reflects the method, not lower model sensitivity.

produces lower values than the true TCR. As we shall see, there is only a loose relationship between the rate of warming globally and the rate of warming in the Northwest. Judging from our analysis and comparing with TCR, the models chosen for our analysis are neither the most nor the least sensitive on the global scale.

3. Model evaluation: 20th century climate of the Northwest.

For this study the Pacific Northwest is defined as the region between 124° and 111° west longitude, 42° to 49° north latitude: Washington, Oregon, Idaho, and western Montana. Models have different resolutions, but the number of model grid points enclosed in this latitude-longitude box is typically 12-20. We simply average the temperature and precipitation values at all the Northwest grid points to define a regionally averaged time series. The reason for such averaging is that variations in model climate on scales smaller than a few hundred km is small and not very meaningful. Put another way, the models represent the variations of climate that would be the case on a fairly smooth planet with similar land-sea distributions and large smooth bumps where Earth has major mountain ranges.

Another consideration in comparing global models with observations is that there are different ways to calculate "observed" regionally averaged temperature and precipitation. A common approach is to average weather station data into "climate divisions" and combine the climate divisions into a state or regional average with area weighting ("PNW OBS"). The drawback of this approach is that it takes no account of the contribution to a regional average of high terrain, which has very few weather stations. A better estimate interpolates (horizontally) and extrapolates (vertically) observations to a uniform, high-resolution grid. Such an estimate, however, would be unsuitable for comparing with climate model output, which lacks the vertical relief. A third approach is to assimilate observed data into a weather prediction model at the spatial resolution typical of climate models; this has been done as part of the NCEP/NCAR reanalysis ("NCEP"). Both climate division and NCEP data are used for comparison with models in Figures 6-8, and there are large differences between the two "observed" averages (Figures 7-8). A quantitative evaluation of the relative merits of the various estimates of "observed" climate is beyond the scope of this paper but worth pursuing.

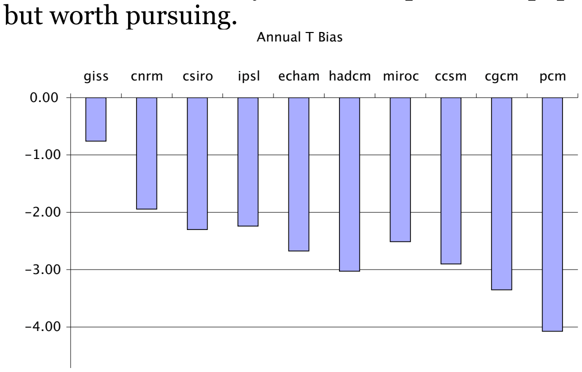


Figure 6. Difference (°C) between each model's mean annual temperature and observed temperature for the Pacific Northwest, for 1970-99 using climate division data.

The models' simulations of Northwest temperatures are uniformly too cold (**Figure 6**) and this largely determines the root-mean-square (rms) error of their seasonal cycle, which is how they are ranked in Figure 6-7. The rms error of the seasonal cycle in precipitation (**Figure 7**) shows that 8 of the models have similar errors and two are much worse than the others, owing to their very wet winter climate (Figure 8).

As shown in **Figure 8**, the models represent the gross features of the Northwest's mean seasonal cycle, including the dry winters and wet

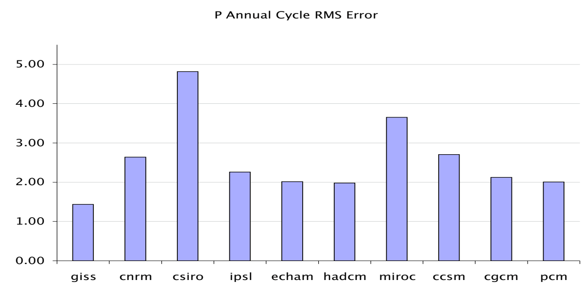


Figure 7. Each model's rms error in mean monthly precipitation. Order of models is the same as in Fig. 6.

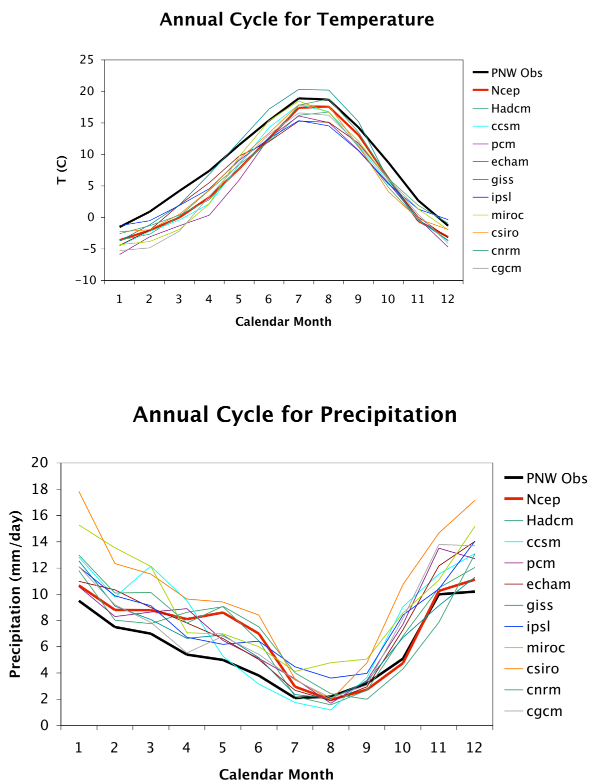


Figure 8. Mean seasonal cycle for each climate model from its 20th century simulation, compared with observations estimated from climate division data (black) and the NCEP/NCAR reanalysis (red).

summers and the magnitude of the annual cycle (though as noted the models are uniformly a bit too cold). Note also the difference between the two "observed" datasets, especially in springtime precipitation.

Another facet of 20th century climate that can be evaluated is the trend in temperature. For the global average, many models simulate a warming

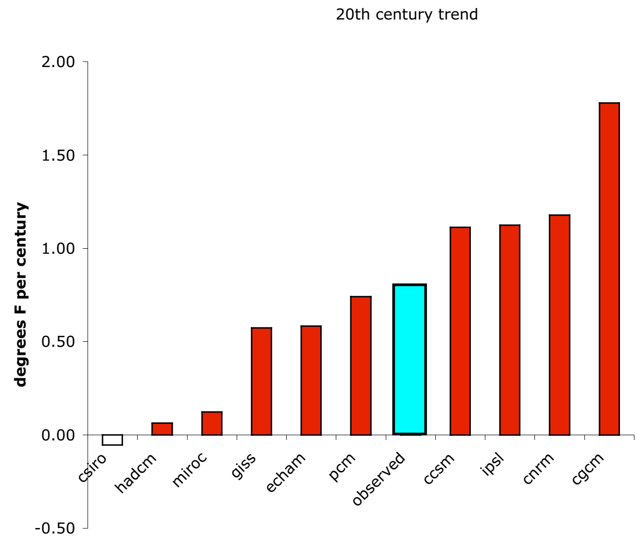


Figure 9. Each model's linear trend in annually averaged temperature for the 20th century, and the observed trend (blue).

rate similar to the 0.8°C warming observed in the 20th century (**Figure 9**). At the regional scale, the warming rate could be dominated by changes in atmospheric circulation rather than greenhouse forcing; nonetheless, six of the models simulate a warming for the Northwest in the neighborhood of the observed warming of 0.8°C during the 20th century. We do not perform the same comparison for precipitation since there is no evidence for a response of global precipitation to greenhouse forcing.

4. 21st century trends in the annual mean

The annually averaged, regionally averaged temperature for all 20 simulations is shown in **Figure 10**, along with smooth curves. Curve fitting is accomplished by regressing each model's annual temperature data on the logarithm of the atmospheric concentration of CO2, an approximation of global radiative forcing (see Figure 1). This approach highlights the region's response to the forcing on century timescales, masking model interdecadal variability which, while interesting, can confound the forced change, especially for precipitation. Note how different the evolution of temperature is after about 2050 for the two socioeconomic scenarios, owing to the markedly different radiative forcing. Note also the different warming rates in the 20th century.

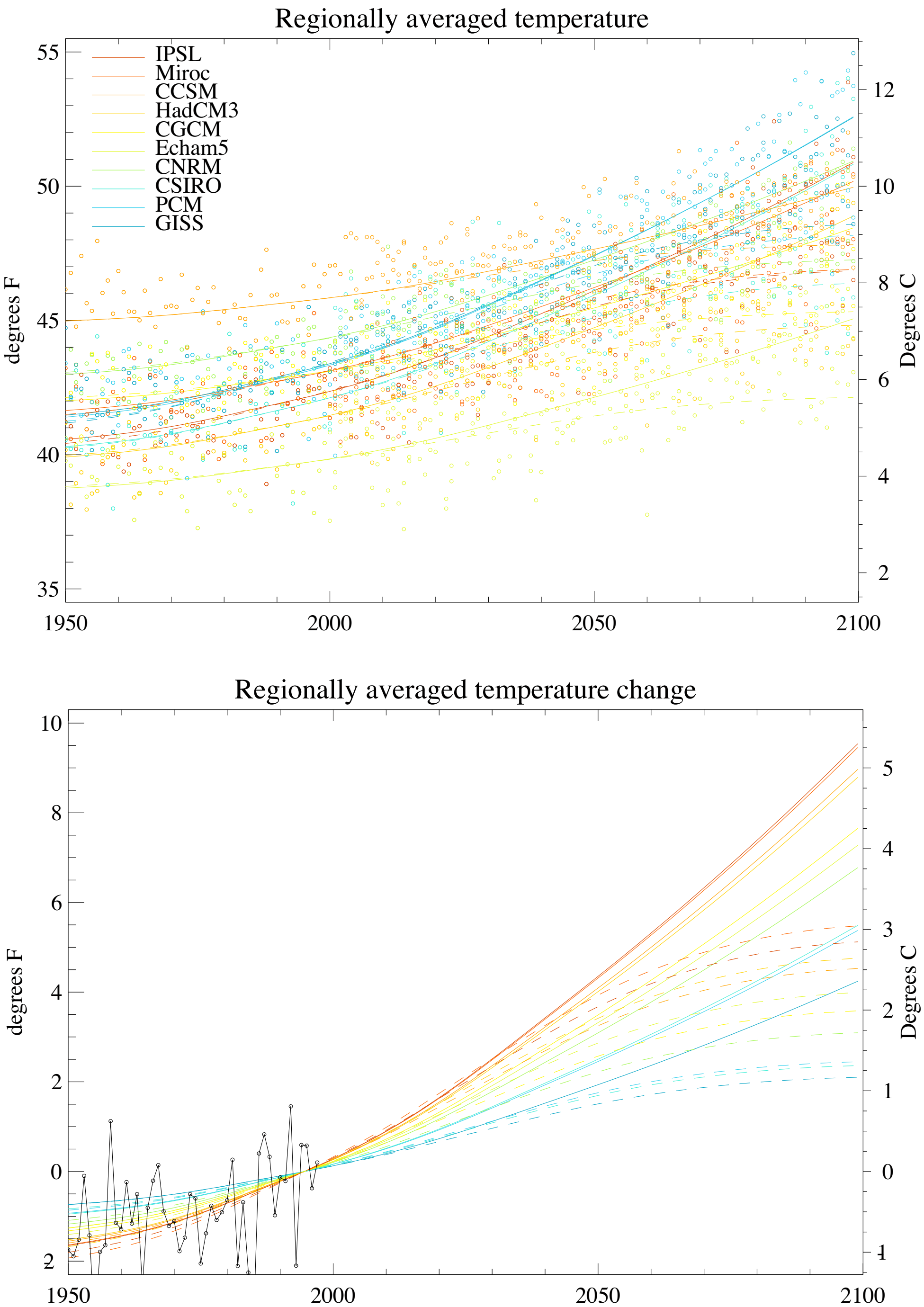


Figure 10. In the top panel, each symbol represents one year's temperature in one simulation. Smooth curves are drawn for each simulation; A2 scenarios are solid, B1 dashed. Models are color-coded according to their warming rate in the A2 scenario. In the bottom panel, the smooth curves from the top panel are replotted after subtracting the mean for the 1990s, along with observed annual temperatures (black). This forms the basis for the summary Figure on page 1.

For temperature, the observed trend has already been substantial compared with the interannual variability. On the other hand, for precipitation, the fluctuations in the past overshadow the trends predicted by all but the wettest scenarios in the future (**Figure 11**). Changes in precipitation are mostly rather small in the models, except for the CSIRO, IPSL, and CGCM scenarios in the A2 scenario in the late 21st century.

Another way to view the scenarios is to plot the change in temperature on one axis and the change in precipitation on another axis (**Figure 12**). Models clearly fall into a few clumps: a large clump around the multi-model mean change of 1.7°C and 2% precipitation increase, a second clump with very large increases in precipitation, and a third with decreases in precipitation. Unlike the situation in the global mean, where the precipitation change and temperature change of models tend to be correlated, there seems to be no correspondence between temperature change and precipitation change in the Northwest.

Other aspects of Northwest climate may change as well. For example, Meehl and Tibaldi (2004) showed projected changes in heat waves (defined as the warmest 3-day average minimum temperature) for North America, and the Northwest had relatively moderate increases (about 2°C in 100 years) compared with much of the country. However, in the same simulation (Meehl et al. 2005), the Northwest had the largest decrease in the number of frost days (40-50) in the country **(Figure 13)**. In section 6 we discuss changes in the climatology of wind as it pertains to the wind industry.

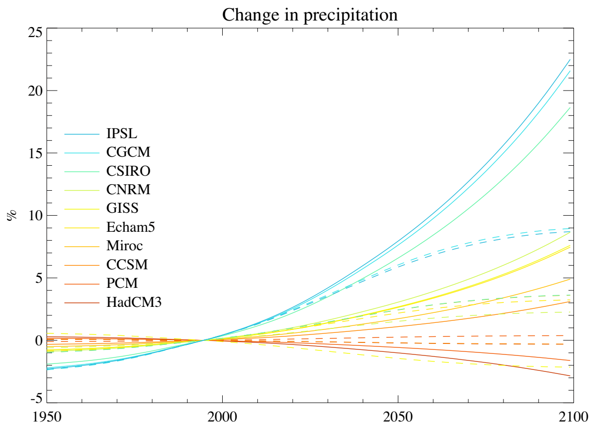


Figure 11. Smoothed precipitation traces for the 20 model simulations are shown as in Figure 6b. For preparing the summary table shown on page 1, 30-year averages were used, and the answers are substantially similar. Models are ranked from driest (red) to wettest (blue).

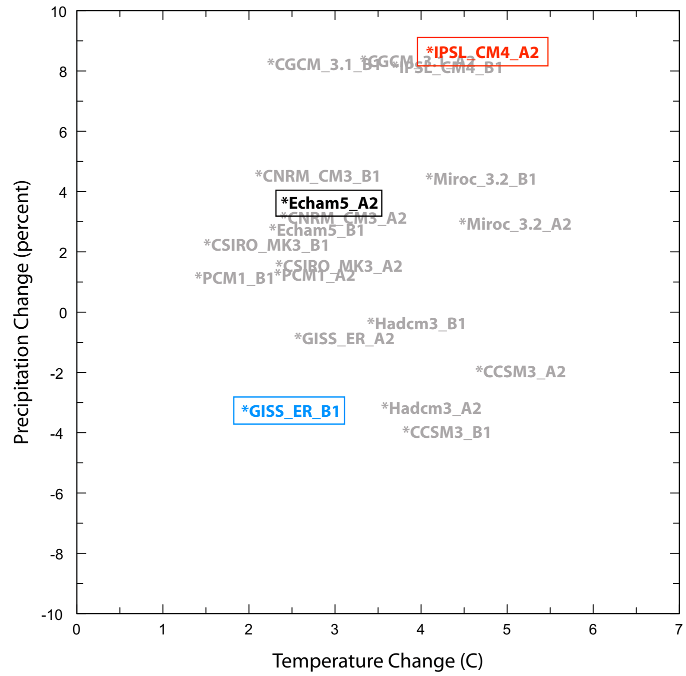


Figure 12. Scatterplot of change in annually averaged temperature and precipitation for each of the 20 scenarios, for the "2040s" (i.e., 2030-2059 minus 1970-99). Three suggested "marker" scenarios are highlighted.

5. Seasonality of changes in climate

For a fuller picture of how climate may change in the Northwest, we present also the changes in the mean annual cycle of temperature and precipitation (**Figure 14**). In most of these model simulations for both 2020s and 2040s, the increases in temperature are largest in summer (June-August).

Three of the models -- HadCM3, CNRM, and GISS -- produce substantially more (at least twice as much) warming in summer than in winter, and all but PCM and CGCM have greater warming in summer than in winter. This result stands in contrast to the common result that winter warming exceeds summer warming, and may result from soil moisture feedbacks. It has worrisome implications for water demand, agriculture, and forest fires, and will affect electricity demand.

Precipitation changes are largest in winter (December-February), and tend to be positive. In summer, precipitation declines slightly in most scenarios.

6. Relevance for the energy industry

Climate changes are likely to affect the energy industry in several ways. First, the winter warming is likely to reduce energy demand for heating in winter and increase demand for cooling in summer. With relatively low use of air conditioning in the Northwest, however, it is not clear whether increases in summer cooling demand will offset the reductions in winter heating demand.

Second, the changes in streamflow, especially on the Columbia, will substantially change the seasonal shape of hydroelectricity supply (**Figure 15**, Hamlet and Lettenmaier, 1999). Summer production will decline and winter production will increase. Firm energy reliability is unlikely to change much, unlike nonfirm energy (ibid.), but an important additional point to consider is the effects that changing streamflow will have on other uses of water, primarily summer-dependent uses like irrigated agriculture, municipal and industrial, recreational, and instream flows (Payne et al. 2004). Largest changes in flow have been observed (Regonda et al., 2005; Hamlet et al. 2005) in basins whose mean temperature is near freezing. Were the reservoir management system changed, especially with respect to flood control, advances in seasonal streamflow forecasting could net an increase of $150 million/year in aggregate for Northwest hydropower without compromising other resource objectives (Hamlet et al. 2002).

PGE expressed interest in knowing about changes in flow on the Clackamas and Deschutes Rivers in Oregon. The Climate Impacts Group has

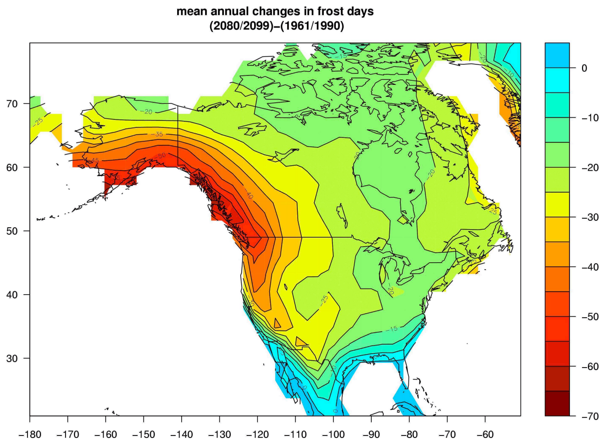


Figure 13. Changes in the number of frost days per year. From Meehl et al. (2004).

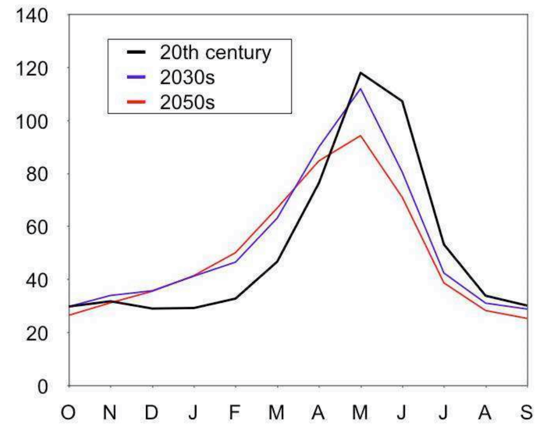


Figure 15. Simulated flow of the Snake River at Ice Harbor for 1950-2000 (black) and for future decades under warming scenarios.

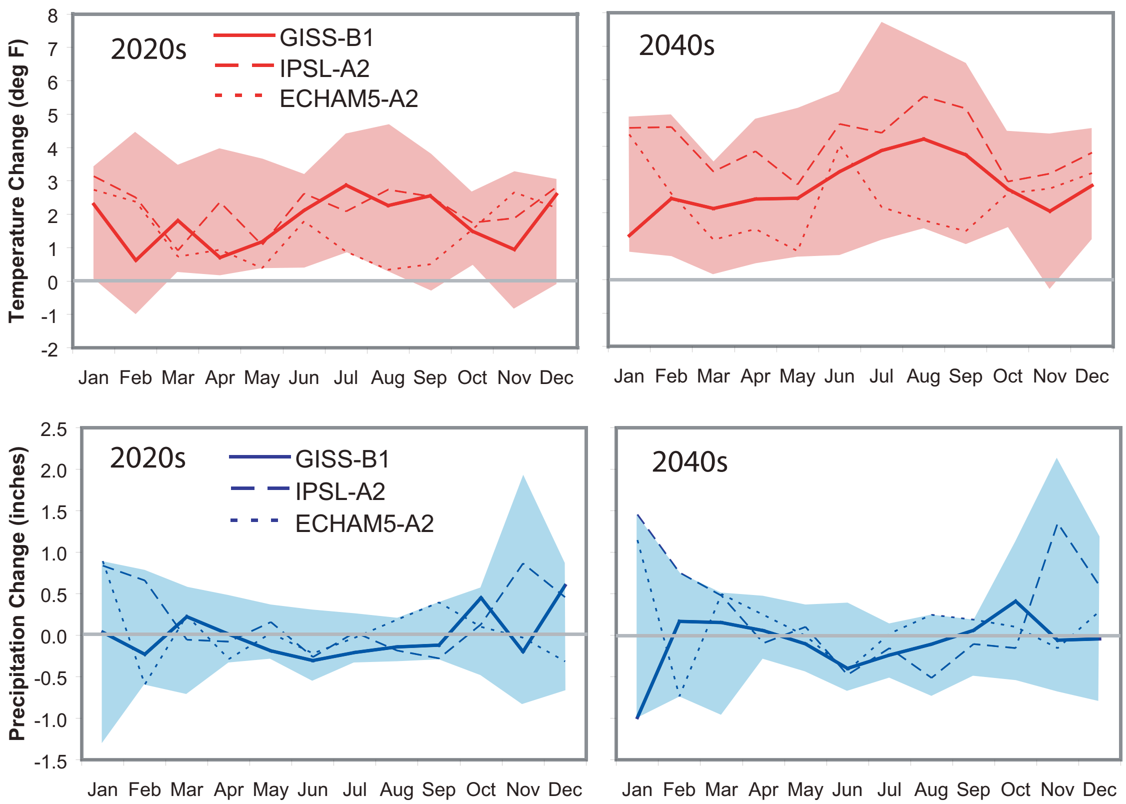


Figure 14. Changes in temperature (top) and precipitation (bottom) month by month, for all scenarios (shaded envelopes) and for the three marker scenarios.

performed simulations of the hydrology of the Northwest and has extracted streamflow at numerous locations in the Northwest, including the Deschutes (**Figure 16).** Simulating the flow on the Deshutes is fraught with difficulties owing to the substantial contribution of groundwater through the porous bedrock in the upper basin (O'Connor and Grant, 2003), so its sensitivity to warming might be less than shown in Figure 16.

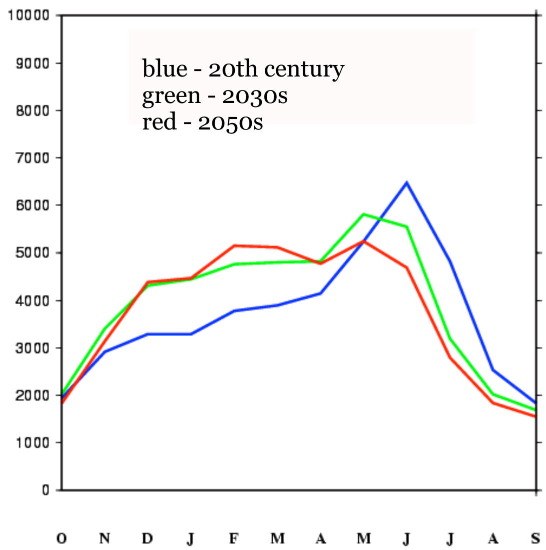


Figure 16. As in Figure 15 but for the Deschutes River at Pelton Dam.

The distributed hydrologic model, VIC (for "variable infiltration capacity"), which was used to produce the results in Figures 15 and 16, has a spatial resolution of roughly 10 km by 12 km, too coarse to accurately represent flow in a small river basin like the Clackamas. However, the University of Washington's hydrology group (part of the Climate Impacts Group) has a second distributed model, the DHSVM, which is suitable for smaller river basins and has been run for the adjacent Bull Run watershed in a study for the Portland Water Bureau (Palmer and Hahn 2002). Though primarily rain-dominated, the Bull Run has a small contribution to flow from spring snowmelt, which disappears entirely with a small amount of warming. To be more quantitative for the Clackamas would require running the DHSVM for the Clackamas.

A third potential vulnerability of the energy industry to climate change is in wind energy production. PGE has specifically asked about changes in the wind intensity at three locations: (45.6°N, 120.2°W), (45.6°N, 120.6°W), and (46.0°N, 118.7°W). Questions about the effect of climate change on winds at such fine spatial scales are best answered through the use of a mesoscale climate model to "dynamically" downscale the global climate model simulation. We have recently implemented a regional climate model based on the MM5 mesoscale modeling system and have applied this model for dynamical downscaling of global climate model output. Nested 135, 45, and 15km grids are used to downscale from climate model resolutions of approximately 150-300km. The inner, 15-km grid covers the study area including the states of Washington, Oregon, and Idaho. Among other features, the model includes detailed topographic and land-use information, which is important for simulating winds at the required spatial scale.

We present here wind results from the PCM global climate model simulation for the 1990s, 2020s, and 2050s dynamically downscaled using this MM5 modeling system. The 21st Century simulations are based on the A2 emissions scenario. The warming response for the Pacific Northwest for this simulation is in the middle of the range of models considered (**Fig 12**). We extracted the 6-hourly maximum sustained wind speed from the MM5 simulation and interpolated from the 15-km model grid to the three stations listed above. The resulting station time series were used to form cumulative distribution functions of the winds to illustrate the probability distribution of wind speeds for each decade.

For most seasons, the changes are negligible, but for the December-January-February season there is a slight (5-10%) decline in the moderate wind speeds (**Figures 17-19**); these changes are so small we do not place significant confidence in their being a robust response to global warming. The possible changes in wind energy have not been as thoroughly studied as changes in hydropower, but, in our judgment, wind power is not likely to be significantly vulnerable to climate change.

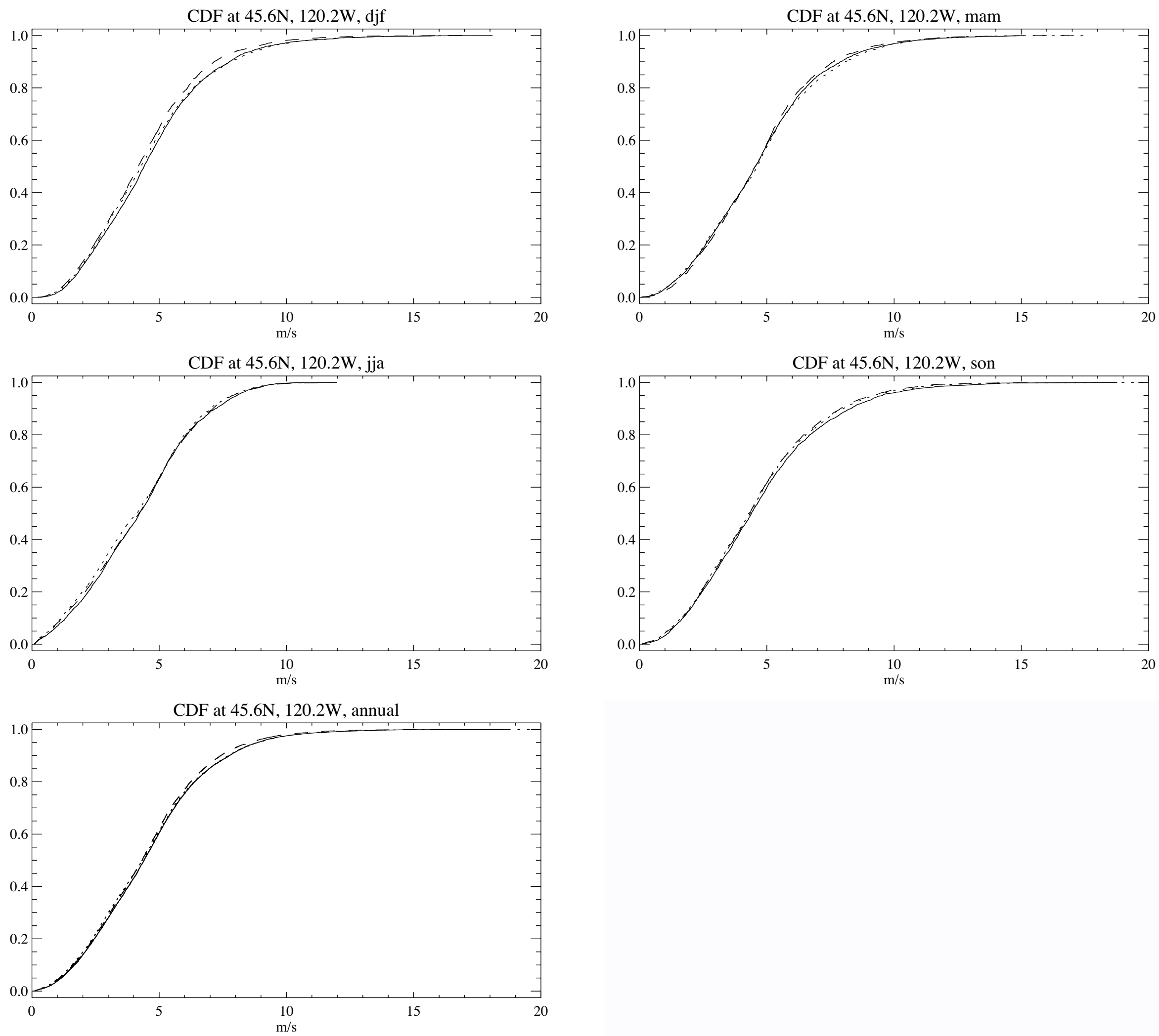


Figure 17. Cumulative density functions of wind speed at 45.6°N, 120.2°W, for three-month seasons (DJF= December-February, etc.) and annual (bottom left) for 1990s (solid), 2020s (dotted), and 2050s (dashed).

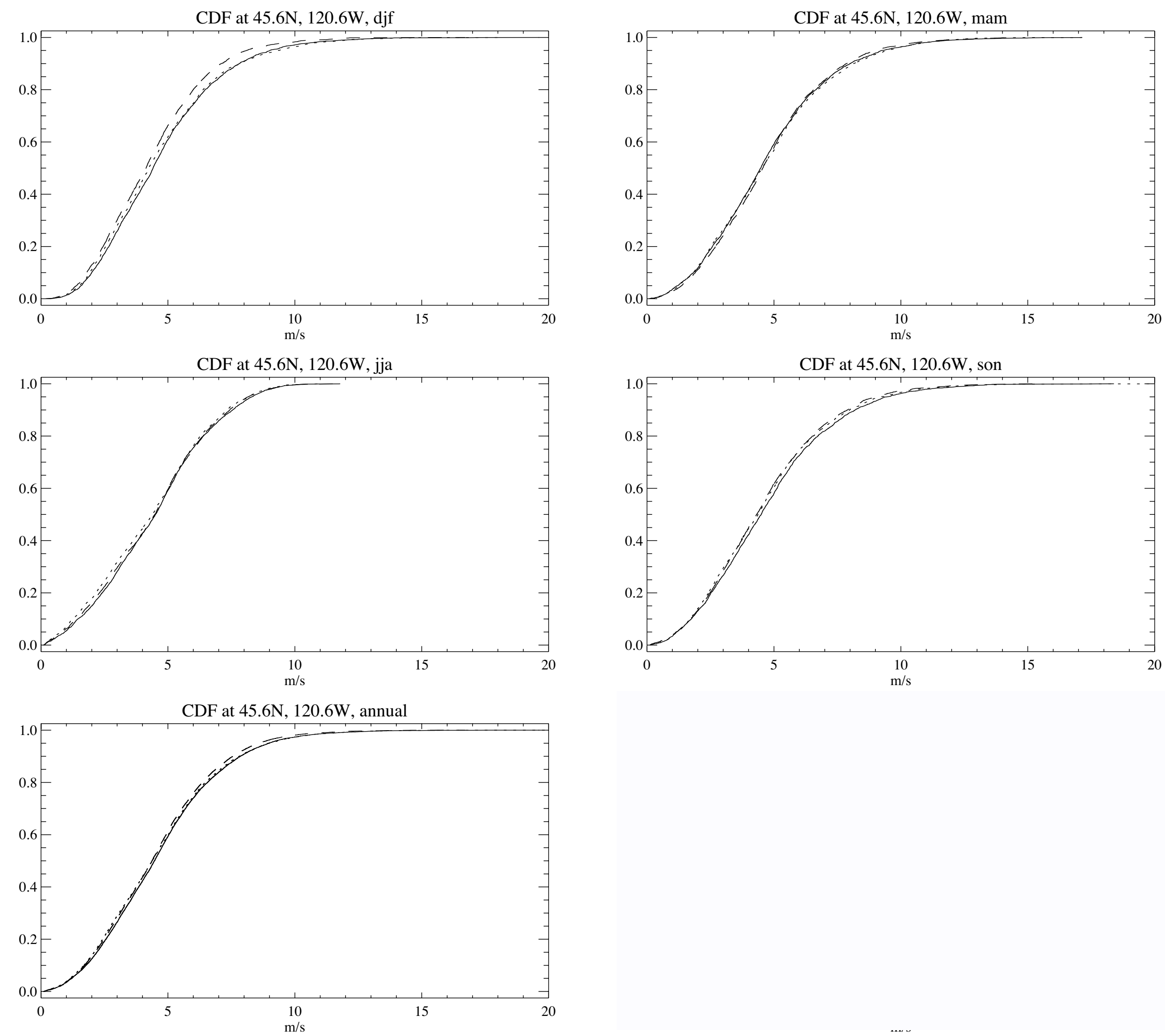


Figure 18. As in Figure 17 but for 45.6°N, 120.6°W.

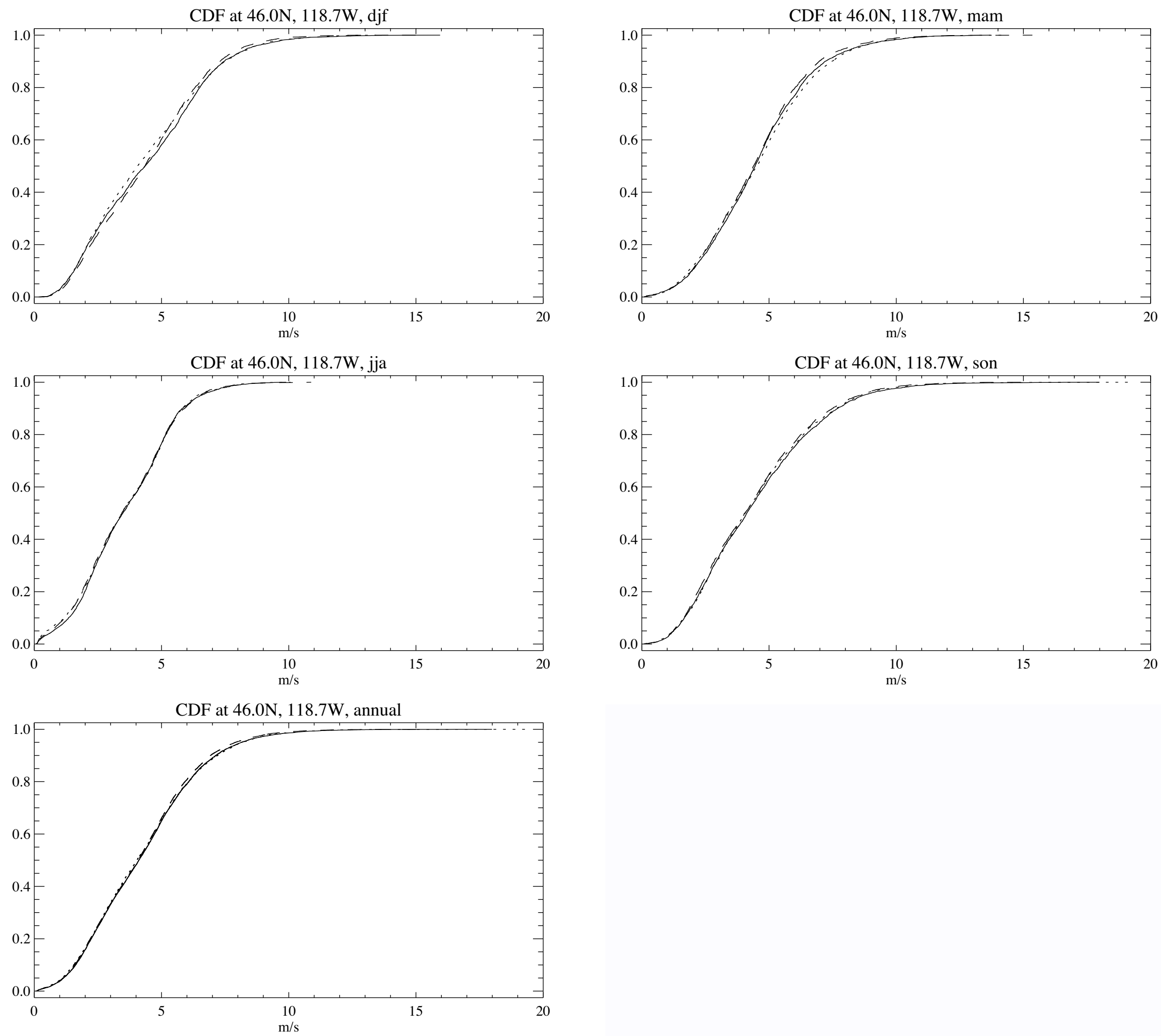


Figure 19. As in Figure 17 but for 46.0°N, 118.7°W.

7. Conclusions

We commend PGE for its curiosity about the effects of climate change. Funding for this project enabled us to examine the new round of climate scenarios, which resulted in a slight downward revision of projected temperature changes for technical reasons explained elsewhere (Mote et al. 2005b). The new scenarios also produced a surprising result that summer warming may exceed winter warming. Temperatures in the next 50 years are likely to far exceed those of the 20th century. Precipitation changes are unlikely to exceed those experienced in the 20th century, however.

Even with sizeable increases in precipitation, summer flow and summer hydro production are likely to decline in a warming world. The region needs to develop a coordinated approach to managing water resources under these changing circumstances.

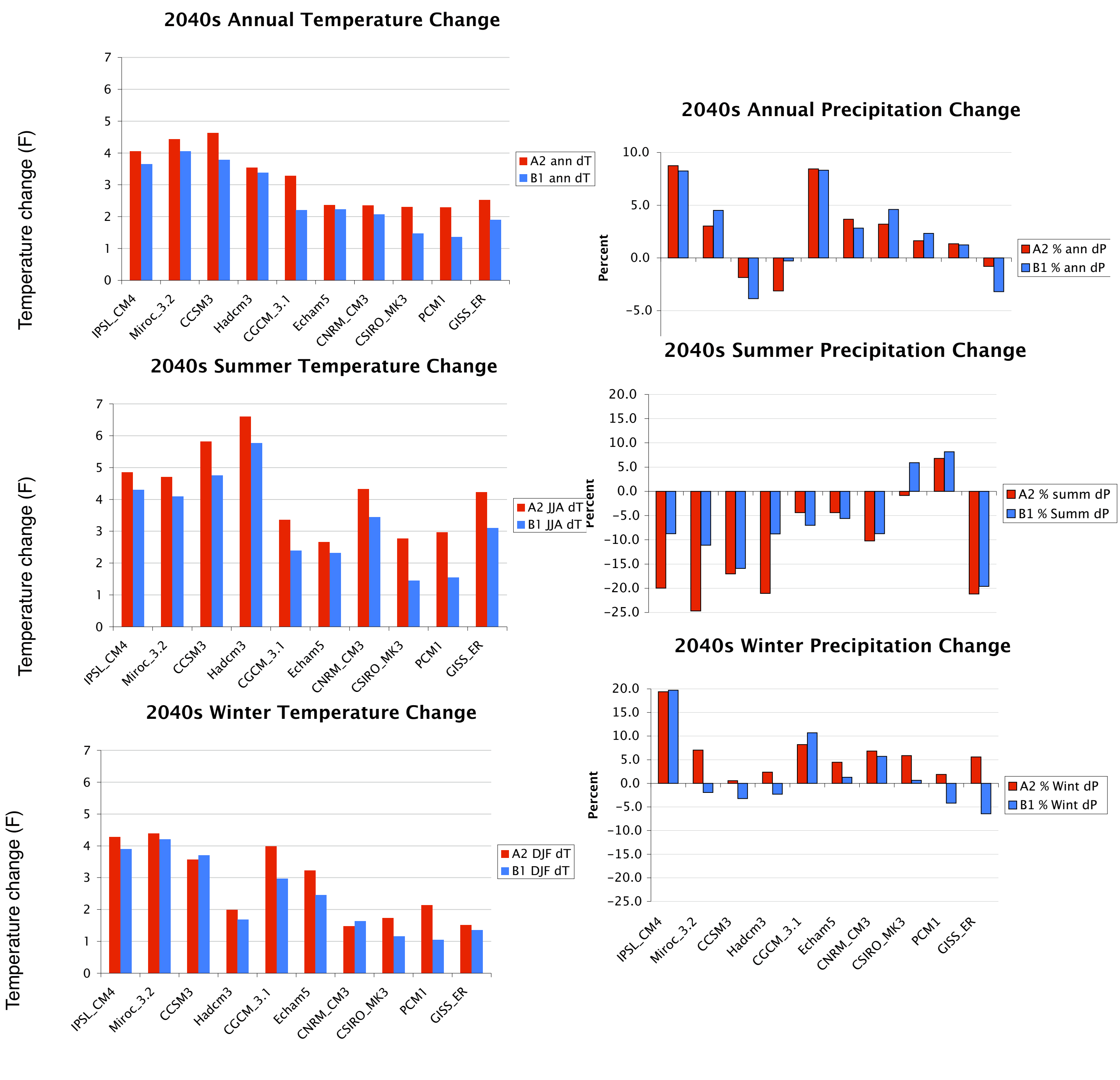


Figure 20. Details of the models' individual projections of temperature and precipitation change.

References and details about the models

Model	Institution	Version	Contact	References
ccsm3	NCAR (National Center for Atmospheric Research, Boulder, CO, USA)	CCSM3.0, version beta19 (2004): atmosphere: CAM3.0, T85L26 ocean: POP1.4.3 (modified), gx1v3 sea ice: CSIM5.0, T85 land: CLM3.0, gx1v3	ccsm@ucar.edu	Collins, W.D., et al., 2005: The Community Climate System Model, Version 3 Journal of Climate, Main website: http://www.ccsm.ucar.edu
cgcm_3.1	CCCma (Canadian Centre for Climate Modelling and Analysis, Victoria, BC, Canada)	CGCM3.1 (2004): atmosphere: AGCM3 (GCM13d, T47L31) ocean: CCCMA (OGCM3.1,192x96L29)	Greg Flato (Greg.Flato@ec.gc.ca)	
cnrm_cm3	CNRM (Centre National de Recherches Meteorologiques, Meteo-France, Toulouse, France)	CNRM-CM3 (2004): atmosphere: Arpege-Climat v3 (T42L45, cy 22b+) ocean: OPA8.1 sea ice: Gelato 3.10 river routing: TRIP	david.salas@meteo.fr, sophie.tyteca@meteo.fr, jean-francois.royer@meteo.fr	D. Salas-Mélia, F. Chauvin, M. Déqué, H. Douville, J.F. Gueremy, P. Marquet, S. Planton, J.F. Royer and S. Tyteca (2004) : XXth century warming simulated by ARPEGE-Climat-OPA coupled system
csiro_mk3	CSIRO (CSIRO Atmospheric Research, Melbourne, Austrvalia)	CSIRO Mk3.0 (2000): atmosphere: spectral (T63L18) ocean: MOM2.2 (1.875x0.925L31)	Mark Collier (Mark.Collier@csiro.au), Martin Dix (Martin.Dix@csiro.au), Tony Hirst (Tony.Hirst@csiro.au)	Model described by Gordon et al. The CSIRO Mk3 Climate System Model, 2002, www.dar.csiro.au/publications/gordon_2002a.pdf
echam5	MPI (Max Planck Institute for Meteorology,Hamburg, Germany)	ECHAM5/MPI-OM(2004): atmosphere: ECHAM5 (T63L32) ocean: OM (1x1L41) sea ice: ECHAM5	Joerg Wegner (wegner@dkrz.de)	ECHAM5: E. Roeckner et. all, 2003,The atmospheric general circulation model ECHAM5Report No. 349OM: Marsland et. all, 2003,The Max-Planck-Institute global ocean/sea ice modelwith orthogonal curvelinear coordinatesOcean Modell., 5, 91-127.OM: Haak, H. et. all, 2003:Formation and propagation of great svalinity anomvalies,Geophys. Res. Lett., 30 , 1473,10.1029/2003GL17065.
giss_er	NASA/GISS (Goddard Institute for Space Studies)New York, NY	E3Af8aoM20A	Kenneth Lo (cdkkl@giss.nasa.gov)	www.giss.nasa.gov/research/modeling
hadcm	Met Office (Exeter, Devon, EX1 3PB, UK)	HadCM3 (1998): atmosphere: (2.5 x 3.75) ocean: (1.25 x 1.25) sea ice: land: MOSES1	jason.lowe@metoffice.gov.uk, simon.gosling@metoffice.gov.uk	Gordon, C., C. Cooper, C.A. Senior, H.T. Banks, J.M. Gregory, T.C. Johns, J.F.B. Mitchell and R.A. Wood, 2000. The simulation of SST, sea ice extents and ocean heat transports in a version of the Hadley Centre coupled model without flux adjustments. Clim. Dyn., 16, 147-168. Johns, T.C., R.E. Carnell, J.F. Crossley, J.M. Gregory, J.F.B. Mitchell, C.A. Senior, S.F.B. Tett and R.A. Wood, 1997. The Second Hadley Centre Coupled Ocean-Atmosphere GCM: Model Description, Spinup and Vvalidation. Clim. Dyn. 13, 103-134.
ipsl_cm4	IPSL (Institut Pierre Simon Laplace, Paris, France)	IPSL-CM4_v1	Sebastien Denvil, sebastien.denvil@ipsl.jussieu.fr	
miroc_3.2	CCSR/NIES/FRCGC (Center for Climate System Research, Tokyo, Japan / National Institute for Environmental Studies, Ibaraki, Japan / Frontier Research Center for Global Change, Kanagawa, Japan)	MIROC3.2 (2004): atmosphere: AGCM (AGCM5.7b, T42 L20) ocean & sea ice: COCO (COCO3.3, 256x192 L44) land: MATSIRO (T42)	Toru Nozawa (nozawa@nies.go.jp)	K-1 Coupled GCM Description (K-1 Technical Report No.1) in preparation
pcm1	NCAR (National Center for Atmospheric Research, Boulder, CO, USA)	Parallel Climate Model (PCM) version 1.1, (2000): atm : CCM3.6.6, (modified), T42L18 ocn : POP1.0 (modified),	pcm1@ucar.edu	Washington, W.M., et.al., 2000: Parallel climate model (PCM) control and transient simulations. Climate Dynamics, Volume 16 Issue 10/11 (2000) pp 755-774 Main website: http://www.cgd.ucar.edu/pcm

Additional information is available at http://www.atmos.washington.edu/~salathe/AR4_Climate_Models/

Other references.

Barnett, T.P., D.W. Pierce, K.M. AchutaRao, P.J. Gleckler, B.D. Santer, J.M. Gregory, and W.M. Washington, 2005: Penetration of human-induced warming into the world's oceans. *Science*, 309, 284-287.

Cayan, S. A. Kammerdiener, M. D. Dettinger, J. M. Caprio, D. H. Peterson, 2001: Changes in the onset of spring in the western United States. *Bull. Amer. Meteorol. Soc.,* 82, 399-415.

Fu, Q., C.M. Johanson, S.G. Warren, and D.J. Seidel, 2004: Contribution of stratospheric cooling to satellite-inferred tropospheric temperature trends. *Nature,* 429, 55-58.

Gillett, N.P., A.J. Weaver, F.W. Zwiers, and M.F. Wehner, 2004: Detection of volcanic influence on global precipitation. *Geophys. Res. Letts.,* 31, doi: 10.1029/

Hamlet, A.F., and D.P. Lettenmaier, 1999: Effects of climate change on hydrology and water resources in the Columbia River Basin. *J. Amer. Water Resources Assoc.* 35(6):1597-1623.

Hamlet, A.F., D. Huppert, and D. P. Lettenmaier. 2002. Economic value of long-lead streamflow forecasts for Columbia River hydropower. *ASCE Journal of Water Resources Planning and Management* 128(2): 91-101

Hamlet, A.F., P.W. Mote, M.P. Clark, and D.P. Lettenmaier, 2005: Effects of temperature and precipitation variability on snowpack trends in the western U.S. J. Climate, 18, 4545-4561.

IPCC 2001: *Climate Change 2001: The Scientific Basis*. J.T. Houghton et al., eds. Cambridge University Press, Cambridge, UK. 881 pp.

Karoly, D.J., and Q. Wu, 2005: Detection of regional surface temperature trends. *J. Climate,* 18, 4337-4343.

Kump, L.R.; Kasting, J.F.; and Crane, R.G. 1999. The Earth System. Upper Saddle River, NJ: Prentice Hall (351 pp.)

Mann, M.E., C. Amman, R. Bradley, K. Briffa, P. Jones, T. Osborn, T. Crowley, M. Hughes, M. Oppenheimer, J. Overpeck, S. Rutherford, K. Trenberth, and T. Wigley, 2003: On past temperatures and anomalous late-20th century warmth. *EOS Transactions of the American Geophysical Union*, 84, 256-257.

Meehl and Tebaldi, 2004: More intense, more frequent and longer lasting heat waves in the 21st century, *Science*, 305, 994-997.

Meehl, G.A., C. Tebaldi and D. Nychka, 2004: Changes in frost days in simulations of twentyfirst century climate. *Climate Dynamics* 22, 71ff.

Mitchell, J.F.B., D.J. Karoly, and others, 2001: Detection of climate change and attribution of causes, in J. T. Houghton et al., eds., *Climate Change 2001: The Scientific Basis*. Contribution of Working Group I to the Third Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press: 695-738.

Mote, P.W., 2003a: Trends in snow water equivalent in the Pacific Northwest and their climatic causes. Geophys. Res. Letts., 30, DOI 10.1029/ 2003GL017258.

Mote, P.W., 2003b: Trends in temperature and precipitation in the Pacific Northwest during the twentieth century. Northwest Sci., 77, 271-282.

Mote, P.W., D. Canning, D. Fluharty, and others. 1999. Impacts of climate variability and change: Pacific Northwest (110 pp). Available from Climate Impacts Group, 206-616-5350.

Mote, P.W., A.F. Hamlet, M.P. Clark, and D.P. Lettenmaier, 2005a: Declining mountain snowpack in western North America. Bull. Amer. Meteorol. Soc., 86, 39-49, DOI 10.1175/BAMS-86-1-39.

Mote, P.W., E. Salathé, and C. Peacock, 2005b: Scenarios of future climate for the Pacific Northwest. A report prepared for King County (Washington) by the Climate Impacts Group (Center for Science in the Earth System, University of Washington, Seattle.)

O'Connor, J.E., and G. Grant, 2003: A peculiar river: Geology, geomorphology, and hydrology of the Deschutes River, Oregon. American Geophysical Union, Washington DC. 219pp.

Palmer, R.N., and M. A. Hahn. 2002: The Impacts of Climate Change on Portland's Water Supply: An Investigation of Potential Hydrologic and Management Impacts on the Bull Run System. Report prepared for the Portland Water Bureau, University of Washington, Seattle. 139 pp.

Payne, J.T., A.W. Wood, A.F. Hamlet, R.N. Palmer, and D.P. Lettenmaier, 2004: Mitigating the effects of climate change on the water resources of the Columbia River basin. *Climatic Change* 62(1-3):233-256.

Peterson, T.C., 2003: Assessment of urban versus rural in situ surface temperatures in the contiguous United States: no difference found. *Journal of Climate* 16: 2941-2959.

Prather, M., D. Ehhalt, and others, 2001: Atmospheric chemistry and greenhouse gases, in J. T. Houghton et al., eds., *Climate Change 2001: The Scientific Basis*. Contribution of Working Group I to the Third Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press: 239-288.

Prentice, I.C., and others, 2001: The carbon cycle and atmospheric carbon dioxide, in J. T. Houghton et al., eds., *Climate Change 2001: The Scientific Basis*. Contribution of Working Group I to the Third Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press: 183-238.

Ramaswamy, V., and others, 2001: Radiative forcing of climate change, in J. T. Houghton et al., eds., *Climate Change 2001: The Scientific Basis*. Contribution of Working Group I to the Third Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press: 349-416.

Regonda, S.K., B. Rajagopalan, M. Clark, and J. Pitlick, 2005: Seasonal cycle shifts in hydroclimatology over the western United States. J. Climate, 18, 372-384.

Stewart, I.T., D.R. Cayan, and M.D. Dettinger, 2005: Changes towards earlier streamflow timing across western North America. J. Climate, 18, 1136-1155.

cover photo credits
power lines: Oak Ridge National Lab, ornl.gov
wind turbines: Sandia National Lab, sandia.gov
Bonneville Dam powerplant: US Army Corps of Engineers, usace.mil

Cite as: Mote, P., E. Salathé, and C. Peacock. 2006. Energy-relevant impacts of climate change in the Pacific Northwest. A report prepared for Portland General Electric by the Climate Impacts Group (Center for Science in the Earth System, University of Washington, Seattle.)

For copies of this document, see cses.washington.edu/db/pubs/allpubs.shtml or email philip@atmos.washington.edu

D. Black & Veatch Coal Technology Study

Executive Summary

Black & Veatch Corporation, November 2005

1.1 Objectives

Portland General Electric (PGE) retained Black & Veatch to support PGE's next generation resource plan investigations. The intent of the study is to provide appropriate data to allow PGE to analyze coal alternatives for its portfolio. The study scope was to compare supercritical pulverized coal (PC) and integrated gasification combined cycle (IGCC) technologies. Although the intent of the study was to generically compare supercritical PC and IGCC, the Boardman site was chosen for the comparison because choosing a specific site allows for a more robust study of the two alternatives.

1.2 Plant Descriptions

Black & Veatch developed performance and cost estimates of two base load generation technology options. For purposes of this evaluation, it was critical that the technologies be evaluated on a consistent basis relative to each other. The following two base load technologies were considered:

- PC – Advanced Supercritical, 850 MW net
    - Emissions control equipment includes selective catalytic reduction (SCR), fabric filter, semi-dry lime spray-dry absorber (SDA), and activated carbon injection (ACI).
    - Throttle conditions: 4,000 psig/1,100° F/1,100° F.
- IGCC – 2x1 7FA with Shell gasification technology, 507 MW net.
    - 100 percent syngas fuel with limited fuel oil backup.
    - COS Hydrolysis, MDEA Acid Gas Removal, Claus SRU with tailgas recycle, candle filter, syngas scrubbing, sulfided carbon bed adsorption, N2 diluents for NOx control.
    - Space allocated for future SCR.
    - Space allocated for future CO_2 capture

- Throttle conditions: 1,550 psig/1,000° F/1,000° F.

The plants were sized so that their respective efficiencies were optimized for a given turbine frame and expected "hot day" condenser pressure. The cost estimates assumed that this project would be an add-on unit at the Boardman, Oregon site. Performance and cost estimates were developed on the basis of Powder River Basin (PRB) coal. The IGCC plant is based on the Shell Coal Gasifier Process.

1.3 Technology Screening Performance and Cost Estimates

Black & Veatch developed performance and cost estimates of two base load generation technology options: an 850 MW net advanced supercritical PC unit and a 507 net MW IGCC unit. The cost estimates assume that this project would be an add-on unit at the Boardman, Oregon site.

1.3.1 Overall Assumptions

The Boardman site has an elevation of 696 ft. The hot day conditions were provided by PGE based on data for Boardman. Performance estimates are based on the following assumptions:

- Ambient barometric pressure: 14.10 psia.
- Hot day: 85° F dry bulb, 35 percent relative humidity.
- Southern PRB coal properties were used for PC and IGCC cases. These properties were provided by PGE based on coal data from the Buckskin mine.

1.3.2 Performance Cases

Full load performance cases were estimated for each technology at Hot Day ambient conditions. A summary of plant performance measures for each technology at full rated capacity is shown in Table D-1. Hot day performance is also summarized in Table D-1. Because performance was estimated for a Hot Day, the net outputs and heat rates for the two cases are degraded from what would be expected for cases that could be estimated at average day or ISO conditions.

Table D-1: Summary of Performance Estimates*

Technology	**Supercritical PC**	**IGCC**
Gross Output, MW	914.0	610.5
Fuel	Coal	Coal
Hot Day Performance		
Fuel Input, MBtu/h (HHV)	7,765	4,393
Auxiliary Load, MW	64.0	103.6
Net Output, MW	850.0	506.9
Net Plant Heat Rate (HHV), Btu/kWh	9,134	8,667

* Performance based on turbine backpressure of 3.0 in. Hg

1.3.3 Total Project Cost

The cost estimates in Table D-2 include estimated costs for equipment and materials, construction labor, engineering services, construction management, indirect and other costs. Cost estimates were made on the basis of overnight engineering, procurement, and construction (EPC) cost estimates for 2005. Percentage estimates for Owner's costs were also developed and have been included in the project cost estimates. When specific project costs are reported, they are frequently presented at ISO conditions. Without having estimated IGCC performance at ISO, Black & Veatch expects that the specific project cost for IGCC at ISO conditions for this project would be close to $1,850/kW.

Table D-2: Estimated Total Project Costs

	Supercritical PC	**IGCC**
Gross Output, MW	914	610
EPC Cost, 2005 $million	1,022	970
Net Output, MW	850	506.9
Specific EPC Cost, 2005 $/kW	**1,202**	**1,914**
Owner's Cost, $million	306	388
Project Cost, 2005 $ million	*1,328*	*1,358*
Specific Project Cost, 2005 $/kW	**1,563**	**2,679**

1.3.4 Non-fuel O&M Costs

The operations and maintenance (O&M) cost estimates, presented in Table D-3, were developed by Black & Veatch based on the project specific study data. As with the capital cost estimate, the unitary O&M costs for IGCC at ISO conditions will be less than shown in Table D-3. The fixed cost would be about $28.90/kW while the variable O&M cost would be about $5.15/kWh.

Table D-3: Estimated O&M Costs (2005 $)

	Supercritical PC	**IGCC**
Gross Output, MW	914	610
Staff Count*	40	103
Fixed Costs, $1,000	14,552	15,163
Net Output, MW	850	507
Fixed Costs, $/kW	**17.12**	**29.97**
Variable Costs, $1,000	13,790	20,000
Capacity Factor, %	85.0	82.4
Annual Generation, GWh	6,329	3,652
Variable Costs, $/MWh	**2.18**	**5.48**
Tot. Ann. O&M, $1,000	**28,342**	**35,163**
Total O&M, $/kW	**33.34**	**69.36**

* Incremental Staff additions for Unit 2

E. Cornforth Carbon Sequestration Study

Executive Summary

Subsurface carbon sequestration is a multi-discipline operation that incorporates leading-edge technologies within the engineering and sciences of geology, geochemistry, hydrogeology, geophysics, petroleum geology and other supporting fields. Currently, research into geologic sequestration of greenhouse gases is being performed world-wide at a high level. Portland General Electric (PGE) should expect that rapid advancements in the technologies of sequestration will occur and that the concepts presented here will evolve.

The original purpose of this study was to provide a feasibility level understanding of the concept of subsurface, or geologic carbon sequestration at PGE's Boardman Plant and a hypothetical coal mine-mouth plant in Wyoming or Montana. The information and processes presented in this report provide a review and discussion of the science and engineering of sequestration, the regulatory issues and public involvement that would be involved in this type of a project, and the typical process of investigation and design. Following this review, two conceptual facilities are discussed and developed to provide order-of-magnitude conceptual-level cost estimates. The intent of this study is to enable PGE to incorporate carbon sequestration into their Integrated Resource Plan to assist in future planning and development decisions.

Discussions were held with Big Sky Carbon sequestration Partnership, and applicable reports and presentations available on the World Wide Web were assessed for useable content. Components of a geologic sequestration facility are discussed to develop two conceptual carbon sequestration facilities, one in Oregon and the other in Wyoming/Montana. Components include: a geologic trap, facilities, permitting, public involvement, and investigation and design.

In general, geologic sequestration requires an underground sink and seal. The sink would be a permeable and porous body or unit of geologic material, and the seal would be a low-permeable and low-porosity material, or a chemical reaction that contains or captures the injected material within the sink. Analogies are hydrocarbon reservoirs and underground mineral deposits. Due to inherent variables in geologic stratigraphy, structure, hydrology, chemistry, and rock mechanics, the properties of any sink and seal will be unique, i.e., no two sequestration operations will be the same.

Sequestration facilities include injection sites and monitoring systems, and establishing the baseline condition of the geology and environment. An injection site might require ½-acre; however, multiple injection wells could spread out over a number of square miles. Power at each site would be necessary to compress and heat gases. Prior to any

testing and operation at a physical injection site, baseline conditions would need to be established for groundwater; underground geophysics, geochemistry and biology; and surficial and atmospheric geochemistry and biology.

Monitoring systems would measure and verify injection of carbon gases. They would validate and reduce uncertainty in criteria for the designed system, and would satisfy regulatory permitting and health and safety concerns. Monitoring would be performed from the establishment of baseline conditions through operation and storage. Monitoring systems would be both temporary and permanent, and consist of subsurface, surface, aerial and possibly satellite methods. Due to technological challenges of measuring groundwater and rock characteristics within varying types of material at the necessary depths, state-of-the-art equipment and processing will be required.

Investigation, design, construction and operation of a sequestration facility would require regulatory review from federal, state and local jurisdiction. Existing and proposed pilot test projects in the United States are triggering Environmental Protection Agency review of the Underground Injection Control Program, Safe Drinking Water Act. The Clean Water Act could also provide the regulatory framework to address the needed environmental protections.

Tasks that would be part of the investigation and design process include: a concept phase; Phase 1 feasibility and site selection based on characterization and modeling; Phase 2 preliminary design and pilot test; Phase 3 project development and final design; and Phase 4 construction and operation.

Carbon sequestration in basalt is currently only a theoretical concept. A pilot test is planned for demonstration near Richland, Washington in summer 2007. Technical issues that need to be overcome include, but are not limited to, the long-term affects of injection and the ability to monitor and verify injection into deep saline aquifers in basalt. The characteristics of basalt make this a significant challenge. Other anticipated significant issues include designated "groundwater critical" areas in the Umatilla Basin and regulatory requirements. Based on the geologic criteria, a conceptual facility at Boardman might include five injection wells and 12 monitoring wells over a minimum area of about 30 square miles. Order of magnitude cost estimate for development of a sequestration facility with a 30-year life in the Columbia River Basalt at Boardman is about $35 million (2006 dollars). Note that these costs do not include long-term operation and maintenance costs or the costs for CO_2 capture, compression, and transportation to the injection well sites.

Carbon sequestration in coal is currently at a feasibility stage with a number of pilot tests planned or currently underway in the United States and world wide. Technical issues that need to be overcome include, but are not limited to, the long-term effects of injection, groundwater resource impacts, predictive modeling limitations, and permanence. Other anticipated issues include regulatory requirements. Based on the geologic criteria, a conceptual facility at a coal mine-mouth plant in Montana or Wyoming might include 90 injection wells and possibly 20 monitoring wells over a minimum area of one square mile. Order of magnitude cost estimate for development of a sequestration facility in coal of the Powder River Basin, Montana or Wyoming is about $124 million (2006 dollars). The large difference in comparison to basalt is primarily due to the greater number of injection wells that would be necessary for the thin coal beds.

F. KEMA Customer Research

Portland General Electric

Focus Groups and In-depth Interview Findings on the 2006 Integrated Resource Planning Process

SUBMITTED BY: KEMA, INC.

Date: December 16, 2005

ES Executive Summary

ES.1 Overview

This Executive Summary summarizes the overall objectives, methodology, and findings from four focus groups (two residential; two business focus groups) held on August 30 and 31, 2005 as well as in-depth interviews KEMA conducted with ten of Portland General Electric's "Key Customers" (business customers who are assigned a Key Customer Manager) between October 13 and November 15, 2005. These focus groups and interviews were conducted to identify perspectives these customers had on a wide range of energy resource options PGE is considering as part of its 2006 Integrated Resource Planning process.

ES.1.1 Focus Group and In-depth Interview Objectives

The objective of the four focus groups, as well as ten in-depth interviews with "Key Account" respondents, was to assess perceptions of and receptivity of PGE customers to a variety of energy resources, including:

- Identifying factors that would make a variety of energy supply options more or less preferable;
- Assessing participant understanding of utility reliance on fuel commodity markets to supplement existing resource mix;
- Understanding participant concerns about environmental issues and global climate change;
- Exploring participants' perspectives about economic and national security relating to various energy supply options.
- Assessing willingness to pay for more preferable resource options.

ES.2 Methodology

ES.2.1 Focus Groups

Each focus group had either ten or eleven participants in attendance. Twelve participants for each group were randomly recruited from a list of PGE customers (recruiting screeners utilized are included in Appendix A).

Participants held a variety of employment titles, and included a mix of annual income levels and education levels. The focus groups had an even gender distribution. Most participants were older than 45, with a mix of participants who had been PGE customers for more than 10 years, 5 to 10 years, and less than 5 years. Residential participants were asked about their primary home heating fuel, and the 45% said that they heated their homes using electricity (40% natural gas; 15% dual fuel sources).

Each focus group was conducted by KEMA utilizing a Moderator Guide (Appendix B) to conduct the discussion. The moderator explained that the exhibits handed out were for discussion purposes only and did not represent the final positions or decisions of PGE.

Focus groups are a qualitative research method. They are useful for identifying and exploring the range of attitudes, opinions, and preferences on a particular topic or issue. The open-ended nature of focus groups allows the researcher to make unexpected connections or to discover alternative ways to think about a topic. However, focus groups do not confirm hypotheses, nor do they allow for estimates regarding the percentage of people who hold a certain opinion or attitude. The information presented should be evaluated within the context of the qualitative nature of the research.

ES.2.2 In-depth Interviews

KEMA was provided a "Key Account" sample of 163 key customer accounts by PGE, which included information for each unique PGE POID number (including contact name and information, market segment, PGE sales rep and other internally-maintained information for each of these customers, such as annual MWh and annual revenue). From that sample, KEMA randomly drew a sub-sample of 53 from which to begin calling to schedule interviews. This sub-sample was drawn to achieve a 5-to-1 ratio between the sample and target number of completes (the target number of completes was set at ten). In-depth interviews were scheduled and completed between October 13 and November 15, 2005 (interview timing was driven by key customer contact availability).

KEMA developed an Interview Guide with supporting documents, which served as the guide for discussion with key account customers (See Appendix C for the final version of the In-Depth Interview Guide, and Appendix D for the four exhibits utilized and referenced throughout the in-depth interviews). The first two pages of the "Key Customer Interview Guide" (Appendix C) outline in detail the procedures utilized to call, schedule, and conduct each interview.

In all cases, the interviewer e-mailed the four exhibits (Appendix D) discussed during the interview to the Key Account customer once an interview time had been confirmed. Each exhibit is clearly marked "For Discussion Purposes Only" and this was re-emphasized during the interview. As the "Procedures" section of the Interview Guide (Appendix C) notes, the interviewer requested at the conclusion of each in-depth interview that the respondent delete or destroy the exhibits, as they were for discussion purposes only and are not final or approved PGE materials.

The ten completed interviews averaged 40 minutes in length. All ten of the PGE customers interviewed affirmatively requested that their responses be kept anonymous. Eight market segments were represented among the ten completed in-depth interviews.[1]

ES.3 Key Findings

The key findings among focus group participants are presented in Section 1.1.3; key findings among Key Account respondents are presented in Section 2.1.3. An overview of focus group and in-depth interview key findings is presented below.

ES.3.1 Key Generation Attributes

Business Focus Group participants

- Reliability and price predictability are most critical to business customers.

[1] The market segments represented among the key customer accounts interviewed included: Assembly/Fabrication

High Tech (2), Major Account, Miscellaneous Commercial (2), Warehouse, School, Utility, and Residential housing.

- Business Focus Group participants overwhelmingly cited price predictability and reliability of a generation source as the most critical attributes of generation sources for business focus group customers – even more so than higher relative rates or any environmental or national security discussed separately.

Key Account customers

- Among the ten Key Account customers interviewed, nine of ten respondents cited "reliability" (meaning a continuous and uninterrupted source of power) as the first or second most important factor when they consider their power supply from PGE. Six of ten Key Account respondents cited cost as an important generation attribute.
- Five of ten Key Account customers interviewed thought that whether or not the long-term sustainability of resources was one of the top factors (though not as critical to them as price predictability or reliable generation) PGE should consider

Business and Residential Focus Group participants

- The majority of all residential and business focus group participants indicated that PGE should fill future resource gaps with generation sources that they know will be sustainable (meaning continually available and located within the U.S.) for 20 or more years in the future. A predominant view expressed is that if a resource has a risk of being depleted in the next two or three decades, it is not advisable to include it in PGE's capacity mix in the short term.

ES.3.2 PGE Generation Ownership and Location

- **Business and Residential Focus Group participants** predominately felt that local, PGE-owned generation is preferred (by a majority of all focus group participants) when compared with purchased. Participants in all groups indicated that PGE owning generation was a key driver for lower commodity prices as well as having more control over the reliability of a resource. Several focus group businesses (and a larger proportion of residential participants) advocated that generation sources (e.g. nuclear, coal) with more potential pollution potential or risks be cited out of state. Several residential (and a few business) respondents associated PGE-owned, in-state generation with more local control over resource reliability, price levels, and predictability.
- **Key Account customers** are divided on their preferences for PGE to own vs. purchase power. Five of the ten respondents said their company had no preference as to whether PGE owned vs. purchased power. The other five respondents preferred PGE own generation – all using the term "control" without prompting from the interviewer. Above all, respondents' preference for reliability and keeping costs low and predictable was best met by the approach that gave PGE the most control. A majority of non-residential customers felt the location of generation is not important. Six of the ten Key Account respondents said it was not important to their company whether the source of their generation was physically located in

the state of Oregon (versus out of state), prioritizing reliability and costs above generation location.

ES.3.3 Cost and Willingness to Pay

- **Business Focus Group participants** expressed a strong preference for cost predictability that they would be willing to pay more for a resource or mix of resources if they could be guaranteed long term price predictability (ideally, a capped generation charge) and if PGE could explain where the increase would be allocated.
- **Residential Focus Group participants** were resistant to price increases, even if those increases were for resources they later said they preferred (such as wind). Among the 20 residential focus group participants, four are already paying an additional amount for green power option through PGE. However, the consensus among the remaining 16 residential participants was that they should not have to pay more (and would not be amenable to paying more) for a particular energy option, even if it had environmental benefits associated.
- **Key Account respondents** were not willing to pay additional for even preferred resource options, but also emphasized price predictability. The majority (seven out of ten) of the in-depth interview respondents said their company would not be willing to pay PGE rates that were higher (of any percentage) for a particular energy supply option, even if they valued the option. The three respondents who indicated their companies might be willing to consider a higher percentage, two would consider up to (but no more than) a 5% higher cost for wind resources if that higher cost were explained and justified. However, during another part of the interview, nine of ten Key Account customers said they preferred higher, more predictable rates as opposed to lower but potentially unstable rates.

ES.3.4 Energy Supply Option Preferences and Trade offs

Focus Group participants – Consensus Points

- **A diverse supply mix is important to all focus group participants**. Most business and residential participants recognized that a diverse mix of generation is needed to meet PGE's future resource gap by 2012. However, there was not a clear consensus among respondents (either within customer classes or across both residential and business groups) regarding their preference for what level of generation source or ownership diversity should be pursued by PGE. The way residential customers and business customers viewed and ranked these trade-offs is described specifically in the ranking exercises and discussions, reported in Sections 1.3, 1.4, and 1.5.
- **Super Critical Pulverized Coal and Integrated Gasified Combined Cycle Coal ranked as the second and third least preferable resource options**, respectively, by more than half of business focus group participants. Respondents cited the tremendous environmental

impact from emissions, as well as the lack of sustainability of coal in the long term as their main reasons. Residential focus group participants ranked Integrated Gasified Combined Cycle Coal, Combined Cycle Combustion Turbine, and Super Critical Pulverized Coal among their least preferred energy supply options because of the emissions that occur during the process of generation. After additional discussion on this point, residential participants said they did not view these three resources as distinct from each other.

Key Account respondents

- Six of the ten Key Account respondents indicated that the **fuel source of their power generation did not matter to their company**. Price predictability and reliability are the most critical attributes of generation sources for **Business Customers (Focus Groups and Key Accounts) –** even more so than higher relative rates or any environmental or national security discussed separately.

Consistent Across All Focus Groups and In-depth Interviews

- **Wind and energy efficiency rank highest**. All focus group participants (and seven of ten Key Account customers) ranked wind the highest (top preference for most residential participants, second preference among most business participants) because it has the least emissions during the process of generating electricity. Energy efficiency was cited across focus groups and in-depth interviews as a top or second preferred energy supply option because of the low capital costs and because it was viewed as a resource they could personally affect and control.
- Business and Residential Focus Group participants viewed **renewable energy as a preferred resource**. Both business and residential Focus Group participants advised that PGE should build more of their own renewable generating capacity in the short term, which is the key to future sustainability in their view. If PGE is able to clearly explain the reasons for any associated higher rates and perhaps fix the generation price for renewable options, the key criteria residential and business focus group customers articulated will be met. This preference for wind energy and energy efficiency program development was also consistent among Key Account interviews.
- **Conventional coal, nuclear energy least preferred energy resource options**. Twelve of 20 residential focus group participants (and 12 of 19 business participants) viewed nuclear energy as a non-option at this time citing a mistrust of current safety precautions for nuclear generation or waste storage and an unrealistic opportunity to site a new nuclear plant. Although business participants were more willing to engage in considering nuclear energy options, they concluded that this option (unless prices were predictable and power was shown to be sustainable and reliable in the long term) was not realistic. Most Key Account respondents (six out of ten) ranked conventional coal as their lowest preference, citing

emissions and pollution from the generation process. The second-to-last preference was nuclear power, with four of ten respondents citing the lack of a solid plan for nuclear waste disposal and general risky nature that loomed from the generation process at nuclear plants.

Table F-1: Summary of Feedback by PGE Customer Group[2]

PGE Customer Class/Format	Feedback Consensus by PGE Customer Type						
	Key Generation Attributes	Should PGE own more generation or contract?	Should generation be located in or out of Oregon?	Willing to Pay More under some circumstances?	Energy Supply Option Preferences and Trade-offs		
					Most-preferred Supply Options	Least-preferred Supply Options	Key Considerations
Residential Focus Group Participants (n=20)	Long-term sustainability, minimum price increases	PGE-Own	In Oregon (out of state if it has waste or risk associated)	No	Energy Efficiency/Load Management; Wind	Nuclear; Conventional Coal	Initial cost to develop is high (might translate to rates); long-term sustainability, environmental impacts
Business Focus Group Participants (n=21)	Reliability, price predictability	PGE-Own	No strong preference	Yes (for price predictability)	Energy Efficiency/Load Management; Wind	Conventional Coal; Nuclear	Long term price predictability; long-term sustainability; environmental impacts
Key Account (Business) Respondents (n=10)	Reliability, price predictability	Divided responses	No strong preference	Mixed responses	Wind; Energy Efficiency/Load Management	Conventional Coal; Nuclear	Long term price predictability; reliability; environmental impacts

[2] This table summarizes the majority response(s) by PGE customer class and format on a number of topics. It is intended to offer an overview of feedback on several key issues, but, due to space limitations, is not comprehensive to all categories of issues addressed in focus groups and in Key Account interviews. Feedback from focus group respondents and Key Account respondents is presented on all topics in this report as a whole.

G. AURORAxmp® Resource Expansion

Table G-1 details the long-term resource additions by area in the Western Electricity Coordinating Council (WECC). The period of the analysis is 2009-2040; however, we froze the WECC load at its 2030 level to avoid increasingly speculative resource selections after 2030. After 2031, no new resources are added to the WECC. All areas with an RPS standard contain a significant percentage of renewable resources in their incremental resource mix. Table G-2 shows resources added in the WECC by technology.

Table G-1: Resource Added by Area (Nameplate MW) (2009-40)

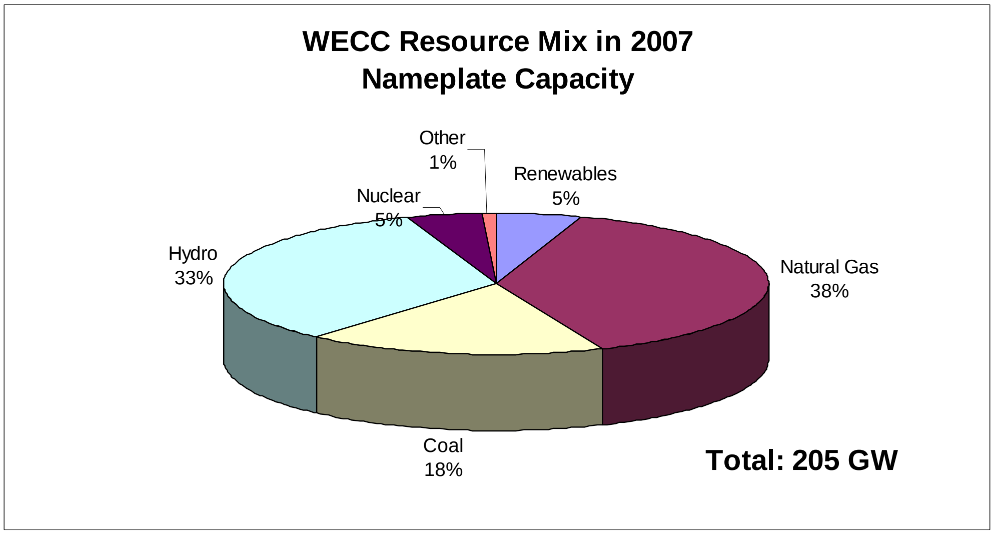
	AURORA Selection	RPS	Total	RPS %
Arizona	2,950	6,457	9,407	69%
Canada-Alberta	5,800	-	5,800	0%
Canada-British Columbia	1,100		1,100	0%
CA-NP15+	1,200	10,834	12,034	90%
CA-SP15+	8,400	21,465	29,865	72%
CA-ZP26+		1,849	1,849	100%
Colorado	5,575	2,894	8,469	34%
Idaho South		-	-	
Mexico-Baja Calif-North	500	47	547	9%
Montana	2,550	594	3,144	19%
Nevada North		637	637	100%
Nevada South	3,700	2,582	6,282	41%
New Mexico	2,225	1,046	3,271	32%
OWI COB		1,097	1,097	
OWI Northeast		543	543	100%
OWI Northwest		4,193	4,193	100%
OWI Southeast		-	-	
OWI Southwest		3,858	3,858	100%
Utah	2,225		2,225	0%
Wyoming	1,700	-	1,700	0%
	37,925	58,097	96,022	61%

Table G-2: Resources Added by Technology, Nameplate (MW)

	MW	%
RPS	58,097	61%
CCCT-Gas	18,800	20%
SCP Coal	16,150	17%
IGCC Coal	1,575	2%
Wind	1,400	1%
SCCT	-	0%
	96,022	100%

Figure G-1 shows the WECC resources by technology in 2007 and then by 2031, after the AURORAxmp resource expansion. Capacity by 2031 is nearly 50% greater than in 2007.

Figure G-1: WECC Resource Mix by Technology, 2007 and 2031



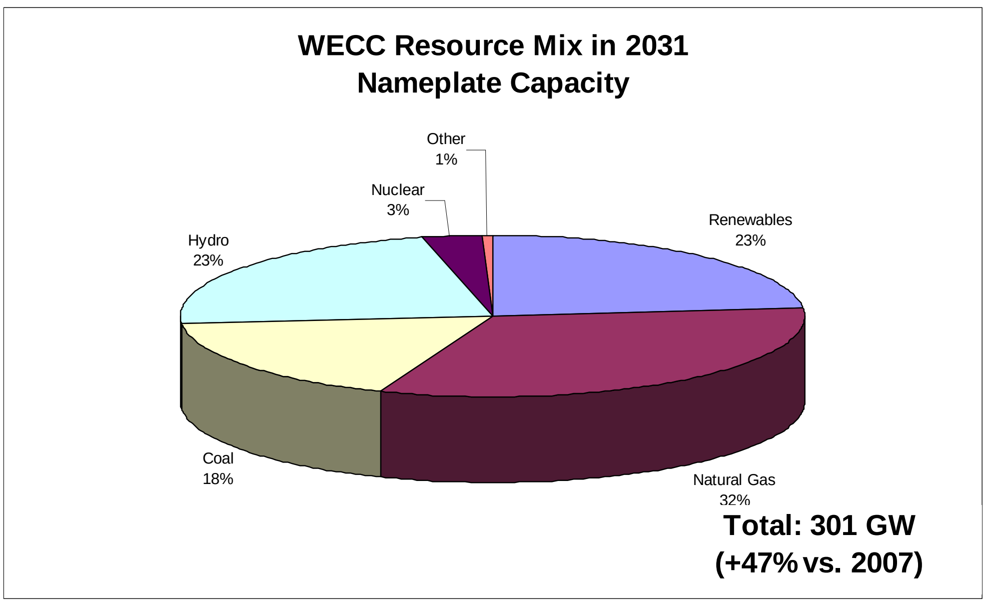


Table G-3 shows the long-term annual average electricity prices resulting from our WECC expansion in AURORAxmp.

Table G-3: WECC–Long-Term Annual Average Electricity Prices (Nominal dollars per MWh)

Nominal$/ MWh	AZ	AB	BC	CA-NP15+	CA-SP15+	CA-ZP26+	COo	IdahoSouth	BajaCA North	Montana	Nevada North	NevadaSouth	New Mexico	OWI COB	OWI NE	OWI NW	OWI SE	OWI SWt	Utah	WY
2009	65.4	64.2	64.7	69.5	72.3	67.4	65.8	65.3	69.9	57.9	66.7	68.8	63.4	65.1	63.0	64.6	63.2	65.2	64.1	60.9
2010	64.5	64.4	64.1	68.0	71.4	66.4	63.1	64.3	69.3	56.9	65.9	67.9	62.0	64.4	61.9	63.5	62.0	64.2	63.0	59.1
2011	60.0	61.3	60.3	63.2	66.8	61.9	58.6	59.8	64.9	52.8	61.7	63.4	57.7	59.7	57.6	59.3	57.7	59.9	58.8	54.9
2012	55.1	57.5	55.6	57.0	61.6	56.7	52.2	53.7	60.1	47.6	52.1	58.5	52.9	53.7	52.3	53.8	52.3	54.4	53.5	49.4
2013	56.7	59.9	57.2	58.7	63.3	58.3	52.0	54.2	62.3	47.8	52.8	60.1	54.3	54.6	52.7	54.4	53.0	55.0	54.4	50.1
2014	59.7	65.5	61.8	61.8	66.6	61.4	53.2	56.7	65.8	50.2	55.5	63.4	57.0	57.6	55.4	57.3	55.8	57.9	57.0	52.4
2015	63.3	70.0	64.6	65.0	70.4	64.7	52.1	57.2	69.9	46.6	49.0	67.1	59.9	59.5	57.3	59.4	58.0	60.0	58.6	52.3
2016	64.4	70.4	64.8	66.3	71.6	65.8	50.9	58.0	71.4	46.7	50.9	68.3	61.0	60.5	57.9	60.2	58.7	60.7	59.6	52.2
2017	66.8	71.5	66.7	68.5	74.0	67.9	53.5	60.4	73.9	49.4	53.5	70.7	63.6	62.7	60.1	62.1	60.7	62.7	62.2	54.9
2018	69.1	75.8	69.5	70.9	76.5	70.1	56.1	62.5	76.5	51.5	56.1	73.2	66.1	64.9	62.1	64.3	62.8	64.9	64.8	57.6
2019	72.2	78.4	73.2	73.9	79.6	72.9	57.3	64.6	80.3	50.7	59.4	76.4	69.5	67.6	64.6	67.0	65.3	67.5	67.8	55.6
2020	74.2	80.2	75.6	76.3	80.9	74.9	58.3	66.5	79.7	52.5	62.3	78.4	72.0	69.5	66.2	68.7	67.0	69.2	69.8	57.1
2021	76.4	83.9	78.5	78.6	82.9	76.9	61.1	68.6	82.1	55.3	64.8	80.7	74.7	71.6	68.3	70.9	69.0	71.4	72.3	59.9
2022	79.0	84.7	81.7	81.5	85.6	79.6	64.0	71.1	84.4	58.1	67.4	83.0	77.6	74.3	70.7	73.4	71.5	74.0	75.0	62.8
2023	82.7	86.1	84.2	84.6	89.1	82.5	67.2	74.0	87.9	61.2	70.4	86.7	81.5	77.0	73.5	76.3	74.3	76.9	78.7	66.2
2024	86.7	89.2	89.0	87.9	93.1	85.6	70.4	77.0	91.7	64.4	73.2	90.3	86.0	80.3	76.6	79.5	77.4	80.1	82.7	69.6
2025	88.5	91.4	91.6	90.1	94.7	87.5	73.2	79.0	94.2	67.0	75.6	91.7	86.5	82.1	78.4	81.3	79.2	81.9	84.5	72.4
2026	86.6	92.6	93.9	91.3	93.7	88.5	72.2	79.2	94.4	66.8	76.2	89.5	82.4	83.0	79.4	82.4	80.1	82.8	80.3	68.3
2027	86.8	94.1	93.9	93.4	94.7	90.3	73.3	80.2	96.0	68.7	77.2	89.9	80.2	84.6	81.0	83.9	81.6	84.4	77.7	69.4
2028	90.7	100.6	99.5	96.9	98.8	93.7	76.8	83.7	99.8	72.0	80.4	93.9	84.0	88.1	84.5	87.5	85.2	88.1	81.3	72.7
2029	92.8	98.0	100.5	98.7	100.1	95.4	79.9	85.9	101.9	74.1	83.0	95.5	86.6	89.9	86.4	89.5	87.2	90.0	84.0	75.7
2030	93.2	101.0	100.8	100.6	101.0	97.0	82.8	88.1	103.7	76.6	85.6	96.2	88.2	91.7	88.2	91.4	89.1	91.9	86.3	78.2
2031	98.4	106.0	105.7	103.6	106.0	99.9	87.9	92.3	108.4	79.5	88.9	101.3	93.2	94.7	91.3	94.5	92.1	95.0	91.3	82.4
Real.lev.2008$	56.4	59.7	57.8	58.7	62.0	57.6	49.2	52.7	61.4	44.8	50.6	59.3	54.1	54.1	52.0	53.8	52.4	54.2	53.5	47.6

H. Portfolio Analysis Results

Table H-1 and Table H-2 below show the results of our scenario analysis. We calculated the expected Net Present Value of Revenue Requirement (NPVRR) from 2009 to 2031 for each of the 13 portfolios under each of the 18 futures.

Table H-1: Scenario Analysis Detail -- Bookends ($ Billion)

			CCCTs	IGCC w/o Seq.	IGCC w/seq	Market	PV Coal	Wind + SCCTs
A	Low Gas Price		2	11	13	1	9	12
		NPVRR	$14.58	$16.04	$16.49	$14.07	$15.30	$16.07
B	No CO2		3	11	13	1	2	12
		NPVRR	$15.78	$16.22	$17.11	$15.22	$15.47	$16.78
C	Gas -20%, Ren. +20%		2	11	12	1	3	13
		NPVRR	$15.28	$16.39	$16.83	$14.66	$15.67	$17.11
D	Gas -20%, Ren. +20%, 50% PTC		2	11	12	1	3	13
		NPVRR	$15.28	$16.39	$16.83	$14.66	$15.67	$17.40
E	Gas -10%, Ren. +10%		2	11	13	1	3	12
		NPVRR	$16.04	$16.96	$17.42	$15.43	$16.24	$17.40
F	Low PGE Load Growth (1%)		8	11	13	1	5	12
		NPVRR	$16.44	$17.12	$17.58	$15.92	$16.40	$17.24
G	Reference Case		8	11	13	1	5	12
		NPVRR	$17.10	$17.77	$18.24	$16.58	$17.06	$17.90
H	Coal w/25 yr-life		7	12	13	1	10	11
		NPVRR	$17.10	$18.03	$18.59	$16.58	$17.30	$17.90
I	No PTC		4	11	12	1	3	13
		NPVRR	$17.10	$17.77	$18.24	$16.58	$17.06	$18.49
J	$10ton CO2 tax		8	12	13	1	10	11
		NPVRR	$18.16	$18.99	$19.15	$17.67	$18.29	$18.83
K	High PGE Load Growth (3%)		8	11	13	1	5	12
		NPVRR	$18.38	$19.05	$19.52	$17.86	$18.33	$19.18
L	High WECC and PGE Load Growth		5	12	13	10	4	11
		NPVRR	$20.36	$21.01	$21.46	$20.65	$20.29	$20.92
M	$25ton CO2 tax		9	13	11	7	12	10
		NPVRR	$21.73	$23.20	$22.24	$21.48	$22.55	$21.90
N	$15 Gas and Low WECC Load Growth		13	10	12	9	1	11
		NPVRR	$22.07	$21.44	$21.95	$21.37	$20.73	$21.67
O	$15mmBtu Gas for 10 yrs		13	9	12	11	1	10
		NPVRR	$23.03	$22.23	$22.72	$22.62	$21.51	$22.46
P	High Gas Price		13	8	11	12	1	10
		NPVRR	$23.93	$22.66	$23.18	$23.67	$21.95	$22.96
Q	$40ton CO2 tax		9	13	10	11	12	8
		NPVRR	$25.26	$27.44	$25.32	$25.44	$26.86	$24.99
R	High Gas and $25 CO2 Tax		13	11	9	12	10	7
		NPVRR	$28.26	$27.73	$26.86	$28.07	$27.13	$26.66
	Average Rank (1 best, 12 worst)		7	11	12	4	5	11
	Unweighted Avg, w/o C,E,F,J,K,M,O		$19.71	$20.23	$20.39	$19.35	$19.53	$20.16
	Rank		10	12	13	3	9	11

The tables also report the relative ranking of each portfolio for a given future. A rank of 1 indicates that the portfolio is the least cost for that particular future, whereas a rank of 13 indicates that the portfolio is the highest cost.

Table H-2: Scenario Analysis Detail – Diversified Portfolios ($Billion)

			Diverse + Gas	Diverse Green	Diverse + Coal	Diverse Green w/CCCTs	Diverse Coal w/CCCTs	Diverse + Contracts	Diverse + Contracts + CCCTs
A	Low Gas Price		4	10	7	8	6	5	3
		NPVRR	$15.06	$15.32	$15.20	$15.23	$15.13	$15.06	$14.99
B	No CO2		8	10	6	9	4	7	5
		NPVRR	$15.91	$16.07	$15.85	$16.00	$15.80	$15.86	$15.80
C	Gas -20%, Ren. +20%		6	10	8	9	7	5	4
		NPVRR	$15.87	$16.17	$15.94	$16.13	$15.91	$15.85	$15.81
D	Gas -20%, Ren. +20%, 50% PTC		6	10	8	9	7	5	4
		NPVRR	$16.03	$16.38	$16.10	$16.33	$16.07	$16.01	$15.81
E	Gas -10%, Ren. +10%		6	10	8	9	7	5	4
		NPVRR	$16.35	$16.57	$16.39	$16.53	$16.36	$16.31	$16.27
F	Low PGE Load Growth (1%)		7	10	6	9	3	4	2
		NPVRR	$16.44	$16.56	$16.43	$16.48	$16.37	$16.38	$16.31
G	Reference Case		7	10	6	9	3	4	2
		NPVRR	$17.09	$17.22	$17.09	$17.14	$17.03	$17.04	$16.97
H	Coal w/25 yr-life		6	9	5	8	3	4	2
		NPVRR	$17.09	$17.22	$17.09	$17.14	$17.03	$17.04	$16.97
I	No PTC		8	10	7	9	5	6	2
		NPVRR	$17.41	$17.63	$17.40	$17.55	$17.34	$17.39	$16.97
J	$10ton CO2 tax		5	9	7	6	4	3	2
		NPVRR	$18.07	$18.17	$18.09	$18.08	$18.02	$18.00	$17.93
K	High PGE Load Growth (3%)		7	10	6	9	3	4	2
		NPVRR	$18.37	$18.50	$18.37	$18.42	$18.31	$18.32	$18.25
L	High WECC and PGE Load Growth		7	9	6	3	1	8	2
		NPVRR	$20.41	$20.50	$20.39	$20.24	$20.19	$20.46	$20.23
M	$25ton CO2 tax		4	5	8	2	6	3	1
		NPVRR	$21.33	$21.34	$21.48	$21.16	$21.34	$21.25	$21.09
N	$15 Gas and Low WECC Load Growth		8	6	4	7	5	2	3
		NPVRR	$21.08	$20.97	$20.83	$20.98	$20.83	$20.81	$20.81
O	$15mmBtu Gas for 10 yrs		8	7	4	6	2	5	3
		NPVRR	$21.96	$21.82	$21.67	$21.71	$21.59	$21.71	$21.61
P	High Gas Price		9	6	4	3	2	7	5
		NPVRR	$22.76	$22.54	$22.39	$22.38	$22.26	$22.62	$22.48
Q	$40ton CO2 tax		5	3	7	1	6	4	2
		NPVRR	$24.61	$24.53	$24.91	$24.19	$24.64	$24.55	$24.24
R	High Gas and $25 CO2 Tax		8	4	5	1	2	6	3
		NPVRR	$26.67	$26.34	$26.45	$26.15	$26.31	$26.49	$26.32
	Average Rank (1 best, 12 worst)		6	8	6	6	4	5	3
	Unweighted Avg, w/o C,E,F,J,K,M,O		$19.47	$19.52	$19.43	$19.39	$19.33	$19.39	$19.24
	Rank		7	8	6	5	2	4	1

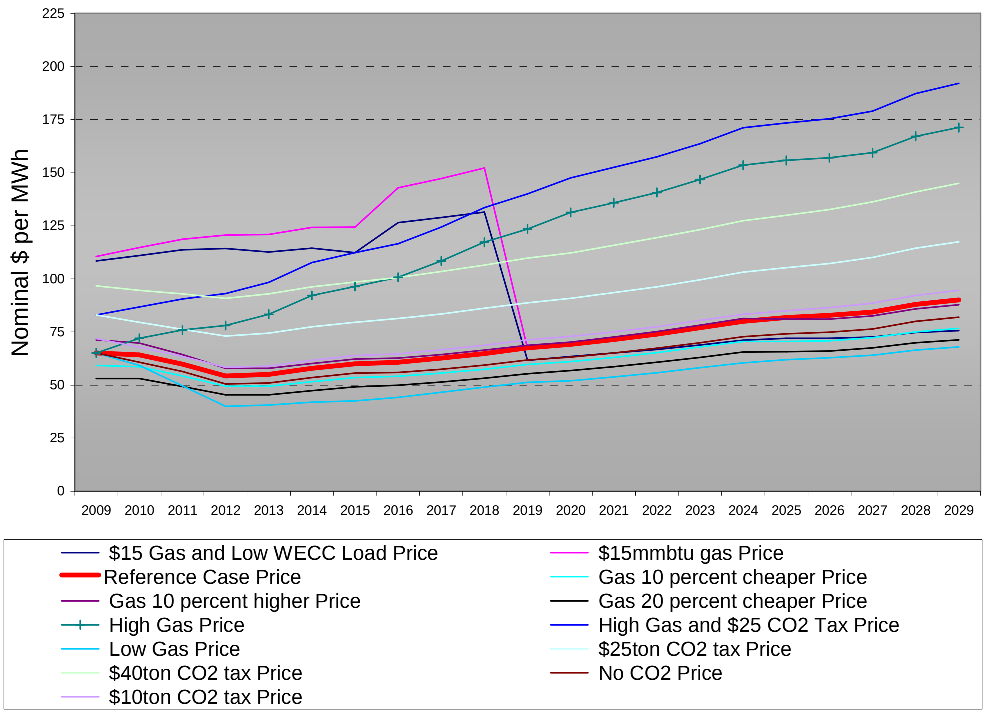
Table H-3 shows the calculated electricity prices for PGE used in the reference case. All prices shown are annual average electricity prices. The marginal heat rates for flat, on-peak, and off-peak prices are calculated by dividing the electricity price by the annual average gas price for PGE (an average of Sumas and AECO hub prices).

Table H-3: Reference Case Electricity Prices

	AURORAxmp PGE Price Projection (Nominal $/MWh)				Marginal Heat Rates (MMBTU/MWh)		
	Flat	On-Peak	Off-Peak	On-Off Peak Delta	Flat	On-Peak	Off-Peak
2009	$65.2	$71.4	$57.0	$14.4	8,074	8,842	7,059
2010	$64.2	$70.3	$56.1	$14.2	8,594	9,411	7,510
2011	$59.9	$65.5	$52.5	$13.0	8,757	9,576	7,675
2012	$54.4	$59.5	$47.7	$11.8	8,810	9,636	7,725
2013	$55.0	$60.2	$48.1	$12.1	8,709	9,533	7,617
2014	$57.9	$63.5	$50.4	$13.1	8,726	9,570	7,596
2015	$60.0	$65.7	$52.3	$13.4	8,439	9,241	7,356
2016	$60.7	$66.3	$53.2	$13.1	8,567	9,358	7,509
2017	$62.7	$68.5	$55.1	$13.4	8,642	9,442	7,595
2018	$64.9	$70.9	$56.9	$14.0	8,729	9,536	7,653
2019	$67.5	$73.5	$59.5	$14.0	8,671	9,441	7,643
2020	$69.2	$75.3	$61.1	$14.2	8,501	9,251	7,506
2021	$71.4	$77.7	$63.0	$14.7	8,582	9,339	7,572
2022	$74.0	$80.6	$65.2	$15.4	8,691	9,466	7,657
2023	$76.9	$83.8	$67.7	$16.1	8,829	9,621	7,773
2024	$80.1	$87.6	$70.1	$17.5	8,990	9,832	7,868
2025	$81.9	$89.5	$71.7	$17.8	8,985	9,819	7,866
2026	$82.8	$90.6	$72.4	$18.2	8,884	9,721	7,768
2027	$84.4	$92.5	$73.6	$18.9	8,852	9,701	7,719
2028	$88.0	$96.8	$76.5	$20.3	9,016	9,918	7,838
2029	$90.0	$99.0	$78.1	$20.9	9,018	9,920	7,826
2030	$91.9	$101.1	$79.7	$21.4	9,005	9,907	7,810
2031	$95.0	$104.8	$82.0	$22.8	9,095	10,034	7,851

In our scenario analysis, high electricity prices are the result of high gas prices, high CO_2 tax, and a WECC load growth higher than in the reference case. Low gas prices and no CO_2 tax are drivers for the low electricity price projections. Figure H-1 below shows the price range.

Figure H-1: PGE Electricity Prices across Scenarios



Stochastic Portfolio Analysis Results

Table H-4 shows stochastic analysis results for each of the 13 portfolios included in our study.

Table H-4: Stochastic Portfolio Analysis Results

	CCCTs	IGCC w/o Seq.	Market	PV Coal	Wind +SCCTs	Diverse +Gas	Diverse Green
Average NPVRR	$16.50	$17.19	$16.00	$16.50	$17.56	$16.63	$16.80
Tail VaR90 NPVRR	$18.67	$18.81	$18.28	$18.11	$19.23	$18.45	$18.52
TailVaR90 NPV Variable Cost	$13.86	$12.74	$14.34	$12.66	$11.76	$12.29	$11.98
RVI	33.4%	24.9%	39.0%	26.2%	26.2%	29.5%	28.2%

	Diverse +Coal	Diverse Green w/CCCTs	Diverse Coal w/CCCTs	Diverse + Contracts	IGCC with Seq.	Diverse + Contracts + CCCTs
Average NPVRR	$16.63	$16.72	$16.57	$16.59	$17.70	$16.52
Tail VaR90 NPVRR	$18.35	$18.41	$18.26	$18.38	$19.29	$18.28
TailVaR90 of NPV Variable Cost	$12.07	$11.83	$11.95	$12.15	$12.48	$12.01
RVI	28.3%	27.1%	27.4%	30.1%	23.4%	29.1%

Printed on 100% post consumer recycled paper. Please recycle.

PGE

121 S.W. Salmon Street ● Portland, Oregon 97204
PortlandGeneral.com

Printed on 100% post consumer recycled paper. Please recycle.