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March 27, 2014

Via Electronic Filing and U.S. Mail
Oregon Public Utility Commission
Attention: Filing Center
PO Box 1088
Salem OR 97308-1088

Re: LC 56 – Portland General Electric Company's 2013 Integrated Resource Plan

Attention Filing Center:

In accordance with Commission Orders 07-002 and 08-246, Portland General Electric Company ("PGE") hereby files an original and five (5) copies of its **2013 Integrated Resource Plan** (IRP). The 2013 IRP is also available electronically on PGE's IRP website, at: www.portlandgeneral.com/IRP.

PGE's plan is the result of a public process in which we conducted a number of public meetings and workshops, actively solicited input from Staff and stakeholders, and participated in regional forums that helped inform our planning process.

On November 22, 2013, we issued a draft IRP for public review and received comments in January 2014. Along with various updates on topics, with newer information since circulation of the draft IRP, we have added discussion and revised the document as needed for resource opportunities and a revised load forecast that became available after the draft was issued. We held a public meeting earlier this month to share these post-draft changes with Staff and stakeholders.

PGE requests that the Commission set a scheduling conference to establish the due dates for the filing of comments.

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

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Sincerely,

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Enclosures
cc: LC 48 Service List (without enclosures)
LC 56 Service List (without enclosures)

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **Portland General Electric Company's 2013 Integrated Resource Plan** to be served by electronic mail to those parties whose email addresses appear on the attached service list from OPUC Docket No. LC 48 and LC 56.

Dated at Portland, Oregon, this 27th day of March, 2014.

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2013 Integrated Resource Plan

Portland General Electric

Portland General Electric Company

2013 Integrated Resource Plan

March 2014

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I. *Executive Summary*

Process

The public phase of this IRP started in the spring of 2013, as the competitive bidding process for new resources identified in the last IRP was drawing to a close. The IRP was launched after completion of the new energy and capacity requests for proposals (RFPs) process in order to incorporate the selected resources into the supply/demand assessment and portfolio analysis for this plan.

Between April and November 2013, PGE conducted four public meetings, three technical workshops, and provided responses to over forty parking lot questions from our stakeholders. Public meeting and technical workshop materials are available online at www.portlandgeneral.com/IRP. All meetings and workshops were well attended and stakeholders provided valuable comments and feedback throughout the process.

Pursuant to OPUC IRP Guidelines, PGE circulated a Draft IRP on November 22, 2013, for stakeholder review. On January 22nd, PGE received joint comments from the Renewable Northwest Project (RNP), Citizen's Utility Board (CUB), Northwest Energy Coalition (NWEC), and Natural Resources Defense Council (NRDC), and separate comments from OPUC Staff. We do not believe the comments received to date note any significant criticisms or deficiencies, or suggest that PGE should provide major new analysis for the final IRP prior to filing with the OPUC.

As a commitment arising out of the last IRP with regard to the Boardman 2020 plan, PGE also conducted a multi-meeting process with certain stakeholders and a consultant (E3) to develop low-carbon portfolio alternatives to evaluate in this IRP. Chapter 1 - IRP Process provides an overview of this work. The low-carbon portfolios were evaluated alongside other candidate portfolios developed by PGE or suggested by stakeholders during the public meetings and technical workshops. In addition to the low-carbon portfolio development process, PGE completed or refreshed the following studies:

- As required by Order No. 12-013, we developed a study of PGE's requirements for, and supply of, dynamic capacity through the next two RPS compliance periods (2015 and 2020). This study was vetted in a stakeholder technical workshop and is included as Chapter 5 - Flexible Capacity Needs.
- We retained Black and Veatch (B&V) to evaluate current commercial generating and storage options, with their associated performance characteristics, engineering lives, brownfield construction costs, and operating costs. The generic plant cost and performance characteristics from this study serve as the basis for our resource assessment in Chapter 8 - Supply-side Options.
- We updated the 2011 wind integration study to include the new resources from the recently completed energy and capacity RFP process, and used a 2018 baseline year, among several other updates and modeling enhancements.

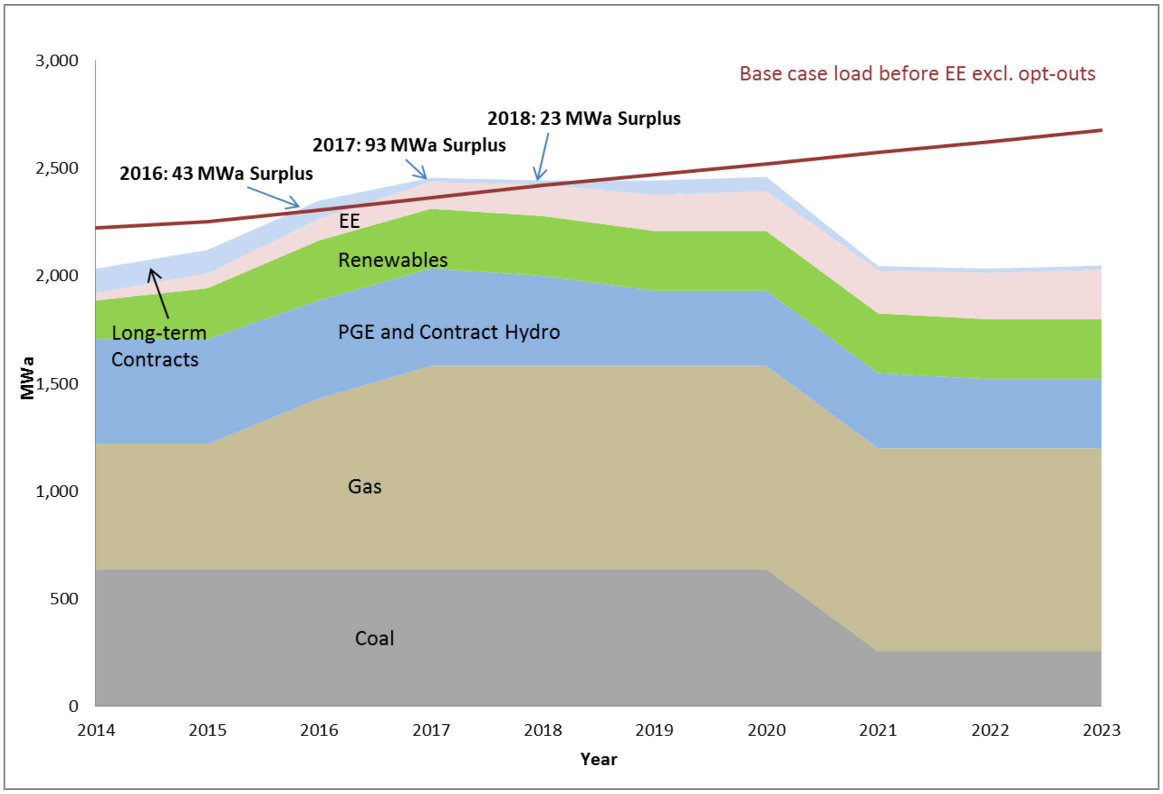
The results are incorporated in the resource costs for prospective wind generation. This study again employed a Technical Review Committee, was vetted in a stakeholder technical workshop, and is summarized in Chapter 8 - Supply-side Options.

- We contracted with Definitive Insights to update a customer preferences survey and quantitative analysis. We also shared the results of the study in a public meeting to provide decision context regarding resource preferences and cost expectations of our residential, commercial, and industrial customers. The study results are presented in Appendix H.
- We engaged a consultant with statistical expertise to provide stochastic PGE load and wind data sets for use in our reliability study. Portfolio reliability inputs and results are presented in Chapter 9 - Modeling Methodology and Chapter 10 - Modeling Results, respectively.

Resource Need

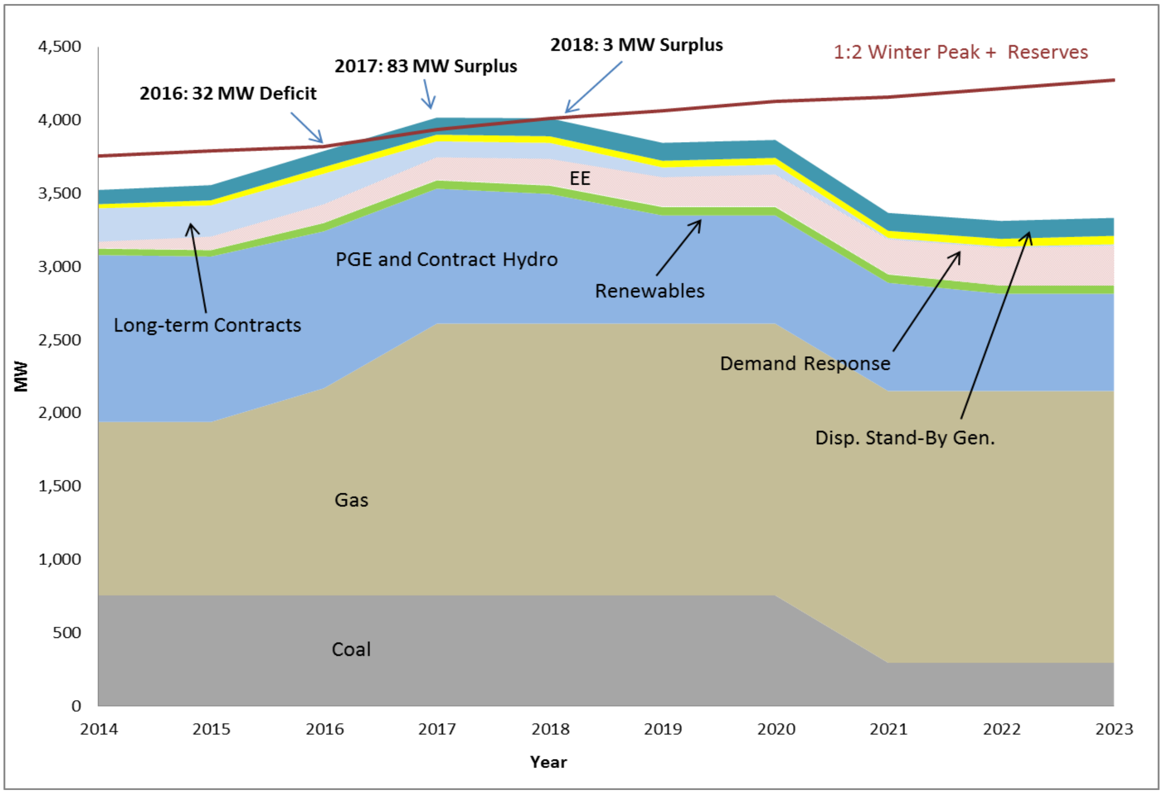
Figure 1 and Figure 2 display PGE's load-resource balance on an annual average energy basis and a winter capacity basis by year, including the new energy and capacity projects acquired through the competitive bidding process concluded in 2013. PGE's load-resource balance in this IRP relies on the most recently available information as of February 2014, reflecting our December 2013 load forecast and February 2014 expected resource portfolio. Figure 1 assumes a long-term (2014–2033) annual average load growth rate of 1.3% per year. Figure 2 assumes a peak winter load based on normal weather (i.e., 1-in-2 weather), plus a planning reserve margin calculated as 6% of load, plus 5% of PGE hydro generation and 7% of PGE thermal generation. More detailed discussion about the load forecast and forecast sensitivities to both loads and resources is found in Chapter 3 - Resource Requirements.

Figure 1: PGE's projected annual average energy load-resource balance



For the current IRP Action Plan horizon (through 2017), our projected annual average energy supply-demand position, as displayed in Figure 1 above, can be characterized as generally balanced, to slightly surplus, until 2019, at which point growing deficits emerge. Results above assume normal hydro conditions. Poor hydro conditions could reduce available supply by as much as 100 MWa in any given year through 2017.

Figure 2: PGE's projected winter (January) capacity needs



For winter capacity, as displayed in Figure 2 above, we are largely balanced through 2018 with respect to our projected 1-in-2 winter peak demand. Growing deficits emerge post-2018 due to contract expirations and load growth.

Given these projections, no major new resource actions are warranted in the current IRP Action Plan horizon.

In the intermediate-term (five to eight years hence) PGE will need to implement resource actions to meet the growing 2020 RPS requirements and to replace energy from the Boardman coal plant, which is scheduled to cease coal-fired operations in 2020. Additional energy and capacity actions may also be required to offset expiring contracts, potentially decreasing availability of market supply, and to integrate higher levels of variable energy resources (e.g., wind). These actions will be identified in a future IRP.

Portfolio Analytical Approach

PGE's planning horizon for this IRP is 20 years, from 2014 through 2033. We simulate the expected cost of different portfolios by:

- Accounting for projected fixed cost of existing resources;
- Modeling the life-cycle fixed cost of new resources and computing a real levelized, fixed revenue requirement;

- Dispatching existing and new resources in AURORAxmp, an electric portfolio economic dispatch model widely used in the Pacific Northwest; and,
- Adding fixed and variable costs and computing the net present value of revenue requirement (NPVRR) of each portfolio from 2014 to 2033.

PGE's Action Plan horizon is consistent with OPUC Guideline 4n, which requires: "an action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources." The context for this guideline is that such actions will be in accord with a preferred portfolio which is part of the 20-year planning horizon. This means our IRP Action Plan is primarily focused on major activities we will undertake by 2017. Appendix A outlines the relevant OPUC IRP Guidelines and how PGE addresses them.

PGE developed 18 candidate portfolios and tested them against 36 potential future environments ("Futures"). Most portfolios have a common amount of ETO-forecasted Energy Efficiency (EE) and maintain physical compliance with the Oregon Renewable Portfolio Standard (RPS). In addition, all portfolios acquire our targeted amounts of Dispatchable Standby Generation (DSG) and Demand Response (DR). Finally, most portfolios add peaking resources to reach a common resource adequacy target. To meet remaining future energy needs, portfolios then test different mixes of renewables (dominated by wind in most cases) and base load gas units. The futures are used to test for several key uncertainties, such as higher and lower carbon compliance costs, higher and lower gas prices, higher and lower plant construction costs, higher and lower market power prices, etc. These trial portfolios and Futures are described in detail in Chapter 9 - Modeling Methodology.

The process of developing candidate portfolios and assessing their performance across the futures is a lengthy one. Given the time required to complete this process and the fact that our proposed Action Plan does not include major new resources, the candidate portfolios and related analytical results reflect our projected load-resource balance as of circulation of the Draft IRP in November 2013.

We designated the future with the most likely set of input assumptions as the "Reference Case". All candidate portfolios were tested under Reference Case assumptions and 35 sets of alternative Futures. We then compared reference case costs with costs in the alternative futures for each portfolio to assess variability and severity of potential adverse outcomes. This approach enables us to measure the expected cost (based on the Reference Case set of assumptions) against cost risk (the potential for cost outcomes that are higher, based on the alternative Futures, than the expected case). Further description of the Reference Case assumptions and the risk metrics is found in Chapter 9 - Modeling Methodology.

Preferred Portfolio

Figure 3 presents a cost summary by portfolio for Reference Case assumptions, along with the range of cost outcomes for each combination of portfolios and futures. We refer to these combinations as "Scenarios".

Figure 3: Candidate portfolio cost distribution

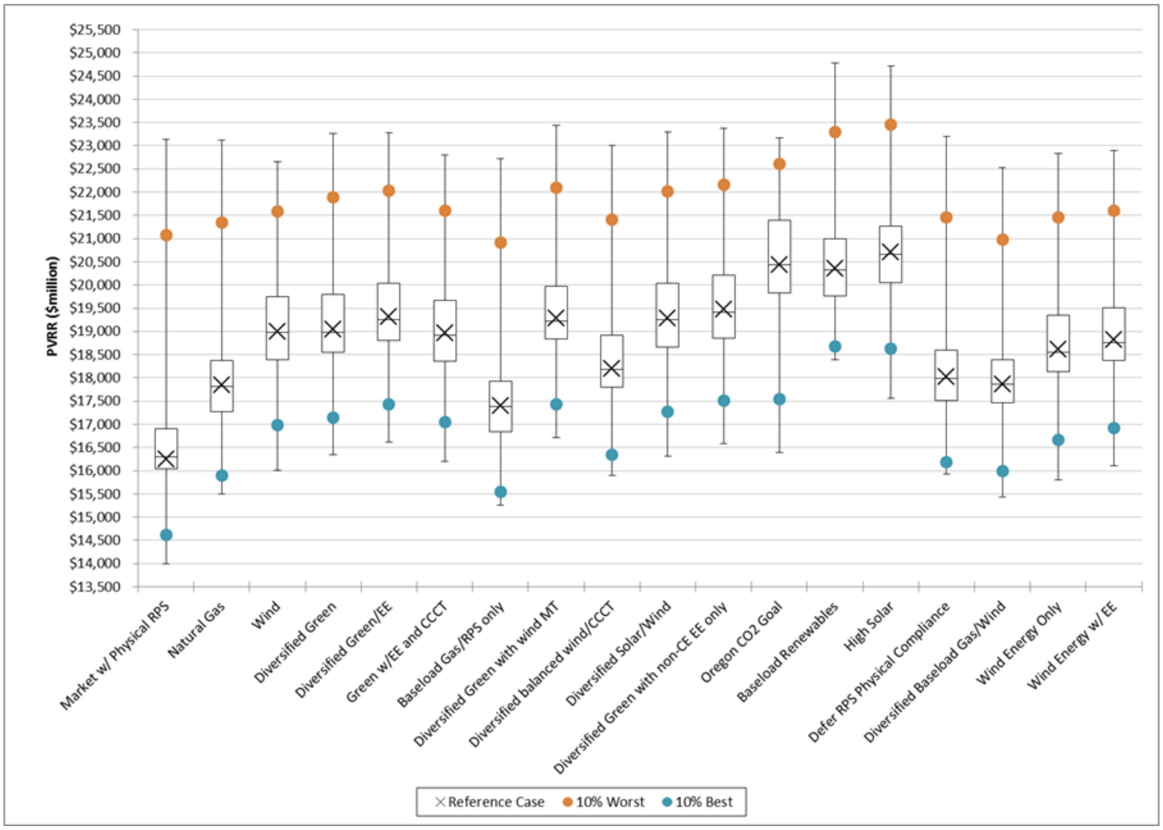


Figure 3 visually shows that a few portfolios outperform the others with respect to exhibiting lower costs under reference case assumptions, and demonstrating an increased potential for low cost outcomes and reduced exposure to high cost outcomes. Driven by low forecast gas prices, portfolios that include highly efficient natural gas-fired generation along with cost effective energy efficiency (EE) and renewable resources to meet RPS requirements, continue to outperform other candidate portfolios. In addition, our analysis per IRP Guideline 8 (trigger point analysis) illustrates the point that, under most circumstances, portfolios with higher penetration levels of renewable resources (beyond RPS requirements) remain more expensive compared to new base load gas generation from a combined cycle combustion turbine (CCCT).

When considering overall cost, risk, and reliability performance, the top three performing candidate portfolios are: Baseload Gas/RPS only, Diversified Baseload Gas/Wind, and Natural Gas. The top three portfolios perform similarly and each could be considered a viable candidate for a preferred portfolio. Each of these three candidate portfolios follow the above described model of combining EE, base load natural gas plants, new renewables to meet RPS requirements, and natural gas peaking units to provide capacity. These top portfolios differ in the timing of base load gas resource additions, as well as the amount of natural gas peaking units and new renewables. Of these, we recommend Baseload Gas/RPS only as the preferred portfolio, as it performs best with regard to expected cost, and achieves similarly favorable risk and reliability performance when compared to the other two candidates. At the same time, we reiterate that we are not recommending any new major supply-side resource additions as part of our proposed IRP Action Plan. Therefore, the top performing portfolios from this IRP (along with other candidate resource combinations) will be re-examined for Action Plan selection in the next IRP. Further detail regarding the composition of candidate portfolios can be found in Chapter 9 - Modeling Methodology and Appendix B. More information regarding candidate portfolio cost, risk, and reliability performance is available in Chapter 10 - Modeling Results.

PGE's Proposed Action Plan

Because no major resources are needed in the current Action Plan time horizon, the conclusions above have no effect on resource selection at this time and will be revisited with updated load and price forecasts, policy assumptions and model results in the next IRP. Our proposed IRP Action Plan thus consists of demand side activities that are currently underway: increased Energy Efficiency (EE), additional Demand Response (DR), and new Dispatchable Standby Generation (DSG).

In addition, we propose several enabling study and research actions to help inform the next IRP. These recommended study and research actions were developed in collaboration with PGE stakeholders at our recent public meetings. Following is PGE's proposed Action Plan, which is categorized by supply-side actions, demand-side actions, enabling studies, and transmission:

1. **Supply-side Actions:** Retain legacy hydro resources, if available and economic:
    a. Major Resources: PGE requests no new major resource additions in this IRP.
    b. Hydro Contract Renewals: PGE has expiring legacy hydro contracts. We propose renewal, or partial renewal of these contracts, if they can be renewed cost-effectively for our customers. As we discuss in Chapter 2 - PGE Resources, this is a proposal for an alternative acquisition method under Guideline 2a of the Commission's Competitive Bidding Guidelines (Order No. 06-446).
    c. DSG: an additional 23 MW by 2017 (for a total of 116 MW).

2. **Demand-side Actions:** Continue demand-side procurement:
    a. EE: ETO cost effective deployment of Energy Efficiency: 124 MWa (158 MW) by 2017.
    b. DR: an additional 25 MW (total DR of 45 MW) by 2017.

3. **Enabling Studies:** Perform research to inform the next IRP regarding:
    a. Best practices review of load forecast methodology;
    b. Assessment of emerging EE in conjunction with the ETO;
    c. Assessment of the potential for distributed generation in PGE's service area (focus on solar photovoltaic);
    d. Continuation of the Boardman biomass technical & economic viability project;

e. Assessment and development of operational flexibility: continue to assess potential regional Energy Imbalance Market and other operational and market solutions to enhance dynamic dispatch capabilities;
f. Evaluation of new analytical tools for optimizing the flexible resource mix to integrate load and variable resources; and,
g. Assessment of longer-term gas supply options to hedge price volatility.

4. **Transmission:** Various regional and national changes that affected the transmission market in the Northwest (both demand and supply availability) led us to make significant modifications to our proposed Cascade Crossing Transmission Project over time, and ultimately resulted in our decision to terminate the project. We have determined that, under current conditions, the best alternative for meeting the transmission requirements for remote resources and market access over the current planning horizon is to retain and/or acquire service under BPA's OATT.

We provide more discussion about our proposed Action Plan in Chapter 12 - PGE Proposed Action Plan.

2013 IRP Content

PGE's IRP covers the following topics:

1. Chapter 1 reviews the public process that supported the IRP. It also focuses on compliance with OPUC IRP Guidelines for resource planning and other relevant Orders. In addition, this chapter provides detail regarding the low-carbon portfolio study discussed above.

2. Chapter 2 describes our existing resources and contracts, resource additions and expirations since our last IRP, and resources currently being implemented as a result of our recent energy and capacity RFPs. This chapter also addresses expiration dates for existing resources, where applicable.

3. Chapter 3 provides PGE's forecast load growth (both energy and winter/summer capacity), and presents PGE's resulting outlook for resource needs when netting resources against customer energy and peak demand requirements.

4. Chapter 4 is devoted to demand-side alternatives to meet the resource needs demonstrated in Chapter 3. This includes both Energy Efficiency and Demand Response. An update to the PGE's evaluation of the potential for Conservation Voltage Reduction is included.

5. Chapter 5 details our study of PGE's flexible resource supply of and demand requirements.

6. Chapter 6 focuses primarily on the forecast cost for gas and coal fuel supply, including transportation costs.

7. Chapter 7 is devoted to environmental compliance and risks. It outlines PGE's Climate Principles, reviews our adherence to OPUC IRP Guideline 8 requirements, and assesses the uncertainty associated with greenhouse gas emissions compliance costs.

8. Chapter 8 provides an assessment of supply-side energy, capacity, and storage resource alternatives, with their associated performance characteristics, and estimated capital and operating costs. This includes both renewable and fossil-fuel options.

9. Chapter 9 combines the elements of the prior chapters and discusses our "portfolios" and "futures" modeling and evaluation framework. The chapter also discusses how we have addressed the various risks and uncertainties identified in the OPUC IRP Guidelines.

10. Chapter 10 provides portfolio results and the insights we gained from the portfolio modeling.

11. Chapter 11 provides an overview of PGE's transmission portfolio, future requirements, and strategy.

12. Chapter 12 describes PGE's proposed Action Plan in further detail.

Major Elements of PGE's Next IRP

We believe that this IRP provides a robust assessment of PGE's projected future resource needs, as well as the expected cost and risks of alternatives for meeting those needs. While the current IRP Action Plan does not include any major new resource additions, growing RPS requirements, plant retirements, and contract expirations are anticipated to result in significant future supply deficits that will need to be examined in subsequent resource plans. As a result, we expect PGE's next IRP to address increased 2020 RPS requirements, options for replacing output from the Boardman coal plant, and other potential energy and capacity needs. We anticipate launching the process for the next IRP in late 2014 or early 2015 with an expected OPUC filing in 2016.

1. IRP Process

Our planning is guided by orders issued by the Public Utility Commission of Oregon (OPUC). The primary goal of the Integrated Resource Plan is to identify a resource action plan that 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 a variety of candidate portfolios of new and existing supply- and demand-side resources under varying potential future conditions. Cost and risk analysis is conducted over a planning horizon of at least 20 years. Throughout 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 four public meetings to discuss with stakeholders our future energy needs, modeling assumptions and methodology, and analytical results.
- PGE hosted three additional public workshops each with a technical focus to address portfolio composition, wind integration costs, and flexible capacity needs.
- PGE also participates in a number of regional forums and work groups that inform and influence our planning.

1.1 Regulatory Requirements

Order No. 07-002: IRP Guidelines

In January 2007, the OPUC issued Order No. 07-002 adopting updated IRP Guidelines. The Commission stated that 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. This IRP meets the requirements of Order No. 07-002, while at the same time addressing the changing power supply and policy environment that we face. Specifically, our IRP incorporates:

- Energy efficiency provided by the Energy Trust of Oregon (ETO).
- All system load in our energy and peak demand forecasts, except for customers expected to opt-out of PGE service on a long-term basis (five-year opt-outs).
- 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.
- Risk analysis, both on a stochastic (i.e., analysis incorporating random fluctuations in inputs that mimic historical actuals) and on a scenario basis.

We provide a detailed description of how we comply with the provisions of Order No. 07-002 in Appendix A. We further include several other modeling sensitivities beyond those required in Order No. 07-002 (see Chapter 10 - Modeling Results).

The following metrics are used to describe portfolio cost and risk:

- Net present value of revenue requirement (NPVRR) and associated risk for each candidate resource portfolio, including both variability of costs and the severity of adverse outcomes. The compositions of our candidate portfolios are provided in Appendix B, while the detailed results of our portfolio analysis are presented in Appendix C.
- Reliability measures, including loss of load probability, expected unserved energy, and TailVar90 of expected unserved energy.
- Stochastic as well as long-term scenarios.
- A wide range of possible future CO_2 compliance costs.

Order No. 10-457: PGE's 2009 IRP

We filed our last IRP in November 2009 and an associated Addendum in April 2010. The Commission issued Order No. 10-457 on November 23, 2010, acknowledging PGE's 2009 IRP. PGE filed annual updates in November 2011 and 2012. On October 3, 2013, the Commission issued Order No. 13-359 authorizing PGE to extend the due date for its next IRP to March 30, 2014.

In Order No. 10-457, the Commission required PGE to include a number of items in subsequent IRP Updates and in this IRP. A list of these items and where they have been addressed follows:

- An updated benefit-cost analysis of Cascade Crossing Transmission Project (CCTP): the economic analysis was updated in our 2011 IRP Update. We provide an update herein for CCTP in Chapter 11 - Transmission.
- A Demand Response analysis: an extensive demand response update was provided in our 2011 IRP Update. In 2012 we provided a further update on the status of demand response procurement. Chapter 4 - Demand-side Options contains our latest analysis and projections for demand response.
- A Conservation Voltage Reduction (CVR) analysis: while PGE was not required to address CVR in our IRP Updates, we did provide our plan for CVR evaluation in the 2011 IRP Update. The information was refreshed in 2012, and we address it again here in Chapter 4 - Demand-side Options.
- A wind integration study: PGE provided a wind integration study in the 2011 IRP Update. We have updated the study for our 2013 IRP; we discuss the updated study in Chapter 8 - Supply-side Options and include it as Appendix D.
- Evaluation of Renewable Energy Credits (REC) strategy: the OPUC required PGE to evaluate methods of meeting Oregon's Renewable Portfolio Standards (RPS) requirements, including the use of unbundled versus bundled RECs. PGE's 2011 IRP Update contained a detailed analysis examining different approaches to meeting the state requirements. Our current approach to meeting the RPS standards is included in Chapter 7 - Environmental Considerations.

Order No. 12-013 – Guideline 14: Flexible Capacity

In Order No. 12-013 the Commission adopted a guideline addressing the need for flexible capacity. That order came in Docket No. UM 1461, titled "Investigation into Rate Structure for Electric Vehicle Charging." OPUC Staff recognized that electric vehicles (EV) could potentially be used as flexible peaking resources going forward. As such the guideline calls for utilities to forecast both the need and supply of flexible capacity, and treat EVs as any other flexible capacity resource for analytical purposes.

We discuss the flexible capacity need and supply in Chapter 5 - Flexible Capacity Needs. EVs are discussed in further detail in Chapter 3 - Resource Requirements.

1.2 Public Process

We started the public phase of this IRP in spring 2013, as the competitive bidding (request for proposals or RFP) process for new energy and capacity supply, identified in the 2009 IRP, was drawing to a close. This IRP was launched at the close of the RFP process as it was necessary to incorporate the new resource additions to better inform this resource plan.

Between April and October 2013, PGE conducted four public meetings, three technical workshops, and provided responses to over forty submitted questions from public meeting and workshop participants. All meetings and workshops were well attended by stakeholders and the IRP has benefitted from their feedback.

Pursuant to OPUC IRP Guidelines, PGE circulated a Draft IRP on November 22, 2013, for stakeholder review. On January 22nd, PGE received joint comments from the Renewable Northwest Project (RNP), Citizen's Utility Board (CUB), Northwest Energy Coalition (NWEC), and Natural Resources Defense Council (NRDC), and separate comments from OPUC Staff. We do not believe that the comments received to date note any significant criticisms or deficiencies or suggest that PGE should provide major new analysis for the final IRP prior to filing with the OPUC.

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

- Bonneville Environmental Foundation
- Citizens' Utility Board (CUB)
- City of Portland
- Energy Trust of Oregon (ETO)
- General Electric Company (GE)
- Industrial Customers of Northwest Utilities (ICNU)
- Natural Resources Defense Council (NRDC)
- NW Energy Coalition (NWEC)
- NW Natural
- Northwest Power and Conservation Council (NWPCC)
- Oregon Department of Energy (ODOE)
- Oregon Environmental Council (OEC)
- Oregon Public Utility Commission (OPUC)
- Pacific Environmental Advocacy Center
- Renewable Northwest Project (RNP)
- Sierra Club
- Williams Northwest Pipeline

The public meetings and technical workshops included discussion on some of the following fundamental building blocks:

- Load-resource balance (future energy and capacity requirements)
- Fuel market fundamentals and forecasts (natural gas and coal)
- Transmission and natural gas transportation considerations
- Flexible capacity needs
- Energy and capacity resource options
- Demand-side resources
- Supply-side generation resources

- Boardman emissions controls
- Federal and state policy developments, including potential climate change legislation and proposed EPA rules for greenhouse gasses
- Modeling approach and IRP risk metrics

See Appendix E for a detailed description of topics covered throughout our public process.

To facilitate ease of communication with interested parties PGE published all IRP presentation materials from the public meetings on our website. These materials may be accessed at www.portlandgeneral.com/irp.[1] In addition, PGE will post the 2013 IRP Report and accompanying technical appendices on its website, once filed with the OPUC.

1.3 Low-Carbon Portfolio Process

In 2010, as part of the 2009 IRP process and deliberations respecting the Boardman 2020 Plan, PGE made a commitment to a group of stakeholders to work cooperatively to develop and evaluate low-carbon portfolio alternatives for this IRP. To meet that commitment, PGE conducted a multi-meeting process with the stakeholder group and an energy and environment-focused consulting firm.

Stakeholders in this process included CUB, RNP, NWEC, OEC, and Angus Duncan (collectively, the Group). In selecting a consultant to assist in developing low carbon portfolios, the Group and PGE jointly developed a Scope of Work document and conducted a competitive bidding process in which both the Group and PGE identified potential qualified consulting firms that were invited to bid. Appendix F provides a copy of the competitive bidding Statement of Purpose for the joint work on low carbon portfolio options. We received four responses to the solicitation. All bids received were reviewed both by the Group and by PGE. The bid selection criteria focused on the background and ability of the consultant to provide the identified deliverables. The Group recommended the firm Energy and Environmental Economics, Inc. (E3), a California-based firm with Pacific Northwest region-specific experience and a good match of backgrounds and similar work products for other utilities. PGE supported this choice.

An initial meeting of E3, the Group and PGE was held in Portland. Subsequent meetings were held by phone conference. All parties had equal access to E3. E3 initially sent several detailed requests to PGE regarding our portfolio, resource types and CO_2 intensity, and plant planned retirement dates, in order to calculate the ongoing baseline CO_2 footprint for PGE.

[1] In several areas, information and assumptions presented in the workshops, which began in April 2013, were subsequently revised. The material contained in this document takes precedence over all previously published material.

While the Commission requires IRPs to focus on planning for the next 20 years, with Action Plan items for the next two to four years, the purpose of this exercise was to look specifically at longer-term carbon reduction goals (to 2050) and to examine potential portfolio actions that would put PGE's portfolio on a CO_2 reduction glide-path toward those goals. Since our IRP modeling extends to 2033 (20-year planning horizon), we established a 2033 interim modeling target. This interim modeling target was established by linearly interpolating between a 2020 target of 2005 actual PGE CO_2 emissions less 15% and a 2050 target at 2005 emissions less 80%.

E3 developed a supply curve of potential actions to reduce portfolio carbon emissions. In addition to actions already being undertaken by PGE (e.g., aggressive acquisition of EE, RPS implementation with new renewable resources, and cessation of coal operations at Boardman), the options they identified fell into three categories:

- Identification of emerging EE opportunities for inclusion in resource planning. Because it is difficult to identify future potential EE technologies, the ETO EE forecast declines materially after 2017. While it is plausible that additional EE will be available post-2017 beyond the levels that we have included in our planning, it is difficult to project both quantity and cost, since the future technologies/measures are not yet identified. PGE, and the ETO, have discussed jointly pursuing a study for the next IRP to explore the emerging EE sector, subject to Commission approval, as part of the Action Plan for this IRP.
- Use of renewable resources beyond RPS requirements. In this region, planning for renewables has focused on wind, primarily because it has been the predominant economically competitive renewable resource. However, the economics of PV solar are improving. Therefore, PGE proposed an Action Plan item to examine the further potential for distributed generation/solar.
- Elimination of Colstrip as part of the PGE portfolio by 2030. However, we note that, PGE as a 20% owner has limited discretion and influence regarding the continued operation of this mine-mouth coal plant.

As a result of the E3 work, we have included additional low-carbon candidate portfolios that incorporate higher levels of EE (beyond ETO targets) and add renewable resources (modeled as wind) in excess of the 2025 RPS requirement.

E3 presented their findings in the first PGE public meeting for this IRP. Appendix F provides a copy of E3's final report, which also served as the basis for their presentation at the public meeting (the report is in a PowerPoint format). Appendix F also provides a set of joint "Priority Recommendations" from the Group and serves, in part, as inspiration for some of the low-carbon candidate portfolios evaluated in this IRP, as well as some of the proposed Action Plan study and research items to help inform subsequent resource plans.

1.4 Other Studies to Inform IRP

In addition to the low-carbon portfolio alternatives process, PGE undertook or refreshed the following studies:

- In accordance with Order No. 12-013, we developed a study of PGE's dynamic capacity needs through the next two RPS compliance periods (2015 and 2020). This study was vetted in a technical workshop and is included as Chapter 5 - Flexible Capacity Needs in this document.
- We engaged Black and Veatch (B&V) to help assess current commercial generating and storage technologies, including their associated performance characteristics, engineering lives, brownfield construction costs, and operating costs. The estimates serve as the basis for our generic resource assessment in Chapter 8 - Supply-side Options. The B&V reports are included as Appendix G.
- We updated the 2011 wind integration study to include new resource additions from the recent RFP processes. The revised study targets a 2018 baseline year, among several other updates and modeling enhancements. The results are incorporated in the resource cost for prospective wind resources. This study again employed a Technical Review Committee, was vetted in a technical workshop, and is discussed in Chapter 8 - Supply-side Options and presented in Appendix D in this document.
- We contracted with market research firm, Definitive Insights to update a customer resource preferences study (previously conducted in 2008). The results were shared in a public meeting to provide context regarding the perspectives of residential, commercial, and industrial customers with respect to energy supply resource options. The updated study indicates that customer attitudes have not changed significantly since 2008. Generally customers rank EE and renewables as preferred choices, but not to the exclusion of maintaining a diversified, low-cost energy supply. The study results are presented in Appendix H.
- We engaged a consultant with statistical expertise to provide stochastic PGE load and wind data sets for use in our reliability studies. Portfolio reliability results are presented in Chapter 10 - Modeling Results.
- In accordance with Order No. 10-457, PGE "consider[ed] conservation voltage reduction (CVR) for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings" (see OPUC Order No. 10-457 at 22). Our CVR research and pilot initiative is discussed fully in Chapter 4 - Demand-side Options.

1.5 Participation in Regional Planning

PGE also participates in a number of regional forums that inform 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:

- Northwest Power and Conservation Council
  - Generating Resources Advisory Committee (GRAC)
  - Resource Adequacy Advisory Committee (RAAC)
  - SAAC (System Analysis Advisory Committee)
  - Conservation Resources Advisory Committee (CRAC)
- Transmission Expansion Planning Policy Subcommittee (TEPPC)
- Transmission Issues Policy Steering Committee
- BPA Collaborative
- WSPP (formerly the Western Systems Power Pool)
- Northern Tier Transmission Group (NTTG)
- Transmission Coordination Work Group (TCWG)
- Oregon Global Warming Commission
- Northwest Wind Integration Action Plan
- Western Electricity Coordinating Council (WECC) Variable Generation Subcommittee
- American Wind Energy Association (AWEA) Utility Work Group
- Utility Variable-Generation Integration Group (UVIG)
- Oregon Wave Energy Trust (OWET)
- Energy Trust Renewable Advisory Council
- Energy Trust Conservation Advisory Council
- Northwest Energy Efficiency Alliance Regional Portfolio Advisory Council
- Pacific Northwest Utilities Conference Committee (PNUCC),
- Western Energy Institute (WEI)
- Northwest Pipeline Shipper Advisory Board
- Small Modular Reactor Interest Group (hosted by Energy Northwest)
- Solar Electric Power Association (SEPA)
- Western Export Group (WEG)

2. PGE Resources

PGE's existing resources represent a diverse combination of hydroelectric, wind, solar, natural gas- and coal-fired generation, and long-term contracts for energy and capacity. We also buy and sell power in the wholesale market to balance our portfolio and reduce costs. PGE's power supply portfolio in 2014[2] includes annual average energy availability (by fuel type) of approximately:

- 11% non-hydro renewables (predominantly wind)
- 22% PGE-owned and mid-Columbia hydro generation
- 29% natural gas-fired generation
- 32% coal-fired generation, and,
- 6% long-term contracts.

Chapter Highlights

- PGE's current owned generating resources include five thermal plants (natural gas- and coal-fired), seven hydroelectric plants, and the Biglow Canyon wind facility with total combined generating availability of 1,564 MWa. In addition, we have 436 MWa of long-term contracts.
- PGE recently completed two RFPs for additional energy and capacity resources. New resources under construction include the Port Westward 2 flexible gas plant, the Carty base load gas plant, and the Tucannon River wind farm. The Energy and Capacity RFP also resulted in two seasonal peaking contracts.
- These new power plants and seasonal contracts will provide approximately 462 MWa of energy capability on an annual basis, along with 784 MW of peaking capacity to PGE's portfolio.
- Through the end of 2017, some existing contracts expire, totaling 143 MWa of energy and 370 MW of capacity.

[2] This breakdown is based on our owned and contracted resources alone; it does not incorporate market purchases or energy efficiency.

2.1 PGE Today

PGE serves approximately 835,000 customers in 52 cities. We are Oregon's largest utility. Our service territory attracts major employers in diverse industries, such as high technology and health care. Historically PGE has experienced annual load growth above the national average. However, with the U.S. and Oregon in a continued post-recession slow economic recovery, we have tempered our future growth projections. Further discussion on load projections is found in Chapter 3 - Resource Requirements.

PGE's 2014 power supply portfolio includes a diverse mix of owned hydro, wind, natural gas, coal, and solar resources currently capable of providing 1,564 average mega-watts (MWa) of energy on an annual basis and 2,419 megawatts (MW) of winter peaking capacity. We also rely on long-term power contracts for 436 MWa of energy and 832 MW of capacity. Dispatchable stand-by generation (DSG) and demand response resources (DR) provide 125 MW of customer enabled capacity. In total these resources provide 2,000 MWa of energy and 3,376 MW of capacity in 2014.[3] In addition, ongoing EE provides a material reduction to customer energy requirements.

2.2 Actions Taken Since the 2009 IRP

By 2016, PGE will complete the supply-side actions described in our 2009 IRP Action Plan (as acknowledged in Order No. 10-457). Port Westward 2 is targeted to be online the first quarter of 2015 and Carty is projected to be online mid-2016 to fill our flexible capacity and base load energy requirements. The Tucannon River wind project has an online target of the first-half of 2015, to maintain physical compliance with the 2015 Oregon Renewable Portfolio Standard (RPS). We have also entered into seasonal capacity contracts to meet seasonal peak load requirements. These additions will add 462 MWa and 784 MW of energy and capacity respectively to our power supply.

The following provides additional information regarding the new power plants:

- Port Westward 2 is an approximately 220 MW natural gas-fired reciprocating engine power plant that will provide both wind and load following capability (as well as energy, peak capacity, and other ancillary services). The plant configuration is modular with twelve, roughly 18 MW generators that can be dispatched separately or in combination. Construction began in May 2013 adjacent to the existent Port Westward and Beaver plants in Columbia County. It is expected to be online in the first quarter of 2015.
- Carty is a 440 MW (inclusive of duct-firing) base load combined cycle combustion turbine (CCCT) facility to be built adjacent to the Boardman plant. The plant will include a highly efficient Mitsubishi Heavy Industries (MHI) G-class combustion turbine. It is expected to be online in mid-2016 and will provide around 360 MWa of energy capability, enough to serve about 300,000 residential customers.

[3] For energy: 1,564 + 436 = 2,000. For capacity: 2,419 + 832 + 125 = 3,376.

- The Tucannon River project is a wind farm with 116 Siemens wind turbine generators (2.3 MW each) with a total nameplate capacity of 267 MW. The project is located near Dayton, Washington. The plant's 36.8% expected capacity factor results in a projected plant output of 98 MWa. The project will be complete in the first-half of 2015.
- We have entered into two contracts which provide 100 MW of seasonal capacity to meet on-peak load requirements. These contracts commence in 2014 and expire at the conclusion of the winter 2019 season. Additional seasonal amounts originally contemplated are no longer necessary due primarily to lower than forecast cost of service load and associated seasonal peak demand (Chapter 3 - Resource Requirements discusses changes to our load forecast since the 2009 IRP.)

Beyond these major new resources, PGE has also contracted to purchase the output of various smaller operating solar and Qualifying Facility (QF) projects since the 2009 IRP, as set forth in the existing resources sections below. These new contracts currently total approximately 38 MW in nameplate capacity.[4]

On the customer side, PGE has continued to be active in developing new distributed generation and DR resources. Since filing the 2009 IRP, PGE has acquired additional DSG. As of year-end 2013, PGE had approximately 93 MW of DSG usable capacity available, which is expected to grow to 116 MW by 2017.

PGE has sought additional DR capability through various programs, including Schedule 77 curtailment contracts, time-of-use pricing, and a residential direct load-control pilot. In particular, we have contracted with a third-party aggregator to acquire commercial customer automated demand response (ADR). The new ADR program was launched this year and implemented load reduction events with the first two participating customers that exceeded performance expectations. We target the addition of 45 MW of DR by 2017. We discuss DR programs in more detail in Chapter 4 - Demand-side Options.

Between 2014 and 2017, PGE will potentially lose approximately 143 MWa of energy resources, as existing contracts expire. We will seek to renew some of these resources, if economic and available. However, we cannot rely on uncertain renewals for planning purposes. Over the same period, we will also potentially lose approximately 370 MW of winter capacity due to contract expirations.

Figure 2-1 shows PGE's 2014 energy resource mix on an annual average availability basis. Figure 2-2 shows PGE's 2017 energy resource mix on an annual average availability basis after the new supply actions and resource expirations discussed above.

[4] These resources' combined contribution to meeting system peak demand is much less than 38 MW, as most of them are wind or solar.

Figure 2-1: PGE 2014 average annual energy resource mix (availability)

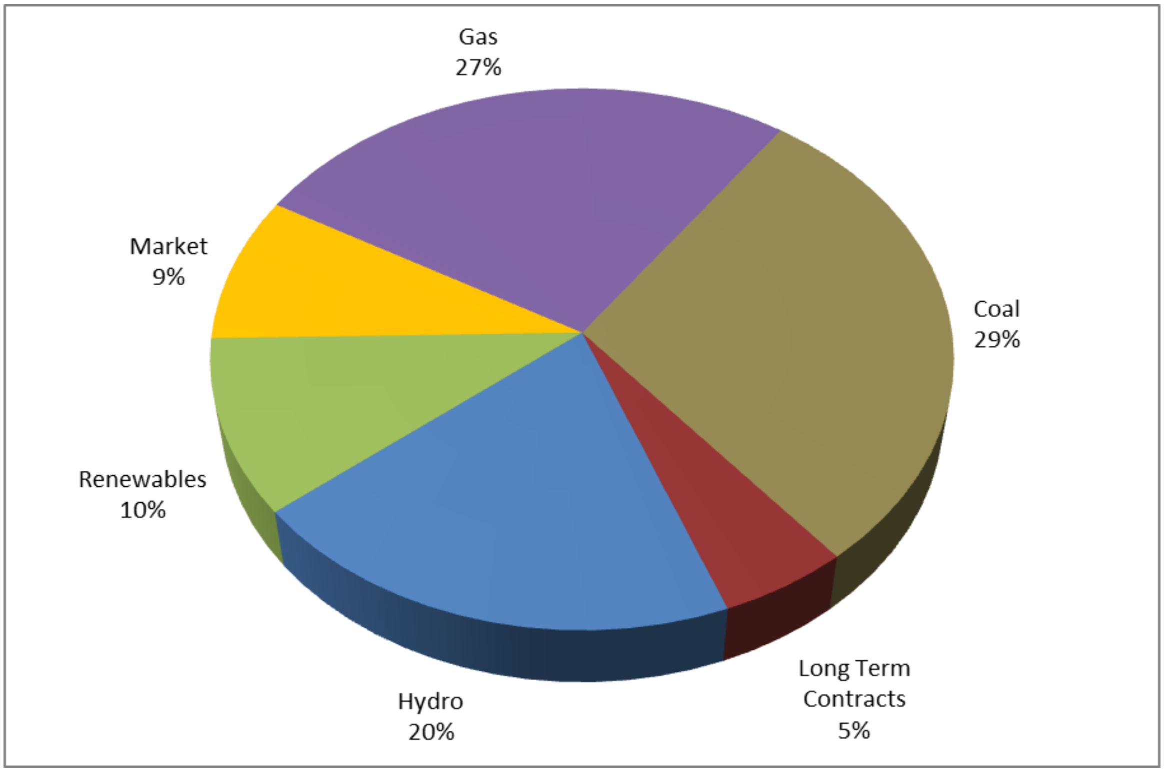
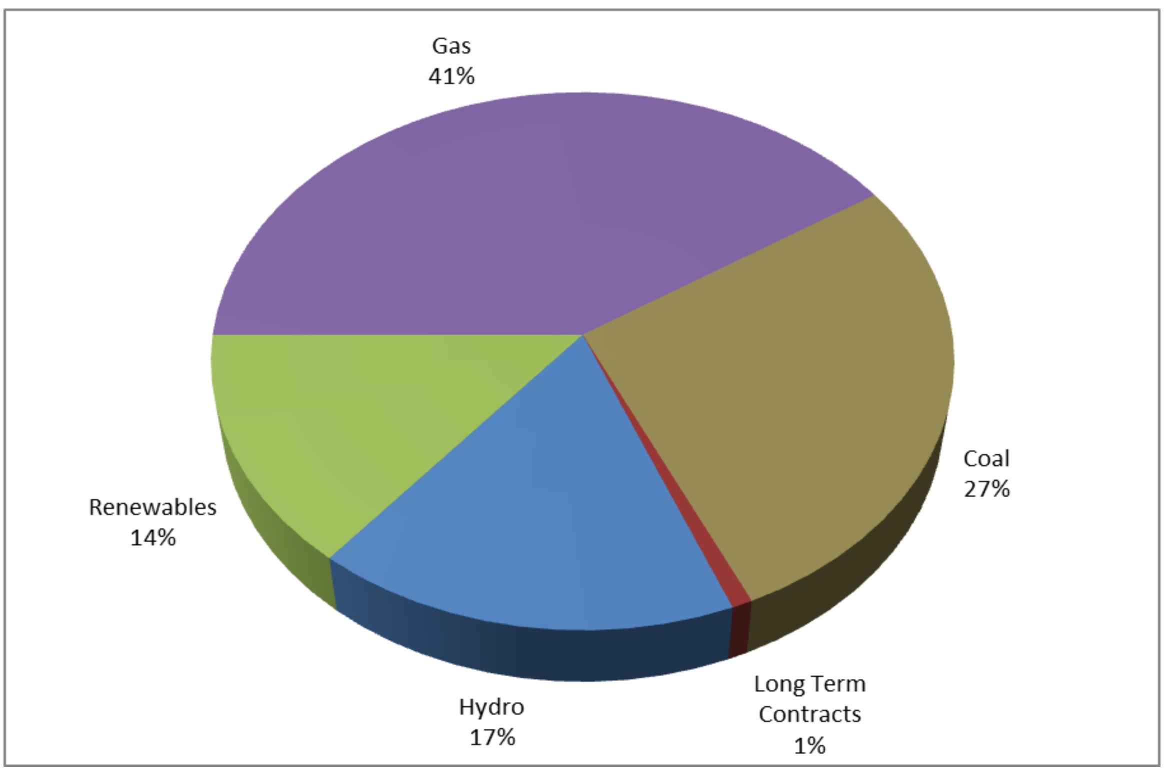


Figure 2-2: PGE 2017 average annual energy resource mix after resource additions and expirations (availability)



2.3 Thermal Plants

PGE currently has an ownership interest in five thermal resources – three natural gas-fired and two coal-fired plants – with combined January peak capability of 1,939 MW in 2014. Supply of fuel to thermal plants is discussed in Chapter 6 - Fuels.

Port Westward

Port Westward reached commercial operation in June 2007. The combined-cycle combustion turbine (CCCT) plant, located in Clatskanie, Oregon, is among the most efficient natural-gas-fired generators of its type in the Northwest. The plant supplies approximately 414 MW of capacity in January (based on expected ambient temperature), including almost 394 MW base load plus 20 MW of duct firing, with a heat rate of approximately 6,800 Btu/kWh (Higher Heating Value, or HHV). Average annual energy capability is approximately 349 MWa.

Beaver

Beaver is a CCCT facility located in Clatskanie, Oregon. The plant was placed into service in 1976. Beaver has a peak January capacity of 509 MW. The six combustion turbines (CTs) are dual fuel, operating on either natural gas or No. 2 diesel fuel oil via on-site tank storage. These CTs can be operated in simple cycle or in combined cycle by feeding heated gases from six vertical flow heat recovery steam generators to a single steam turbine. A separate simple cycle unit (Beaver 8), added to the site in 2001, has a January peaking capacity of 21 MW. As Beaver is usually used for peaking and firming purposes, its annual average economically-dispatched energy is assumed to be negligible for energy planning in this IRP.

While Beaver has a relatively high heat rate of 9,260 Btu/kWh in combined cycle, it has been increasingly dispatched due to low gas prices and high market prices during the summer, and to offset differences between forecast and actual wind energy production. It is an increasingly valuable resource for supply reliability, particularly during peak load conditions as we lose legacy hydro contracts. In addition, Beaver provides back-up capacity for firming variable energy resources (VERs) such as wind and solar. Going forward, Beaver will continue to be critical to the portfolio as we lose additional hydro and increase penetration of VERs in our portfolio. Thus, we are committed to a maintenance program that assures continued reliable and safe operations of this plant.

Coyote Springs I

Coyote Springs I (Coyote) is a gas-fired CCCT facility located in Boardman, Oregon. It has been in service since 1995. Originally, Coyote had a January capacity of 245 MW and forecasted average annual energy availability of 209 MWa, including 2 MW of duct-firing capacity. In 2011, PGE upgraded the plant to improve its heat rate and capacity. Coyote now provides January capacity of 260 MW and an average annual energy of

232 MWa. This plant also provides an efficient combined cycle heat rate of approximately 7,100 Btu/kWh.

Boardman

Boardman is a 575 MW pulverized coal plant located in Boardman, Oregon. It went into service in 1980. Coal for Boardman is transported by rail from Powder River Basin coal mines. PGE is the operator of the plant, and has an 80% ownership interest, equal to 460 MW share of the plant. Forecasted average annual energy availability for PGE's share of the plant is 383 MWa. In the November 2010, the OPUC acknowledged PGE's 2009 IRP Action Plan, which called for the cessation of coal-fired operations at Boardman by year-end 2020.

Updates to Boardman Co-ownership

Idaho Power Company and Power Resources Cooperative (PRC) each own 10% of the Boardman plant. In 1985, PGE conveyed 15% of its share of the Boardman plant to Bank of America Leasing (BAL) as part of a leveraged lease arrangement. The lease and associated agreements relating to the transaction expired on December 31, 2013, at which time BAL transferred the assets back to PGE pursuant to the terms of the 1985 agreements. Under the transfer, PGE assumed all of the rights and obligations associated with the 15% ownership interest, resulting in our 80% ownership interest noted above. We have incorporated the additional 15% Boardman output from the BAL ownership transfer in our updated load-resource balance. The related transmission is discussed in Chapter 11 - Transmission, Section 11.1.

PRC is interested in selling its share of the Boardman plant to PGE. PGE is interested in acquiring the 10% share (approximately 57 MW), as long as the acquisition is beneficial for our customers. PGE and PRC are currently negotiating a project sale agreement and related agreements for the sale and purchase of the PRC interest. Under these agreements:

- PGE would acquire all of PRC's rights and obligations relating to the 10% ownership share of the plant. These include generation, operations and maintenance, and decommissioning liabilities.
- PRC would assign to PGE a long-term power purchase agreement under which PRC currently sells its share of the plant output to the Turlock Irrigation District (TID). The PPA expires December 31, 2018.
- The parties would financially settle an existing power purchase agreement between PRC and PGE for delivery during the period 2019-2020 pursuant to which PRC is obligated to sell and deliver to PGE's system, and PGE is obligated to purchase the output from PRC's 10% share of the plant.

We expect to execute definitive agreements with PRC in March 2014 and to close December 31, 2014, subject to certain conditions-precedent, including approval by the Oregon Public Utility Commission. This transaction does not affect our projected load-resource balance, given the existing power purchase agreements that PRC has with TID (through 2018) and PGE (2019-2020) for its share of the Boardman plant output. For this reason, we do not believe this transaction is appropriate to include in the IRP Action Plan. The PRC agreement is included for approval in PGE's current general rate case for the 2015 test year.

Colstrip

Colstrip Units 3 and 4 are coal-fired units located in Colstrip, Montana. The plants went into service in 1984 and 1986, respectively. The Colstrip plant is operated and managed by PPL Montana. PGE owns 20% of Units 3 and 4, representing 296 MW of capacity as of July 2013. Colstrip is a mine-mouth facility, with coal transported by conveyor belt directly from the on-site mine to the plant. Forecasted annual average energy availability for PGE's share of Colstrip Units 3 and 4 is 256 MWa.

Activities to Increase Fossil Fuel Generation Performance

PGE has performed a number of upgrades to our thermal generation plants throughout their operating history. Table 2-1 below summarizes upgrades to our thermal resources completed since 2009.

PGE works closely with our Original Equipment Manufacturers (OEM) to evaluate the ongoing performance of our thermal generation plants. GE monitors the performance of our Coyote Springs CT plant, while Mitsubishi monitors the operations of our Port Westward CT plant. Through their evaluation of operational data, they can not only detect deterioration of plant efficiency, they are able to make recommendations to improve efficiency.

In 2011, GE retrofit our Coyote Springs combustion turbine to bring its performance and output up to the 7FA fleet standards. As Coyote's CT was one of the first manufactured in the 7FA fleet, there were modifications adopted in later fleet units that would benefit Coyote Springs' efficiency and output. Beyond improved efficiency, the modifications to our Coyote Springs plant also allow us to lower the unit's minimum operating output level (turn-down) during off-peak hours and increase load change ramp rates.

In addition, we are currently using a monitoring software application called GE-SmartSignal to monitor our Boardman coal plant, and Beaver and Port Westward gas plants operations. SmartSignal's main function is to detect degradation in equipment performance. This enables PGE to make necessary repairs or equipment replacements prior to failure. We are also working with the SmartSignal platform to develop operational output algorithms to improve plant performance.

Similarly, we are also evaluating alternatives to increase the operating flexibility of our fossil-fuel plants. Adding Automatic Generation Control (AGC) to some of our thermal plants would allow these plants to provide regulation and other ancillary services; however, incremental operations and maintenance (O&M) costs may arise from operating thermal plants more dynamically than in the past. While these modifications typically will not increase generation output or energy conversion efficiency, they may improve overall system performance and cost by helping to meet growing flexibility demands as we add increasing levels of variable energy resources.

Table 2-1: PGE plant efficiency upgrades since 2009

Year	Project Description	Plant Output (MW)	Plant Heat Rate (Btu/KWh)
2010	Beaver - Replace bypass stack dampers	2.50	
2010	Coyote Springs - Preheat ammonia injection line	0.35	
2011	Coyote - Upgrade CT	28.12	(258)
	Total Output Improvement	**30.97**	

2.4 Hydro

PGE owns and operates three hydroelectric projects consisting of seven plants:

- **Pelton-Round Butte Hydro Project**: Two-thirds shares in two plants located on the Deschutes River near Madras, Oregon. PGE's shares of Pelton and Round Butte are 73 MW and 225 MW respectively.[5] These plants provide combined expected energy production of 110 MWa. The Confederated Tribes of the Warm Springs Reservation (Tribes) own the remaining one-third shares of Pelton-Round Butte.[6]
- **Clackamas River Hydro Project**: Four plants located on the Clackamas River: Oak Grove (33 MW), North Fork (43 MW), Faraday (43 MW) and River Mill (23 MW). These plants provide expected energy production of 77 MWa.
- **Willamette Falls Hydro Project**: Sullivan (16 MW), located on the Willamette River at Willamette Falls. Expected Sullivan energy production is 14 MWa.

The Pelton-Round Butte project is the only PGE-owned hydro resource that provides reservoir storage flexibility. The other projects are limited in their ability to store water and shape energy, and are generally operated as run-of-the-river projects. At the usable capacity numbers listed above, these hydro resources account for approximately 14% of PGE's 2014 generation capacity. In addition to energy production, these resources (particularly Pelton-Round Butte) provide peaking and load-following capabilities. A portion of PGE's hydro capacity is also used to meet required spinning and supplemental (operating) reserve requirements, which are necessary for responding to system contingencies.

In March 2007, Pelton-Round Butte was certified by the Low Impact Hydropower Institute (LIHI), making it the second-largest hydro project in the U.S. to receive the designation. The LIHI distinction allows 50 MWa of the power generated at Pelton-Round Butte to qualify under the Oregon RPS.

[5] The figures in this section refer to *usable* capacity (i.e., the maximum generation maintainable for four hours).
[6] The Tribes also own the Pelton Regulating Dam (Re-reg Dam) associated with Pelton-Round Butte, which has usable capacity of 10 MW and expected energy of 10 MWa.

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-Round Butte Hydro Project on June 21, 2005, and a new 30-year license for Willamette Falls, which covers our Sullivan plant, on December 8, 2005. A new license for the Clackamas River Hydro Projects (the Oak Grove, North Fork, Faraday, and River Mill plants) was issued on December 21, 2010. The new license is for a 45-year term. Relicensing is cost-effective, as the costs of relicensing are substantially lower than procurement of other resource alternatives.

2.5 Non-hydro Renewable Resources

Biglow Canyon

Completed in three phases in 2007, 2009, and 2010, the Biglow Canyon Wind plant located in the lower Columbia River Gorge near Wasco, Oregon has a total generating capacity of 450 MW. Based on an expected capacity factor of approximately 31.8%, annual average energy production is estimated at 143 MWa. The project is interconnected to a 230 kV transmission line and substation that terminates at BPA's John Day 500 kV substation. Under the agreement between PGE and BPA for the interconnection of Biglow I-III, BPA absorbs intra-hour fluctuations in accordance with applicable tariff terms and conditions, and PGE receives the hourly scheduled energy from BPA.

Klondike II

Effective December 1, 2005, PGE began taking delivery of the entire output of the 75 MW Klondike II Wind Farm located in Sherman County, Oregon under a power purchase agreement (PPA) with PPM Energy, Inc. (now Iberdrola Renewables). The expected output from this facility is 26 MWa on an annual basis. In accordance with the terms of the PPA, Iberdrola provides energy firming and shaping services for the output of Klondike II. This contract runs through November of 2035.

Vansycle Ridge

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

ProLogis and ODOT Solar Projects

PGE developed three customer-sited photovoltaic (PV) solar projects in our service territory between 2008 and 2010. The 88 kW AC Oregon Department of Transportation (ODOT) demonstration project is owned by PGE. PGE is the managing member of

LLCs that own projects on ten ProLogis rooftops, totaling approximately 3 MW AC, the outputs of which are sold to PGE under Qualifying Facility contracts. PGE receives Renewable Energy Credits (RECs) from the ODOT and ProLogis projects.

Bellevue and Yamhill Solar

In 2010, PGE signed contracts with enXco to purchase the power from the Bellevue and Yamhill Solar Facilities. The former is a 1.4 MW AC ground-mounted fixed-tilt solar PV plant near Amity, Oregon. The latter is a 1 MW AC ground-mounted fixed-tilt solar PV plant in Yamhill County, Oregon. The contracts terms are 25 years and their output is Oregon RPS-qualified.

Baldock Solar

In 2012, PGE completed a sale-leaseback transaction with Bank of America Leasing and Capital (BALC) for the Baldock solar project. PGE leases the solar project from BALC, receiving the energy output and a portion of the RECs. The Baldock project is an approximately 1.5 MW AC ground-mounted fixed-tilt solar PV plant near Aurora, Oregon.

Outback Solar

PGE signed a contract with Outback Solar, LLC in 2012 to purchase the output of a 5 MW AC ground-mounted tracking solar PV plant located in Lake County, Oregon. The contract term is 25 years and the output is Oregon RPS-qualified.

Customer-owned Distributed Generation

PGE's support to customers who self-supply a portion of their electrical needs (predominantly through PV solar arrays) is discussed in Chapter 8 - Supply-side Options, Section 8.4.

2.6 Other Contracts

Hydro System Contracts

PGE has contracts for specified project shares of the hydro facilities on the Mid-Columbia identified below. We receive percentage shares of the output in exchange for paying a proportional amount of the plants' costs.[7]

- **Wells**: PGE has a contract with Douglas County PUD at the Wells hydroelectric project on the middle section of the Columbia River (Mid-C) for 147 MW of capacity and 85 MWa of energy under normal water conditions.

[7] The term "capacity" as used in this section means usable peaking capacity and energy is measured under average water conditions.

This contract expires at the end of August 2018. For IRP purposes, we currently assume no further energy or capacity from Wells post-2018.

- **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 Wanapum hydro projects, also on the Mid-C. PGE's share of these projects (as of 2013) provides approximately 143 MW of capacity and 87 MWa of energy under normal water conditions. This agreement runs through spring of 2052.
- **NextEra**: In 2011, PGE entered into a four year purchase of dynamic capacity capability from NextEra Energy Power Marketing LLC beginning January 1, 2012. PGE receives 3% of both the Rocky Reach and Rock Island plants for a total of 58 MW (30 MWa) under normal water conditions. This contract expires in 2015.

Pelton-Round Butte Agreement

In 2000, PGE reached an agreement with the Tribes in which they became a one-third owner of the Pelton-Round Butte project (Pelton-Round Butte or PRB). The Tribes' share of the output is 149 MW of capacity and 55 MWa of annual energy at normal water conditions. The Tribes also own 100% of the generation from the associated Re-regulation Dam (Re-reg Dam), which has 10 MW of capacity and 10 MWa of annual energy.[8] Under the Ownership and Operation Agreement (OOA), reached in 2002, each year PGE purchases the full output of the Tribes' share of PRB (currently 33.33%) and all of the net output of Re-reg Dam. Under the OOA, the Tribes have the right to sell their one-third share of the output of PRB and the net output of Re-reg Dam to a third party, provided that the Tribes give notice to PGE by April 1 of the prior year. Once the Tribes provide notice to exercise their right to sell, the Tribes no longer have an obligation to sell their share to PGE and PGE no longer has an obligation to purchase. Warm Springs Power and Water Enterprises (WSPWE), the entity that manages the Tribes' shares and interest in PRB and the Re-reg Dam, informed PGE of their intention to explore their rights to sell their share of the output beginning in 2015 via an auction process. PGE and WSPWE further agreed, while WSPWE evaluated the auction option, to begin discussing the potential for a long-term agreement under which PGE could continue to receive the output the Tribes currently sell to PGE under the OOA.

PGE and WSPWE recently agreed in principle to a contract structure under which PGE will continue to receive the output from the Tribes' share of the PRB project and all output from the Re-reg Dam for a 10-year period beginning in 2015. During this time period, the Tribes will forego their rights to sell their share of the PRB and Re-reg Dam output to a third party. Given the likelihood of completing this transaction with the Tribes, we have included the 10-year PRB/Re-reg Dam contract in our updated load-resource balance.

[8] The Re-reg Dam's capacity value is substantially less than its nameplate rating, given its function to smooth out flows from the overall "Pelton-Round Butte + Re-reg Dam" complex.

In 2022, the Tribes gain another one-sixth share of the plant, reducing PGE's ownership interest to slightly more than 50%.

Portland Hydro

PGE has a contract with the City of Portland to purchase the output of the Portland Hydro Project, located on the Bull Run River. The contract runs through August 2017 and provides 10 MWa of energy and 36 MW of capacity.

Canadian Entitlement Allocation

This agreement relates to the Columbia River hydro projects. Columbia River storage reservoirs located in Canada are operated to increase the overall value of the Columbia River hydro system. However, these benefits are shared with Canada. The original agreement ended in 2003, but an extension agreement is effective until 2024. This agreement currently costs approximately $3 million per year.

Wells Settlement Agreement

Under this agreement with Douglas County PUD, which runs through August, 2018, we purchase approximately 18 MWa of non-firm energy in 2014, falling to 13 MWa by 2018.

Capacity Exchange Contracts

PGE has two long-term hydro-based 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 contract extends through 2016.
- **Eugene Water and Electric Board**: 10 MW contract expires mid-2014.

TransAlta

We executed a 10-year, 100 MW (93 MWa) fixed price PPA with TransAlta as an action item pursuant to our 2002 IRP Final Action Plan. The agreement extends through September 2016.

Iberdrola

PGE has both winter (Dec-Feb) and summer (Jul-Sept) Seasonal Capacity Contracts with Iberdrola Renewables. These contracts are for 100 MW each and go into effect in July of 2014 and run through February of 2019.

PaTu Wind

PGE entered into the PaTu Wind Farm power purchase agreement in 2010 for a term of 20 years. The contract is for the purchase of wind power from PaTu Wind Farm, LLC, located in Sherman County, Oregon. PaTu has a nameplate capacity of approximately 9 MW and is a Qualifying Facility (QF) under the Public Utility Regulatory Policy Act of 1978 (PURPA) agreement.

Coffin Butte

PGE signed a contract with Power Resources Cooperative (PRC) to purchase QF power from PRC's existing Coffin Butte landfill gas plant beginning October 2012 for a term of 15 years. The Coffin Butte plant has a nameplate capacity of approximately 5.7 MW. The agreement is a PURPA contract.

Green Lane Energy

PGE signed a contract with Green Lane Energy, Inc. in 2012 to purchase QF power from a plant located in Lane County, Oregon. The plant produces renewable energy by a digestive and fermenting process that extracts biogas from regionally sourced grass straw and food/beverage residues. The term of this PURPA contract is 20 years and the nameplate capacity is 1.6 MW.

Covanta Marion

PGE purchases the output of the Covanta Marion municipal solid waste burning facility located in Brooks, Oregon, under a PURPA contract. This contract began in 1984 and will expire at the end of June 2014. This agreement provides 16 MW of capacity and approximately 10 MWa of energy.

Other QF Contracts

In addition to the four QFs discussed above, PGE receives output from approximately 20 other QF projects for approximately 12 MW of nameplate capacity and 6 MWa of energy. Technologies include wind, solar, hydro, and biogas.

PGE has contracts for the output from an additional 28 MW and 9 MWa in new QF projects between late 2014 and late 2016. These include Fremont Solar (8 MW, expected online late 2014), Bear Creek Butte (10 MW, wind, expected online late 2015), and West Butte (10 MW, wind, expected online late 2016). Fremont Solar will be located in Christmas Valley in Lake County. Bear Creek Butte and West Butte will be located in Crook County.

In addition to the Covanta Marion contract ending in 2014, a 5 MW QF contract (5 MWa expected energy) will expire in late 2015.

Expiring Contracts

PGE has a number of contracts that expire, or are being modified. These reductions total about 293 MWa of energy and 776 MW in capacity by year-end 2024. Expiring resources are listed along with their annualized energy and capacity in Table 2-2.

Table 2-2: Expiring resources with annualized energy and capacity

Contract	Expiration	Energy (MWa)	Capacity (MW)
Covanta Marion (Ogden Martin)	2014	10	16
EWEB capacity	2014	NA	10
NextEra	2015	30	58
TransAlta	2016	93	100
WWP Capacity	2016	NA	150
Portland Hydro Project	2017	10	36
Douglas County (Wells)	2018	85	147
Bi-Seasonal Capacity	2019	NA	100
Warm Springs Tribes' Share of Pelton-Round Butte	2024	65	159
Total		**293**	**776**

During the action plan time period (2015-2017), PGE will seek to renew some of its expiring legacy hydro contracts. Because these are renewals of existing contracts, PGE does not believe that an RFP is required under the Commission’s Competitive Bidding Guidelines. However, if the Commission disagrees with PGE’s conclusion, PGE proposes an alternative acquisition method for these resources in this IRP pursuant to Guideline 2b of the Commission’s Competitive Bidding Guidelines (Order No. 06-446). Under Guideline 2b, a utility is not required to issue an RFP if an acknowledged IRP provides for an alternative acquisition method for a Major Resource.

As an alternative acquisition method, PGE proposes the renewal of legacy hydro contracts that are cost-effective for customers, without issuing an RFP. This method is warranted because of the unique nature of these resources. Hydro resources are carbon-free and offer operating flexibility that other types of generation can't supply as effectively. In addition, these types of resources are not being built anymore, rendering them scarce. Further, these projects are either largely or completely depreciated, reducing the forward-going costs to both the owners and potential off-takers. For these reasons, we do not believe an RFP would be fruitful and, in fact, we believe the time required to conduct an RFP would in all likelihood jeopardize our ability to renew these low cost, flexible, and carbon-free resources – a result that is not in the best interest of PGE, our customers, or the environment.

Table 2-3 summarizes the contracts and resources remaining in our portfolio in 2017.

Table 2-3: Contracts and resources remaining in PGE's portfolio in 2017

		In-Service Date	Energy Potential (MWa)	January Capacity (MW)
Type	**Plants**			
Coal	Boardman	1980	383	460
Coal	Colstrip	1985	256	296
Gas	Beaver	1976	N/A	509
Gas	Beaver 8	2001	N/A	21
Gas	Port Westward	2007	349	394
Gas	Port Westward 2	2015	N/A	230
Gas	Coyote Springs	1995	232	260
Gas	Carty	2016	364	441
Wind	Biglow Canyon I	2008	40	6
Wind	Biglow Canyon II	2010	55	8
Wind	Biglow Canyon III	2011	49	8
Wind	Tucannon River	2015	98	13
Hydro	Oak Grove	1924	23	33
Hydro	North Fork	1958	23	43
Hydro	Faraday	1907	19	43
Hydro	River Mill	1911	12	23
Hydro	Sullivan	1895	14	16
Hydro	Round Butte	1964	77	225
Hydro	Pelton	1957	34	73
		Total PGE-Owned	**2,026**	**3,104**

		In-Service Date	Energy Potential (MWa)	January Capacity (MW)
Type	**Contracts**			
Hydro	Wells		101	147
Hydro	Grant PUD		87	143
Hydro	Tribes' Share of Pelton/R. Butte		65	159
Hydro	Portland Hydro Project		7	36
Hydro	Canadian Entitlement Extension		-10	-20
Wind	PPM Klondike II		26	19
Wind	Vansycle Ridge		8	1
QF	Small QF Contracts		16	9
Renewable	Small Renewable Contracts		5	1
Capacity	Dispatchable Standby Generation		0	116
Capacity	Demand Response		0	45
Capacity	Bi-Seasonal Capacity		0	100
		Total Contracts	**306**	**756**
		Total Resources	**2,332**	**3,860**

3. Resource Requirements

PGE's planned and existing resources are sufficient to meet our customers' expected future energy and capacity requirements over the action plan horizon.

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

In addition to evaluating our future load-resource balance and resulting resource requirements, this chapter also provides an assessment of regional resource adequacy and its impact on PGE.

Chapter Highlights

- Our reference case load forecast shows long-term energy demand growth rates of 1.3% annually in the long-term, with peak demand growing 1.0% in winter, 1.3% in summer.
- We do not plan long-term resources for five-year opt-out customers.
- We propose to maintain a minimum peak reserve margin of 12%, which includes a 6% contingency reserve margin and the required approximately 6% operating reserve margin.

3.1 Demand

In this chapter, PGE's resource need analysis uses a December 2013 long-term system load forecast.[9] For IRP purposes, we identify annual energy needs under our reference case (i.e., most likely case) load growth, and high-load and low-load sensitivity forecasts based on standard deviations from the reference case.

Five years after the "Great Recession" of 2008–2009, its effect continues to be manifest in a slower than anticipated economic recovery and associated energy demand growth. The pace at which the economy is returning to historically normal employment rates, business growth and economic activity has been slower than expected and well below prior economic recoveries. PGE's low load growth is also driven in part by curtailments or closures among paper and solar manufacturing customers.

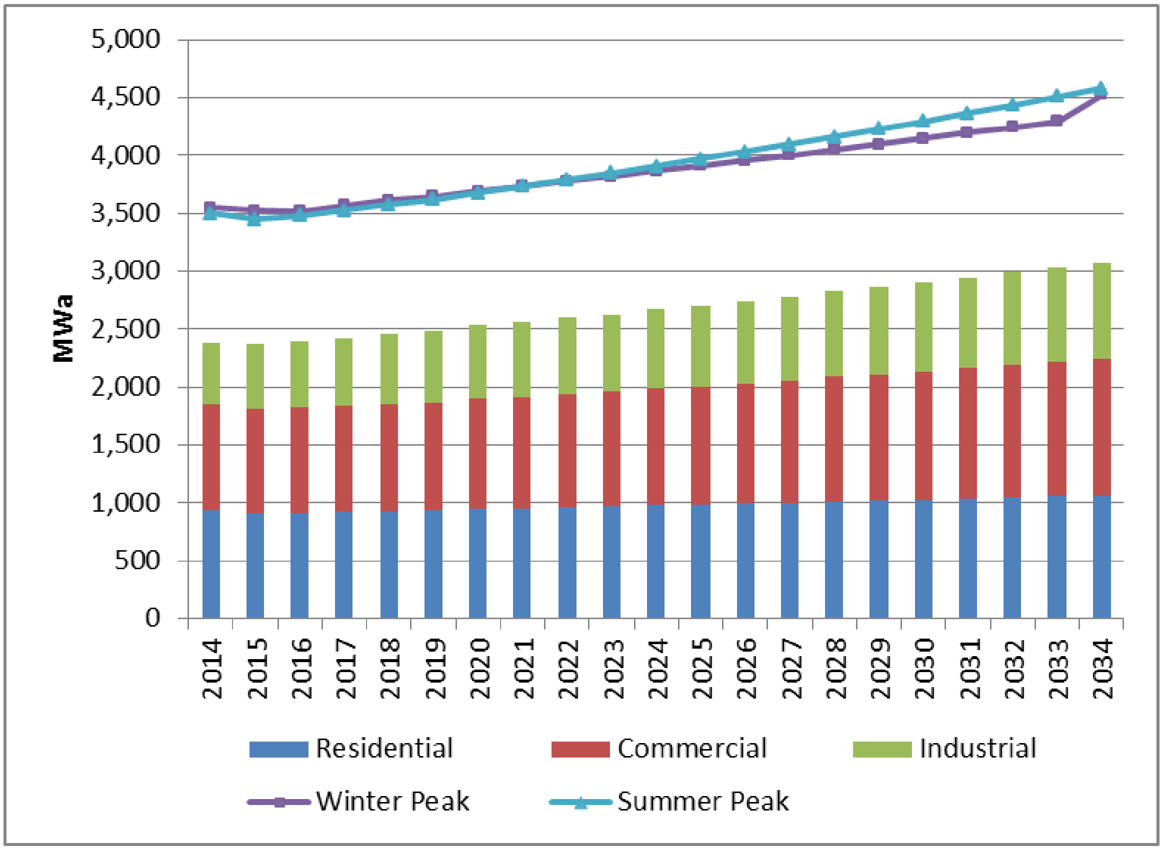
Nevertheless, the long-term outlook for future economic, population and load growth in Oregon and PGE's service territory is positive. Oregon employment and population growth is expected to outpace the national average; while PGE's urban service territory exceeds the Oregon state average. In the short-term (2014 to 2018), PGE's load growth reflects the expected improved pace of economic growth in Oregon, as forecast by the Oregon State Office of Economic Analysis. It also reflects expansions currently underway among certain high tech customers, as well as various changes expected from other large customers.

PGE's annual energy forecast is developed assuming normal weather conditions, based on 15-year average weather conditions.[10] Figure 3-1 displays annual load and peak winter and summer demand under our reference case forecast from 2014 through 2033. Energy load growth averages 1.3% per year over the 2014-2033 period. Due to the 2008-2009 global recession,[11] along with ongoing robust energy efficiency savings, we do not expect aggregate demand to return to pre-recession levels until 2016.

Similarly, our peak demand growth rate forecast for this IRP is lower than forecast in the 2009 IRP. However,, summer peak demand for 2014 through 2033 grows at a somewhat faster rate than winter peak demand (1.3% vs. 1.0%), gradually moving us closer to becoming a dual peaking utility, under normal weather conditions, by the first half of next decade. Annual peak demand is represented 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.

[9] PGE based its reference case load forecast on the Oregon Office of Economic Analysis September 2013 Economic Forecast and Global Insight's August 2013 U.S. Economic Forecast and actual energy deliveries through July 2013.
[10] Average weather conditions between 1998 and 2012 are used for the current energy forecast.
[11] It is important to recognize that load forecasts are influenced, especially in the near-term years, by the position of the base year (2013 in the case of this IRP) with respect to the current economic cycle and industry conditions among large customers. For example, we expect higher than average growth rates in years immediately following a recession. We also expect higher than average growth rates in years in which large customers open plants.

Figure 3-1: Reference case demand forecast by class: 2014 to 2034



While PGE has historically been winter peaking, summer demand has been growing faster than winter demand as a result of increasing cooling systems penetration and decreasing residential electric space and water heat penetration. However, the summer energy growth trend is now also being tempered by an approaching saturation of residential air conditioning.

Despite the approaching dual seasonal peaking, PGE expects winter energy consumption to continue to exceed summer energy deliveries because winter heating and lighting needs are more sustained than summer periods of cooling, resulting in materially more heating days than cooling days. Currently, the difference between average January load and average August load is about 330 MWa. The corresponding difference in January peak demand vs. August peak demand is around 50 MW under normal weather conditions. However, deviations in temperature can cause the system peak to occur in the summer. PGE experienced an annual system peak in the summer for the first time in 2002 and has since experienced four additional summer peak years.

Energy Demand Forecast Methodology

PGE's load forecast is a 20-year forecast of customers and expected energy deliveries. The core retail energy delivery (load) model and the forecast process are regression-based equations which predict energy deliveries for 25 customer groups. These load forecast models estimate energy deliveries to their respective customer groups as a function of historic weather, forecasted employment (which drives customer growth), and group-specific economic drivers. PGE re-estimates the load regression equations at least once per year to incorporate recent delivery and economic data into the forecast.

For this forecast we used data from 1985 through July 2013 for the residential equations and data from 1990 through July 2013 for the commercial and industrial equations. A limitation of the NAICS- (North America Industry Classification System) based Oregon employment data dictated the latter choice since this data was not available prior to 1990.

PGE relies primarily on three sources of economic information for our forecast drivers:

1. U.S. economic forecasts are obtained from IHS Global Insight.

2. Oregon State economic and unemployment forecasts are obtained from the Oregon Office of Economic Analysis (OEA). The Oregon OEA develops the Oregon Economic and Revenue Forecast, which includes the state unemployment forecast, on a quarterly basis.

3. California employment forecasts are provided by the California Employment Development Department (EDD). California employment forecasts are included in PGE's customer forecast models to proxy the "push-and-pull" economic forces driving Oregon's net in-migration. As Oregon becomes more attractive, primarily from an employment perspective, in-migration to the state increases, with a large share of in-migration originating in California.

Each forecast update uses the most recent forecasts available from these three sources in tandem with the coefficients from the load regression models to develop the retail energy forecast. In addition, customers who are large energy users provide us with specific operation information, direct inputs, and, if available, forecasted energy use. PGE uses this customer information along with company and industry data from third-party sources to augment the regression model forecast. A significant proportion of our load fluctuations can be attributed to revised expectations for a few major customers.

Historically, there were brief periods (anywhere from one to five years) during which demand for electricity in PGE-served areas declined due to boundary changes, business cycles, or departures of large customers from the system. However, overall demand has always rebounded and grown over time based on macroeconomic and fundamental drivers. We expect this trend to continue in the future.

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

- **Residential Sector**: 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 40% between 1985 and 2013. Higher air conditioning penetration combined with declining heating penetration will alter diurnal and seasonal load shapes. While residential energy growth has been higher in recent years due to increasing use of air conditioners, the load forecast reflects the assumption of residential summer load growth returning to the annual average by 2019 due to the saturation of air conditioning in the residential sector. Residential energy deliveries are forecasted to grow at an annual average rate of 0.7% over the 20-year horizon, before new incremental energy efficiency. By 2020, residential share of deliveries will decline to 37% due largely to faster relative growth rates in the commercial and industrial sectors.

- **Commercial Sector**: Faster growth in the commercial sector, which is dominated by cooling load, will continue in the forecast period. This sector's share of load grew from 34% to 39% between 1985 and 2013 and is projected to remain close to 40% of all deliveries through 2020. Commercial sector energy is forecasted to grow at an annual average rate of 1.7% before new incremental energy efficiency.
- **Industrial Sector**: Industrial sector energy demand is characterized by load volatility and uncertainty, which will increase as industrial customers react more quickly to changing market conditions and business cycles. Our 20 largest industrial customers account for nearly three-quarters of industrial load. Current forecasts show a continued trend toward greater concentration of industrial loads to a few large industrial customers and their suppliers. Their business decisions can cause overall load to deviate significantly from forecast. Industrial energy deliveries are forecasted to grow at an annual average rate of 2.6% over the 20-year horizon, prior to incremental energy efficiency. Due to this relatively faster growth rate compared to other sectors the forecast projects industrial share of deliveries to grow from 20% in 2013 up to 23% by 2020 and 25% by 2034.
- **Street Lighting**: The street light energy forecast assumes no growth in long-term energy deliveries, which reflects an ongoing conversion to LED-based lamps, which offsets any growth due to new street lamps.

In addition to the use of third-party forecast drivers, PGE also compares our long-term load forecasts to those of similar peer-utilities and other independent sources. Long-run demand growth forecasts ranged from 1.4% to 2.0% for peer utilities in the Pacific Northwest, with the lower end of the range representing either utilities that serve constrained urban cores or utilities that are largely rural. PGE's service territory comprises a metro area with additional area for growth and should fall within the middle to higher-end of this range. Global Insight and the EIA forecasts of future U.S. electricity demand range from 0.8% to 1.5%. Peer utilities tend to publish gross demand forecasts, while the U.S. forecasts, specifically the EIA's forecast, are net of energy efficiency.

Key Assumptions and Drivers

The following are the key assumptions and trends supporting our forecast:

- **Weather**: (temperature) is the largest factor affecting customer electricity demand in the residential and commercial sectors. Industrial loads tend to be less weather sensitive. PGE uses a rolling 15-year average weather assumption to produce the forecast and for the weather-normalization of actual deliveries.[12]

- **Economic Outlook**: PGE loads are highly correlated to Portland-metro region and Oregon state forecasts of net in-migration and economic activity. The economy, demographic trends such as in-migration and life expectancy, and a business environment that favors future growth, all indicate expected future load growth in PGE's service territory.
    - Real GDP Growth: The current IHS Global Insight economic forecasts project real GDP increasing at 3% through 2020 before reverting to a longer-term average of 2.6%.[13]
    - Oregon non-farm payroll (employment) growth is a fundamental economic driver. The OEA forecast projects a 1.4% average annual growth rate over the next ten years, with growth over 2% in the very near-term, slowing to 1% to reflect slower statewide population growth.
- **Population Forecast**: Oregon's position as a magnet state and the general trend of Western states growing faster than the U.S. national average is expected to continue. The OEA currently forecasts population growth of 1.4% in PGE's seven-county region and 1.2% state-wide.
- **Industrial Customer Trends**: Large industrial customer expansions and new manufacturing facilities are based on the best known information and expectations for the customers and their industries.
    - A key driver of future industrial loads is growth in the high-technology sector, particularly led by semiconductor manufacturing. This trend is magnified by the phenomenon of "agglomeration economies"—the tendency for industry sectors to attract similar firms and labor talent.
    - The 2013 forecast reflects current construction on customer expansions and planned future projects, particularly among high tech customers.
    - IHS Global Insight forecasts that Oregon will outpace the national average with respect to manufacturing employment and industrial-sector based growth in the coming decade.

Load Growth Scenarios

The Commission's IRP Guideline 4b as set forth in Order No. 07-002 requires an analysis of high- and low-load growth scenarios in addition to stochastic load risk analysis, with an explanation of major assumptions. We address stochastic load risk analysis in Chapter 9 - Modeling Methodology.

In addition to a reference case forecast, PGE projects high and low long-term growth cases as summarized in Table 3-1. Monthly energy demand by sector is individually forecasted to grow at the mean (average) rate, with the high and low growth cases constructed using plus one standard error for the high case and minus one standard error

[12] The 2013 IRP load forecast is based on the 15-year average weather observed from 1998 through 2012.
[13] IHS Global Insight Long-Term Forecast 30-Year June 2013.

for the low case.[14] 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 industries).

Rather, these high and low cases essentially serve 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 or other long-term trends or technologies that may affect future load growth. However, brief excursions outside the boundaries could still occur in the short-run due to large shocks to the economy.

Table 3-1: PGE demand forecast by case (2015)

Demand Forecast Case	Energy		Winter Capacity		Summer Capacity	
	MWa	Growth Rate	MW	Growth Rate	MW	Growth Rate
Base	2,367	1.3%	3,523	1.0%	3,450	1.3%
High	2,386	1.9%	3,550	1.7%	3,475	1.9%
Low	2,347	0.5%	3,496	0.3%	3,425	0.7%
High (+2)	2,405	2.6%	3,577	2.4%	3,501	2.6%
Low (-2)	2,328	-0.3%	3,469	-0.6%	3,399	-0.1%

Peak Demand Forecast Methodology

PGE develops the peak demand forecast using a coincident peak load factor method. Load factors for each customer class are estimated for each month and then applied to the monthly energy forecast to forecast the monthly peak. Monthly load factors are defined as the ratio of the month's energy (MWa) to the highest one-hour demand (MW) during the month (e.g., the monthly peak). All else equal, peak demand moves in the opposite direction of temperature during the heating season (winter) and in the same direction as temperature during the cooling season (summer). The more extreme the temperature relative to normal during the peak day, the lower (or "worse") the resulting load factor.

The December 2013 load forecast updated the load factors used to develop the peak load forecast to incorporate more recent data. The most significant result of the update was an upward revision of the January load factor, which reduced the January peak by approximately 250 MW. The more recent data reflect the relatively lower electric space heating penetration. In addition, more recent data reflect the growing share of load in

[14] Two additional growth scenarios are developed using plus and minus two standard deviations.

customer classes with very stable load factors across months. These trends tend to improve winter month load factors. While winter season load factors are increasing for the reasons described above, the summer cooling season has seen decreasing load factors due to higher central air conditioning penetration. The August peak increased about 50 MW compared to earlier forecasts.

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, as approved by the OPUC in PGE's general rate case and annual update tariff filings. 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 or five years.[15]

Customer load eligible for the five-year ESS option is limited to an aggregate cap of 300 MWa per Schedule 483, 485 and 489 of PGE's electric tariff. Past experience suggests that some of the one-year (and previously three-year) opt-out customers may default back to PGE's rates over time. Five-year opt-out customers must complete the five-year opt-out election before becoming eligible to elect COS rates and must also provide a two-year notice to PGE before returning. Based on this extended term and reduced return flexibility, we assume that these customers have made a longer-term decision to leave PGE's COS rate plans and, consequently, we do not plan for their long-term power supply needs. IRP Guideline 9 of Order No. 07-002 requires our energy load-resource balance to exclude customer loads that are effectively committed to service by an alternative electricity supplier (i.e., the five-year opt-out customers). Nonetheless, according to Oregon law and related OPUC rules, PGE also remains the provider of last resort for all customers in our system.

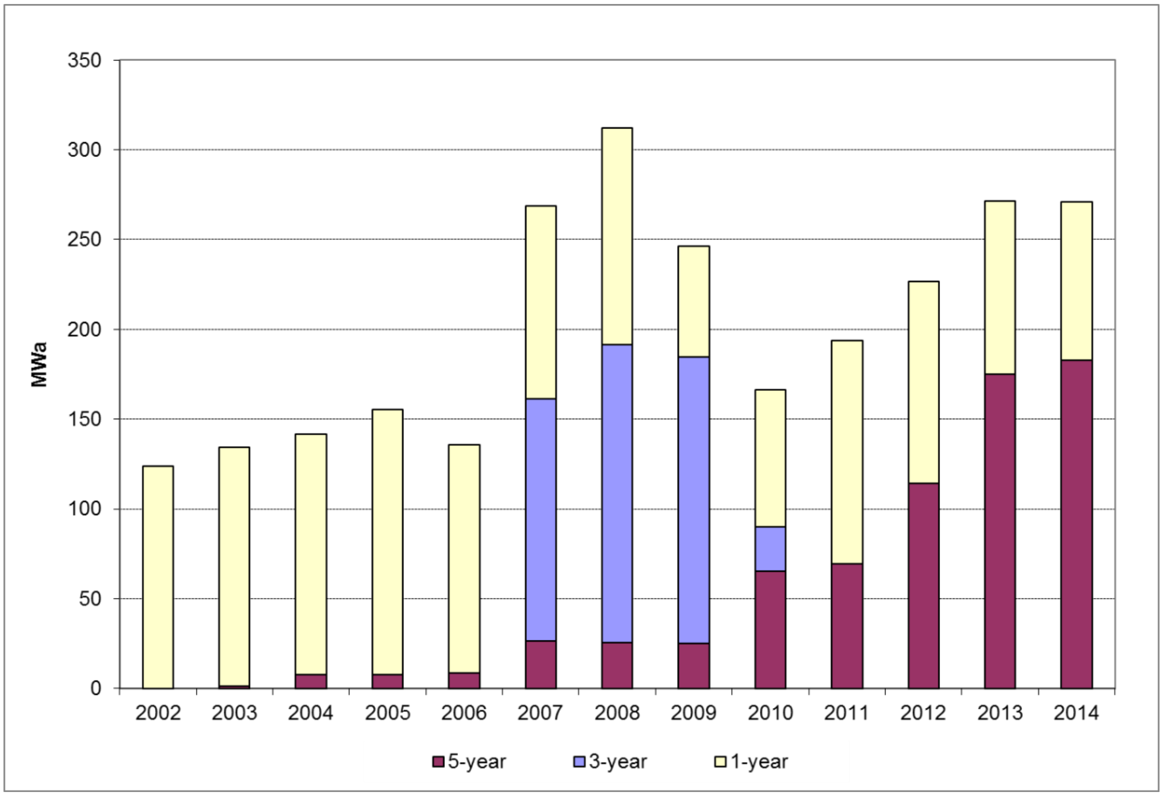
As of October 2013, PGE has approximately 273 MWa of load on non-COS tariffs (roughly 12% of retail load).

Starting from a base of 30 MWa in the 2009 IRP, five-year opt-out load is currently forecasted at 179 MWa for 2014 (of which about 11 MWa was in this year's election). Our updated estimate for 2016 is 181 MWa. The unpredictability of customer opt-out elections increases the overall uncertainty with regard to customer demand projections and resource planning.

Figure 3-2 shows a detailed break-out of non-COS customers by year and by duration of election. The 1-year opt-out window occurs in November, so for 2014 we have assumed the same one-year opt-out customer load as in 2013.

[15] A three-year opt-out option is also available; however, no customers are currently electing that option.

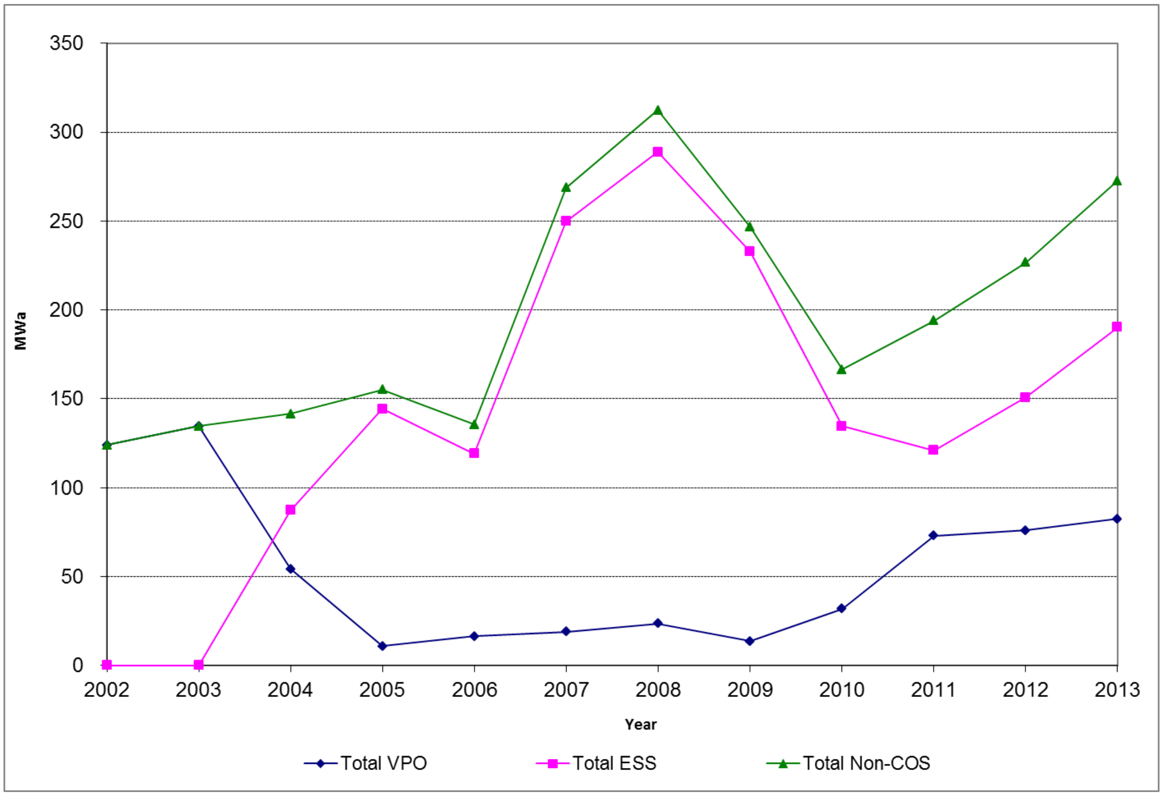
Figure 3-2: Non Cost-of-Service customer load by duration of election



Due to the obligation to serve as provider of last resort for all electric consumers in our service territory, we propose to meet any emergency capacity needs they may have in the short-term market. We do not propose to acquire long-term capacity resources to meet the potential demand from five-year opt-out customers. As a result, we make an adjustment to our capacity load-resource balance to remove this demand, as we did with the corresponding energy.

When PGE's 2014 five-year cost of service opt-out election window closed on September 30, 2013, there was an incremental increase of five-year opt-out load of approximately 11 MWa. The associated demand is approximately 21 MW, due to a seasonal-peaking customer. Figure 3-3 shows PGE's historic energy usage levels for customers who opt out of COS service.

Figure 3-3: PGE Cost of Service opt-out election



In summary, PGE is faced with two sources of load uncertainty with regard to five-year opt-out eligible customers. The first uncertainty is that we do not know from year-to-year if additional customer load will choose to opt-out. For the sake of maintaining a conservative approach to resource adequacy, we assume no future customer opt-outs.

The second uncertainty is the need to be the provider of last resort to customers who have opted-out in the event supply from their ESS is interrupted. We choose to address this risk via market purchases whereby the affected customers would pay market prices.

3.2 Load-Resource Balance

PGE's Energy Load-Resource Balance

Energy load-resource balance in this IRP refers to the difference between the expected energy capability of PGE's resources (generating plants, contracts, and EE) and the expected annual average load under normal hydro and weather conditions.[16] This load-resource balance relies on the most recently available information as of February 2014, reflecting our December 2013 load forecast and February 2014 expected resource portfolio. Because the Beaver and Port Westward II plants are intended primarily for

[16] In our load-resource balance (LRB) analysis, both for energy and for capacity, our load is before all reductions due to post-2013 EE. We then include EE as part of our resource portfolio.

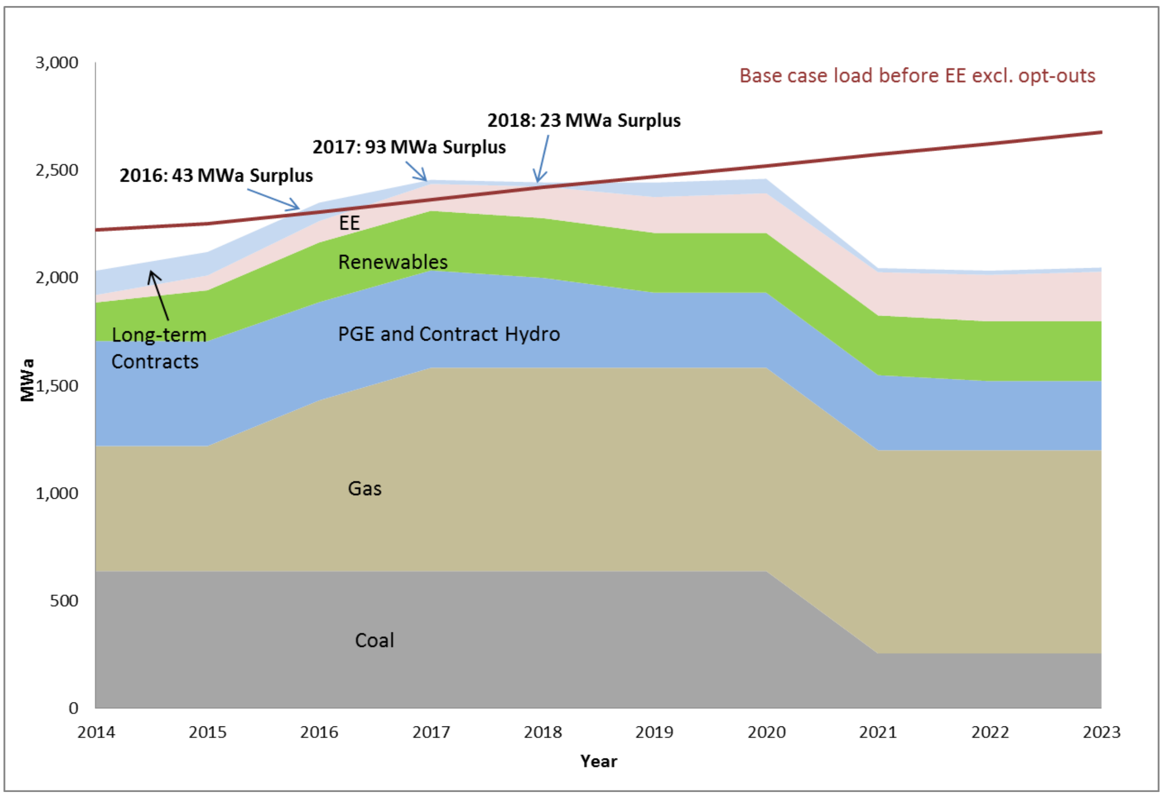
peaking and flexibility, their generation capabilities are not included. Using this adequacy metric suggests that when we are in supply/demand balance on an annual average basis, committed PGE resources will be "short" to load requirements for about half the hours of the year and "long" for the remaining hours. A primary function of PGE's Power Operations group is to make purchases and sales to balance resources to meet customer demand for all hours.

As noted in Chapter 2 - PGE Resources, our share of Boardman is now approximately 90 MW (70 MWa) larger. We also have reached an agreement in principle to extend our current rights to the output of the Tribes' share of Pelton and Round Butte and related Re-reg Dam hydroelectric projects. This agreement provides 65 MWa of expected energy and 159 MW of capacity for a ten-year term (2015–2024). We reflect these resources, as well as the December load forecast in our load-resource balance and other related tables and figures.

Figure 3-4 shows a projection of PGE's portfolio after all resource additions from the 2012 RFPs have been implemented. The figure reveals a relatively flat position through 2020, with a projected surplus of 23 MWa in 2018 and small deficits thereafter. The deficit then becomes more pronounced, because we will no longer operate Boardman as a coal facility. Figure 3-4 is provided in tabular format in Appendix K.

For IRP planning purposes, we assume continued operation of all PGE's owned plants (with the exception of Boardman) throughout the planning horizon (2033).

Figure 3-4: PGE's projected annual average energy load-resource balance



PGE's Capacity Load-Resource Balance

A given resource's capacity value for our IRP metric is the amount of sustained electricity the facility is capable of producing in a given hour on demand (i.e., when called for). As discussed in Section 3.3 below, we evaluate peaking needs by comparing the January one-hour maximum load inclusive of approximately 12% reserves (composed of 6% required operating reserves and 6% planning or contingency reserves), calculated on a 1-in-2 or normal weather basis, to the capability of our resources and contracts (including customer dispatchable standby generation and demand response).

The capabilities of our resources are reported at their summer (August) and winter (January) one-hour peak operating capacities, with the exception of hydro resources, for which we use a sustained four-hour generating capability measure. We report both the winter and the summer peak loads to show the offsetting effects of two factors. Summer peak needs are lower, although they are growing faster than winter needs and are gradually moving us to a dual-peaking utility. However, summer capacity capabilities for thermal resources are also lower. These factors combine to make our projected winter and summer capacity needs approximately the same. Figure 3-5 and Figure 3-6 show PGE's projected capacity needs for winter and summer, respectively, with a breakdown by resource type. Figure 3-5 shows small winter surpluses in both 2017 and 2018, with growing deficits thereafter. Figure 3-6 shows a small summer surplus in 2017, a small deficit in 2018, and larger deficits thereafter.[17] The growing post-2018 deficits in both winter and summer are the result of load growth and contract expirations, both reaching approximately 300 MW in 2020. These deficits are shown after all resource additions from the 2012 RFPs are implemented. They also recognize the additional 15% share of Boardman beginning in 2014, the agreement in principle to extend PGE's rights to the output of the Tribes' share of Pelton and Round Butte and related Re-reg Dam hydroelectric projects beginning in 2015, and the December 2013 load forecast. Figure 3-5 and Figure 3-6 are provided in tabular format in Appendix K.

[17] The large 2016 summer capacity surplus is due simply to timing; Carty will have just become operational, but the TransAlta and Spokane Energy contracts will not expire until later in the year.

Figure 3-5: PGE's projected winter (January) capacity needs

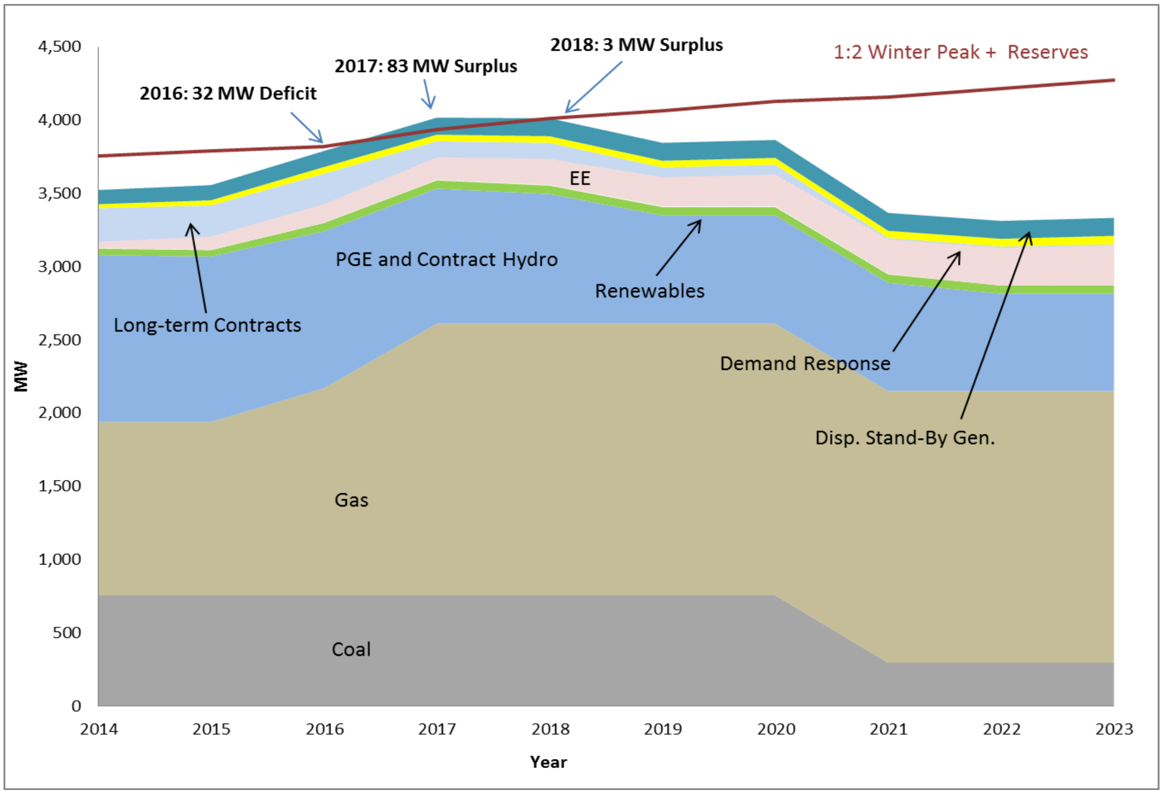
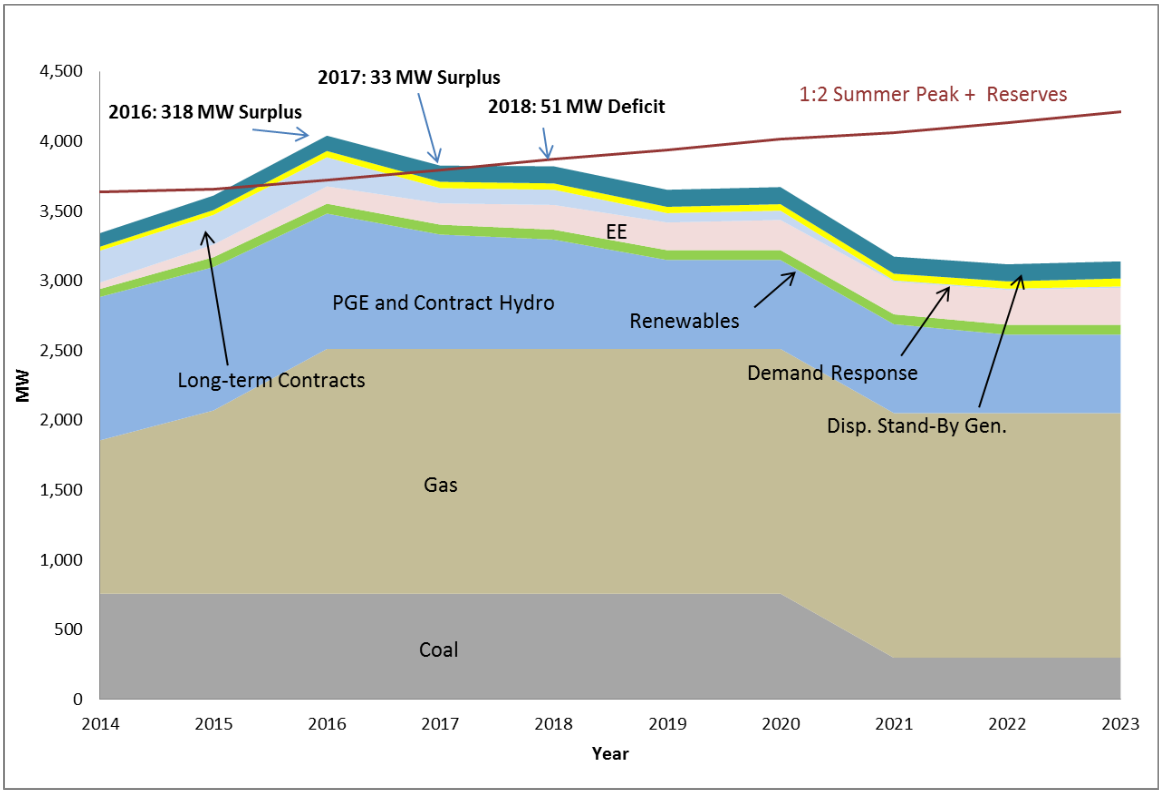


Figure 3-6: PGE's projected summer (August) capacity needs



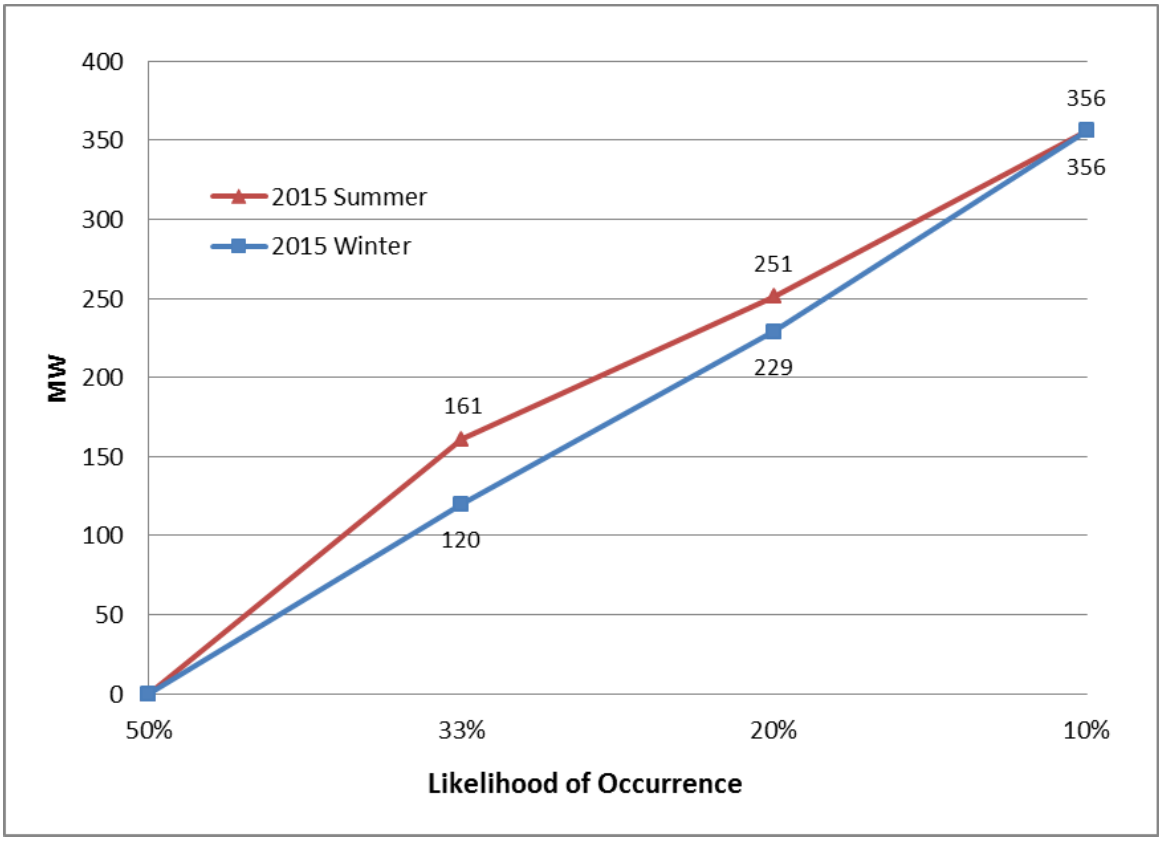
3.3 Reserve Margins and Contingencies

The level of reserves we include in planning for capacity is important for maintaining supply reliability. We plan for approximately 12% reserves, comprising 6% for contingencies and an approximately 6% operating reserve margin. The operating reserve margin is required by Western Electricity Coordinating Council (WECC) reliability standards and is intended to maintain supply stability and power quality during unexpected real-time disruptions within the operating hour (i.e., must be compensated for within one hour). Examples of disruptions include plants unexpectedly going off-line and unanticipated load increases. The contingency reserve covers two types of events: 1) extreme weather events and resulting load excursions (i.e., loads going above those associated with average, or "1-in-2," weather); and 2) unplanned generator and transmission outages (either full or partial) extending beyond the time to be covered by operating reserves.

In Chapter 11 - Transmission, Section 11.2, we discuss the new WECC standard for operating reserves approved by FERC on November 21, 2013 (FERC Order No. 789). The new standard became effective January 28, 2014, and FERC will begin enforcing compliance on October 1, 2014. The updated reliability standard changes the methodology from a calculation of a percentage of generation to serve load to the sum of 3% of load plus 3% of net generation. This update has an immaterial effect on PGE's capacity load-resource balance, and, given the timing of the FERC decision, was not incorporated into our IRP analysis. PGE intends to incorporate the new methodology in our next IRP.

For 2015, our projected winter reserves target is approximately 370 MW, comprising 170 MW for operating requirements and 200 MW for contingencies. The summer reserves target is approximately 5% lower. To assess the sufficiency of these targets for weather-caused load excursions, Figure 3-7 shows the increases in our peak load requirement as we move from our "1-in-2" (50% probability that loads will exceed this amount) standard to more extreme possibilities – "1-in-3" (33% probability), "1-in-5" (20% probability), and finally "1-in-10" (10% probability). The 10%, or once every ten years, winter peak requirement is approximately 350 MW greater than our "1-in-2" planning standard. Our reserves approximately align with this contingency. In Chapter 9 - Modeling Methodology, we discuss our assessment of how much market power would be readily available to meet contingencies. We conclude that 300 MW would be available in the market to meet our winter peak through 2018 (200 MW thereafter). We thus expect to meet contingency events with a mixture of committed (PGE owned and contract) resources and market purchases.

Figure 3-7: Impact of temperature on peak loads: incremental peak load from normal to 1-in-10 weather



Boardman currently provides our single largest plant-related exposure. Our 80% share has winter capacity of approximately 460 MW. Our 370 MW winter reserve standard covers most of the Boardman contingency. However, were we to simultaneously experience a "1-in-10" weather event and an unplanned plant outage, our reserves would be insufficient to meet customer demand. PGE will likely revisit the adequacy of our current standard in the next IRP.

3.4 Regional Reliability Outlook

While PGE planning metrics provide a high degree of reliability in our power supply, it is also important to understand regional supply and demand fundamentals.[18] The Northwest Power and Conservation Council (NWPCC) performs this analysis for the region. In Council document 2012-12, the NWPCC updated an earlier study on adequacy for the region. The earlier assessment found that by 2015 the region could face adequacy concerns. Specifically, the report found "relying only on existing resources and targeted energy efficiency savings would result in a 5% likelihood of a shortfall…" The updated

[18] This section addresses regional power supply without consideration of potential transmission availability. Please refer to Chapter 11 - Transmission, for a discussion of regional transmission availability.

assessment raised the probability of facing a 6.6% shortfall by 2017. The report found that this probability could be reduced to the 5% threshold by adding 350 MW of dispatchable generation, or lowering annual load by 300 MWa. The Council's assessment did not include PGE's Carty and Port Westward 2 plants, which add more than 650 MW. Expected regional loads have also decreased since the 6.6% calculation. However, other factors, including the availability of imports from California, have also changed, and could offset the Northwest plant additions and load decrease. The Council currently expects to complete a new study in May of this year.

3.5 Plug-in Electric Vehicles

Plug-in Electric Vehicles (EVs) have been attracting the interest of customers, regulators, and other state and local officials. On both the local and national levels, PGE has been playing a leadership role in a number of areas related to EV technology. In addition to reducing tailpipe emissions and customers' transportation fuel costs, the "smarts" that are built into the cars and their charging systems offer the promise of integration with smart grid technology. In the shorter term, benefits could include smarter charging, with timed, controlled or renewable-integrated recharging of EV batteries. In the longer term, assuming the mass adoption of electric vehicles, EV batteries could potentially become a resource for vehicle-to-home or vehicle-to-grid power.

Federal, state and local policies have been adopted to encourage EV use, and tax credits support the purchase of electric vehicles and the installation of EV charging equipment.

The OPUC is also interested in the potential impact of EVs. A new IRP Guideline and new tariff offerings were added as a result of the investigation conducted in Docket No. UM 1461. The guideline calls for analyzing the potential vehicle-to-grid use of EV batteries on par with other flexible capacity resources. Chapter 5 - Flexible Capacity Needs examines our supply of and demand for flexible capacity resources.

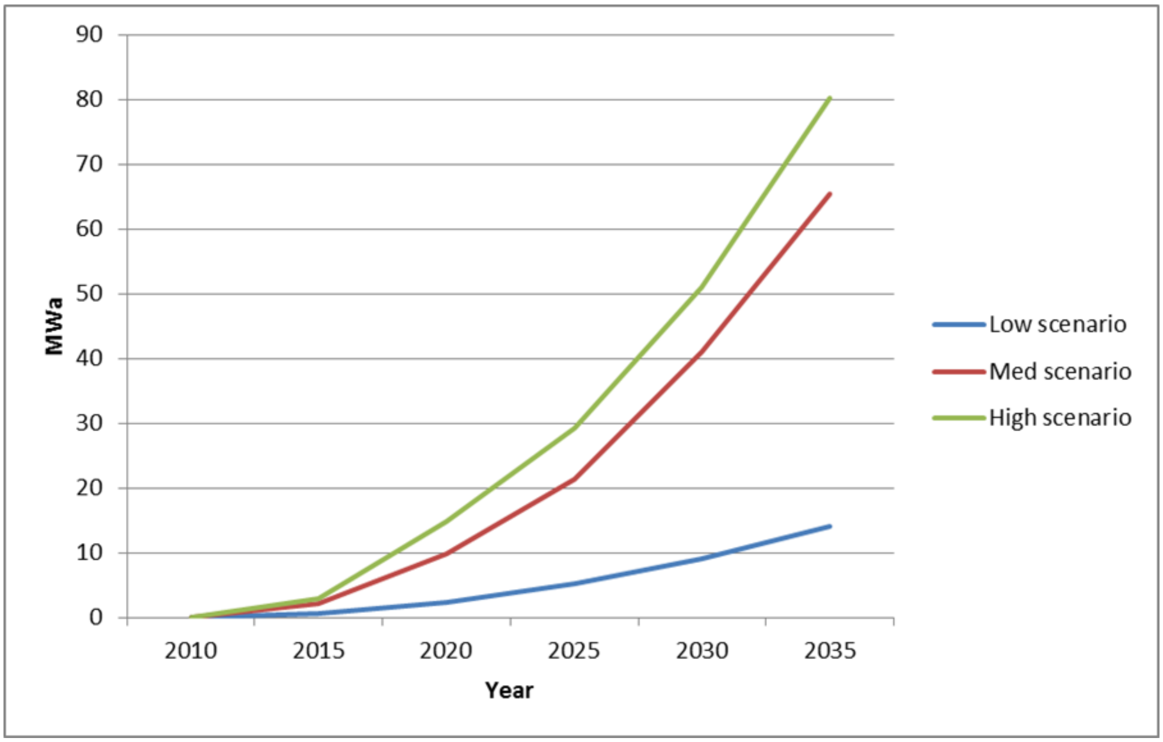
PGE is participating in the EV Project, a federally funded pilot project to facilitate the development and deployment of EV charging stations, with monitoring technology, throughout our service territory. In addition, Nissan partnered with PGE and the State of Oregon to introduce zero-emission vehicles in the State in 2010. Since then, a number of vehicle manufacturers have made their electric cars and trucks available to Oregonians. In 2010 there were three, but today a dozen different vehicles are available here.

Currently PGE has Schedule 344 - Oregon Electric Vehicle Highway Pilot Rider. The rider is an optional, supplemental service to Electric Vehicle Service Equipment Providers (EVSE Provider) served under PGE rate Schedules 32 and 38. The rider supports the Oregon portion of the West Coast Electric Highway Initiative. Under the rider, PGE will assist any publicly funded EVSE Provider in finding suitable sites for and installing up to 20 publicly available DC quick charging stations in conjunction with up to 40 Level II charging stations along the Interstate 5 and Interstate 205 corridors and related arterials within PGE's service territory.

Under the terms of the rider, PGE will meter the EV charging stations and, once installed, will provide the electricity to the EVSE Provider. EVSE Providers will own and operate the charging stations. During the term of this pilot, the Company's objectives are threefold: 1) study the impact of EV charging on the grid infrastructure, 2) learn more about location and siting costs of DC quick chargers and implications for the Company's business processes, and 3) gain information to support outreach and education to customers about EVs and charging. This pilot will terminate on December 31, 2013.[19]

At this point in time PGE does not believe mass deployment of EVs will occur in the near-term, as shown in Figure 3-8 below. Even under a high-growth scenario EV usage would be less than 30 MWa in 2025. Significant growth is eventually expected, just not until later years.

Figure 3-8: PGE's projected electric vehicle penetration



PGE will continue to closely monitor the development and deployment of EVs and EV charging systems and maintain a leadership role in facilitating EV adoption and charging station installation by customers.

[19] PGE is in the process of requesting an extension of the pilot through 2015.

4. Demand-side Options

PGE continues to pursue demand-side options, including energy efficiency (EE) identified by the Energy Trust of Oregon (ETO), and emerging demand response (DR) options. This chapter provides current information on the status of both EE and various DR efforts.

Chapter Highlights

- The ETO is funded with the goal of acquiring all cost-effective EE over time.
- PGE's Firm DR programs are on track to become valuable demand-side capacity resources:
  - Curtailment tariff – 20 MW by 2015
  - Automated demand response pilot – 25 MW by 2016.
- Residential direct load control has the potential to become a significant DR resource, if appliance and technology market transformation in the Pacific Northwest is achieved in the future.
- PGE continues to develop Non-firm DR programs:
  - Critical peak pricing pilots will position PGE for major implementation when technologies support scalability
- PGE is testing Conservation Voltage Reduction at two substations. Upon completion of technical tests, we will perform a cost-benefit analysis and report the results in an IRP Update.

4.1 Demand-side Energy Resources

Energy Efficiency

Oregon Senate Bill 1149, enacted in 1999, instituted a 3% public purpose charge (PPC) to collect funds associated with activities mandated for the benefit of the general public. These activities include energy conservation, market transformation, new renewable energy resources and low-income weatherization. The bill consolidated funding for energy efficiency (EE) at the state level by directing a portion of the funds collected from utility customers to several agencies charged with responsibility for running EE programs, primarily the Energy Trust of Oregon (ETO). Of the total PPC, approximately 78.4% is directed towards conservation/EE activities. Additionally, Oregon's Renewable Energy Act (SB 838), enacted in 2007, authorizes PGE to set aside additional funds to invest in conservation when doing so is more cost-effective than supply alternatives for customers. Through SB 838, PGE began collecting an additional 1.25% in public purpose charges in June 2008 to help acquire additional cost-effective EE. Due to existing cost-effective EE opportunities, the funding level has since increased with a projected amount of approximately $50 million, or about 3.3% for applicable customers.

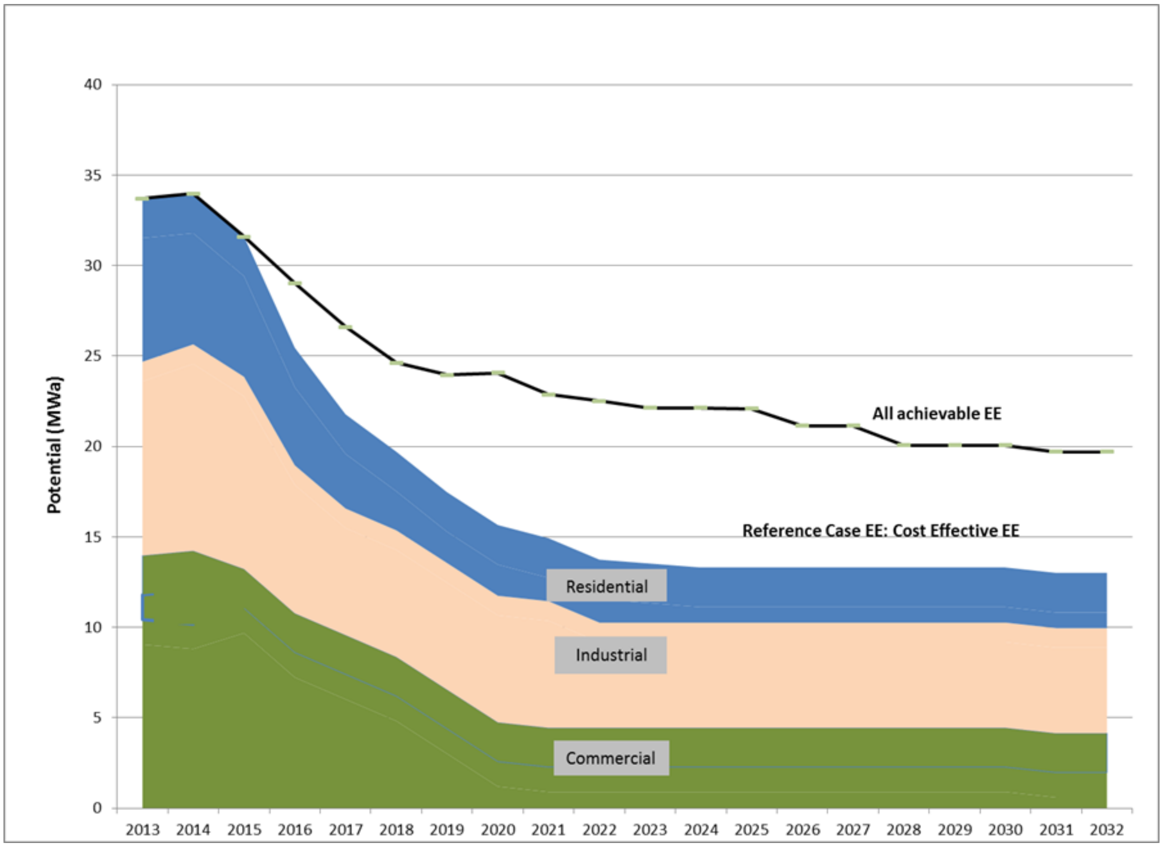
Since 2002, PGE has actively worked with the Energy Trust of Oregon (ETO) to implement energy efficiency measures. Going forward, the joint ETO/PGE goal is to provide sufficient funding to acquire all available cost-effective EE within our service area. The cost-effective limit enables consideration of all measures that are, at most, equal in cost to an avoided electric generation resource, with appropriate adjustments to reflect additional value that EE brings, such as avoided capacity and emissions. The following provides the amounts of EE the ETO expects to acquire and details how that projection was developed.

ETO Targets

For this IRP, ETO has developed two different projections:

- **Reference case deployment**: This is the amount of EE that the ETO can confidently project acquiring in the next 20 years based on currently available and cost-effective measures. Total cumulative EE by 2032 is 361 MWa (at the meter), with a deployment close to 30 MWa per year in the shorter term, declining to 14 MWa per year in the longer term, as illustrated in Figure 4-1. This is the cost-effective, achievable energy efficiency over the 20-year planning horizon of PGE's IRP. This is our reference case assumption.
- **All deployable EE**: This includes all EE that can be acquired in the next 20 years, regardless of any economic or cost-effectiveness screening. Total accumulated EE by 2032 rises to 479 MWa. This target will be used in the portfolio analysis to test the cost/risk trade off of pursuing more EE than currently paid for by PGE's customers. Pursuit of this higher EE acquisition level would also require an increase in funding.

Figure 4-1: PGE's EE deployment 2013-2032



Note that EE acquisitions (and associated costs) fall rapidly after 2016. The post-2016 reduction reflects continuation of existing programs with declining EE opportunities (due to previous implementation of energy efficiency measures). However, it is expected that new opportunities will become cost-effective (e.g., LED lighting) such that it is likely that future EE acquisition will exceed what is currently projected.

PGE worked closely with ETO planners, providing our load growth assumptions based on PGE's load forecast as of March 2013 and any other information required, like cost of capital and avoided cost inputs. The following summarizes the process used by the ETO to develop a PGE-specific EE estimate:

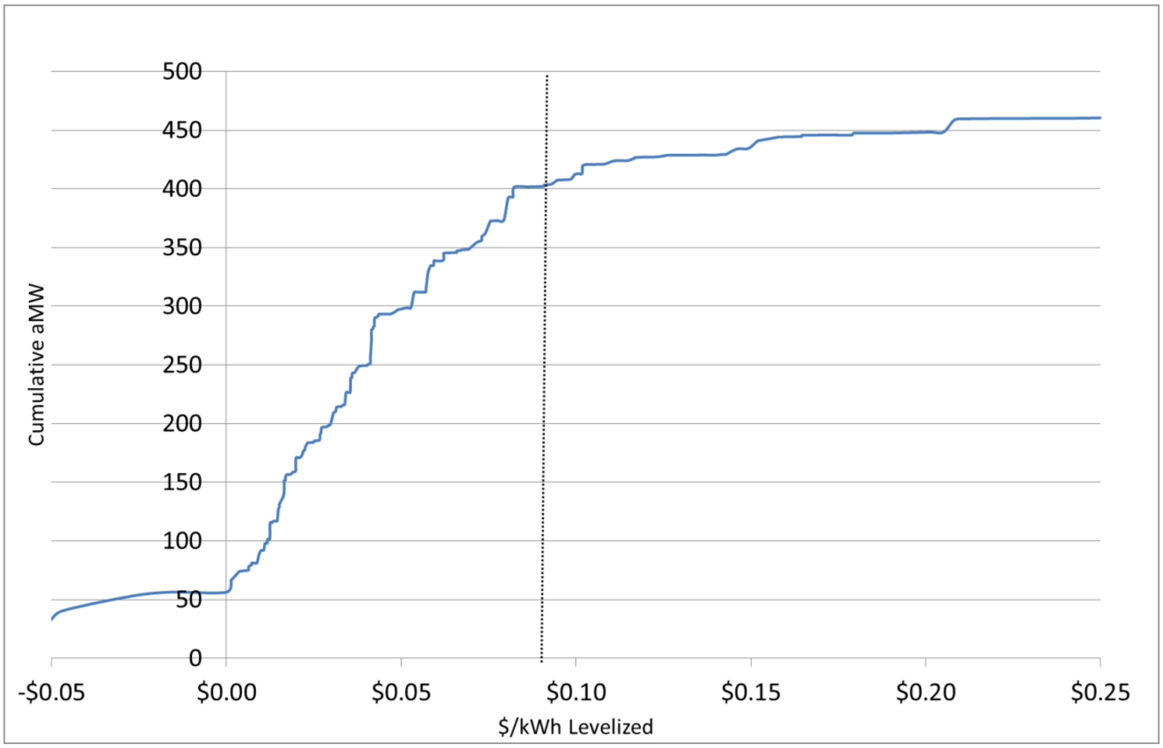
1. Estimate of the known technical potential EE for PGE, PacifiCorp, NW Natural and Cascade Natural Gas. This study was first performed by Stellar Processes in 2002 and is updated every two years.

2. Identify the achievable potential for non-lost opportunity measures for PGE. These are conservation measures that can be acquired at any time, as opposed to those that can be procured under specific conditions or at a specific time (such as insulation in buildings under construction).

3. Screen the achievable potential for cost-effectiveness using the total resource cost (TRC) test. This ranks measures by comparing the net present value of the benefits of EE with the total costs. Benefits include:
   a. Annual kWh savings * avoided cost; and,
   b. Quantifiable non-energy benefits, such as water savings from low-flow showerheads.

4. Develop the achievable resource supply curve and select those measures whose cost is lower than PGE's adjusted avoided cost. Figure 4-2 reveals that most of the achievable potential is below avoided cost and therefore included in the reference case EE deployment.

Figure 4-2: Achievable EE resource supply curve for PGE



The resulting estimate of 361 MWa by 2032 is the reference case assumption in our analysis.

In our IRP modeling, as a partial proxy for an E3-inspired lower carbon case, we included a portfolio which procures all achievable EE to compare its cost and risk performance to the reference EE deployment. Costs were computed by using the total resource cost (TRC) estimate provided by ETO with a cost adder of 20% to take into account administrative and delivery costs. Table 4-1 shows the detailed annual EE procurement, the utility cost and the TRC for the two EE deployment cases modeled: reference and all achievable EE.

Table 4-1: Energy efficiency projections

	Cost Effective EE				All Achievable		
	Energy (after losses) (MWa)	Utility Cost $ million	Total Resource Cost $ million		Energy (after losses) (MWa)	Utility Cost $ million	Total Resource Cost $ million
2013	33.7	$79.5	$82.8		33.7	$79.5	$118.6
2014	34.0	$79.7	$82.6		34.0	$79.7	$118.4
2015	31.6	$77.1	$79.1		31.6	$77.1	$129.9
2016	25.4	$62.7	$64.9		29.0	$71.5	$124.0
2017	21.8	$54.2	$56.2		26.6	$66.2	$118.3
2018	19.7	$49.5	$51.3		24.6	$61.9	$113.8
2019	17.5	$44.2	$46.2		23.9	$60.8	$115.4
2020	15.6	$40.0	$42.2		24.1	$61.8	$122.1
2021	14.9	$38.4	$40.4		22.9	$59.3	$119.4
2022	13.7	$35.8	$37.8		22.5	$58.9	$115.3
2023	13.5	$35.6	$37.2		22.1	$58.5	$111.2
2024	13.3	$35.4	$36.6		22.1	$59.1	$111.2
2025	13.3	$35.7	$36.6		22.1	$59.6	$111.2
2026	13.3	$36.1	$36.6		21.1	$57.6	$105.9
2027	13.3	$36.4	$36.6		21.1	$58.1	$105.8
2028	13.3	$36.8	$36.6		20.1	$55.7	$103.4
2029	13.3	$37.2	$36.6		20.1	$56.3	$103.4
2030	13.3	$37.5	$36.6		20.1	$56.8	$103.4
2031	13.0	$37.0	$36.0		18.4	$52.8	$99.4
2032	13.0	$37.4	$36.0		18.4	$53.4	$99.4
Total 2013-2032	**360.6**	**$926.2**	**$948.7**		**478.5**	**$1,244.6**	**$2,249.2**
Administrative and delivery costs adder 20%							
Total cumulative EE investment w/ admin costs			**$1,138.5**				**$2,699.1**

In the near term, the portfolio with all achievable EE is not materially different in total MWa savings from the reference case, while investments are significantly higher. In order to capture all the achievable savings, the ETO would have to pursue a different measure mix to acquire savings that otherwise would become lost opportunities for measures that are currently not cost effective. Examples of the more costly lost opportunity measures for commercial deployment are high efficiency air conditioners, direct/indirect evaporative cooling units, and windows. New and replacement residential measures in this category include heat recovery ventilation and solar water heating.

4.2 Demand Response Potential Study

Study Summary

In 2012, the Brattle Group conducted an updated study of demand response potential in PGE's service territory. The updated study provided significantly more detail relative to the 2009 study including: appliance saturation, DR potential for over 50 customer segments, updated avoided costs, customer price elasticity estimates, and DR participation assumptions. The results of that study are available at www.portlandgeneral.com/irp.

Although the Brattle study evaluated DR potential based on several criteria such as technical potential, maximum achievable potential, and current trends, PGE's primary goal for the study was to identify the potential for our automated demand response (ADR) pilot. We provided the Brattle Group study update to the bidders to help inform them of ADR potential among relevant PGE customers. For the IRP, we continue to focus on the specific characteristics of the programs that we believe provide the best DR potential.

Specifically, PGE is targeting DR programs that provide firm, cost-effective capacity that address the conditions specific to PGE's service territory. In contrast to much of the U.S. where demand response has been significant, PGE lacks the following pre-conditions that have led to DR success in those jurisdictions:

- Significant multi-month 24-hour air conditioning load;
- Significant irrigation load;
- Significant price differentials between peak and off-peak periods;
- High overall rates leading to the ability to provide larger incentives;
- Greater customer experience with and acceptability of time-varying rates.

Where traditional DR has been solely about maintaining reliability during very infrequent peaking events or generation outage events (so-called DR 1.0), PGE is seeking DR which is also fast-acting and flexible (so-called DR 2.0), and preferably automated. PGE is implementing DR programs with strict specifications to meet both types of needs. These specifications limit the amount of DR potential, but create programs with greater certainty during curtailment events.

Given this DR context for PGE, we view direct load control as the best alternative for future DR potential. We also consider firm and fast-responding programs as more valuable. We describe these in more detail in the following sections.

4.3 Firm Demand Response Programs

Introduction

PGE currently has two firm demand response programs in operation: the curtailment tariff, Schedule 77 for our large non-residential customers (able to reduce demand by 201 kW), and the ADR pilot for non-residential customers. Schedule 77 has been in effect since July, 2009, and the ADR pilot became operational in August 2013. These programs represent PGE's achievable firm demand response potential for the next five years.

Looking forward, we foresee the transformation of the appliance market providing the greatest potential for direct load control in the residential sector as major household appliances are produced with standardized and programmable communication interfaces.

Program Assessment

To evaluate DR programs and determine cost-effectiveness, PGE compares the levelized cost of the program against that of a LMS100 simple-cycle combustion turbine (SCCT). Due to operational constraints, however, a DR program may not have the same reliability or operational value as a SCCT. Examples of operational constraints on DR programs include:

- The number of events that can be called per year
- The timing and duration of those events
- The extent to which the load reduction is not automated
- The firmness/reliability of the response
- The amount of advanced notification that must be given to the participants.

To reflect the impact of the relevant operational constraints, PGE derates the cost of the SCCT as compared to the DR resource. The deration factors will vary by DR option, depending on its performance characteristics, and will allow for appropriate comparability between resources (a similar approach is discussed below with respect to critical peak pricing). Additional benefits that PGE considers include portfolio diversity, environmental impact, program expandability, etc.

Finally, we present our findings to other interested parties, including low-income agencies, and the Commission to vet the analyses. We strive for consensus, and receive regulatory approval before proceeding with deployment. To the extent that a program has an energy efficiency element, PGE would coordinate with the Energy Trust of Oregon to maximize the achievable benefits. Through this process, PGE endeavors to identify and implement the best programs and service options for our customers.

Curtailment Tariff

PGE currently has 16 MW participating and available for curtailment in its Schedule 77, Firm Load Reduction Program. As reported previously, the tariff is callable up to 48 hours per year and PGE is on track to achieve the targeted 20 MW by 2015 as listed in Table 4-2. This past August, PGE transitioned Schedule 77 from a pilot to a program.

Automated Demand Response

In the last IRP update (page 17), PGE noted that its original ADR pilot had been terminated in early 2012 because PGE's ADR contractor "experienced financial difficulties and was unable to meet the terms of its agreement". PGE subsequently issued a Request for Qualifications in August 2012 and then issued a new RFP on October 16, 2012, to establish a new ADR pilot program. Since that time, PGE completed the RFP process, selected an ADR provider and received Commission approval to implement a new ADR pilot. During the Commission proceedings (UE 272 and UM 1514), PGE demonstrated that the ADR program cost less than the non-derated cost of an LMS100 SCCT unit. Because of our expedited efforts, PGE and its selected provider, EnerNOC, Inc., began operations in August 2013.

The new ADR pilot has two phases. The first phase runs through June 2015. This will allow three operating seasons to be evaluated for performance and cost effectiveness, with evaluation completion by April 2015. If the evaluation is favorable, the second phase will run through 2016, which will allow a second opportunity to review the subsequent two operating seasons and the pilot as a whole. This evaluation will be completed by April 2016. If the second evaluation is favorable, PGE will submit the ADR program as an ongoing capacity resource in our 2017 Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (Schedule 126) similar to other power cost and capacity items.

As of November 14, PGE has enrolled nine customers. It is projected these customers may achieve roughly 3 MW of demand reduction, subject to validation this winter after equipment installation. We project that ADR will ramp up to 25 MW over the course of the pilot and be available for curtailment during both summer and winter seasons.

Table 4-2: Firm demand response acquisitions by 2018

Year	Curtailment Tariff MW	Automated Demand Response Summer* MW	Automated Demand Response Winter* MW	Total Demand Response MW
2012 Actual	16	0	0	16
2013	17	0.5	3	20
2014	19	6	9	28
2015	20	12	15	35
2016	20	18	21	41
2017	20	25	25	45
2018	20	25	25	45

*The summer season is July–September; the winter season is December–February.

Water Heater Direct Load Control Pilot – Salem Smart Grid Project

As reported in PGE's November 2011 IRP update, we have an operating Water Heater Direct Load Control (DLC) Pilot that is part of the Salem Smart Grid Project. This pilot is unique in that it tests responses to a mock regional pricing signal. It is, however, limited to less than 100 participants; it is not associated with "smart" appliances (i.e., the water heaters were retro-fitted with communication devices); and it is not scalable beyond the Salem demonstration project. The pilot is projected to run through 2014.

Smart Water Heater Direct Load Control Pilot

PGE's 2011 IRP update also described a very small pilot that would test a plug-in communication device in five "smart" electric water heaters with which PGE would test DLC. PGE is currently refining the communication interface's technologies to achieve consistent and reliable signals to the water heater.

The ability to develop residential DLC is contingent on the speed of appliance market transformation. Ultimately, PGE believes appliance market transformation has the potential to create the greatest DR capacity among residential customers due to its ease of use by customers with either direct load control or with dynamic pricing.

Other appliances, in addition to water heaters, could provide demand response through DLC. These could include heating, ventilation, and air conditioning systems (HVAC systems) via thermostats, electric spas, and electric vehicle chargers. If customers had one of the above primary appliances, secondary appliances such as dryers, dishwashers, refrigerators, or stand-alone freezers could provide additional DR. The secondary appliances only become cost effective in a market where DLC on "market-transformed" primary appliances is relatively mature and common place. This might easily be 10 years after the first program success at scale.

Although significant progress has been made in establishing a standard interface[20] or socket for "smart" appliances, two difficult tasks still remain:

- Incorporate the socket on appliances so that consumers region- or nation-wide can automatically replace old/obsolete appliances with "smart" appliances
- Establish standard communication protocols.

Once the socket is adopted, the normal replacement cycle and new construction will allow an increasing share of water heaters to become DR- compatible. As that occurs, PGE will be able to implement a direct load control program that can expand with the growing resource.

For forecasting purposes, PGE has estimated a proxy water heater direct load control program to represent all potential residential direct load control resources. All potential residential load control appliances have similar success considerations (i.e., need for communication and hardware standards, establishment of market penetration, etc.). This estimate is based on projections of water heater saturation (assuming the hurdles described above are overcome) and that, with time, existing appliances are replaced by "smart" appliances. Because the average life of a residential water heater is 12 years, over 15 years will be required from the time waters heaters are first mass produced with the new sockets until most vintage water heaters are replaced. Based on these assumptions and those listed below, PGE's estimate for the proxy resource is provided in Table 4-3.

Table 4-3: Proxy resource – water heater direct load control program

Year	MW
2015	0.0
2016	0.0
2017	0.0
2018	0.1
2019	0.3
2020	1.4
2021	3.6
2022	7.5
2023	12.7
2024	20.0
2025	28.3
2026	36.7
2027	44.9
2028	51.9
2029	58.6
2030	64.9

[20] National standard, ANSI/CEA 2045, created for this was released in December 2012.

Major assumptions for this proxy program are as follows:

- We expect it to be an opt-in program;
- By 2016, many new water heaters are sold with a standard communication socket;
- By 2020, 95% of all new water heaters are sold with the socket;
- By 2030, 89% of all installed electric heaters have the standard communication socket;
- By 2021 50% of electric water heater sales are assumed to be of the heat pump type and by 2030, this will be 65%;
- The average avoided peak demand is 0.6 kW for resistance water heaters and 0.3 kW for heat pump water heaters; and
- Program adoption rates are 4% in 2020, 34% in 2025, and 50% in 2030.

PGE can only estimate when the DR potential from appliance market transformation might be fully attainable. In the interim, we can prepare ourselves with direct load control and dynamic pricing pilots until the applicable technologies and communication and hardware standards provide scalability.

PGE is also exploring ways to support the Northwest Energy Efficiency Alliance and the Northwest Power and Conservation Council in order to encourage manufacturers to incorporate the sockets into their products for regional distribution.

PGE expects that, in time: 1) a standard appliance socket will be adopted, 2) a standard communication protocol will be developed, and 3) direct load control through “smart” residential devices (appliances, thermostats, etc.) will provide a significant DR resource. While there may be considerable DR potential by 2020, the development and timing of fully integrated “smart” appliance technologies for scalable programs will most likely limit this capacity to a later date. As a result, PGE has estimated an alternative based on the proxy resource (Table 4-3) and believes this represents the more likely firm DR potential for residential customers in PGE’s service territory.

4.4 Non-Firm Demand Response Programs

Critical Peak Pricing (CPP) Pilot

PGE concluded its CPP pilot for residential customers, Schedule 12, in October 2013, as authorized by the OPUC. To complete the CPP pilot, PGE will submit a detailed evaluation to Commission Staff in March 2014. While the final analysis is pending, the initial evaluation (submitted to Commission Staff on March 29, 2013) provides meaningful insights for future CPP efforts. Major aspects of the third-party evaluation[21] include the following:

- The pilot realized measureable load reductions for the comparable event days.

[21] Prepared by KEMA, Inc.

- The pilot experienced attrition its first year of operation, with the number of participants dropping from approximately 1,000 customers to approximately 610. The primary reasons that customers dropped out of the pilot were:
  - The failure to save money;
  - Difficulty in being able to shift/reduce load; and
  - Discomfort and inconvenience.
- Surveys showed overall customer satisfaction was approximately 65% following the first two operating seasons.

The report also provided a cost/benefit analysis of developing a fully scalable CPP program. Based on an analysis by PGE's information technology (IT) department, we estimated that the cost to develop a fully scalable CPP program, based on PGE's current system, is approximately $6.1 million. The primary requirements for these costs are:

- Configure PGE's current customer information system (CIS) and automate numerous processes for enrollment, customer communications, event dispatch, meter configuration, etc. that are currently manual during the pilot period.
- Redesign PGE's meter data consolidator (MDC) in order to address the additional data storage and processing capacity needed for a large increase in 15-minute interval data.

To estimate the net benefits of a fully scalable CPP program, we used a cost/benefit model previously employed in Docket No. UE 189. The model used updated cost information and benefits as estimated from: 1) the KEMA study; and 2) the avoided cost of a least-cost, supply-side resource.[22] We also assumed participation levels of 1.5%, 5.0%, and 10.0%, by the fifth year of the program.

The analysis results in a net present value (NPV) cost for CPP over a 20-year program life for each assumed participation level. These results are due to the estimated costs associated with the existing CIS and MDC. However, PGE is developing new CIS and MDC systems as a component of PGE's 2020 Vision program.[23] Because, the new CIS and MDC systems will be much more robust and ready to accommodate the necessary level of interval data and more complex pricing structures, the cost to implement a CPP program after 2017 will be significantly less than with the current systems. Consequently, PGE believes implementing a fully scalable CPP program is best accomplished after 2017. Nonetheless, we think there is significant benefit to establishing a follow-up CPP pilot to better position ourselves for a future large-scale effort. In order to achieve the maximum benefit from a potential second CPP pilot we propose to undertake these preparatory steps:

[22] Because CPP represents a non-firm resource with day-ahead notice, it delivers less benefit than a firm resource that can respond within 10 minutes. Consequently, PGE derated the avoided capacity cost of the supply-side resource by 50%.
[23] See PGE Exhibits 600 and 900 in PGE's UE 262 general rate case filing for more details on these major initiatives.

- Pursue customer education as part of our strategic pricing roadmap to see what impact it plays on enrollment, retention and performance in our next pilot.
- Identify CPP and time-of-use requirements for new systems and programs.
- Continue to monitor DR programs and results from other utilities.
- Develop an education program to better inform customers regarding the purpose of, and how to effectively participate in, dynamic pricing options and DR programs.
- Evaluate and propose additional pilot alternatives that could help PGE develop a CPP program.
- Continue to implement PGE's Customer Engagement Transformation program in which we will replace the current CIS and MDC. This will create the platforms on which a more cost-effective, fully scalable CPP program can be developed along with the other benefits discussed in PGE Exhibit 900 in Docket No. UE 262.

Time-of-Day Pricing

Time-of-Day (ToD) pricing currently applies to PGE's Schedule 89 and Schedule 85 customers. This means that ToD pricing is available for all non-residential customers with monthly demand greater than 201 kW. As of January 2014, with Commission approval of UE 262 pricing, ToD pricing will also extend to Schedule 83 customers (i.e., non-residential customers with demand greater than 31 kW per month).

Energy Tracker^{SM}

PGE released its Energy Tracker^{SM} program in December 2011. This is an energy information tool that utilizes the interval data from PGE's Advanced Metering Infrastructure system. It provides customers with energy use information that can help identify reduction and peak shifting strategies that customers may find useful to implement.

More recently, PGE is preparing a Phase 2 release of the Energy Tracker^{SM} program, targeted for 2014. Along with a more customer-friendly look and feel, Phase 2 will provide more valuable information to customers in the form of optional alerts related to energy usage and projected billing amounts. With Phase 2 information, customers will be able to see their bill-to-date information along with a projected bill based on their current usage. Additionally, customers will be able to sign up for alerts that will notify them via email and/or text of: 1) current bill information; and 2) if they are projected to exceed preset thresholds. Because these are the two most commonly requested alerts by customers, we expect them to be used extensively.

4.5 Conservation Voltage Reduction (CVR)

As described in our 2012 IRP update, PGE is following the plan described below to meet OPUC requirements related to the potential of distribution system efficiency savings via conservation voltage reduction (CVR). The OPUC required PGE to "consider(ing) conservation voltage reduction (CVR) for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings" (see OPUC Order No. 10-457 at 22).

PGE recently completed a feasibility study to assess the technical potential for CVR savings. Within the feasibility study, the following were considered:

- Selection of the substations Denny and Hogan South, which are representative of PGE's urban substations primarily serving residential loads.
- Use of third-party power flow modeling software, known as CYMDIST, for the evaluation of power flows under four load profiles: Heavy Winter (i.e., the single highest winter load hour), Light Winter (i.e., the average on-peak winter hour), Heavy Summer, and Light Summer.
- Consideration of customer composition (i.e., commercial, industrial, and residential) served by those substations.
- Consideration of load characteristics (i.e., constant impedance, constant power, and constant current) served by those substations.
- Evaluation of system changes necessary to implement CVR.

Preliminary study results indicate that peak load reductions are possible, particularly in the winter. Potential savings will vary based on existing substation equipment, feeder layout, and customer end use mix.

In July, CVR was successfully implemented at the Hogan South substation. Hardware installation, including an upgraded transformer load tap controller and distribution capacitor banks was completed at the Denny substation in October 2013.

The potential for CVR benefits will be evaluated for both constant CVR implementation (kWh) and for peak demand shaving (kW). The intent of PGE's two substation pilot is to identify and quantify the energy and demand savings that may be available through CVR.

With results from the pilot project, PGE will summarize the study results for both substations by:

- Reporting cost estimates for equipment needed to implement CVR.
- Reporting benefits in avoided kilowatt hours and reduced kilowatts of peak demand.
- Performing cost/benefit economic analysis to move from technical potential to cost-effective potential.

PGE's CVR pilot/study plan has the following milestones:

• Substation Selection Methodology	Complete
• CYMDIST Study Methodology	Complete
• Verify CYMDIST Model Accuracy	Complete
• Perform CYMDIST Studies	Complete
• Determine Pilot Project Scope	Complete
• Implement Pilot Project at first substation	Complete
• Implement Pilot Project at second substation	Complete
• Pilot Project Complete	06/30/2014
• Report Project Results & Recommendations	10/31/2014

Based on field performance at the two substations over the course of a full year, the final step will be to assess the potential net benefit of system-wide implementation.

4.6 Future DR Actions

Over the next three years (to 2016), PGE intends to take the following actions to further develop DR:

- Continue to implement the curtailment tariff to achieve the target 20 MW of capacity by 2015.
- Continue to develop and ramp up the ADR pilot to achieve 25 MW by 2017, and complete interim program evaluations in 2015 and 2016.
- Develop an education program and new dynamic pricing pilot (for instance the potential CPP pilot discussed above) in advance of the deployment of new CIS and MDC systems.
- Refine the smart water heater direct load control pilot. This will allow PGE to better position ourselves for the eventual introduction of scalable technologies.
- Continue to evaluate demand and energy savings associated with the two substation CVR pilot and then perform cost/benefit analysis.

5. Flexible Capacity Needs

This chapter examines PGE's supply and demand balance for flexible capacity. We further assess the ability of PGE's resources to respond quickly to changes in load and variation in wind energy production. Our analyses focus on 2015 and 2020, years in which the Oregon Renewable Portfolio Standard (RPS) increases. We provide separate analyses for the second quarter (Q2) and for the other three quarters (Q1, 3, & 4), as certain supply restrictions specifically affect Q2.

Chapter Highlights

- With the addition of new resources from our recent energy and capacity RFP, PGE's flexible resources will be able to meet 2015 demands for rapid generation increases to cover combined decreases in wind resource output and unexpected load increases.
- PGE's current and planned flexible resources are insufficient to meet 2020 demands for rapid generation increases to cover combined decreases in wind output, coupled with unexpected load increases.
- PGE's portfolio has little downward flexibility in both 2015 and 2020 (i.e., very restricted ability to quickly decrease generation to cover increases in wind output, combined with unexpected load decreases).

5.1 Introduction

PGE needs flexible resources to follow the output of variable energy resources (VERs), which are currently primarily wind generation. With completion of the Tucannon River (TR) wind facility, PGE will own and operate 717 megawatts (MW) of nameplate capacity wind generation.[24] The output of these resources varies unpredictably over short time intervals, making it necessary for PGE to either use its own resources to offset the wind output variations, or to purchase integration services from other providers (e.g., BPA). PGE (or the firming provider) must have resources which can rapidly increase energy production when wind output decreases or rapidly decrease energy production when wind output increases. Oregon Public Utility Commission (OPUC) Order No. 12-013 requires utilities to include in their IRPs a forecast of flexible capacity demand requirements and supply capability. As noted above, PGE expects to have a large wind generation increase in 2015 due to the addition of TR and again in 2020 to meet increasing Oregon RPS requirements. Both the 2015 and 2020 views also include Port Westward 2 (PW 2), the flexible resource selected in our recent energy and capacity Request for Proposals (RFP).

PGE's approach to assessing supply and demand for flexible capacity draws on work done by Michael Schilmoeller at the Northwest Planning and Conservation Council (Council).[25] We met twice with Dr. Schilmoeller to discuss our approach. We also attended the Council's Flexibility Metric Round-Table on May 2, 2013, at which several researchers presented their current work on this issue. As this is a new area of research and analysis, additional methods and insights are likely to develop over the next several years.

5.2 Demand for Flexible Capacity in 2015 (Q1, 3, & 4)

This section includes a general discussion of demand requirements for flexible capacity, followed by detailed discussion of projected operating conditions for Quarters 1, 3, and 4. We then examine Q2 conditions separately because the supply of flexible resources is particularly constrained during that period.

Currently wholesale power markets in the Pacific Northwest (PNW) do not function at a granularity of less than one hour. Therefore, if PGE does not purchase wind integration services from another entity, within any one-hour period it must be able to offset variances between forecast and actual VER production with its own flexible resources. PGE must also absorb the differences between forecast and actual load within the hour.

To calculate the maximum flexibility demands resulting from fluctuation in PGE's loads and VER output over any interval up to one hour, we started with load and wind data from the years 2004, 2005, and 2006. The load data are simply observations of PGE's

[24] 450 MW from Phases 1, 2, and 3 of Biglow Canyon, and 267 MW from TR.

[25] Dr. Schilmoeller provides a detailed description and discussion of his approach in a paper, "Imbalance Reserves: Supply, Demand, and Sufficiency."

actual system load at one-minute intervals. The wind data sets are synthetically developed. Specifically, the wind data are derived by running National Renewable Energy Laboratory (NREL) one-minute actual wind speed observations at Biglow Canyon (Biglow) and TR for the 2004-2006 period through power curves for the current Biglow turbines and the turbines to be utilized at the TR site.[26] For the 2015 view, we scaled the load data to be consistent with our 2015 load forecast. The wind data did not require scaling, as the addition of TR almost exactly meets the 2015 RPS requirement.

For analytic purposes, it is convenient to think about flexible capacity demand requirements in terms of changes to "load net of wind" (i.e. deviations in PGE electric load minus unplanned changes to the output of wind generation). Increases in "load net of wind" require the ability to rapidly ramp up energy production, while decreases in "load net of wind" require the ability to rapidly ramp down non-wind generation, or to "feather" (i.e., decrease) wind output. The first situation is both a reliability and economic concern. The second condition is solely an economic concern.

From the data described above, we calculated "load net of wind" for every one-minute interval in the three-year data set. For example, in the 2015 analysis, the "load net of wind" observation based on the one-minute period beginning at 8:33 and ending at 8:34 a.m. on July 23, 2005 is the actual historical PGE load for that minute (scaled by a factor, [forecast 2015 load] / [actual 2005 load]), minus the sum of the "synthetic" Biglow and TR output data for that same minute. Given three years of data and the one-minute level of granularity, our data set consists of approximately 1.6 million observations,[27] of which 1.2 million are associated with Quarters 1, 3, & 4.

From the one-minute "load net of wind" observations, we then calculated all changes from one minute to the next. Generation resources that can ramp up or down within one minute are required to offset the "load net of wind" minute-to-minute changes. For example, the one-minute change associated with 8:34 a.m. on July 23, 2005, is the 8:34 a.m. "load net of wind," minus 8:33 "load net of wind." From this set of all possible one-minute up or down ramping demands from our three-year data set associated with Q1, 3, & 4, we selected the highest and lowest observations as the one-minute up and down ramp requirements for Q1, 3, & 4 of 2015. The highest observation represents the maximum amount by which PGE resources would have to increase output within one minute to continue meeting customer energy demand. The lowest observation represents the maximum amount by which PGE resources would have to decrease output within one minute to avoid over-production.

In a similar way, we calculated all two-minute changes in "load net of wind," with the highest and lowest observations selected as the two-minute up and down ramp requirements for Q1, 3, & 4 of 2015. The highest observation represents the maximum amount by which PGE resources would have to increase output within two minutes to continue meeting customer energy demand. The lowest observation represents the

[26] For the 2020 view, we also include similar data for "Site X," a potential future wind resource location in the Columbia Gorge.

[27] Three years, multiplied by 8,760 hours per year (8,784 in 2004), then multiplied by 60 minutes per hour, results in approximately 1,578,000 data points.

maximum amount by which PGE resources would have to decrease output within two minutes to avoid over-production. We repeated this procedure for increasing time intervals to determine 2015 Q1, 3, & 4 up and down ramp requirements by minute through a one-hour time frame. These requirements over any interval through one hour form a demand curve for up and down ramping from PGE's flexible resources.[28] Figure 5-1 below illustrates PGE's 2015 Q1, 3, & 4 demands for generation flexibility for periods up to one hour. Due to the confidential nature of the data, we do not include exact MW quantity figures in this chapter.

Figure 5-1: 2015 Q1, 3, & 4 ramping demand curves

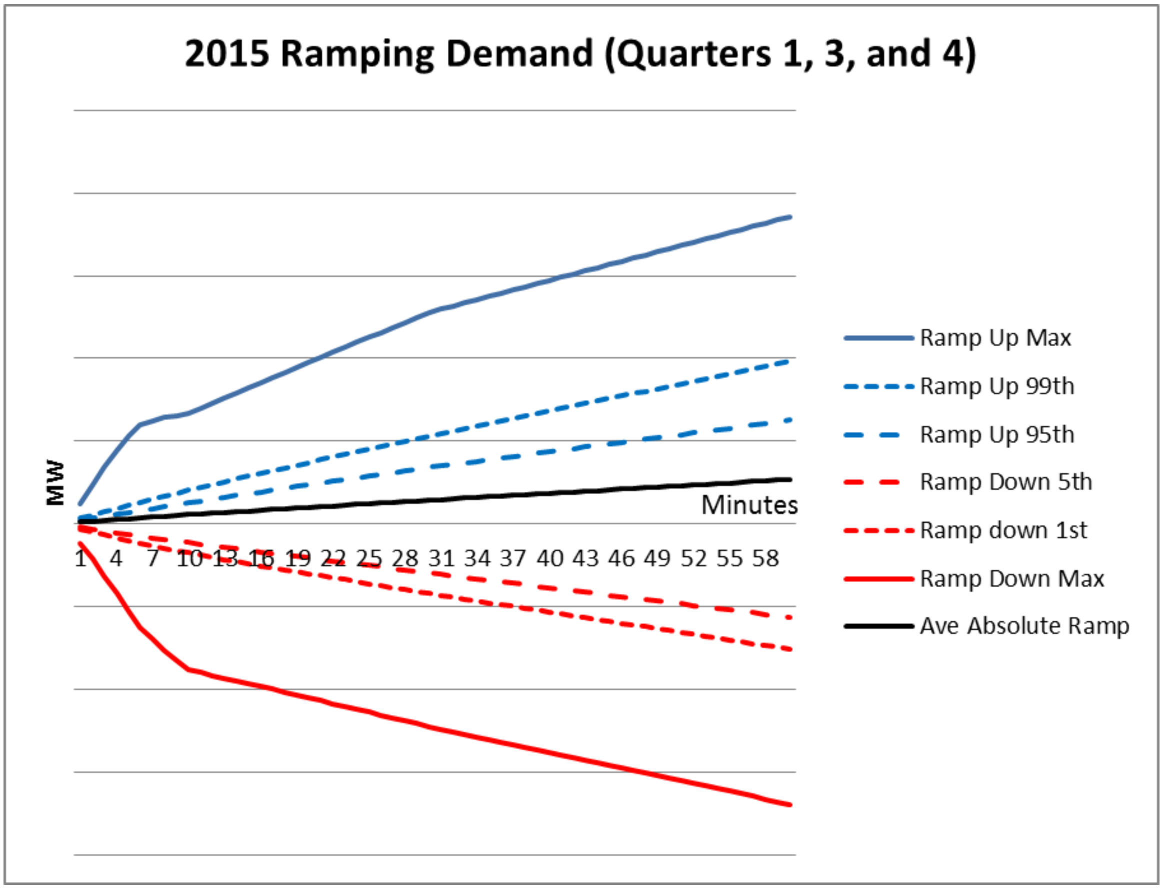


Figure 5-1 also includes percentile information. For example, the blue dotted "Ramp Up 99th" line represents the 99th percentile of the data set for any time interval. If the observation for ten minutes were 50 MW, then 99% of all 2015 Q1, 3, & 4 ten-minute ramp requirements (based on the 2004-2006 data sets) would be less than 50 MW. The red dotted "Ramp Down 1st" line provides the same information from a down ramp

[28] Note that there is no "contiguous" requirement. The maximum 4-minute up ramp requirement for 2015 might be associated with data from the four-minute period ending at 4:34 p.m. on a particular day in 2005, whereas the maximum 5-minute requirement for 2015 might be associated with data from the five-minute period ending at 8:37 a.m. on a particular day in 2004. In other words, the "curve" simply reflects the "worst possible one minute event," the "worst possible two minute event," …. the "worst possible one-hour event," regardless of the times within the three-year data set with which they are associated.

perspective. "Ramp Up 95th" and "Ramp Down 5th" lines provide similar information on the highest and lowest 5% of all up and down ramp requirements. The solid red and blue lines show the "Ramp Up Max" and "Ramp Down Max" requirement, which form our flexibility demand curve. These lines represent more extreme conditions (i.e., substantially higher than the "Ramp Up 99th" and substantially lower than the "Ramp Down 1st" lines). This makes sense from two perspectives: First, our Q1, 3, & 4 data set has almost 1.2 million observations (i.e., the highest 1% of all observations includes approximately 12,000 observations). These most extreme of the 12,000 maximum observations are likely to vary substantially from the 99th percentile observation. Second, we know that in practice extreme, unexpected variations in combined wind generation and load do occur, albeit infrequently.

5.3 Supply of Flexible Capacity in 2015

In Q1, 3, & 4 of 2015, PGE will have several resources with the flexibility to help meet up and down ramp needs. These include contracts for output shares from certain dams on the middle section of the Columbia River (Mid-C), PGE's own Pelton-Round Butte hydro facilities (P/RB), dispatchable stand-by generation (DSG),[29] duct firing at PGE's Port Westward plant, PW 2,[30] Beaver in simple-cycle mode,[31] and automated demand response (ADR).[32]

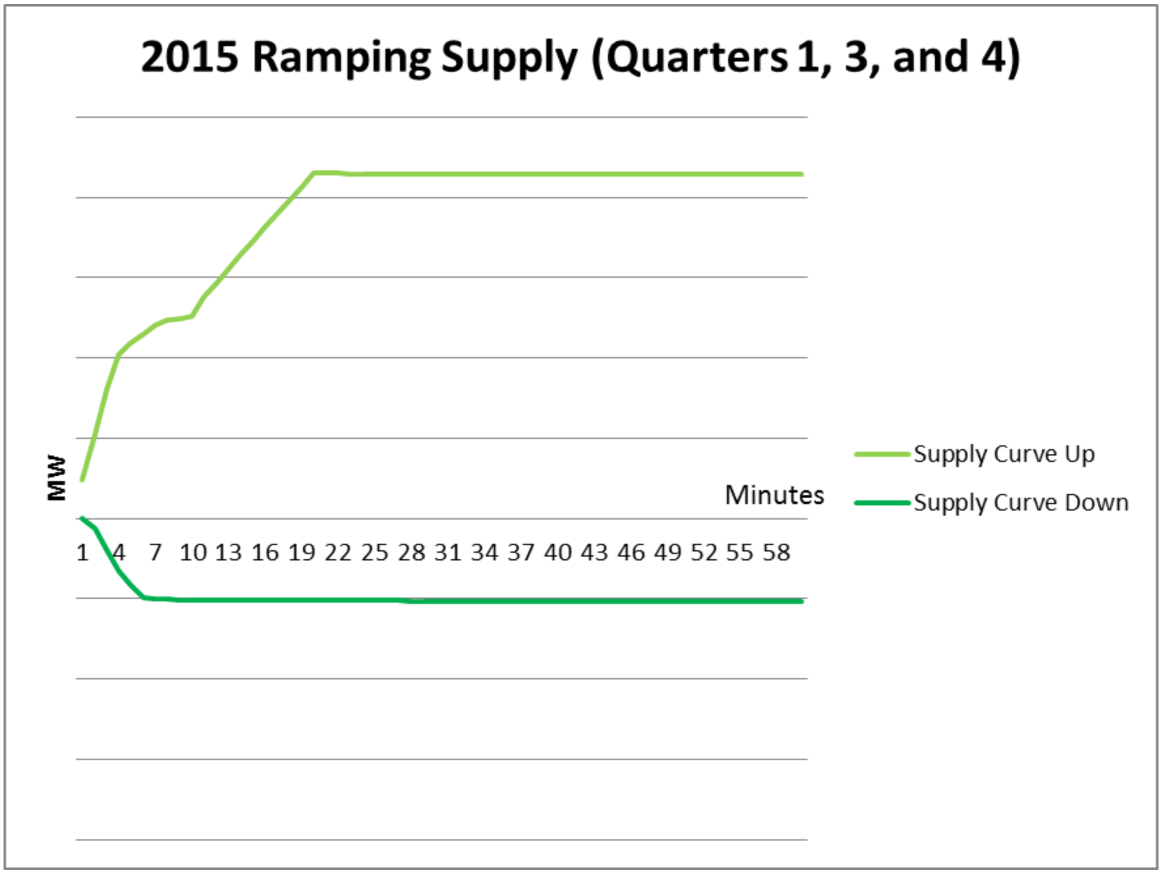
Some of these flexible resources, hydro in particular, can ramp up or down very quickly.[33] DSG can ramp up quickly, but generally cannot ramp down, as it is usually not running for routine energy needs due to its relatively high dispatch cost.[34] PW 2, chosen specifically as a dual-purpose resource to help meet PGE's peak load needs and to provide year-round flexibility at a moderate operating cost, will have rapid up and down ramp capability. However, for this flexibility analysis, we assume that PW 2 is not normally running at the start of an event based on the plant's expected economic dispatch. Therefore, we assume PW 2 can provide its nameplate capacity for up ramp, but no contribution to down ramp. Similarly, it is usually uneconomic to run Beaver for base load energy purposes. Therefore, it is modeled to provide full output in up ramp, but no capability for down ramp. Finally, ADR, at its current state of development, will only be able to provide up ramp. In addition, ADR, like some other resources, can provide up ramp only after a delay.[35]

[29] Diesel-fueled resources at customer sites distributed throughout PGE's service territory.
[30] PGE's new natural gas-fired reciprocating engines, expected to be online by 2015.
[31] Beaver can also be run in combined cycle mode.
[32] We expect to have 15 MW of ADR in place by 2015, and 25 MW by 2020.
[33] We assume that hydro resources are running at their average output levels at the start of an event requiring a flexible response. Then they can ramp up (to their maximum output levels) by an amount equal to their maximum minus their average levels. They can ramp down (to zero) by an amount equal to their average output levels.
[34] There is also a contractual limitation on how frequently PGE can call on DSG.
[35] For ADR, the delay is due to host/customer notification requirements. For other resources, the delay is due to plant operating characteristics – no output for a time as the plant warms up, then a ramp up to maximum output.

The up ramp supply curve is built by "turning on" all up ramp capable resources and moving them up to their maximum output levels as soon as possible (based on operating characteristics). During the first minute, several resources can increase output. A few are already at their maximum output levels by the end of the first minute, meaning that they cannot further increase output during the second minute. Other resources reach their maximum output levels after various short time intervals. Finally, a third group of resources have up ramp capability, but only after delays (i.e., their output levels are zero for several minutes, after which they begin to up ramp to their maximum output levels). The overall up ramp supply curve has kinks at points in time when individual resources meet their maximum output levels and a flat zone for a short period after most resources have reached their maximum output levels, but before the delayed response resources have started ramping up. The light green line in Figure 5-2 shows how much PGE's up ramp resources as a group can increase output over any time interval – one minute, two minutes,.., up to one hour during Q1, 3, & 4 of 2015. This is effectively the up ramp supply curve, or what PGE's ramping resources can provide to meet the potential up ramp demands shown in Figure 5-1.

The 2015 Q1, 3 & 4 down ramp supply curve is simpler, as we assume that all resources except hydro are at zero output levels at the start of an event requiring flexible generation response, and therefore cannot provide down ramp. Additionally, different hydro resources have different down ramps, but they can all decrease output to assumed minimum levels within a short time period. The down ramp supply curve then flattens out, as shown in the green line in Figure 5-2. As with the demand curves in Figure 5-1, we do not include the confidential figures on the vertical axis.

Figure 5-2: 2015 Q1, 3, & 4 ramping supply curves



In addition to the individual resource operational characteristics discussed above, the up and down ramp supply curves include a number of adjustments because we must also account for certain hour-to-hour forecast errors and reserve margin requirements. In this study, we specifically limit the availability of our flexible resources to meet intra-hour "load net of wind" deviations for the following operating/system requirements:

- Contingency reserves of 7% and 5% required for thermal and other generation resources.[36]
    - 3.5% (thermal) and 2.5% (other – e.g. wind and hydro) spinning reserves.
    - 3.5% (thermal) and 2.5% (other – e.g. wind and hydro) non-spinning reserves.
- Hour-to-hour load forecast error (assumed at 2.5% of load based on historical data).
- Hour-to-hour wind forecast error (difference between actual wind over an hour and the "half hour ahead forecast", calculated from our data set).

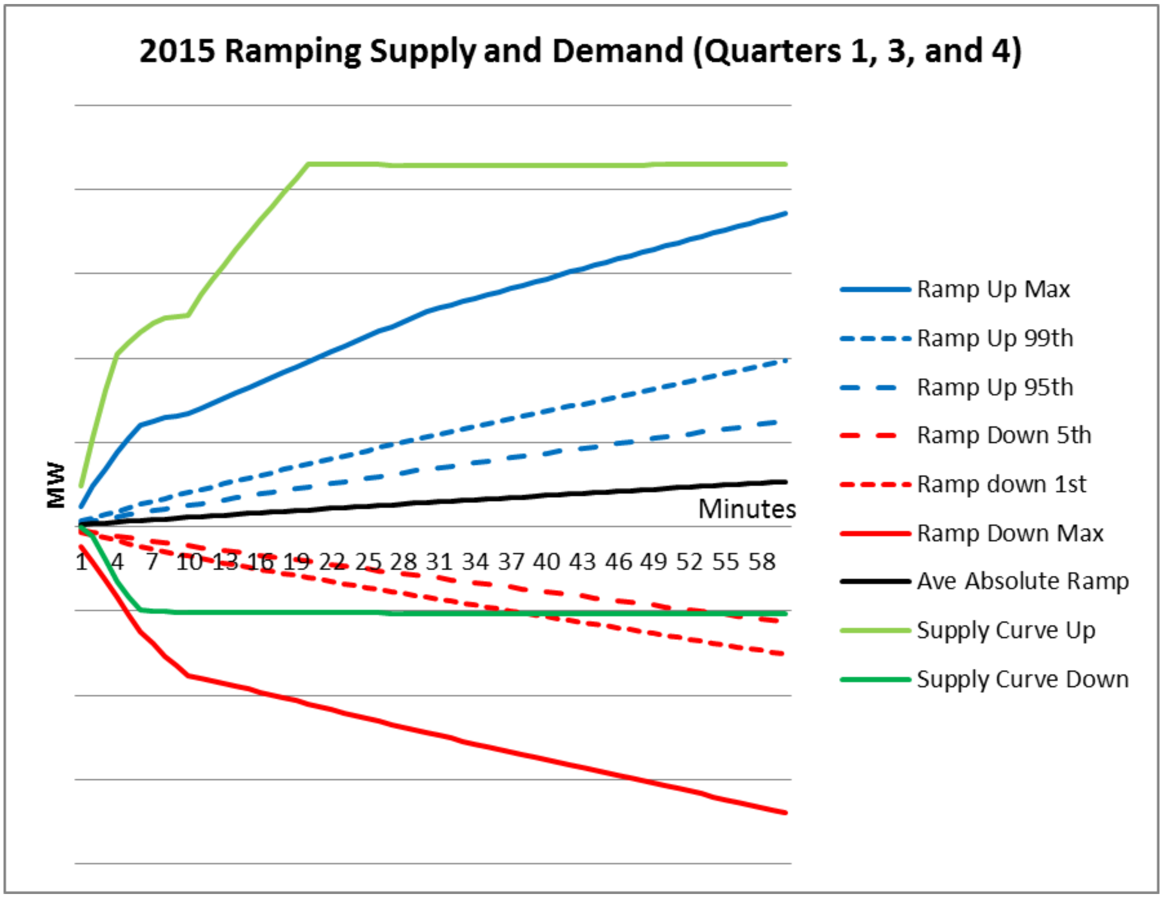
However, this study does not take regulation requirements into account. We also do not include forced outages at generation plants.

[36] Proposed changes to these requirements would not significantly affect our analysis.

5.4 *Adequacy of Flexible Capacity in 2015 (Q1, 3, & 4)*

Figure 5-3 superimposes the ramping supply curves of Figure 5-2 on the ramping demand curves of Figure 5-1. Two conclusions then stand out in Figure 5-3. First, within a one-hour period in 2015, PGE could likely meet any up ramp requirement with its own resources. The light green supply curve is above the blue demand curve for events of any time duration up to one hour. Second, PGE could not meet down ramp requirements with its own resources. The worst case (red Ramp Down Max) demand curve in Figure 5-3 is greater than the green supply curve for events of any time duration.

Figure 5-3: 2015 Q1, 3, & 4 ramping supply and demand curves



On the up ramp side, the addition of 267 MW of wind generation at TR increases the demand for up ramp capability, but the addition of a new flexible resource, PW 2, provides an offsetting increase in supply which is sufficient to cover "load net of wind" demand events for durations of up to one hour.[37]

[37] Wind power outputs from Biglow and TR are only moderately correlated, making our overall wind output steadier, and cheaper to self-integrate, than "two Biglows" or "two TRs." However, the flexibility study focuses on extreme events, and the data from 2004–2006 indicate that there are time intervals during which either both Biglow and TR produce at near maximum output levels or both produce at near zero levels. Load, also part of the "load net wind" observations, is slightly negatively correlated with either of the wind regimes. However, the data also

As noted above, the down ramp side is more problematic in 2015. However, a decomposition of the down ramp demand curve into load and wind changes indicates that rapid increases in wind output make up most of the down ramp demand.[38] Therefore, a possible response would be to feather (or essentially shut off) the wind resources and meet the remaining requirement with PGE's down ramp capable resources. The remaining down ramp requirement is due to negative load changes, and the data indicates that, in most circumstances, PGE's flexible resources can provide an adequate response. This solution is costly, however, due to the lost energy value and production tax credits associated with the curtailed wind generation.

5.5 Flexibility Supply, Demand, and Adequacy in 2015 (Q2)

The above assessment regarding PGE's flexible capacity supply and demand is relevant for all quarters in 2015 except Q2. Q2 requires a separate analysis because our Mid-C resources are more constrained in that quarter due to spring run-off and fish passage constraints.

The 2015 Q2 flexibility supply curve differs from the 2015 Q1, 3 &, 4 supply curve developed above in two respects. First, the up ramp supply curve shifts down with the removal of Mid-C flexibility. Second, the down ramp supply curve shifts up, also due to removal of Mid-C flexibility. In fact, after forecast error and other adjustments, PGE has essentially zero down ramp capability in Q2.

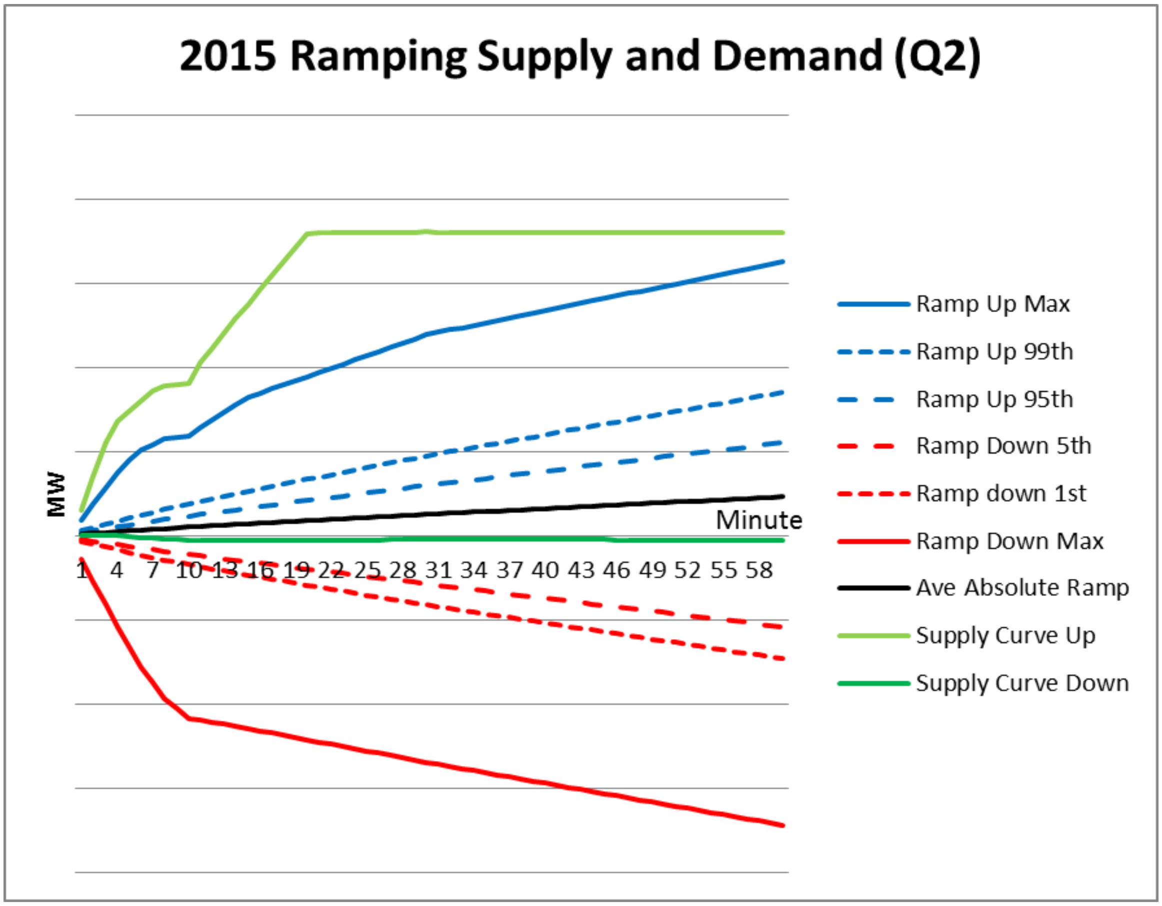
The 2015 Q2 flexibility demand curve differs from its Q1, 3, & 4 counterparts discussed above in that it consists only of extreme events associated with time intervals within Q2 of the years 2004-2006. The Q2 up ramp demand curve is somewhat lower than its Q1, 3, & 4 counterparts. Extreme up ramp demand values from the Q2 data set are lower than the extreme values from the Q1, 3, & 4 dataset.

Figure 5-4 shows 2015 Q2 supply and demand curves for flexible capacity. Supply and demand for up ramp have shifted down (compared to the Q1, 3, & 4 results) by approximately the same amount. (Compare Figure 5-3 and Figure 5-4) Therefore, the overall conclusions reached above for Q1, 3, & 4 also hold for Q2. In Q2 of 2015, we would be able to respond to extreme up ramp demand events for durations of up to one hour with our flexible resources.

indicate that there are extreme events, during which both Biglow and TR produce at maximum levels and load decreases substantially (or during which both Biglow and TR produce no output and load increases substantially).

[38] This is particularly true for events of less than 30-minute duration.

Figure 5-4: 2015 Q2 supply and demand curves for flexible capacity



On the down ramp side, PGE's lack of down ramp capability is more pronounced in Q2 than in Q1, 3, & 4. As noted above, the red demand curve does not shift significantly, but the green supply curve shifts up considerably with removal of the Mid-C hydro down ramp capability. This results in an inability to cover even the load decrease component of extreme Q2 demand events, although the wind increase component could still be addressed by wind generation curtailment. Again, there would be cost impacts associated with a wind curtailment approach to addressing down ramp needs.

5.6 *Flexible Supply, Demand, and Adequacy in 2020 (Q1, 3, & 4)*

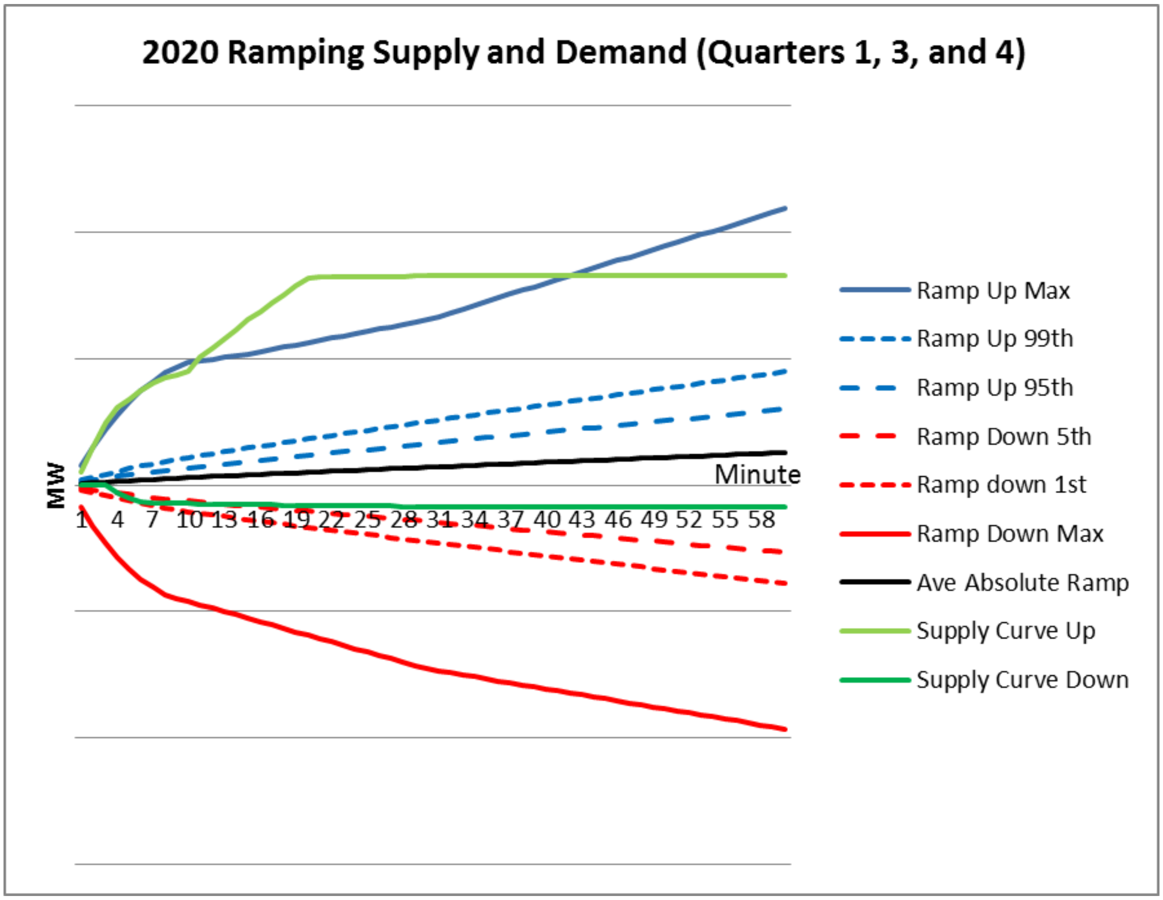
Our analytical approach for 2020 is the same as for 2015. However, some of the input assumptions change between 2015 and 2020.

On the demand side, "load net of wind" observations and related calculations include 2004-2006 load data scaled up to expected 2020 load. As a proxy for additional wind to meet a 2020 physical RPS requirement, the analysis also includes wind data from a 475 MW nameplate "Site X" (a site in the Columbia River Gorge for which we have NREL data for the 2004-2006 period). Wind observations for 2020 are then the sum of output data for Biglow, TR, and "Site X." The addition of increased load and "Site X" results in more extreme ramp demands in 2020. In other words, the 2020 up ramp demand curves are higher than their 2015 counterparts and the 2020 down ramp demand curves are lower than their 2015 counterparts.

On the supply side, we project ADR to increase by 10 MW between 2015 and 2020. Duct firing at the Carty plant will also be available. However, Mid-C contracts expiring between 2015 and 2020 will significantly decrease PGE's Q1, 3, & 4 ramping capability, both up and down. The combined result of these changes is decreased Q1, 3, & 4 ramp capability, both up and down.

Figure 5-5 shows PGE's demand for and supply of flexibility in Q1, 3, & 4 of 2020. On the up ramp side, PGE's flexible resources would not be able to meet potential Q1, 3, & 4 demands for periods of more than approximately 40 minutes. At this point, our resources have reached their ramp up maximum capability; however, the demand needs. On the down ramp side, PGE's flexible resources are very limited. As previously noted, wind can be feathered, but this is expensive. In addition, PGE's resources would not be able to cover even the load decrease component (aside from wind generation changes) of the most extreme 60-minute Q1, 3, & 4 events implied by the data set.

Figure 5-5: 2020 Q1, 3, & 4 supply and demand for flexibility

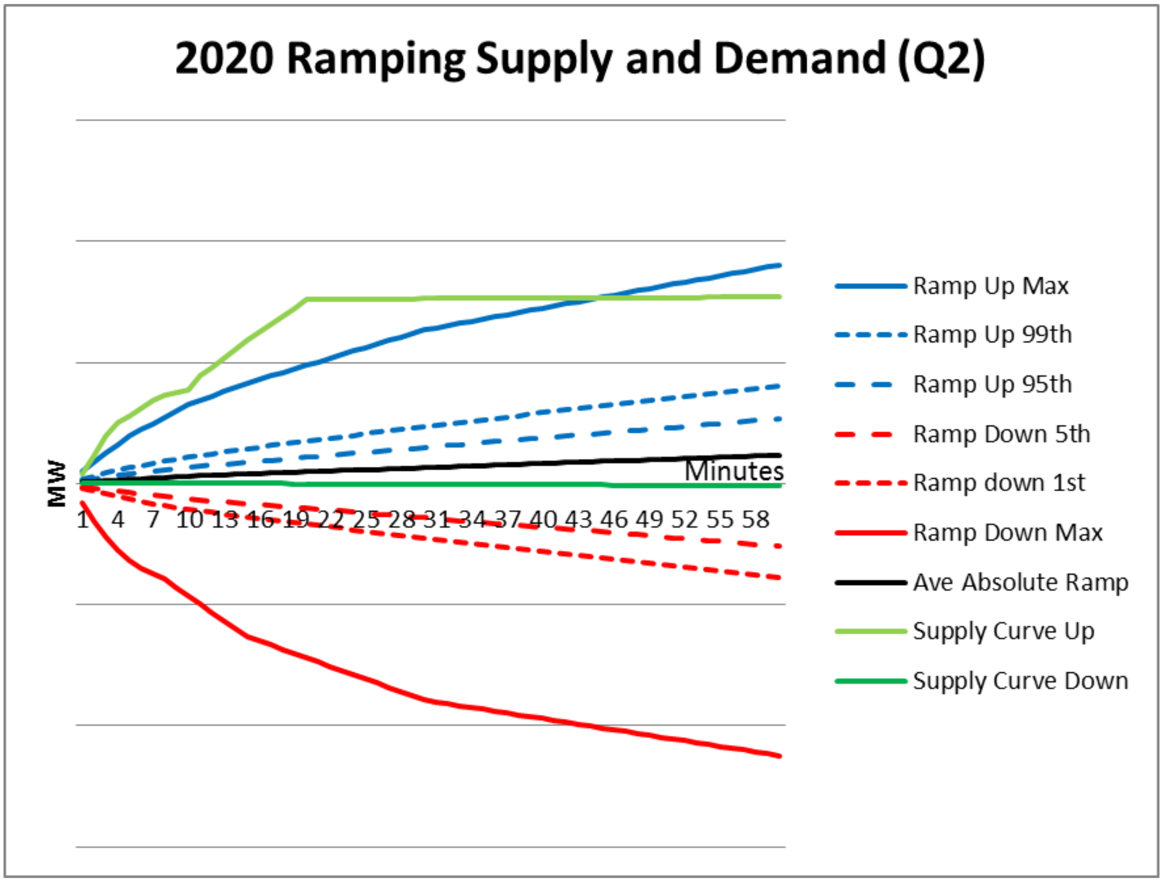


5.7 Flexible Supply, Demand, and Adequacy in 2020 (Q2)

Figure 5-6 provides the Q2 2020 look at flexible resource supply and demand. As discussed above, the Mid-C resource cannot reliably supply either up or down ramp during Q2. Compared to the 2020 Q1, 3, & 4 supply look shown in Figure 5-5, the 2020 Q2 up ramp supply curve shifts down with the removal of Mid-C capability. Loss of Mid-C capability also shifts the down ramp supply curve up enough to almost eliminate all down ramp capability. For down ramp demand, the red down ramp demand curves in Figure 5-5 and Figure 5-6 are similar, although Q2 extremes are somewhat greater than their Q1, 3, & 4 counterparts for intervals of 15 minutes or longer. For up ramp demand, the blue demand curve for Q1, 3, & 4 is somewhat greater than its Q2 counterpart for all time intervals.

On the up ramp side, the downward shifts in Q2 supply and demand curves (with respect to their Q1, 3, & 4 counterparts) are off-setting. Therefore, as in Q1, 3, & 4, PGE's flexible resources could only cover potential Q2 up ramp demands of up to approximately 40 minutes. Additional flexible resources would be needed to meet possible up ramp requirements of longer duration. On the down ramp side, loss of Mid-C capability in Q2 simply makes an already challenging Q1, 3, & 4 situation worse. In 2020, PGE's Q2 down ramp capability is essentially zero.

Figure 5-6: 2020 Q2 supply and demand for flexibility



5.8 *Summary and Conclusions*

Our study results indicate that in 2015, PGE's flexible resource supply will be able to meet potential "load net of wind" up ramp requirements for durations of up to one hour. Expected portfolio changes through 2015, namely the addition of TR (increases up ramp demand) and PW 2 (increases up ramp supply), are largely offsetting. However, absent the addition of new flexible capacity resources, PGE would not be able to meet potential within hour "load net of wind" up ramp events by 2020. New potential wind generation additions to meet the 2020 RPS requirements, combined with expected load growth, will increase our flexible resource demand, while overall supply will decrease during that time due to reduced hydro availability.

On the down ramp side, PGE would not be able to meet all potential "load net of wind" events as soon as 2015. By 2020, this condition worsens, with PGE's resources providing only very limited down ramp capability in Q1, 3, & 4, and virtually none in Q2. As discussed earlier, deficits in up ramp capability pose a potential reliability risk, while down ramp supply deficits are largely an economic risk due to the ability to curtail wind generation.

We did not modify Figures 5-2 through 5-6 to reflect the agreement in principle with the Tribes for their share of Pelton and Round Butte output, as the impact is largely known without resorting to refreshing the analysis.[39] However, the increased ramping capability from the Tribes' share is modest relative to the ramping needs identified in this chapter. On the down ramp side, we still would not be able to meet all potential "load net of wind" events as soon as 2015. On the up ramp side, we still would not be able to meet potential within hour "load net of wind" events by 2020.

In this IRP Action Plan we are not proposing any new resource additions to address future flexible capacity needs. However, our analysis suggests that by 2020 expected demand for intra-hour flexibility will exceed supply, resulting in deficits for both up ramp and down ramp capability. We expect to further address our flexible resource requirements, along with other future energy and capacity needs and options for meeting those needs, in the next IRP Action Plan.

[39] The associated Re-reg Dam (wholly owned by the Tribes) does not provide ramping capability.

6. Fuels

This section addresses fuel supply/demand fundamentals and drivers, fuel price forecasting methodology, fuel portfolio composition and requirements, and the strategy for fueling PGE's natural gas- and coal-fired generating units. We also address the role of hedging.

Our approach to projecting fuel prices is to first develop a reference case forecast based on near-term market indicators and longer-term fundamentals developed by third-party, expert sources. For this IRP, we used independent research and price forecasts from Wood Mackenzie Limited (Wood Mackenzie) for natural gas pricing and the U.S. Energy Information Administration (EIA) for coal pricing. Along with reference case prices, we also utilize high- and low-price sensitivities.

Our least-cost strategy for natural gas procurement is to buy physical and use financial instruments to hedge price risk via a layered five-year strategy. We holistically manage natural gas supply, transportation, storage, and plant dispatch because this portfolio approach minimizes overall costs.

Chapter Highlights

- We expect natural gas prices to increase moderately over the planning horizon, with a reference case forecast levelized price over the planning horizon of $4.76/MMBtu.
- However, shocks to supply and demand are possible; shale oil developments will impact supply and LNG exports will impact demand. Nonetheless, the high- and low-price gas forecasts vary by roughly only $1 both up and down.
- We will meet the fuel requirements of our new gas plants, Port Westward 2 and Carty, by a combination of increased firm transportation and increased storage capability.
- We expect coal prices to increase very moderately over the planning horizon. Shocks to either coal supply or demand are less likely.

6.1 Natural Gas Price Forecast

Overview

Natural gas and coal prices are important inputs to the AURORAxmp model as they are the major drivers of the wholesale electricity prices and the economic performance of power plants in the Western Electric Coordinating Council (WECC) area. All PGE candidate portfolios of future resources include new gas-fired plants to varying degrees. Thus, when assessing portfolios of new resource alternatives, natural gas prices are a primary focus.

Our reference case natural gas forecast, as used in the portfolio analysis for this IRP, is derived from market price indications through 2016 and the Wood Mackenzie long-term fundamental forecast[40] starting in 2019 and going through 2031. We transition from the market price curve to Wood Mackenzie's long-term forecast by linearly interpolating for two years (2017 and 2018). To develop western market prices, we input the long-term Henry Hub price forecast and apply basis differentials for Sumas, AECO, and other WECC gas supply trading hubs.[41] Wood Mackenzie's forecast horizon is to 2031; after 2031 we escalate at inflation.

We chose Wood Mackenzie because they are well-respected, experienced in their fields of expertise, and they provide unbiased and transparent assumptions. In addition to the reference case forecast, they also provide high and low case forecasts. We use these alternative forecasts in our scenario analysis to assess the economic risks associated with different portfolio options.

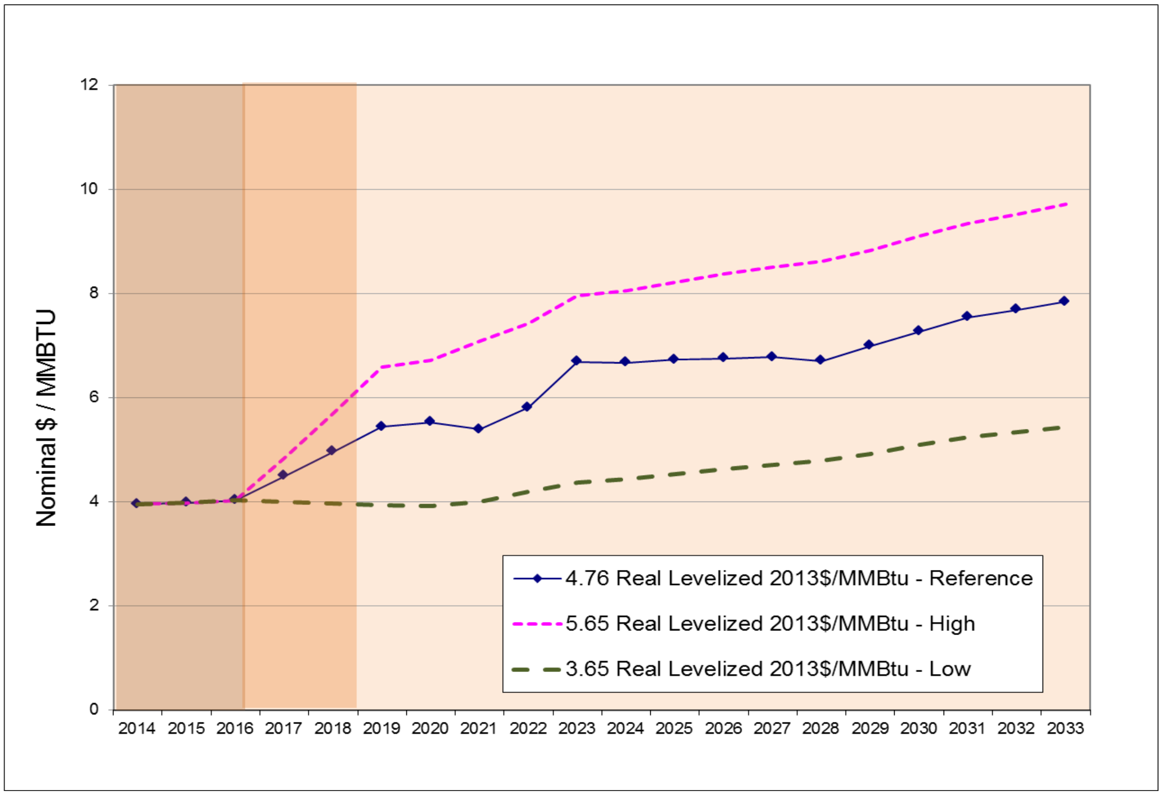
Wood Mackenzie provides bi-annual updates of its long-term fundamentals forecast. The most recent forecast update available for use in our IRP analysis was issued in May 2013. In this assessment, Wood Mackenzie projects modest long-term natural gas price increases from current levels of approximately $3.50 per million British Thermal Units (MMBtu). The reference case real levelized price for the period from 2014 to 2033 is $4.76/MMBtu (in 2013 dollars).

Figure 6-1 shows our reference case, high, and low forecasts for the average of Sumas and AECO hub prices over the IRP analysis period based on the most recent Wood Mackenzie forecast at the time we performed our portfolio analysis.

[40] Wood Mackenzie. North America Gas Long-Term View: Spring 2013.

[41] Sumas and AECO are the two primary Pacific Northwest natural gas trading hubs from which we fuel our plants. Hub deltas are calculated as annual percentage differences from Henry Hub prices. Other WECC gas hubs modeled in AURORAxmp include Malin, Opal, and Stanfield, among others.

Figure 6-1: IRP long-term forecast – average of Sumas and AECO hub prices



Drivers behind recent price increases from the 2012 bottom of $2.00/MMBtu and the modest projected future increases include:

- **Current and projected gas demand growth**: Low natural gas prices are causing increased displacement of electric generation from less efficient coal plants in the power industry. Gas is also a feedstock for industrial processes and manufacturing, including the chemical and fertilizer industries, which are making a comeback in the U.S. Finally, increased Canadian and U.S. exports via liquefied natural gas (LNG) are projected later this decade.
- **Carbon Regulation**: Assumed implementation of federal carbon regulation in the 2020s, resulting in accelerating displacement of coal by gas.
- **Continued expansion of shale gas supply**: Shale gas development is projected to more than offset a decline in conventional gas production. During the next 10 years, overall U.S. gas supply is expected to increase from 65 billion cubic feet per day (bcfd) to 85 bcfd, with much of the increase occurring in areas linked to the Pacific Northwest via shale gas expansion in western Canada. Expected 2031 domestic supply is projected at 102 bcfd.

Wood Mackenzie updated its forecast in December 2013 and substantially confirmed its prior outlook on gas prices and supply. Specifically, long-term prices were revised downward by $0.40/MMBtu to $4.36/MMBtu (2013$ real levelized 2014-2033). Figure 6-2, Figure 6-3, and Figure 6-4 below compare our Final IRP reference, high and low gas price forecasts with those used in the portfolio analysis

Figure 6-2: IRP and Fall 2013 reference gas forecasts – average of Sumas and AECO hub prices

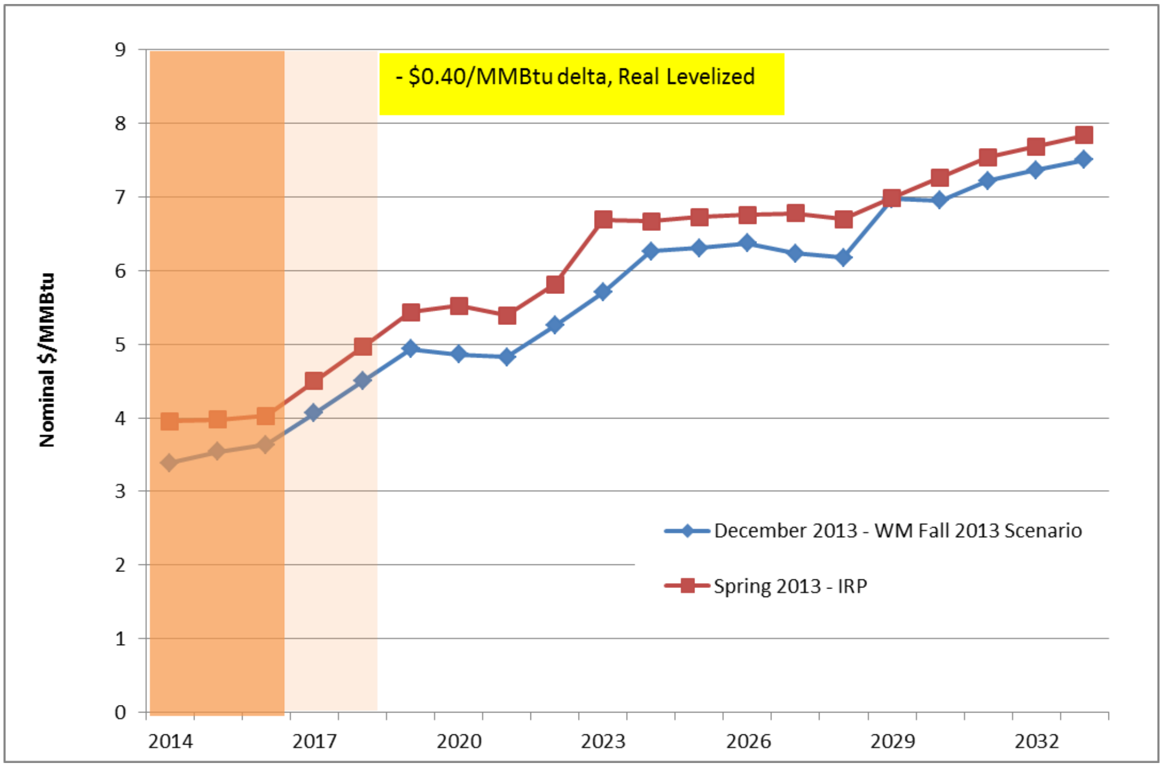


Figure 6-3: IRP and Fall 2013 high gas forecasts – average of Sumas and AECO hub prices

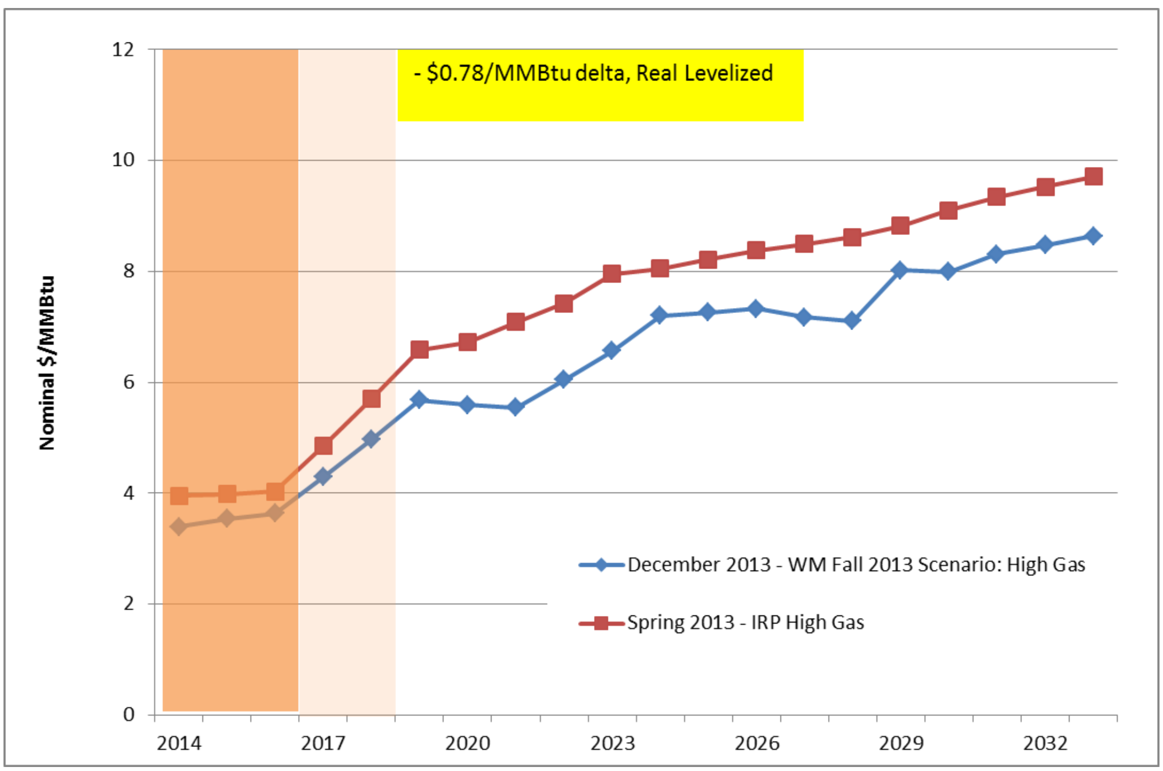
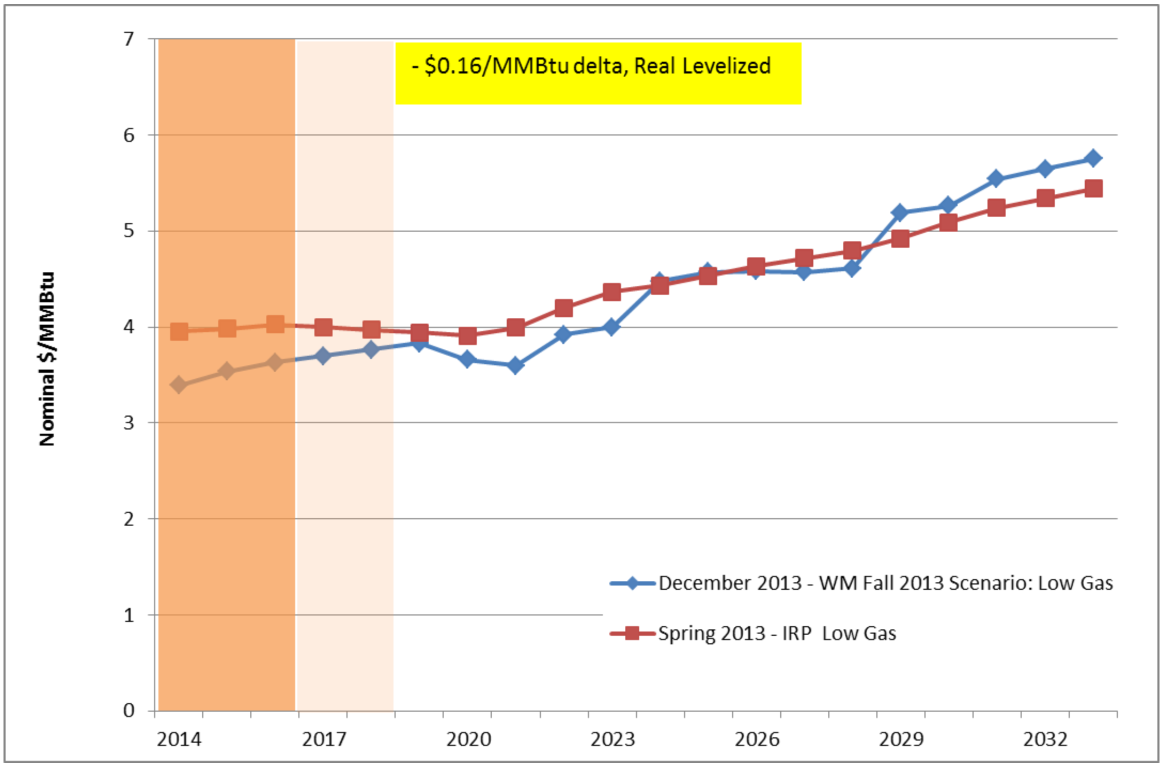


Figure 6-4: IRP and Fall 2013 low gas forecasts – average of Sumas and AECO hub prices



Wood Mackenzie did not identify specific factors behind this slight drop in the price forecast, except for the ongoing success of fracking in keeping gas supply costs down and recovering an increasing amount of hydrocarbons. The section below details the fundamentals behind Wood Mackenzie's long-term models, which, again, are substantially the same for the two forecasts.

As the new gas forecast does not materially change the fundamental outlook on gas supply and prices, and because PGE is not proposing any new long-term resource in this IRP, we did not update our portfolio analysis with the new gas prices. Doing so would be inconsequential for our strategic choices and proposed Action Plan for this IRP.

Natural Gas Forecast Fundamentals

Since PGE's 2009 IRP, shale gas innovations have changed domestic gas industry fundamentals. Abundant current and expected future supply is now the defining feature of the U.S. gas industry.

Ammonia and methanol plants, along with a general resurgence of the manufacturing sector, are expected to increase domestic gas demand. However, gas demand in the power sector, the main source of the demand growth over the past 10 years, is projected by Wood Mackenzie to grow only modestly because of:

- Low electric demand growth projections (around 1% annually nationally), in substantial part due to expectations of further gains in residential and commercial energy efficiency;
- Proliferation of renewable resource standards in many states; and,
- Short-term opportunities to take advantage of relatively lower national coal costs (coal demand is contracting because of various emissions regulations).

Wood Mackenzie expects significant LNG exports to begin late this decade. Dozens of LNG export terminals have been proposed to the Federal Energy Regulatory Commission (FERC), a few have been approved and one, Sabine Pass, is already under construction. However, LNG exports will not be a major element in the U.S. supply/demand balance until well into the 2020s.

Longer-term (2020s and beyond), carbon policy and maturing transport markets will sustain gas demand, but Wood Mackenzie's assessment is that supply will likely be more than adequate to absorb increased demand. Therefore, price spikes are less likely.

However, Wood Mackenzie identifies the following uncertainties:

- **Project commitments**: Development timelines and capacities of LNG terminals might fall short of expectations and consequently depress gas demand. In this case, gas prices would be closer to the low-price scenario in Figure 6-1, especially during the next 10 years.
- **U.S. Gross Domestic Product (GDP) and policy**: Stronger GDP growth, or a rebound in energy intensity, would push gas demand up. Increased carbon emissions could push regional and federal carbon legislation forward more quickly or aggressively, increasing electric fuel switching from coal to gas. In these cases, gas prices would be closer to the high-price scenario in Figure 6-1.
- **Investment in coal mine capacity**: Uncertainty with regard to future environmental regulation, particularly for carbon, is making mining companies hesitant to invest in new capacity. Without further investments, coal might become less price-competitive with gas. This could exert some upward pressure on gas prices.
- **Progress in extraction methods**: A modest price increase is sufficient to incent producers to increase drilling. Increased drilling also sometimes leads to cost reductions through technological improvements. These factors might result in an even higher supply of low-cost gas, maintaining prices in the $4.00/MMBtu range, even with expanding exports.

Wood Mackenzie's assessment is that price dampening factors are likely to dominate the supply/demand dynamics of natural gas price fundamentals, at least over the next decade. Longer-term (beginning in the late 2020s), exports and electric fuel switching could greatly increase and lead to strong upward pressure on gas prices, resulting in the need to develop more expensive shale gas fields to meet export demand.

Gas Transportation Cost

PGE has gas pipeline transportation contracts for existing and planned power plants (see Section 6.2 for more detail). For generic new gas-fired plants in our candidate portfolios, it is not practical to forecast the cost of gas transportation without knowledge of the plant location, in-service timing, and supply options.

In our modeling of new gas-fired plants located in the Pacific Northwest, we based fixed gas transport costs on current 2013 rates of $0.41 per dekatherm (Dth) on Northwest Pipeline (NW Pipeline) and $0.47/Dth on Gas Transmission Northwest (GTN, a unit of TransCanada Pipelines Limited). We then assumed escalation at inflation starting in 2014. We feel this is a reasonable proxy for any future transportation requirements to meet gas-fired plant fuel needs.

NW Pipeline and GTN comprise the primary system for long-haul natural gas transmission from the Canadian and Rocky Mountain supply basins to Pacific Northwest gas-fired plants. NW Pipeline's system extends from the Canadian Border (at Sumas, Washington, which also connects with the Spectra Pipeline) to the Rockies region. This pipeline interconnects with the Kelso-Beaver (K-B) Pipeline and serves or will serve our Port Westward (PW), Beaver, and Port Westward 2 (PW 2) plants. GTN's system extends from the Canadian Border (Kingsgate, Idaho) to Malin, Oregon. This pipeline serves or will serve our Coyote Springs (Coyote) and Carty plants.

6.2 Gas Acquisition, Transportation, and Storage Strategy

Introduction

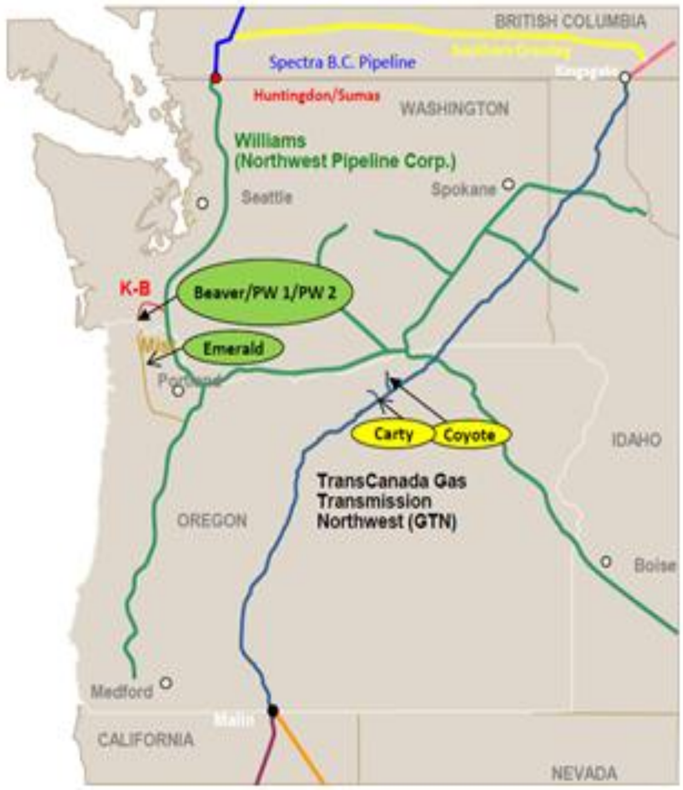
This section begins with an overview of our gas plants, pipelines, and storage facility. We then look at physical gas supply, as well as associated price hedging. Next, we discuss transportation and storage, including how these are important parts of our portfolio approach to managing gas resources. Finally, we consider possible developments which could impact our strategy in the future.

Overview

With the addition of the PW 2 and Carty power plants, PGE's natural gas-fired generation portfolio totals roughly 1,900 MW of nameplate capacity, representing a mixture of base load resources and flexible peaking supply. With gas-fired power plants representing such a significant proportion of our resource portfolio, managing the effects of natural gas prices and supply are key elements of PGE's overall strategy to supply reliable power at reasonable prices.

Figure 6-5 shows the locations of our current (PW, Beaver, and Coyote) and future (PW 2 and Carty) gas-fired resources. The figure also shows the locations of transport pipelines and storage facilities. We holistically manage transportation, storage, and plant dispatch as components of a portfolio.

Figure 6-5: Gas-fired plants, pipelines, and storage



We currently acquire and deliver natural gas to the PW, Beaver,[42] and Coyote plants.

For the PW/Beaver site, NW Pipeline provides gas transportation services from Sumas, Washington. The K-B Pipeline provides the final link from the main NW Pipeline to these plants. We have a contract for use of Northwest Natural Gas Company's (NW Natural) Mist Storage Facility, which also connects to the PW/Beaver site. For Coyote, GTN provides gas transportation services from Alberta, Canada.

PW 2, which is located adjacent to PW, is expected to be completed in the first quarter of 2015. The current Mist storage contract expires in 2017. To replace the Mist agreement and provide for PW 2's fueling needs, we have entered into a Precedent Agreement with NW Natural for firm storage at NW Natural's North Mist Expansion project, located north of the Mist Storage Facility. The North Mist Expansion agreement will provide PGE approximately twice the storage volume we currently have at Mist.

[42] We do not include Beaver 8 in this strategy because it is small (24 MW of nameplate capacity). The gas transportation and storage strategy discussed for the PW-Beaver Complex can also serve the needs of Beaver 8 when necessary.

We expect to complete Carty in mid-2016. To supply Carty with gas, we have signed a Precedent Agreement with GTN for construction of and service on the Carty Lateral line. We have also secured firm gas transportation on the main GTN line.

Supply

Our general gas procurement strategy is to use financial instruments to hedge price risk and then purchase physical gas at index. This is a least cost approach to achieving two important goals with respect to fueling our natural gas plants:

1. Reliable physical supply, and

2. Price risk mitigation.

PGE uses market instruments such as financial swaps to hedge gas price exposure. This allows us to fix the price of gas without buying the physical commodity until it is required. Over time, the overall gas market has transitioned from long-term physical purchases to a combination of shorter-term physical purchases (at index)[43] and financial instruments to lock in prices over longer periods of time. Specifically, PGE's Mid-Term Strategy employs a layering approach to gas price hedging. Under this approach, the price customers pay for gas expected to be used in a particular year is determined by the aggregate financial transactions made for that year during the preceding five-year period. We provide a detailed discussion of PGE's natural gas and wholesale electricity hedging strategy below in Section 6.4.

Physical gas supply contracts for winter, summer, and annual delivery periods trade in a liquid wholesale market. We transact in this market to secure physical gas at the AECO and Sumas trading hubs. In addition to seasonal and annual purchases, we use day-ahead purchases, off-system sales, and storage to balance our portfolio. In making unit commitment and dispatch decisions with respect to our gas-fired plants, we compare market electric and gas prices, operating the plants when the market price for electricity is greater than the cost of purchasing gas and burning the fuel to produce power. This economic dispatch approach, enhanced by transportation and storage flexibility, reduces our overall power supply costs.

[43] Under an index contract, the price paid is the market price for gas at the time of delivery.

Transport and Storage

PW 2 and Carty will add to our firm transportation and storage requirements as shown in Table 6-1. In addition, our Mist storage contract expires in 2017.

Table 6-1: Port Westward 2 and Carty fueling requirements

	Port Westward 2	Carty
Size (MW)	220	440
Gas Demand (Dth/day)	45,000	75,000
Pipeline/Storage	NW Pipeline/Mist	GTN

To meet Carty's requirements, we have secured firm transmission rights for 75,000 Dth/day on the GTN pipeline. In addition, we have signed a Precedent Agreement with GTN for the Carty Lateral line and are participating in Nova Gas Transmission Limited's (NGTL) open season.[44] To meet PW 2's requirements, in addition to existing requirements for PW and Beaver, we have a two-part strategy. First, we will retain our current NW Pipeline transmission rights. Second, under our Precedent Agreement with NW Natural, we will replace Mist storage with expanded capabilities at the new North Mist Expansion facility. Table 6-2 lists these expanded capabilities.

Table 6-2: North Mist Expansion storage rights

Contract Provision	Size/Scope
Total Capacity	2.54 billion cubic feet
Withdrawal Rights	120,000 Dth/day
Injection Rights	56,000 Dth/day
Flexibility	No notice service

The combination of North Mist Expansion storage and firm transportation rights on NW Pipeline will meet the combined fueling needs of Beaver, PW, and PW 2 (225,000 Dth/day).

Ongoing and Future Developments

Much of the future shale gas production is expected to come from Canadian sources, more than half of which are located in the Western Canadian Sedimentary Basin (WCSB). PGE will be able to access this WCSB gas through the Spectra and

[44] The full gas transportation path for Carty includes NGTL, Foothills Pipeline System (Foothills), GTN, and the Carty Lateral, in that order. We are confident that NGTL will meet our open season request. Foothills has available capacity. Then, as discussed above, we have already secured firm transmission rights with GTN and signed the Precedent Agreement with GTN for the Carty Lateral.

TransCanada Pipelines. Furthermore, increases in shale gas production in the Marcellus region (Northeast U.S.) will displace Canadian exports which have historically supplied that region. These shifts will likely impact flow patterns and result in additional gas supplies in Pacific Northwest markets.

Two possible expansion projects could impact PGE in the future. First, NW Pipeline is considering the Evergreen Expansion, which would increase capacity from Sumas southward along the I-5 corridor. Second, NW Natural is evaluating interest in the Cross Cascades Pipeline, which would run between Madras and Molalla.[45] Both projects depend on firm customer commitments and would not be completed until 2017 or 2018 at the earliest. Given the high level of uncertainty with regard to the execution of these projects, we are monitoring developments at this time.

The combination of rapidly evolving gas supply and uncertainty about the pace and extent of economic expansion, oil prices, electric demand and fuel switching, emissions regulations, and other factors make future gas prices uncertain. While most predict relatively low and stable gas prices over the long-run, short-term variations will likely occur. Our Mid-Term Strategy's layering approach addresses these uncertainties, working to reduce year-to-year customer rate impacts associated with natural gas fuel costs.

We have also considered longer-term procurement of physical gas supply as a means of minimizing price risk for customers. However, structures under which PGE would acquire long-term supplies of physical gas are currently unattractive. Our concerns about these structures include significant risk premiums built into the pricing, as well as collateral issues associated with long-term purchase commitments.

Compared to firm pipeline transportation, storage provides much more fueling flexibility for gas-fired resources that will be increasingly used to follow wind and other variable energy resources. Storage at North Mist Expansion will allow PGE to maximize the capabilities of PW 2 to follow rapid changes in wind production and customer electricity demand. We are not aware of any other new storage facilities under development in the region; however, various entities have begun to study potential new gas storage development sites, as well as the more general topic of gas-electric interdependence.

The Western Gas-Electric Regional Assessment Task Force under the Western Interstate Energy Board has recently selected Energy and Environmental Economics (E3) to perform a study of the existing and likely future gas-electric infrastructure in the western U.S. The study is also tasked with identifying problems and possible solutions. Specifically, the study should "drill down on short (intra-day, volatile week) time periods to assess gas deliverability during big gas-fired generation ramps such as rapid and significant changes in wind and solar variable generation." The study should be completed in the summer of 2014. In addition, the Northwest Gas Association and the Pacific Northwest Utilities Conference Committee (PNUCC) have done joint work on "natural gas and electric convergence," summarizing the current Northwest infrastructure

[45] The project previously included other potential partners and was known as the Palomar Pipeline.

as a starting point. We will continue to monitor these and other research efforts regarding natural gas plant fueling.

6.3 Coal Price Forecast, Supply, and Market Conditions

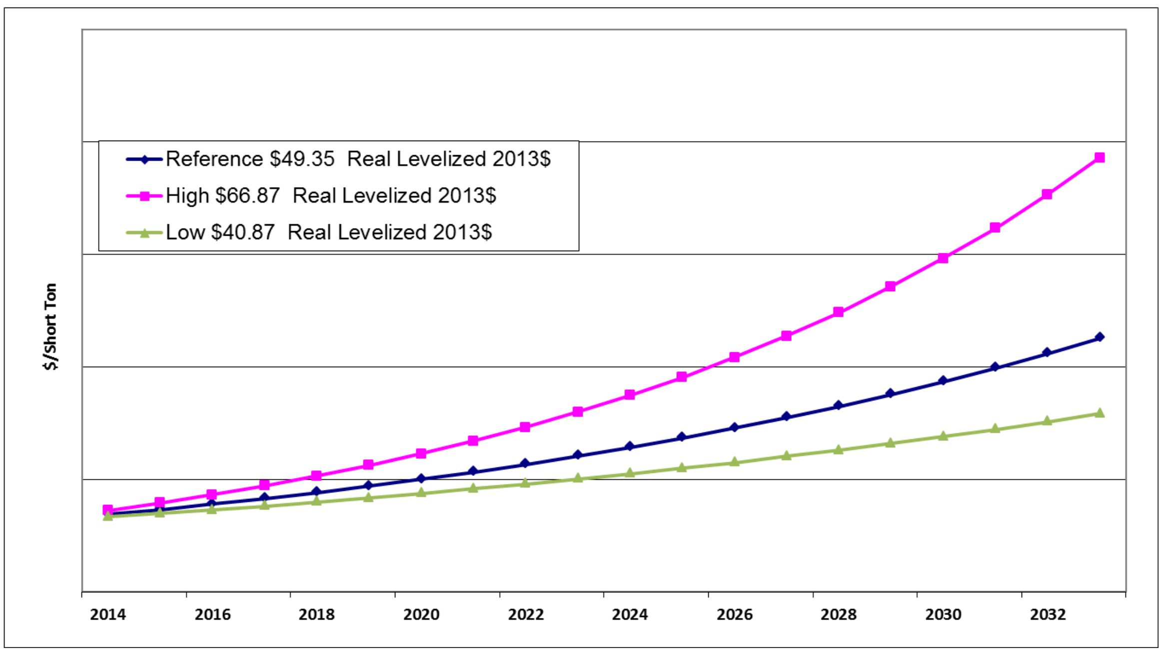
Coal Price Forecasts

PGE's approach to developing coal price forecasts is similar to that used for natural gas. We rely on current contracts for coal delivered to Boardman through 2014. We then use the EIA Annual Energy Outlook 2013 (AEO) from 2015 forward.

We also add transportation costs to the commodity price forecast for Boardman coal. Transportation can amount to approximately two-thirds of the total costs for a rail delivered coal plant like Boardman. We base rail delivery costs on PGE contracts through 2017. After 2017, we rely on an outside consultant's forecast of coal transportation costs and potential surcharges.

The resulting forecasts for the period 2014-2033 are shown in Figure 6-6.

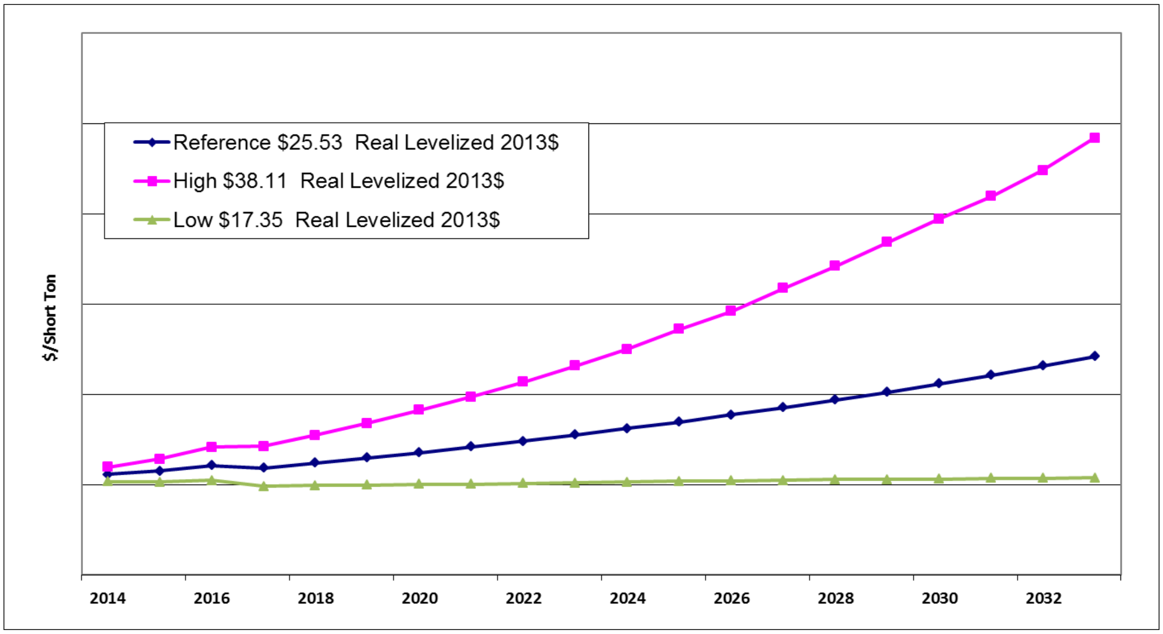
Figure 6-6: Powder River Basin 8,400 Btu/lb. delivered coal, nominal $/short ton



We simulated high and low coal price futures for all coal prices in this IRP (PGE's plants and regional generic coal prices) to capture the uncertainty around coal price forecasts. The high and low price futures are estimated using the projected annual percentage difference between base case and high and low case coal commodity forecasts in the EIA's AEO. We apply that difference to the annual price of the reference case coal for each modeled coal source.

For Colstrip, a mine mouth plant, we use estimated plant coal commodity costs for 2014-2017. For modeling purposes, projections of coal prices for 2018 and beyond apply an escalation factor based on average increases since 2010.[46] The projected coal commodity costs for Colstrip are provided in Figure 6-7.

Figure 6-7: Colstrip commodity cost of 8,500 Btu/lb. coal, nominal $/short ton



For other WECC coal price forecasts used in AURORAxmp, we use updated delivered coal prices from the EIA's Electric Power Monthly February 2013 Table 4.10a and apply an escalation factor based on the average escalation of delivered coal prices for the Pacific Northwest (inclusive of rail costs).

Coal Supply

Production in the Southern Powder River Basin has grown strongly in recent years. This basin now represents almost 40% of U.S. coal production on a tonnage basis and is expected to increase to roughly 50% by the end of our long-term planning horizon.

Market Conditions

The 2013 EIA AEO projects modest increases (1.4% annually) in mine mouth prices. This reflects the expectation of:

- Modest increases in production costs associated with moving to reserves that are more costly to mine; and,

[46] The current contract for coal supply expires at year-end 2019. Colstrip's co-owners have commenced discussions with the mine owner for renewing the agreement, but at this point future cost and term details have yet to be determined.

- Technological improvement that partially offsets the movement to higher cost reserves.

U.S. coal production is still overwhelmingly influenced by domestic demand, but in the longer-term, exports will play an increasing role. EIA projects a contraction of U.S. coal production until 2016, when export terminals will open up new markets and increase overall demand, stimulating additional domestic supply.

On the demand side, domestic consumption has been depressed by formidable competition from natural gas (gas prices plummeted to $2/MMBtu in 2012), expansion of state renewable resource requirements, and stricter environmental regulations (mercury, regional haze, acid gas, etc.). In the mid-term, greenhouse gas emission regulations may prevent new coal plant additions and promote early retirements of less efficient units. Starting in 2016, however, EIA projects coal production increases averaging 0.6% per year through 2040. This increase is the result of growing exports and increased use in the electricity sector, as electricity demand grows and natural gas prices rise.

The EIA reference case does not anticipate significant shocks to either demand or supply.

6.4 Natural Gas and Wholesale Electric Market Hedging

Electric utilities face two primary energy market exposures that can be hedged: natural gas and wholesale electricity. The former is generally a driver to the latter, since natural gas plants frequently are the marginal resource in regional resource dispatch stacks. In contrast, there is no liquid coal market to lean on for hedging; instead, coal is primarily hedged through long-term purchase agreements.

PGE's current portfolio of generation assets is "short" to the customers' demand it serves (the generation from our owned and contracted resources is not sufficient to meet our annual average load). The additions of the Tucannon River wind farm, and the Carty and Port Westward 2 gas-fired plants, enable PGE to more closely meet our customers' average electricity demand. Because the Carty and Port Westward 2 plants will meet more of the electricity need through the consumption of natural gas, these resource additions shift PGE's short electricity position to a short gas position.

In developing a hedging strategy, PGE differentiates *commodity* risk exposure into two primary types of risks:

1. Exposure to price movements (referred to as *price* risk); and,

2. Exposure to the procurement of actual physical gas or wholesale market electricity (referred to as *physical* risk).

Different contractual instruments can be used to hedge one risk vs. the other. In addition, some products can simultaneously hedge both.

Price risk can be hedged through the use of financial products called futures or fixed-for-float swaps. As part of the market-wide implementation of the Dodd-Frank reporting rules, PGE is transitioning from executing primarily financial fixed-for-float swaps to using futures. These financial products allow PGE to pay a known fixed price associated with a future commodity transaction.

Physical risk exposure can be effectively hedged using either a fixed physical or index physical transaction with a counterparty. These contracts both procure physical energy. Fixed physical contracts have the advantage of hedging both price and physical risk exposures, while index physical products only procure for the energy (the risk of future price movements still exists).

Hedging Strategy

PGE considers its risk exposures to coal, natural gas, and wholesale electricity prices in aggregate. As stated above, the hedging strategy for coal is handled primarily through long-term contracts. For PGE, price risk and physical risk are therefore concentrated around natural gas and wholesale electricity. PGE further divides this risk into three windows of time:

1. Long-term risk;
2. Mid-term risk; and,
3. Near-term risk.

PGE defines long-term risk as risk beyond five years. The wholesale market for natural gas and electricity does not offer liquidly traded products to effectively hedge this risk. Further, risks associated with this timeframe include much more than commodity risk. Beyond the five-year planning horizon, PGE would also need to consider its portfolio risk exposures to regulatory, legislative, and technological changes to name a few. Therefore, in accordance with the Public Utility Commission of Oregon (OPUC) IRP Guidelines, PGE discusses these risks and recommends actions to mitigate them within the IRP process. A commodities-only hedging program would not be an effective tool for this window of risk.

Mid-term risk is defined as risks beyond 24 months but less than 5 years. The goal for PGE’s mid-term hedging program is to address price volatility. In order to reduce our customers’ exposure to wholesale commodity markets, the mid-term hedging program layers in purchases over time. Each purchase is made using financial instruments that fix a small portion of customers’ prices at a known cost for a portion of either the gas or electricity need. These small and mostly systematic purchases allow for a closer match of customer prices and the commodities’ forward markets over time. In a market with rising prices, layering purchases will yield lower costs to customers when compared to a portfolio that was not hedged at all. While in an environment of declining wholesale market prices, layering purchases over time will not yield as low a price as an un-hedged portfolio. Ultimately, success of this strategy is not to be judged by the absolute price delivered to customers, but rather its success hinges on the predictability and stability of PGE's customers' prices.

Near-term risk is defined as risk within a 24-month window. PGE relies primarily on the wholesale market for both natural gas and electricity to hedge this risk. Within this window of time, PGE may find itself buying from or selling into the commodities markets depending on the expected economic dispatch of the generation portfolio. This 24-month window is also the most liquid, with a wholesale market that offers annual, quarterly, and monthly products that more closely match PGE's risk exposures. This procurement window, therefore, allows for shaping of the supply portfolio to better match its needs. Ultimately, PGE submits its portfolio for OPUC and intervener review within the Annual Power Cost Update procedure (Schedule 125).

Natural Gas Hedging

PGE employs a number of hedging strategies for natural gas supply:

- PGE layers-in contracts of differing durations of up to five years in advance of our need for a portion of expected future fueling requirements. As we get closer to our fueling need, purchases are increased to ensure that we have acquired contracts to meet our expected requirements roughly one year in advance. This deliberate layering or time diversification avoids over exposure to a single price and adverse market conditions.
- PGE employs fuel storage as a cost-effective means of providing seasonal reliability and price hedging.
- To improve longer-term price and supply stability, we are also exploring opportunities for gas-in-the-ground reserves, but have not executed any such transactions. Such contracts are priced at a premium and require collateral. However, given the historically low gas prices, our Action Plan calls for further exploration of the potential merits of long-term gas supply (including storage and reserves).

All natural gas hedging transactions are subject to strict corporate governance requirements with regard to credit, collateral, contract limits, transaction authorizations, etc.

Wholesale Electricity Hedging

Spot market electricity prices can be unusually volatile for the following reasons:

- Unlike most commodities, including natural gas, electricity cannot be stored directly.
- Demand for electricity is in real time.
- Generally, there is no real time consumer price feedback for electricity demand.
- Electricity prices are particularly vulnerable to shocks, such as extreme weather, generating plant outages, and transmission congestion.

- Natural-gas fired plants tend to be the marginal resource much of the time, where the gas commodity is the dominant cost component and is itself volatile.

The factors that contribute to spot electricity price volatility can also make it difficult to hedge. PGE thus believes that the most effective supply and price hedge is to reduce our reliance on spot and short-term purchases of market electricity. PGE's goal when designing candidate portfolios in this IRP is to be essentially flat to our annual average load by 2017 and each year thereafter. We say "essentially" because we do recommend continuing to supply up to 100 MWa of energy in any given year, and 300 MW of capacity (declining to 200 MW in 2019), from short-term markets as a hedge against load variability. Such energy resources can be a combination of energy efficiency, owned "base load" generating resources such as wind and natural gas, PPAs, forward term purchases of one year or longer duration, and fixed price contracts to buy and sell electricity seasonally.

For periods of higher winter and summer demand, where our resources are insufficient, we recommend a combination of demand-side and supply-side measures to meet the one-hour annual peak. Such measures include energy efficiency, demand response, dispatchable standby generation, flexible natural gas generation, and seasonal contracts to buy electricity.

In addition, as a mid-term strategy, PGE enters into financial fixed-for-floating wholesale electricity swaps of durations up to five years to balance our portfolio to load and further reduce exposure to wholesale price volatility. As with natural gas, such hedge transactions are also subject to strict corporate governance requirements with regard to credit, collateral, contract limits, transaction authorizations, etc.

Cost and Limitations of Hedging

Hedging is basically a form of insurance to reduce the risk of physical supply disruption or to provide improved price stability. As such, over the long-run, this risk reduction comes via a somewhat higher cost or premium. The premium is composed primarily of transaction costs and a liquidity premium, which typically increases with duration, for locking-in a fixed price. Financial price hedging can reduce the severity of unwanted price outcomes, but it does so at the cost of also foregoing potentially favorable price changes.

The Role of Hedging in the IRP

Not surprisingly, markets for natural gas and spot electricity (both physical and financial) become less robust and less liquid as the duration of a transaction increases. Ten years is currently the longest transaction term available, however, liquidity diminishes rapidly once terms extend beyond two years from the current point. Of the two, financial hedging instruments are typically available in longer durations than their physical counterparts. Hedging is thus primarily an operational and tactical tool. By contrast, the IRP is primarily a strategic planning tool to aid in long-term resource portfolio decisions.

When making an IRP resource decision with up to a 35-year life, hedging tactics play a less prominent role in the decision. For instance, we cannot hedge against a future in which natural gas prices are substantially higher over the long-run than what we had assumed at the time of the resource acquisition decision. Thus, in this example, hedging can reduce the variability of prices, but not the overall level of the prices themselves. For this reason, we do not attempt to employ market hedging instruments in our IRP analysis.

Consideration of hedging reinforces the importance of developing a portfolio that limits exposure to events and price movements that can cause large and adverse changes in value. Hedging is a set of strategies employed to reduce exposure to adverse outcomes, such as price movements. One of the most common forms of hedging with respect to portfolio construction and management is asset diversification. From the stand-point of an electric utility, this can be accomplished by increasing the number and type of resources (both technology and fuel types) used to serve customer demand. By diversifying its portfolio of energy and capacity resources, a utility is less likely to experience large, adverse changes in the cost to produce and deliver electricity to its customers over time.

The Use of Hedging in PGE Modeling

PGE's primary portfolio cost modeling tool, AURORAxmp, is an hourly production cost model that dispatches resources and establishes electricity prices based on marginal costs. Since no long-term markets or forecasts exist for the price or availability of market hedging instruments for electricity or fuels, it is not possible to include these in the long-term production cost model. However, PGE's IRP modeling does explicitly consider the value of hedging with physical resources through varying the composition of our candidate portfolios, and examining relative cost and reliability performance. This is accomplished primarily in two ways:

1. First, by constructing incremental portfolios that are "pure plays", and deliberately relying on relatively high levels of a single resource type, and then comparing its performance on cost and supply (reliability) risk against portfolios that are more diversified. The diversified portfolios are intrinsically better hedged by reducing exposure to single risks. By constructing portfolios with divergent resource compositions and assessing their price and reliability performance we gain insights into the value of hedging through diversification.

2. The second way that we are able to test the value of hedging is by constructing a "market portfolio" that relies heavily on short-term electricity purchases. The cost variability and supply reliability of this portfolio can then be evaluated against portfolios that have long-term assets that "fix" a portion of the price of electricity produced. In this way an electric generator (wind farm, gas plant, etc.) or other long-term resource can be viewed as an electric market hedge. The degree of hedge (or risk mitigation) is a function of the proportion of the cost of electricity from the resource that is fixed (and thus not exposed to market price changes), versus the proportion of total cost that

is variable and influenced by energy market prices. For example, a wind turbine has a high proportion of fixed costs (investment and fixed operating costs) and virtually no variable costs that are directly influenced by electricity and fuel prices, and thus provides considerable hedge value against energy market price changes. By contrast, a significant portion of the total electricity cost from a natural gas plant is determined by variable fuel costs, and thus the gas plant provides only a partial mitigation against energy market price risk. The hedge value of acquiring a long-term physical resource can be assessed through comparing the price variability and supply reliability performance of the incremental portfolio dominated by short-term electric market purchases against that of the portfolios which include more long-term resources. This is one of the elements we assess via our risk assessment approach and risk metrics explained in Chapter 9 - Modeling Methodology.

7. Environmental Considerations

One of the biggest challenges we face is to reliably meet the energy needs of our customers at a reasonable cost, while being good stewards of the environment. At the same time, the political and public policy climate related to future energy and environmental issues continues to evolve. Consequently, the potential for increased environmental regulations and shifts in energy policy add a significant element of uncertainty to resource planning.

This section outlines PGE's CO_2 reduction principles and the environmental compliance assumptions used in our analysis. It also assesses uncertainties related to potential environmental regulation and policy developments, and discusses our progress in meeting Oregon's Renewable Portfolio Standard (RPS). The assumptions described here are used in determining the real levelized costs of the generation resources outlined in Chapter 8 - Supply-side Options and Chapter 9 - Modeling Methodology.

Chapter Highlights

- PGE supports carbon regulation that is national in scope and that applies equally to all sectors of the economy.
- Energy efficiency, renewables, and cessation of coal operations at Boardman greatly reduce PGE's CO_2 "footprint" over time.
- All of our portfolios comply with Oregon's RPS.
- The real levelized costs for new gas and IGCC coal generating plants include estimates for offset payments to the Climate Trust per OEFSC rules.
- We model a carbon dioxide (CO_2) compliance cost in our reference case of $17.61 per short ton (real levelized 2013$). The CO_2 cost starts at $16 per short ton in 2023 (escalating at 8% a year).
- We also model five alternate CO_2 compliance scenarios in our portfolio analysis: no carbon cost, $17.48, $35, $16, and $136 per short ton with different start dates and varying growth rates.

7.1 Sustainable Actions for CO_2 Reduction

Sustainability Context

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

Subsequent sections in this chapter discuss actions we've already taken, and future actions we've committed to take which will further reduce PGE's CO_2 emissions. We also discuss the impact of these past and future actions on PGE's carbon footprint.

Principles for Addressing CO_2 Emissions

We believe that it is prudent to take reasonable steps to reduce greenhouse gas emissions and mitigate potential environmental impacts as the public policy and political leadership at the regional, national, and international levels grapple with how to implement carbon reduction regulation, while minimizing economic disruption.

PGE will be guided by the following principles for sustainably reducing our CO_2 footprint:

- Continue PGE's mandate to provide customers with reliable and affordable electric power while adhering to OPUC IRP principles of least cost/least risk resource planning.
- Continue to support acquisition of all cost-effective EE within our service area through the Energy Trust of Oregon (ETO).
- Support federal action to achieve carbon emissions reductions equitably across all sectors of the economy.
- Continue to support public policies that seek out lower-impact resources while striving to increase generating portfolio diversity.
- Continue to advocate for tax policy and incentives that help mitigate the cost to utility customers for energy efficiency and renewable power.
- Continue to collaborate with regulators and stakeholders to ensure we have sustainable regulatory and statutory structures that will help deliver on these principles.

7.2 PGE Activities in Support of a Sustainable, Diversified Future

An ongoing objective for PGE is to undertake cost-effective actions that are environmentally responsible, while retaining supply diversity. The following activities, some of which are discussed further in other sections of this or other chapters, demonstrate the commitment of PGE and our customers to meet growing energy needs at a reasonable cost while being good stewards of the environment:

1. With the addition of the Tucannon River wind farm, PGE will have approximately 817 MW of wind capacity in its portfolio.

2. According to AWEA, as of the end of 2012, PGE with 450 MW of owned wind, ranks 4th in that category (utility ownership). For IOUs, PGE ranks 14th for total wind on system, when including ownership and PPAs.

3. PGE has contracts with several parties for solar PV projects. PGE also provides support for residential customers with solar through the Solar Payment Option program, and other net metering options.

4. PGE took a lead position in the addition to the SB 838 (2007) legislation allowing for additional funding for EE. This has led to an expansion in ETO EE activities to the maximum achievable at the prescribed cost-effectiveness limits. In many instances, the EE acquired would otherwise have become a lost opportunity. The investment in EE also provides a beneficial impact to PGE's load factor by having a 50% greater impact on winter demand compared to average annual reductions.

5. PGE's customers lead the nation with respect to participation in the utility's voluntary renewable power options. Since 2009, PGE has been ranked number one in the nation by the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) for the number of renewable energy customers participating.[47] And in 2012, PGE's voluntary programs sold more renewable energy than any other voluntary utility program in the U.S.[48]

6. PGE has always sought out the potential for efficiency upgrades to its thermal and hydro plants, resulting today in these plants producing over 150 MW more output than at original design for no additional fuel consumption.

7. PGE's 2009 IRP called for the cessation of coal operation at its Boardman facility at the end of 2020. PGE continues to examine the feasibility of using the Boardman facility for biomass conversion.

8. PGE, following the lead of the Governor's office, has been a utility leader in helping attract solar manufacturing facilities to this area. We also worked with the State of Oregon to develop the nation's first solar highway project.[49]

9. PGE is a leading utility in efforts to build an initial electric vehicle public recharging infrastructure, which has in turn attracted interest by the vehicle manufacturing industry to use Portland as a test base for plug-in electric vehicles.

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[47] U.S. Department of Energy, *Top Ten Utility Green Power Programs*, http://apps3.eere.energy.gov/greenpower/resources/tables/topten.shtml (last visited Sept. 13, 2013).

[48] Portland General Electric, DOE ranks PGE No. 1 in U.S. for sales of renewable energy, http://www.portlandgeneral.com/our_company/news_issues/news/06_05_2013_doe_ranks_pge_no_1_in_u_s_for.aspx (last visited Sept. 13, 2013).

[49] See Chapter 2 - PGE Resources, Section 2.5, for more detail on this project.

10. During 2013 and 2014, PGE is converting cobra-head style high-pressure sodium street lights to LED lighting. By the end of 2014, PGE will have converted approximately 25,000 fixtures. The LED lights use 60-70% less energy, last four times longer, and improve nighttime visibility. The LED components are recyclable.

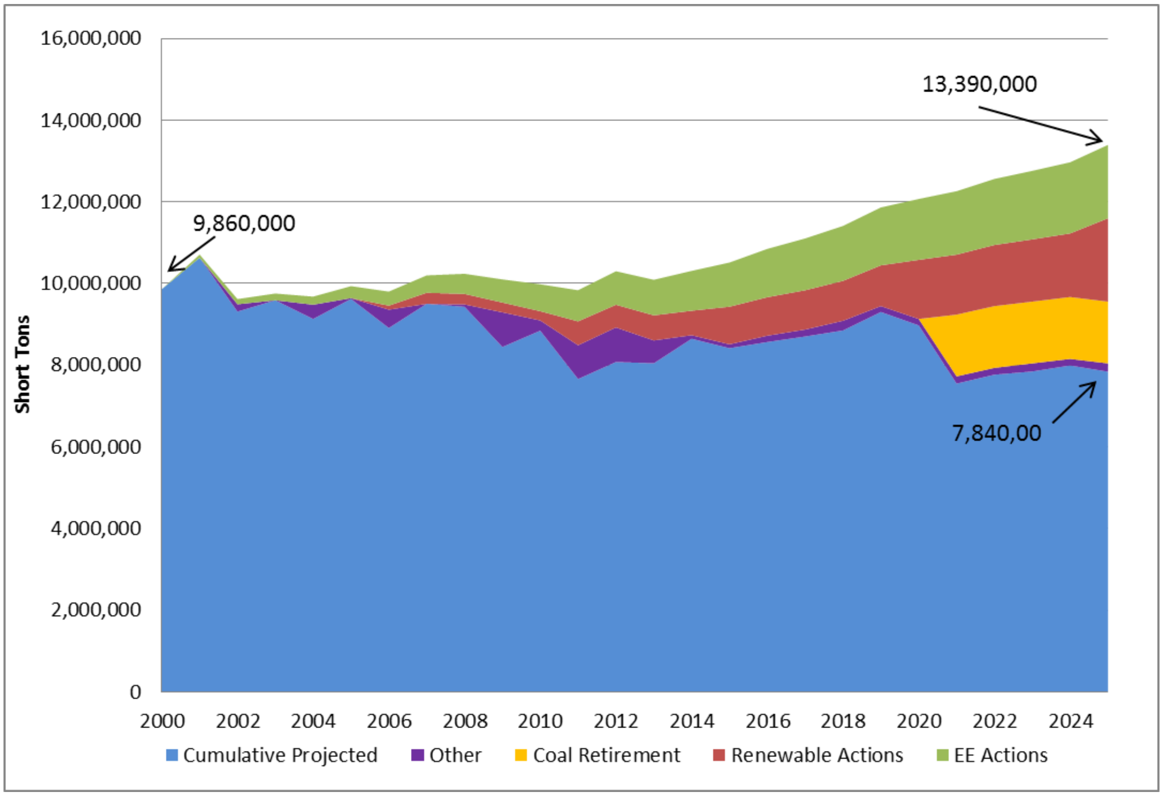
7.3 Results of PGE's Carbon Reduction Actions

In this section, we focus on the results, both historical and projected, of PGE's carbon reduction actions over the 2000-2025 period. Our actual CO_2 emissions in 2000 were 9.9 million (short) tons. Had we simply met load growth with combined-cycle combustion turbine (CCCT) generation or undifferentiated wholesale power market purchases, our projected emissions for 2025 would be roughly 13.4 million tons. However, based on actions we have already implemented and new actions we plan to execute in the future, we now project 2025 portfolio emissions of only 7.8 million tons.

Three primary actions account for most of the large reductions in projected emissions (difference between the 13.4 and 7.8 million tons in 2025). First, energy efficiency (EE) measures have reduced the need for new greenhouse gas-emitting generation. The carbon reduction effect of these EE measures is shown in green in Figure 7-1. We use actual historical figures through 2012 and Energy Trust of Oregon (ETO) projections going forward. Second, rather than meeting all new load net of EE with gas-fired generation; we have acquired additional renewable energy resources, primarily wind. Figure 7-1 includes in red our Biglow Canyon (currently operating) and Tucannon River (under construction) wind facilities, as well as renewable generation contracts (primarily wind). This figure also includes additional future renewables which will be needed to meet 2020 and 2025 Oregon RPS. The third major action which will contribute to a major reduction in carbon emissions is planned cessation of coal-fired generation at Boardman at the end of 2020. Figure 7-1 shows in orange the carbon reduction effect of substituting "market mix" power (roughly equivalent to a CCCT) for Boardman coal generation beginning in 2021.

Our projected 2025 CO_2 emissions of 7.8 million tons are 20% lower than our actual year 2000 CO_2 emissions of 9.9 million tons. They are also 41% lower than the 13.4 million ton level which would otherwise occur absent continued EE, new renewable resources and the planned cessation of coal operations at Boardman.

Figure 7-1: PGE carbon profile over time



Whereas Figure 7-1 considers absolute CO_2 emissions, Figure 7-2 considers these emissions relative to customer demand, which increases over time. Specifically, Figure 7-2 measures carbon intensity by CO_2 output divided by load.[50] The "normalizing for load" approach shows a 37% decrease in carbon intensity over the period 2000-2025. In year 2000, we emitted 0.46 tons of CO_2 for every MWh served, while in 2025 we project much lower emissions intensity of 0.29 tons per MWh.

[50] Load in Figure 7-2 is the load associated with a "meet load growth with CCCT projection; do not acquire EE or renewable resources and do not cease coal operations at Boardman" scenario.

Figure 7-2: PGE carbon intensity over time

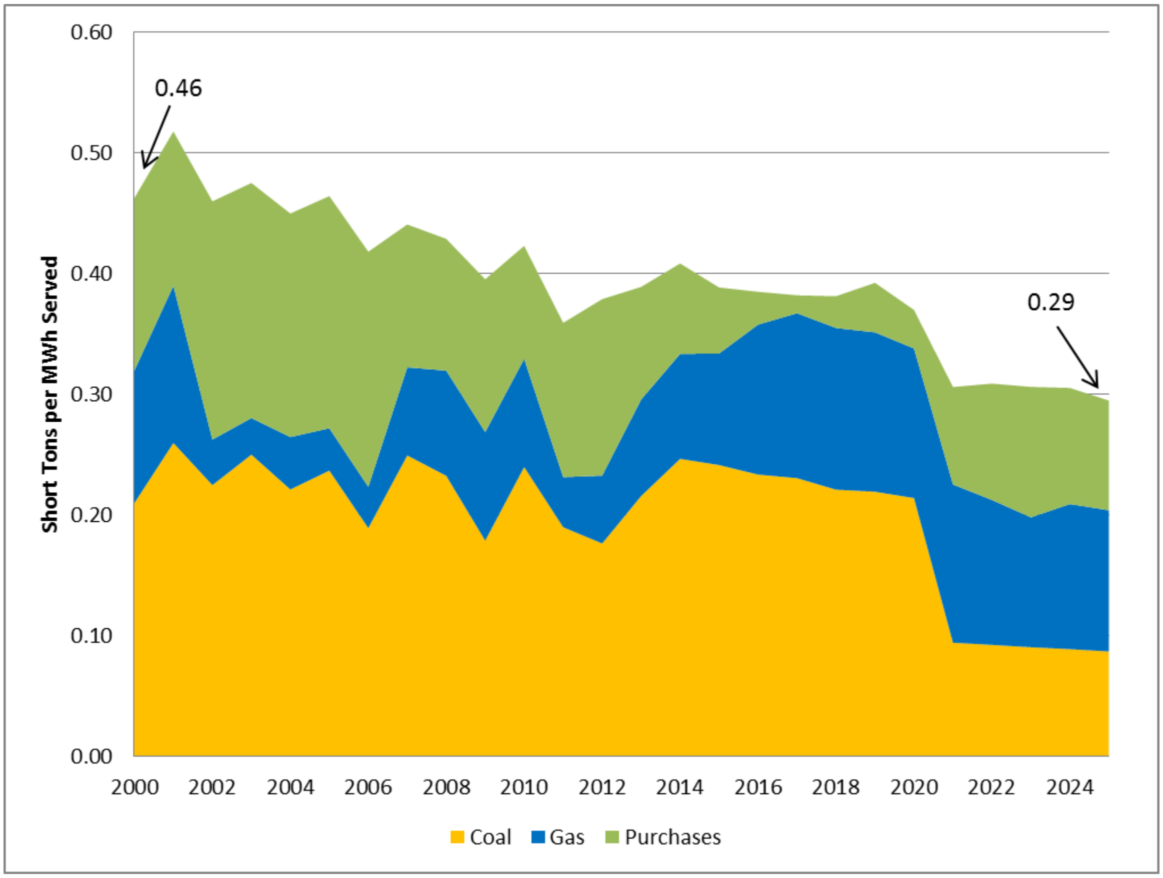


Figure 7-1 and Figure 7-2 show that, over time, EE, renewables, and cessation of coal operations at Boardman combine to substantially reduce PGE's carbon footprint. These figures are similar to those at the end of Chapter 10 - Modeling Results, Section 10.3.[51]

7.4 Renewable Portfolio Standard

On June 6, 2007, Oregon adopted a Renewable Portfolio Standard (RPS), codified at ORS chapter 469A. The Oregon RPS requires that 25% of our retail energy 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.

[51] Specifically, Figure 7-1 and Figure 7-2 reflect essentially the same strategy as our "Baseload Gas/RPS only" portfolio described in Chapter 9 - Modeling Methodology. Therefore, they show generally the same results as do the figures at the end of Chapter 10 - Modeling Results, Section 10.3, for the "Baseload Gas/RPS only" portfolio.

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
- Up to 50 MWa per year of energy generated from certified low-impact hydroelectric facilities

The legislation further provides that Tradable Renewable Energy Credits, 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 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 do not apply toward meeting the RPS compliance targets.

The legislation allows a REC to be carried forward or "banked" and used to meet RPS requirements in a future compliance year other than in the calendar year it was generated, with specific limitations. RECs are tracked via the Western Renewable Energy Generation Information System (WREGIS). According to Oregon Administrative Rule 330-160-0030(1), the banking of RECs begins January 1, 2007. Unbundled RECs may be used to meet a maximum of 20% of a utility's annual REC requirement. Under ORS 469A.180, an electric company may also use alternative compliance payments to meet the RPS requirements.

The Oregon RPS requires that each electric company and each ESS must file a compliance report annually and that each electric company must file an implementation plan at least once every two years.

Under ORS 469A.100, an electric company is not required to comply with the RPS to the extent that the incremental cost of compliance would exceed 4% of its revenue requirement in a compliance year. The cost cap is met by applying the incremental cost of development of a renewable resource over an equivalent nonrenewable resource.[52] 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.

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

OPUC Docket AR 518

AR 518 was a rulemaking docket which addressed detailed implementation of the RPS.

Phase I of the rulemaking focused on the new renewable energy portion of the public purpose charge. Phase II of the rulemaking addressed RECs that may be used to meet the RPS.

Phase III of the rulemaking addressed estimating the annual revenue requirement and the incremental cost of compliance, the timing of updated information on costs, a general outline for the bi-annual implementation plan, a general outline for the annual compliance reports, and a general outline for compliance standards and alternative compliance payment rates and use of such funds. The rules were adopted by the Commission on August 3, 2009, Order No. 09-299.

After adoption of the rules, there were further discussions among parties as to how to calculate the incremental cost of compliance for purposes of the 4% test. OPUC docket UM 1616 resulted in a draft stipulation among all parties that provides additional specifications on how to compute the cost of renewable and proxy resources. If adopted, the new specifications should not result in material changes to cost calculations.

Solar Photovoltaic Capacity Standard

The Solar Photovoltaic Capacity Standard is a legislative mandate that by January 1, 2020, PGE must own or contract to purchase 10.9 MW of solar photovoltaic capacity. Individual solar systems must be between 500 kW and 5 MW in size. Such systems are RPS-qualified. PGE is on track to meet the standard. Systems to comply with this standard include the Bellevue, Yamhill, Baldock, and Outback projects described in Chapter 2 - PGE Resources, Section 2.5.

Status of PGE's RPS Compliance

In our 2009 IRP, we targeted 122 MWa of new renewables to achieve physical resource compliance with Oregon RPS requirements in 2015. Due to the continued economic slowdown resulting in reduced load and additional customer opt-outs being served by an Energy Service Supplier, this forecast was lowered to approximately 101 MWa for our 2012 Renewable Resource RFP.

As discussed in Chapter 2 - PGE Resources, our Renewable RFP resulted in acquisition of the Tucannon River Wind Farm, a 267 MW project with a capacity factor of approximately 36.8%, which equals roughly 98 MWa on an annual basis. This resource is expected to be in-service the first-half of 2015 and will allow us to meet the projected 2015 RPS requirement (on an annualized basis). Table 7-1 below provides and assessment of our current and future RPS resources and requirements.

Table 7-1: RPS resources and requirements

	2015	2020	2025
Calculate Renewable Resource Requirement:			
PGE retail bus bar load	2,435	2,707	2,964
Remove incremental EE	(69)	(184)	(259)
Remove Schedule 483 5-yr. load	(181)	(186)	(186)
A) Net PGE load (MWa)	2,185	2,338	2,520
Renewable resources target load %	15%	20%	25%
B) Renewable Resources Requirement	**328**	**468**	**631**
Existing renewable resources at bus bar:			
Biglow Canyon	143	143	143
Tucannon River*	57	98	98
Klondike II	26	26	26
Vansycle Ridge	8	8	8
Pelton-Round Butte LIHI Certification**	50	50	50
Solar***	10	11	11
Post-1995 Hydro Upgrades	12	12	12
C) Total Qualifying Renewable Resources	**307**	**349**	**349**
Compliance positions:			
D) Excess/(Deficit) RECs (C less B)	(21)	(119)	(282)
E) % load served by RPS renewables (C divided by A)	14.0%	14.9%	13.8%

*Tucannon River Wind Farm is assumed online by June 2015

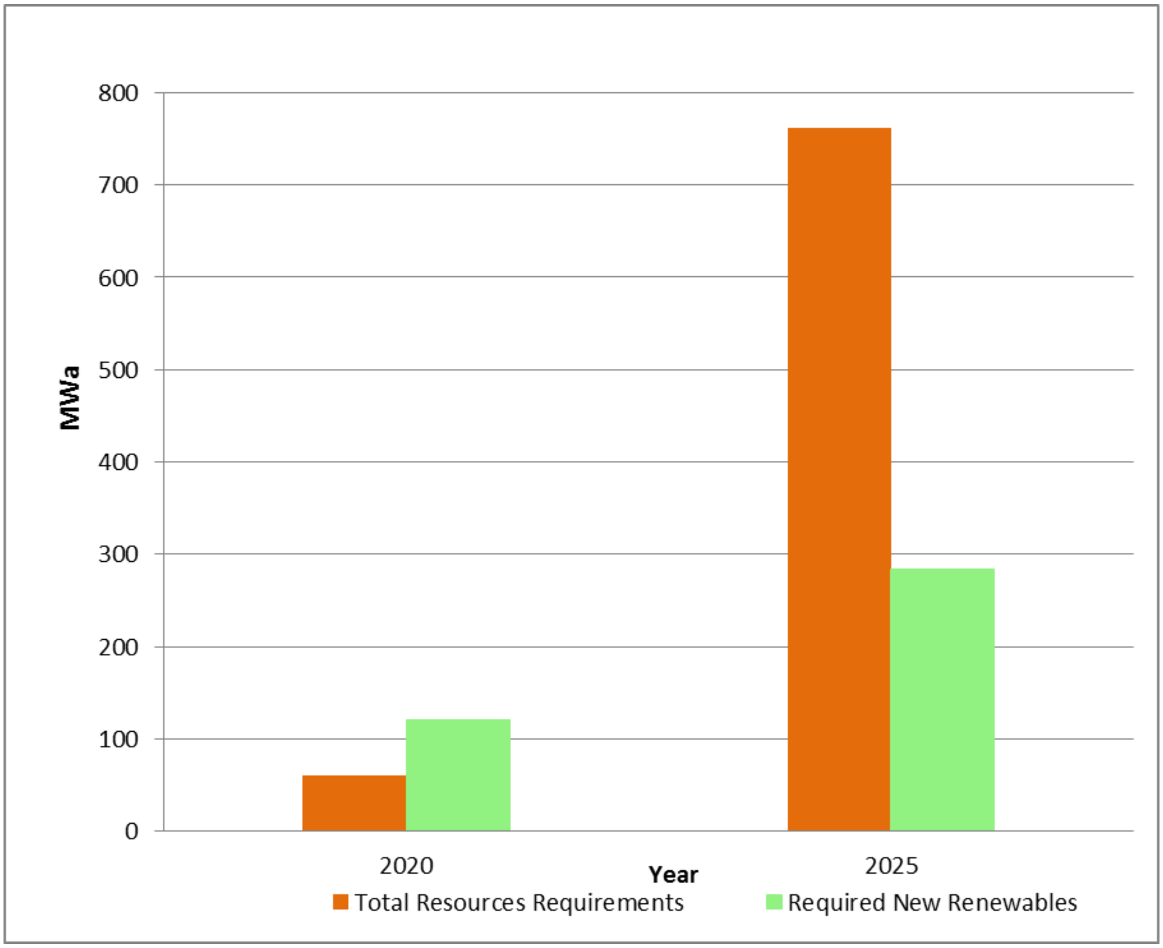
** 50 MWa is annual useable LIHI RECs

***Includes RECs from assorted solar projects, PGE's Solar Payment Option, and ETO funded projects

Impact of the RPS on PGE's Future Resource Mix

To remain in physical compliance with the RPS, PGE will need to acquire additional renewable resources by 2020 and 2025. The 2020 renewable gap is approximately 119 MWa, growing to 282 MWa by 2025 (see Figure 7-3) below. These gaps account for about 58% of our new resource need in 2020 and 36% of the need in 2025.

Figure 7-3: PGE total resource needs and needs for physical RPS compliance in 2020 and 2025



Our latest wind project has a projected capacity factor of approximately 36.8%. However, for modeling purposes, we meet our future renewable needs with additional wind projects our projected regional average capacity factor of 32.5%.[53] This implies adding approximately 360 MWs of nameplate capacity in 2020 and another 500 MWs by 2025 (about 860 MWs in total). While here we use wind as a proxy for meeting ongoing RPS requirements, we believe a growing proportion of future new renewables will come from other sources, including: solar PV, with the possibility of biomass, geothermal, or (in time) wave energy projects.

7.5 Greenhouse Gas Regulation

OEFSC Rules – The 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

[53] See Chapter 8 - Supply-side Options.

the OEFSC rules, at OAR 345-024-0500 et. seq., there are specific standards for base load gas plants, non-base load (peaking) power plants and non-generating energy facilities that emit CO_2. See Table 7-2.

Table 7-2: Standard emissions for base load gas plants as set by OEFSC under Division 24, OAR 345-024-0500

Plant Type	Emission
Base load gas plants	0.675 lb. CO_2/kWh
Non-base load gas plants	0.675 lb. CO_2/kWh
Non-generating facilities	0.504 lb. CO_2/horsepower-hour

The standard for base load plants currently applies only to natural gas-fired plants. The standards for non-base load plants and non-generating facilities apply to all fuels.[54]

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 financially settle the obligation via payment to The Climate Trust, which has been designated as a qualified organization by the OEFSC. Under the monetary alternative, the site certificate holder is responsible for two types of payments: 1) offset funds 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 8 - Supply-side Options include estimates for these payments to the Climate Trust. In the event of a federal carbon tax, or an Oregon emissions standard, the Oregon Legislature could repeal the current OEFSC rules. However, for modeling purposes, we have assumed they would continue.

Federal, State and Regional Legislation

PGE has supported federal legislation addressing global climate change. Over the years, we have engaged in the development of climate policy at the local, state, regional and federal level. We continue to believe that regulation of greenhouse gas emissions is best done at the federal level in order to minimize cost shifts between states and regions, and to facilitate more cost effective emissions reductions.

In Congress, PGE supported a federal framework for addressing carbon emissions under the American Clean Energy and Security Act of 2009, commonly referred to as the "Waxman-Markey" cap and trade bill. Although that legislation passed the House of Representatives, it did not advance in the Senate. Similar legislative proposals initiated out of the Senate failed to pass before the 111th Congress adjourned. Since then, no comprehensive climate legislation has been considered on the floor of either chamber. Given the current political environment, it appears unlikely in the near term that climate legislation will be adopted by Congress and signed into law.

[54] Examples of non-generating facilities include certain pipelines and synfuel plants converting coal or oil to gas.

At the regional level, the Western Climate Initiative (WCI) effort has also stalled in recent years. Among U.S. states, only California adopted the cap and trade design suggested by the WCI. Oregon failed to adopt enabling legislation in 2009 to implement the WCI cap and trade and has not returned to the issue. The effect on PGE of California's climate actions includes reporting emissions on sales of energy into the state. We also must acquire carbon credits to off-set emissions associated with power sold to California.

In Oregon, the legislature has adopted a number of policies addressing greenhouse gas emissions in the State. In 2009, an emissions performance standard was adopted (SB101), setting a limit on new investments in base load generation sources and prohibiting emissions from those sources that exceed 1,100 lbs. CO_2/MWh. That policy was amended in 2013 to: 1) ensure the standard applies to in-state and out of state facilities, 2) remove the ability to lower the threshold, and 3) give the OPUC the ability to recommend voiding the policy in light of federal laws and regulations.

Oregon continues to investigate ways to achieve greater greenhouse gas reductions, passing SB 306 (2013) which requires a study of a state-only, economy-wide carbon tax. The study is scheduled to be submitted to the legislature in November 2014.

Another area of continued policy focus is energy efficiency. Oregon's Governor adopted a 10-year energy plan in 2013 that included the goal of meeting all electric load growth in the state with energy efficiency. The 2013 legislature also adopted additional energy efficiency standards for appliances.

EPA Regulation of Greenhouse Gases from the Power Sector

While Congress has been less active on climate policy in recent years, the Obama Administration has continued to make the issue a priority through administrative action – in particular through the Environmental Protection Agency (EPA). In Massachusetts v. EPA, 549 US 497 (2007), the Supreme Court held that greenhouse gases fall within the definition of pollutants under the Clean Air Act, providing the EPA with clear legal authority to promulgate regulations on greenhouse gas emissions. EPA moved forward with a finding that greenhouse gas emissions from motor vehicles endanger public health and welfare, triggering the Clean Air Act's Prevention of Significant Deterioration (PSD) program and the Title V operating permit programs for other sources of greenhouse gases beyond the transportation sector, including power plants. The PSD and Title V permit requirements became effective for large stationary sources on January 2, 2011.

Under the new source review (NSR) requirements of the PSD program, stationary sources of "pollutants subject to regulation" are required to obtain permits if they are new sources or existing sources that have undergone "major modifications". A major modification of an existing source is defined as a physical change or a change in the method of operation that results in a significant increase of emissions. New sources or existing sources that undergo major modifications are required to obtain PSD permits and demonstrate the use of "Best Available Control Technology" (BACT). BACT determinations are made on a case-by-case basis subject to EPA guidance. In 2010, EPA issued BACT guidance for greenhouse gases, which focused on using the most energy efficient technology available as opposed to requiring changing fuel types or installing pollution control technologies.

Title V operating permits contain air emissions control requirements that apply to a facility, such as national emissions standards for hazardous air pollutants, new source performance standards, or best available control technologies required by a PSD permit. In general, since there are currently no such air emission control requirements, existing facilities with GHG emissions greater than 25,000 tons per year that already have operating permits would not need to immediately revise them. At the end of a five-year period when the operating permit must be renewed, these facilities would be required to include estimates of their GHG emissions in their permit applications. Facilities may use the same data reported to EPA under its reporting rules.

In late2010, EPA announced its intent to establish greenhouse gas New Source Performance Standards (NSPS) for coal- and natural gas-fired power plants. Under Section 111(b) of the Clean Air Act, EPA establishes emission performance standards for new and modified sources. Under Section 111(d) of the Clean Air Act, EPA sets forth guidelines for existing sources, which are subject to state implementation. With respect to new and modified sources, EPA initially proposed requiring new coal or natural gas-fired facilities to meet an emission rate standard of no more than 1000 pounds of CO_{2e}/MWh. EPA has since announced that it will revise that proposal before it becomes final. For reference, our Port Westward plant's 2012 emissions were approximately 830 lbs./MWh. We expect Carty to be somewhat more efficient and have emissions of approximately 810 lbs./MWh.

In June 2013, the President proposed a "Climate Action Plan," which instructed the EPA to carry out the NSPS rulemakings. Specifically, the President ordered EPA to issue its revised NSPS proposal for new facilities no later than September 2013, with a final rule to follow "in a timely fashion" after considering public comments. With respect to existing plants, the President directed EPA to issue proposed guidance by June 2014, final guidance by June 2015, and a requirement that states submit to EPA their respective implementation plans no later than June 30, 2016. In carrying out these regulations, EPA is to "develop approaches that allow the use of market-based instruments, performance standards, and other regulatory flexibilities."

There are many questions about how EPA will implement NSPS, in particular as it relates to existing sources. 111(d) has been little used by the agency, making it difficult to rely on past precedents to predict outcomes of the rulemaking process. While some legal experts would argue that EPA is limited to a strict focus on existing generation efficiency improvements at a given facility, others would suggest that EPA could take a more expansive approach such as setting statewide caps on greenhouse gas emissions or encouraging investments in energy efficiency or renewables as alternative compliance approaches. In any case, states have wide authority to implement the program based on the guidelines EPA develops, provided the state plan is as least as protective.

On September 20, 2013, EPA proposed a reworked rule restricting greenhouse gas emissions for *new* fossil-fueled power plants, including different limits for gas- and coal-fired generation. It sets a common standard of 1,000 lbs./MWh for all new fossil generation. Gas combustion turbines using less than 850 MMBtu/hour would have a higher limit of 1,100 lbs./MWh. This standard does not apply to plants already under construction but even if it did, Carty would meet this strict standard. Port Westward 2 would not be regulated under the proposed rule, but would also meet the standard if applied. All new plants included in the candidate portfolios in this IRP are expected to meet the proposed EPA standards, or, in the case of simple cycle "peaking" units, are not expected to meet the definition of an electric generating unit under the proposed rule. Appendix I contains a Pacific Northwest Utilities Conference Committee (PNUCC) letter to the PNUCC Power and Natural Gas Planning Task Force regarding impacts to regional resources which confirms our conclusions above.

Carbon Costs in IRP Analysis

Guideline 8 of the Commission's IRP Guidelines requires us to construct a base-case scenario to reflect what we believe to be the most likely regulatory compliance future for CO_2, nitrogen oxides, sulfur oxides and mercury emissions. Consistent with the guideline, we have modeled a range of CO_2 costs based on externally available estimates. We believe a cost for CO_2 emissions is likely in the future, although not until sometime after 2020.

As mentioned above, Congress has not considered comprehensive CO_2 legislation in recent years, leaving no current federal guidance on timing or amount for an emissions compliance regime. We therefore adopted, for our reference case CO_2 compliance, the assumption that Wood Mackenzie applies in its long-term scenario study for natural gas. This approach provides carbon assumptions consistent with the natural gas price forecast, and therefore provides uniformity among major modeling assumptions in the IRP.

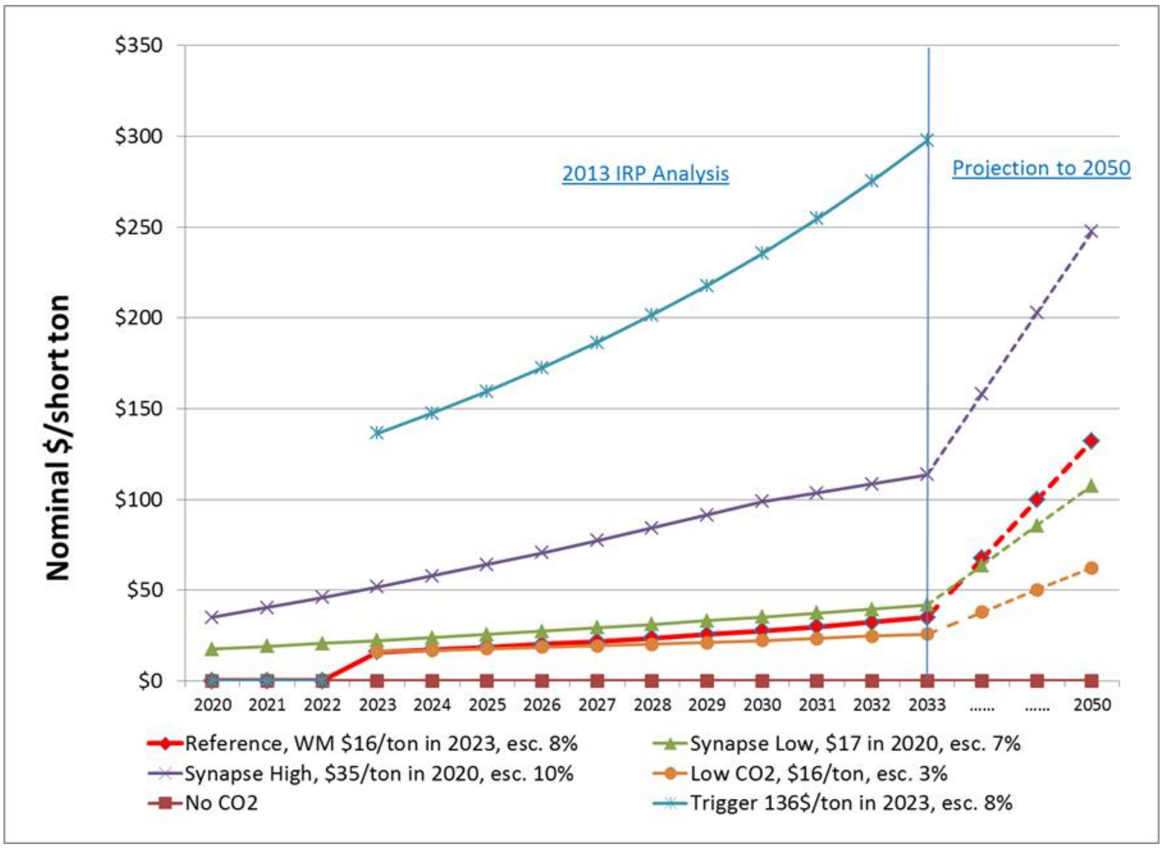
Our IRP reference case charges all CO_2-emitting electric power plants in the WECC with a carbon cost based on the plant's CO_2 emissions rate. For portfolio modeling in our reference case, we use the Wood Mackenzie assumption of $16 per short ton (nominal $), starting in 2023, escalating at 8% a year going forward.

Wood Mackenzie describes the rationale behind the timing and magnitude of a carbon tax as follows: "We continue to assume formative policy is unlikely until the early 2020s given the current political and economic environment. Furthermore, such efforts will necessarily balance a host of issues including cost containment and the overall impact to individual consumers and the economy as a whole. Understanding that the issues of GHG emissions and global climate change are here to stay for the foreseeable future, along with the current political and economic environment, Wood Mackenzie now assumes federal carbon policy in their Base Case outlook will not take effect until 2023. When enacted, such policy is expected to include a ceiling mechanism for carbon prices at levels that would mitigate economy-wide impacts emanating from the potential for a sharp increase in retail electricity prices. While this does not assume or model specific legislation, the assumed pricing level is not significantly different than price containment reserves that have been outlined in prior Congressional proposals."

All carbon compliance cases in this IRP model existing regulation in California, Alberta and British Columbia. We simulate the California cap and trade program by imposing a tax equal to the allowance floor price to all generation in California and all imports to California. This is equal to $9.10 per short ton in 2013, growing to $14.55 by 2020. After that, we escalate the tax at inflation until 2023, when the assumed Federal tax is imposed for all States. We model a tax of C$15 per metric ton in Alberta and C$30 per metric ton in British Columbia. Neither Canadian province escalates the tax.

In addition to the reference case assumption, we simulated several compliance scenarios ranging from the present CO_2 regulatory level to the highest cost compliance case as developed by Synapse Energy Economics Inc.,[55] defining a reasonable range of CO_2 price estimates for use in utilities' IRPs. They are shown in Figure 7-4 and described below.

Figure 7-4: Carbon dioxide price scenarios



Overall, we simulated six different potential compliance scenarios described below. Our simulations are performed for the IRP planning period of 2014-2033, but we also show

[55] Synapse Energy Economics Inc., 2012 Carbon Dioxide Price Forecast October 4, 2012. Rachel Wilson, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman.

projected prices in 2050, as this year is often cited as a target year in studies on global climate change:

1. Our reference case is described above. It assumes a CO_2 price of $16 per short ton starting in 2023, escalating at 8% a year after that. By 2050 this trend would lead to a tax of $132 per short ton.

2. The no carbon future assumes no federal tax;

3. The Synapse low future assumes a federal tax of $17.48 per short ton starting in 2020 escalating at approximately 7% a year. By 2050 this trend would lead to a tax of $107 per short ton. This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly – for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility.

4. Low CO_2 future assumes a tax of $16 per short ton starting in 2023 escalating at 5% a year on average after that. By 2050 this trend would lead to a tax of $62 per short ton. This is reflective of the low-end estimate of the social cost of carbon (SCC) of the Interagency Working Group on Social Cost of Carbon, United States Government.

5. The Synapse high future assumes a tax of $35 per short ton starting in 2020 escalating at 10% a year on average through 2033. Escalation is 5% a year thereafter, resulting in a 2050 tax of $247 per short ton. This case pursues aggressive emissions reduction targets; greater restrictions on the use of offsets (nationally or internationally); restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; or higher baseline emissions. This future is a reasonable proxy for the high-end of the SCC.

6. Trigger point CO_2, this assumes a tax of $136 per short ton starting in 2023 escalating at 8% a year on average after that (or 150 $/short ton real levelized from 2023 to 2033 in 2013$). This is a future generated in compliance with the Commission's IRP Guideline 8 which mandates utilities to identify the CO_2 "turning point" which would trigger the selection of a portfolio of resources that is substantially different from the preferred portfolio.

In response to a request by our stakeholders, we compared our futures to the May 2013 estimate of social costs of carbon updated by the Interagency Working Group (IWG) on Social Cost of Carbon, United States Government.[56] They range between $11 and $60 per short ton now and escalate up to $53-$200 per short ton by 2050 (Figure 7-5). The agency does not propose a specific policy for CO_2 reductions. Most likely a

[56] Interagency Working Group on Social Cost of Carbon, United States Government. Technical Support Document: -Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866. May 2013.
http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf

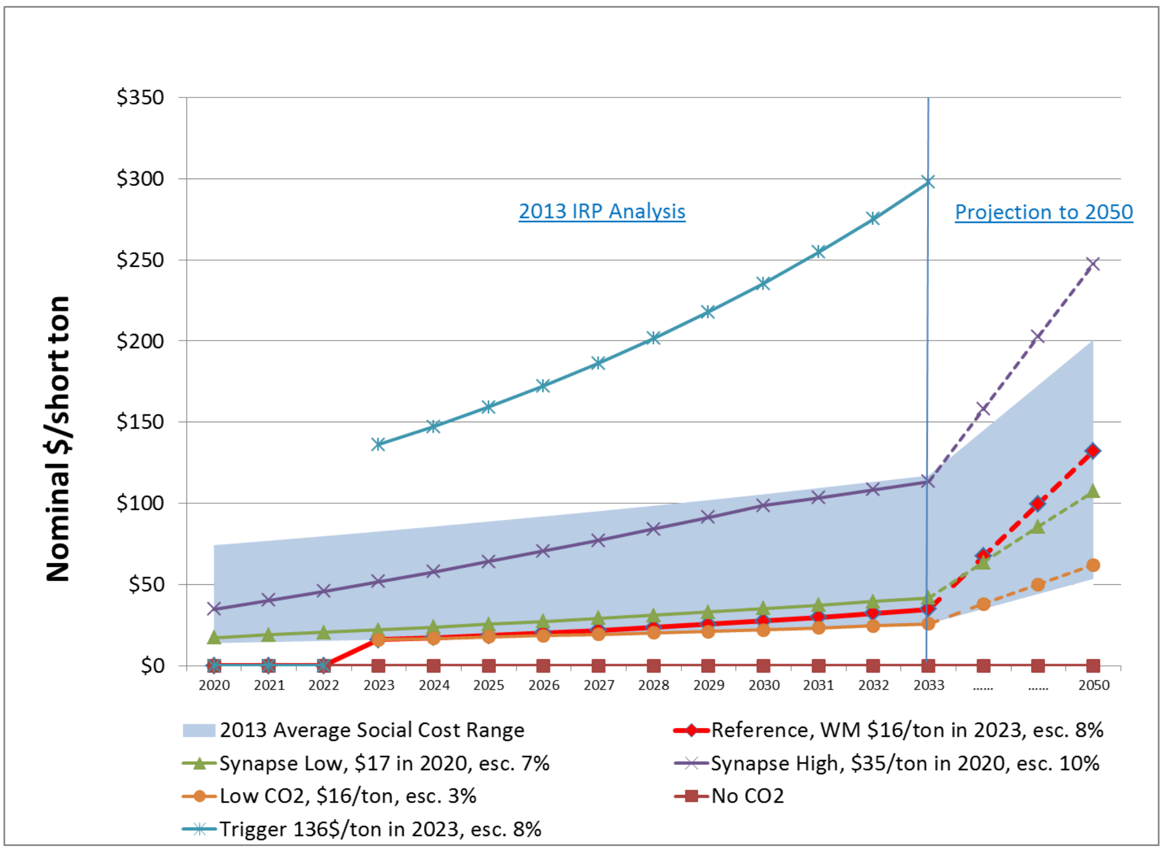
combination of investments in energy efficiency, technology standards, renewable portfolio standards, and carbon taxation regimes would all have to be implemented.

PGE's current portfolio strategy incorporates many of these policies to reduce our carbon footprint:

- Pursuit of all cost effective energy efficiency achievable in our territory;
- Physical compliance to the Oregon RPS as a renewable resource requirement floor in all of our trial portfolios;
- Adoption of EPA and Oregon Energy Facility Siting Council CO_2 emission standards for new energy facilities; and,
- Use of a CO_2 cost in our IRP reference case assumptions for assessing new electric generation resource options.

Figure 7-5 shows how much of the total social cost estimated by the IWG is modeled in our IRP as a carbon tax. Our reference case assumes that such a tax does not need to exceed the minimum levels of the estimated costs (i.e., other policies are sufficient to cut most of the emissions) while the Synapse high cost future assumes increased reliance on a tax to avoid assumed social costs.

Figure 7-5: Total social cost estimated by the IWG as modeled in PGE's IRP as a carbon tax



On October 28, 2013, the Governors of California, Oregon, and Washington, and the Premier of British Columbia signed the Pacific Coast Action Plan on Climate and Energy (Pacific Coast Plan). Under this agreement, the four jurisdictions will work together on broadly coordinated actions to reduce greenhouse gas emissions. Although the agreement does not impose legally binding obligations, it includes 14 sections which set broad goals across multiple sectors, including transportation, energy efficiency, and electricity production. The agreement also aims for consistency with national policy goals, along with as much consistency across the four jurisdictions as is practicable.

One of the goals of the Pacific Coast Plan is accounting for the costs of carbon pollution. The Plan states that Oregon will build on existing programs to price carbon emissions and set a mid-range (sometime in the 2030's) emission reduction target. Our IRP is consistent with this goal. Our six carbon price futures encompass a broad range of outcomes which are consistent with potential outcomes under the Plan. We analyze the performance of all portfolios, including those with larger energy efficiency and renewable components, under these six carbon price futures.[57]

7.6 Sulfur Dioxide, Nitrogen Oxide and Particulates

All *existing* PGE thermal plants are currently in compliance with emissions standards for sulfur oxides (SO_x), nitrogen oxides (NO_x), and airborne particulates. In IRP, when modeling *new* plants, we impose costs based on the adoption of the best available control technology (BACT) standard. Thus, the compliance costs are embedded in the overall capital costs for new resources. Table 7-3 summarizes our modeling assumptions for SO_x, NO_x, and particulates, as well as CO_2 for new plants.

[57] See Chapter 9 - Modeling Methodology and Chapter 10 - Modeling Results for our modeling structure and results.

Table 7-3: Control technology and relative costs modeling assumptions in IRP

	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	
CO_2	Offset payment to Climate Trust per OEFSC rules	Various estimates of future federal legislation	$16 per short ton	2023	8%	a) No carbon adder b) $16 per short ton starting in 2020 escalating at 5% a year on average after that c) $17.48 per short ton starting in 2020 escalating at approximately 7% a year d) $35 per short ton starting in 2020 escalating at 10% a year on average after that e) $136 per short ton starting in 2023 escalating at 8% a year on average after that
Particulate	Cost of BACT[1] included in generic capital cost assumption	NA	-	-	-	NA
NOx	Cost of BACT[1] included in generic capital cost assumption	NA	-	-	-	NA
SO_2	Cost of BACT[1] included in generic capital cost assumption	SO_2 allowances cost per Title IV of the Clean Air Act	$2 per short ton	ongoing	2011 Market quotes. Assume escalation at inflation	NA

In addition, for our existing and planned thermal plants, we project the following investments summarized in Table 7-4 for ongoing compliance with projected environmental standards.

Table 7-4: Major planned environmental investments, $ Millions

	PGE share	Projected PGE Cost ($ million)				Notes
		2013-2015	2016-2020	2021-2025	2026-2033	
Boardman	80%	15.0	-	-	-	SO_2 control, Dry Sorbent Injection
Colstrip 3 and 4	20%	2.5	7.3-9.5	-	0-152	Potential CCR by 2018; Pond lining by 2020; potential SCR by 2027
Beaver 1-7	100%	3.0	-	-	-	Cooling tower fill replacement and upgrade to CEMS unit
Beaver 8	100%	-	-	-	-	No environmental retrofits anticipated
Port Westward	100%	1.5	-	-	-	Replace SCR catalyst
Port Westward 2	100%	-	-	-	-	No environmental retrofits anticipated
Carty	100%	-	-	-	-	No environmental retrofits anticipated
Coyote Springs	100%	0.6	-	-	-	Replace catalytic reducer (SCR)
Total		**22.6**	**1.8**	**-**	**0-40**	

7.7 Compliance with Guideline 8 (Order No. 08-339)

Guideline 8 requires that our portfolio planning reflect the most likely regulatory compliance future for CO_2, nitrogen oxides (NO_x), sulfur oxides (SO_x) and mercury emissions. In addition, the guideline directs that "the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection." In Section 7.3 we discussed how our planning reflects a likely range of CO_2 compliance cost scenarios. As discussed above, PGE's emissions levels of NO_x, SO_x and particulates do not have a material impact on our resource decisions because new resources enter service compliant with emissions requirements, while our existing thermal resources are compliant with reasonably predictable compliance futures. This extends to mercury and air toxics (MATS) as well. As such, we did not conduct sensitivity analyses on these emissions.

New Resources

For new resources, as mentioned above, fossil fuel plants are assumed to be constructed to BACT standards (including all associated costs); hence, they enter service compliant with the current emissions requirements. Natural-gas-fueled plants have only small amounts of NO_x and SO_x emissions and are not regulated by mercury rules. Furthermore, PGE does not propose a new traditional pulverized-coal plant in any of its candidate portfolios. All PGE portfolios for new resources thus reflect the most likely regulatory compliance futures for federal emissions requirements for CO_2, SO_x, NO_x, and mercury.

Existing Resources

All plants are currently in compliance with applicable rules. Table 7-4 above shows upcoming requirements for existing PGE resources to remain in compliance with all current federal requirements.

Gas Plants

With regard to PGE's existing and planned resources, as stated above, our natural-gas-fired plants have only small amounts of NO_x and SO_x emissions that are within air emissions requirements and are not regulated by MATS rules.

Colstrip 3&4

PGE's has a 20% ownership interest in Colstrip Units 3 & 4. These plants were built approximately ten years after Colstrip Units 1 & 2 and five years after Boardman was placed in service. Units 3 & 4 use low-sulfur coal and scrubbers to reduce sulfur dioxide emissions below the limits set by Phases One and Two of the Clean Air Act. PGE and the plant co-owners recently installed low-NO_x burners and new mercury controls such that the units will remain in air emissions compliance until approximately mid-next decade.

At that point in time, the ongoing "reasonable progress" improvement requirement for U.S. EPA Regional Haze Regulations and guidelines for Best Available Retrofit Technology (i.e., RH BART) could trigger the need for a selective catalytic reduction (SCR) system retrofit by 2027.[58] Because this potential requirement is over a decade away, an analysis or decision regarding the economics of a potential SCR retrofit is premature for this IRP.

A proposed revision to the coal combustion residual (CCR) rule will have a small cost impact to Colstrip 3&4. The expected compliance date for CCR is 2018. The expected

[58] No additional equipment or costs are required immediately for the MATS rule or the EPA Regional Haze Federal Implementation Plan (FIP). However, the Reasonable Progress requirement of the Regional Haze Rule will likely require addition of selective catalytic reduction (SCR) systems for each unit by 2027.

cost impact will depend on whether the CCRs are designated as non-hazardous or hazardous.

Boardman

In the 2009 IRP Action Plan, we proposed an emissions control and operating plan for the Boardman plant to comply with both the federal Regional Haze Best Available Retrofit Technology requirements (RH BART) and the Oregon Utility Mercury Rule standards. This plan was referred to as the Boardman 2020 plan. The Boardman 2020 plan includes the installation of emissions abating technologies for NOx, SO_2, and mercury, and the early cessation of coal operations at Boardman in 2020.

We are now well on our way to implementing the Boardman 2020 Plan. In 2011 and 2012 we installed 32 low NO_x burners and 12 over-fire air ports to meet NO_x limits. In 2011, we also installed an activated carbon injection system to reduce mercury emissions. All the modifications are currently operational and meeting the targeted limits.

In 2013, PGE installed a dry sorbent injection (DSI) system to deliver a chemical reagent called trona into the exhaust gas stream and reduce SO_2 emissions. The DSI system consists of a trona train off-loading station, four storage silos, and redundant milling and delivery systems. The system was successfully commissioned and tested, and has been in operation since September 2013. PGE will use the remaining time until the 2014 emissions compliance deadline to refine operations for the most efficient use of activated carbon injection and trona injection systems while still meeting targeted SO_2 reductions.

Implementation of the Boardman 2020 Plan allows the plant to remain fully compliant with state and federal emissions requirements. Finally, we continue to plan for the orderly cessation of coal-fired operations at the plant at the end of 2020.

8. Supply-side Options

This chapter provides background information on the various electric generating resources we consider in this IRP for meeting PGE's future capacity and energy needs. We examine renewable, thermal, and distributed generation options. For each option we discuss the criteria for evaluation and selection, present the resource options and associated attributes, and describe the technologies. In addition, we describe our data sources, assumptions for costs, anticipated advances in technology, and areas of uncertainty. The results of our resource modeling are presented in Chapter 10 - Modeling Results. The supply-side section concludes with a discussion of emerging technologies, followed by a discussion of alternatives to utility ownership.

Chapter Highlights

- We include in our analysis those supply-side alternatives that are currently available or are expected to become available to meet PGE's resource needs.
- We describe the reference case capital and operating costs and underlying assumptions for all resources included in our portfolio analysis.
- These include natural gas-fired combined-cycle combustion turbines, and reciprocating engines, and utility-scale renewables (biomass, geothermal, solar, and wind).
- We also describe the supply-side alternatives available in the region including nuclear and coal-fired generation.
- We review developing technologies such as battery storage, pumped storage, and hydrokinetics for inclusion in future IRPs.
- We conclude with an update on PGE's involvement in efforts to establish a regional Energy Imbalance Market

8.1 Renewable Resource Options

Wind

Utilities currently rely on wind generation projects to meet a major portion of Oregon's renewable portfolio standard (RPS) requirements. As technological advances continue, turbines, towers, rotors, and total project size have all increased over the last few years. The typical size for a new utility scale wind project is between 100 and 400 MW. The typical turbine size is 1.5 MW to 3 MW. Increased scale and technology enhancements are improving both wind project efficiency and economics. As a result, geographically advantaged wind sites that have higher wind speeds and lower interconnection costs can be cost-competitive for energy production (with the production tax credit or "PTC"), compared to fossil-fueled generation alternatives. However, these variable energy resources (VERs) do not provide the same level of capacity or ancillary services benefits as dispatchable thermal generators, and therefore must be combined with other resources to achieve the same level of system reliability. The current PTC benefit for qualified projects is approximately $23/MWh (nominal, indexed to inflation). Given this substantial economic benefit, the PTC remains critical to the competitiveness of wind for the Pacific Northwest.

In addition, wind turbine manufactures have developed machines that take better advantage of lower wind speed sites. Tower heights are being extended from 80 meters up to 120 meters. Longer blades with updated airfoil shapes are also being installed to capture available energy at these low wind speed sites.

We evaluated wind performance based on capacity factors provided by Black & Veatch (B&V) for two regions: 1) Oregon/Washington, and 2) Montana/Wyoming. A representative site in the Oregon/Washington region has an average wind speed for 80 meter hub height turbines of between 6.0 and 6.5 meters per second (m/s). A representative site in the Montana/Wyoming region has an average wind speed of 8.0 to 9.0 m/s at the same hub height. Correspondingly, Oregon/Washington region wind has an estimated capacity factor of 31-35%, whereas Montana/Wyoming region sites have an estimated capacity factor of 39-41%.

For modeling purposes, we use a capacity factor of 32.5% for Oregon/Washington region wind, based on the estimates provided by B&V and validated by the average capacity factor of the Pacific Northwest wind projects bid into PGE's recent renewables request for proposals (RFP). The Montana wind estimated capacity factor of 39% is based on information provided by B&V.

A number of wind turbine suppliers opened new manufacturing plants in North America; however, demand for wind turbines and related components decreased significantly in 2012 due to uncertainty regarding the extension of the PTC. Turbine costs are expected to increase with general inflation, in part due to increases in commodity costs for steel, oil and related materials. While there may be periods where market pressure causes short-term fluctuations in capital costs, the overall cost outlook for wind turbines and major components is steady. We discuss cost trends further in Section 8.4 below.

Transmission availability and integration costs are major hurdles to development of new wind plants. The most viable Pacific Northwest wind sites are on the east side of the Cascades. Montana offers significant wind resource opportunities; however, construction of new transmission lines to move the power to large load centers in Washington and Oregon would add significant costs to these resources.

PGE Wind Integration Study – Phase 4

In 2007, given projections for a significant increase in wind generating resources, Portland General Electric (PGE) began efforts to forecast costs associated with self-integration of wind generation. These efforts entailed developing detailed (hourly) data and optimization modeling of PGE's system using mixed integer programming. This Wind Integration Study was intended as the initial phase of an ongoing process to estimate wind integration costs and refine the associated model.

In October 2009, PGE began Phase 2 of its Wind Integration Study and contracted for additional support from EnerNex (a leading resource for electric power research, plus engineering and consulting services, to government, utilities, industry, and private institutions), which provided input data and guidance for Phase 1. A significant driver of Phase 2 was the expectation that the price for wind integration services, as currently provided by the Bonneville Power Administration (BPA), would increase significantly as growing wind capacity in the Pacific Northwest would exceed the potential of BPA's finite supply of wind-following resources in the future. In addition, PGE believes that BPA's variable energy services rate and subsequent generation imbalance charges represent only a portion of the total cost to integrate wind, as calculated in the Phase 2 study.

PGE conducted a Phase 3 internal study to inform the decision for the BPA FY 2014-2015 election period for wind integration services. The result of the study was a PGE election to contract with BPA to provide regulation, load following and imbalance (30 minute persistence forecast for a 60 minute schedule) services for Biglow Canyon for the term of the 2014-2015 election period.

A significant goal for Phase 4 of the Wind Integration Study was to include additional refinements (some of the enhancements were suggested in the "Next Steps" section of Phase 2) for estimating PGE's costs for self-integration of its wind resources and to determine the sensitivity of wind integration costs to gas price variability. As in the Phase 2 Wind Integration Study presented in our last IRP, the Phase 4 effort included seeking input, deliverables, and feedback from a Technical Review Committee (TRC) and other external consultants. Since launching Phase 4, we have reprogrammed and refined the wind integration model, updated the analysis and results, and also held a public technical workshop to discuss progress and modeling details. The workshop was attended by staff from the Oregon Public Utility Commission (OPUC), the Oregon Department of Energy (ODOE) and other interested parties that have participated in PGE's 2013 Integrated Resource Planning proceeding (OPUC Docket No. LC 56). In addition to this public review, the Phase 4 data and methodology have been carefully evaluated by the TRC, which provided valuable insight and information associated with wind integration modeling.

The Phase 4 model employs mixed integer programming implemented using the General Algebraic Modeling System (GAMS) programming and a Gurobi Optimizer. GAMS is a high-level modeling system for mathematical programming and optimization that we used to program/compile the objective function and operating constraint equations. The Gurobi Optimizer is a state-of-the-art solver used to solve the resulting constrained optimization problem. The Phase 4 model incorporates the improvements made in Phase 2, including:

- Three-stage scheduling optimization with separate Day-Ahead, Hour-Ahead, and Within-Hour calculations;
- Refined estimates of PGE's reserve requirements.

The additional model improvements incorporated in Phase 4 include:

- Separate increasing ("INC") and decreasing ("DEC") reserve requirement formulations for regulation, load following and imbalance reserves;
- Gas supply constraints limiting gas plant fuel usage to the Day-Ahead nomination levels +/- drafting and packing limits on the pipeline;
- Ability to economically feather wind resources; and
- Implementation of the dynamic transfer constraint to allow for limited intra-hour dynamic capacity provision for Boardman, Coyote and Carty.

The results of the study indicate that PGE's estimated self-integration costs (in 2018$) is $3.99 per MWh (in the reference gas price case). In the high gas price case, our estimate is $4.24 per MWh, and in the low gas price case it is $3.57 per MWh. These prices fall within the range calculated by other utilities in the region.

It is important to note that PGE's estimated self-integration costs are exclusive of the necessary investment required in software automation tools, generation control systems, communications/IT infrastructure, and the potential need for personnel additions to manage the self-integration of variable energy resources. In addition, the wind integration cost estimates do not include any incremental operations and maintenance (O&M) costs arising from operating plants more dynamically than in the past. Specific model assumptions are detailed in Appendix D, but, in short, reflect a potential 2018 state in which PGE would integrate almost 717 MW of wind using existing PGE resources, and new resources acquired in the 2012 RFPs. As the supply of variable energy resources and the associated demand for flexible balancing resources increases over time, subsequent phases of the Wind Integration Study will assess the effects of these changes.

Solar Photovoltaic

Solar power is a small, but growing component of the PGE renewable resource mix. Solar generation is more predictable and more available during summer load hours than wind. In addition, for distributed solar projects, there are no transmission constraints.

Technical Options

Photovoltaic (PV) systems convert sunlight directly into electricity. There are three main types of commercially available PV technologies to date: crystalline Silicon (c-Si) modules, thin-film modules, and concentrating PV systems (CPV). The most widely used technology is c-Si, which is also the technology with the longest operational history, dating back more than 30 years. The amount of power produced by PV modules depends on the technology used and the intensity of the solar radiation incident on the material.

Thin-film modules are typically suited for applications where overall weight is a primary constraint, such as large-scale rooftop installations.

According to B&V, CPV systems require regions with high insolation (with high solar resource and clear skies) to be cost effective. These regions tend to be arid and desert-like, such as the southwestern United States. They are an unattractive system for the Portland area and for Oregon in general. Relatively few commercial CPV installations currently exist worldwide.

Solar PV's Fit to PGE Load

When looking at the value solar PV brings in offsetting PGE load, refer to Figure 8-1 and Figure 8-2, which show PGE's typical weekday daily load shape in winter and summer seasons along with the coincident solar insolation, measured in watt-hours per square meter, in the Portland area.

Figure 8-1: PGE load vs. Portland solar capability (winter)

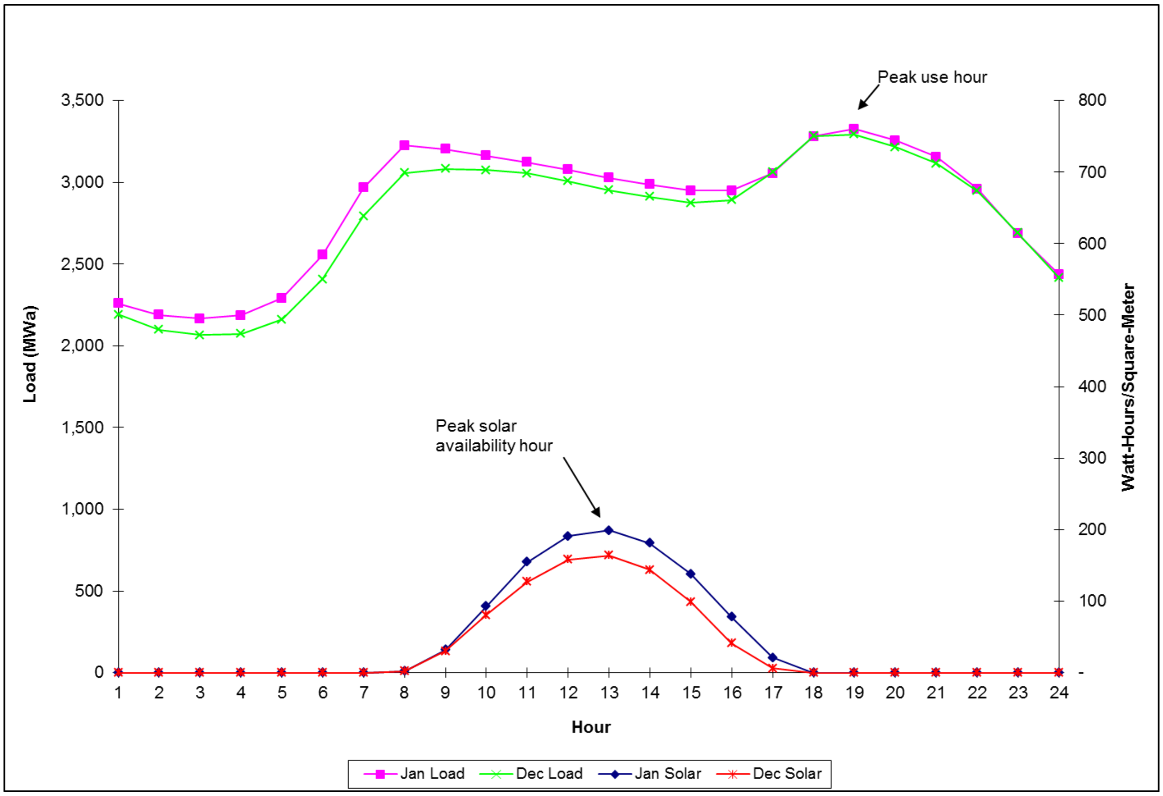
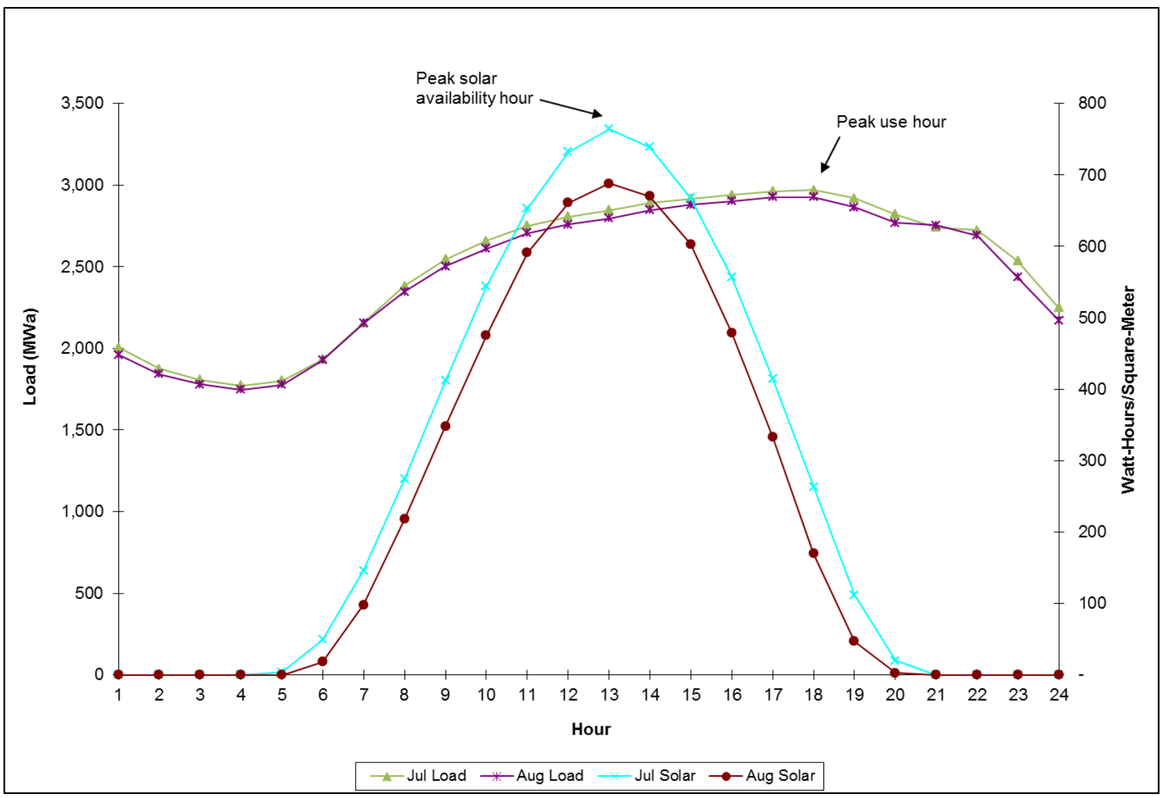


Figure 8-2: PGE load vs. Portland solar capability (summer)



In the winter, solar provides relatively low overall energy and is not a good match to our peak load requirements. PGE is expected to remain a winter peaking utility throughout the planning horizon. Not surprisingly, in the summer, energy generation is much higher, but still doesn't match peak load hours.

PV located in central or southeast Oregon would provide materially higher annual capacity factors due to higher insolation values, but the overall production profile discrepancy between solar energy and peak loads remains.

It is still an open question as to whether a sunnier, but remote location for solar PV is economically superior or inferior to distributed PV in the Portland area. Table 8-1 below captures the relative advantages of each.

Table 8-1: Distributed vs. central solar PV comparative advantages

Attribute	Distributed Portland Area	Utility-scale SE Oregon
Higher insolation		√
Axis tracking		√
Counts toward RPS		√
Control of maintenance		√
Economies of scale		√
Avoided line losses	√	
Avoided transmission	√	
Reduced site cost (rooftops)	√	
Geographic diversity	√	

In a later section addressing distributed generation options, we discuss the emerging potential for residential and commercial customers to install solar PV on-site.

Utility-scale solar PV modeling in the IRP

We model utility-scale PV systems for portfolio analysis in this IRP (distributed solar PV is addressed in Section 8.3) based on information provided by B&V. The utility-scale PV system is assumed to be a fixed tilt 10 MW AC system. Relevant assumptions employed in the development of performance and cost parameters for the 10 MW utility-scale solar PV system include the following:

- The PV system model was developed with PVsyst software version 5.60. PVsyst is an industry standard modeling tool for PV systems developed by the University of Geneva in Switzerland.

- The specific commercial equipment selected for the purposes of conceptual design, system modeling, and cost estimates is representative of Tier-1 manufacturers. The remaining balance of systems equipment and materials were assumed to be typical for this type of project.
- The solar resource data selected was the TMY2[59] data set from the National Renewable Energy Laboratory (NREL) for the Bend/Redmond, OR area.
- The annual capacity factor is 22 percent.

We include integration costs of $0.25/kW-month in 2014$ escalating at inflation. This cost is reflective of the Variable Energy Resource Balancing Service for solar resources tariff rate initially proposed by BPA in the latest rate cycle, which is the most recent estimate available at the time of our resource modeling. PGE has not conducted a separate integration cost study for solar, as the quantity of solar generation in our portfolio is currently small and not expected to reach significant levels for this IRP cycle.

Biomass

Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially roughly 100 years ago.[60] When burning biomass, pressurized steam is generated in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing (e.g., grinding, drying) to improve the physical and chemical properties of the feedstock. Advanced technologies, such as integrated biomass gasification combined cycle and biomass torrefaction[61] or pyrolysis, are under development but have not achieved widespread commercial operation at utility scales.

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating values of the fuels (as compared to fossil fuels), biomass plants are less efficient than modern fossil fuel plants. Also, because of added transportation costs, biomass is generally more expensive than conventional fossil fuels on a $/MMBtu basis.

[59] TMY2 data sets are typical meteorological year sets for the years 1961-1990.
[60] The Rankine cycle is the fundamental operating cycle of all power plants where an operating fluid is continuously evaporated and condensed (e.g. water is pumped in to a boiler where heat from a burning fuel boils the water to make steam to turn a turbine to make electricity; the used steam is condensed back to water and pumped back to the boiler).
[61] Torrefaction is a roasting process (often applied to biomass) in an airless environment at about 540ºF, which removes moisture and volatile substances to create a harder fuel that is easier to store, move, crush, and burn in a power plant.

Biomass projects that collect thinning from forests to reduce the risk of forest fires are increasingly seen as a way to restore a positive balance to forest ecosystems while avoiding uncontrolled and expensive forest fires.

Biomass may be viewed as a near carbon-neutral power generation fuel. While carbon dioxide (CO_2) is emitted during biomass combustion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. The CO_2 re-absorption time will be potentially longer when fueling with woody biomass (e.g., forest thinning). Furthermore, biomass fuels contain low levels of sulfur compared to coal and, therefore, produce less sulfur dioxide (SO_2); biomass fuels may also contain relatively lower amounts of toxic metals, such as mercury, cadmium, and lead.

Biomass combustion facilities typically require technologies to control emissions of nitrogen oxides (NO_x), particulate matter (PM), and carbon monoxide (CO) to meet state and or federal regulatory requirements.

We modeled performance and cost parameters for a biomass facility employing a Bubbling Fluidized Bed (BFB) boiler, with a net generation output of 25 MW. Relevant assumptions employed in the development of performance and cost parameters for the 25 MW biomass energy facility include the following:

- The primary fuel for the biomass facility is assumed to be woody biomass, with an average moisture content of 40% and an as-received heating value of 5,100 Btu/lb. (HHV).
- Plant average annual capacity factor of 85%.
- Cost estimate includes a wood fuel yard sufficiently sized to store 30 days of woody biomass fuel.
- Air quality control equipment includes Selective Non-Catalytic Reduction (SNCR) systems for NOx control, sorbent injection for acid gas control, and a fabric filter for particulate matter (PM) control.

Boardman Biomass Pilot Project

PGE is continuing its research effort to assess the technical and economic viability of biomass fuel conversion at the Boardman plant subsequent to the discontinuation of coal-fired operations in 2020. We have been working with EB Clean Energy and others on the delivery, installation, and commissioning of a small torrefaction demonstration unit at Boardman. Torrefaction is a form of pyrolysis which converts biomass feedstock into a “bio-char” to be used as combustion fuel for the plant.

The torrefaction equipment is expected to be commissioned by the end of Q1 2014. The production of torrefied bio-fuel will commence immediately thereafter. PGE plans to complete the planned mill and co-firing tests (burning a mix of coal and bio-fuel) in Q2 2014, followed by a 100% torrefied bio-fuel test burn in Q2 2015. Importantly, the mill testing is the first indicator that provides information on the properties of the torrefied biomass.

This testing plan will allow us to assess the ability of existing equipment to pulverize and combust the bio-fuel, along with any operational impacts to balance-of-plant systems, and will provide emissions performance data for biomass.

It is contemplated that Boardman biomass would operate as a base load, seasonal operation when market prices and customer demand are typically highest. The plant could also provide capacity and energy, if needed, during the balance of the year. PGE is continuing to assess nearby fuel supply options, including dedicated biomass crops and existing sources of agricultural and forestry residue.

Biomass at Boardman would help meet the growing future Oregon RPS requirement and provide diversity within our renewable resource portfolio. In addition, biomass at Boardman would provide a unique source of dispatchable, base load renewable energy and also provide peak capacity value. Should testing confirm technical feasibility, the next key steps will focus on identifying sufficient cost-effective biomass fuel sources, and assessing the overall project economic and risk mitigation value of Boardman biomass as compared to other renewable resource alternatives.

Geothermal

Geothermal power is produced by using steam or a secondary working fluid in a Rankine cycle to produce electricity.

The most commonly used power generation technologies are direct steam (or dry steam), single-flash, dual-flash, and binary systems. In addition, efforts are underway to develop "enhanced geothermal" projects. The choice of technology is driven primarily by the temperature and quality of the steam/liquid extracted from the geothermal resource area. Considering the temperatures associated with geothermal resource areas located in Oregon, it is anticipated that geothermal developments would utilize either binary geothermal systems or enhanced geothermal systems, as described below:

- Binary: Binary cycle systems are employed for development of liquid-dominated geothermal reservoirs that do not have temperatures sufficiently high enough to flash steam (i.e., less than 350°F or 177°C). In a binary system, a secondary fluid is employed to capture thermal energy of the brine and operate within a Rankine cycle. Additional details regarding binary geothermal systems are discussed below.
- Enhanced geothermal (or "hot dry rock"): For geologic formations with high temperatures but without the necessary subsurface fluids or permeability, fluid may be injected to develop geothermal resources. Typically, the geologic structure must be hydraulically fractured to achieve a functional geothermal resource. While enhanced geothermal projects are currently being demonstrated around the world (including the Newberry Volcano EGS demonstration near Bend, Oregon), this technology is not yet considered commercial.

Three geothermal projects bid into PGE's recent Renewables RFP. Two of these projects were binary cycle systems. The third did not specify, but, based on the site temperature, it would also have likely been a binary system. About 90% of systems currently being developed in the U.S. are binary. For these reasons, we chose to model the binary geothermal technology option. Further, based on the typical size of potential Oregon resources, we chose to model the performance and cost parameters for a 20 MW (net) facility.

Binary plants may be especially advantageous for low brine temperatures (i.e., less than about 350°F or 177°C) or for brines with high dissolved gases or high corrosion or scaling potential. Dry cooling is typically used with a binary plant to avoid the necessity for make-up water required for a wet cooling system. Dry cooling systems generally add 5 to 10% to the cost of the power plant compared to wet cooling systems.

Total estimated potential geothermal generation in the state of Oregon is approximately 830 MW (including Newberry Crater).[62] Greater potential exists in southern Idaho and northern Nevada. Idaho possibly has twice the potential as Oregon, and Nevada has potentially thousands of MWs waiting to be developed. However, PGE currently faces significant transmission challenges in moving energy produced in either Idaho or Nevada to PGE's service territory.

Challenges to developing geothermal generation include permitting (as many of the best resources are on federally-managed lands), and the risk that test wells will not produce economic energy (dry-hole risk).

Commercial-scale geothermal energy appears to be a limited generation alternative for PGE. Current subsidies under the federal PTC and from the Energy Trust of Oregon (ETO)[63] may make some projects more cost-competitive, if transmission is accessible. Actual project costs can vary significantly, based on the hydrothermal reservoir quality and location relative to transmission.

8.2 Thermal Resource Options

Natural Gas Generating Resources

Natural gas-fired generation is one of the fastest growing sources of electric supply in the U.S., increasing from under 20% of national electricity production in 2005 to roughly 30% by 2012.[64] Much of this growth stems from the abundance and relative low cost of natural gas fuel supplies (on a $/Btu basis), as well as displacement of older, less efficient coal-fired generation.

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[62] Source: Western Renewable Energy Zones. "Phase 1 Report". June 2009.
[63] See http://www.energytrust.org/geothermal/index.html for more information on ETO subsidies available for geothermal projects.
[64] EIA Short Term Energy Outlook, November 2013.

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, based on design, via a variety of hydrocarbon sources, but natural gas is the intended fuel we consider in IRP. They can be run in simple cycle, 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.

Improvements in CT technology, such as forced cooling of the combustion parts, have resulted in increased efficiency. CCCTs can also be equipped with duct firing to provide added generation capacity in the steam turbine (but with somewhat reduced overall efficiency). Duct firing consists of injecting and burning additional gas in the combustion turbine exhaust ductwork to boost the temperature of the exhaust gases going to the HRSG. The increase in exhaust temperature will produce more steam in the HRSG resulting in additional energy production from the steam turbine.

Natural Gas Capacity Resources

One of the most recent examples of technological advances in simple cycle combustion turbine (SCCT) machines is the General Electric LMS100PA (LMS100). The LMS100 is an intercooled aero derivative CT with two compressor sections and three turbine sections. Based on information provided by B&V, key attributes of the LMS100 include the following:

- High full- and part-load efficiency;
- Minimal performance impact during hot-day conditions;
- High availability;
- 50 MW/min ramp rate;
- 10 minutes to full power;[65]
- Ability to cycle on and off without material impact of maintenance costs or schedule;
- Natural gas interface pressure requirement of 850 psig; and,
- Dual fuel capability.

An additional SCCT offered by GE is their heavy frame 7FA. These units are available in a rapid start (76% of full-power in 10 minutes), simple cycle configuration – with turndown to 49% of base load.

Reciprocating engines (e.g., Wartsila and Jenbacher) are another means of meeting capacity, load following and variable generation resource integration needs. These internal combustion, piston-driven machines are designed to burn natural gas (or other fuels).

[65] PGE information indicates that full power may be reached in approximately 6 minutes.

Wartsila offers a standard, pre-engineered six-engine configuration for the 18V50SG and the 18V50DF, sometimes referred to as a "6-Pack". The 6-Pack configuration has a net generation output of approximately 100 MW and ties the six engines to a single bus and step-up transformer. This configuration provides economies of scale associated with the balance of plant systems (e.g., step-up transformer and associated switchgear) and reduced engineering costs. Key attributes of the Wartsila 18V50SG include the following:

- High full- and part-load efficiency;
- Minimal performance impact during hot-day conditions;
- 10 minutes to full power;[66]
- Minimal power plant footprint;
- Low starting electrical load demand;
- Ability to cycle on and off without material impact of maintenance costs or schedule;
- Natural gas interface pressure requirement of 75 psig; and,
- Not dual fuel capable (the 18V50DF model can operate on liquid fuels).

The Wartsila engines have a max output of approximately 18.3 MW each. They can be run independently, as well as in combinations at the same or different power levels. This provides an advantage over a GE LMS100, in that a flatter, more efficient heat rate can be maintained over a broader power range.

Next Generation Nuclear

Existing U.S. nuclear power plants have been largely custom-built – a one-at-a-time process that caused delays in approval and construction along with the potential for large cost overruns. Today, with several standard designs already approved by the U.S. 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 nuclear plant designs feature passive safety systems such as gravity-fed water supplies to cool a reactor core during an emergency to prevent overheating. The simplified designs, with fewer pumps, valves, and piping, have reduced both risk and cost. Large, standardized modules 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.

Barriers to construction of the next generation nuclear plants include concerns from the financial community about cost estimates and the potential for overruns. In addition, a permanent nuclear spent fuel repository site has not been approved. The Obama Administration does not view the Yucca Mountain Repository as an option for storing spent nuclear fuel and has rejected funding for the site. In addition, there are significant political and regulatory barriers to the construction of nuclear power plants, particularly

[66] PGE information indicates that full power may be reached in approximately 6 minutes.

in States such as Oregon where state law prohibits the construction of new nuclear plants until a permanent spent fuel repository is operating.

To address some of the risk issues related to scale, national efforts are underway to develop an NRC-approved standardized Small Modular Reactors design, which offers the advantage of adding incremental generation to match load growth and provide a manageable construction schedule and financing. These designs also have built-in passive-safety systems.

During PGE's 2007 IRP, the OPUC Staff recommended that PGE include nuclear resources as an option in future plans. Accordingly, we include nuclear plant energy as an out-of-state resource option in this plan for the regional build-out, although no state contiguous to Oregon is planning for new nuclear plant construction. However, we do not include nuclear as a resource option in PGE portfolios. With respect to potential timing of new nuclear development in the U.S., we believe that the new SMR designs discussed above will not be commercially deployed until after 2020. We relied on information developed by B&V for NREL in 2012. That report is provided in Appendix G.

Pulverized Coal

Coal is the most widely used fuel for the production of power in the U.S. with roughly 40% of national electricity consumption served by coal plants.[67] The political climate in the Northwest, and Oregon in particular, is not favorable for new pulverized-coal (PC) plants due to environmental considerations. There are currently no new PC plants being considered or permitted for Oregon or Washington.

In a PC plant, coal is ground into fine particles and blown into a furnace where combustion takes place. The heat from the combustion of coal is used to generate steam to supply a steam turbine that drives a generator to make electricity.

PC plants are traditionally categorized as either subcritical or supercritical based on the steam cycle of the units. Subcritical steam generation units operate at pressures such that water boils first and then is converted to superheated steam. At supercritical pressures, water is heated to produce superheated steam without boiling. Due to the improved thermodynamics of expanding higher pressure and temperature steam through the turbine, a supercritical steam generating unit is more efficient than a subcritical unit.

Oregon's Greenhouse Gas Emissions Performance Standard (Senate Bill 101 (2009)) limits CO_2 emissions to 1,100 pounds per MWh from incremental long-term generation. The statute was amended in 2013 to preclude a potential loophole for long-term purchases from generators outside Oregon. Because this law generally precludes PGE from acquiring output from coal generation without significant reduction in carbon emissions, such as from carbon capture and sequestration, PGE has not modeled new coal generation (or purchase) as an option for PGE's resource portfolio. We do, however, leave coal generation as an out-of-state option for the regional build-out described in

[67] EIA Short Term Energy Outlook, November 2013.

Chapter 9 - Modeling Methodology. Coal-fired plant information was developed by B&V for NREL in 2012. That report is provided in Appendix G.

Integrated Gasification Combined Cycle Coal (IGCC)

IGCC is a technology for coal-fueled generation that offers the potential for significantly lower emissions compared to conventional pulverized coal technology. IGCC has the capability to separate and capture CO_2, and to produce lower non-CO_2 emissions.

Gasification consists of partially oxidizing a carbon-containing feedstock 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 for the endothermic gasification reactions.

Entrained flow gasifiers have been operating since the mid-1990s, to produce electricity in four 250 to 300 MW IGCC plants located in Europe (two plants) and the United States (two plants). Coal-based operating experience of IGCC systems has been focused almost exclusively on bituminous coals and petcoke. Sub-bituminous (i.e., Powder River Basin or "PRB") coals have been tested only in a limited fashion, but due to the nature of the U.S. coal market and the abundance of PRB coal, there is strong interest in using it for IGCC applications. We assumed the use of PRB coal for an IGCC plant in this region.

Dry-feed gasification processes are better suited for high moisture fuels (e.g., PRB coal), as these processes minimize the moisture added to the gasifier (beyond the inherently high moisture of the fuel). Because these dry-feed processes are better suited for PRB, the Shell dry-feed process was selected as the likely gasification technology for this plan.

Entrained flow gasification processes may also offer the potential to co-fire biomass fuels. However, the wet feed system assumed for this IRP would limit biomass co-firing to a maximum of 5% (by weight) of the total fuel stream.

8.3 Distributed Generation Operations

Benefits of Distributed Generation

Within our service area, PGE and our customers currently engage in two primary types of distributed generation (DG):

- Dispatchable Standby Generation (DSG), and,
- Distributed PV solar.

We model both of these types of DG resources in our IRP, in conjunction with central-station generation. DSG is common to all of our portfolios. Our proposed Action Plan recommends ongoing acquisition of DSG and market development of distributed PV solar. It is difficult to know, at this point in time, how much cost-effective distributed PV solar may become available within the next few years, particularly since it is an emerging technology and market with an uncertain maturation curve. Below, we share the findings of a preliminary scoping analysis regarding the potential scale of distributed solar PV in our service area (in the absence of cost restraints).

Distributed generation can provide advantages over central-station generation, including: enhanced localized reliability; improved efficiency due to avoided transmission losses; and for customers who have installed distributed generation, it can provide a partial hedge against changing future power costs.

Dispatchable Standby Generation (DSG)

PGE's DSG program uses diesel-fueled back-up generators at commercial and industrial customer sites to supply capacity 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 deployment of communications and control technology, PGE can remotely start the generators to both displace the generator owner's load and supply excess power to the grid. Under the DSG program, PGE is responsible for communication and control equipment, generator maintenance and fuel costs. This program increases customer satisfaction and provides PGE with an economic source of capacity that is distributed within our service territory, thereby reducing costs and risks associated with transmission, fuel supply, and large single-shaft exposure.

DSG generators also provide benefit as standby operating reserves for PGE. 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 capacity from customer-owned generation.

The operation of the back-up generators is limited by State of Oregon emissions permit restrictions. A recent EPA rule imposes additional constraints such that most DSG units classified as "emergency" will be limited to 50 hours per year of DSG non-emergency operation. Plans for the future may include pursuing retrofits to change the classification of several, if not most, generators to "non-emergency" so that the 50-hour limit per year can be removed. However, most of the value of DSG is in the first 50 hours per year.

DSG usable capacity available is expected to be approximately 93 MW by the end of 2013. The current expectation is that we will be able to add 30-40 MW in the 5-year period from 2014-2018 with our current project management staffing level.

Distributed Solar[68]

The national solar PV market is changing rapidly. The costs of installing solar PV have been declining steadily, resulting in increased interest in installing solar PV. Additionally, increased attention on carbon emissions from traditional power generation

[68] Distributed Solar refers to solar electric power generation sited at a customer's premise. It can be either retail (e.g., on the customer's side of the electricity meter), providing electric energy primarily to offset customer load on that site, or wholesale (e.g., connected directly to the distribution network), providing wholesale capacity and energy to an electric utility for use by multiple customers; this section refers to the latter.

sources, and on U.S. energy independence, is motivating customers and utilities to reevaluate solar PV. Because of this growing convergence of interest and reduced cost, PGE believes that investigating the potential for additional utility involvement in distributed solar PV makes sense.

In the Action Plan window, PGE will pursue pilot programs and research initiatives with the goal of assessing potential business models and policies that expand the installation of cost-effective distributed solar PV. These programs and policies will also seek to avoid cross-subsidies, limit lost revenue, and properly value the energy and ancillary benefits that come from distributed solar generation. We may also study the value of solar to PGE's distribution system, implementing tariffs that appropriately share the benefits and costs of distributed solar among customers and providing direct incentives to customers through the utility for the installation of solar PV. PGE is also evaluating installation of utility-scale solar PV via a potential new program that would allocate solar benefits to customers who lack the ability to site their own PV systems due to inappropriate rooftop space, non-home ownership (e.g., renters), or insufficient capital capacity.

Distributed Solar PV Assessment

PGE recently conducted a preliminary scoping analysis to assess the technical potential for distributed PV within our service area. Our objective was to gauge whether distributed PV could become a game changer that would cause us to reassess the need or timing for new utility-scale renewable resources in the future. This preliminary scoping makes no assumption about the economic attractiveness of the installed systems to either PGE or the customer.

We first performed a rough estimate of the total square feet of roof space and brownfield ground sites in our service area including residential, commercial, and public structures. The data were derived from databases maintained by the Portland Bureau of Planning and Sustainability (for rooftops) and Maul Foster (for brownfields). The total rooftop square footage was adjusted upward (from a Portland metro area assessment) to account for our entire service area. Viable rooftop space, which varied by building type, was estimated to be between 10 and 20% of the total roof area. Only the portion of a rooftop that faces the correct direction (i.e., south or southwest) can be utilized. Additionally, sites cannot be subject to significant shading and they must be structurally capable of adding a PV system. The rooftop potential is also adjusted for those sites or customers that cannot participate for other reasons (potential financial or structural limitations). Likewise, brownfield sites adjacent to environmentally sensitive lands or deemed to have higher commercial potential were eliminated.

After we determined potential square footage, we then looked at how much power these sites could jointly produce. Our analysis assumed fixed mount systems, and a DC to AC inverter conversion of 85%. Based on current PV module conversion efficiency, and the Portland area annual insolation, the annual average AC capacity factor will be 12% of the DC nameplate module rating.

Based on these preliminary scoping figures, we estimate the potential for about 1,300 MW (DC) of distributed solar within our service area. The corresponding annual average output is about 155 MWa (AC). This is equivalent to about four years of load growth before incremental energy efficiency. PGE customers are currently adding solar PV of about 9 MW DC per year, or roughly 1 MWa AC.

For widespread adoption to occur, solar PV pricing will need to continue to fall until it reaches parity with embedded prices, along with materially reduced incentives and more efficient regulatory and pricing structures. Small solar PV systems currently enjoy significant incentives; however, some of these incentives are expected to expire in the near future (e.g. the Investment Tax Credit). Others, like the ETO incentives, would have to be reduced if the number of solar installations accelerated.

We observe that, even at a much accelerated rate of adoption, the annual average load reduction impact is likely to be gradual and modest. It is not expected to materially reduce the need for other generation resources in the near future. However, since the AC capacity-to-energy ratio is in excess of 6-to-1, an additional 25 MWa of annual solar energy will translate to over 150 MW during peak output hours. This large ratio of peak-to-average generation may have a significant impact on our requirements for back-up generation to provide load-following and other ancillary services, particularly during the higher solar production months.

8.4 Current Customer Distributed Generation Programs

Net Metering

PGE's net metering tariff helps incentivize customers to install renewable generation. Customers with their own renewable power sources may offset part, or all, of their load. Under our net metering program, the customer handles all installation arrangements and the system must meet all applicable codes. We provide a bi-directional 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 website 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.

Solar Payment Option

The Solar Payment Option Pilot Program (a.k.a. feed-in tariff) provides customers an incentive to install a photovoltaic system of less than 500 kW on their home or business. Because the customer receives a generous incentive rate, the ETO and state tax incentives are prohibited in this pilot. Before installing a solar system, customers must apply for, and be awarded capacity, during an open enrollment window. Customers may apply for capacity directly on PGE's web site or work with a third-party vendor who will apply for them. The customer contracts associated with these systems have a 15-year term. PGE provides a separate meter to allow the measurement of energy being produced by the customer's solar system. The 5-year pilot program is a legislative mandate. Recently the enrollment period was extended and the final enrollment window is May 1, 2015.

8.5 Supply-side Resource Cost Summary

The technological advances in electricity generation in the past 20 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, hydrokinetic generation and modular-nuclear technologies could play a role in meeting future energy needs. For this IRP, however, we include only those supply-side technology alternatives that are, or are expected to become, commercially available during our Action Plan horizon. These are:

- Natural gas-fired: SCCTs, CCCTs, and Reciprocating Engines
- Next-generation nuclear (out of state)
- IGCC with carbon capture
- Utility-scale renewable resources including: biomass, geothermal, solar PV, and wind energy
- Customer-sited CHP and DSG

Expected Cost per kW

New WECC resources are modeled in AURORAxmp based on the construction and operating parameters, and capital and operating costs shown in Table 8-2. O&M includes integration costs for wind and solar. For resources located outside of the BPA Control Area, O&M also includes wheeling based on the estimated incremental cost of new transmission builds on BPA's system. Capital costs include Climate Trust offset payments (see Chapter 7 - Environmental Assumptions for more information) and owner's costs.

Table 8-2: WECC new resource costs

IRP Modeling Assumptions - 2013$	Typical Nameplate MW	Earliest Date Available Year	Economic Life Years	Expected Availability/CF % [1]	Overnight Capital Cost $/kW [2]	Fixed O&M $/kW-yr	Variable O&M $/MWh [3]	Degraded Heat Rate BTU/kWh
PGE Options for Portfolio Analysis								
Binary Geothermal	20	2014	30	89%	$ 8,929	$ 208.96	$ 23.55	N/A
Small-scale BFB Biomass	25	2014	30	87%	$ 7,580	$ 224.25	$ 9.48	13,515
Central Station Solar PV	10	2014	25	22%	$ 2,797	$ 18.35	$ 2.87	N/A
Wind Plant PNW	300	2014	27	33%	$ 2,213	$ 40.77	$ 3.63	N/A
Wind Plant Montana	300	2014	27	39%	$ 2,142	$ 40.77	$ 3.63	N/A
Natural Gas CCCT-DF	395	2016	35	94%	$ 1,121	$ 10.28	$ 3.23	7,043
Wartsilla Reciprocating Engine	98	2014	30	94%	$ 1,707	$ 16.00	$ 8.98	8,571
SCCT - LMS100	96	2014	30	97%	$ 1,391	$ 12.95	$ 3.67	9,184
Additional options for WECC resource expansion only								
Coal - Super Critical Pulverized	594	2018	40	85%	$ 2,946	$ 23.44	$ 3.78	9,561
Coal - IGCC Sequestration Ready	466	2018	35	82%	$ 7,467	$ 66.15	$ 11.62	12,143
Nuclear	1,125	2019	40	90%	$ 6,218	$ 129.45	$ 1.41	N/A

Notes:
1) Expected Availability is expected capacity factor for Wind and Solar PV
2) Capital also include OEFSC payments to Climate Trust of Oregon for gas
3) Variable O&M includes integration costs for Wind (from PGE Wind Integration Study) and Solar PV (BPA VERBS rate)

The costs and operating parameters for these resources incorporate information provided by independent consultant B&V, and research, professional judgment and experience of PGE technical staff.

Table 8-3 provides cost assumptions from the Energy Information Administration's 2013 Annual Energy Outlook (AEO) and from the Northwest Power and Conservation Council's Sixth Northwest Conservation and Electric Power Plan. PGE's assumptions in Table 8-2 form the basis of the overnight capital costs reported in Table 8-3. Our resource cost estimates approximate those reported in the AEO in most cases. Significant differences are noted below:

- PGE's estimate for biomass includes selective non-catalytic reduction for NOx control and sorbent injection for acid gas control. It is unclear that the estimate contained in the EIA's 2013 AEO includes the cost of this pollution control equipment.
- PGE's estimate from B&V for geothermal includes a higher cost of drilling/developing a well field compared to the EIA report ($4.5 million per well vs. $1 million to $1.5 million per well). In addition, the B&V report has a higher overhead factor for owners' cost. After scaling the capital costs for comparable plant capacities, and adjusting for well field development costs and owners' costs, the values across sources are generally in the same range.
- The EIA central-station solar costs are for a single-axis tracking PV system; PGE's central station solar cost is for a fixed ground mount system. Tracking systems have higher capital costs, but also higher efficiency.

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 broad validation.

Table 8-3: Overnight capital comparison

	Overnight Capital (2013$/kW)			Nameplate Capacity (MW)		
Resource Technology	PGE 2013 IRP [1]	2013 EIA [3]	NWPCC 6th Plan [7]	PGE 2013 IRP	2013 EIA	NWPCC 6th Plan
Binary Geothermal	$ 8,929	$ 4,466	$ 5,487	20	50	39
Small-scale BFB Biomass	$ 7,580 [4]	$ 4,353	$ 3,430	25	50	25
Central Station Solar PV	$ 2,797 [5]	$ 4,121 [6]	$ 10,289 [6]	10	20	20
Wind Plant PNW	$ 2,213	$ 2,422	$ 2,401	300	100	100
Wind Plant Montana	$ 2,142	$ 2,324	$ 2,401 [8]	300	100	100
Natural Gas CCCT-DF	$ 1,121	$ 1,158	$ 1,280	395	400	415
Wartsilla Reciprocating Engine	$ 1,707	N/A	$ 1,315	98	N/A	100
SCCT - LMS100	$ 1,391	N/A	$ 1,292	96	N/A	99
Coal - Super Critical Pulverized	$ 2,946 [2]	$ 3,262	$ 4,001	594	650	450
Coal - IGCC Sequestration Ready	$ 7,467	$ 6,975	$ 5,487	466	520	518
Nuclear	$ 6,218 [2]	$ 5,556	$ 6,287	1,125	2,234	1,117

Notes:
[1] Unless otherwise noted, source is: Black & Veatch, "Characterization of Supply-Side Options", February 2013.
[2] Black & Veatch, "Cost and Performance Data for Power Generation Technologies", February 2012. Prepared for National Renewable Energy Laboratory.
[3] U.S. Energy Information Administration, "Updated Capital Costs for Utility Scale Electricity Generating Plants", April 2013. Estimates prepared by Science Applications International Corporation and include locational cost adjustments.
[4] PGE estimate includes selective non-catalytic reduction for NOx control and sorbent injection for acid gas control.
[5] Estimate is for a fixed-tilt system.
[6] Estimate is for a single-axis tracking system.
[7] Northwest Power and Conservation Council, "Sixth Northwest Conservation and Electric Power Plan", February 2010. Values were escalated from 2006$ to 2013$.
[8] Overnight capital cost does not reflect additional transmission costs.

Potential for Future Cost Changes

Advances in technology are usually characterized by a combination of a decline in real cost per kW, due to learning effects and economies of scale, and an increase in conversion efficiency (i.e., a better heat rate) for thermal plants (or, alternatively, increases in wind energy capture and conversion efficiency for renewable resources) due to actual technology improvements. We projected anticipated efficiency and/or cost advances based on discussions with power sector original equipment manufacturers (OEM's) and power plant developers, as well as a review of generation efficiency trends over the last few years.

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. Due to the slow recovery in the world economy, we see general stability in the input costs of new generating resources (commodity and construction pricing). For this reason, we project neither significant cost declines nor increases per kW for our primary supply-side alternatives in our reference case assumptions. We do, however, test Portfolios against Futures in which capital costs may be higher or lower than the reference case. These Futures are presented in Chapter 9 - Modeling Methodology.

Gas turbine technology

Simple-cycle technology is relatively mature and, when fueled with natural gas, has negligible new environmental requirements going forward. Future improvements will likely be in the area of increased flexibility, which should have a minor effect on increasing capital costs. New, major technological breakthroughs for SCCTs (e.g., more complex equipment, exotic metals) implying higher capital costs are not foreseen at this point.

To optimize turbine efficiency, the U.S. Department of Energy (USDOE) is currently seeking to increase the turbine inlet temperature by promoting research including use of advanced thermal barrier coating materials, enhanced cooling techniques, and improved turbine aerodynamics. These advancements have the potential to increase the simple cycle efficiency 1.0% for every 70° F increase in turbine inlet temperature.

However, PGE's engineering research indicates that these gains are expected to be incremental over the coming years because current gas turbines are approaching maximum efficiency as limited by the Brayton cycle.[69] Because natural gas prices are currently low in the United States, gas turbine suppliers are focusing attention on responding to demand quickly. Major turbine manufacturers are introducing new advance class turbines with increased efficiency and firing temperatures. As the turbine development cycle is several years, further significant technology improvements are not expected within the next 10 years.

Wind turbine technology

The average price of wind turbines in the US market has varied widely over the past 15 years, largely driven by the dynamics of market supply and demand. Significant and persistent changes in the average turbine price are not expected over time, but year-over-year changes may still occur, with some "expensive" years and some "inexpensive" years, depending on manufacturing capacity and market demand. Future market demand may be driven by periods of increased wind project development leading up to years with increased state RPS compliance targets (for instance, RPS targets in most WECC states increase in 2020).

Conventionally, wind turbines have been designed to operate within moderate to high wind regimes (generally speaking, with average wind speeds of 7.5 to 9 m/s, depending on the site terrain/vegetation and air density). In recent years, there has been a focus on designing turbines to operate at sites characterized by lower wind regimes (with average speeds less than 7.5 m/s). In simple terms, this has generally been achieved by increasing the hub heights and size of the rotors and blades relative to size of the generator within the turbine.

With the introduction and development of low-wind resource machines, some increases in cost per kW of capacity may be seen (relative to costs of more conventional wind turbine models) because of the increased size of the blades and height of the tower for these low-speed machines. Both the blades and towers for low-wind machines require more material and can present additional transportation challenges. However, the cost per kW increase may not be reflected in costs on an energy basis because of the expected performance increase from these low-wind machines.

[69] The Brayton cycle is the fundamental operating cycle for jet engines and turbines used to produce electricity. A compressor-fan pulls air into the front of the turbine. The air is mixed with a fuel (e.g., natural gas), ignited to produce a hot gas that spins a turbine-generator, and exhausted out the back of the turbine.

Project performance has been increasing relatively steadily over the past decade, though the pace of advancement has slowed. The average capacity factor of the entire U.S. fleet has increased from less than 30% in the early 2000s to nearly 35% at the end of 2011. Expected capacity factors of new projects have increased, but have generally leveled off in the low to mid-30% range in this region.

Looking at the current wind turbine market, expected technology changes, which are incremental but cumulative, and wind turbine developments relative to US wind maps, it appears that while average performance has not increased greatly over the past few years, the potential performance at a given site may have increased greatly. A moderate- to low-wind site that would have a capacity factor in the low-30% range using a conventional turbine design may now be able to achieve a capacity factor in the upper-30% range using a new low-wind resource design. While these new turbine models are not suitable for every site, they may make a significant contribution to total wind generation by improving the economic feasibility of some sites.

As a result, a decline in economically accessible higher wind speed sites is expected to be largely off-set by improved wind turbine generator technology and efficiency over time. A greater upward trend is expected in average capacity factors in low- to moderate-wind speed areas with the use of the new turbine designs discussed above. However, while the total average performance of newer projects should increase, the increase may not be large in aggregate as a result of the development of lower wind speed areas closer to load centers and transmission access. Our Scenario analysis tests Portfolios against Futures that represent both higher and lower capacity factors for wind resources; these Futures are discussed in Chapter 9 - Modeling Methodology.

Solar PV

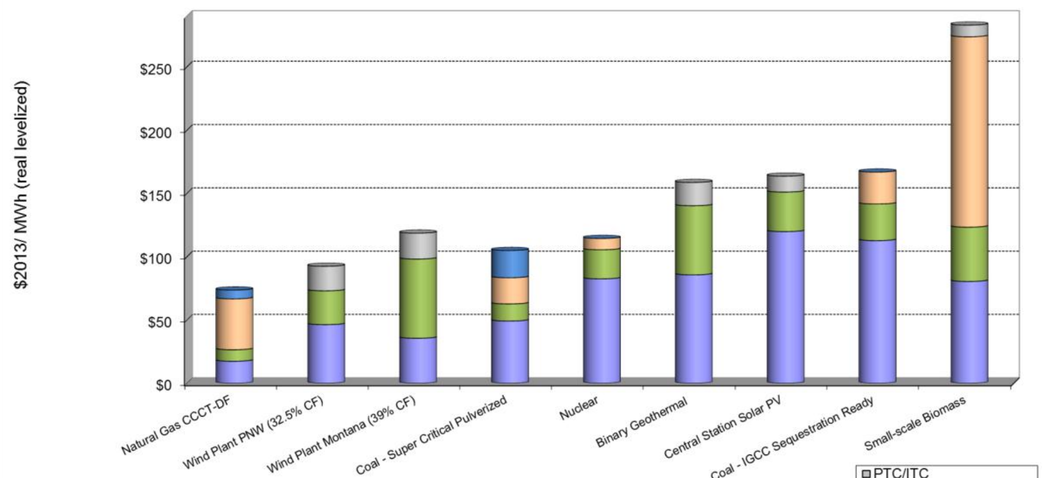
Solar power in this region remains more expensive than wind or natural gas-fired generation. However, costs for solar continue to decline with improved technology and manufacturing efficiencies. For instance, solar PV capital costs have declined steadily due to decreased raw silicon costs, increased panel production, efficiency improvements and innovation. Over time these cost reductions could reduce the cost differential between solar and other electric generation technologies. Based on recent industry reports, future solar panel cost declines will likely slow and stabilize. While improvements in balance of plant costs (e.g., installation) are possible, based on the information provided by B&V, we are not modeling further reductions in capital costs for solar PV in our reference case. As discussed in Chapter 9 - Modeling Methodology, our Scenario analysis does test Portfolios against a Future including overnight capital costs for solar PV resources that are 10% lower than the reference case assumption.

8.6 New Resource Real Levelized Costs

Fuel, fuel transportation, emissions, and transmission costs are added to the capital and operating costs summarized in Table 8-2 to derive estimated real levelized, fully allocated energy costs for new generating resources available to PGE. Capital costs include amounts for depreciation, property tax, return on capital, income tax, and estimated cost of new transmission (for Montana wind). We discuss our financial assumptions in Chapter 9 - Modeling Methodology. O&M costs include transmission and integration costs. The Production Tax Credit (PTC, applied to wind, geothermal, and biomass) and Investment Tax Credit (ITC, applies to solar PV) assume the credits available as of November 2013.

To calculate a real levelized cost of energy, a life-cycle revenue requirements model was used, in conjunction with our production cost model AURORAxmp. We applied PGE's incremental cost of capital and 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 8-3.

Figure 8-3: Generic resources life-cycle revenue requirements ($/MWh)



NOTES:
O&M includes wheeling and integration
Renewables include current production tax credit (PTC) and investment tax credit (ITC) incentives through 2023
Costs assume Reference Case CO_2 tax beginning 2023
Coal - Super Critical and Natural Gas CCCT are based on dispatch at 70% capacity factor
Coal and nuclear resources are not eligible for consideration in PGE portfolios
Costs reflect assumptions including technology, environmental policy, tax incentives, and fuel supply, among others

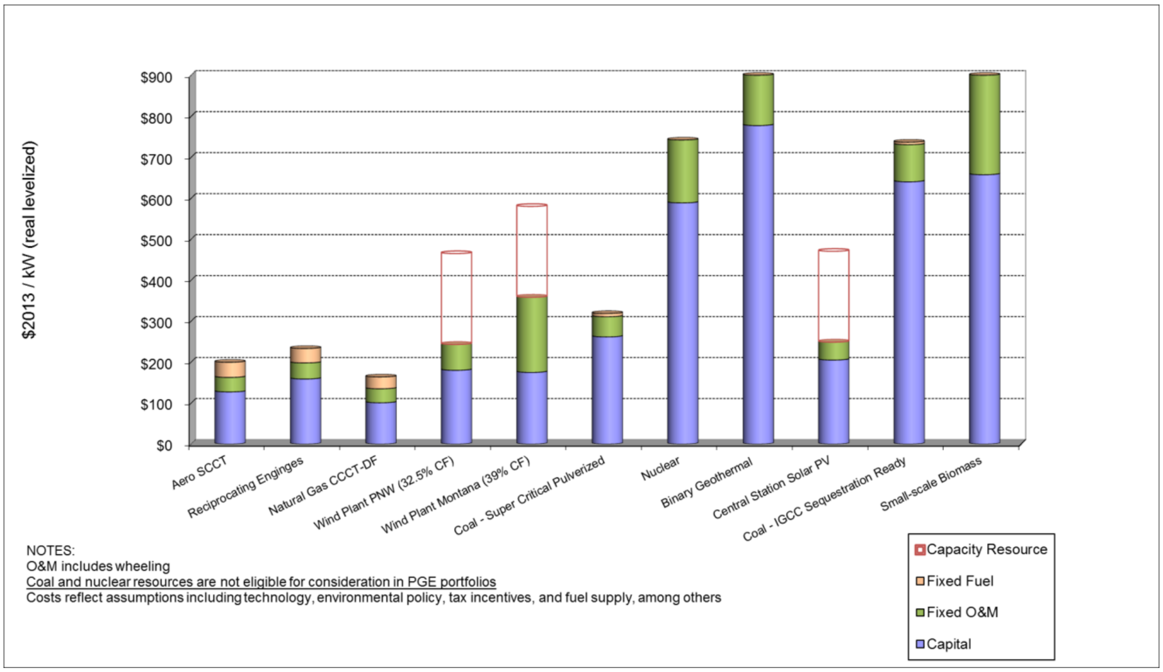
Figure 8-3 represents the cost per MWh of energy produced, including both fixed and variable cost components. In Figure 8-3, all resources, except the CCCT and super critical coal, are must-run or have low variable costs. Thus, the CCCT and super critical coal are the only resources which are at times displaced by the market, making a cost per kWh comparison to other energy resources more challenging. For this resource cost comparison, we have included the cost of the CCCT and super critical coal based on an assumed 70% capacity factor.

In Figure 8-3, the gray cylinders at the top of the bars for wind, geothermal, solar PV and biomass represent the societal resource cost as though there were no PTC or ITC (ITC applies to solar PV, PTC applies to the others). The PGE customer cost that we use for purposes of modeling resource costs assumes inclusion of the benefit from the PTC or

ITC – it is the cost to the top of the green cylinder, without the gray cylinder. Assumptions regarding the PTC and ITC found in Figure 8-3 are found in the next section, after Figure 8-4.

Resources used primarily for flexibility and capacity, such as reciprocating engines, are not included in the graph above, as they are not utilized for providing base load energy. Rather, the cost of each resource being able to provide 1 kW of year-round capacity is illustrated in Figure 8-4. We add only the fixed costs of our default capacity resource, reciprocating engines, to make intermittent solar and wind projects equivalent to other resources on a portfolio capability and cost basis.

Figure 8-4: Generic resources life-cycle revenue requirements per 1 kW of capacity ($/kW)



While the stand-alone costs for a given resource type are instructive, the resources become building blocks within portfolio analysis where economic dispatch and risk analysis are added. Further, our approach to portfolio construction calibrates all candidate portfolios to materially similar capacity and reliability levels. The only exception to this approach is the “Market with physical compliance” portfolio, which evaluates the cost and risk of not adding long-term resources beyond those needed to achieve physical compliance with Oregon RPS, but instead relying on shorter-term market purchases.

Sources and Assumptions for PGE Real Levelized Costs

We applied the following key assumptions in estimating the reference case resource costs shown in Table 8-2, Figure 8-3, and Figure 8-4:

General

- BPA wheeling rates are assumed to grow annually at inflation, with annual real growth of approximately 2.1% over the analysis time period.
- Energy Trust incentives are determined on a project basis and as such, we have included no ETO incentives in our real levelized cost of energy.
- Production Tax Credit (PTC) and Investment Tax Credit (ITC) renewal at 2013 incentive levels are assumed through 2022 for qualifying resources (approximately $22.45/MWh real levelized in 2013$ for PTC, ITC is equivalent to 30% of eligible expenditures with a reduction to 10% after 2022). The ITC is applied to solar PV installations in our analysis. The PTC is applied to wind, geothermal, and biomass options in our analysis.
- As of year-end 2013 the PTC was not extended, and the ITC is scheduled to expire at year-end 2016. At the time of our modeling we did not know if they would be extended in their current forms and amounts (if extended at all). Due to the uncertainty, for reference case modeling purposes we conservatively assumed eventual renewal in their current forms until 2023, when we assume they will be superseded by more comprehensive carbon regulation.

Wind

- We include two geographic locations for wind resources: Pacific Northwest (PNW), with a capacity factor of 32.5%, and Montana, with a capacity factor of 39%.
- Capital cost estimates are based on information provided by B&V. PGE's recent experience from the 2012 RFP for renewable resources is also incorporated into the estimated capital cost for new PNW wind resources.
- B&V provided information for new 100 and 300 MW wind resources. For portfolio construction, PGE assumes wind resources are scalable to meet projected energy needs.
- PTC renewal is incorporated per the assumptions discussed above.
- Integration costs of $3.63/MWh in 2013$, escalating at inflation, are included in O&M.
- Incremental transmission for Montana wind is estimated based on published transmission system expansion proposals and other publicly available information.

Central Station Solar PV

- We include the estimated cost and operating parameters of a central station solar PV resource located in Central Oregon, based on a ground-mount fixed-tilt configuration.
- Cost and performance estimates are based on an assessment provided by B&V; actual solar project costs may vary significantly depending on location, type of technology and whether or not a tracking system is used.

- ITC renewal is incorporated per the assumptions discussed above.
- Integration costs of $0.25/kW-month in 2013$, escalating at inflation, are included in O&M.

Geothermal

- Costs are representative of a binary geothermal system.
- PTC renewal is incorporated per the assumptions discussed above.
- Estimated capital costs include the cost of well development.
- Variable O&M costs estimated by B&V include costs associated with the development of 1 new supply well every 5 years; it is assumed that 1 out of every 5 replacement supply wells is dry (i.e., does not provide sufficient flow and is therefore unusable), and well replacement costs include costs associated with the drilling of dry wells.

Biomass

- Performance and cost parameters are estimated for a biomass facility employing a Bubbling Fluidized Bed (BFB) boiler; actual biomass project costs may vary significantly depending on fuel type and availability, as well as particular site and host characteristics.
- Air quality control equipment includes Selective Non-Catalytic Reduction (SNCR) systems for NOx control, sorbent injection for acid gas control, and a fabric filter for particulate matter (PM) control.
- PTC renewal at current levels is incorporated per the assumptions discussed above (representing 50% of the PTC available for wind and geothermal).
- The cost of the biomass fuel is highly dependent on the fuel mix, the scale of the plant, and transportation costs. For modeling purposes, we assumed a delivered hog fuel cost of $75 (in 2012$) per dry ton, but we also modeled a high case of $150 (in 2012$) for green biomass pellets.

Base load Natural Gas

- Capital and operating costs are estimated based on a Mitsubishi G-series combustion turbine (501GAC) in combined cycle with a duct burner providing base load generation capability of 348 MW (degraded, duct firing capability represents an additional 48 MW).
- Costs include a CO_2 offset payment to the Climate Trust of approximately $15/kW, based on current requirements (see Chapter 6 - Fuels).
- For portfolio construction, PGE assumes base load natural gas plants are not scalable to meet the projected energy needs (i.e., a plant is added to the modeled portfolios in its entirety).

Natural Gas Capacity Resources

- We use capital and operating costs from B&V for the GE LMS100 SCCT and Wartsila rapid-start reciprocating engines.

- Costs include a CO_2 offset payment to the Climate Trust of approximately \$27/kW for the LMS100 and the Wartsila reciprocating engines, based on current OEFSC requirements.
- For portfolio construction, PGE models reciprocating engines as the default capacity resource. The reciprocating engine configurations are assumed to be scalable to meet the projected capacity needs.

Nuclear (for WECC expansion only, not included in PGE candidate portfolios)

- We use capital and operating costs based on a report prepared by B&V for NREL.
- The nuclear plant proxy is based on a commercial Westinghouse AP1000 reactor design producing 1,125 MW.

Integrated Gasification Combined Cycle (for WECC expansion only, not included in PGE candidate portfolios)

- Cost data and operating parameters for an integrated gasification combined cycle plant with carbon capture come from the B&V study commissioned by PGE.
- A dry-feed entrained flow gasification process is assumed, utilizing Powder River Basin coal as the fuel.
- Carbon capture equipment is designed and sized for CO_2 capture efficiency of 90 percent.[70]
- Net output with carbon capture is approximately 466 MW (degraded).
- CO_2 transportation and sequestration are not included in the overnight EPC capital cost.
- For IGCC, we assumed no federal investment tax credit.
- Due to the uncertainty of sequestration cost and feasibility, our reference case IGCC plant cost is sequestration ready, but does not include sequestration.

Super Critical Coal (for WECC expansion only, not included in PGE portfolios)

- We use capital and operating costs based on a report prepared by B&V for NREL.
- The estimate includes the cost of a SCR reactor. The boiler is assumed to include low NOx burners and other features to control NOx.
- Net output is approximately 594 MW (degraded).

[70] The information provided by B&V includes carbon capture only and not costs associated with sequestration. Sequestration is very site specific and the technology is still in the R&D phase.

8.7 Emerging Technologies

We describe below a number of emerging or evolving technologies which, although neither technologically or economically viable to meet our needs in the current planning cycle, may present significant potential sources of new supply for future resource plans.

As PGE loses access to hydro and increases its concentration of variable wind and solar resources, various types of new storage options may be needed over time. Thus, we first discuss storage options.

Battery Storage

Battery energy storage systems employ multiple (up to several thousand) interconnected batteries and are charged via an external source of electrical energy. The battery energy storage system discharges this stored energy to provide a specific electrical function. Examples of these functions, as defined by the Energy Storage Association (ESA), are as follows:

- **Spinning Reserve**: the use of energy storage to supply generation capacity that is online and dispatchable within 10 minutes.
- **Non-Spinning Reserve**: a resource that follows spinning reserve dispatch during loss of generation or transmission events and usually required to respond within 10-15 minutes.
- **Capacity Firming**: the use of energy storage to fill in capacity (power) when variable energy resources, such as solar and wind, fall below their scheduled output.
- **Voltage Support**: the use of energy storage to manage and supply reactive power on the grid to maintain a unity power factor.
- **Frequency Regulation**: the use of energy storage to maintain grid system frequency with a resource that is capable of responding within seconds.
- **Ramping Service**: using energy storage ramping to offset excessive ramping of other generating facilities, often variable energy resources such as solar or wind.

The size of a battery energy storage system is based on two parameters: power (MW) and energy (MWh). The energy storage capacity of a battery designates how long a given energy storage system can discharge at a given power. Other parameters relevant for energy storage systems are:

- **Ramp-rate**: how quickly an energy storage system can change its power output, typically in MW/ min.
- **Round-trip efficiency**: the amount of energy discharged from an energy storage system relative to the amount required for charging.
- **Discharge duration:** how long a battery can be discharged at a given power.
- **Charge/Discharge rate (C-rate)**: how quickly the battery can charge or discharge relative to a one-hour charge or discharge (for example, a 2C rate charges or discharges in 30 minutes)

Operational parameters associated with battery energy storage technologies include:

- **State-of-charge (SOC)**: how much energy is stored in an energy storage system relative to the maximum energy storage capacity. In general, maximum lifetime of battery systems occurs when the SOC is maintained between 10 and 80% (that is, the battery is operated such that it is neither fully charged nor discharged).
- **Depth of discharge (DoD)**: how discharged an energy storage system is relative to the maximum energy storage capacity.
- **Cycles-to-failure (CtF)**: the number of cycles at 100% DoD until the battery's energy storage capacity is degraded to 80% of its original capacity.

Battery types employed within battery energy storage systems include flow, lithium-ion (Li-ion), and advanced lead-acid batteries.

Flow batteries consist of two tanks of different electrolytes separated by an electrochemical cell membrane. During the charging cycle, an electrical current causes ions to flow from Tank "A" across the membrane to Tank "B". During the discharge cycle, ions flow back from Tank "B" across the membrane to Tank "A". The ion exchange back across the electrochemical cell membrane produces an electric current.

Li-ion battery systems are the prevalent battery technology for battery energy storage projects presently under development. Various Li-ion battery systems are installed around the world, including projects in the United States. According to the USDOE Energy Storage Database, the United States installed (or under construction) capacity of Li-ion is about 56 MW.[71]

Salem Smart Power Center (SSPC)

PGE employs a 5 MW (1.25 MWh) Li-ion system at the SSPC as part of the Pacific Northwest Smart Grid Demonstration. This advanced Li-ion battery system provides uninterrupted power, reactive power (VAR support), and ancillary services, and can also be configured for use as energy storage for small-scale ancillary services in firming and shaping intermittent resources, such as solar and wind generation. The SSPC is part of a demonstration project co-funded by the USDOE under the American Recovery and Reinvestment Act. The primary contractor is Battelle, with PGE serving as a sub-contractor on the project. PGE has created substantial leverage through our approximately $6 million investment, which has been matched three-to-one by the USDOE and other partners. The project was formally launched in 2010 and went live in May 2013; the next phase implements specific demonstration objectives for two years. At the end of the demonstration, portions of the project will continue to operate as part of PGE's transmission and distribution system. Routine usage over time should allow continued assessment of its value to system reliability and renewables integration.

[71] "DOE Energy Storage Database (beta). Sandia National Laboratories. http://www.energystorageexchange.org

Pumped Hydroelectric Storage

A pumped storage hydroelectric facility requires a lower and upper reservoir. During times of minimal load demand or excess renewable energy, lower cost energy is used to pump water from a lower reservoir to an upper reservoir. When energy is required (during a high value or peak electrical demand period), water in the upper reservoir is released through a turbine to produce electricity.

In addition to providing electricity at times of peak power demand, pumped hydroelectric storage can provide the same ancillary services as batteries. The chief practical difference between the two storage technologies is scale. Pumped hydro systems are typically hundreds of megawatts in size versus tens of megawatts for battery systems. The other difference is location. Whereas pumped hydro would likely be outside PGE's service area and require transmission, batteries can be within PGE's system and thus provide a local reliability function.

Because the PNW is hydro-rich and most dams on the Columbia also provide storage (without recourse to the energy losses associated with reverse pumping), there has historically been no need for pumped hydro storage. PGE has looked at the potential development of a pumped hydro project on the Deschutes River, but found that it was not cost effective as compared to other types of similarly performing capacity resources. In its last RFP for flexible capacity, PGE invited proposals from all technology types, including battery and hydro storage. We did not receive any pumped hydro proposals. Nonetheless, as the concentration of variable resources grows, and our legacy access to hydro continues to shrink, pumped hydro as a supply option may become more economically viable.

Other Storage

Compressed air energy storage (CAES) offers the potential to address the variable nature of certain renewable resources in a synergistic manner with gas combustion. CAES uses off-peak wind generation to compress and store air underground. The compressed air is then used in the compressor-combustion stage of an ordinary CCCT, where compression of air requires almost two-thirds of the energy from the combustion energy. The effect is to dramatically increase the efficiency of the CCCT by using less gas to produce more electricity. A CAES facility has high capital costs and suffers efficiency losses associated with the compression. It also requires a site that has a gas pipeline, transmission, wind, water[72] and suitable underground storage.

PGE recently participated in a study published in 2013 by Pacific NW National Lab "Techno-economic Performance Evaluation of Compressed Air Energy Storage in the Pacific Northwest", PNNL-22235. The report concluded that CAES is feasible in storage reservoirs within the Columbia River Basalt Group.

A similar technology involves using wind energy to separate hydrogen from water and then combusting the hydrogen in a CT or reciprocating engine. Losses during energy

[72] The site may not need a lot of water if the CT uses a dry cooling system.

conversion, in addition to the additional infrastructure involved, currently make direct use of the electrical energy created from wind turbines more attractive.

Thermal Energy Storage Pilot Project

Given the potential need for energy storage identified above, PGE works with various technology partners, research universities, and governmental agencies to support the demonstration of promising energy storage technologies. One example of this type of partnership is our work with Corvallis, Oregon based Applied Exergy (AE). AE has a unique thermal energy storage system – Thermal Approach to Grid Energy Storage (TAGES). TAGES technology works to store energy in the form of an icy slush to be released later using waste heat. This could potentially optimize the efficiency of thermal generation plants, and thereby reduce greenhouse gas emissions per MWh. The technology could also help to integrate variable energy resources (e.g., solar and wind).

PGE has agreed to advance the evaluation of a TAGES demonstration project at our power plant in Boardman, Oregon using the stack exhaust gas waste heat to improve the efficiency of the storage system. The two-year pilot project at Boardman is intended to determine if TAGES implementation is technically and economically feasible, while also providing a proof of concept for AE's technology in an industrial setting. Data collection to validate the TAGES model could take place in 2014, with equipment installation then occurring in 2015. AE's TAGES technology uses off-peak/surplus energy to run micro-channel chillers which create slush that is stored in super-insulated tanks. Later, when the grid needs energy, waste heat from Boardman's stack exhaust, in conjunction with the stored slush, would be used to drive a highly efficient Organic Rankine cycle (ORC) turbine-generator set. AE will supply a system that charges up to 500 kW per hour (eight hours to charge) and discharges up to 1 MW for 3–4 hours. The thermal energy storage technology takes place in two stages:

1) The energy storage phase occurs when grid or plant electricity is used to drive a standard refrigeration cycle coupled with Applied Exergy's patented micro-channel chillers to create slush. The micro-channel chiller super-cools water to form tiny ice cubes that are stored in a heavily insulated tank.

2) The return energy phase uses energy generated using a conventional ORC generator driven by low temperature waste heat (exergy) and the cold temperature of the slush. The increased temperature differential, between the waste heat and the cold slush, allows for significant round trip energy efficiency (75% to 95%). During the Pilot project at Boardman, the waste heat from the stack exhaust gas will be used to vaporize the ORC working fluid. After the vaporized fluid drives a turbine-generator to produce electricity, it is condensed in the slush tank prior to circulating back to the waste heat exchanger.

Hydrokinetic Energy

Hydrokinetic energy is the production of energy from the movement of water – that can include ocean waves, tidal and currents, and in-stream energy production. Harvesting energy from waves can involve hydraulic, mechanical, and pneumatic generation. Tidal and ocean currents can be used to generate electrical energy by turning turbines installed under water.

River In-Stream Energy Conversion (RISEC) is a term used to describe the conversion of the kinetic energy of the unimpeded moving water in a river (or man-made canal) into electrical energy. This type of hydrokinetic power provides efficient, reliable, environmentally friendly electrical energy

Hydrokinetic Energy Generators are usually free-standing mechanical devices that are rotated by the flow of passing water. These devices can be open, three blade, horizontal axis rotors attached to a base; shrouded, multi-blade, horizontal axis turbine rotors, or an open, vertical axis, multi-cup rotor submerged in a river or canal.

Verdant Power has installed three-blade turbines, completely submerged, in New York's East River, between Manhattan and the boroughs of Queens and Brooklyn, to generate energy via the strong river current.

Deployment of hydrokinetic energy generators along the Oregon Coast was delayed for the past five years while the Oregon "Territorial Sea Plan" was amended to include potential sites for renewable energy. The amended Plan was adopted in January 2013. The WET-NZ, one-half scale wave energy device was tested off the coast of Newport, Oregon during the late summer of 2012. Currently, the Northwest National Marine Renewable Energy Center is developing the Pacific Marine Energy Center (PMEC). PMEC will encompass a variety of sites and test facilities, based on scale and technology, for testing wave and current converters.

8.8 Resource Ownership vs. Power Purchase Agreements

Guideline 13

Guideline 13 of the OPUC IRP requirements addresses resource acquisition. It requires an electric utility to:

- Identify its proposed acquisition strategy for each resource in its action plan.
- Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.
- Identify any Benchmark Resources it plans to consider in competitive bidding.

We note that this guideline is confined to resource acquisition considerations. The guidelines do not suggest attempting to distinguish between ownership and Power Purchase Agreements (PPAs) within the least cost/least risk portfolio modeling or Action

Plan recommendations. In this IRP, PGE is not proposing the acquisition of any major new generating resources, execution of PPAs, or any Benchmark Resources. Thus, PGE does not consider a resource ownership discussion to be particularly applicable to this IRP.

Beyond generic descriptions of third-party ownership structures and potential generic pros and cons, PGE believes this question is better addressed within the competitive bidding process, as indeed it was in our recently concluded RFPs. Because pricing and terms for PPAs is very counterparty-, technology-, deal structure-, risk allocation-, duration-, and location-specific, and is then subject to subsequent post-bid negotiations, the IRP cannot provide indicative pricing and risk differences between ownership and PPAs for consideration in trial portfolios. Indeed, IRP is generally agnostic with respect to ownership structure and instead focuses on the inherent cost and performance attributes of the generating asset, and how that asset will meet needs and address risk within the broader generation portfolio (e.g., resource type and fuel diversification considerations).

Nonetheless, we have, in previous IRPs, identified instances in which a PPA is actually our preferred structure. The primary example is in meeting our seasonal energy needs. For such needs that arise during a small fraction of the year, it makes sense to seek third-party power, if such can be found cost-effectively. Seasonal exchange contracts are one such example. Another example is a seasonal capacity call option. Pursuit of these products is driven by the need to fit the resource to the short-term or seasonal load requirement. Another example where a PPA is the preferred IRP approach to resource acquisition is renewal, where possible and cost-effective, of existing legacy hydro contracts.

In the following sections, we briefly describe PPAs and Tolling agreements, the two primary market alternatives for mid- and long-term contracts for wholesale electricity today. We then provide a brief summary of the ongoing UM 1182 docket, which addresses certain issues relating to ownership and PPAs.

Power Purchase Agreements

PPAs are longer-term contracts (three to 25 years) 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, generation plant bus bar, or at a market hub such as Mid-Columbia). Typical PPAs are executed under the Western Systems Power Pool (WSPP) Schedule C, whereby the sellers are obligated to deliver the energy at the contracted price. In case of seller default, the seller may owe liquidated damages to the buyer.

Most long-term PPAs increase rating agency debt imputations and margin/collateral requirements – both can result in increased costs for the purchaser. Credit rating agencies measure and report imputed debt associated with long-term purchase commitments to reflect the future cash flow obligations of the buyer as if it were debt. Once imputed debt is accounted for, credit rating agencies are able to compare the risk of default for different companies, normalized for their choices to build a resource or enter into a PPA. This, in turn, impacts the purchaser's credit rating and cost of borrowing.

Margin/collateral requirements are now a standard feature of most fixed price PPAs. This feature is meant to protect both the buyer and the seller from the likelihood of default when market prices move materially above or below the negotiated fixed price of the PPA. Though long-term PPAs offer a good hedge against market price movements, they bring with them potentially higher collateral requirements and associated costs.

Tolling Agreements

Tolling agreements are typically take-and-pay contracts where the buyer pays a fixed demand payment or option premium for the right to receive 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 above for a PPA, such as unit availability and point of delivery.

UM 1182: Summary and Status

The ongoing UM 1182 investigation addresses some of the Commission's Competitive Bidding Guidelines. When concluded, the ownership vs. PPA IRP Guideline will have been addressed by the OPUC.

Parties to the docket include Northwest & Intermountain Power Producers Coalition (NIPPC), Citizen's Utility Board (CUB), and the three electric IOUs doing business in Oregon. Twelve potential issues, or "comparative risks", were originally identified:

1. Construction cost over-runs
2. Environmental regulatory risk
3. Heat rate degradation
4. Increases in fixed O&M costs
5. Wind capacity factor error
6. Capital additions
7. Counterparty risk
8. Changes in allowed return on equity
9. Changes in forced outage rates curve
10. Verify output heat rate and power
11. End effect
12. Construction delays

The prior phase of the docket addressed four of these:

1. Construction cost over-runs,
2. Heat rate degradation,
3. Wind capacity factor error, and
4. Counterparty risk.

After receiving opening testimony, reply testimony, pre-hearing briefs, and reply briefs from the parties (including PGE) and OPUC Staff, this phase of the docket culminated in Order No. 13-204, dated June 10, 2013. For detail on the position of the parties and the Commission resolution regarding the four issues, please refer to the Order.

The Commission ordered the utilities to adopt two changes, both concerning how the RFP process is conducted:

1. The independent evaluator must "provide a more comprehensive accounting of the risks and benefits to ratepayers for construction costs of utility-owned resources"; and,

2. Utilities shall "use a qualified and independent third-party expert to review the expected wind capacity factor for all projects on the short list".

The remaining eight items are the subject of the current phase of this docket. The Commission directed that "parties should focus on qualitative recommendations, rather than propose quantitative adjustments". Opening comments were filed September 30, 2013, and reply comments were filed November 1, 2013. We are awaiting a final Commission Order.

8.9 Energy Imbalance Market

Regional Effort to Form an Energy Imbalance Market (EIM)

The development and operation of a regional EIM that includes associated improvements in operational infrastructure is a potential way to lower the region's integration costs associated with increasing penetration of variable energy resources. It also offers the prospect of enhancing regional transmission system reliability. PGE is a participant in multiple regional initiatives that are exploring the framework and potential benefits of an EIM. PGE is generally supportive of pursuing a systematic, comprehensive approach to a regional EIM that would improve the reliability, integrity, and efficiency of meeting the region's power needs.

In March 2012, twenty-two public and investor owned utility organizations formed a Market Assessment and Coordination Committee (MC) as a Northwest Power Pool (NWPP) initiative. In January 2014, twenty public and investor owned utility organizations committed to funding the ongoing work of the NWPP MC for a period of 12 months. Following is a high-level summary of activities and findings of the NWPP MC to date and a brief description of the planned future activity.

Activities and Findings to Date

- Jim Piro, CEO of PGE, Bill Gaines, the Director and CEO of Tacoma Public Utilities, and Elliot Mainzer, BPA Administrator, currently serve as co-chairs of the NWPP MC Executive Committee. PGE has contributed significant internal resources toward the NWPP MC effort and is staffing leadership positions within the NWPP MC for 2014.

- In October 2013, the NWPP MC released its Phase 1 report and a summary of its Phase 2 work-in-progress, which assessed the forecast potential costs and benefits of implementing an EIM in the NWPP footprint and the associated bilateral market enhancements necessary to create an EIM. The NWPP MC also addressed governance and implementation considerations.
- The production cost model studies conclude that, in aggregate, the benefits to the region outweigh the combined costs of the market operator and of the individual utilities to participate in an EIM covering the NWPP footprint. It was widely recognized, however, that a number of reasonably expected qualitative benefits resulting from the comprehensive set of tools proposed by the NWPP MC were not reflected in the model. These include more efficient use of transmission facilities and an overall increase in the reliability of the bulk electric system due to more advanced system monitoring and coordination among entities.
- The report estimates each participant's share of total EIM benefits (referred to as "illustrative parsing"). Based on that preliminary apportionment, PGE would receive approximately 5% of net benefits. In 2020, per the report's preliminary, conservative estimate, this could result in a modest annual net production cost benefit to PGE of between $2.1 and $4.6 million. However, actual production cost net benefits could be lower or higher. These net benefits are only inclusive of market operator costs, not market participant costs that would likely be incurred by PGE when preparing its systems and personnel to interact with the EIM.
- Preliminary estimates for EIM market operator start-up costs for the region are estimated between $31 and $60 million.
- In February of 2014, the NWPP MC released its Phase 2 report which explored further the qualitative assessments made in Phase 1 and presented a framework for the NWPP MC to move forward with its initiatives.
- The report estimated that substantial, broad-based benefits can be realized across the NWPP region within roughly three years of the start of implementation, contingent on sufficient participation and start-up funding from the NWPP MC member-utilities. Early benefits of infrastructure investment accrue mainly to reliability, whereas production cost savings from more efficient dispatch are expected to be realized only after full implementation of the region-wide EIM.
- The report also identified key areas where the NWPP MC members had opportunity to enhance aspects of their commercial and operational practices to improve reliability and efficiency within the existing bilateral market context. Finally, the report outlined how these enhancements could serve as a foundation for future regional coordination efforts, such as an EIM, and set a framework for progressing through the multiple recommended enhancements.
- The decision was made to fund this framework in the form of a NWPP MC Phase 3, which is focused on implementing enhancements to the infrastructure that supports the reliability of the system and the continuation of coordinated

market design scoping, including the issuance of a Request for Proposal (RFP) to potential operators. PGE was a key advocate for continuation to Phase 3. PGE agrees the work scheduled for Phase 3 will bring wide-ranging benefits to NWPP Members, including PGE's ratepayers, and will set a stable foundation for future market enhancement efforts in the NWPP Member area.

Following are a few observations about the proposed NWPP MC EIM structure.

NWPP MC EIM Proposed Structure

- It is important to note that the use of the term EIM to describe the future coordinated market opportunities for the NWPP Members is shifting over time, for clarity, to a focus on the core components being considered under the NWPP MC operational framework, market design, and RFP. These include a Security Constrained Economic Dispatch (SCED) platform, which is the software tool that underlies intra-hour coordination, and a number of associated bilateral market protocols and member agreements that bolster the feasibility and functionality of within-hour coordination. As the proposed structure is settled on in Phase 3, a new descriptor for the coordinated intra-hour opportunities will be developed by the NWPP MC.
- Participation in the EIM and offering resources for dispatch would be voluntary, but it would be mandatory for participants to settle load and generation imbalances through the EIM.
- EIM market participants would voluntarily submit availability of resources, ramp rates and price curves to the EIM market operator.
- The EIM would not provide capacity or reduce the amount of flexible reserves each entity requires to meet their own load-resource balance. Rather, the EIM would provide a more economic dispatch of the resources committed.
- An EIM Market Operator for the NWPP area would be a stand-alone entity, not a transmission service provider.
- The EIM Market Operator would run a SCED every five minutes to obtain optimal economic, reliable dispatch solutions for participants across the market footprint.
- To proceed, PGE will need to commit significant internal resources to developing appropriate interfaces between its existing infrastructure and the Market Operator's infrastructure. PGE will also have to work with its peers to align operational and business practices such that the region continues to manage its interconnected systems reliably, sustainably, and at least cost, while staying responsive to multiple regulatory and stakeholder mandates.

Following is a high-level summary of activity related to other regional EIM initiatives.

- PacifiCorp and the California Independent System Operator (CAISO) signed an agreement in February 2013 to develop an EIM comprising the balancing authorities they control (the CAISO-PAC EIM). PGE has been an active participant in the CAISO-PAC EIM stakeholder processes conducted separately by the CAISO, PacifiCorp, and BPA. Because PGE's service territory is adjacent to PacifiCorp's in Oregon and PGE owns transmission rights on the AC transmission line which connects PGE's load and resources to the CAISO, PGE has been studying the cost-benefit analysis performed by PacifiCorp, the market protocols proposed by the CAISO, and the business practices that govern access to BPA's system to assess if the form of the CAISO-PAC EIM proposal could deliver value to PGE's customers.

- PGE is also monitoring the Western Governor's Association's PUC EIM initiative and has provided support and input at their meetings.
- PGE is likewise monitoring initiatives at BPA, WECC, and Peak Reliability as decisions made by these organizations will impact and influence PGE's potential future opportunities to engage effectively and efficiently with either the NWPP MC or CAISO-PAC EIM efforts.

9. Modeling Methodology

The goal of the IRP is to identify a mix of new resources that, when considered with our existing portfolio, provides the best combination of expected costs, and associated risks and uncertainties for PGE and our customers. In this chapter we provide both a conceptual overview of how we think about and assess resource cost and risk for the IRP, as well as a detailed description of our analytical methods, tools, and metrics.

The history of resource planning has consistently demonstrated uncertainty with respect to assumptions for customer demand, new resource costs, regional electric supply and prices, fuel cost and availability, as well as changes in state and federal energy policy, including related legislative and regulatory requirements. As a result, we believe that it is most effective to assess resource and portfolio performance across a wide range of credible potential future environments. In addition, we believe that there is 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 resource portfolio and action plan.

Chapter Highlights

- We used AURORAxmp® to conduct fundamental electricity supply-demand analysis in the Western Electricity Coordinating Council (WECC), dispatch existing and potential new resources, and project hourly wholesale market prices.
- We constructed discrete candidate portfolios representing a different mix of resource fuel types, technologies, in-service timing, etc. We then calculated the total expected long-term revenue requirement for each portfolio.
- We assessed the total expected portfolio cost (measured as the Net Present Value Revenue Requirement or NPVRR) and related risk using various metrics for each portfolio based on reference case assumptions (cost) and scenario analyses (risk).
- We measured the reliability of the different portfolios by performing stochastic loss of load simulations.

As with our previous IRP, we use AURORAxmp® by EPIS, Inc. 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 (2014 through 2033 for this IRP). In doing so, we gain better insights into the impacts of different potential future resource choices, both by PGE and other regional participants, through sensitivity/scenario-testing.

We continue to use net present value of revenue requirements (NPVRR) to assess the expected cost of portfolios. We evaluate risk according to two primary categories:

- Deterministic scenario risk, which we describe as “futures”; and,
- Stochastic risk, used primarily for assessing reliability.

More detail regarding our approach to modeling and assessing risk is presented later in this chapter.

9.1 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. This process includes:
   a. Collecting resource cost information using third party intelligence in order to compute life-cycle revenue requirement for each new WECC/PGE resource option (see Chapter 8 - Supply-side Options).
   b. Identifying a topology that captures the main transmission links in the WECC.
   c. Applying planning reserve margins that best represent ongoing WECC resource requirements and practice.
   d. Testing alternative long-term PGE procurement strategies (portfolios) for cost and risk. This, in turn, requires:
      i. Dispatching existing and future alternative resources available to PGE in AURORAxmp, using its projections of hourly electric market prices and resource availability (subject to transmission constraints) for all areas in the WECC;
      ii. Grouping alternative resource mixes in different portfolios and calculating the total long-term variable power cost of each portfolio in AURORAxmp;
      iii. Combining the variable power cost from AURORAxmp with the fixed revenue requirement (capital and fixed operating costs, determined using our Excel-based revenue requirement model), for each of the alternative portfolios;
      iv. Calculating the NPVRR over the planning horizon (from 2014 through 2033) for each of the portfolios. The NPVRR is our primary long-term cost metric;

v. Using scenario analysis to assess portfolio risk performance for each portfolio based on changes in portfolio costs under varying future conditions (i.e., changes in fuel prices, emissions costs, etc.).

e. Measuring the carbon emissions of different strategies.

2. We perform stochastic analysis to test the reliability of each portfolio by shocking load, hydro, wind production, and plant availability.

3. Finally, we compare portfolios using the reference case[73] cost, the scenario-based deterministic risk metrics, and the stochastic-based reliability metrics. Because future carbon compliance is an uncertainty of particular interest, we also estimate the carbon footprint for each portfolio over the planning horizon.

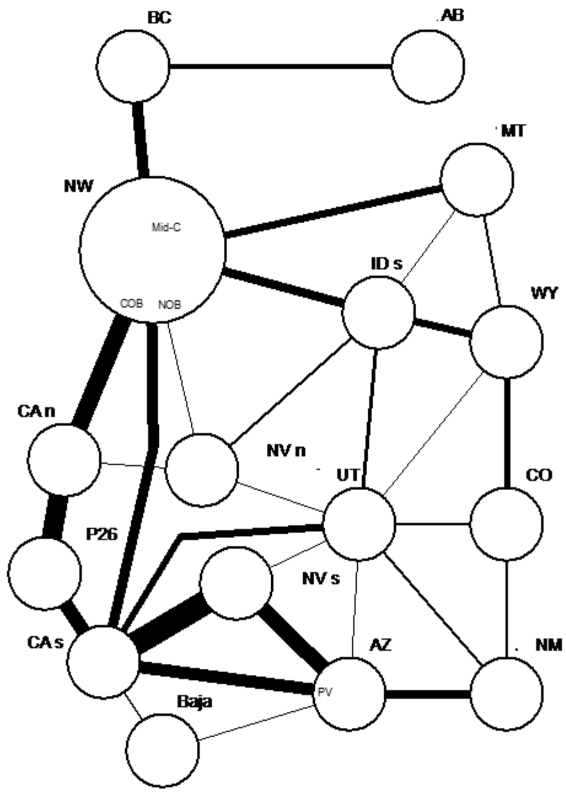
WECC Long-Term Wholesale Electricity Market Prices

We use 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 the WECC. The definition of zones and transmission capability between them is also defined as a topology and is shown in Figure 9-1.

[73] This refers to a baseline set of assumptions. See the "Reference Case" section later in this chapter for an extended explanation.

Figure 9-1: WECC topology



AURORAxmp simulates the WECC markets on an hourly scale by calculating the electricity demand of each of the 16 zones and stacking resources to meet demand and reliability standards with the least-cost resources, given operating constraints. The variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period establishes the marginal price for each zone.

Our modeling relies on the default data base in AURORAxmp. We update it when necessary by using our professional judgment and the advice and expertise of consultants, WECC studies, and the Northwest Power and Conservation Council (NWPCC). Following are the main assumptions we used and a description of the results.

Regional Resource Modeling Assumptions

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

- A reliability standard that adds sufficient resources in the WECC to meet the 1-in-2 peak load plus reserves ranging from 12% to 20%, depending on the zone. 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 surplus capacity on the east side).
- A carbon cost of $16 per short ton starting in 2023, escalating at 8% a year thereafter. We base these assumptions on guidance from Wood Mackenzie,

an international firm that specializes in global and regional fundamentals-based energy research.

- Implementation of all approved state RPS targets in place as of 2013. Table 9-1 summarizes these requirements.

Table 9-1: WECC state RPS targets

	2015	2020	2025 and after
Arizona	5%	10%	15%
California	20%	33%	33%
Colorado	20%	30%	30%
Montana	15%	15%	15%
Nevada	20%	20%	25%
New Mexico	15%	20%	20%
Oregon	15%	20%	25%
Utah			20%
Washington	9%	15%	15%

As required by Guideline 1a of Order No. 07-002, we applied PGE's after tax marginal weighted-average cost of capital of 6.43% as a proxy for the long-term cost of capital in the WECC. Table 9-2 contains our other financial assumptions.

Table 9-2: PGE financial assumptions

	Percentage
Income Tax Rate	39.94%
Inflation Rate	1.93%
Capitalization:	
Preferred Stock	-
Common Stock (50% at 9.75%)	4.88%
Debt (50% at 5.19%)	2.59%
Nominal Cost of Capital	7.47%
After-Tax Nominal Cost of Capital	6.43%
After-Tax Real Cost of Capital	4.42%

For modeling purposes, we allowed AURORAxmp to make plant retirements after 2021, when economic. We also input publicly announced plant retirements before that date. These include San Onofre (nuclear) in California, Centralia (coal) in Washington, and Boardman (coal) in Oregon.

Resource adequacy standards and RPS implementation are key drivers of modeled long-term resource additions in the WECC. Figure 9-2 shows resource additions and retirements by fuel type over our study period. It 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 2033 is composed of 52% gas-fueled plants, 16% non-hydro renewable resources, 20% hydro, 9% coal, and 3% nuclear. For more detail, see Appendix J.

Figure 9-2: Resource additions and retirements by fuel type

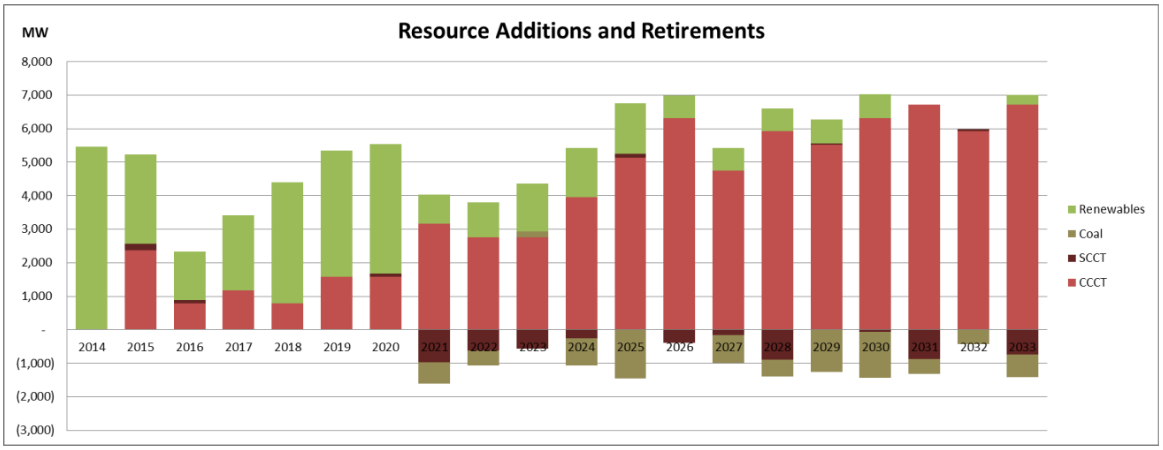
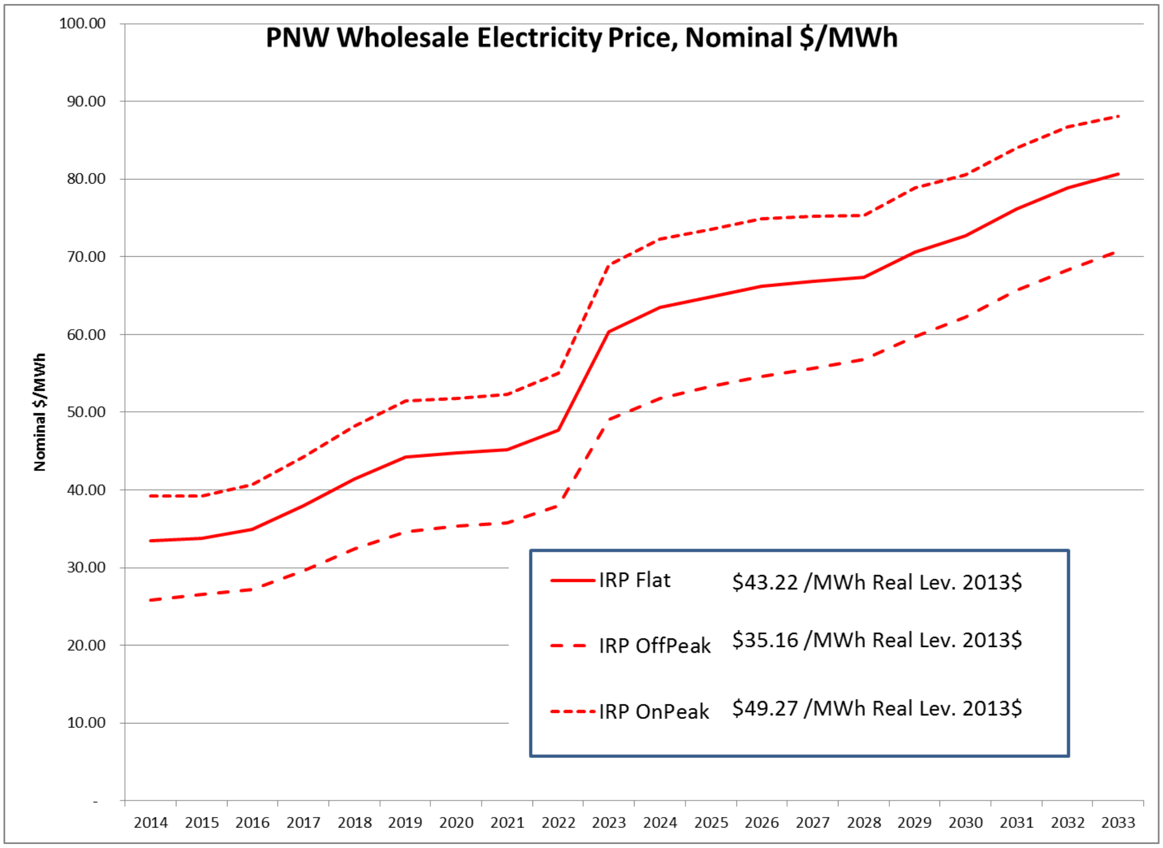


Figure 9-3 shows the resulting average annual (or flat) electricity market price projection for the Pacific Northwest using the reference case assumptions described in the following paragraphs; it is $43.22/MWh (real levelized for the period of our analysis, 2014–2033, in 2013$). On-peak (top dotted line) and off-peak (bottom dotted line) projected electricity market prices are $49.27/MWh and $35.16/MWh, respectively. These prices include the introduction of an assumed federal carbon tax of $16 per short ton in 2023, escalating at 8% thereafter, as evidenced by the “kink” in the graph in 2023.

For more detail, see Appendix J.

Figure 9-3: PNW reference case electricity prices 2014-2033



The wholesale electricity market prices generated are representative of normal market conditions and depict our reference case market. These prices are not adequate to achieve a positive recovery of and return on invested capital for new generating resources, because:

- AURORAxmp assumes that surplus power will be priced at short-term marginal cost and will be traded, if economic, until transmission limits are reached.
- Reserve margins imposed to assure system reliability and resource adequacy standards cause the WECC to be in surplus for most hours of the year.
- New generating plants are added at their typical plant size, which may be larger than the incremental resource need at the time of addition. New resource additions, which are typically large, thus cause temporary over-supply conditions until load growth catches up to new, "lumpy" resource additions.

Therefore, it is assumed that fixed costs, particularly for capacity, would need to be recovered through traditional rate base 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 occur and can cause reserve margins to shrink, resulting in scarcity and market prices that can dramatically exceed fully allocated costs. To examine these potential market shocks we designed future scenarios that include sustained high electric prices and/or higher-than-expected load growth.

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

9.2 Portfolio Analysis

The next step of our analysis is to identify the mix of resources that, when added to the existing PGE portfolio to meet future customer demand, achieves the best combination of expected cost and risk. We will use the following terminology when discussing portfolio analysis:

- Portfolios are a mix of resources which will meet our future energy and capacity needs. They are detailed later in this section.
- Reference case assumptions are the most likely or expected case model inputs which drive the economic performance of resources over the planning horizon (20 years). They are detailed in Section 9.3.
- Futures are a set of deterministic input variables that describe a variety of potential future circumstances over the planning horizon and test the change in performance of candidate portfolios (from the reference case assumptions).
- Scenarios are the intersections of portfolios with futures. Table 9-3 below visually demonstrates this.

Table 9-3: Portfolios, futures, and scenarios

Future / Portfolio	Future 1	Future 2	Future 3	Future 4
Portfolio 1	Scenario 1,1	Scenario 1,2	Scenario 1,3	Scenario 1,4
Portfolio 2	Scenario 2,1	Scenario 2,2	Scenario 2,3	Scenario 2,4
Portfolio 3	Scenario 3,1	Scenario 3,2	Scenario 3,3	Scenario 3,4
Portfolio 4	Scenario 4,1	Scenario 4,2	Scenario 4,3	Scenario 4,4

We created candidate portfolios by first identifying energy resource gaps as detailed in Chapter 3 - Resource Requirements and then adding resources to fill the gaps as detailed below. The process of developing candidate portfolios and assessing their performance across the futures is a lengthy one. Given the time required to complete this process and the fact that our proposed Action Plan does not include new major resources, the candidate portfolios and related analytical results reflect our projected load-resource balance as of circulation of the Draft IRP in November 2013. Additionally, since there has been no material change to technologies and operating costs (including natural gas costs), updated portfolio analysis would not yield significant differences.

Next, we identified resources that are commercially available, geographically accessible, and for which there are no legal constraints. These criteria eliminated the following options:

- Coal, both traditional and IGCC, the former because of Oregon's carbon emission limits for new generating sources, the latter because the viability of large-scale permanent carbon sequestration, and attendant cost, could not be reasonably assessed.
- Nuclear, because of the Oregon ban on new nuclear plants before the construction of a federal nuclear waste repository facility. In our 2009 IRP, we simulated a new nuclear plant in Idaho, but costs and transmission assumptions for PGE are now too speculative to effectively model.
- Wave energy, because this technology is not commercially available. Ultimate timing and costs for commercial availability are unknown.

Filling Our Energy Need

To fill our annual average annual energy requirement, first we identify customer demand-side resources. This is, primarily, EE as projected by the Energy Trust of Oregon (ETO) through December 2032.

If the need is not met by customer-enabled resources, we add market purchases, renewables and fossil fuel resources as follows:

- Spot market purchases can meet up to 100 MWa of our annual energy need. This amount is the result of a qualitative assessment of market availability during normal operations and constitutes a buffer for load forecasting and resource availability variations.
- Renewable resources necessary to maintain physical compliance with the Oregon Renewable Portfolio Standard (RPS) in 2020, 2025 and 2030 (116 MWa, 164 MWa, and 61 MWa, respectively).
- A mix of additional renewables and natural gas-fired combined cycle combustion turbines (CCCTs) to meet our annual average energy gap through 2025.

Except for RPS resources and EE, no additional long-term commitments are modeled after 2025, as new resource costs and other parameters become increasingly speculative. For modeling purposes, incremental needs after 2025 are met with market purchases for all portfolios. Incremental energy requirements are modest once EE and RPS renewables are procured through 2025.

Filling Our Capacity Need

When assessing PGE's need for capacity resources, we first calculate the capacity value of our existing resources and any energy resources added to a portfolio. We then add projected customer-enabled resources, such as demand response and dispatchable standby generation. (Distributed solar PV is included as an embedded adjustment to loads.) Then any remaining capacity necessary to meet our one-hour peak load, inclusive of planning and operating reserves, is filled by spot market purchases and gas peaking units. Reciprocating engines are used as the capacity resource proxy because they have the best dynamic response capabilities and their cost and performance is well understood by PGE.

Our portfolios rely on market purchases for up to 300 MW to meet capacity needs through 2018, and 200 MW thereafter. This gives our portfolios the necessary flexibility to adapt to load forecast uncertainty and/or changes in resource availability.

Portfolios composed of existing and incremental resources are then input in the AURORAxmp model and dispatched from 2014 through 2033 (20 years). Fixed costs are modeled for the entire life-cycle (inclusive of estimated salvage value) and then input in AURORAxmp using their real levelized revenue requirement.

AURORAxmp output includes the total annual revenue requirement by portfolio under reference case assumptions and for all simulated futures. The NPVRR from 2014 to 2033 is used to compute the cost and risk performance of portfolios across different futures. Futures and portfolios were constructed with input from OPUC staff and other stakeholders during the IRP workshops and public meetings. See Section 9.3 for a description of the various futures we modeled.

Wind Resource Capacity Contribution

For portfolio modeling purposes, wind resources are assigned a capacity contribution at peak load equivalent to 5% of the nameplate capacity. This capacity contribution is derived from PGE's recent generation experience with Biglow Canyon Wind Farm. Hourly generation data from 2011 and 2012 for Biglow Canyon were paired with hourly loads for the same years. Capacity factors were calculated on an hourly basis, and then examined across periods of top load hours. The Biglow Canyon capacity factors (CFs) and concurrent loads for each of the top 100 load hours in 2011 and 2012 are plotted in Figure 9-4 and Figure 9-5 below.

Figure 9-4: 2011 Top 100 load hours: Biglow Canyon hourly CF and PGE load

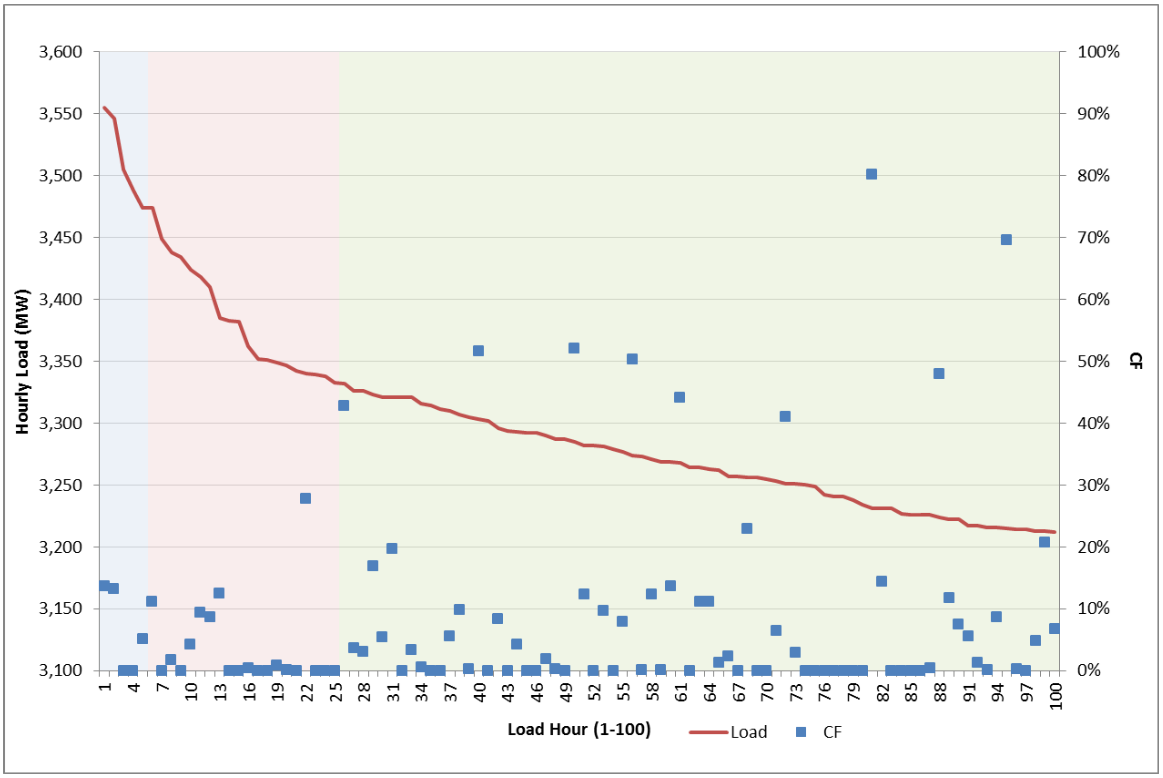
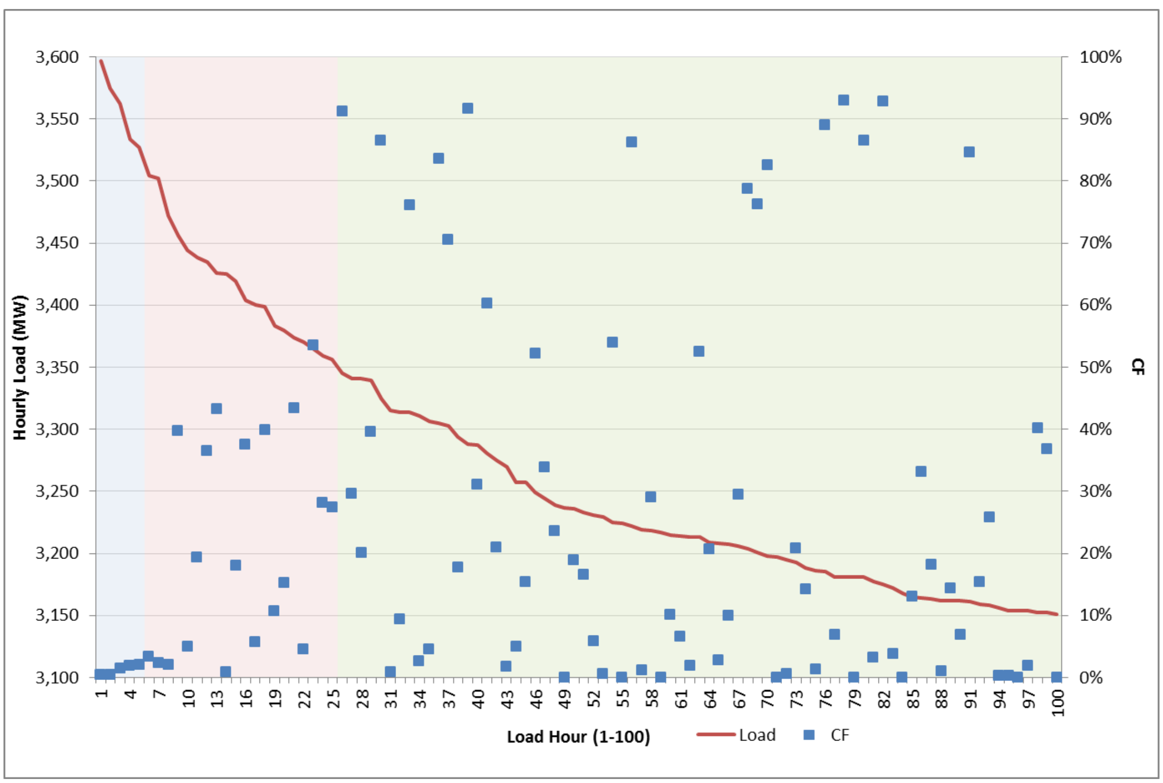


Figure 9-5: 2012 Top 100 load hours: Biglow Canyon hourly CF and PGE load



Using these data, we apply a CF exceedance approach to determine the capacity contribution in each period. The exceedance level is set at the 50th percentile. In other words, we choose the median CF for each period of load hours studied. We are aware that other entities have performed similar studies and established the exceedance CF at more restrictive levels than the 50th percentile. For reference purposes, we also provide the 90th percentile exceedance CF. The results of our study using the median CF for the top 5, 25, and 100 load hours in 2011 and 2012 are reported in Table 9-4, below.

Table 9-4: 2011 and 2012 top load hours: median and 90th percentile CF

Top	Median CF			90th Percentile CF		
Hours	2011	2012	Average	2011	2012	Average
5	5.05%	1.40%	3.22%	0.00%	0.42%	0.21%
25	0.11%	10.67%	5.39%	0.00%	1.09%	0.55%
100	1.30%	15.39%	8.34%	0.00%	0.39%	0.19%

It is difficult to select a single point for the capacity contribution based on two years of generation data. The data summarized for these two years appear to represent very different experiences, creating a range of possible values. Our selected value of 5% is well within this range and remains a reasonable capacity contribution assumption for long-term planning purposes. As PGE gains more actual generation experience with the Biglow Canyon and Tucannon River wind farms, we will continue to assess the contribution of actual wind generation to our actual peak load.

Portfolio Composition

Similar to the portfolio approach we used in the prior IRP, we design "pure play" portfolios (incremental portfolios focused on a single or a few resource types) for benchmarking; then add more diversified portfolios. This approach allows us to examine the cost and performance differences of various resource types, as well as the potential risk mitigation benefits of diversification. All portfolios share in common the following resources: 372 MWa (428 MW) of new EE added through 2033 (figures are busbar-equivalent), 90 MW of new demand response, and 30MW of DSG. To meet RPS standards, most portfolios also add 116 MWa (357 MW) of wind in 2020; 164 MWa of wind (504 MW) in 2025; 61 MWa of wind (188 MW) in 2030. Some portfolios[74] include additional EE beyond the amount stated above.

The portfolios are detailed below:

[74] Portfolio (15), "defer RPS physical compliance," defers until 2025 the 116 MWa (357 MW) of wind that most portfolios add in 2020. Portfolio 5, "Diversified Green/EE," Portfolio 6, "Green w/EE and CCCT," Portfolio 8, "Diversified Green with wind MT," and Portfolio (18), "Wind Energy w/EE," add additional EE to test the cost impact of pursuing all achievable demand-side resources before committing to additional supply-side ones.

"Pure Play" Portfolios

Portfolio #1: Market

This portfolio meets incremental energy needs with spot market purchases. More precisely, we add the resources common to all portfolios (listed above), and, on the capacity side, this portfolio adds 97 MW of gas reciprocating engines (peakers) in 2020, 130 MW in 2025 and 15 MW in 2030. Annual average market purchases equal 133 MWa in 2020, 491 MWa in 2025 and 548 MWa in 2030. During winter peaking events, the reliance on market grows to 731 MW, 1,226 MW, and 1,469 MW for 2020, 2025, and 2030, respectively. This portfolio does not meet reliability standards and is therefore not a viable strategy for PGE.

Portfolio #2: Natural Gas

This portfolio tests the impact of choosing natural gas-fired CCCTs to meet incremental energy needs. We assume that partial ownership of CCCTs is not an option. Therefore, the addition of a CCCT results in a short-term energy surplus as it is added to the existing portfolio at its full nameplate capacity level. This portfolio adds 326 MWa (395 MW) in 2021 and in 2024. Capacity needs are addressed by adding a total of 749 MW of reciprocating engines between 2016 and 2025.

Portfolio #3: Wind

This portfolio is similar to Natural Gas, but selects wind instead of CCCTs to meet incremental energy need. For modeling purposes, this Portfolio builds wind resources to provide an equivalent amount of energy as is provided by CCCTs in the Natural Gas Portfolio. Wind plants are assumed to be located in the PNW and accessible with existing transmission. We add 326 MWa (1,003 MW) of wind in 2021 and in 2024. Reciprocating engines are also added between 2016 and 2025 and provide 1,153 MW of capacity.

Diversified Portfolios

These portfolios are combinations of:

- Base load CCCTs,
- Renewables,
- Spot market purchases,
- Capacity resources: natural gas peaking units, demand-side resources, and different levels of EE.

These portfolios examine more diversified strategies for procuring incremental resources to meet energy and capacity needs through 2025. As a modeling simplification, after 2025 all portfolios except one rely on spot market purchases. Appendix B shows the annual detail by portfolio and resource type for energy (i.e., resources typically used to meet base load needs) and peaking capacity (i.e., additional resources needed to meet peak demand).

We also developed and evaluated a few portfolios that add a combination of renewables and energy efficiency to meet incremental energy needs. These are reflective of work done by Energy and Environmental Economics, Inc. (E3), a consulting group engaged by PGE and certain stakeholders. That process is described in Chapter 1 - IRP Process. We evaluated different renewable resource technologies – energy efficiency, wind, solar, geothermal and biomass – as well as varying online dates, to quantify the impact of these strategies on PGE's total portfolio costs.

In addition, we developed and evaluated portfolios that rely on a mix of renewables and high efficiency CCCTs (in lieu of renewables and reciprocating units). These portfolios take advantage of the low projected cost of natural gas, but adding CCCTs for capacity in lieu of peaking units may not provide the flexibility and ancillary services capability needed to incorporate higher penetration levels of wind and solar PV resources.

We modeled 18 portfolios in total. In addition to the three pure play options, we examined the following portfolios:

Portfolio # 4: Diversified Green

This portfolio seeks a more diverse set of renewable resources (i.e., beyond wind only) to meet our energy need. We add: 50 MWa of wind in 2017; 20 MWa of biomass in 2020; 50 MW of geothermal, a 20 MWa central solar PV station, and 300 MWa of wind in 2021; and a 20 MWa central solar PV station in 2025. 1,111 MW peakers are added for capacity between 2016 and 2025.

Portfolio #5: Diversified Green/EE

This portfolio is similar to Portfolio 4, but with aggressive procurement of EE (91 MWa, 116 MW) beyond the cost effective deployment level. The additional EE displaces 23 MWa of RPS-required resources and 71 MW of peaking capacity need. 1,040 MW of peakers are added for capacity between 2016 and 2025.

Portfolio #6: Green w/EE and CCCT

This portfolio is similar to Portfolio 5, but with the addition of a CCCT (326 MWa, 395 MW) in 2021. This portfolio tests the cost effectiveness of procuring baser load resources and fewer peaking resources to meet the same load. The higher base load procurement reduces the need for incremental capacity resources; 645 MW of peakers are added for capacity between 2016 and 2025.

Portfolio #7: Baseload Gas/RPS only

This portfolio adds a CCCT (326 MWa, 395 MW) in 2019 and another CCCT in 2021 to meet PGE's energy need. It also adds wind resources to meet RPS targets through 2030. For capacity, 463 MW of peaking supply are added between 2016 and 2025.

Portfolio #8: Diversified Green with wind in Montana

This portfolio executes a procurement strategy proposed by E3. This is a low carbon portfolio aimed at putting PGE on a glide path to reduce CO_2 emissions to 80% below our 2005 level by 2050. Detail on this E3 proposal can be found in Appendix F, the final E3 report to PGE. In short, the suggested strategy is: maximize EE and fill the remaining energy need with renewables, mainly wind. Incremental capacity needs are met with gas peakers. Also, we maximize EE procurement to 91 MWa (116 MW) beyond the cost effective deployment level. This portfolio also builds: 17 MWa (52 MW) of wind in both 2017 and 2018; 22 MWa (25 MW) biomass, 17 MWa (20 MW) geothermal, 20 MWa (91 MW) of central solar PV and 300 MWa (846 MW) of wind in 2021. 50% of the wind added in 2021 is in the Pacific Northwest, 50% in Montana. Montana wind has a higher capacity factor (39% vs. 32.5%), but also higher transmission costs and losses. For capacity, 1085 MW of peakers are added between 2016 and 2025.

Portfolio #9: Diversified balanced wind/CCCT

This Portfolio pursues a diversified procurement strategy that includes: 23 MWa (71 MW) of wind in 2017; 59 MWa (181 MW) of wind in 2018; a 326 MWa (395 MW) CCCT in 2021; 100 MWa (308 MW) of wind in 2023; 17 MWa (20 MW) of geothermal and a 20 MWa (91 MW) PV central solar station in 2025. In addition, 806 MW of peakers are added for capacity between 2016 and 2025.

Portfolio #10: Diversified Solar/Wind

This Portfolio pursues a renewables focused strategy, but unlike portfolio 4, procures only a mix of wind and solar, and no geothermal or biomass. This portfolio thereby eliminates the more costly renewables (biomass and geothermal), but also procures more peakers, as both wind and solar are low-capacity value resources. We add: 50 MWa of wind in 2017; a 20 MWa central solar PV station in 2020; 300 MWa of wind and 70 MWa of central solar PV in 2021; and 80 MWa of central solar PV in 2025. For capacity, 1,161 MW of peakers are added between 2016 and 2025.

Portfolio #11: Diversified Green with non-CE EE only

This portfolio is identical to Portfolio 4, except for procuring all additional EE. This portfolio tests the risk reduction impact of EE.

Portfolio #12: Oregon CO_2 Compliance

This portfolio models the most aggressive reduction of CO_2 emissions in 2020 by limiting total CO_2 emissions to the level of our 1990 emissions, less 10%. To achieve this goal, Portfolio 10 (Diversified Solar/Wind) is adjusted to retire the Boardman coal plant and terminate our interest in the Colstrip coal plant in 2019. These plants are replaced by an equivalent amount of energy from wind (286 MWa, 880 MW) and a CCCT (326 MWa, 396 MW) in 2020. This portfolio also includes 300 MWa (733 MW) of additional wind in 2021, 50% of which is in Montana, because of the magnitude of the wind investment required. Finally, 70 MWa and 80 MWa of central solar PV are added in 2021 and 2023 respectively. For capacity, 1,026 MW of peakers are added between 2016 and 2025.

Portfolio #13: Baseload renewables

Similar to Portfolios 4 and 10, but adds more expensive base load renewables (biomass and geothermal) instead of wind, which reduces the need for higher levels of capacity/peaking resources. RPS targets are still met with wind in 2020, 2025, and 2030. More precisely, we add: 50 MWa of geothermal (56 MW) in 2017; 20 MWa and 100 MWa of biomass in 2020 and 2021 respectively (23 MW and 115 MW); 250 MWa of geothermal in 2021; 20 MWa of central solar PV in 2021 and 2025. In addition, 767 MW of peakers are added for capacity between 2016 and 2025.

Portfolio #14: High solar

Similar to Portfolio 10, but adds only central station solar PV for energy targets. This results in the addition of 50 MWa in 2017, 20 MWa in 2020, 370 MWa in 2021 and 80 MWa in 2025. PGE did not assess the technical viability of this magnitude of solar resources in Oregon and modeled this portfolio primarily for benchmark purposes. RPS targets are still met with wind in 2020, 2025, and 2030. For capacity, 1,135 MW of peakers are added.

Portfolio #15: Defer RPS physical compliance

Similar to Portfolio 9, but defers physical RPS compliance in 2020 to 2025; it does not quantify the cost of using RECs until 2025.

Portfolio #16: Diversified Baseload Gas/Wind

Similar to Portfolio 9, but adds two CCCTs instead of one, one in 2019 and another in 2021 (326 MWa, 395 MW), overshooting the energy need, but minimizing the addition of peakers to 411 MW between 2016 and 2025. We modeled this portfolio to assess the economic benefit of adding low-heat rate (high efficiency) gas instead of flexible capacity resources. We have not evaluated whether a CCCT could provide sufficient flexibility to firm variable energy resources, nor have we quantified the increased operations and maintenance (O&M) costs of using CCCTs for regulation, load following, and peaking operations.

Portfolio #17: Wind Energy Only

This is a portfolio requested by stakeholders in an IRP technical workshop. It minimizes the cost of Portfolio 4 by adding only PNW wind for energy purposes instead of pursuing a diverse renewable mix. This is because wind has the least cost of all renewables evaluated in this IRP. We add: 50, 330, and 60 MWa of wind located in the PNW in 2019, 2021, and 2022, respectively. We also add 1,186 MW of peakers to meet incremental capacity needs between 2016 and 2025.

Portfolio #18: Wind Energy w/EE

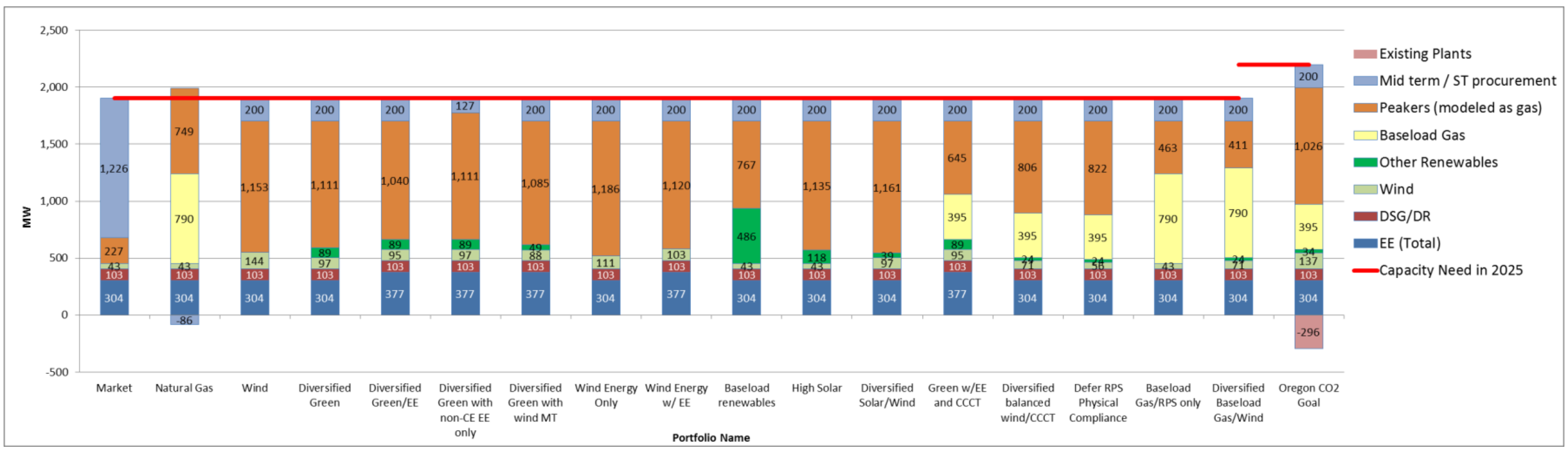
Similar to portfolio 17, but pursues all EE achievable. The incremental EE displaces 55 MWa of wind and 66 MW of peaking capacity.

Because we start with resource differences that are as stark as possible among the resource choices (the so-called “pure play” portfolios), and then progress to portfolios with increasingly subtle differences, the 18 portfolios effectively explore the range of realistic portfolio options that are potentially available.

Figure 9-6 and Figure 9-7 below show the total resource additions through 2025 by portfolio and resource type. Figure 9-6 depicts total annual energy availability while Figure 9-7 shows the corresponding usable capacity during peak events.

Figure 9-6: Portfolio cumulative resources through 2025: annual average availability by type

Figure 9-7: Portfolio cumulative resources through 2025: usable capacity by type



9.3 Reference Case

The Reference Case Future is based on the expected, or most likely, assumptions regarding resource costs (e.g. capital, O&M), market, prices, governmental policies and regulation and other conditions used as our "base case" assumptions in all candidate portfolios. The reference case is also the baseline against which we test portfolio performance under alternate future conditions. The following section summarizes the key inputs used in our reference case.

- **Commodity fuel price**: Natural gas prices are approximately $4.76/MMBtu (real levelized 2013$ for the period 2014-2033), based on an average Sumas/AECO price. Our commodity coal price is approximately $49/ton (real levelized 2013$ for the period 2014-2033) and is based on prices for Powder River Basis (PRB) coal. Both forecasts rely on independent third-party fundamental research for long-term prices and market quotes for near-term prices. Natural gas prices are constant in real dollars after 2031. More details regarding fuel prices are in Chapter 6 - Fuels.
- **Fuel transportation cost**: For natural gas, costs are based on current 2013 rates, $0.41 per dekatherm (Dth) for NW Pipeline and $0.47/Dth for GTN. We then assume escalation at inflation starting in 2014. Coal rail transportation and handling costs are based on PGE's forecasted transportation costs to Boardman, including any possible surcharges.
- **Resource costs**: We use the cost assumptions detailed in Chapter 8 - Supply-side Options.
- **Renewable Energy tax credits**: We use the Production Tax Credit (PTC) and the Investment Tax Credit (ITC), as applicable in 2013, for all qualifying renewable resources. As of year-end 2013 the PTC was not extended, and the ITC is scheduled to expire in the near future. At the time of our modeling we did not know if they would be extended, thus, for modeling purposes we assumed renewal at the current level until 2023, when we assume they will be superseded by more comprehensive carbon regulation. Given the uncertainty regarding continuation of these credits, we also include sensitivities within our portfolio analysis in Section 9.4, in which the PTC and ITC are assumed to expire without any extension or renewal.
- **Transmission cost to PGE's system**: We use BPA's transmission tariff rates (with escalation to factor in expected rate increases) for all new generation resources within the Pacific Northwest (PNW). We add transmission losses and wheeling to BPA's system and our expected share of the investment cost of a new transmission line to BPA for all resources placed outside the PNW. Due to the timing of BPA's BP-14 rate proceeding, the tariff rates used in our resource modeling do not reflect the recent outcome of that rate proceeding. PGE does intend to use those rates in our future long-term resource modeling.
- **PGE load**: We use the base case long-term load growth forecast described in Chapter 3 - Resource Requirements. Under this forecast, growth averages 1.56% per year between 2014 and 2033.

- **Environmental assumptions**: We use the assumptions detailed in Chapter 7 - Environmental Considerations. In addition to compliance with all existing regulation in the WECC, British Columbia, and Alberta, we model a CO_2 tax of $16 per short ton in 2023 escalating at 8% a year on all WECC thermal plants.
- **Renewable portfolio standard (RPS)**: We apply RPS standards in all WECC states that currently have renewable resource requirements. We impose, as a minimum, physical compliance with Oregon's RPS for all of PGE candidate portfolios, except one, that tests the impact of postponing 2020 physical compliance to 2025.

We use the NPVRR estimated under these assumptions to measure the cost of each candidate portfolio.

9.4 Futures

We evaluated the economic risk associated with the different portfolios with scenario analysis. To examine portfolio performance under varying potential circumstances, we constructed several discrete futures based, in part, on stakeholder feedback received at a technical workshop. We then tested each portfolio against each future and computed the NPVRR for each portfolio and future combination.

We believe that the 36 futures developed and tested are broad and diverse, reasonably reflecting the types of changing circumstances that could be encountered and the resulting impact on the cost and risk of various portfolio choices. In particular, we wanted to ensure that our futures tested the robustness of each candidate portfolio against possible changes in underlying fundamentals that could result in large changes in energy market prices or significantly impact the cost or value of the resources within the portfolio.

We evaluated all portfolios across the following 36 futures:

- **Reference Case**: this case includes our base assumptions for load, gas prices, CO_2 price, wholesale electricity prices, capital costs, and government incentives (see Section 9.3 above).
- **Fuels**:
    - High gas for the Pacific Northwest (PNW), $5.65/MMBtu, an increase of $0.89/MMBtu over the reference case in real levelized 2013$ for the period 2014-33. As detailed in Chapter 6 - Fuels, the shale gas breakthrough has fundamentally changed the gas industry and triggered a substantial reduction of projected prices. Wood Mackenzie, the source of our forecast, assumes that the abundance of gas production in the U.S. will effectively cap gas prices for the planning horizon of this IRP. Therefore, the high gas future is not dramatically higher than the reference case.

    - Low gas for the PNW, \$3.65/MMBtu, a decrease of \$1.11/MMBtu below the base case in real levelized 2013\$ for the period 2014-2033.
    - High coal prices (prices approximately 35% higher than the reference case).
    - Low coal prices (prices approximately 20% lower than the reference case).
    - High PNW hydro: simulating 1997 (good) hydro conditions in the PNW.
    - Low PNW hydro: simulating 1937 (critical) hydro conditions in the PNW.
    - Poor hydro: simulating hydro output that is half of normal (generation equal to approximately 25% of nameplate capacity). This future is intentionally extreme and aims at representing competition from alternative uses (agriculture, etc.) and/or stricter environmental rules.
    - High capacity factor for PGE's new wind plants in the PNW: 36%.
    - Low capacity factor for PGE's new wind plants in the PNW: 29%.
- **A credible range of potential carbon regulation costs, in accordance with Guideline 8**:
    - Continuation of EPA regulatory actions regarding CO_2, but no legislated federal carbon tax.
    - \$17.48 per short ton starting in 2020 and escalating at approximately 7% after 2020;[75]
    - \$35 per short ton starting in 2020 and escalating at approximately 10% after 2020;[76]
    - Low CO_2, \$16 per short ton starting in 2023 and escalating at approximately 5% thereafter;
    - Trigger point CO_2, \$136 per short ton starting in 2023 and escalating at approximately 8% thereafter.
    - Note that neither PTC nor ITC extend beyond 2022.
- **Capital cost futures aimed at quantifying the consequences of incurring investment costs higher or lower than those described in Chapter 8 - Supply-side Options**:
    - High capital costs for gas-fired thermal units: overnight capital costs 10% higher than reference case.
    - High capital costs for wind and solar: overnight capital costs 10% higher than reference case.
    - High capital costs for all resources: overnight capital costs 10% higher than reference case.
    - Low capital cost for all resources: overnight capital costs 10% lower than reference case.
    - No renewal of PTC and ITC after current sunset dates.

[75] Synapse Energy Economics Inc., 2012 Carbon Dioxide Price Forecast October 4, 2012. Rachel Wilson, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman. ("Synapse Low")
[76] Synapse Energy Economics Inc., 2012 Carbon Dioxide Price Forecast October 4, 2012. Rachel Wilson, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman. ("Synapse High")

    - Low capital costs for wind and solar: overnight capital costs 10% lower than reference case.
    - High capital costs for wind and solar, with no CO_2 tax.
    - Reduced expected economic life for wind plants: from 27 to 22 years.
    - Increased expected economic life for wind plants: from 27 to 32 years.
- **PGE long-term load growth futures, as required by Order No. 07-002**:
    - Low: 0.81% annual average growth between 2014 and 2033.
    - Very Low: virtually no growth (0.02%).
    - High: 2.06%.
    - Very high: 2.69%.
    - Maximum opt-out election from PGE's cost of service (300 MW).
- **Credible combinations of discrete futures**:
    - High CO_2 cost with high natural gas prices, which adversely affects the performance of thermal plants.
    - No CO_2 cost with low natural gas prices, which benefits thermal plants.
    - High wholesale electricity prices: simulated through robust WECC load growth combined with sustained poor hydro in the PNW (year 1937 hydro) and increased forced outages at aging thermal plants.
    - Low wholesale electricity prices: simulating through modest WECC load growth and high penetration of renewable technologies with very high capacity factors.
    - Perfect storm: simulated though severe scarcity of resources in the WECC, high gas prices, and constraining CO_2 regulation. This future is designed to examine highly adverse electric market conditions.
- **High distributed solar penetration in PGE's territory**: up to 217 MW DC of incremental distributed PV in PGE's territory by 2033.

Table 9-5 below summarizes the combinations of the risk factors described above across our Futures.

Table 9-5: PGE futures and risk drivers

↓ Futures Risk Drivers→	Fuel Prices	CO_2	Load	Hydro Conditions	Capital Costs	Plant Performance
1 Reference Case						
Fuel/CO_2						
2 High Gas	X					
3 Low Gas	X					
31 Very High Gas	X					
4 High Coal	X					
5 Low Coal	X					
12 No Carbon Tax		X				
13 Synapse low CO2		X				
14 Synapse High CO2		X				
30 CO2 trigger		X				
33 16 dollars CO2 in 2023		X				
34 High Capital Cost Wind and Solar/No CO2		X			X	
25 High Gas and CO2	X	X				
26 Low Gas and No CO2	X	X				
Load						
6 Hi load test 1 std dev			X			
7 Low load test 1 std dev			X			
8 Hi load test 2 std dev			X			
9 Low load test 2 std dev			X			
28 Max PGE Opt Outs			X			
24 Solar PV Penetration			X			
Hydro						
10 High Hydro				X		
11 Low Hydro				X		
Capital Cost						
17 High Capital Cost Gas Thermal					X	
18 High Capital Cost Wind and Solar					X	
19 High Capital Cost					X	
20 Low Capital Cost					X	
21 No PTC and ITC					X	
27 Low Capital Cost Wind and Solar					X	
35 22 yr life for wind					X	
36 32 yr life for wind					X	
Power Prices						
15 High Electricity Prices			X	X		X
16 Low Electricity Prices			X			X
29 Perfect Storm	X	X	X	X		X
32 High Electricity Prices w/freeriders			X	X	X	X
Wind CF						
22 PGE Wind High CF						X
23 PGE Wind Low CF						X

9.5 PGE's Approach to Risk Assessment

IRP Guidelines

PGE's approach to resource/portfolio risk assessment is consistent with the OPUC's IRP Guidelines:

- Guideline 1.b. identifies the following sources of risk and uncertainty: loads, hydro generation, plant forced outages, fuel prices, electric prices, and greenhouse gas compliance costs.
    - In addition, utilities should identify other sources of risk.
- Guideline 1.c. dictates at least two measures of PVRR risk: variability of cost, and severity of bad outcomes.

  - Guideline 1.c. also calls for analysis of any proposed use of physical and financial hedges (for fuels).
- Guideline 4 calls for high and low load growth scenarios and stochastic load risk analysis.
- Guideline 8 requires specific scenario analysis for environmental compliance risk.
- Guideline 11 requires loss of load probability analysis of reliability risk.
- Order No. 12-013 adds a new guideline to address flexible capacity risk.

Deterministic Scenario Risk (i.e., Futures)

PGE's primary approach to risk assessment is to test the performance of all trial portfolios against the 36 futures described in the prior sections. This scenario approach allows for transparent comparisons where the underlying policy and cost drivers are identified and examined, both separately and in combinations. Within this deterministic scenario approach, pursuant to IRP Guideline 1.c., we look at metrics that measure both the *severity* of potential adverse outcomes, as well as the overall *variability* of outcomes as measured against the reference case cost.

Stochastic Risk

Some risks and uncertainties are best addressed using stochastic analysis. Stochastic inputs commonly exhibit a distribution of values with a mean, a standard deviation, and auto-regression. Commonly tested stochastic inputs are weather-driven loads (hourly), gas price changes (daily), hydro generation volume (hourly, but for an entire predefined "water year"), wind generation volume (hourly), and generating plant forced outages (hourly, by event). Note that these stochastic variables are generally associated with volumetric demand and supply risk for electricity, with gas prices being the exception.[77] Market electric prices are also stochastic, but these are an *output* from the AURORAxmp modeling (derived from testing the other stochastic variables), not an input. Stochastic inputs are particularly useful for performing reliability analysis.

PGE Analysis and Studies that Assess Risk and Uncertainty

Table 9-6 below summarizes modeling inputs that are uncertain due to a variety of reasons: weather, the economy, generating plant reliability, market-driven prices, fundamentals-based costs, and policy drivers. Note that some inputs are appropriate for stochastic analysis, others are better examined through deterministic or scenario analysis via futures, and a few can be tested through either or both methods. The table then shows the studies performed that address given risks. Note that several risks are addressed in more than one study.

Also note that because the purpose of stochastic analysis is to mimic variability observed in the real world, analysis that uses actual historical hourly load and wind data

[77] Coal prices are stochastic as well. But since no PGE IRP portfolio proposes new coal, it is not relevant to this analysis.

(i.e., observations that have not been weather-normalized) inherently reflects the variability that stochastic analysis seeks to simulate. Thus, our wind integration and flexible supply studies, which employ historical actual hourly load and wind data, incorporate the impacts from random weather-driven variations we wish to examine.

Table 9-6: Uncertainty drivers

	Volume Uncertainty						Cost Uncertainty					
	Weather-driven Load	Economy-driven Load	Hydro Year	Wind Variability (within year)	Wind Capacity Factor	Gen. Forced Outages	Gas Prices	Coal Prices	Market Electric Prices	CO2 Cost	New Gen. Capital Costs	PTC Sunset
Stochastic?	√		√	√		√	√		√			
PGE Discrete Future?		√	√		√		√	√	√	√	√	√
Used In:												
Portfolio Scenarios		√	√		√		√	√	√	√	√	√
Reliability Study	√		√	√		√						
Flexible Supply Study	√			√								
Wind Integration Study	√			√					√			
PGE Mid-term Strategy							√		√			

Following is a brief overview of the analysis we have performed in this IRP to assess both deterministic and stochastic risks:

- **NPVRR uncertainty**: Variability of costs and severity of bad outcomes are identified via the scenarios (portfolios and futures). PGE has developed 36 futures to test robustness of differing portfolios against a range of potential future cost drivers. These were discussed in Section 9.3 above.
- **Reliability risk**: Addressed via a Loss of Load Probability Study for top-performing portfolios. Employs Monte Carlo analysis which incorporates stochastic inputs for loads, hydro generation, wind generation, and generating plant random forced outages. A later section in this chapter presents the details of that analysis. We then include the analysis results in Chapter 10 - Modeling Results.
- **Supply flexibility risk due to the growing role of variable resources in the portfolio**: Addressed using a study performed and vetted in an IRP workshop using three years of actual minute-level loads and associated minute-level pro-forma wind generation. (Actual loads and wind generation are equivalent to stochastic loads and wind.) Chapter 5 - Flexible Capacity Needs addresses this study.
- **Wind integration risk and cost**: Considers costs related to uncertainty of wind, weather-driven actual loads, and gas prices. Identifies appropriate supply responses going forward to minimize costs while maintaining system reliability. Chapter 8 - Supply-side Options addresses PGE's updated wind integration study.
- **CO_2 compliance risk**: Captured by both specific scenarios at varying levels of CO_2 compliance cost, as well as the trigger-point analysis called for in IRP Guideline 8. The potential cost for CO_2 compliance is not a stochastic

variable, but rather a discrete policy variable. The CO_2 price level scenario analysis is included in the following section. Chapter 10 - Modeling Results contains the results of the trigger-point analysis.

- **Natural gas price risk**: Near-term to mid-term gas and electric price volatility risk is assessed and mitigated via PGE's mid-term strategy. For longer-term scenario price risk, PGE includes three futures with low and high gas prices. Gas price uncertainty is also incorporated in the wind integration study.
- **Coal price uncertainty**: High and low coal price futures are included for WECC-wide coal-fired resources, including Boardman and Colstrip.
- **Wholesale electric price uncertainty**: We include several futures to capture circumstances and fundamental changes that could lead to higher or lower wholesale electric prices. Electricity prices are also a function of uncertain fuel prices, which we address via scenarios.

Portfolio Cost and Risk Assessment Results

In order to ensure that we adhere closely to OPUC IRP Guidelines, we use a simplified approach to assessing a preferred portfolio, particularly with regard to risk, which is described in Chapter 10 - Modeling Results.

9.6 Loss of Load Probability Analysis Methodology

Guideline 11 of OPUC Order No. 07-002 requires PGE to analyze supply reliability within the risk modeling of the candidate portfolios we consider. To do this, we calculate three related metrics for each of the top performing portfolios. These metrics allow us to assess the resource adequacy of our top-performing portfolios in general, and to determine relative performance of the portfolios on a reliability basis.

Throughout this discussion, it should be understood that the loss of load probability (LOLP) metrics calculated are best interpreted as indicators of market dependence beyond certain limits detailed below. Reliability in this IRP can then be interpreted to mean the extent to which PGE can rely on its owned and contracted resources, as well as limited market purchases, to meet load. Portfolios that are more reliable in this sense are less exposed to fluctuations in market availability and potential supply disruption events in which PGE would be unable to produce or secure sufficient power to meet customer demand.

LOLP Modeling Methodology

We start with our assessment of how much electricity we can confidently procure in the spot market during peaking events. Specifically, it is not prudent to assume availability of wholesale spot market power during the peak WECC summer months (July through September). In this summer period we cannot rely on regional diversity or imports as the entire WECC can be affected by heat events. In particular, imports from California would not be available during a west-wide summer peak weather event. This assumption is consistent with NWPCC's summer assumption for the NW region as a whole.

However, for the remainder of the year, we assume moderate availability of market power. For years prior to 2019, we assume that 300 MW will be available in all non-summer hours. This drops to 200 MW beginning in 2019. These amounts are estimates based on the experience and professional judgment of our power operations staff, but we have no assurance that 300 MW (200 post-2018) would be available if needed, and therefore reliability risk for the "non-summer" months could be higher if market supplies were more limited during a contingency event.

We use AURORAxmp to assess our risk (probability) of being unable to serve any amount of customer energy needs and the resulting amount of expected unserved energy in MWa. For this purpose, we set electricity market prices in AURORAxmp to high levels in order to force all available PGE owned and contracted resources to dispatch first. Then, for each hour in the 2017-2025 period, AURORAxmp balances available PGE resources against PGE load and makes market purchases if necessary.

Specifically, we add required reserves to customer load, and then subtract 200 or 300 MW, if appropriate, to represent available market supply (as discussed above). If PGE resources generate more than this amount in a given hour, there is no LOLP problem associated with that hour. If PGE resources generate less than this amount, then we note that there is an LOLP event in that hour. We also note the size of the event (i.e., how much potentially unavailable power we have to purchase in the hour). We test the years 2017 through 2025. We do not make major discretionary resource additions in our portfolios after 2025.[78] Therefore, the years we assess are the relevant ones for exploring relative reliability across portfolios.

To rank portfolios by relative market exposure, we test each portfolio against 100 stochastic future iterations for 2017-2025. For each iteration of our dispatch model, we change four variables – weather-driven load, hydro availability, wind output, and plant forced outages. Load and wind are varied on an hourly basis. We input load for all modeled hours and one representative week of hourly wind production for every month of the model runs. Hydro is input on a monthly basis. Plant forced outages are generated via mean times to failure and to repair. The stochastic logic assumes that the parameters for each variable's random future behavior are established by its past random behavior. Of the four random variables modeled, we generate PGE load, hydro generation, and wind exogenously, and then import them into AURORAxmp. We use AURORAxmp's internal risk logic to model plant forced outages.

As noted above, we run 100 iterations to capture the random variations in the input variables. All other inputs are identical to those assumed in the deterministic dispatch model used to run the reference case futures.

[78] We do add wind to meet the RPS in 2030.

We next discuss our LOLP metrics. This is followed by a detailed discussion of the stochastic nature of our four stochastic variables.

LOLP Metrics

We use three metrics in our reliability analysis:

Loss of Load Probability (LOLP)

We calculate LOLP as the average across the 100 risk iterations of the ratio of the number of hours of PGE resource insufficiency (Loss of Load Hours or LOLH) to the total number of hours included in the study.

FORMULA: If for each year and risk iteration, LOLH is the number of hours across the year during which PGE must make potentially unavailable market purchases in order to meet its load, and H is the number of hours in the year (either 8760 or 8784), the LOLP for the year is calculated as:

$$= \frac{1}{100} * \left(\sum_{1}^{100} \frac{Loss\ Of\ Load\ Hours\ (LOLH)}{H} \right)$$

This metric measures the percentage of hours that customer load plus required reserves (adjusted by 200 or 300 MW as appropriate outside of the summer season) will exceed PGE's owned and contracted generating capacity. For example, a 0.1% LOLP for a particular year indicates that PGE, on average, would expect to be forced to try to make potentially unavailable market purchases for approximately 9 hours of the year. (0.1% x 8760 = 9) This metric only addresses the likelihood of PGE having to make potentially unavailable market purchases. It does not measure the amount we would have to purchase. For example, LOLP treats an hour in which we would have to try to purchase 1000 MW the same as an hour in which we would have to try to purchase only 20 MW. It is a measure of frequency, but not magnitude or severity. For this reason, we consider our next reliability metric, which focuses on magnitude.

Expected Unserved Energy (EUE)

For each year, we calculate the EUE as the average (across 100 risk iterations) of the amount of power PGE must purchase via the potentially unavailable spot market to meet customer demand (and required reserves), expressed in MWa.

FORMULA: If for each year and risk iteration, Unserved Energy (UE) is the total amount of power purchased on the potentially unavailable spot market in MWh, and H is the number of hours in the year (either 8760 or 8784), EUE is calculated as:

$$= \frac{1}{100} * \left(\sum_{1}^{100} \frac{UE}{H}\right)$$

This metric measures the average amount that PGE must try to purchase on the spot market, in any hour of the year. EUE is a good indicator of the expected magnitude of resource insufficiency. However, because it is the average of 100 iterations and expressed as the average across all hours of the year, it does not measure the potential severity of bad outcomes. For measuring the severity of bad outcomes, we turn to our third metric.

TailVar 90 Unserved Energy (TailVar UE)

We calculate this metric, in MW of potentially unserved load, as the average amount we would have to purchase on the potentially unavailable spot market during the worst 10% of all LOLH across the 100 iterations. For a given portfolio, TailVar UE can be calculated either for the entire 2017-2025 period, or by year. This metric provides an estimate of the potential severity of resource deficiency. It focuses on the performance of portfolios under extreme, or "right tail" events.

Stochastic Input Variables

We discuss our approach to each of the four stochastic variables below. For two of these variables, load and wind, we retained Marty Howard of Benchmark Heuristics to develop appropriate methodologies.[79]

PGE Load

Our load simulation is the sum of four parts:

1. An annual average or level forecast equal to the actual annual expected load for that year.

2. A seasonal pattern of expected deviations from the annual average. For example, we expect loads to be higher in January than in May. We construct our seasonal deviation pattern on a weekly basis.

3. A pattern of expected hourly deviations from the expected weekly average to provide for diurnal load, or on-peak, off-peak patterns. We construct these deviation patterns across a typical week on a seasonal basis. In other words,

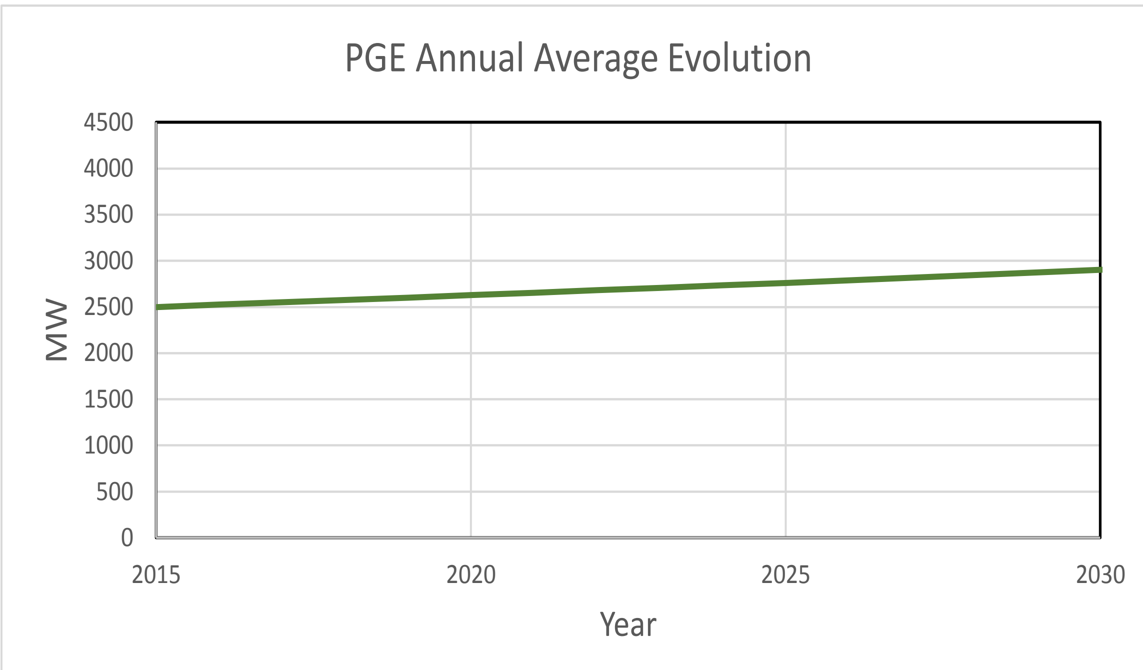
[79] Mr. Howard has an M.A. in mathematics and has worked for more than three decades in the electric utility industry.

we take into account that hourly deviations across a typical January week differ from those across a typical June week.

4. A time series of hourly deviations from the three systematic patterns. These deviations represent temperature-induced variations from hourly one-in-two weather-based patterns. We construct this time series element via an AR-GARCH (autoregressive-generalized autoregressive conditional heteroskedastic) process.[80] The time series component reproduces the short-term stochastic time dependence that is seen in historic hourly demand data. One characteristic of that dependence is varying variability; there are periods during which hour-to-hour swings are large, and other periods during which those swings are smaller. The GARCH component of the time series modeling is effective at capturing this kind of behavior.

Schematically, the following series of figures illustrate the process. Figure 9-8, Figure 9-9, and Figure 9-10 show the three systematic elements.

Figure 9-8: PGE load annual input



[80] We considered moving average (MA) terms. However, we did not use them because they added very little descriptive power to our time series model.

Figure 9-9: PGE load seasonal input

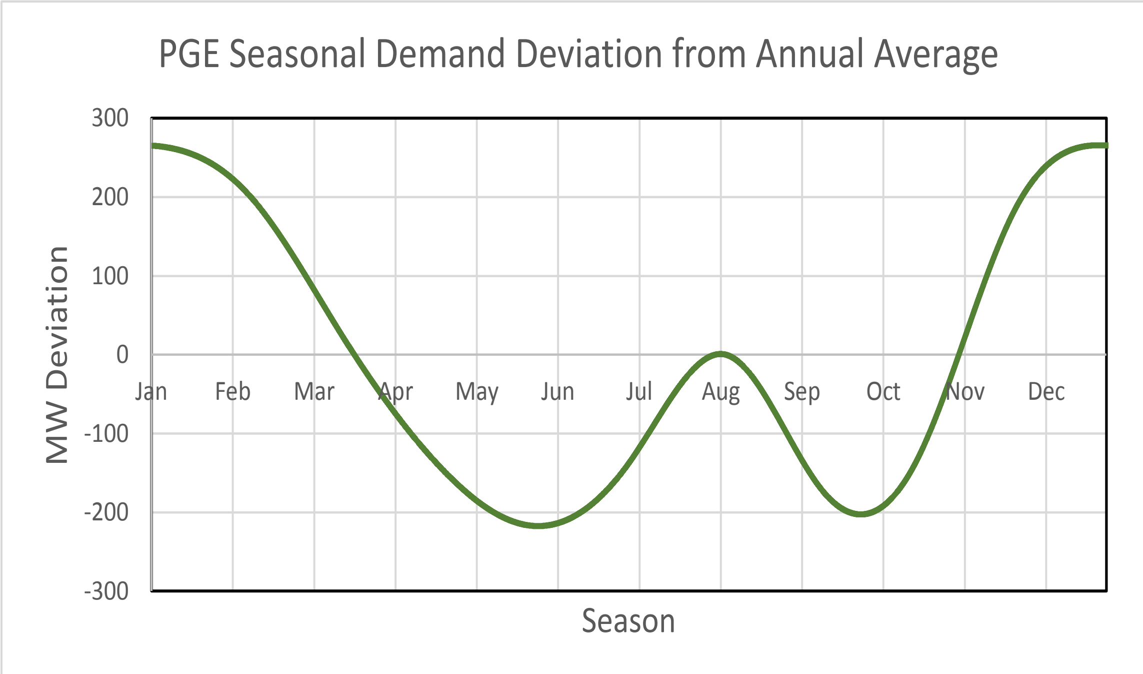


Figure 9-10: PGE load hourly input

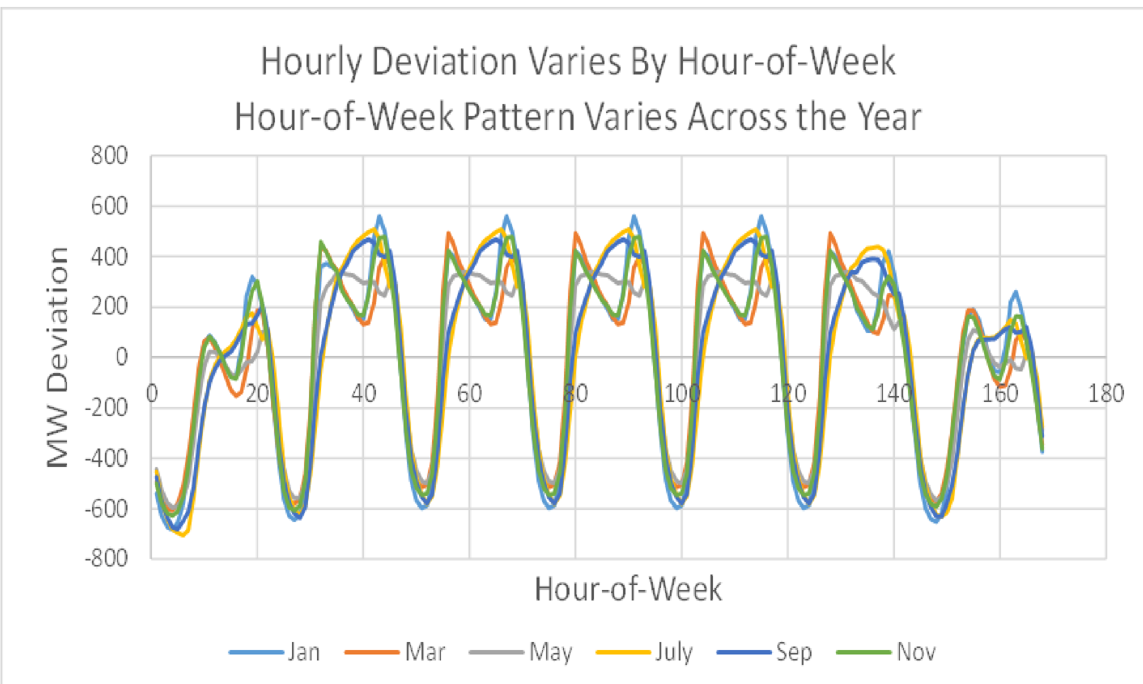


Figure 9-11 and Figure 9-12 compare the results of our load simulation process with an actual historical example. The patterns across a two-week January period are very similar. This demonstrates that our simulation process is reasonable.

Figure 9-11: Simulated January week load

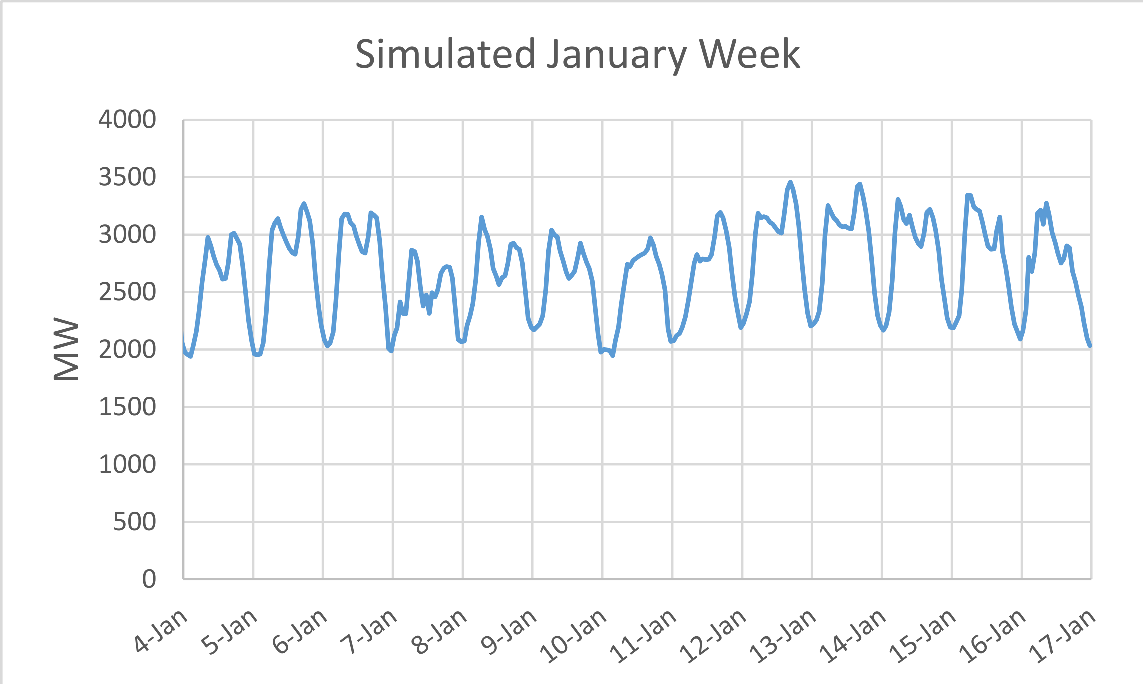
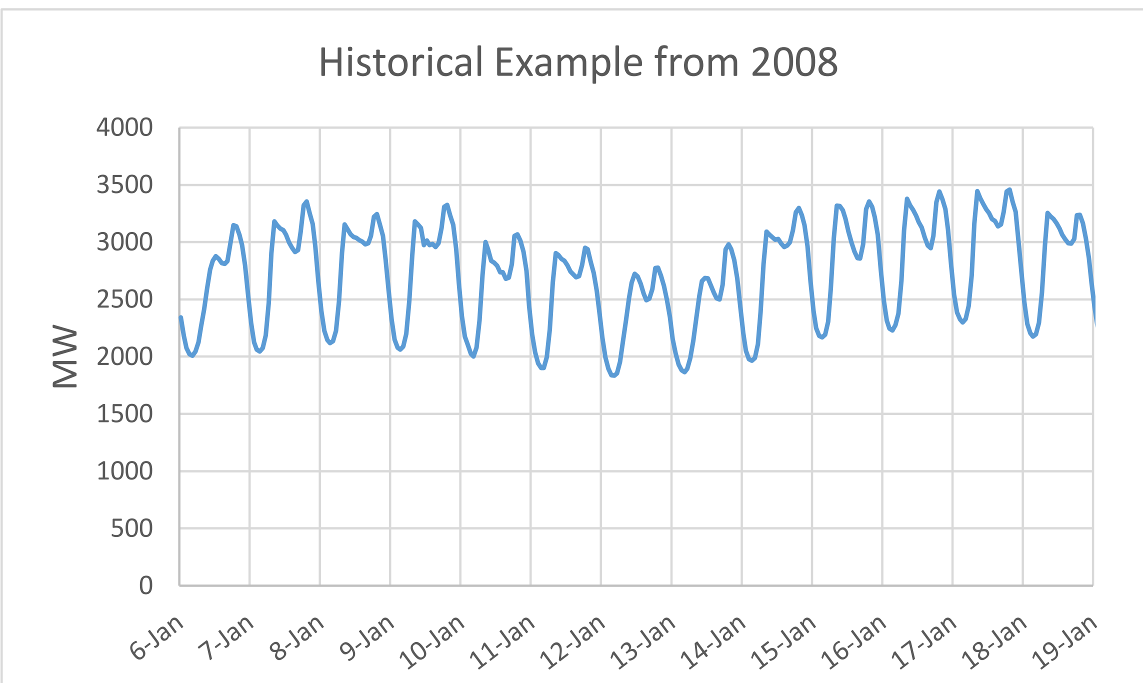
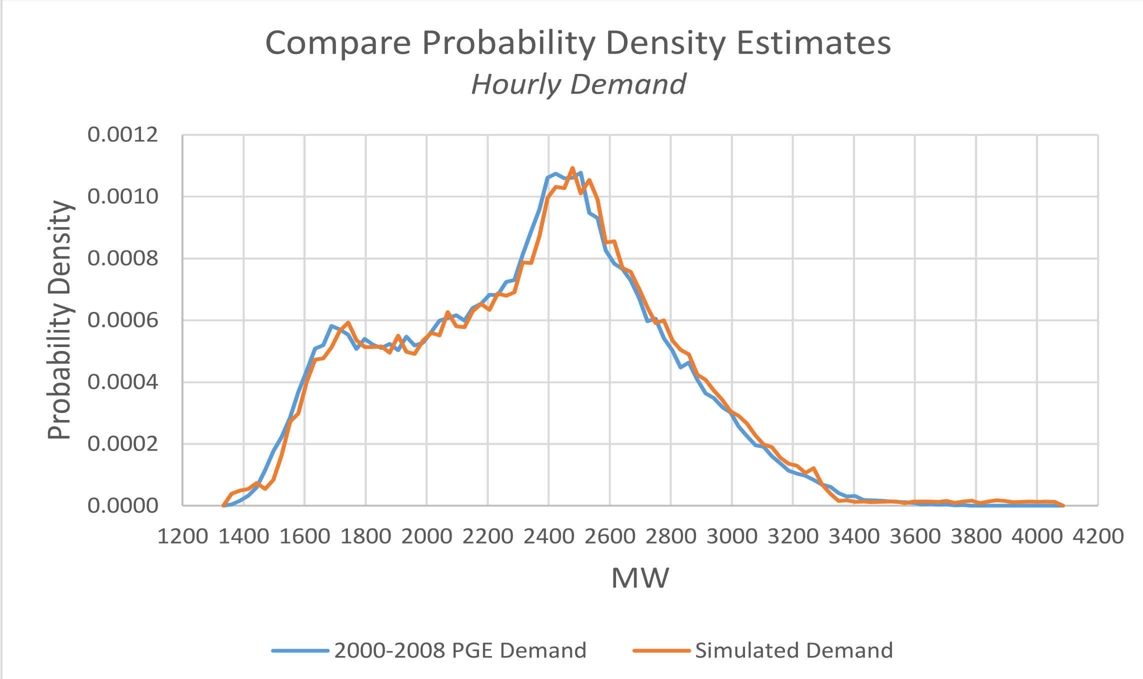


Figure 9-12: Actual January week load



To further test the reasonableness of our load simulation methodology, we constructed probability density estimates from both actual and simulated (with our methodology) data for the 2000-2008 period. Figure 9-13 below shows that our methodology produces results which follow a demand pattern quite similar to actuals.

Figure 9-13: Simulated and actual hourly demand probability densities



Wind

We begin our construction of stochastic wind farm output data by noting that actual wind production occurs in an episodic way, with output rising and falling, sometimes rapidly, sometimes very slowly, as weather phenomena pass over the wind site. These episodes appear to occur with random durations, and to move over these durations by random amounts, within production constraints (i.e., between zero and the nameplate capacity of the wind farm). We can describe and quantify this behavior for simulation in the following way:

- We begin with actual data for our current and under construction wind plants, Biglow Canyon and Tucannon River.
- We linearly transform this data for each wind farm to the zero-one interval.[81] This transformation is easily inverted to match the scale of a particular wind plant, and conforms to input formatting used by AURORAxmp.

[81] If the minimum generation is zero, each production value is transformed as:

$$transformed\ production = {}^{actual\ production}\!/_{nameplate\ capacity}$$

If the minimum generation is some particular value, then the transformation is calculated as:

$$transformed\ production = {}^{(actual\ production - minimum\ production)}\!/_{(nameplate\ capacity - minimum\ production)}.$$

- After further transformation to take into consideration seasonal patterns, we fit a series of linear segments to the data. This allows us to estimate the episodes of wind up-ramp and down-ramp. We then construct a sequence of random ramps with changes and durations consistent with this historical ramp data.
- We analyze deviations of the data from the linear segments as an AR-GARCH time series.
- Finally we consider stochastic wind output to be a function of these last two factors – the random ramp data and the AR-GARCH time series. We combine these two factors to produce 12 weekly vectors for each year of each stochastic iteration. Each vector represents a typical week within a particular month, and consists of 168 hourly capacity factors. Within the 168 factors, there is one for each hour of each day of the week. Then, for example, the factor for hour 4 of Tuesday is used for each of the "Tuesday-Hour 4" hours in the relevant month.

Figure 9-14 and Figure 9-15 below compare our distribution of simulated Biglow and Tucannon River capacity factors with historical data. Our simulated capacity factor duration data track well with actual historical data and exhibit similar underlying volatilities.

Although we haven't attempted to examine or measure it, there is a cross-correlation on an hourly basis between loads and wind generation. For instance, during periods of extreme cold or warm temperatures, wind is strongly negatively correlated with load.

Figure 9-14: Simulated and actual Biglow Canyon capacity factor densities

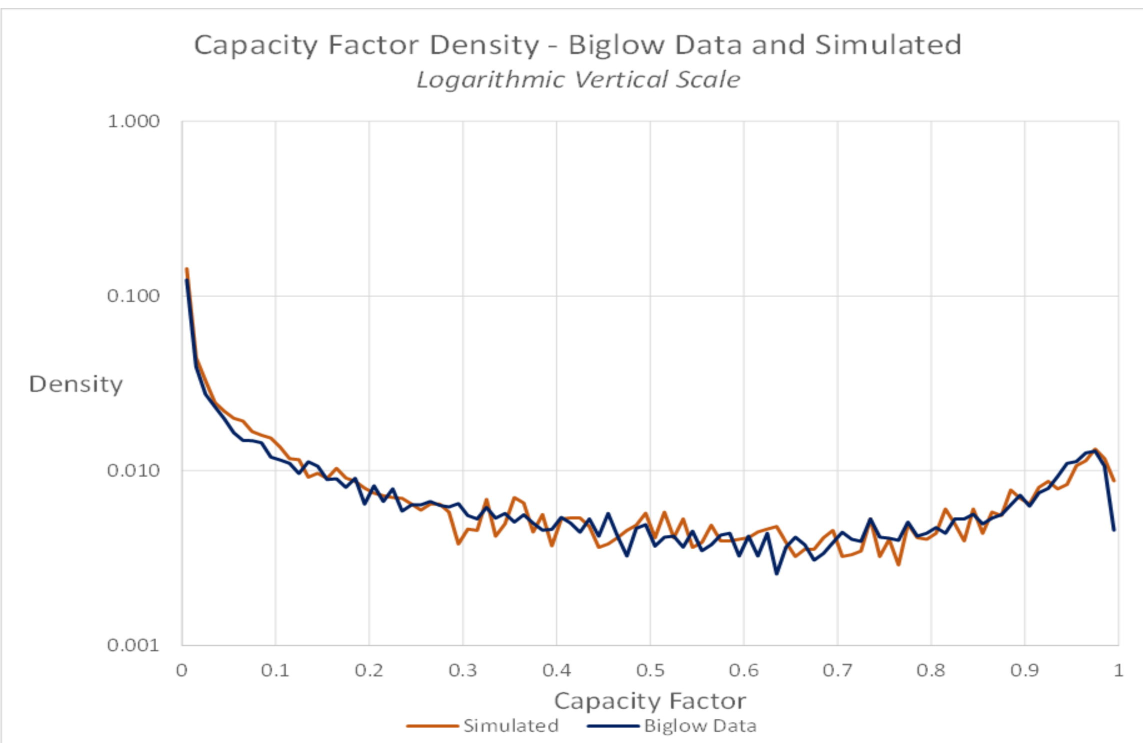
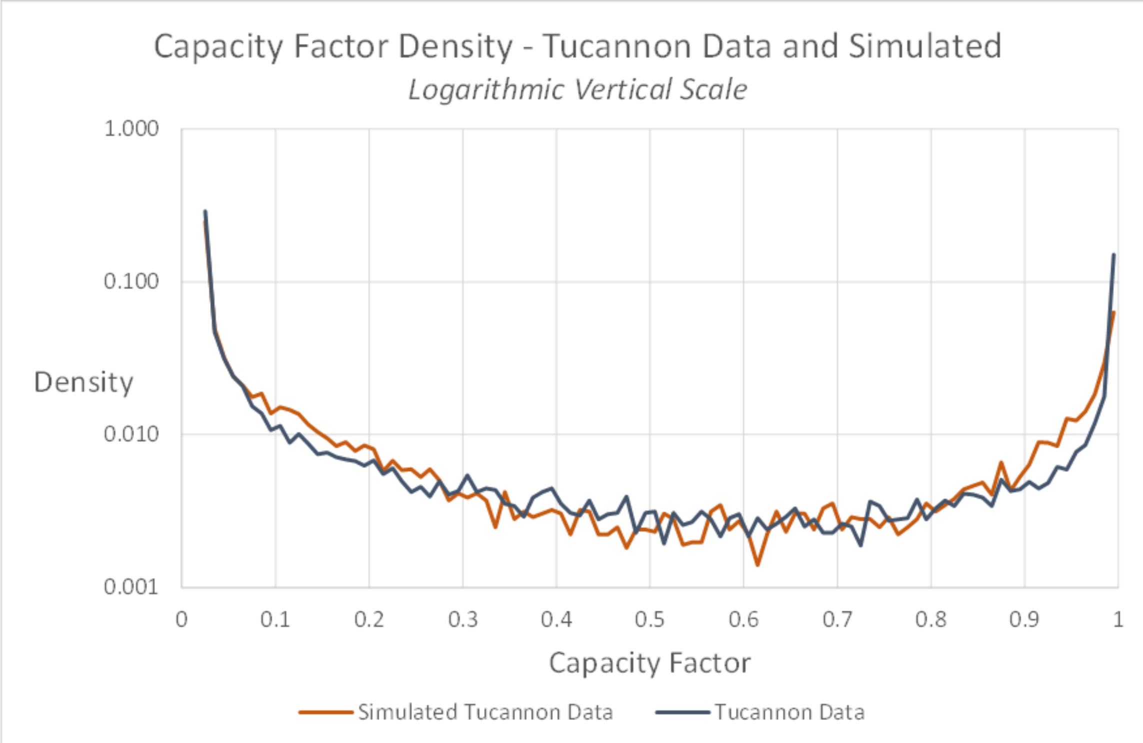


Figure 9-15: Simulated and actual Tucannon River capacity factor densities



Hydro Generation

Available hydropower varies from year to year, based on the amounts and timing during the year of precipitation and snow pack, and on the timing of water runoff. To simulate this annual variation, we tie Pacific Northwest hydropower to the historical hydro output of the region. We randomly sample from 50 historic water years starting in 1929.[82] We input these water years into the 12 AURORAxmp areas covering the Pacific Northwest and western Canada. Each area is described by 12 monthly factors and one annual factor, which together describe the hydro condition of one actual historical water year. The monthly factors capture significant monthly serial correlation.

We sample years independently with replacement. For any year within an iteration, each of the 50 hydro years has an equal chance of being selected. This results in no serial correlation across years. It also implies that it is possible, albeit unlikely, that one historical hydro year could be sampled many times within a single iteration.

Hydro years have no specified correlation with any other random variable in the study.

Forced Outages

Plant forced outages occur when plants are forced to shut down outside of planned maintenance periods and are therefore unable to provide generation. AURORAxmp

[82] This data is readily available from the Northwest Power and Conservation Council.

simulates forced outages internally by sampling from a distribution based on plant-specific Forced Outage Rates (FORs), Mean Times to Failure (MTTF) and Mean Times to Repair (MTTR). In our stochastic analysis, we use the same FORs as in the deterministic analysis, and then specify a MTTR for each of PGE's plants based on data from the North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS).

The AURORAxmp forced outage logic assumes that a plant's MTTR and MTTF are both exponentially distributed, and the logic chooses the MTTF such that, on average, the FOR of the plant in the simulation approaches the input FOR.

10. Modeling Results

The following chapter presents the results of our portfolio analysis and modeling, as well as our conclusions regarding the cost and risk results. As discussed in Chapter 9 - Modeling Methodology regarding our analytical approach, IRP models do not provide incontrovertible answers to questions regarding future resource needs and strategies for meeting those needs; they merely provide estimates of future performance for various alternatives, or a range of potential results, given a set of assumptions. However, IRP portfolio analysis does provide important insights and guidance to the strategic decision-making process, resulting in a selection of resources more likely to perform well under various conditions. 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 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 other alternatives under a wide range of credible future circumstances.

To assess the performance of each candidate resource portfolio, we calculate the net present value of revenue requirements (NPVRR) for each portfolio described in Chapter 9 - Modeling Methodology across each distinct, potential future and then we examine these resulting scenarios using the two primary views of risk required by IRP Guidelines (variability and severity). We also examine portfolio performance based on stochastic simulation of reliability risk. Taken together, these performance metrics present a comprehensive assessment of portfolio performance under uncertain future conditions.

Chapter Highlights

- We evaluate our portfolios across the 36 futures on the bases of expected cost, variability of outcomes, and potential severity of bad outcomes.
- Based on our evaluation, we identify Baseload Gas/RPS Only as the preferred portfolio. However, a few other portfolios also perform well compared to the remaining candidates.
- We perform stochastic reliability analysis on our top performing portfolios. Reliability results are essentially the same across our top performing portfolios.
- Most portfolios, including the preferred portfolio, have CO_2 emissions that meet or exceed a 2005 less 15% reduction target.

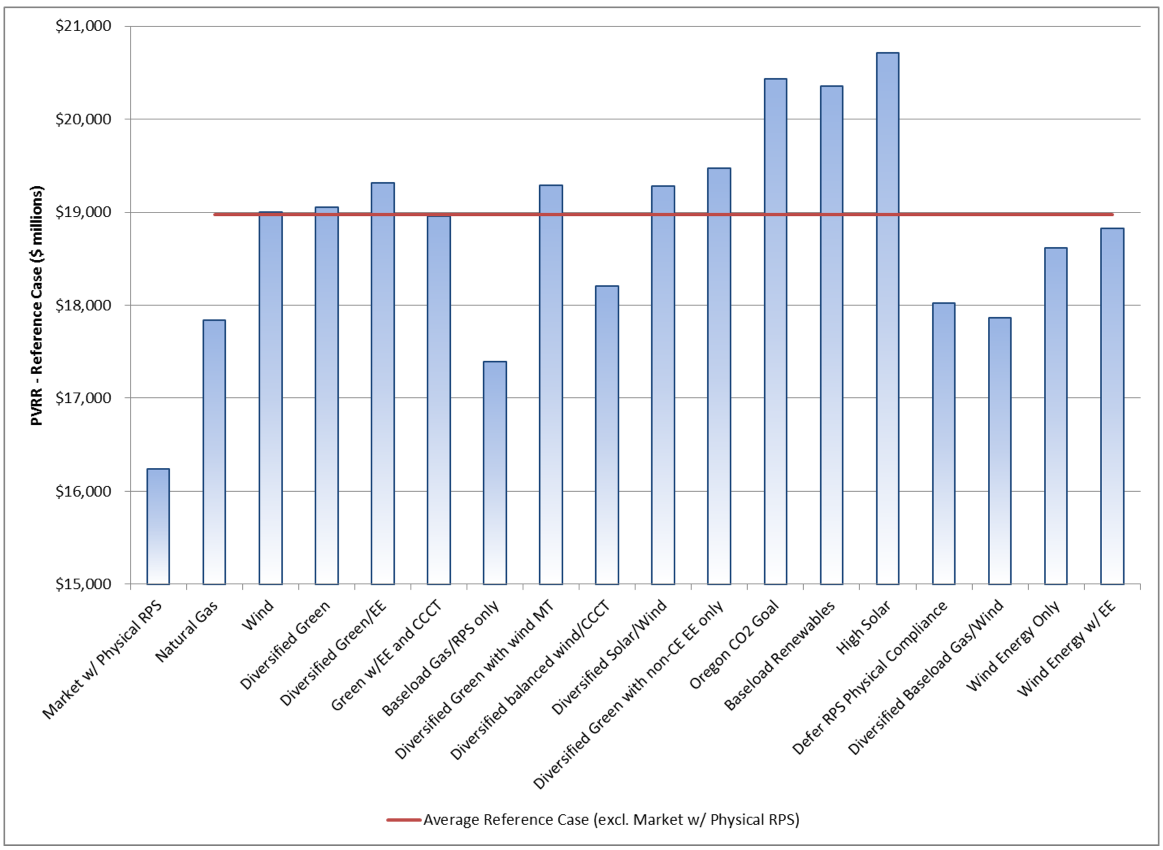
10.1 Portfolio Cost and Risk

A primary purpose of portfolio analysis is to identify a combination of resources that consistently performs well across different potential future environments. These scenarios serve as a good proxy for the kinds of uncertainty that could be encountered. To assess the performance of each candidate portfolio, we calculate the NPVRR for each combination of incremental resources described in Chapter 9 - Modeling Methodology, in conjunction with the existing PGE portfolio, across the 36 futures described in Chapter 9 - Modeling Methodology (see also Appendix C).

Portfolio Expected Cost, Severity, and Variability of Costs

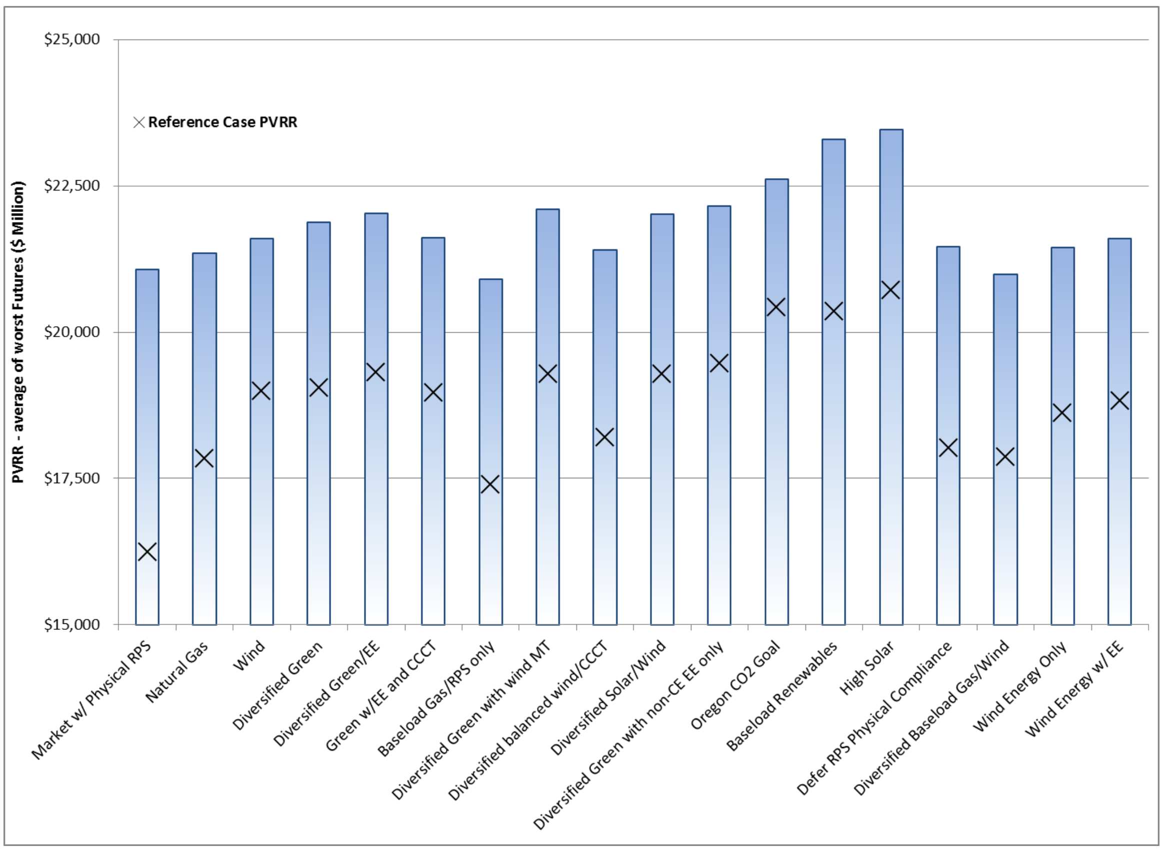
Our assessment of Portfolio performance begins with reference case expected costs shown in Figure 10-1. As described in Chapter 9 - Modeling Methodology, the reference case represents our expected, or more likely, future state for each of the input variables. The lowest cost portfolio, when considering only the reference case NPVRR, is Market with Physical RPS. Following the Market Portfolio, Natural Gas, Baseload Gas/RPS only, Diversified Balanced Wind/CCCT, Defer RPS Physical Compliance, and Diversified Baseload Gas/Wind all perform well on an expected cost basis (under reference case assumptions).

Figure 10-1: Candidate portfolio cost: reference case



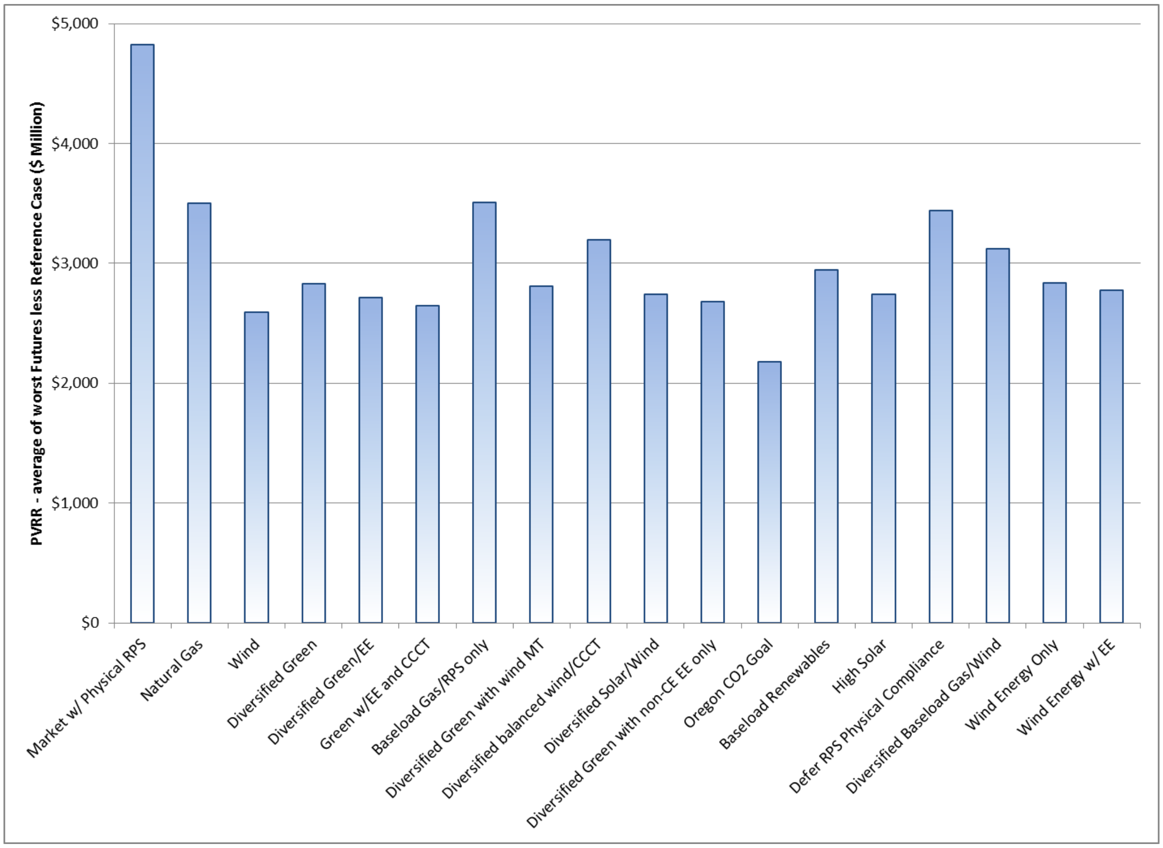
When assessing Portfolio risk, we look at both the severity and variability of costs. We measure severity as the average of the four highest cost outcomes across all futures for a given portfolio. The four highest cost outcomes were selected as an approximation for the 90th percentile of cost outcomes. This metric focuses on the absolute magnitude of bad outcomes (without regard to the expected cost as defined by the reference case). We do include the reference case cost on Figure 10-2 to provide context. Under this risk metric, the relative results for our portfolios remain generally consistent with the cost results under the reference case; that is, portfolios with lower reference case costs tend to have less severe outcomes under adverse conditions, and those with higher reference case costs tend to have more severe outcomes in challenging environments. According to the "severity" risk metric the top five performing portfolios are Baseload Gas/RPS only, Diversified Baseload Gas/Wind, Market w/ Physical RPS, Defer RPS Physical Compliance, and Natural Gas.

Figure 10-2: Candidate portfolio risk: average of four worst outcomes (severity)



Our next risk performance measure focuses on the variability of costs across futures, which we have defined as the average cost of the four highest cost futures for each portfolio, less the reference case expected cost (see Figure 10-3). Where the severity metric focuses solely on the absolute level of bad outcomes for each portfolio, this metric evaluates the difference between the costs of those bad outcomes and reference case expected costs. To illustrate why this variation may make a difference, portfolios that are dominated by spot market purchases may have low reference case expected costs, but may have exposure to extreme changes in cost (from expectation) due to the potential for high-cost future environments. Conversely, portfolios dominated by fixed costs (e.g., wind) may have a higher reference case expected cost, but reduced exposure to potential future cost changes because the portfolio cost structure is less subject to external/market influences. When looking at absolute cost exposure, the higher fixed-cost portfolios appear to be the most risky. However, when measuring risk based on the "variability" metric (degree of variation from expected costs) the Market Portfolio appears the most risky followed by those containing relatively higher proportions of base load natural gas.

Figure 10-3: Candidate portfolio risk: average of four worst outcomes less reference case (variability)

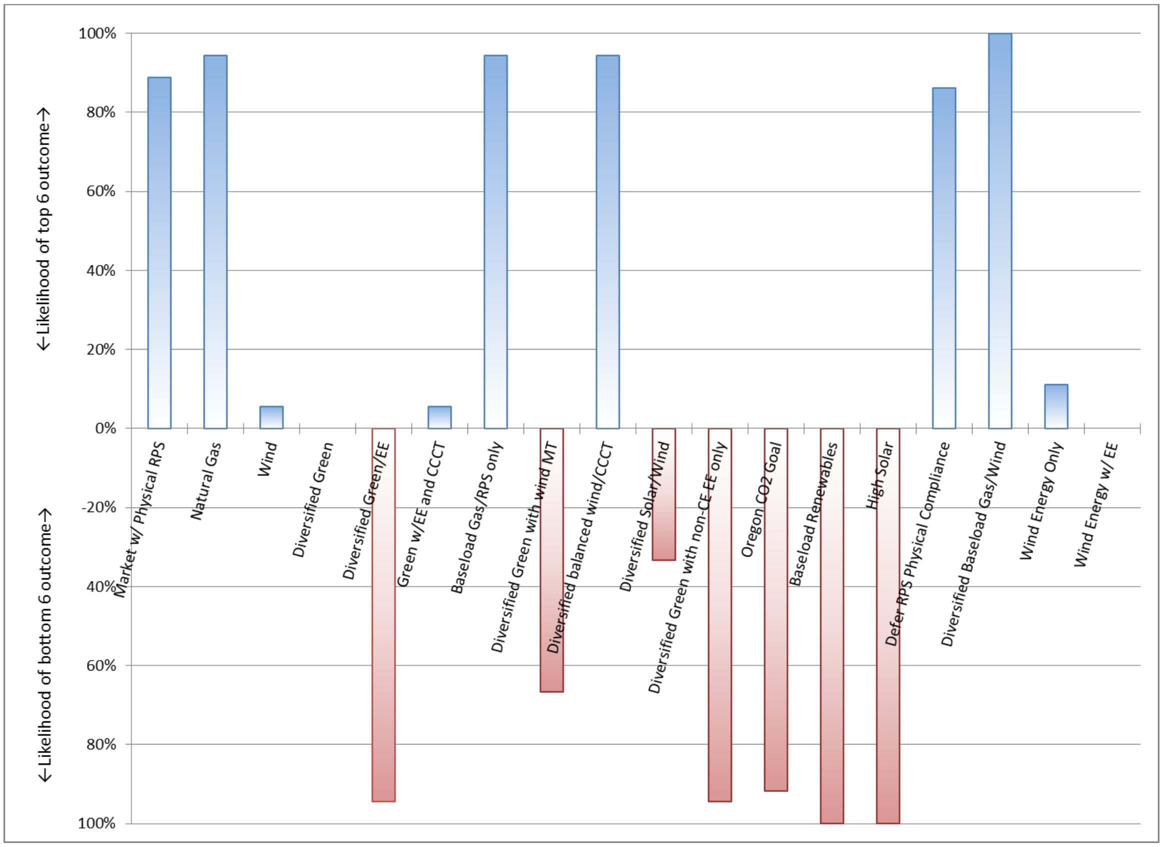


Likelihood of High or Low Expected Cost

An approach to further distinguish the performance of candidate portfolios is to examine each portfolio's likelihood of being among the best or worst cost performers across all futures. This assessment provides insights about the "durability" of each portfolio. Top portfolios will more frequently outperform their peers under each future, while also less frequently perform poorly (as compared to other candidate portfolios). The likelihood of good or bad performance is calculated based on the percentage of time a given portfolio ranks among the top-third out of the 18 portfolios tested across all 36 futures, less the percentage of time that same portfolio falls in the bottom-third. Figure 10-4 depicts this joint probability of achieving good performances while avoiding poor performances.

This graph suggests that portfolios combining base load natural gas with renewables to achieve the 2020 RPS requirement (i.e., diversified portfolios) are generally able to avoid bad outcomes while maintaining the ability to participate in low cost outcomes. The portfolios titled Baseload Gas/RPS only, Diversified Balanced Wind/CCCT, Diversified Baseload Gas/Wind, Natural Gas and Defer RPS Physical Compliance all perform well under this "durability" metric.

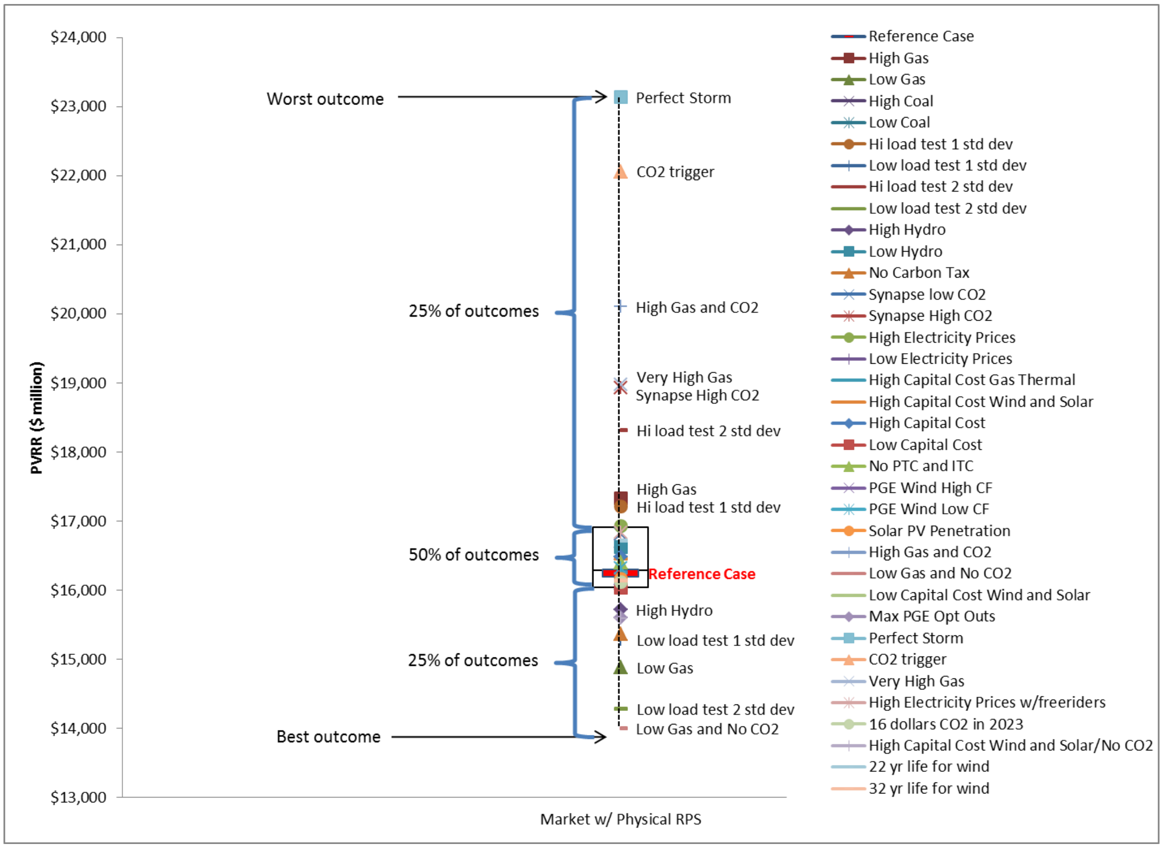
Figure 10-4: Scenario results: likelihood of "good" vs. "bad" outcomes



Observations

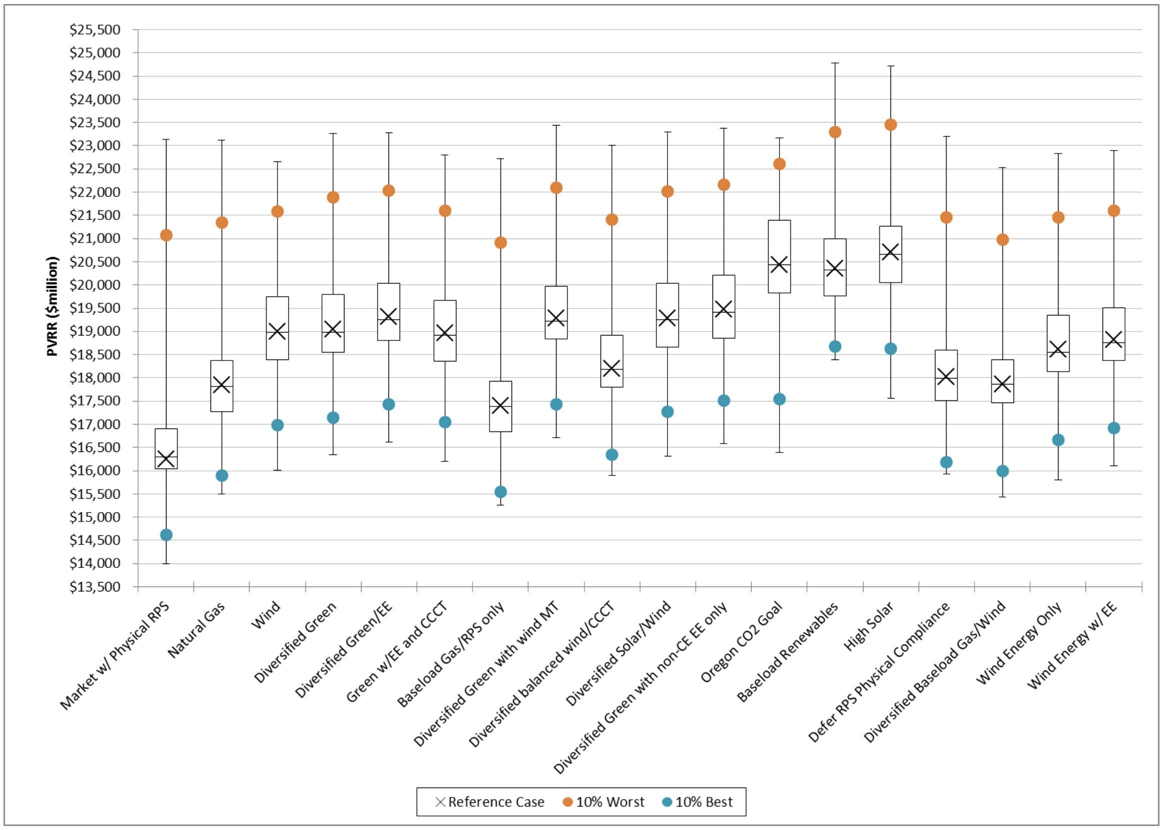
We use a box-and-whisker plot to combine the various aspects of portfolio evaluation (described above). Figure 10-5 provides an illustration of how we translate the scenario results into the plot, in this case using the results for the Market with Physical RPS Portfolio. For this illustration, the PVRR for this portfolio resulting from each of the 36 futures is plotted from highest cost (the future representing the worst outcome) to lowest cost (the future representing the best outcome). The upper and lower ends of the vertical line, or "whiskers," represent the highest and lowest cost outcomes, respectively, for the portfolio. We draw a box around the middle 50% of outcomes, or interquartile range, which gives us an indication of the dispersion of results for purposes of comparing portfolios. The horizontal line dividing that box represents the median cost for this portfolio.

Figure 10-5: Candidate portfolio cost detail across all futures: Market with Physical RPS



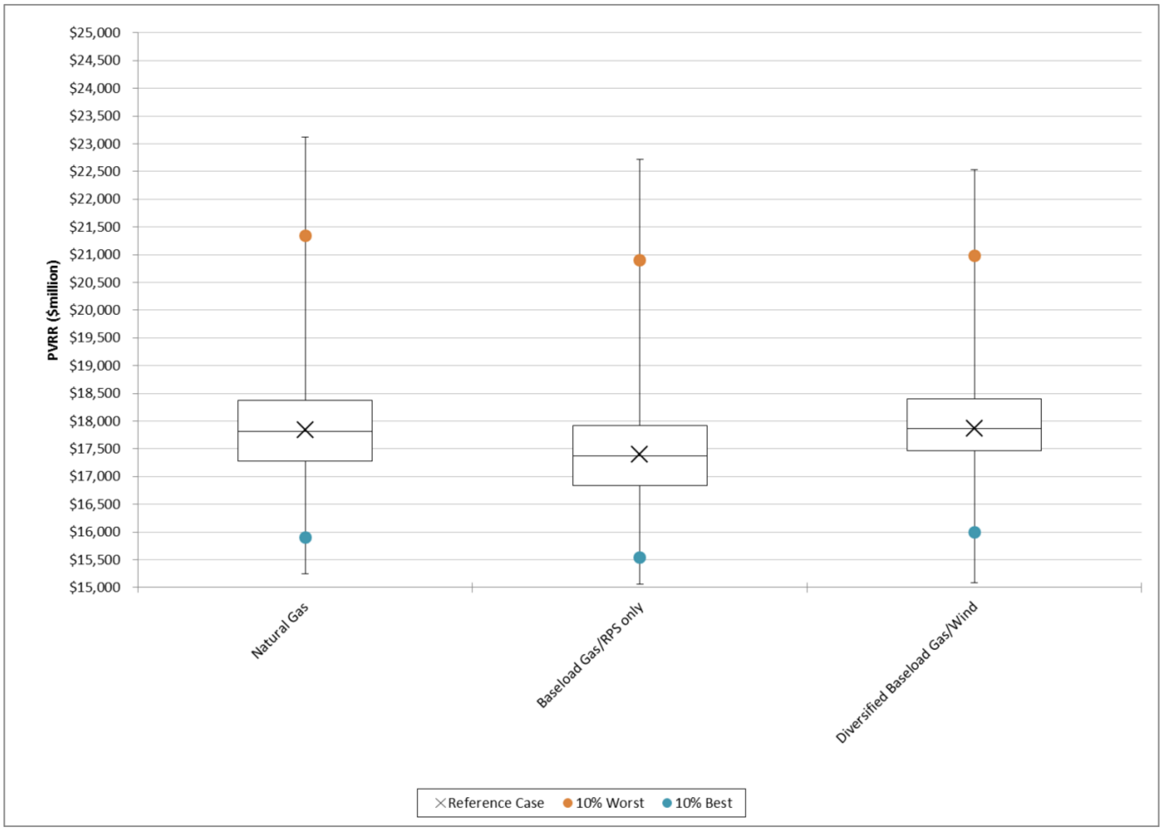
The box-and-whisker plot in Figure 10-6 provides a convenient means to visually assess the distribution of scenario results in terms of PVRR (vertical axis). We overlay the reference case expected costs, as well as the average of the four best and the four worst cost outcomes, onto the box-and-whisker plot. Visual inspection of Figure 10-6 reveals several portfolios that perform well overall, setting aside Market with Physical RPS for reliability reasons discussed below: Natural Gas, Baseload Gas/RPS only, Diversified Balanced Wind/CCCT, Defer RPS Physical Compliance, and Diversified Baseload Gas/Wind. These portfolios have low reference case expected costs, maintain the opportunity for favorable low cost outcomes (as represented by the average of the four best outcomes), and limit exposure to high cost futures (as represented by the average of the four worst outcomes). This list of portfolios is consistent with those stated above as being more likely to rank in the top-third of portfolios tested as discussed above.

Figure 10-6: Candidate portfolio cost distribution



We can further narrow this subset by eliminating the two Portfolios with clearly higher expected costs under the reference case assumptions, Diversified Balanced Wind/CCCT and Defer RPS Physical Compliance. The three Portfolios that remain have very similar expected costs in our reference case as illustrated in Figure 10-7. The PVRR across the three are separated by 2.7%. When considering overall cost and risk performance, the top three performing candidate portfolios are: Baseload Gas/RPS only, Diversified Baseload Gas/Wind, and Natural Gas. The top three portfolios perform similarly and each could be considered a viable candidate for a preferred portfolio. All of these portfolios follow the same basic model of combining EE, base load natural gas plants, new renewables to meet 2020 RPS requirements, and natural gas peaking units to provide capacity. These top portfolios differ with respect to the timing of base load gas resource additions, as well as the amount of natural gas peaking units and new renewables. Of these, we recommend Baseload Gas/RPS Only as the preferred portfolio as it performs best with regard to expected cost, and achieves similarly favorable risk and reliability performance when compared to the other two candidates. At the same time, we reiterate that we are not recommending any new major supply-side resource additions as part of our proposed IRP Action Plan. Therefore, the top performing portfolios from this IRP (along with other candidate resource combinations) will be re-examined for Action Plan selection in the next IRP.

Figure 10-7: Cost distribution for top three candidate portfolios



10.2 Reliability Analysis

In Chapter 9 - Modeling Methodology, we defined the three reliability metrics called for in the IRP Guidelines, which are recapped below:

1. Loss of Load Probability (LOLP) measures the likelihood or frequency of loss of load hours (LOLH): hourly events during which we would have to make potentially unavailable market purchases to meet load and reserve obligations. We express LOLP as a percentage.

2. Expected Unserved Energy (EUE) measures the average magnitude of potentially unserved load and/or unmet reserve requirements. For a year, we divide the number of mega-watt hours (MWh) that a portfolio has to purchase from uncertain market sources by the number of hours in a year. We then express EUE in MWa.

3. TailVar Unserved Energy (TailVar UE) measures the potential severity of energy deficits. It is the average quantity that we would have to purchase on the potentially unavailable spot market during the worst 10% of all LOLH. We express TailVar UE in MW.

We also noted that we assume limited "firm market" purchases, but only during non-summer months. Given this differentiation, we express some of our results on a seasonal basis. We focus on our five top performing portfolios, which are Diversified Baseload Gas/Wind, Natural Gas, Baseload Gas/RPS only, Diversified Balanced Wind/CCCT, and Defer RPS Physical Compliance. We also include one LOLP comparison between our top five portfolios and the Market portfolio.

LOLP Results

Figure 10-8 shows average LOLP over the 2017-2025 analysis timeframe for the top five portfolios and for the Market portfolio. Because of the Market portfolio's deliberate deficit strategy, its average LOLP results (nearly 12%) are very unfavorable compared to those of the top five portfolios, which all have similar results (less than 0.5%).

Figure 10-8: LOLP average 2017-2025

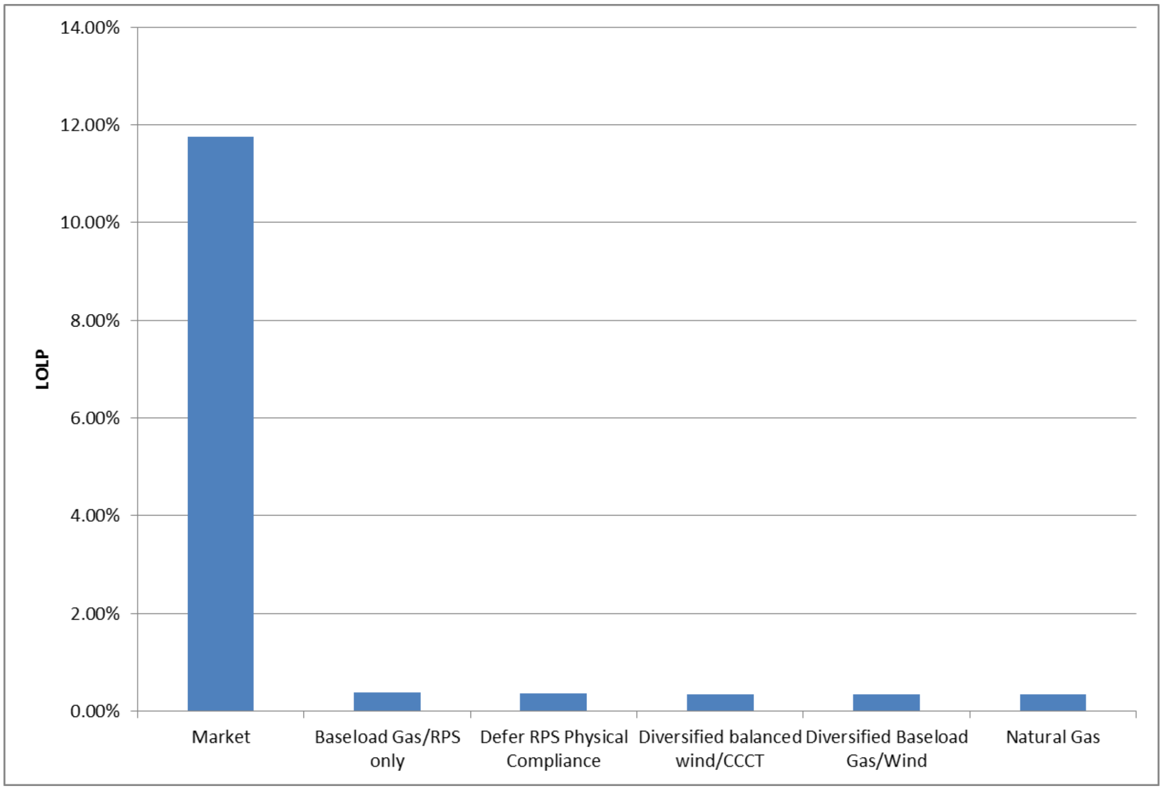


Figure 10-9 provides seasonally differentiated average results (2017-2025) for the top five portfolios. Results are similar across the portfolios. Even though we exclude market purchase availability during the months of July through September, our projected LOLP risk is lower during the summer season. This is due to the fact that our expected summer loads are lower than our expected winter loads, which more than offsets reduced access to market resources.

Figure 10-9: LOLP for top candidate portfolios 2017-2025

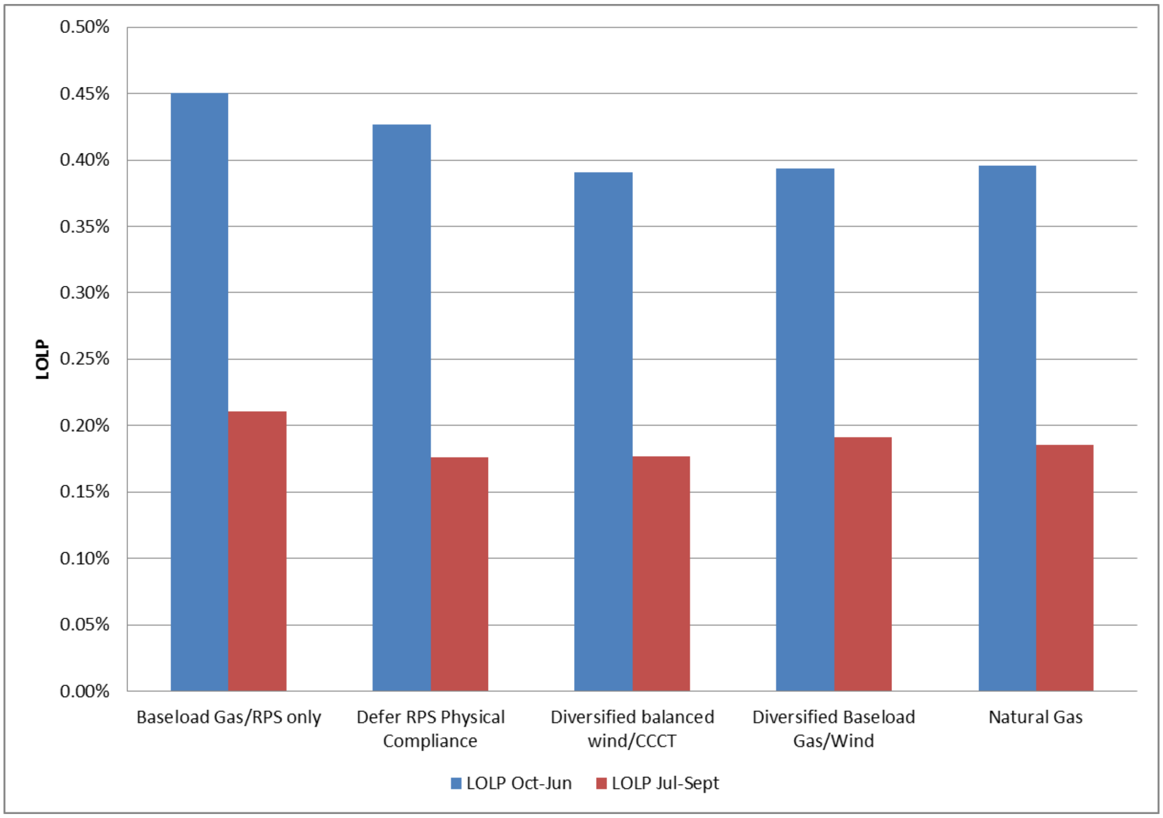


Figure 10-10 shows average (summer and non-summer results combined into one measure) LOLP by year for the top portfolios. There is some variation from year to year, due to the "lumpiness" of our assumed resource additions. Also, LOLP drops in 2021 with the cessation of Boardman coal operations, a large single shaft resource with a relatively high forced outage rate. The various changes in resources from one year to the next affect all of the top portfolios to approximately the same extent. The Natural Gas portfolio performs particularly well at the end of the analysis period because it includes additional base load energy in 2024 compared to the other portfolios, adding a combined-cycle combustion turbine in that year.

Figure 10-10: LOLP for top candidate portfolios by year

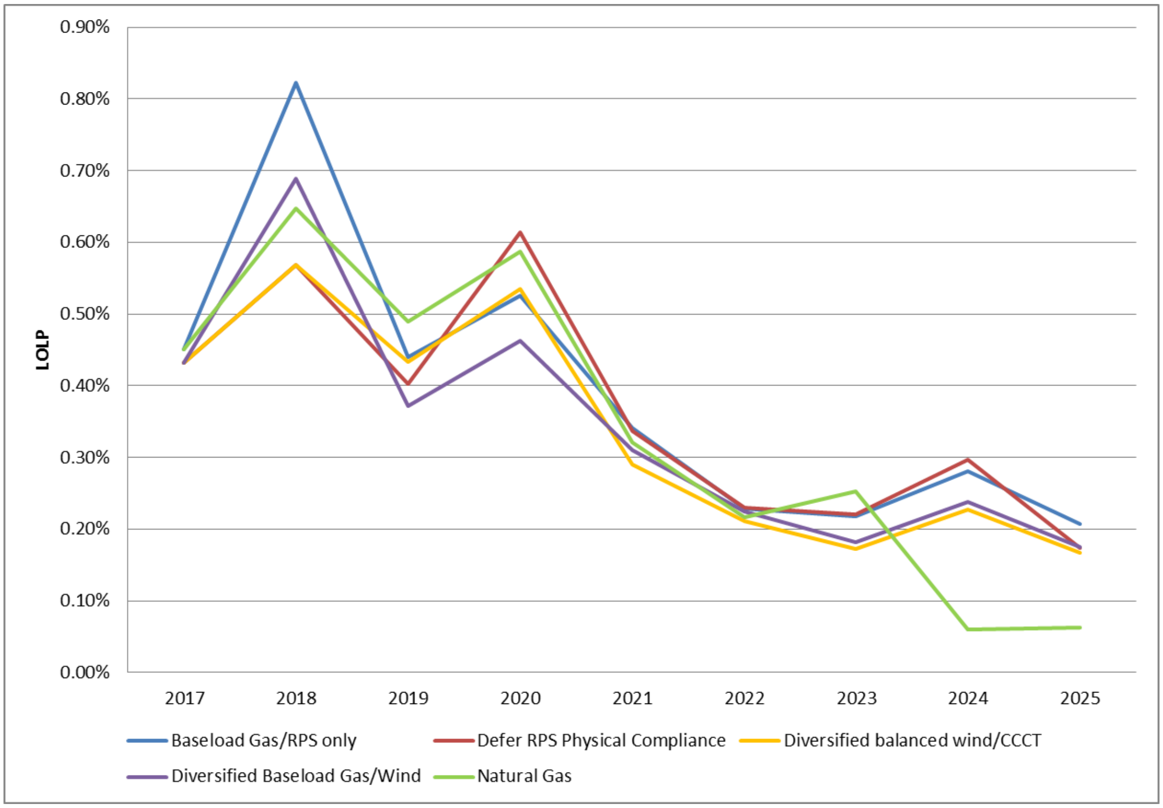


Figure 10-8, Figure 10-9, and Figure 10-10 support the conclusion that all five of our top portfolios perform similarly under our LOLP metrics.

EUE Results

Figure 10-11 shows that seasonally differentiated EUE (in MWa) results (2017-2025) are very similar for all five top portfolios. Summer EUE is lower than for the rest of the year because lower summer loads outweigh lack of access to market power.

Figure 10-11: Unserved energy for top candidate portfolios 2017-2025

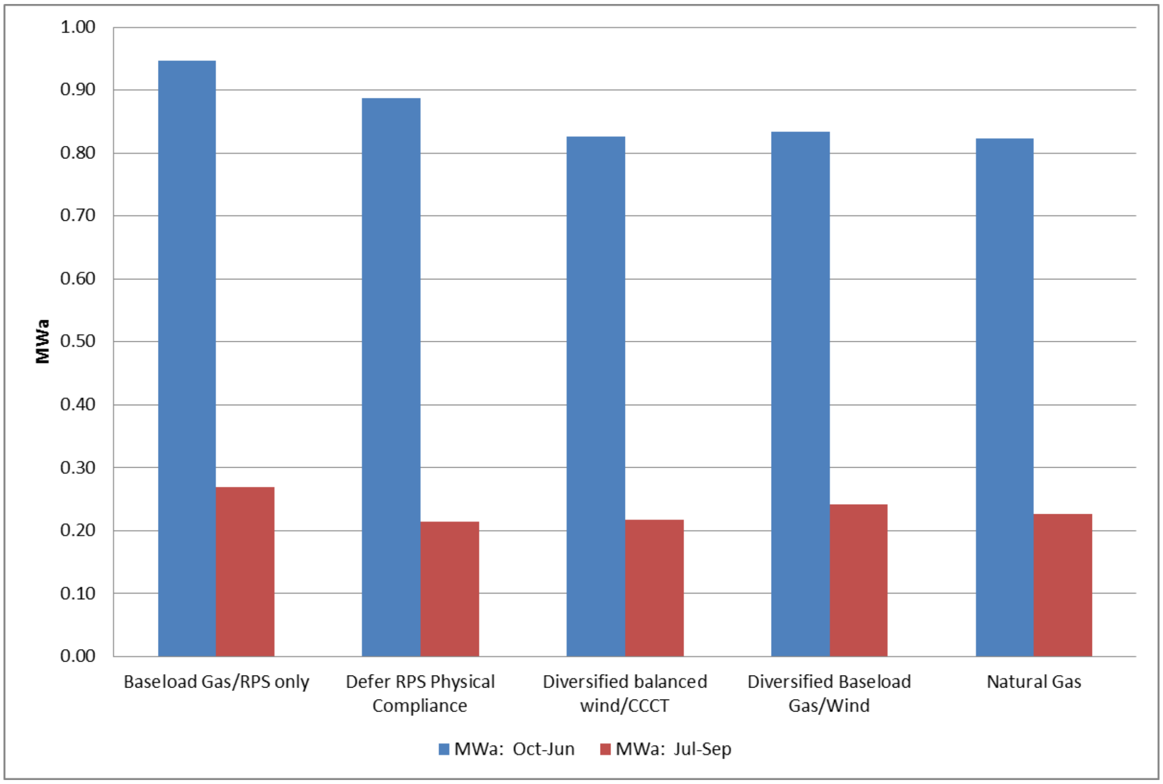


Figure 10-12 shows EUE by year. All portfolios are impacted in much the same way by the timing and "lumpiness" of resource additions, as with the similar graph on an LOLP basis above. After 2020, all portfolios perform relatively well, with yearly EUE of less than one MWa. For context, expected load in these years is more than 2,500 MWa.

Figure 10-12: Unserved energy for top candidate portfolios by year

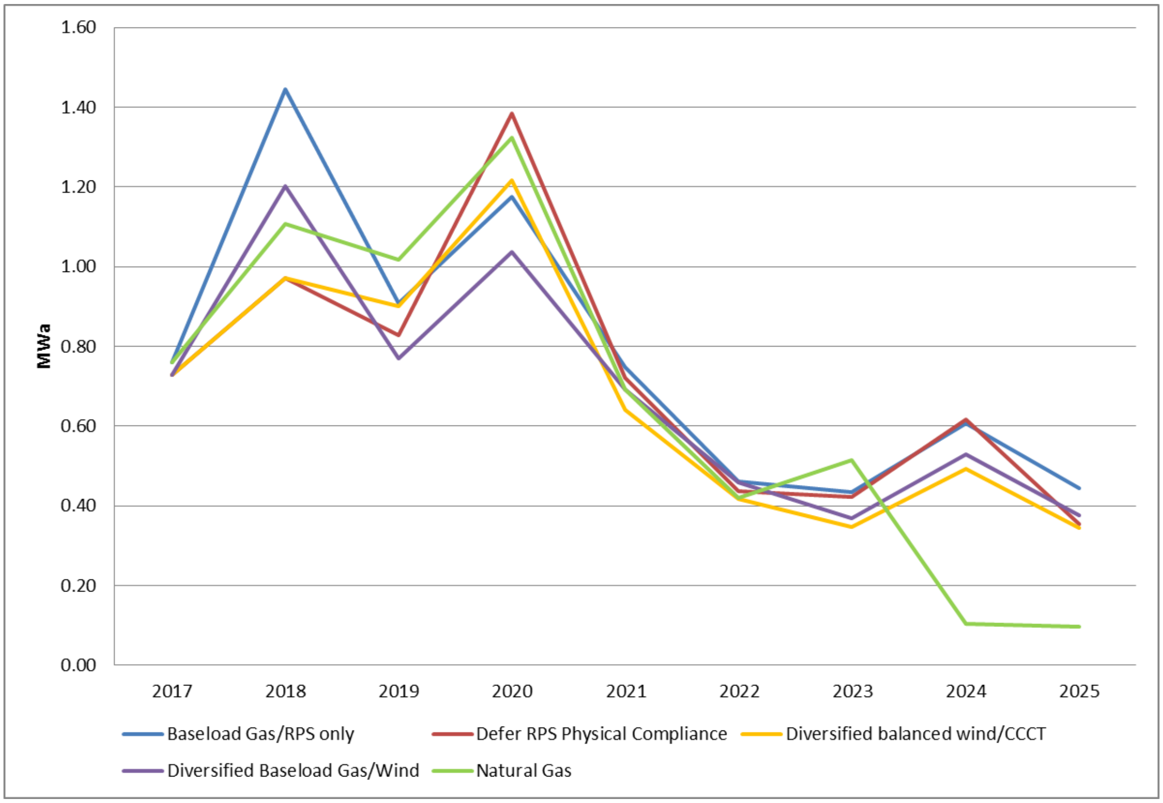


Figure 10-11 and Figure 10-12 show that all five of our top portfolios perform similarly on the basis of EUE.

TailVar EUE Results

Figure 10-13 shows that our TailVar EUE results are very similar across the top five portfolios, varying somewhat by season. Here, we see that despite a low probability of occurrence, in the worst 10% of LOLH cases, a substantial inability to meet load with available resources can occur.

Figure 10-13: TailVar90 for top candidate portfolios 2017-2025

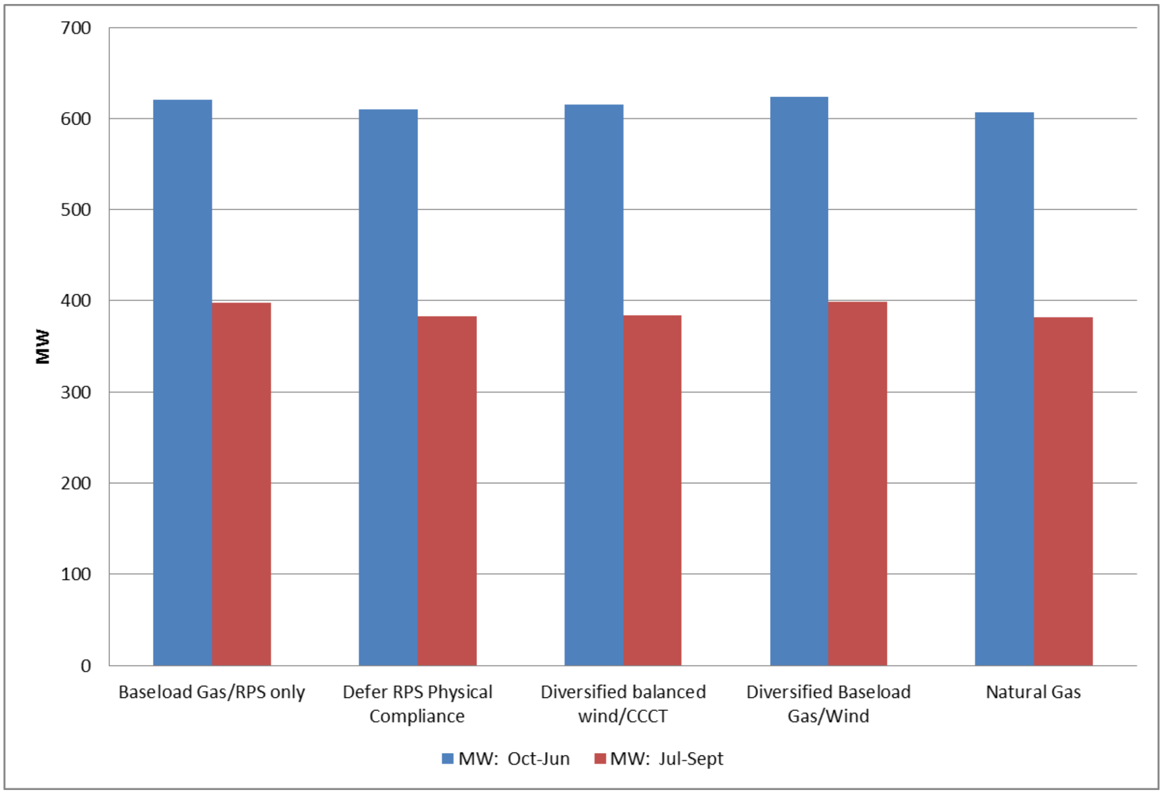
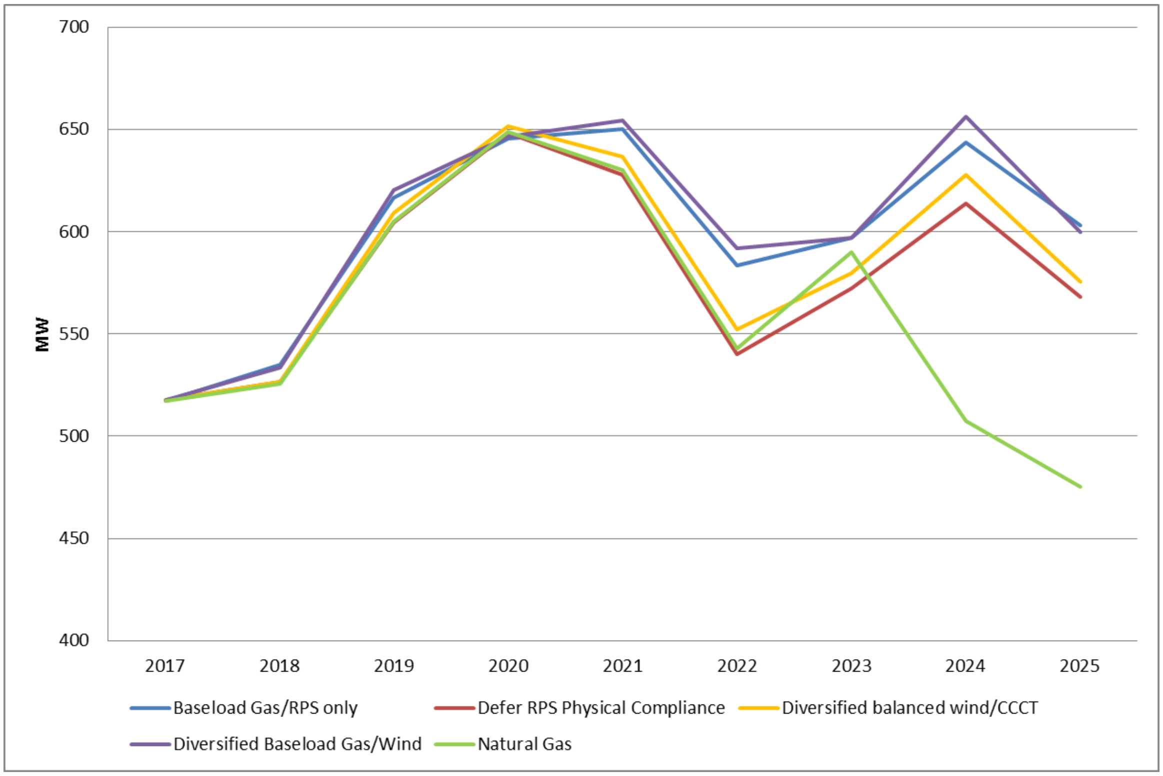


Figure 10-14 shows our TailVar EUE results by year. Results are similar across our top five portfolios, with the Natural Gas portfolio outperforming the others at the end of the analysis period because it adds more base load energy in 2024 compared to the other portfolios.

Figure 10-14: TailVar90 for top candidate portfolios by year



Summary Reliability Results

As expected, the Market portfolio is significantly more risky with regard to supply reliability than any of our candidate portfolios. All five of the top portfolios (Diversified Baseload Gas/Wind, Natural Gas, Baseload Gas/RPS only, Diversified Balanced Wind/CCCT, and Defer RPS Physical Compliance) perform similarly as measured by the LOLP and EUE metrics. The top five portfolios also perform similarly under the TailVar EUE metric. Therefore, when accounting for one portfolio being longer at the end of the period than the others, it is not possible to say that our stochastic reliability analysis materially favors any one of the top five portfolios.

10.3 CO_2 Analysis

Oregon IRP Guidelines require utilities to examine several carbon compliance scenarios in order to estimate the potential impact of carbon costs on candidate portfolios and potential resource selections (Guideline 8, Order No. 08-339). To comply with this guideline, PGE performed the following analysis:

1. Identified the most likely regulatory compliance future for CO_2. This is described in detail in Chapter 7 - Environmental Considerations.

2. Developed additional compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. This is also described in detail in Chapter 7 - Environmental Considerations.

3. Tested alternative portfolios against the compliance futures. Note that these compliance futures are a subset of the futures we tested in the broader portfolio analysis.

4. Identified the CO_2 "trigger point," which would trigger selection of a portfolio of resources substantially different from the preferred portfolio.

5. Identified an Oregon Compliance Portfolio consistent with Oregon's greenhouse gas reduction goals (Oregon House Bill 3543).

As a modeling simplification, we represent carbon regulation as a tax on CO_2 emissions from electric generating units (modeled as an adder to the dispatch cost) and on net market purchases. Emissions are computed using the following factors:

- Coal fuelled plants: 205 lbs./MMBtu.
- Natural gas fuelled plants: 119 lbs./MMBtu.
- Biomass, geothermal, wind, and solar energy resources: no net carbon emission.
- Long-term (LT) contracts: no carbon emission for specified hydro contracts (i.e. Mid-C contracts) and LT-wind contracts. Market purchase emissions were applied to all other non-specified source contracts (see below).
- Net market purchases: we assume approximately the emissions of a CCCT with a 7,500 BTU/kWh heat rate, representative of F technology units (119 lbs./MMBtu). This results in 900 lbs./MWh (0.45 short tons/MWh), which is consistent with the Oregon Department of Energy (ODOE) current statewide assumption.

Greenhouse gas limitations or reductions can be achieved using several alternative policy and regulatory measures. Examples include: taxation, hard cap on emissions, cap & trade system, and a ban on certain technologies. Regardless of the actual regulatory instrument, modeling a tax on CO_2 emissions is a simplified and widely used way of quantifying the potential cost associated with CO_2.

We analyzed the impact of potential CO_2 regulatory costs from zero to $150 per short ton (in 2023$) on each of our portfolios and also simulated scenarios with an earlier beginning carbon tax date. Recapping from Chapter 7 - Environmental Considerations:

1. Our reference case uses Wood Mackenzie's estimate for future federal carbon control policy implementation. It assumes a CO_2 price of $16 per short ton starting in 2023, escalating at 8% a year thereafter. By 2050 this trajectory would lead to a tax of $132 per short ton (in nominal dollars).

2. The no carbon tax future assumes any federal tax. California cap and trade, as well as Alberta and British Columbia taxes, are, however, modeled in their respective jurisdictions.

3. The Synapse low CO_2 cost future assumes a tax of $17.48 per short ton starting in 2020, escalating at approximately 7% a year. By 2050 this trajectory would lead to a tax of $107 per short ton.

4. The Synapse high CO_2 cost future assumes a tax of $35 per short ton starting in 2020, escalating at approximately 10% a year. By 2050 this trajectory would lead to a tax of $247 per short ton.

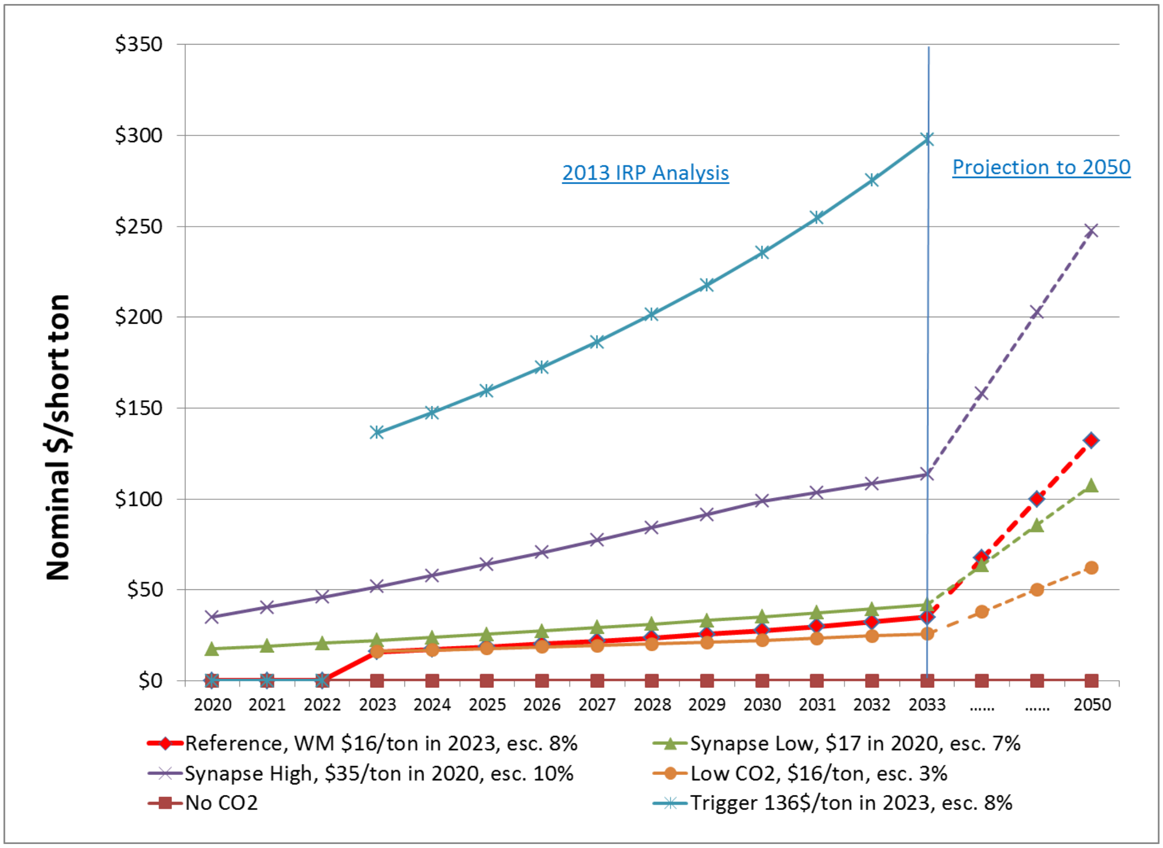
5. The low CO_2 cost future assumes a tax of $16 per short ton starting in 2023, escalating at 5% a year on average after that. By 2050 this trajectory would lead to a tax of $62 per short ton.

6. The trigger point CO_2 cost future assumes a tax of $136 per short ton starting in 2023, escalating at approximately 8% a year (or $150 per short ton real levelized from 2023 to 2033 in 2013$).

Figure 10-15 below shows the annual detail by future from 2020 through 2033, the final year of analysis for this IRP. The figure also includes a trend line by future, which projects CO_2 prices to 2050, a year often quoted as a target year for global carbon emissions reduction targets.[83]

[83] The Oregon Department of Energy has observed in its 08/30/2013 recommendation to PGE that this "is what is required under the U.S. treaty agreement from Cancun as interpreted by the OECD, a research arm of all major developed countries."

Figure 10-15: CO_2 futures



As mentioned above, in each future simulated, the tax shown above is added to the dispatch cost of fossil fuel-fired power plants according to their emission factors. Resources are then dispatched in AURORAxmp from 2014 to 2033 to assess impacts on unit dispatch of thermal plants.

Impact of CO_2 Compliance Scenarios on Portfolio Performance

All of PGE's candidate portfolios share existing resources and similar minimum RPS targets along with new natural gas-fired generation. Therefore, the imposition of CO_2 prices has similar effects across portfolios. Table 10-1 below shows the relative performance of different portfolios under various CO_2 prices. We assess the NPVRR in 2013$ of each portfolio under different CO_2 price levels and the results show, as expected, that low carbon portfolios hedge better against high carbon cost futures. However, the CO_2 cost reduction benefit of the "renewables heavy" portfolios is generally not sufficient to outweigh the relatively high expected cost of those portfolios as compared to other portfolios that mix renewables with base load gas units. More precisely:

- The Market portfolio is always the least cost. In this analysis, the Market portfolio appears to perform well due to its low overall expected cost, which is, however, achieved by allowing an unacceptable level of reliability risk (as demonstrated earlier in this chapter).

- Portfolios that procure renewables to meet RPS and substitute high- efficiency CCCTs for gas peakers to meet residual energy and capacity need (Natural Gas, Baseload Gas/RPS only and Diversified Baseload Gas/Wind) perform better in all CO_2 futures except the trigger point future,
- Portfolios which meet most of the annual energy requirement with renewable resources, and add gas peakers for capacity need, perform best only in the highest CO_2 future: $136 per short ton starting in 2023.

Table 10-1: Candidate portfolio cost in different CO_2 compliance scenarios

	Portfolios	No Carbon Tax	rank	Low CO_2, $16/ton, esc. 3%	rank	Reference, WM $16/ton in 2023, esc. 8%	rank	Synapse Low, $17 in 2020, esc. 7%	rank	Synapse High, $35/ton in 2020, esc. 10%	rank	Trigger 136$/ton in 2023, esc. 8%	rank
1	Market	$15,369	1	$16,115	1	$16,243	1	$16,812	1	$18,927	1	$22,059	1
2	Natural Gas	$16,984	3	$17,717	3	$17,840	3	$18,388	4	$20,326	4	$23,125	9
3	Wind	$18,369	11	$18,908	10	$18,999	10	$19,453	10	$20,879	10	$22,649	3
4	Diversified Green	$18,352	10	$18,950	11	$19,053	11	$19,517	11	$21,097	11	$23,260	12
5	Diversified Green/EE	$18,646	14	$19,218	14	$19,315	14	$19,766	14	$21,268	13	$23,274	13
6	Green w/EE and CCCT	$18,298	9	$18,864	9	$18,959	9	$19,400	9	$20,850	9	$22,792	5
7	Baseload Gas/RPS only	$16,541	2	$17,274	2	$17,397	2	$17,942	2	$19,881	2	$22,722	4
8	Diversified Green with wind MT	$18,592	12	$19,186	13	$19,286	13	$19,752	13	$21,318	14	$23,438	16
9	Diversified balanced wind/CCCT	$17,424	6	$18,093	6	$18,206	6	$18,723	6	$20,506	6	$23,001	8
10	Diversified Solar/Wind	$18,603	13	$19,184	12	$19,283	12	$19,739	12	$21,259	12	$23,292	14
11	Diversified Green with non-CE EE only	$18,810	15	$19,376	15	$19,472	15	$19,920	15	$21,402	15	$23,369	15
12	Oregon CO2 Goal	$20,012	17	$20,370	17	$20,430	17	$20,699	16	$21,634	16	$23,169	10
13	Baseload Renewables	$19,630	16	$20,248	16	$20,354	16	$20,833	17	$22,491	17	$24,783	18
14	High Solar	$20,022	18	$20,612	18	$20,711	18	$21,173	18	$22,699	18	$24,713	17
15	Defer RPS Physical Compliance	$17,195	5	$17,905	5	$18,024	5	$18,573	5	$20,485	5	$23,195	11
16	Diversified Baseload Gas/Wind	$17,091	4	$17,754	4	$17,865	4	$18,371	3	$20,102	3	$22,532	2
17	Wind Energy Only	$17,914	7	$18,513	7	$18,616	7	$19,082	7	$20,665	7	$22,831	6
18	Wind Energy w/ EE	$18,142	8	$18,726	8	$18,826	8	$19,287	8	$20,829	8	$22,900	7

The three portfolios that perform best, on average, across the CO_2 futures are Baseload Gas/RPS only, Natural Gas, and Diversified Baseload Gas/Wind (excluding the Market portfolio due to its unacceptable reliability risk performance).

Trigger Point Analysis

We performed this analysis by identifying at what CO_2 price level the cost of a substantially different alternative portfolio (i.e., one that achieves substantially lower CO_2 emissions) reaches parity with the cost of our preferred portfolio. We compared the two portfolios:

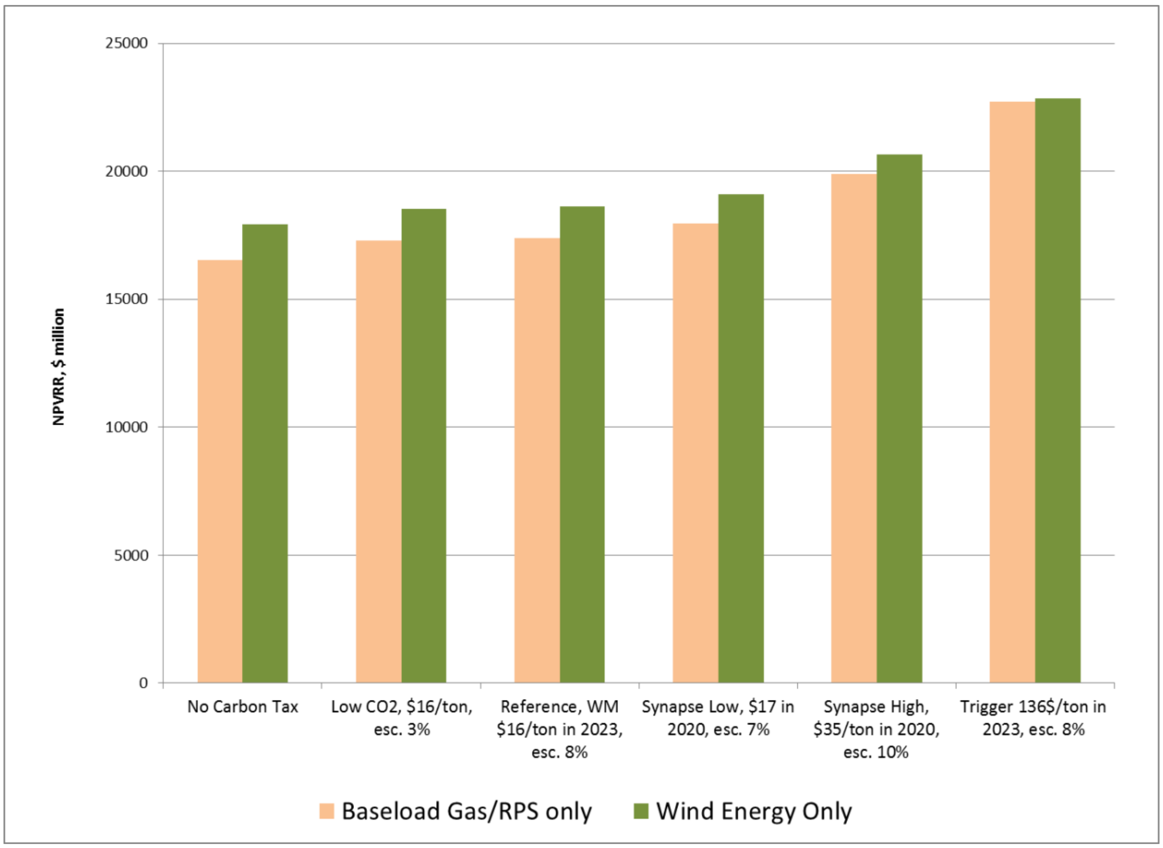
- Baseload Gas/RPS only, which procures enough renewables to meet RPS targets, and then fills the remaining energy need with base load gas. This portfolio simulates a diversified wind/gas strategy and is our least cost candidate portfolio under reference case assumptions;

- Wind Energy Only, which is the least cost of the candidate portfolios that add only EE and renewables (wind) to meet base load energy needs. Gas peakers are only added for capacity in this portfolio.

We then identified the CO_2 price future in which the Wind Energy Only portfolio is preferable to a diversified gas/wind strategy. By testing successively higher CO_2 taxes, we found that the trigger point CO_2 price is approximately $136 per short ton starting in 2023, escalating at 8% thereafter. (For comparability, we used the same start year and inflation rate as the Reference Case carbon cost we're comparing to.)

Figure 10-16 below shows the level of CO_2 price at which the preferred portfolio is replaced with the alternative portfolio, as the least-cost strategy.

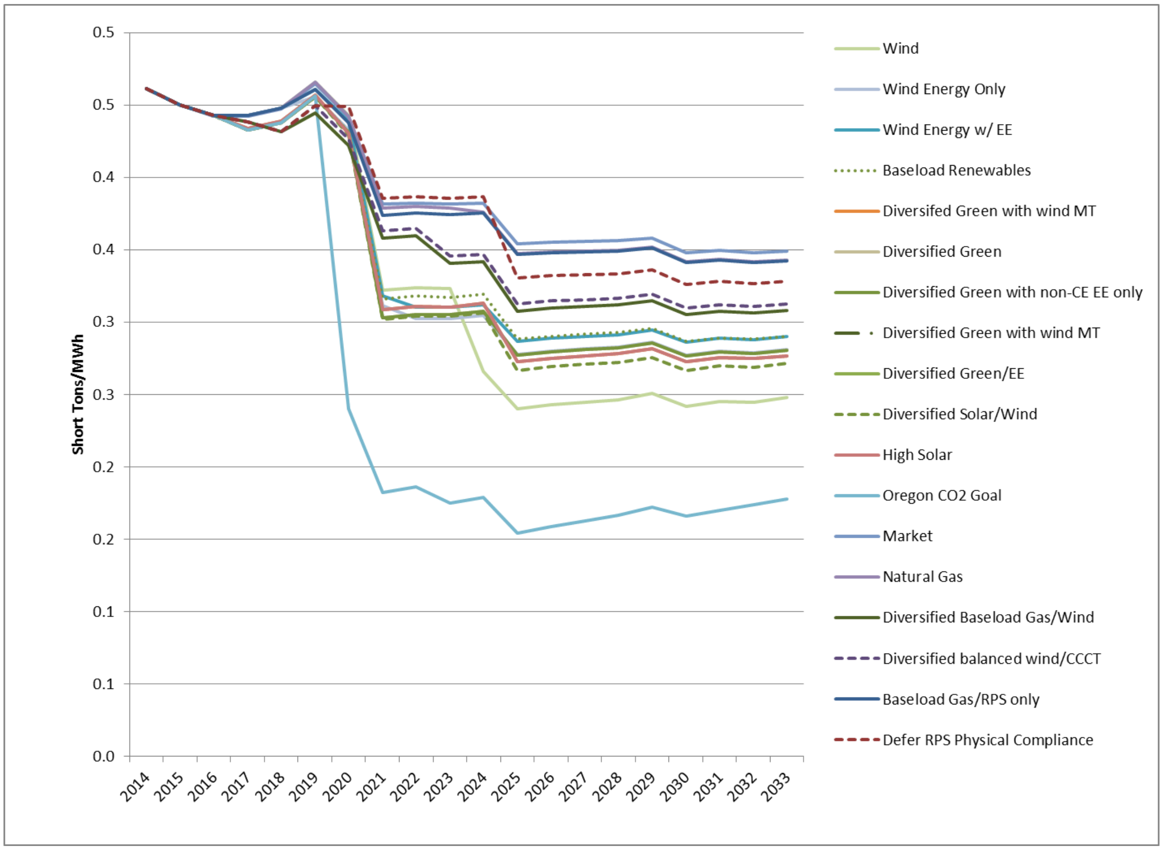
Figure 10-16: Trigger point analysis



Oregon Compliance Portfolio

All portfolios in this IRP show a marked reduction in CO_2 intensity (emission per MWh served) over time; see Figure 10-17. This is due to the relatively low emissions levels of resources considered: high-efficiency gas plants, renewables, and energy efficiency, the lowest carbon emission resources currently available in the market.[84]

Figure 10-17: CO_2 intensity by candidate portfolio



Total CO_2 emissions, in total short tons, also decline (see Figure 10-18) first in 2020-2021, when we meet a 20% RPS requirement and cease coal-fired operations at our Boardman plant. Then in 2025 we add renewables to meet the 25% RPS target. Because PGE has not modeled plant additions after 2025, additional resource need is met with market purchases beyond 2025, which adds to the modeled CO_2 results for all portfolios. Actual post-2025 procurement will be addressed in future IRPs.

The higher emitting portfolios are those that rely more on natural gas and market purchases, and add renewables only to the minimum RPS level. They have emissions of approximately 8 million short tons in 2025. The portfolios that exceed the minimum RPS level and pursue an all-green strategy to meet our annual energy needs (the diversified green portfolios) have emissions levels that are similar to one another (approximately 6.5 million short tons in 2025).

[84] Nuclear plants would be a zero emission resource but they are not an option for Oregon until completion of a Federal nuclear waste repository in the USA. Nor do any new nuclear plants have traction currently in an adjacent state. Therefore, we do not simulate nuclear energy additions in any of our portfolios in this IRP.

Oregon IRP Guidelines require us to design a portfolio that meets the Oregon CO_2 goal of 1990 emissions less 10%. The Oregon CO_2 goal portfolio is designed to meet the Oregon goal.

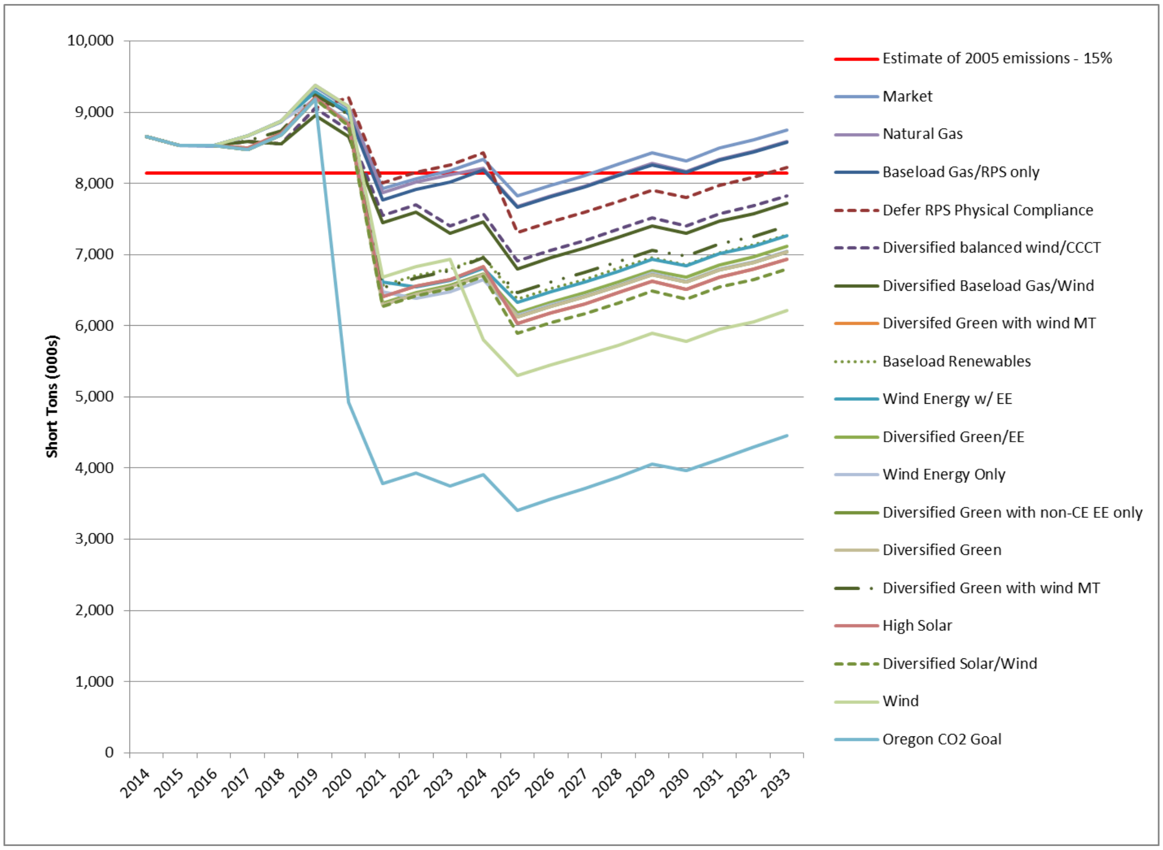
An alternative aspirational goal often quoted in State and regional carbon policy discussions is to instead reduce CO_2 to the level of 2005 emissions less 15%. To capture the full spectrum of possible future CO_2 targets, we tested the following:

1. A reduction of CO_2 emissions by 2020 to a level 10% below that of 1990. Specifically, by 2020, PGE emissions would be:
    a. Approximately 4.5 million short tons, if PGE reduced emissions to those estimated for 1990 based on the resource mix PGE had at the time.
    b. Approximately 6.2 million short tons, if we normalize the 1990 emissions by adjusting for the subsequent closure of Trojan and imputing average Northwest market-mix emissions for Trojan's output.

2. A reduction of CO_2 emissions by 2020 to a level 15% below that of 2005, or 8.2 million short tons.

The 1990 target without normalization – emissions at 4.5 million short tons – is extremely challenging to achieve without significant replacement cost and supply risk. In 1990, PGE relied extensively on both nuclear and hydro resources, both of which have no associated carbon emissions. Since that time, we have closed Trojan, our nuclear plant, and we have steadily been losing access to legacy hydro contracts (via expiration). In 1990, nuclear and hydro resources covered approximately 1,200 MWa, or 62%, of PGE customer's energy requirements. In 2012, remaining hydro resources covered only approximately 500 MWa, or 22% of our energy needs. We have replaced zero emission nuclear and hydro power in substantial part with gas plants and power purchased in the wholesale market, both of which have associated greenhouse gas emissions. The only portfolio that meets the 1990 minus 10% target by 2020 is the Oregon CO_2 Goal, which achieves this by replacing our 20% share of the Colstrip coal plant with a natural gas-fueled combined cycle turbine and a mix of wind and energy efficiency. This is the most expensive candidate portfolio that we evaluated in this IRP.

Figure 10-18: Reference Case CO_2 emissions in total short tons by candidate portfolio



The 1990 normalized goal is more achievable, but still at a higher cost than other portfolios, using an aggressive green strategy accompanied by strong energy efficiency policies. All of the diverse green portfolios do meet this target by 2025, when we achieve the final RPS target.

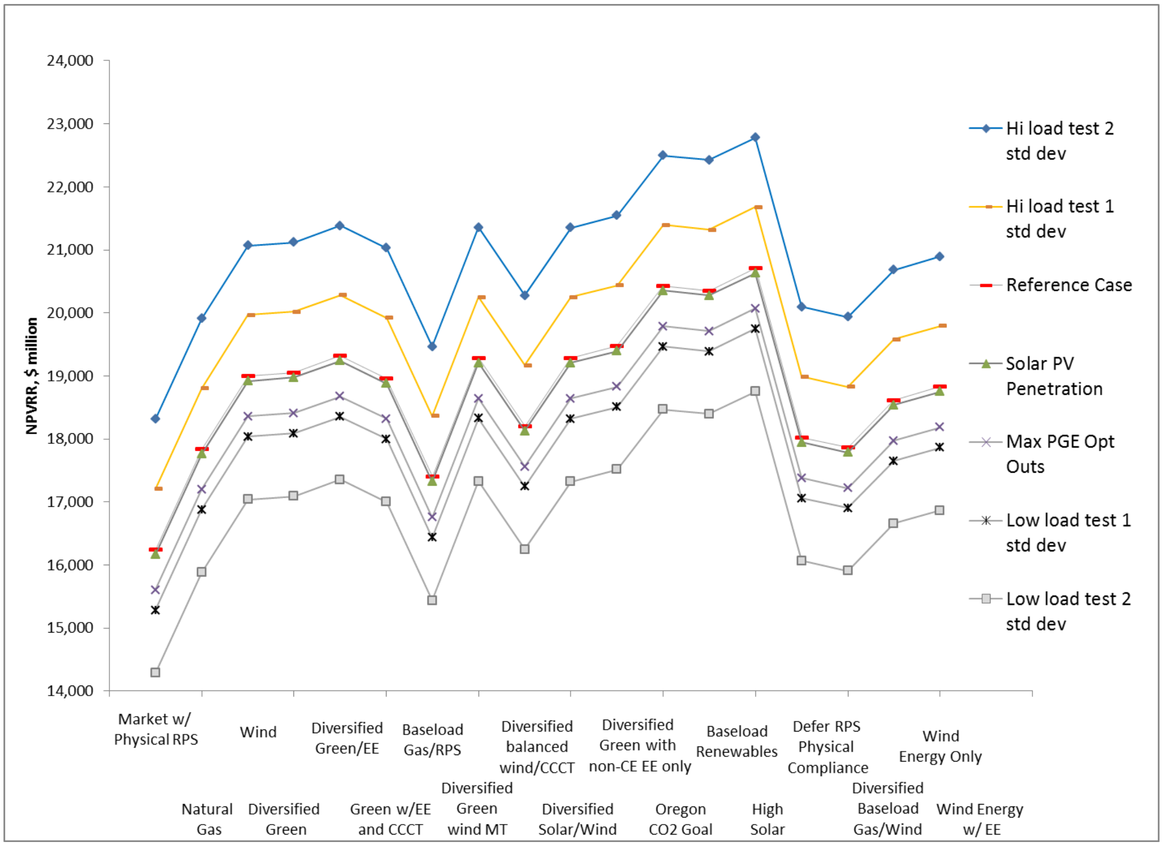
The CO_2 target that is achievable at a more reasonable cost and replacement supply impact is the 2005 less 15% goal. Portfolios which pursue a diversified gas and renewable strategy all have overall emissions in the 8 million short ton range. Each of these portfolios meet the 2005 minus 15% CO_2 target by 2020.

10.4 Load Growth Analysis

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 or uncertain changes in electric end uses, such as widespread adoption of PHEVs or solar PV.

Figure 10-19 shows portfolio performance under multiple PGE load growth futures, and shows that 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 reduce market purchases by the same amount. That is, all boats rise with the tide, or fall with the tide. The resulting risk is being long for a period of time with commitments to longer-term resources when loads do not meet expectations, or conversely, of being supply deficient if load growth exceeds expectations.

Figure 10-19: Candidate portfolio performance by load future



11. Transmission

PGE's service territory is a relatively compact area located primarily in the Willamette Valley and occupying a small geographic portion of the Pacific Northwest. At the same time most of our existing resources and market purchases are outside of our service territory, but within the Pacific Northwest region. As such, we depend heavily on Bonneville Power Administration (BPA) to provide transmission service to deliver power from these resources to our customers. These resources include:

- Hydroelectric resources in central Washington, central Oregon, and east of Portland;
- Renewable (predominantly wind) resources east of the Cascades;
- Thermal resources in eastern Oregon and Montana; and,
- Thermal generation between Portland and the Puget Sound area.

Currently, PGE is developing additional wind resources in eastern Washington, and thermal resources in northwest and eastern Oregon as the result of our recent competitive bidding processes for renewable, and energy and capacity resources. We anticipate that the majority of our options for future supply-side resources, including additional renewable resources to meet future Renewable Portfolio Standard (RPS) requirements, will require transmission either from the BPA system and/or our own transmission assets.

In this chapter, we examine our current transmission portfolio and expected future requirements. We also assess the implications of transmission constraints on system reliability, our ability to meet the state RPS and our ability to meet our customers' ongoing power needs. Additionally, we describe our continued efforts to work cooperatively with our regional counterparts to coordinate regional transmission plans.

Chapter Highlights

- PGE is heavily reliant on BPA transmission to deliver power to our customers.
- Renewable and non-renewable resources needed to meet RPS and energy demand requirements may need new transmission in order to deliver the power to our customers.
- We describe the evolution of our collaborative work with BPA and the decision we made to terminate our proposed Cascade Crossing Transmission Project.

1.1 Transmission Assessment

PGE's Transmission Resources

As mentioned above, power from our out-of-area resources is delivered to us primarily through the use of BPA transmission service. We presently contract for 3,393 MW of transmission capacity from BPA under Point-to-Point (PTP) contracts. These PTP contracts are used to deliver our thermal generation, remote hydro resources, wind resources and market purchases to load. All totaled, BPA currently delivers two-thirds of the power we obtain from our existing resources. This is down from three-fourths, which was the case prior to the integration of Port Westward into our transmission system.

Figure 11-1 shows our overall transmission holdings and use. The dashed green lines represent PGE internal generation for which BPA transmission to our service territory is not required. The solid purple lines represent transmission rights acquired from BPA, mapped to our external generation and market purchases and delivered to PGE load. The solid red lines represent our BPA transmission rights that deliver power to the intertie. The blue line shows our BPA transmission rights used for station service to the Biglow Canyon wind project. The ovals show our generation resource capability, while rectangles show long-term contract resources. The tan bars represent cutplanes, or bottlenecks, on the BPA transmission system.[85] The values represent our transmission position relative to generation for each location. In general, PGE's transmission rights and generation are balanced. However, PGE's transmission rights from Mid-Columbia (Mid-C) are in excess of our generation from Mid-C to allow us to access the market for balancing load and meeting peak demand.

As discussed in Chapter 2 - PGE Resources, Section 2.3, under the terms of a 1985 Sale & Lease Back Agreement, Bank of America Leasing (BAL) returned their 15% share of the Boardman plant to PGE (effective midnight, December 31, 2013). PGE plans to utilize 100 MWs of BPA PTSA transmission rights, which are currently being deferred on an annual basis, to deliver the newly acquired output from Boardman to PGE's load. On the next deferral date, November 2014, PGE plans to begin taking Conditional Firm (CF) transmission service under the PTSA rather than defer service. The CF transmission service will become Firm transmission service once the Big Eddy-Knight Transmission Project is completed. Prior to November 2014, PGE plans to redirect transmission service from Mid-C to Boardman in order to deliver the power to PGE load.

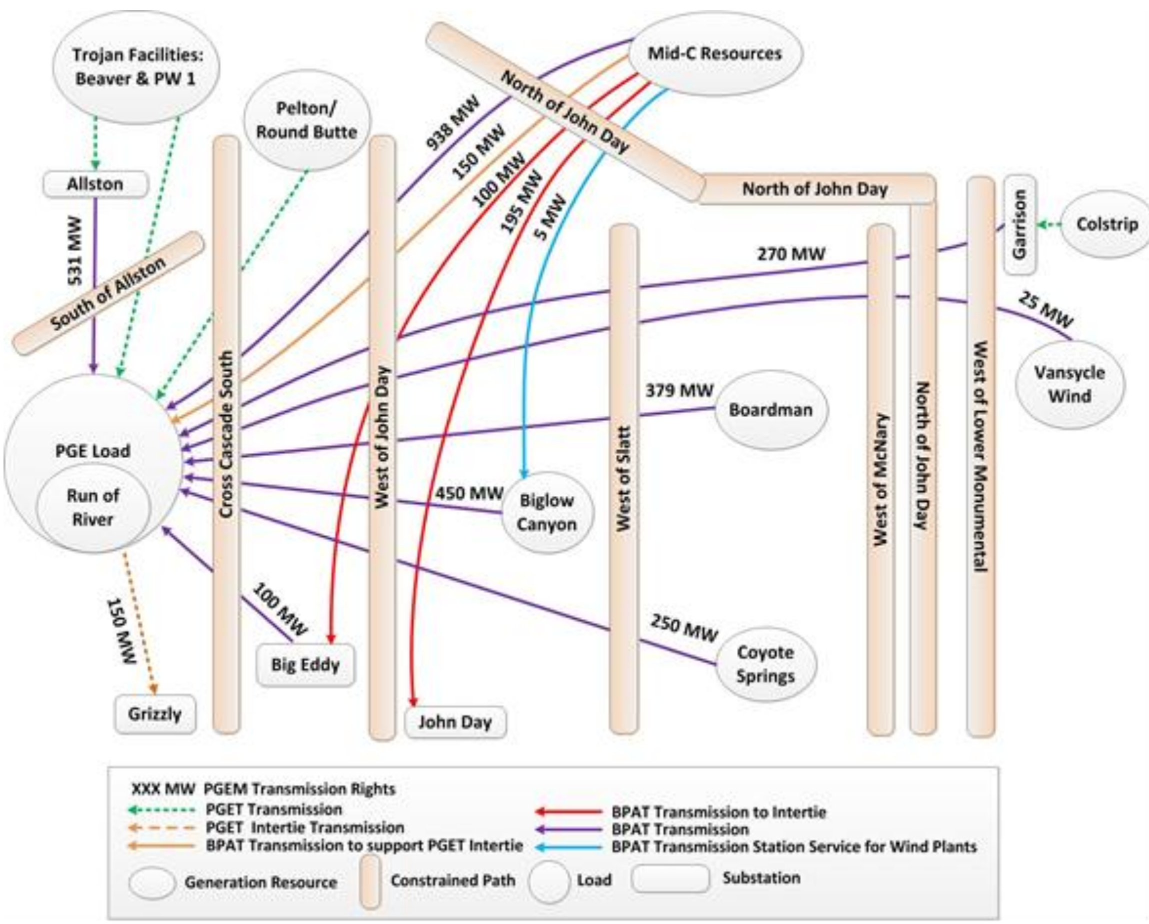
In addition to the 15% share of the Boardman plant acquired from BAL, PGE also acquired BAL's 10.714% of PGE's share of the California-Oregon Intertie (COI). On October 24, 2013, PGE posted a notice on OASIS announcing that it planned to hold an open season for 102 MW of transmission service in the north to south direction. An open season was the most fair and transparent way to allocate this newly acquired capacity. Bids for the transmission capacity were due by December 8, 2013. All capacity awarded through the Open Season was conditioned on the FERC's approval of PGE's acquisition

[85] A cutplane is an imaginary line that is used on a transmission map to identify which transmission lines make up a transmission path. Cutplanes are used to monitor power flows on key portions of the transmission system.

of the capacity (Docket No. EC14-13-000), and upon a successful closing of the commercial transaction.

On December 19, 2013, the FERC authorized the commercial transaction that returned the transmission capacity to PGE, and the commercial transaction closed shortly before midnight on December 31, 2013. PGE engaged an independent accounting firm to allocate the 102 MW of transmission rights among ten successful bidders, with eight bidders receiving 10 MW and two bidders receiving 11 MW. PGE's merchant function received 10 MW of transmission rights under the independent accounting firm's random selection process. The entire list of successful bidders is posted on PGE's OASIS site (http://www.oatioasis.com/pge/index.html).

Figure 11-1: PGE's current transmission resources and use

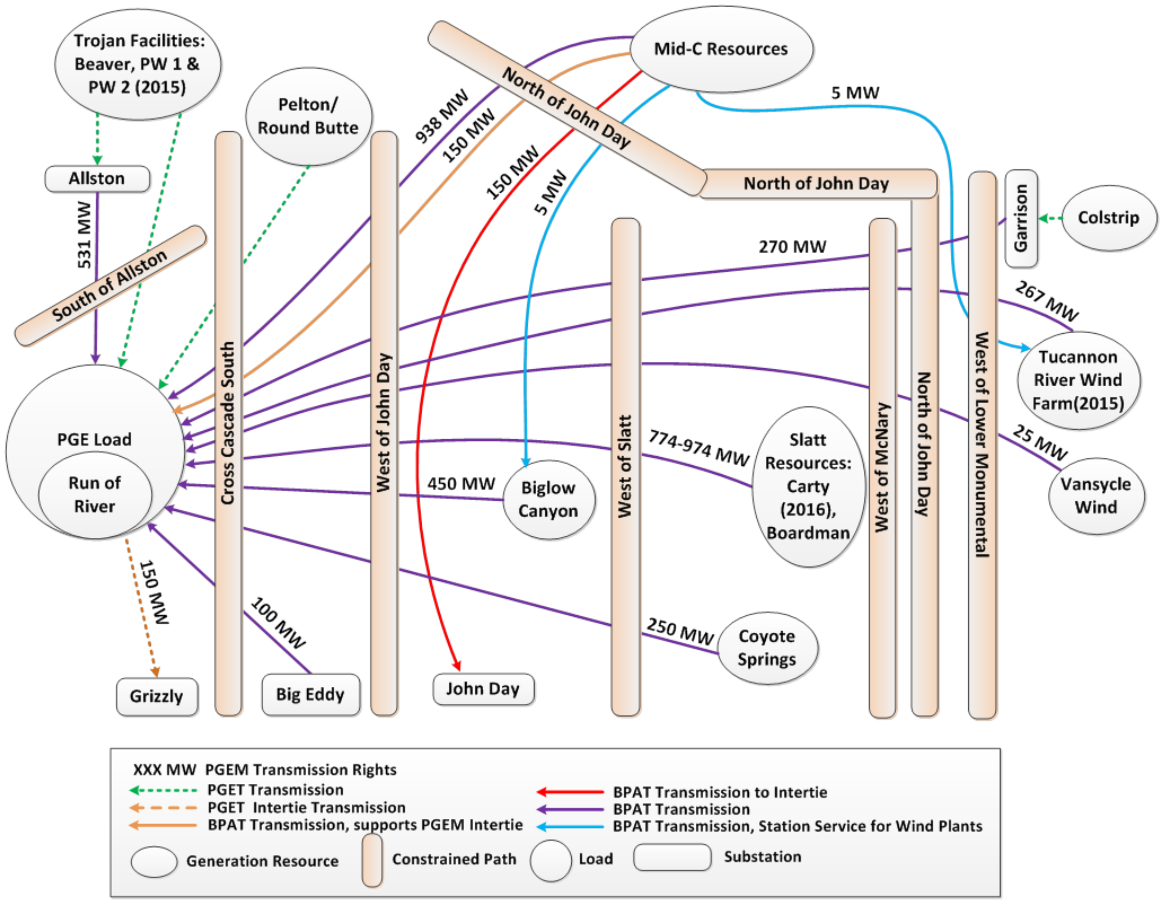


PGE's Transmission Resources Needed for New Generating Resources

As mentioned in Chapter 2 - PGE Resources, through our recent RFP processes, PGE is developing a new capacity resource (Port Westward 2 or PW 2), a new energy resource (Carty), and a new renewable resource (Tucannon River wind farm). To enable the delivery of energy from these new plants we have secured long-term transmission service from BPA by Precedent Transmission Service Agreement (PTSA) contracts acquired from third-parties for both Carty and Tucannon River. We will utilize PGE's existing transmission rights for PW 2.

In Figure 11-2, we show our existing and developing generating resources and transmission rights needed to meet our future load requirements for 2016.

Figure 11-2: PGE's transmission resources and use with new resources and transmission

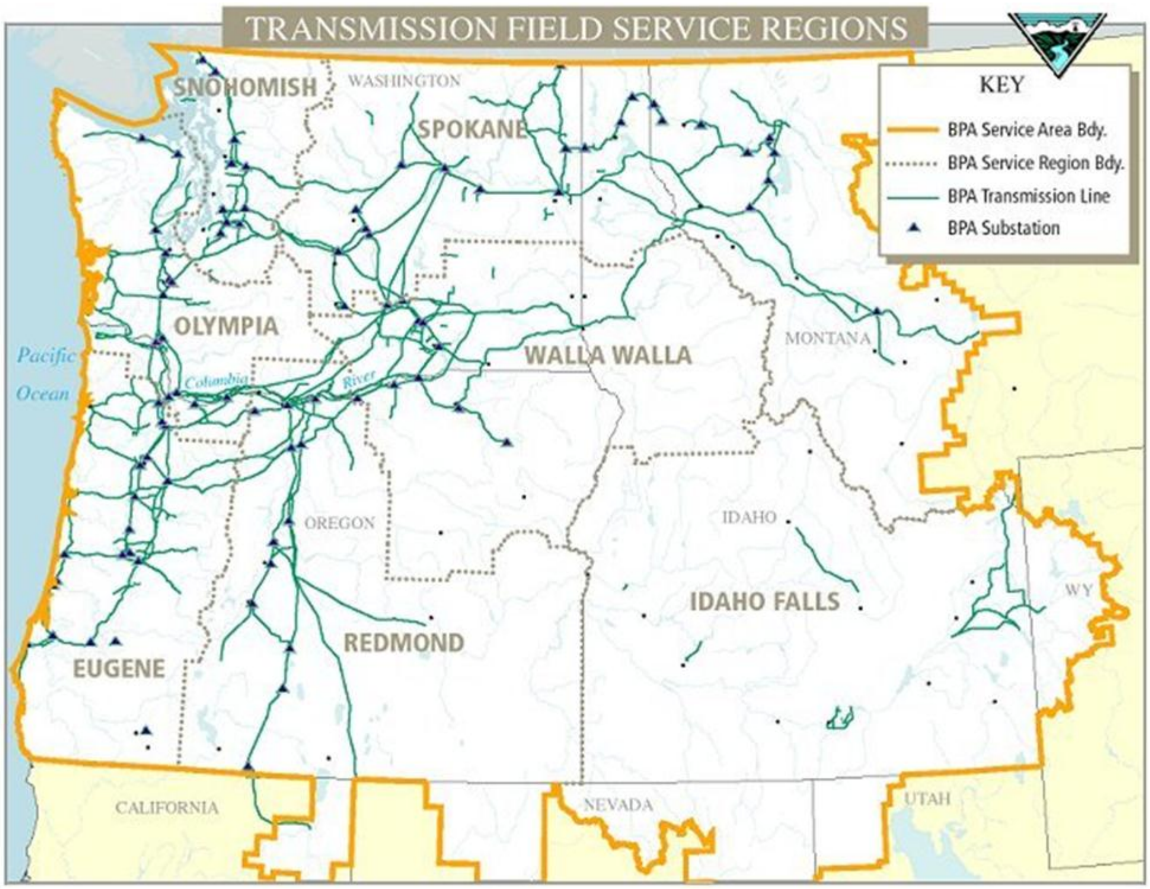


In Figure 11-2 above, the PTP transmission from BPA is 4,115 MW. This includes BPA transmission for Carty and Tucannon River. It should be noted that transmission capacity is procured to support the firm capacity of the resource that it integrates, and that the resource capacity shown in Figure 11-2 includes over 700 MW of wind resources. To ensure that we can deliver the full output of variable energy resources such as wind, we acquire firm transmission rights to match the nameplate rating of the generation. In other words, since wind facilities in the region typically have a capacity factor of approximately 33%, the amount of firm transmission capacity we reserve to deliver the power to load is approximately three times the average energy output of the wind facilities.

Regional Assessment

Since its creation in 1937, BPA has played a central role in managing the power and transmission facilities of the Federal Columbia River Power System in the Pacific Northwest. The BPA transmission system includes 15,000 miles of wires and 300 substations in eight states. BPA provides over three-fourths of the Northwest's high-voltage transmission as it moves power from 31 federal hydroelectric stations and one nuclear power station to Northwest customers. BPA's large interregional transmission lines connect power systems from as far away as Canada and the Southwest, and allow for the sale of surplus power outside the region and the movement of power within the region. The BPA Service Area Boundary is shown in Figure 11-3 below.

Figure 11-3: BPA service area



Increased stress on BPA's transmission system due to load growth and new, diverse generation resources has led BPA to change the way it manages the system and the transmission products it offers. BPA now uses flow-based techniques to assess the utilization of the transmission system. Usage of the system consumes available transfer capacity across constrained flow-gate areas (also known as cutplanes). BPA will limit, or curtail, the usage of the system to stay within the transfer limits of the cutplanes. BPA can dispatch federal and non-federal generation in its balancing authority area, without regard to merit order dispatch, as another method of staying within cutplane limits.

Further, BPA offers a conditional firm transmission product that allows the transmission provider to maximize usage of the system, recognizing that outside of peak seasons much of the transfer capacity goes unused. BPA's use of the conditional firm products can have the effect of making existing firm transmission rights less reliable and more likely to be curtailed over time. The overall impact of squeezing-out the remaining transmission capacity in the region's transmission system has been to produce a very complex constraint management system in order to ensure reliability.

Figure 11-4: Pacific Northwest transmission system

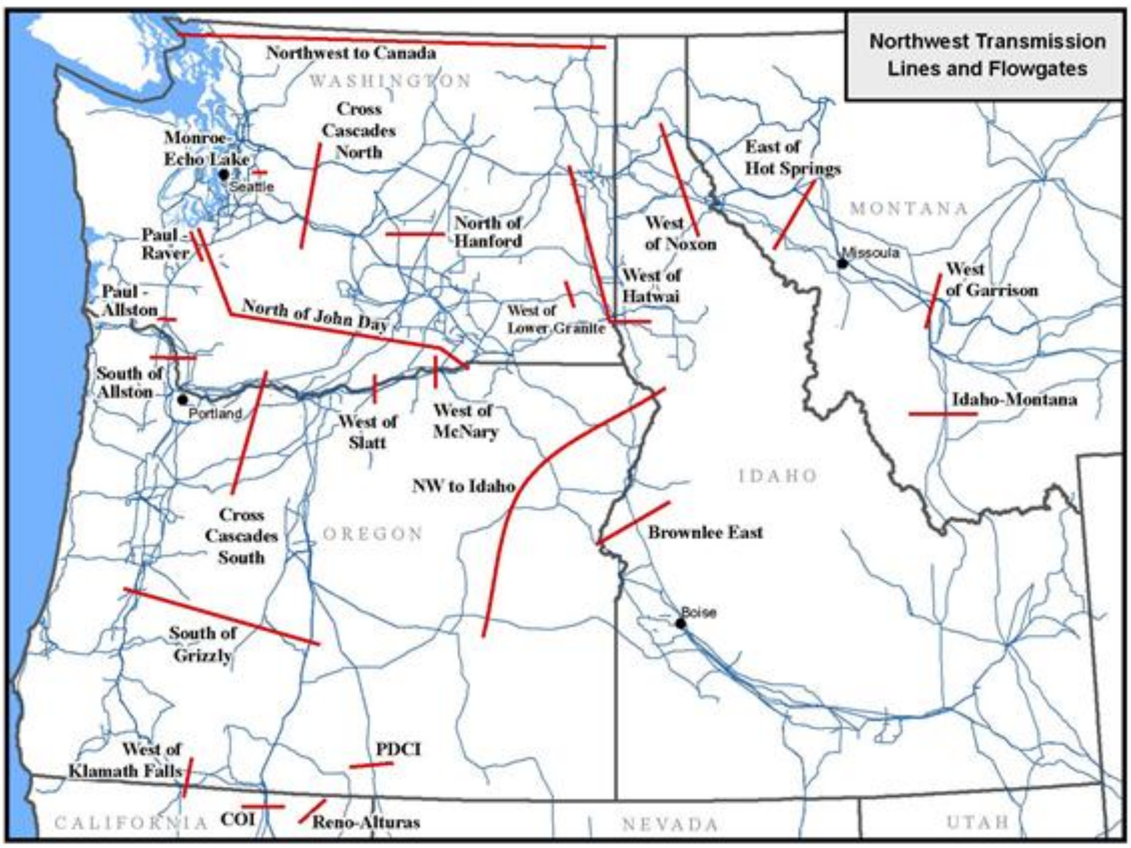


Figure 11-4 provides a graphical representation of the Pacific Northwest transmission system and the major cutplanes monitored by BPA. The blue lines drawn on the figure are the major transmission lines that serve the Pacific Northwest. The red lines show the major intra-regional cutplanes that BPA manages daily. These interties and cutplanes limit both intra- and inter-regional transfers. The South of Allston (SoA) cutplane, which has no available capacity, is the most critical cutplane for PGE. This constraint limits flows to Portland irrespective of where the source is located in BPA's system due to the flow-based nature of the interconnected power grid. For example, power scheduled from McNary to Portland will divide and flow across both the North and South Cross-Cascades cutplanes.

The highest stress on the system occurs during the summer and winter months. This is when congestion is greatest. During the summer, high levels of hydro generation in Canada and the Pacific Northwest are transmitted to California and the Desert Southwest, which creates high north-to-south flow conditions, causing high flows on the SoA path. These flows to California can be limited by the flow on the North of John Day and SoA cutplanes. The amount of generation online between the North of John Day and SoA cutplanes on the west side of the Cascades heavily impacts the flow that occurs across the SoA cutplane into the Portland area load center.

During the winter, high levels of hydro generation in the Pacific Northwest, combined with thermal resources located east of the Cascades, are transmitted to the west-side load centers in Washington and Oregon. This creates high east-to-west flow conditions across the Cascades. The ability to serve west-side load centers from east-side resources can be limited by the flows on the Cross-Cascades North and South cutplanes.

To eliminate these transfer constraints within the system, transmission upgrades are needed and some have been, or are being, undertaken. However, very few major transmission facility additions have occurred in the Pacific Northwest in the last two decades. In that same period regional loads have grown, generation facilities have been added, and ratings on transmission lines have been increased. For example, from 1989 to 2008 PGE's net system average energy increased by 32% and peak load increased 14.5%. In the last 20 years we have also added Coyote Springs, Port Westward, and Biglow I, II and III generating facilities, and are currently developing Carty, Port Westward II, and Tucannon River. Additionally, from 1992 to 2007 regional loads increased 29% (excluding Direct Service Industry load) requiring the construction of several thermal plants in the McNary area and, more recently, several thousand MW of wind facilities east of the Cascades. All of these changes have placed stress on the system as energy throughput has increased, resulting in the reduction in transmission system available capacity and increasing the number of events challenging system reliability.

Over the past several years, BPA has completed or initiated some upgrades to its transmission system to satisfy the requests in its transmission queue. These include the West of McNary upgrades, the nearly completed Big Eddy-Knight upgrades, and the planned Central Ferry-Lower Monumental transmission line. These additions provide BPA with necessary capacity to facilitate transfers across the West of McNary and West of Cascades-South (WOCS) paths. BPA is also continuing with development of the I-5 Reinforcement project that will provide additional capacity across the SoA path. BPA will determine whether or not to proceed with the project in late 2014. If the project goes forward, it is expected to be in service spring 2018

However, the expansion efforts mentioned above will not be sufficient. Many parts of the transmission network are simultaneously utilized to deliver power from new generation resources. Generation resources to meet future load growth are often located away from load centers (often east of the Cascades). Our Carty and Tucannon River generation facilities, for instance, will utilize transmission from eastern Oregon and Washington for delivery to PGE's load in the Willamette Valley. BPA's Network Open Season (NOS) process, PTSA reform, and regional planning activities seek to address these concerns. These activities and the proposed projects associated with them are described later in this chapter.

1.2 Regional Transmission Planning

Clearly, there is a need for coordinated transmission planning to address the region's transmission challenges. Congress and FERC have also recognized the need to improve regional transmission planning. As a result, transmission planning has undergone significant transformation over the past 25 years through a series of acts enacted by Congress and orders issued by FERC. Currently, transmission planning remains a complex function that is coordinated between affected utilities and the various processes and procedures that are established in multiple organizations. These organizations have differing roles in the various aspects of the transmission planning function. We describe our Transmission Planning Process in Attachment K to our Open Access Transmission Tariff (OATT). Here, we will briefly describe the transmission organizations that we participate in and the roles they play. The objective of the rules and processes that guide our planning efforts is to ensure that needed transmission facilities are identified and evaluated in open and transparent processes that will provide reliable and cost-effective solutions to deliver resources to meet our customer's energy needs.

In July 2007, FERC issued Order 890 which, in part, introduced new planning policies for the industry to follow, including the requirement to adopt an open, transparent and coordinated transmission planning process. Order 890 requires transmission providers to adhere to additional requirements, such as comparability, information exchange, dispute resolution, regional participation, processing of economic planning studies to address congestion or the integration of new resources, and development of a process for cost allocation.

As a result of Order 890, existing regional planning groups have adapted their processes to implement the requirements of the Order and new sub-regional planning groups have formed. The regional and sub-regional planning groups that address issues relevant to PGE include TEPPC, Northern Tier Transmission Group (NTTG), ColumbiaGrid, and the Transmission Coordination Work Group (TCWG).

Further changes in processes have recently been required due to FERC issuing its Order 1000. Order 1000 further enhances the requirements of Order 890 by requiring public transmission utilities to participate in regional transmission planning which includes: (1) consideration of public policy requirements, (2) cost allocation among beneficiaries, and (3) coordination with neighboring transmission planning regions.

WECC

PGE is a member of the Western Electricity Coordinating Council (WECC) and the newly formed Peak Reliability company. WECC is one of eight regional councils of the North American Electric Reliability Council (NERC) and includes two provinces of

Canada, portions of Mexico, and all or most of 14 Western states. WECC is responsible for ensuring the overall reliability of the regional system, and does so by coordinating planning activities in the region. The Planning Coordination Committee (PCC) oversees member adherence to the three processes relevant to transmission planning: regional planning, project rating and project reporting. These activities ensure that facility additions are communicated to WECC members, are provided ratings and meet reliability criteria for the planning horizon (1 to 10 years). WECC also conducts regional economic studies on the transmission system through the Transmission Expansion Planning Policy Committee (TEPPC) and its subcommittees.

Peak Reliability performs the Reliability Coordinator (RC) function and provides operational oversight by monitoring and directing the operation of the Western Interconnection to ensure that the bulk electric system (BES) is operated to acceptable system operating limits (SOLs) and in a reliable manner by adhering to applicable NERC/WECC compliance standards. It assists in outage coordination to ensure that applicable limits (SOLs and possible Interconnection Reliability Operating Limit (IROLs)) are determined and adhered to. Peak Reliability is mainly responsible for the operating horizon (from real time, day ahead, up to the operating seasons within a year).

BAL-002-WECC-2 is a NERC and WECC approved update to the Regional Reliability Standard. It is meant to specify and quantify the types of contingency reserves required to ensure bulk electric system reliability under normal and abnormal conditions. This updated standard addresses FERC concerns set forth in Order 740 including, but not limited to:

- Standardizing definitions,
- Restoration period for contingency reserves,
- Calculation of minimum contingency reserves,
- Using firm load to meet contingency reserve requirements, and,
- Using demand side management as a contingency reserve resource.

FERC approved the new WECC standard for operating reserves on November 21, 2013, (FERC Order No. 789). The new standard became effective January 28, 2014, and FERC will begin enforcing compliance on October 1, 2014.

The changes to the Regional Reliability Standard require the PGE Balancing Authority, as a Load Serving Entity, to change the calculation methodology of minimum contingency reserve requirement. The prior Regional Reliability Standard BAL-STD-002-0 calculated minimum contingency reserves based on the greater of the most severe single contingency, or the sum of 5% of the load responsibility served by hydro and wind generation and 7% of the load responsibility served by thermal generation. The updated reliability standard changes the methodology from a calculation of a percentage of generation to serve load to the sum of 3% of load plus 3% of net generation.

The changing contingency reserve requirement methodology coincides with changing system conditions for PGE including the addition of new generating resources and modest load growth estimates. The updated reliability standard has an immaterial effect on PGE's capacity load-resource balance, and, given the timing of the FERC decision, was not incorporated into our IRP analysis. PGE intends to incorporate the new methodology in our next IRP.

TEPPC

TEPPC is a Board committee of WECC that provides policy direction and management of the economic transmission planning process; it guides the analyses and modeling for the Western interconnection and oversees a specialized database for this purpose.

NTTG

While WECC is a forum for coordinating planning activities, it does not perform the actual planning of facilities. This function resides with the utility planners and is further coordinated in sub-regional planning forums such as Northern Tier Transmission Group (NTTG) and ColumbiaGrid.

NTTG was formed in 2007 to address future sub-regional transmission and resource needs and to support the regional WECC process. PGE became a member of NTTG in 2008. Other participating utilities include PacifiCorp, Idaho Power, NorthWestern Energy, Deseret Power Electric Cooperative, and Utah Associated Municipal Power Systems.

PGE is a Funding Member of NTTG and we satisfy our sub-regional transmission planning commitment and objectives through NTTG. NTTG focuses on evaluation of transmission projects that move power across the sub-regional bulk transmission system, servicing loads that include parts of Utah, Wyoming, Montana, Idaho, Oregon, Washington and California. NTTG also provides an open forum for coordinated analysis between sub-regional planning efforts with adjacent sub-regional groups and other planning entities that impact the planning decisions, system adequacy and operation of multiple transmission providers. This effort allows us, along with other entities, to address local transmission needs due to future load growth and resource additions, and avoid duplication of study efforts through coordination within sub-regional and regional transmission planning forums.

NTTG conducts an eight-quarter biennial transmission planning cycle. The NTTG biennial plan spans 10 years and is intended to coordinate the system transmission plans of member transmission providers, to provide for the integration of new generation and to reduce transmission congestion. The NTTG Steering Committee adopted the 2012–2013 Biennial Transmission Plan Final Report on December 3, 2013. The final 2012–2013 biennial plan facilitates regional assessments and reports by WECC and TEPPC. NTTG began a new biennial transmission planning cycle in January 2014. It is in the process of acquiring project plans to be studied and will begin developing economic studies in the second quarter.

NTTG members have submitted three compliance filings related to Order 1000 and have sought a delay in implementation of Order 1000 processes until FERC issues final rulings on those filings. On October 17, 2013, however, FERC issued an order requiring that NTTG members implement all proposed Order 1000-related tariff changes while the filings are pending. Certain developer qualification processes are underway now and will continue through the end of 2013. Quarter 1 of NTTG's proposed Order 1000-compliant transmission planning processes will begin on January 1, 2014.

PGE also is a member of the planning committee and actively participates in a Technical Work Group (TWG) consisting of planning engineers from the NTTG member transmission providers. Projects studied in the 2012-2013 transmission plan by the TWG included:

- Teckla-Osage-Lange (Black Hills)
- Boardman-Hemingway (Idaho Power Co.)
- Gateway West (with PacifiCorp) (Idaho Power Co.)
- Montana Intertie (Path 8) Upgrade (NorthWestern Energy)
- AMPS line (Path 18) Upgrade (NorthWestern Energy)
- Gateway Central (PacifiCorp)
- Gateway South (PacifiCorp)
- Gateway West (with Idaho Power) (PacifiCorp)
- Hemingway-Captain Jack (PacifiCorp)
- Walla Walla-McNary (PacifiCorp)
- Cascade Crossing (Portland General Electric) [Terminated]
- Horizon-Keeler (Portland General Electric)
- Blue Lake-Gresham (Portland General Electric)
- Pearl-Sherwood (Portland General Electric)

PGE is no longer pursuing development of Cascade Crossing and will not submit it for study in the 2014-2015 Biennial study process. This decision is discussed in greater detail below in Section 11.5.

ColumbiaGrid

ColumbiaGrid is a non-profit membership corporation formed to improve the operational efficiency, reliability and planned expansion of the sub-regional portion of the Northwest transmission grid owned and operated by its members, which are located primarily in Washington State. We participate in ColumbiaGrid forums, but are not a member.

1.3 BPA's Network Open Seasons

Notwithstanding recent efforts to improve regional transmission planning, relatively little significant transmission has been built recently in the Northwest. As a result of the lack of new transmission capacity and resulting system congestion, BPA has had to implement remedial actions and reactive power compensation to maximize the existing transmission capacity. BPA has also developed curtailment calculators to maintain reliability. Prior to 2008, BPA's long-term transmission service queue contained over 14,000 MW of service requests, excluding Intertie service, yet few transmission projects were being built. A major hurdle to the development of new transmission was that customers were required to provide all of the capital funding for the transmission system upgrades and expansions to support their individual projects.

In 2008, BPA introduced its first NOS process to alleviate the bottleneck created as a result of previous transmission planning and funding mechanisms. Under the NOS, parties requesting new transmission service must commit, in advance, to purchase service at embedded-cost rates by signing a PTSA. Importantly, the NOS approach does not require BPA's customers to fund, in advance, the entire cost of transmission network facilities needed to provide the service. BPA makes the necessary investment through its borrowing authority or other arrangements. The requesting party is responsible for submitting a refundable security deposit equal to one year of service once the PTSA is executed. If necessary and available, BPA may offer conditional firm service to bridge service until necessary facilities can be completed.

In addition, under NOS, BPA does not conduct individual system impact studies on each transmission request. Instead, the agency performs a single cluster study of all requests to determine what new facilities, if any, will be needed to accommodate all of the requests. The clustering of transmission requests not only speeds up the system impact analyses, it allows BPA to evaluate the network effects that result from interactions among requests, including implications on system reliability.

As a result of the 2008 NOS, BPA was able to clear the queue by eliminating requests that were not backed with a PTSA. Approximately 8,054 MW of prior requests for service were removed from the queue. As a result of clearing the queue, BPA was able to offer 1,834 MW of service without building additional transmission system reinforcements. BPA identified five projects that would enable it to grant an additional 3,585 MW of requests. Specifically, BPA stated that it would construct McNary-John Day, Big Eddy-Knight, Central Ferry-Lower Monumental, and I-5 Reinforcement.

The 2009 NOS process was initiated on June 1, 2009. As a result of the NOS, BPA obtained a commitment of 1,553 MW in PTSAs and removed an additional 3,304 MW from the queue. In 2010, BPA announced that no new transmission projects were needed as a result of the 2009 NOS.

The 2010 NOS process was initiated on June 1, 2010. BPA offered PTSAs for 7,304 MW of transmission and obtained commitments for 3,759 MW in PTSAs. BPA announced that the projects needed to facilitate the 2010 PTSA were the Northern Intertie and CUP West projects.

In July 2011 BPA announced that it would begin a PTSA Reform process due to customer interest in modifying or reforming PTSA commitments. BPA received proposals to terminate or modify approximately 3,400 MW of PTSAs and other transmission service agreements. BPA reached agreements with three customers to modify or terminate PTSAs for 1,395 MW.

PGE has not signed any PTSAs with BPA. We did not sign a PTSA as part of the 2008 or 2009 NOS processes because we had sufficient transmission and no new generation resources to integrate at that time. During the 2010 NOS, PGE was exploring development of Cascade Crossing and anticipated that it could accommodate our projected transmission needs. Consequently, PGE did not sign any PTSAs as a result of the 2010 NOS.

Since this IRP does not include any significant new generation resources and current transmission needs have been met, PGE does not have any transmission service requests currently being studied in BPA's 2013 NOS. PGE will consider participating in a future NOS process in order to acquire transmission rights for future generation resources, as needed. However, PGE recognizes that participation in a NOS process, in and of itself, does not guarantee that we can acquire future transmission service or that there will be sufficient interest by other parties to enable BPA to proceed with construction of transmission projects that may be needed to meet our requests. Participation in a BPA NOS process also does not guarantee that a BPA transmission project would be the most cost-effective transmission option to meet our transmission needs.

1.4 Transmission External to BPA

As previously stated, PGE is proposing no new generation resources during the IRP action plan window. Consistent with OPUC IRP Guideline 4c, we have modeled all of our existing transmission rights, as well as future transmission additions associated with the resource portfolios tested. For modeling purposes, future generation projects in our portfolios that require BPA transmission are assigned BPA tariff rates. Generation projects external to BPA's transmission system are modeled as being dependent on new third-party transmission projects. In our portfolio analysis we included an analysis of wind resources in Montana. Montana wind resources would require new transmission infrastructure to deliver power to the Northwest because there is no available east-to-west transfer capability on the existing transmission facilities. We used BPA's cost estimate for the potential Broadview-Ashe expansion to estimate the cost of new transmission in Montana. We computed a MW cost of participation and assigned that cost to the resource capacity assumed in our portfolio analysis.

1.5 PGE Transmission Options

PGE began conceptualizing the Cascade Crossing Transmission Project (CCTP or Project) in response to Order No. 04-375 issued by the Public Utility Commission of Oregon (OPUC or Commission) in 2004. In Order No. 04-375, the Commission directed us to work with BPA and others to address how we might develop additional transmission capacity over the Cascade Mountains, recognizing the need to connect future east-side generating resources to Willamette Valley loads. At that time, few major transmission lines had been constructed in the Pacific Northwest for several decades.

The regional transmission infrastructure was considered to be increasingly constrained with limited capacity to accommodate additional generation resources — particularly those east of the Cascades Mountains — to meet customer loads to the west. Order No. 04-375 directed PGE to include an analysis of transmission constraints and availability in our subsequent IRP. In the 2007 IRP, we concluded that, over the long-term, PGE would ". . . likely require new transmission to our service territory to allow us to access future remote resource options".[86]

Focused planning for the potential construction of a high-voltage transmission line (then called Southern Crossing) began in 2008 when PGE initiated Phase 1 of the WECC Regional Planning Process to determine the potential path rating for a new transmission line to be located within the WOCS path. A Critical Issues Analysis report, completed in March 2009, examined the feasibility of a new 500 kV transmission line between Boardman and Salem. Subsequently, in the 2009 IRP Action Plan, we proposed construction of the Cascade Crossing Transmission Project, which was intended to:

1. Provide PGE with additional transmission capacity to serve PGE load from future renewable and non-renewable energy projects, as well as from existing energy resources;

2. Respond to specific interconnection requests from energy generation developers, including approximately 1,200 megawatts (MW) for proposed wind-energy projects;

3. Relieve congestion on the electric grid to ensure a reliable electrical system; and,

4. Respond to Oregon's RPS.

The Commission acknowledged the Action Plan (Order No. 10-457) with the requirement that PGE provide an updated benefit-cost analysis of CCTP in its next IRP. In PGE's 2011 IRP Update, we estimated the cost of a 215-mile double-circuit line to be approximately $1.031 billion and anticipated that the line could be optimized with an interconnection to BPA in the Salem area that would potentially provide PGE with as much as 2,000 MW of transmission capacity with an additional 600 MW for a potential equity partner.

State, Federal and Tribal permitting processes began in 2010. Concurrently, PGE and BPA began discussions around the additional capacity of the proposed new line. Agreement between PGE and BPA was necessary to effectuate the Project because of the interconnection and the fact that each entity's transmission facilities would need to work together as part of the larger networked transmission system within the WOCS transmission path operated by BPA. An initial MOU between the parties was executed in February 2011. A set of guiding principles was incorporated in the MOU. Among other provisions, the MOU stated that "the Agreement must be good for the Northwest as a

[86] 2007 PGE Integrated Resource Plan, Chapter 9 (Transmission), Section 9.1, p. 147.

whole" and that the parties "are committed to demonstrate a collaborative decision-making process to enhance the regional transmission capabilities".

Expanded Transmission Options & Timing

PGE and BPA continued working collaboratively between early 2011 and late 2013 to identify the best means for increasing PGE's transmission capacity, reducing the impacts of any new transmission, managing costs, and benefitting customers of both entities. The initial discussions focused on interconnection of the Project with BPA's regional transmission system, allocation of transmission capacity across a shared transmission path connecting eastern Oregon to the Willamette Valley, and the potential for PGE to utilize BPA's idle easement within that shared path. As described below, the collaborative work led us to propose significant modifications to the Project and, eventually, to suspend consideration of building our own transmission facilities. We subsequently reached the conclusion that it would be in the best interest of our customers to remain on BPA's standard OATT service to meet our current transmission needs.

Originally proposed as a 215-mile, single- or double-circuit transmission line from the Boardman area to Salem, as the Project discussions evolved with BPA it became apparent to PGE and BPA that the opportunity existed to modify the Project in a way that would significantly reduce environmental impacts and benefit the regional transmission system while still meeting PGE's original purpose of bringing remote resources to our load center cost-effectively. Those discussions culminated in the execution of a non-binding MOU in January 2013 confirming the parties' mutual interest in pursuing a modified transmission build that would terminate the line east of the mountains at a new PGE substation (Pine Grove), where it would interconnect with BPA's system rather than directly connecting to PGE's system at Salem. The revised Project design eliminated approximately 100 miles of construction associated with the proposed line and avoided environmental impacts to Federal forest, Tribal and exclusive farm use lands.[87] Consequently, this MOU envisioned a combination of construction, investments and/or asset transfers.

Following the conclusion of BPA's "PTSA Reform process" in March 2013, BPA's transmission planners began to suggest that a new eastside line, and associated Pine Grove substation, may not be needed until as late as 2029. The combination of changing market conditions that slowed development of wind energy, along with completion of new BPA transmission construction intended to transmit new generation, resulted in a reduced need for new transmission facilities. Specifically, as evidenced by the results of BPA's PTSA Reform process,[88] a number of projects that had signed agreements with

[87] The originally planned line would have crossed the Mt. Hood and Willamette national forests, the Confederated Tribes of Warm Springs reservation and farmlands in the Willamette Valley protected by Oregon's exclusive farm use (EFU) provisions.

[88] BPA began a process in September 2011 whereby projects that had signed a precedential transmission service agreement (PTSA) stemming from BPA's 2008 NOS process could modify or terminate their agreements. This was called the "PTSA Reform" process. Through this process, BPA received proposals from 12 transmission customers seeking modifications to their transmission service agreements representing approximately 3,400 MW of transmission. These requests were to terminate, delay or otherwise modify existing agreements for service. In

BPA for transmission service, including some that had prompted BPA to build new transmission facilities to accommodate them, began to request modification or termination of their agreements. It became clear, given the termination or delay of these projects and reduced forecasts for load growth, that PGE could instead pursue conveyance of capacity ownership rights from BPA sufficient to serve PGE's needs over the next decade.

Several factors led to the changes in the market:

1. **California's Senate Bill X 1-2**: Some of the diminished demand for renewable energy in the Northwest is the result of 2011 legislation in California that put out-of-state renewable energy projects at a competitive disadvantage over in-state projects. The California Renewable Energy Act (SB X 1-2) employs formulae that generally favor in-state development. As the new law took effect, the demand for renewable energy imported from the Northwest was reduced. Developers anticipating selling into the California market were left with fewer options.[89]

2. **Load Growth**: In the 2009 IRP, PGE forecasted a 2.2% annual growth rate in customer energy demand (before accounting for load reduction through energy efficiency). This represented approximately a 55% load increase over a 20-year planning horizon. Since 2009, actual load growth has been below forecast and projected future load growth has been reduced. As discussed in Chapter 3 - Resource Requirements, long-term annual load growth is projected to be approximately 1.5%, which represents an approximate 35% increase over 20 years. The growth in peak demand, which is a more important consideration for transmission planning, is forecast to be 1.4% in this IRP (relative to a 2.0% growth rate in winter peak demand in our prior IRP).

3. **Regional Transmission Capacity**: Several BPA transmission projects, such as the Big Eddy-Knight and John Day-McNary transmission lines, were intended to accommodate renewable energy projects. These assets are now at risk of being underutilized in the near-term due to terminations or modifications of existing transmission service contracts by wind generation developers. Under the collaborative planning approach considered by PGE and BPA, it was preferable to leverage existing infrastructure and attendant capacity, rather than build a new facility.

These market conditions led PGE and BPA to continue evaluating options for the most efficient and cost-effective means for PGE to gain capacity across the Cascades. Several alternatives to a transmission build were considered. Although the eastside portion of the original Project remained operationally viable, planners for both BPA and PGE identified

March 2013, BPA announced that it had reached agreements with three wind developers to terminate or modify PTSAs representing 1,395 MW.

[89] On June 3, 2013, PGE announced the selection of a 267 MW wind energy plant near Dayton, Wash., northeast of Walla Walla. PGE has entered into an asset purchase agreement to acquire the development rights to phase 2 of the Lower Snake River wind farm, currently under development by Puget Sound Energy Inc.

a less expensive option with none of the environmental impacts of a transmission line build.

As a result, on May 30, 2013, the parties signed a new non-binding MOU outlining a new option that would enable PGE to acquire perpetual ownership of transfer capability utilizing existing BPA transmission facilities. As a result, PGE suspended state, Tribal, and Federal permitting activities for the construction of a transmission line. Under the arrangement outlined in the May 2013 MOU, the Parties had contemplated that PGE could obtain ownership of up to 2,600 MW of transmission capacity through a commercial arrangement that would have involved a combination of investment payments to BPA, potential transmission asset exchanges, and certain operational efficiencies provided by PGE to BPA.[90] In return, BPA would convey to PGE exclusive perpetual ownership rights to transmission capacity on its existing system over the WOCS path. The MOU recognized that PGE and BPA still needed to define capacity ownership and the terms and conditions upon which it could be conveyed to PGE.

Between June and October of 2013, our discussions with BPA focused on valuation of the desired transmission capacity ownership rights, including prospects for long-term utilization of the capacity, projected BPA OATT growth rates, load growth forecasts and other financial considerations. Based on both parties' analyses and discussions, we determined that we could not reach an agreement on the financial terms of the proposed commercial arrangement and, therefore, agreed to discontinue discussion of this option.

At the present time, PGE does not intend to pursue further discussions of transmission capacity ownership with BPA, nor does PGE intend to reconsider our option to build the Cascade Crossing transmission line. However, we do anticipate continuing to work closely with BPA on mutually beneficial opportunities.

CCTP Conclusion

Various unforeseeable changes in the transmission market that unfolded between 2007 and 2013 resulted in significant modifications to our proposed Project over time, and ultimately resulted in PGE's decision to terminate the Project. During that period, as instructed by the Commission, we engaged in detailed discussions with BPA and explored numerous options for providing our customers with cost effective transmission to deliver power from existing and future resources, including renewable energy, from east of the Cascades to our service territory. These discussions led to an examination of unique proposals to collaborate on the construction of new transmission resources as well as options that would allow for improved utilization and efficiency of the regional grid. While these discussions did not lead to an agreement with BPA, they have created a new, more collaborative environment for working together to meet our respective customers' needs and to provide for more efficient utilization of the existing transmission system.

We have determined that, under current conditions, the best option for meeting our transmission needs over the current planning horizon is to retain/acquire transmission service offered under BPA's OATT. At the same time, we believe there are certain

[90] The May 2013 MOU envisions PGE offering BPA operational efficiencies gained through defined use of our distributed generation system (i.e., distributed standby generation) and by making our generation available to BPA for re-dispatch and remedial action schemes.

structural impediments to independent development of transmission facilities that may need to be addressed in the future so that smaller transmission providers in the region, such as PGE, may be able to meet their own transmission needs.

12. PGE Proposed Action Plan

This chapter describes PGE's proposed set of actions for this IRP. With the implementation of the supply and demand actions identified in our last IRP (via resource additions from our recent energy and capacity RFPs), combined with moderated load growth net of EE, our projected portfolio position is roughly balanced (on an annual average energy basis) through 2017. Based on this assessment, we do not recommend any new, major supply-side resources for this IRP. However, we are recommending the following actions: renewal of certain legacy hydro contracts (if available and cost effective), customer enabled resource additions, implementation of studies and initiatives to inform the next IRP, and pursuit of BPA OATT service to provide transmission for our remote generation and access to wholesale electricity markets. We have grouped these actions into four categories: Supply-side Actions, Demand-side Actions, Enabling Studies, and Transmission. We have specifically developed the list of Enabling Studies at the suggestion of some of our stakeholders based on feedback at our 3rd public meeting. We subsequently shared our recommended studies with stakeholders at the 4th public meeting and sought their feedback and suggestions.

1. **Supply-side Actions:** Retain legacy hydro resources if economic:
   a. **Major resources:** PGE requests no new major, supply-side resource actions in this IRP. Refer to Chapter 3 - Resource Requirements for more information about PGE's load-resource balance.
   b. **Hydro contract renewals:** PGE has expiring legacy hydro contracts. We propose renewal, or partial renewal of these contracts, if they can be renewed cost-effectively for our customers. See Chapter 2 - PGE Resources for contract resource expirations. As discussed in Chapter 2 - PGE Resources, this is a proposal for an alternative acquisition method under Guideline 2a of the Commission's Competitive Bidding Guidelines (Order No. 06-446).
   c. **DSG:** additional 23 MW by 2017 (for a total of 116 MW). PGE remains a leader in the U.S. with this innovative customer-utility partnership to deliver a low-cost source of capacity, reserves, and reliability. See Chapter 8 - Supply-side Options for additional discussion.

2. **Demand-side Actions:** Continue demand side procurement:
   a. **EE:** ETO cost effective deployment of EE: 124 MWa (158 MW) by 2017. PGE continues to work collaboratively with the ETO to assure sufficient funding for acquisition of all cost-effective EE, subject to customer adoption constraints. See Chapter 4 - Demand-side Options for additional discussion.
   b. **DR:** additional 25 MW (total of 45 MW of DR) by 2017. The Automated Demand Response portion of our DR goal is administered by a third-party provider, EnerNOC. The program successfully launched this year. The vendor expects to reach the goal of 25 MW by 2017. See Chapter 4 - Demand-side Options for additional discussion.

3. **Enabling Studies:** Perform research to inform the next IRP:
    a. **Third-party review of load forecast methodology:** Nationwide, utility load growth has slowed in the last decade. While the Pacific Northwest (and in particular urban centers west of the Cascades) is still expected to outpace National growth trends, we think it is prudent to further examine fundamental electricity demand drivers and forecasting methods to ensure we are applying industry best practices. Accordingly, we plan to engage a third-party review of forecast methods, use of historical and forecast data, and basic assumptions regarding the relationships between electricity demand growth and economic trends, population in-migration, customer usage intensity and patterns, and conservation.
    b. **Assessment of emerging EE in conjunction with the ETO:** We continue to support ongoing acquisition of existing and emerging opportunities to improve end-use efficiency, if cost-effective. To better understand future EE opportunities, we will engage with the ETO and other parties to assess the potential for emerging/future EE measures and technologies, and identify how best to develop and acquire cost-effective opportunities.
    c. **Distributed generation study:** PGE will pursue studies and research initiatives with the goal of assessing potential business models and policies that expand the installation of cost-effective distributed generation. We expect this effort to focus primarily on distributed solar PV.
    d. **Boardman biomass technical & economic viability (continuation of current efforts):** Further assess technical and economic feasibility of re-powering Boardman as a biomass facility after the cessation of coal-fired operations at the plant. See Chapter 8 - Supply-side Options for a timeline for upcoming test burns and associated milestones and activities.
    e. **Assessment and development of operational flexibility:** Dynamic dispatch, Energy Imbalance Market (EIM), etc. We will build on work already under way to better understand PGE's dynamic capacity needs and alternatives to address those needs with both generation/operational means, as well as market-based solutions. This involves better modeling and evaluation methods of "inside the hour" energy, capacity, and ancillary services needs, as well as looking at different ways to participate in an evolving regional marketplace (e.g., Northwest EIM). We are already actively involved in discussions for development of a regional EIM. Chapter 8 - Supply-side Options provides an update on the region's and PGE's EIM efforts.

f. **Evaluation of new analytical tools for optimizing flexible resource mix to integrate load and variable resources:** A key issue going forward is how to optimize the mix of flexible peaking and storage resources to minimize costs in a system with increasing levels of variable energy resources and proportionally shrinking flexible capacity capability. This will require IRPs (which traditionally focus on 20-year and longer planning horizons) to also look "inside the hour" at operational parameters that were formerly the exclusive domain of real-time and day-ahead system operators. New methods and analytical tools for electric utility planning must be developed and acquired to support this new IRP paradigm.

g. **Assessment of longer-term gas supply options to hedge price volatility:** PGE, along with most U.S. utilities, is becoming increasingly gas-intensive. At the same time, gas prices are projected to remain relatively low and stable. We plan to examine potential strategies, costs, and risks of pursuing longer-term supply sources for acquiring and managing natural gas (e.g. storage, long-term contracts, gas reserves). Chapter 6 - Fuels discusses fuel supply issues and strategy.

4. **Transmission:** Various regional and national changes that affected the transmission market in the Northwest (both demand and supply availability) unfolded between 2007 and 2013. The changes to the transmission market led us to make significant modifications to our proposed Cascade Crossing Transmission Project over time, and ultimately resulted in our decision to terminate the project. We have determined that, under current conditions, the best alternative for meeting the transmission requirements for our remote resources and to provide access to wholesale power markets over the current planning horizon is to retain/acquire service under BPA's OATT. At the same time, we believe there are certain structural impediments to independent development of transmission facilities that may need to be addressed in the future so that smaller transmission providers in the region, such as PGE, are better able to develop and construct transmission projects when needed and cost-effective.

Conclusion

We believe the actions set forth above allow us to continue to serve our customers with a portfolio of resources that provides the best combination of expected costs and associated risks and uncertainties. It also positions us well for the next IRP, where major decisions will include examination of alternatives to meet the 2020 RPS requirements, Boardman plant replacement, and additional capacity and/or flexibility requirements. We expect to launch our next IRP in late 2014 or early 2015, with an expected OPUC filing in 2016.

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Appendix A

Compliance with the Commission's IRP Guidelines

Appendix A: Compliance with the Commission's IRP Guidelines

Guideline 1:	Substantive Requirements	PGE Compliance	Chapter
Guideline 1a	All resources must be evaluated on a consistent and comparable basis.		
	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation and storage – and demand-side options which focus on conservation and demand response.	Consistent with Order 08-246, we consider known supply-side and demand-side resources that are expected to become available. We model central-station solar, EE, wind, CCCTs, biomass, and geothermal to meet annual energy needs. For peaking and load following, we model reciprocating engines along with LMS 100, DSG and DR. We also considered, but did not model, next generation nuclear, traditional coal, gasified coal, distributed PV solar, battery storage, pumped hydro, compressed air energy storage, and hydrokinetic energy. We consider development of new transmission capacity and new gas pipeline contracts.	2, 4, 8
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	We developed portfolios with resource types which inherently exhibit the characteristics identified in the guideline. Refer to our portfolios composition table in Chapter 9.	9
	Consistent assumptions and methods should be used for evaluation of all resources.	PGE evaluated all resources using a common set of assumptions, and analytical and modeling approach.	4, 8, 9
	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	We applied PGE's after tax marginal weighted-average cost of capital of 6.43% as a proxy for the long-term cost of capital in the WECC.	9
Guideline 1b	Risk and uncertainty must be considered.		
	At a minimum, utilities should address the following sources of risk and uncertainty:		

	1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices and costs to comply with any regulation of greenhouse gas emissions.	PGE analyzes the variables specified in this guideline through a combination of 35 deterministic futures for the economic scenario analysis. Stochastic modeling is used in the reliability studies and simulates the volatile behavior for weather impact to loads, water years, wind intermittency and plant forced outages with mean times to repair. For greenhouse gas, we have a 2020 Oregon CO_2 Goal portfolio as well as multiple futures simulating alternative carbon pricing schemes.	9, 10
	2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.	N/A to PGE	N/A
	Utilities should identify in their plans any additional sources of risk and uncertainty.	We identify capital cost (higher or lower than projected for both thermal and renewables plants), differing assumed lives for wind plants, earlier discontinuation of the PTC and ITC, and plant availability risk (for wind) by designing multiple futures that stress these variables. Additionally, we created scenarios that combine risk factors: i.e. high carbon costs and high natural gas prices, in order to measure the combined impact on cost and wholesale electricity prices.	9, 10
Guideline 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.	Our IRP Action Plan allows us to continue to serve our customers with a portfolio of resources that provides the best combination of expected costs and associated risks and uncertainties. Our primary tool for examining the mix of expected cost and associated risk was through use of the box-and-whiskers charting.	10, 12

	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.	Consistent with Order 08-246, we plan for the acquisition of major new resources until 2025, hourly dispatch (for variable costs) via Aurora through 2033, and recovery of life-cycle resource investment and fixed costs, including estimated decommissioning.	8, 9, 10
	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 for 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.	We use expected NPVRR All other costs over time for gas transport, transmission, fuel, fixed cost recovery, etc. are included within the revenue requirement modeling for all long-lived and short-lived resources. That is, all costs that would actually be incurred to operate the resource are included. Input assumptions for these costs come from B&V, Wood Mackenzie, EIA, existing contract costs, and other industry sources.	8, 10
	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.	We employ the two measures of NPVRR risk for scenario analysis: variability of costs, and severity of outcomes. We also consider relative likelihood of high or low expected cost.	10
	2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	We include a discussion of traditional physical and financial hedging approaches, their purpose and limitations, for wholesale electricity and for natural gas in Chapter 6.	6
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	We explain how we balance cost and risk in Chapter 10 and describe the criteria we use to determine the best cost/risk portfolio.	10
Guideline 1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	We model a portfolio to achieve the Oregon CO_2 goal, RPS compliance in all portfolios, current requirements for non-CO_2 and CO_2 environmental compliance in all portfolios, and various scenarios for future federal regulation of CO_2.	9, 10

Guideline 2	Procedural Requirements	PGE Compliance	Chapter
Guideline 2a	The public, which includes 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. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	The public, as represented primarily by a number of stakeholder organizations, has been significantly involved in the development of PGE's IRP. Chapter 1 provides an overview of our public process. Appendix E lists all the presentations of the public process. Public meeting materials and the draft IRP are posted on PGE's website.	1, Appendix E
Guideline 2b	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. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	PGE's IRP provides non-confidential information used for portfolio evaluation and development of the action plan.	N/A
Guideline 2c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PGE distributed a draft IRP for public review and comment on November 22, 2013.	N/A

Guideline 3	Plan Filing, Review and Updates	PGE Compliance	Chapter
Guideline 3a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	We filed our last IRP in November 2009 and an associated addendum in April 2010. The Commission issued Order No. 10-457 on November 23, 2010, acknowledging PGE's 2009 IRP. PGE filed annual updates in November of 2011 and 2012. On October 3, 2013, the Commission issued Order No. 13-359 authorizing PGE to extend the time to file its next IRP to March 30, 2014.	N/A
Guideline 3b	The 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 will comply with this Guideline.	N/A
Guideline 3c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	N/A to PGE	N/A
Guideline 3d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	N/A to PGE	N/A
Guideline 3e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	N/A to PGE	N/A

Guideline 3f	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	N/A at this time	N/A
Guideline 3g	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:	N/A at this time	N/A
	Describes what actions the utility has taken to implement the plan;	N/A at this time	N/A
	Describes what actions the utility has taken to implement the plan;	N/A at this time	N/A
	Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and	N/A at this time	N/A
	Justifies any deviations from the acknowledged action plan.	N/A at this time	N/A

Guideline 4	Plan Components	PGE Compliance	Chapter
	At a minimum, the plan must include the following elements:		
Guideline 4a	a. An explanation of how the utility met each of the substantive and procedural requirements;	The purpose of this table is to comply with this Guideline. We include more detailed descriptions and explanations of how we meet the Commission requirements within the body of the IRP filing.	This Appendix
Guideline 4b	b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;	We include high and low load growth scenarios for PGE in Chapter 3. We also analyze stochastic load risk which is primarily the result of weather variations based on historical observations of pre-schedule vs. actual loads. We use stochastic load risk for the estimate of the reliability of the different portfolios tested in IRP.	3, 9,10
Guideline 4c	For electric utilities, 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;	We perform three related analyses: 1) A load/resource balance on energy and January and August capacity, 2) a flexible capacity need study; 3) a reliability analysis comparing the performance between portfolios. All portfolios model existing transmission costs from the source to our system.	3, 5, 8, 9,10, 11
Guideline 4d	For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;	N/A to PGE	N/A

Guideline 4e	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;	We develop resource-specific life-cycle revenue requirements. We relied on the expertise of an external consultant, Black and Veatch as well as on the results of the 2012 RFPs to estimate costs and advances in technology.	8, Appendix G
Guideline 4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;	Each portfolio acquires supply and demand resources to a level that maintains, at minimum, a required 6% operating reserve. Using a loss-of-load analysis, we further examine each portfolio for specific performance given its specific incremental resources with associated shaft risks and market exposure.	9,10
Guideline 4g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;	We base natural gas prices and CO_2 price on current third-party outlooks and include a range of higher and lower cost outcomes.	6, 7, 10
Guideline 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;	We use a combination of predominantly single incremental resource and diversified portfolios which acquire various resources in various combinations with varying timing and durations as specified. The portfolios inherently include the considerations described in 4h.	9, 10
Guideline 4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;	We estimated the expected portfolio cost and a variety of scenario risks, along with reliability and diversity considerations.	10
Guideline 4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;	Our results are shown in Chapter 10 and Appendix C.	10, Appendix C
Guideline 4k	Analysis of the uncertainties associated with each portfolio evaluated;	Uncertainties associated with each portfolio are evaluated in Chapter 10.	10

Guideline 4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;	Our IRP Action Plan does not call for large new generation. It does continue existing programs related primarily to the customer side: EE, DR, and DSG. Our preferred portfolio has the best combination of low expected cost and low risk based on using risk metrics required by these guidelines.	10, 12
Guideline 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;	Our preferred portfolio complies with existing state and energy policies and regulations. We include a portfolio based on the Oregon CO_2 goal. We show the cost barrier to implementation in Chapter 10.	10
Guideline 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.	Our Action Plan includes activities that we intend to undertake or commit to in the next two to four years.	12

Guideline 5	Transmission	PGE Compliance	Chapter
	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.	Our portfolio analysis includes costs for the fuel transportation and electric transmission required for each resource being considered. We include a portfolio that assumes less costly wind from Montana while adding an estimate of the associated transmission cost. We provide an overview of PGE's transmission strategy in Chapter 11.	6, 10, 11

Guideline 6	Conservation	PGE Compliance	Chapter
Guideline 6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	We include the assessment of the Energy Trust of Oregon of technical and achievable potential energy efficiency.	4
Guideline 6b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	N/A	N/A
Guideline 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:		
	Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and	We base our portfolios on studies conducted by the ETO which determine the amount of potential energy efficiency without regard to any funding limits.	4
	Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	Our preferred portfolio and action plan are consistent with the ETO's projection of energy efficiency potential.	4, 12

Guideline 7	Demand Response	PGE Compliance	Chapter
	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	We evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy and capacity needs	4, 10

Guideline 8 (Order 08-339)	Environmental Costs	PGE Compliance	Chapter
Guideline 8a	BASE CASE AND OTHER COMPLIANCE SCENARIOS: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides and mercury emissions. The utility also should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading or a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	We construct a reference case based on third-party (Wood Mackenzie) analysis of federal legislative CO_2 proposals. We assume that compliance comes in the form of a CO_2 price, as well as technological standards for new plants. We assume CO_2 emissions for PGE are regulated at the point of combustion. Our reference case assumes full regulatory compliance for particulates, SO_X, NO_X, and mercury emissions for all our plants. Potential new portfolio additions are assumed to be in full compliance.	7, 10

Guideline 8b	TESTING ALTERNATIVE PORTFOLIOS AGAINST THE COMPLIANCE SCENARIOS: The utility should estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	We test our portfolios against futures that incorporate a range of future CO_2 prices.	7, 10

Guideline 8c	TRIGGER POINT ANALYSIS. The utility should identify at least one CO_2 compliance "turning point" scenario which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent than the identified trigger point will be mandated.	We test the CO_2 price which would trigger the selection of our all-green portfolio over our preferred portfolio (which has new gas).	10
Guideline 8d	OREGON COMPLIANCE PORTFOLIO: If none of the above portfolios is consistent with Oregon energy policies (including the state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those of the preferred and alternative portfolios.	We include a portfolio in which Boardman and Colstrip no longer dispatch after 2020 and a combination of gas and wind resources replace them.	9, 10

Guideline 9	Direct Access Loads	PGE Compliance	Chapter
	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	We exclude estimated five-year opt-out load based on current customer elections.	3
Guideline 10	**Multi-state Utilities**	**PGE Compliance**	**Chapter**
	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	N/A	N/A
Guideline 11	**Reliability**	**PGE Compliance**	**Chapter**
	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation and storage, along with demand side resources, to reliably meet peak, swing and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	We analyze loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy for all of our portfolios.	9,10

Guideline 12	Distributed Generation	PGE Compliance	Chapter
	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.	We evaluate distributed generation (including avoided generation technologies, including DSG, DR, EE, and distributed solar) on par with other supply-side resources. These technologies do not include line losses and transmission costs that burden central station plants.	7
Guideline 13	**Resource Acquisition**	**PGE Compliance**	**Chapter**
Guideline 13a	An electric utility should, in its IRP:		
	Identify its proposed acquisition strategy for each resource in its action plan.	Our acquisition strategy consists primarily of proceeding with demand-side acquisitions and DSG.	12
	Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.	We provide a discussion of resource ownership relative to power purchase agreements in Chapter 8.	8
	Identify any Benchmark Resources it plans to consider in competitive bidding.	PGE is not proposing the acquisition of any long-term supply side resource in this IRP.	N/A
Guideline 13b	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	N/A to PGE	N/A

	Flexible Capacity Resources (Order No. 12-013)	PGE Compliance	Chapter
1	Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;	We presented this analysis in a technical workshop in 2013 and Chapter 5 was written to specifically address this requirement.	5
2	Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and	We presented this analysis in a technical workshop in 2013 and Chapter 5 was written to specifically address this requirement.	5
3	Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis	PGE analysis does not identify a gap regarding up-regulation for reliability in the Action Plan time frame. Chapter 8 addresses flexible generating and storage resources. The Action Plan (Chapter 12) calls for additional research preparatory to the next IRP regarding the mix of flexible supply and storage resources. The role of EVs is addressed in Chapter 3.	8, 12, 3

Appendix B

PGE Candidate Portfolio Mix

Appendix B: Portfolio Details

Cumulative additions - Energy (MWa)

	Total MWa in operation by year (cumulative)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1. Market	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	116	116	116	116	116	280
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	224	247	267	400	417	432	446	461	639
2. Natural Gas	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	116	116	116	116	116	280
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	0	0	326	326	326	653	653
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	224	247	267	400	743	758	773	1,114	1,292
3. Wind	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	116	442	442	442	769	933
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	224	247	267	400	743	758	773	1,114	1,292
4. Diversified Green	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	50	50	50	166	466	466	466	466	630
	Other Renewables	0	0	0	0	0	0	20	90	90	90	90	110
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	274	297	317	470	857	872	886	901	1,099

Appendix B: Portfolio Details

Cumulative additions - Energy (MWa)

	Total MWa in operation by year (cumulative)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
5. Diversified Green/EE	EE (Total)	35	69	111	140	167	192	215	237	258	278	297	316
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	50	50	50	160	460	460	460	460	616
	Other Renewables	0	0	0	0	0	0	20	90	90	90	90	110
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	211	290	317	342	495	887	908	928	947	1,142
6. Green w/EE and CCCT	EE (Total)	35	69	111	140	167	192	215	237	258	278	297	316
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	50	50	50	160	460	460	460	460	616
	Other Renewables	0	0	0	0	0	0	20	90	90	90	90	110
	Baseload Gas	0	0	0	0	0	0	326	326	326	326	326	326
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	211	290	317	342	821	1,213	1,234	1,254	1,274	1,468
7. Baseload Gas/RPS only	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	116	116	116	116	116	280
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	326	326	653	653	653	653	653
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	224	247	593	727	1,069	1,085	1,099	1,114	1,292
8. Diversified Green with wind MT	EE (Total)	35	69	111	140	167	192	215	237	258	278	297	316
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	17	34	34	144	444	444	444	444	600
	Other Renewables	0	0	0	0	0	0	0	59	59	59	59	59
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	211	257	301	326	459	840	861	881	901	1,075

Appendix B: Portfolio Details

Cumulative additions - Energy (MWa)

Total MWa in operation by year (cumulative)		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
9. Diversified balanced wind/CCCT	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	23	82	82	198	198	198	298	298	462
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	37
	Baseload Gas	0	0	0	0	0	0	0	326	326	326	326	326
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	247	329	349	482	825	840	955	969	1,185
10. Diversified Solar/Wind	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	50	50	50	166	466	466	466	466	630
	Other Renewables	0	0	0	0	0	0	20	90	90	90	90	170
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	274	297	317	470	857	872	886	901	1,159
11. Diversified Green with non-CE EE only	EE (Total)	35	69	111	140	167	192	215	237	258	278	297	316
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	50	50	50	166	466	466	466	466	630
	Other Renewables	0	0	0	0	0	0	20	90	90	90	90	110
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	211	290	317	342	501	893	914	934	953	1,156
12. Oregon CO2 Goal	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	50	50	50	452	752	752	752	752	915
	Other Renewables	0	0	0	0	0	0	0	70	70	150	150	150
	Baseload Gas	0	0	0	0	0	0	326	326	326	326	326	326
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	-612	-256	-256	-256	-256	-256
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	274	297	317	450	1,193	1,208	1,302	1,317	1,495

Appendix B: Portfolio Details

Cumulative additions - Energy (MWa)

	Total MWa in operation by year (cumulative)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
13. Baseload renewables	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	116	116	116	116	116	280
	Other Renewables	0	0	0	50	50	50	70	440	440	440	440	460
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	274	297	317	470	857	872	886	901	1,099
14. High Solar	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	116	116	116	116	116	280
	Other Renewables	0	0	0	50	50	50	70	440	440	440	440	520
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	274	297	317	470	857	872	886	901	1,159
15. Defer RPS Physical Compliance	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	23	82	82	82	82	82	82	82	362
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	37
	Baseload Gas	0	0	0	0	0	0	0	326	326	326	326	326
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	247	329	349	366	709	724	739	753	1,085
16. Diversified Baseload Gas/Wind	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	23	82	82	198	198	198	298	298	462
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	37
	Baseload Gas	0	0	0	0	0	326	326	653	653	653	653	653
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	247	329	675	809	1,151	1,167	1,281	1,296	1,511

Appendix B: Portfolio Details

Cumulative additions - Energy (MWa)

	Total MWa in operation by year (cumulative)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
17. Wind Energy Only	EE (Total)	35	69	99	124	147	167	184	201	216	230	245	259
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	50	166	496	556	556	556	720
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	199	224	247	317	450	797	872	886	901	1,079
18. Wind Energy w/ EE	EE (Total)	35	69	111	140	167	192	215	237	258	278	297	316
	DSG/DR	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	25	135	460	515	515	515	671
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	0	0	0	0	0	0
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	0	100	100	100	100	100	100	100	100	100	100	100
		35	169	211	240	267	317	450	797	873	893	912	1,087

Appendix B: Portfolio Details

Cumulative additions - Capacity (MW) (Usable Capacity for renewables)

	Total MW in operation by year (cumulative)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1. Market	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	0	0	0	18	18	18	18	18	43
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	0	0	0	0	97	97	97	97	97	227
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	436	425	472	694	731	1,130	1,252	1,303	1,337	1,226
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
2. Natural Gas	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	0	0	0	18	18	18	18	18	43
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	0	0	395	395	395	790	790
	Peakers (modeled as gas)	0	0	125	125	171	475	475	629	749	749	749	749
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0		
	Mid term / ST procurement reserve	450	450	312	300	300	219	353	204	205	256	-105	-86
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
3. Wind	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	0	0	0	18	68	68	68	118	144
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	125	125	171	475	576	973	1,094	1,094	1,100	1,153
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	312	300	300	219	252	204	205	256	234	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
4. Diversified Green	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	8	8	8	26	72	72	72	72	97
	Other Renewables	0	0	0	0	0	0	23	84	84	84	84	89
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	117	117	164	444	488	886	1,006	1,055	1,059	1,111
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	319	300	300	242	309	204	205	207	238	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903

Appendix B: Portfolio Details

Cumulative additions - Capacity (MW) (Usable Capacity for renewables)

	Total MW in operation by year (cumulative)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
5. Diversified Green/EE	EE (Total)	48	93	143	178	209	237	262	287	310	332	355	377
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	8	8	8	25	71	71	71	71	95
	Other Renewables	0	0	0	0	0	0	23	84	84	84	84	89
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	97	97	131	406	443	833	947	989	989	1,040
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	325	300	306	248	317	211	212	214	242	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
6. Green w/EE and CCCT	EE (Total)	48	93	143	178	209	237	262	287	310	332	355	377
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	8	8	8	25	71	71	71	71	95
	Other Renewables	0	0	0	0	0	0	23	84	84	84	84	89
	Baseload Gas	0	0	0	0	0	0	395	395	395	395	395	395
	Peakers (modeled as gas)	0	0	97	97	131	131	131	438	552	594	594	645
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	325	300	306	523	233	211	212	214	242	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
7. Baseload Gas/RPS only	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	0	0	0	18	18	18	18	18	43
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	395	395	790	790	790	790	790
	Peakers (modeled as gas)	0	0	125	125	125	125	125	234	354	403	411	463
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	312	300	347	174	308	204	205	207	234	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
8. Diversified Green with wind MT	EE (Total)	48	93	143	178	209	237	262	287	310	332	355	377
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	3	5	5	22	64	64	64	64	88
	Other Renewables	0	0	0	0	0	0	0	49	49	49	49	49
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	102	102	134	432	483	874	988	1,030	1,033	1,085
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	320	300	306	225	301	211	212	214	239	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903

Appendix B: Portfolio Details

Cumulative additions - Capacity (MW) (Usable Capacity for renewables)

Portfolio	Total MW in operation by year (cumulative)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
9. Diversified balanced wind/CCCT	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	4	13	13	30	30	30	46	46	71
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	24
	Baseload Gas	0	0	0	0	0	0	0	395	395	395	395	395
	Peakers (modeled as gas)	0	0	121	121	159	463	463	616	721	770	770	806
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	315	300	300	219	353	204	221	207	242	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
10. Diversified Solar/Wind	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	8	8	8	26	72	72	72	72	97
	Other Renewables	0	0	0	0	0	0	5	20	20	20	20	39
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	117	117	164	463	552	949	1,070	1,118	1,118	1,161
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	319	300	300	223	264	204	205	207	242	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
11. Diversified Green with non-CE EE only	EE (Total)	48	93	143	178	209	237	262	287	310	332	355	377
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	8	8	8	26	72	72	72	72	97
	Other Renewables	0	0	0	0	0	0	23	84	84	84	84	89
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	117	117	164	444	488	886	1,006	1,055	1,059	1,111
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	305	280	274	210	270	157	151	147	171	127
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
12. Oregon CO2 Goal	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	8	8	8	69	112	112	112	112	137
	Other Renewables	0	0	0	0	0	0	0	16	16	34	34	34
	Baseload Gas	0	0	0	0	0	0	395	395	395	395	395	395
	Peakers (modeled as gas)	0	0	117	117	164	489	839	839	917	966	974	1,026
	Exising Plants Changes	0	0	0	0	0	0	-670	-296	-296	-296	-296	-296
	Mid term / ST procurement reserve	450	450	319	300	300	198	213	180	223	207	234	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903

Appendix B: Portfolio Details

Cumulative additions - Capacity (MW) (Usable Capacity for renewables)

	Total MW in operation by year (cumulative)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
13. Baseload renewables	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	0	0	0	18	18	18	18	18	43
	Other Renewables	0	0	0	56	56	56	79	481	481	481	481	486
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	68	68	115	396	396	542	663	711	715	767
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	368	300	300	242	353	204	205	207	238	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
14. High Solar	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	0	0	0	18	18	18	18	18	43
	Other Renewables	0	0	0	11	11	11	16	100	100	100	100	118
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	114	114	160	459	526	924	1,044	1,093	1,093	1,135
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	323	300	300	223	286	204	205	207	242	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
15. Defer RPS Physical Compliance	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	4	13	13	13	13	13	13	13	56
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	24
	Baseload Gas	0	0	0	0	0	0	0	395	395	395	395	395
	Peakers (modeled as gas)	0	0	121	121	159	480	480	634	754	803	803	822
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	315	300	300	201	353	204	205	207	242	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
16. Diversified Baseload Gas/Wind	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	4	13	13	30	30	30	46	46	71
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	24
	Baseload Gas	0	0	0	0	0	395	395	790	790	790	790	790
	Peakers (modeled as gas)	0	0	121	121	121	121	121	221	326	375	375	411
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	315	300	338	165	299	204	221	207	242	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903

Appendix B: Portfolio Details

Cumulative additions - Capacity (MW) (Usable Capacity for renewables)

	Total MW in operation by year (cumulative)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
17. Wind Energy Only	EE (Total)	48	93	128	158	183	205	223	240	256	272	288	304
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	0	0	8	26	76	86	86	86	111
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	125	125	164	467	568	956	1,076	1,125	1,133	1,186
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	312	300	308	219	253	213	205	207	234	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903
18. Wind Energy w/ EE	EE (Total)	48	93	143	178	209	237	262	287	310	332	355	377
	DSG/DR	43	43	56	68	75	75	77	79	83	88	95	103
	Wind	0	0	0	0	0	4	21	71	79	79	79	103
	Other Renewables	0	0	0	0	0	0	0	0	0	0	0	0
	Baseload Gas	0	0	0	0	0	0	0	0	0	0	0	0
	Peakers (modeled as gas)	0	0	105	105	135	433	527	909	1,022	1,065	1,068	1,120
	Exising Plants Changes	0	0	0	0	0	0	0	0	0	0	0	0
	Mid term / ST procurement reserve	450	450	317	300	310	225	260	219	212	214	239	200
		540	585	621	650	730	974	1,146	1,564	1,706	1,778	1,835	1,903

Appendix C

PGE Candidate Portfolio Analysis Results

Appendix C: Candidate Portfolio Analysis Results

Table C-1 below shows the results of our Scenario analysis. We calculate the expected Net Present Value of Revenue Requirement (NPVRR) from 2013 to 2033 for each of the 18 Portfolios under each of the 36 Futures.

Table C-1: Portfolio Scenario Analysis Detail ($ Million)

2013 IRP - Portfolio Results - DRAFT filing Nov.2013

NPVRR, 2013$ million

Portfolios →	1	2	3	4	5	6	7	8	9
Futures ↓	Market w/ Physical RPS	Natural Gas	Wind	Diversified Green	Diversified Green/EE	Green w/EE and CCCT	Baseload Gas/RPS only	Diversified Green with wind MT	Diversified balanced wind/CCCT
Reference Case									
1 Reference Case	16,243	17,840	18,999	19,053	19,315	18,959	17,397	19,286	18,206
Fuel/CO_2									
2 High Gas	17,327	18,877	19,758	19,868	20,089	19,716	18,427	20,100	19,144
3 Low Gas	14,886	16,512	18,018	18,001	18,313	17,971	16,076	18,239	17,007
4 High Coal	16,531	18,095	19,248	19,309	19,568	19,202	17,654	19,543	18,464
5 Low Coal	16,092	17,691	18,855	18,907	19,170	18,815	17,248	19,141	18,059
12 No Carbon Tax	15,369	16,984	18,369	18,352	18,646	18,298	16,541	18,592	17,424
13 Synapse low CO2	16,812	18,388	19,453	19,517	19,766	19,400	17,942	19,752	18,723
14 Synapse High CO2	18,927	20,326	20,879	21,097	21,268	20,850	19,881	21,318	20,506
25 High Gas and CO2	20,104	21,506	21,773	22,048	22,178	21,758	21,059	22,267	21,582
26 Low Gas and No CO2	14,003	15,691	17,426	17,330	17,677	17,352	15,251	17,575	16,255
30 CO2 trigger	22,059	23,125	22,649	23,260	23,274	22,792	22,722	23,438	23,001
31 Very High Gas	18,971	20,415	20,819	21,052	21,205	20,801	19,964	21,277	20,520
33 16 dollars CO2 in 2023	16,115	17,717	18,908	18,950	19,218	18,864	17,274	19,186	18,093
Load									
6 Hi load test 1 std dev	17,209	18,805	19,964	20,018	20,280	19,925	18,362	20,252	19,172
7 Low load test 1 std dev	15,280	16,876	18,035	18,089	18,351	17,996	16,433	18,323	17,242
8 Hi load test 2 std dev	18,313	19,909	21,068	21,122	21,384	21,029	19,466	21,356	20,275
9 Low load test 2 std dev	14,284	15,880	17,039	17,093	17,355	17,000	15,437	17,327	16,246
24 Solar PV Penetration	16,165	17,762	18,921	18,974	19,237	18,881	17,319	19,208	18,128
28 Max PGE Opt Outs	15,600	17,196	18,356	18,409	18,672	18,316	16,754	18,643	17,563
Hydro									
10 High Hydro	15,723	17,500	18,697	18,719	19,001	18,712	17,071	18,957	17,869
11 Low Hydro	16,627	17,986	19,080	19,179	19,427	19,013	17,543	19,423	18,349
Capital Cost									
17 High Capital Cost Gas Thermal	16,265	18,001	19,142	19,188	19,441	19,074	17,532	19,418	18,345
18 High Capital Cost Wind and Solar	16,462	18,058	19,715	19,624	19,875	19,519	17,616	19,834	18,604
19 High Capital Cost	16,484	18,220	19,858	19,813	20,054	19,688	17,751	19,999	18,750
20 Low Capital Cost	16,041	17,497	18,430	18,497	18,775	18,430	17,081	18,790	17,786
21 No PTC and ITC	16,397	17,993	19,545	19,733	19,987	19,632	17,551	19,891	18,494
27 Low Capital Cost Wind and Solar	16,135	17,732	18,646	18,759	19,027	18,672	17,289	19,027	18,005
34 High Capital Cost Wind and Solar/No CO2	15,588	17,203	19,085	18,924	19,206	18,858	16,760	19,139	17,823
35 22 yr life for wind	16,717	18,313	20,546	20,223	20,460	20,105	17,871	20,408	19,047
36 32 yr life for wind	16,146	17,743	18,685	18,827	19,094	18,739	17,300	19,059	18,035
Power Prices									
15 High Electricity Prices	16,935	16,740	17,485	17,801	18,043	17,608	16,554	18,108	17,170
16 Low Electricity Prices	16,037	17,798	18,966	18,997	19,276	18,969	17,355	19,243	18,152
29 Perfect Storm	23,139	18,505	17,924	18,841	18,871	18,339	19,036	19,004	18,980
32 High Electricity Prices w/freeriders	16,833	15,503	16,003	16,353	16,620	16,205	15,393	16,709	15,890
Wind CF									
22 PGE Wind High CF	16,164	17,760	18,737	18,857	19,124	18,768	17,317	19,150	18,067
23 PGE Wind Low CF	16,324	17,920	19,262	19,250	19,508	19,152	17,477	19,424	18,347

2013 IRP - Portfolio Results - DRAFT filing Nov.2013

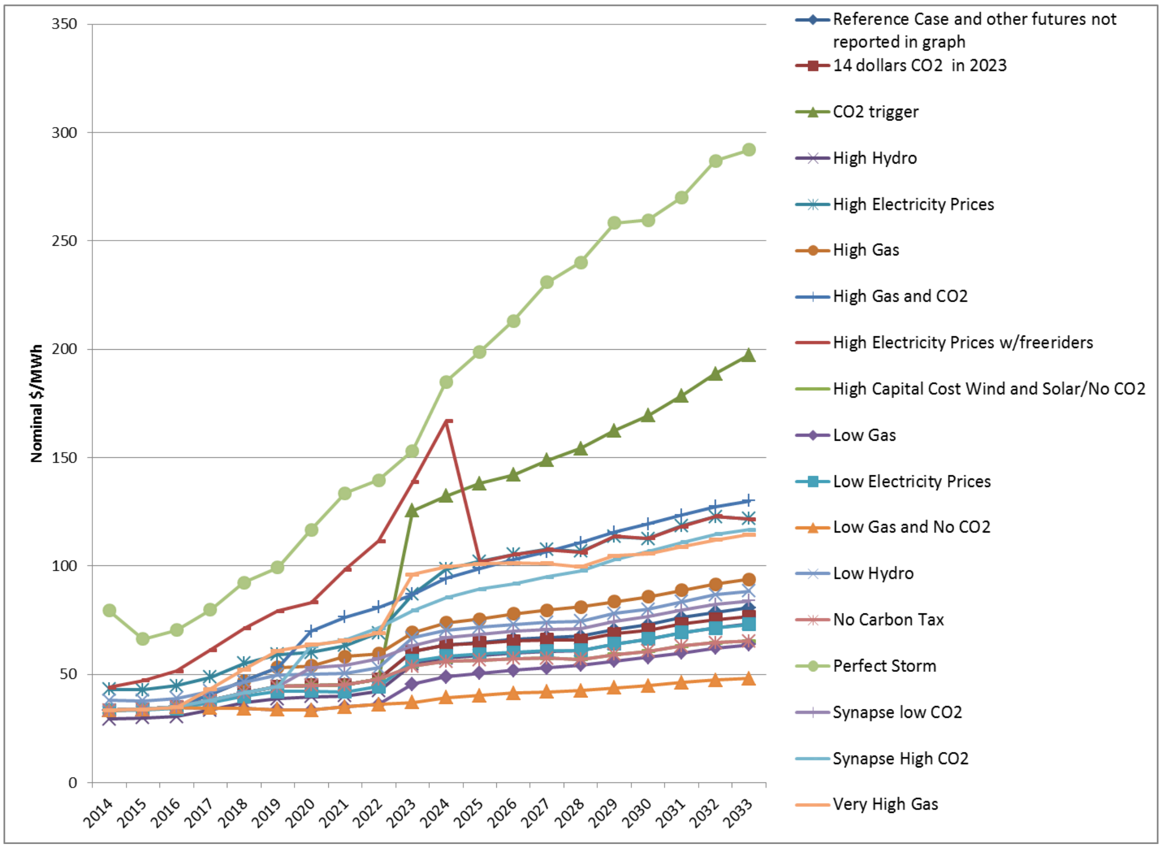
NPVRR, 2013$ million

Portfolios →	10	11	12	13	14	15	16	17	18
Futures ↓	Diversified Solar/Wind	Diversified Green with non-CE EE only	Oregon CO2 Goal	Baseload Renewables	High Solar	Defer RPS Physical Compliance	Diversified Baseload Gas/Wind	Wind Energy Only	Wind Energy w/ EE
Reference Case									
1 Reference Case	19,283	19,472	20,430	20,354	20,711	18,024	17,865	18,616	18,826
Fuel/CO_2									
2 High Gas	20,068	20,238	21,211	21,200	21,487	19,034	18,783	19,440	19,630
3 Low Gas	18,264	18,481	19,415	19,272	19,698	16,736	16,682	17,555	17,790
4 High Coal	19,536	19,725	20,472	20,617	20,966	18,287	18,112	18,872	19,081
5 Low Coal	19,138	19,328	20,398	20,207	20,565	17,875	17,717	18,470	18,681
12 No Carbon Tax	18,603	18,810	20,012	19,630	20,022	17,195	17,091	17,914	18,142
13 Synapse low CO2	19,739	19,920	20,699	20,833	21,173	18,573	18,371	19,082	19,287
14 Synapse High CO2	21,259	21,402	21,634	22,491	22,699	20,485	20,102	20,665	20,829
25 High Gas and CO2	22,186	22,306	22,461	23,464	23,629	21,627	21,174	21,623	21,768
26 Low Gas and No CO2	17,620	17,853	19,046	18,570	19,051	15,933	15,947	16,884	17,139
30 CO2 trigger	23,292	23,369	23,169	24,783	24,713	23,195	22,532	22,831	22,900
31 Very High Gas	21,200	21,339	22,300	22,446	22,614	20,537	20,124	20,628	20,786
33 16 dollars CO2 in 2023	19,184	19,376	20,370	20,248	20,612	17,905	17,754	18,513	18,726
Load									
6 Hi load test 1 std dev	20,248	20,438	21,395	21,319	21,677	18,989	18,830	19,581	19,791
7 Low load test 1 std dev	18,319	18,509	19,466	19,390	19,748	17,060	16,901	17,652	17,862
8 Hi load test 2 std dev	21,352	21,542	22,499	22,423	22,781	20,093	19,934	20,685	20,895
9 Low load test 2 std dev	17,323	17,513	18,470	18,394	18,752	16,064	15,905	16,656	16,866
24 Solar PV Penetration	19,205	19,394	20,352	20,276	20,633	17,945	17,787	18,538	18,748
28 Max PGE Opt Outs	18,639	18,829	19,787	19,711	20,068	17,380	17,222	17,972	18,182
Hydro									
10 High Hydro	18,967	19,167	20,200	19,983	20,389	17,647	17,600	18,282	18,500
11 Low Hydro	19,387	19,571	20,432	20,551	20,830	18,211	17,942	18,736	18,945
Capital Cost									
17 High Capital Cost Gas Thermal	19,425	19,608	20,601	20,447	20,850	18,165	17,995	18,761	18,962
18 High Capital Cost Wind and Solar	19,932	20,044	21,373	20,596	21,284	18,302	18,263	19,229	19,392
19 High Capital Cost	20,074	20,233	21,544	21,015	21,423	18,450	18,400	19,374	19,528
20 Low Capital Cost	18,696	18,917	19,690	19,731	20,037	17,660	17,453	18,095	18,337
21 No PTC and ITC	19,929	20,153	21,444	20,954	21,094	18,157	18,152	19,304	19,458
27 Low Capital Cost Wind and Solar	18,912	19,179	19,935	20,223	20,249	17,882	17,663	18,313	18,547
34 High Capital Cost Wind and Solar/No CO2	19,252	19,381	20,955	19,872	20,595	17,474	17,489	18,528	18,709
35 22 yr life for wind	20,454	20,643	22,214	20,828	21,185	18,610	18,706	19,923	20,032
36 32 yr life for wind	19,057	19,247	20,080	20,257	20,614	17,900	17,693	18,365	18,594
Power Prices									
15 High Electricity Prices	17,844	18,084	18,580	19,605	19,200	17,174	16,729	17,303	17,547
16 Low Electricity Prices	19,244	19,440	20,449	20,285	20,696	17,946	17,863	18,556	18,776
29 Perfect Storm	18,336	18,604	16,386	21,635	19,177	19,478	18,392	18,291	18,472
32 High Electricity Prices w/freeriders	16,305	16,584	16,758	18,490	17,563	16,033	15,439	15,807	16,106
Wind CF									
22 PGE Wind High CF	19,087	19,277	20,183	20,275	20,632	17,926	17,725	18,395	18,622
23 PGE Wind Low CF	19,480	19,670	20,677	20,435	20,794	18,122	18,005	18,837	19,031

Figure C-1 shows the electricity prices for the Pacific Northwest generated in the different futures and highlights their wide range. Aurora generates a different set of electricity prices for the WECC for the different futures described in Chapter 9 of the IRP.

Several futures, and therefore prices, are intentionally extreme in order to capture the risk embedded in futures different from our reference case.

Figure C-1: PNW Wholesale Electricity Price by Future



Appendix D

PGE Wind Integration Study Phase 4

I. Executive Summary: Wind Integration Study Phase 4

In 2007, given projections for a significant increase in wind generating resources, Portland General Electric (PGE) began efforts to forecast costs associated with self-integration of wind generation. This effort entailed developing detailed (hourly) data and optimization modeling of PGE's system using mixed integer programming (MIP). This study was intended as the initial phase of an ongoing process to estimate wind integration costs, and refine the associated model.

In October 2009, PGE began Phase 2 of its Wind Integration Study and contracted for additional participation from EnerNex (a leading resource for electric power research, plus engineering and consulting services to government, utilities, industry, and private institutions), who provided input data and guidance for Phase 1. A significant driver of Phase 2 was the expectation that the cost for wind integration services, as currently provided by the Bonneville Power Administration (BPA), would increase significantly as growing wind capacity in the Pacific Northwest would exceed the potential of BPA's finite supply of wind-following resources. In addition, it is PGE's contention that BPA's variable energy services rate and subsequent generation imbalance charges represent only a portion of the total cost to integrate wind, as calculated in Phase 2.

In the interim between Phase 2 and Phase 4, PGE conducted a Phase 3 internal study to inform the decision for the BPA FY 2014-2015 election period for wind integration services. The result of the study was a PGE election to contract with BPA to provide regulation, load following and imbalance (30 minute persistence forecast for a 60 minute schedule) services for Biglow Canyon for the term of the 2014-2015 election period.

A significant goal for Phase 4 of the Wind Integration Study was to include additional refinements (some of the enhancements were suggested in the "Next Steps" section of Phase 2) for estimating PGE's additional system operating costs incurred by the self-integration of its wind resources and to determine the sensitivity of the wind integration cost to gas price variability. As in Phases 1-3 of the Wind Integration Study, the Phase 4 effort has also included seeking input, deliverables, and feedback from a Technical Review Committee (TRC) and other external consultants. Since launching Phase 4, PGE has reprogrammed and refined the wind integration model, updated the study, and also held a public methodological workshop to discuss progress and modeling details. The public methodological workshop was attended by staff from the Oregon Public Utility Commission (OPUC), the Oregon Department of Energy (ODOE) and other interested parties that have participated in PGE's 2013 Integrated Resource Planning proceeding (IRP – OPUC Docket No. LC 56). In addition to this public review, the Phase 4 data and methodology have been carefully evaluated by the TRC, who provided valuable insight and information associated with wind integration modeling.

The Phase 4 model employs mixed integer programming implemented using the General Algebraic Modeling System (GAMS) programming and a Gurobi optimizer. The Phase 4 model incorporates the improvements made in Phase 2 including:

- Three-stage scheduling optimization with separate Day-Ahead, Hour-Ahead, and Within-Hour calculations;
- Refined estimates of PGE's reserve requirements.

The additional model improvements incorporated in Phase 4 include:

- Separate increasing ("INC") and decreasing ("DEC") reserve requirement formulations for regulation, load following and imbalance reserves;
- Gas supply constraints limiting gas plant fuel usage to the Day-Ahead nomination levels +/- drafting and packing limits on the pipeline;
- Ability to economically feather wind resources; and
- Implementation of the dynamic transfer constraint to allow for limited intra-hour dynamic capacity provision for Boardman, Coyote and Carty.

The results of the study indicate that PGE's estimated self-integration costs (in 2018$) at the reference gas price case is $3.99 per MWh, the high gas price case is $4.24 per MWh, and the low gas price case is $3.57 per MWh. These prices fall within the range calculated by other utilities in the region. **Note: PGE's estimated self-integration costs are exclusive of the necessary investment required in software automation tools, generation control systems, communications/IT infrastructure, and the potential need for personnel additions to manage the self-integration of variable energy resources.** Specific model assumptions are detailed below but, in short, reflect a potential 2018 state in which PGE seeks to integrate almost 717 MW of wind (to physically meet the 2015 Oregon RPS requirement) using existing PGE resources, and future balancing resources acquired in the 2011 RFP, subject to associated operating limitations. As the supply of variable energy resources and the associated demand for flexible balancing resources increases over time, subsequent phases of the Wind Integration Study will assess the effects of these changes.

II. INTRODUCTION

i. REASONS FOR THE PHASE 4 WIND INTEGRATION STUDY

Since the Phase 2 Study, there have been significant changes in the capabilities and inputs to the model. The additional capabilities of the PGE Wind Integration Model were developed in response to public suggestion and internal requests. In addition, gas prices fell off dramatically due to the increased availability of shale gas. As a result of the 2011 RFP process PGE added 266.5 MW at Tucannon River Wind Project, 220 MW flexible gas generators, Port Westward 2, and 440 MW baseload combined cycle gas generator at the Carty Reservoir site. In 2018, PGE loses some of its most flexible capacity on its system with the falling off of some Mid-C contracts. Given the aforementioned changes, it seemed appropriate to update the Phase 2 Study.

ii. STUDY ASSUMPTIONS

Phase 4 of the Wind Integration Study is based on existing PGE owned and contracted resources (as of 2018) plus the 2011 RFP resources which are all planned to be commercially available by 2018. By 2018, PGE will have a varied mix of generation consisting of 2,496 MW of thermal generation (670 MW coal-fired and 1,826 MW gas-fired), 489 MW of PGE-owned hydro generation, approximately 147 MW of long-term hydro power purchase agreements, and 817 MW of wind generation. (One-hundred MW of the wind plant receives long-term third-party wind integration and is not included for this study.) Because PGE is currently a "short" utility, the remainder of its load is covered by market transactions – term contracts and spot market purchases.

Additional assumptions within the model include:

- 2018 is the Wind Integration Study year.
- 2005 actual data was used for hydro flows, wind generation, and load forecast errors.
- 2018 Mid-Columbia (Mid-C) electricity market prices (as used for economic dispatch in the wind integration model) were simulated with AURORAxmp. This is the model used in the Integrated Resource Plan (as discussed in Section 5.3.2, below.
- PGE's 450 MW Biglow Canyon Wind Farm, located in Sherman County, Oregon, is self-integrated.
- PGE's 266.5 MW of Tucannon River Wind Project, located in Columbia County, Washington, is self-integrated.

PGE resources available to provide ancillary services:

- PGE's contractual share of Mid-Columbia hydro generation, which diminishes over time;
- Two-thirds of Pelton-Round Butte hydro generation
- Beaver gas-powered generation, in both combined cycle and simple cycle modes.
- Coyote Springs gas-powered generation
- Port Westward 2 gas-powered generation

PGE resources not available to provide ancillary services:

- Port Westward gas-powered generation
- Carty gas-powered generation
- Boardman coal-powered generation
- Colstrip coal-powered generation

Specific details of PGE's resources and their effective uses for ancillary services are provided in Section V.iv, below.

In Section III of this report, we summarize the public process and third-party review undertaken to ensure that PGE has accomplished its goal of developing an accurate representation of its potential for self-integration using base-line assumptions and robust modeling techniques. In Section IV, we describe the regional wind characteristics used to establish PGE's integration requirements during Day-Ahead, Hour-Ahead, and Within-Hour time frames. In Section V, we provide a detailed description of PGE's wind integration methodology including the programming tools, data assumptions, modeling approach, and calculations for reserves and other variables. In Section VI, we provide a summary of the results and conclusions of our findings. Section VII provides appendices of supporting detail and documentation.

III. PUBLIC PROCESS AND REVIEWS

As with Phase 2 of the Wind Integration Study, Phase 4 sought to assure a robust review by external parties of the logic, assumptions, and data within the model to ensure their accuracy and thereby comply with the Commission directive to have a "wind integration study that has been vetted by regional stakeholders." (Commission Order No. 10-457). To achieve this, several groups were invited to participate in PGE's efforts.

iii. TECHNICAL REVIEW COMMITTEE (TRC)

PGE's TRC consisted of the following members:

- J. Charles Smith, Executive Director, Utility Variable-Generation Integration Group (UVIG)
- Michael Milligan, Ph.D., Principal Analyst, National Renewable Energy Laboratory (NREL)
- Brendan Kirby, P.E., Consultant with NREL
- Michael Goggin, Manager of Transmission Policy, American Wind Energy Association (AWEA)
- Bob Zavadil, E.E., Executive VP of Power Systems Consulting, EnerNex Corporation

The constitution, functions and requirements of the TRC were determined in accordance with UVIG's "Principles for Technical Review Committee (TRC) Involvement in Studies of Wind Integration into Electric Power Systems" as provided in Appendix A.

In accordance with UWIG's TRC Principles agreement, PGE's TRC, in a joint letter displayed in Attachment 1, "endorses the study methodology, execution, and this final report" of PGE's Phase 4 Wind Integration Study.

iv. PROGRAMMING CONSULTANTS

In Phase 4, PGE employed one outside subject matter expert, Jennifer Hodgdon, Ph.D, to assist in the enhancement of the mixed integer programming (MIP) based optimization model that PGE used to calculate costs associated with integrating wind into the PGE system. Dr. Hodgdon helped develop and implement the GAMS and Visual Basic utilized in enhancing the capabilities of the model developed in Phase 2.

Jennifer Hodgdon is owner and Principal Consultant for Poplar ProductivityWare, Seattle and Spokane, WA. She received her Ph.D. degree from Cornell in 1993 and has more than fifteen years of experience as a professional software developer, using a variety of languages and operating systems for many different applications and in various industries.

v. PUBLIC MEETINGS

PGE held two public regional stakeholder meetings in which all members of the service list from PGE's 2013 IRP (OPUC docket LC 56) were invited to attend and provided the opportunity to examine in detail, the methodology of the study and the results. The meetings were held on August 8 and August 29, 2013, and attended by OPUC staff and other interested parties.

During these meetings, PGE provided detailed explanations of the enhancements to the modeling approach, methodology, data inputs, assumptions, bases for cost breakdowns and reserves, and the actual integration costs. PGE also answered numerous questions and engaged in extensive discussion regarding details of the Wind Integration Study.

IV. WIND INTEGRATION ISSUES & METHODOLOGY – OVERVIEW

i. WIND DATA SOURCE

The development of wind power capacity factors and shapes representative of wind generation operations was established initially by using the NREL Western Wind Resource Database (WWRD). The database is a result of 3TIER Group's modeling of wind resources across the entire western United States to generate a consistent wind dataset at a 2-km, 10-minute resolution based on actual wind measurements for the years 2004, 2005 and 2006. The NREL database converted wind to power based on the power curve for Vestas V90 3 MW (Biglow Phase 1), Siemens 141 SWT 2.3 MW turbines (Biglow Phase 2 and 3), and Siemens 108 SWT 2.3 MW turbines (Tucannon River).

The WWRD database provided the following wind data for the study:

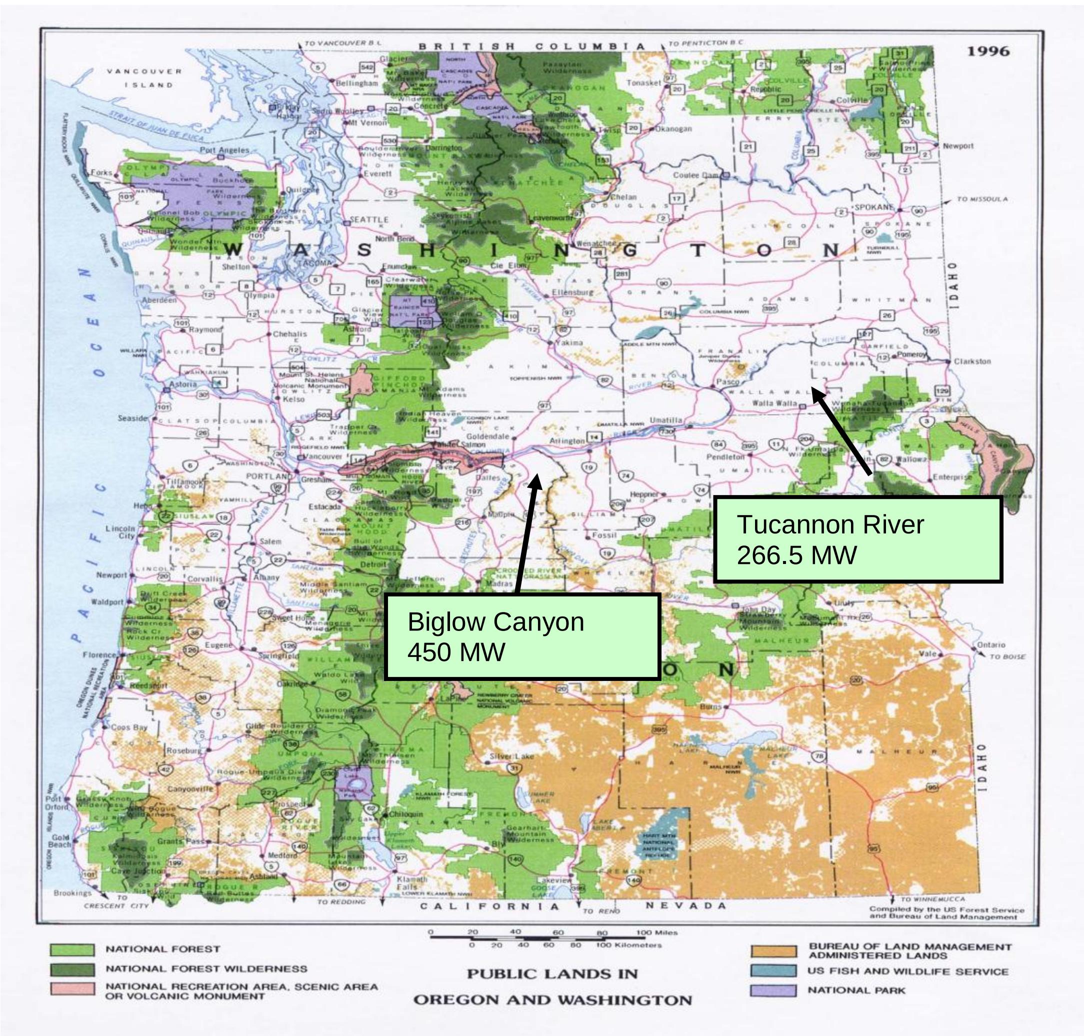
- Date and time (mm/dd/yyyy hh:mm:ss.sss)[1]
- Wind speed (mph)
- Actual wind power output in MW at 1 minute and 10 minute intervals
- Day-Ahead forecast power in MW at 1 hour intervals
- Years 2004, 2005 and 2006

[1] The time stamp hh:mm:ss.sss conveys hours, minutes, seconds and fractional seconds.

- Site Id
- Site location (Longitude, Latitude)

ii. ***WIND SITE POWER OUTPUT***

Virtual wind farms of 266.5 MW in Columbia County on the Tucannon River site and 450 MW in Sherman County on the Biglow Canyon site (see Figure 1, below) in the Columbia River Gorge were developed by selecting multiple wind sites and aggregating the wind site outputs from the NREL database. Capacity factors for the 266.5 MW and 450 MW wind farms based on the 2005 NREL data were 34.4% and 29.6%, respectively.



iii. WIND SITE FORECASTS

PGE methodology for performing forecasts is unchanged from the Phase 2 study[2].

V. WIND INTEGRATION METHODOLOGY

i. OVERVIEW

Phase 4 of the Wind Integration Study seeks to determine the effect on system operating costs resulting from the introduction of wind resources on PGE's system; specifically, of PGE employing its own generating resources to integrate 716.5 MW of wind capacity in 2018. The system operating costs of wind integration at different gas price levels are calculated by modeling total system costs with and without the additional reserve requirements due to wind. The costs of wind integration in this study are measured as the savings in system operating costs that would result if wind placed no incremental requirements on system operations. The cost savings are conditional on the ability of a given set of generation resources to adjust for the variability and uncertainty of wind generation. In the remaining sections of this chapter, we will discuss:

- The need for Dynamic Capacity in PGE's portfolio (Section V.ii.)
- The modeling tools used by PGE in implementing the study (Section V.iii.)
- Data sources, data generation, and modeling assumptions (Section V.iv.)
- The logic and structure of the modeling approach (Section V.v.)
- Methods for calculating incremental reserves for integrating wind (Section V.vi.)

ii. THE NEED FOR DYNAMIC CAPACITY

One of the challenges that PGE faces as a system operator is that we are required to match our system generation to our system load while that load is constantly changing. As PGE adds more variable generation, such as wind, to its portfolio of resources, that challenge becomes more demanding as both generation and load can change moment-to moment. Addressing the challenge of matching total generation with load in real time requires flexible generation that can change production levels over a significant range of operations, and do so in a short time frame. The challenge facing scheduling entities in the Pacific Northwest is that power, predominantly from trades, is currently scheduled for no less than one hour blocks[3]. In 2018, there may or may not be significant and reliable amounts of fast-acting demand response. Therefore, the majority of the responses to changes to load or variable generation must be managed with generators over which

[2] See PGE Phase 2 Wind Integration Report, pp. 13-15 for details of the forecasting methodology.

[3] While there has been some significant movement in the region towards regional imbalance or intra-hour market solutions, at the time of the study there was a large amount of uncertainty about the structure of the market and when/how access to that market might be available.

PGE has physical control and that have been scheduled to allow for intra-hour dynamic generation changes.[4]

As discussed in the Wind Integration Study Phase 2, the reserve requirements for which dynamic capacity must be set aside are as follows: Load Following, Regulation and Contingency Reserves (Spinning and Non-Spinning). Each of these reserves has an independent capacity requirement. Load following and regulation also have an energy requirement that must be assigned to the generator carrying the services.

Contingency Reserves have requirements for storage (for hydro plants) or fuel (for thermal plants). For hydro plants providing contingency reserves, the pond must have sufficient water to produce energy associated with having the spinning or non-spinning reserve called up during the hour. Thermal plants providing contingency reserves have similar fuel reservation requirements.

Increasing and Decreasing Reserve Requirement Model Enhancement

In Wind Integration Phase 2 Reserve calculations, an assumption was made, for simplicity, to make reserve requirements with associated energy (load following and regulation), and increasing and decreasing (INC/DEC) components symmetric. In other words, half of the range of system movement required to account for a particular reserve would be assumed to fulfill the increasing (INC) requirement and half would be assumed to fulfill the decreasing requirement. This symmetry between INC/DEC reserves created simple formulations of reserve requirements and also allowed for a simple accounting of energy and capacity in the constraints supplied to GAMS (two equations per reserve-providing plant). The INC and DEC range requirements are assumed to be the maximum movement above and below the average load net wind for the hour.

In operations, it is observed that the range requirements for load and wind INC and DEC reserves are not usually the same for a particular hour, and inputting independently formulated INC and DEC reserve requirements to the PGE model would better capture system needs for flexibility within an hour. Consider the following examples relating to load following reserve requirements below:

1. Example 1 is a simple example showing if there is just one load net wind movement that is basically equivalent to looking at 2 half hour load net wind blocks that are equally above and below the average load net wind for the hour.
2. Example 2 shows a situation where load net wind decreases steadily over the hour.

[4] For further description of the types of generators required to provide dynamic capacity and a preliminary discussion of reserve range and associated energy please refer to Wind Integration Study Phase 2 pp. 17-19

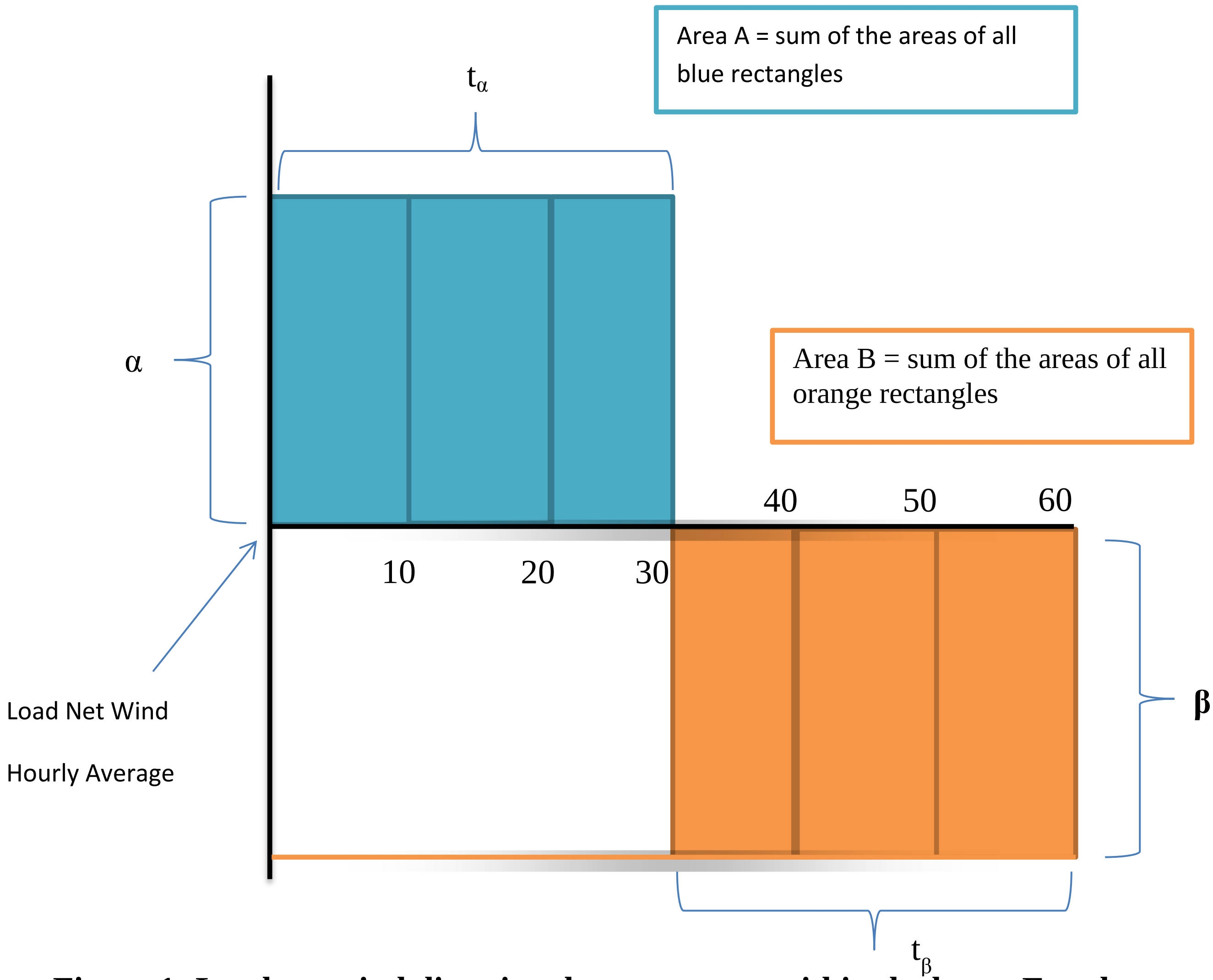


Figure 1: Load net wind direction decreases once within the hour: Equal INC and DEC capacity requirements, $\alpha = \beta$ and $t_\alpha = t_\beta$

The range and duration of required INC and DEC load following reserves are of equal and opposite sign (i.e. $\alpha = \beta$ and $t_\alpha = t_\beta$). In addition, for the formulation to be correct, the energy accounting must reflect the following equality: Area(A) = Area(B). Note that in this case it is also true that Area(A) = β*j - Area(B), where j is the number of time steps in the period, which implies that the energy produced by the reserve providing unit is equal for INC and DEC. This is a simple example of an assumed shape where the INC and DEC reserve requirement shape and the energy associated with providing both reserves are equal and opposite.

Now, consider another example where the intra-hour shape is more complex:

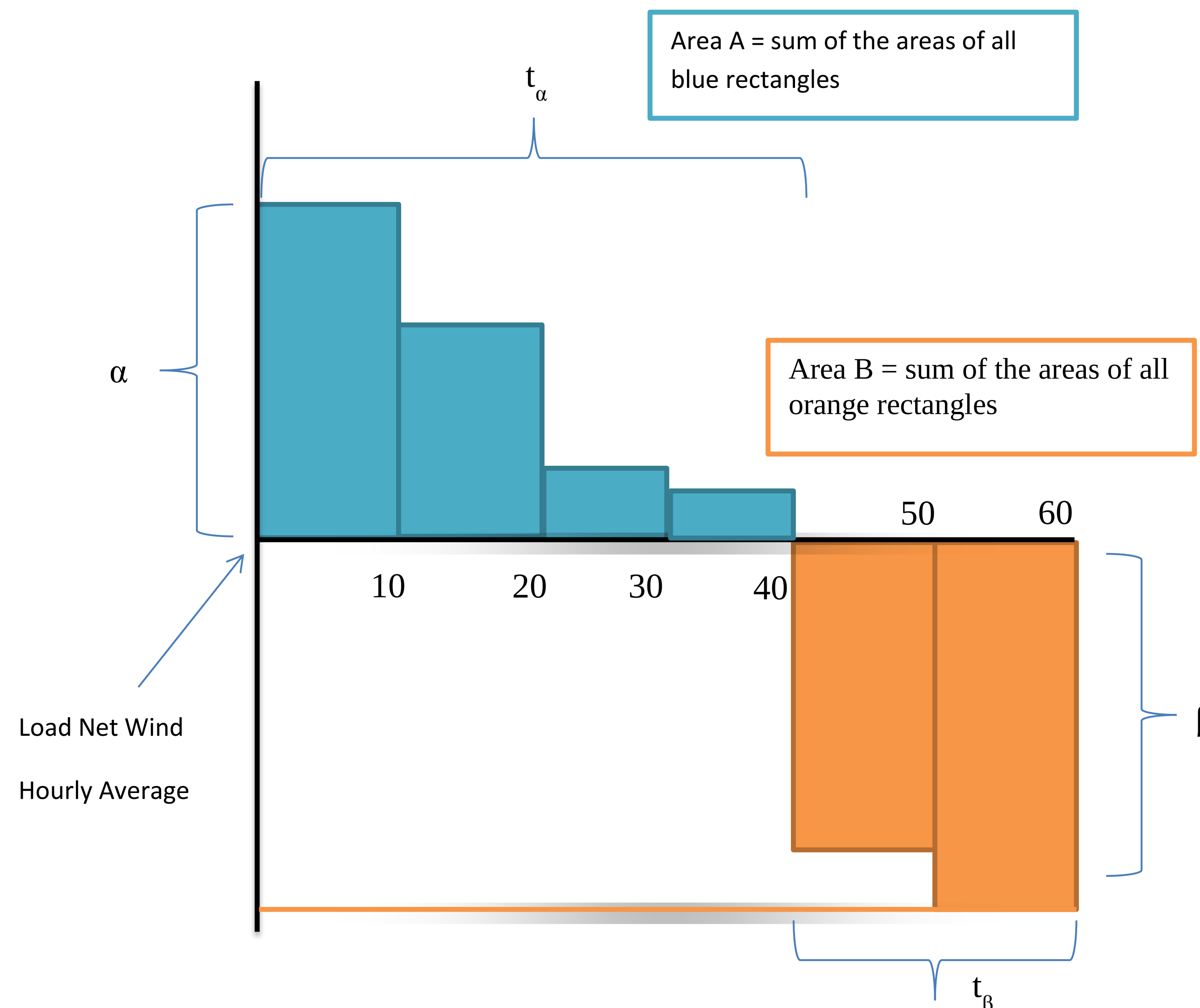


Figure 2: Load net wind decreasing at a non-constant rate through the hour: Equal INC and DEC capacity requirements, $\alpha < \beta$ and $t_\alpha > t_\beta$

The range and duration of required INC and DEC load following reserves are not of equal and opposite sign (in this case $\alpha < \beta$, but $t_\alpha > t_\beta$). However, again, for the formulation to be correct, the energy accounting must reflect the following equality: Area(A) = Area(B). Note that in this case it is NOT true that Area(A) = β*j - Area(B), where j is the number of time steps in the period. In the Phase 4 study, the reserve requirement ranges for load and wind in each hour are considered as above. Once the total reserve requirement ranges and associated energy to provide reserve over that range for Load Following INC, Load Following DEC, Regulation INC and Regulation DEC have been calculated, then the model chooses how to apportion those requirements throughout the portfolio by assigning a percentage to each available plant capable of providing such reserves.

The following is a derivation of the above percentage assignation of reserve requirement.

Let α_k be the amount of inc reserve and let β_k be the amount of DEC reserve provided by plant k. Then let $\sum_k(\alpha_k) = \alpha$ and $\sum_k(\beta_k) = \beta$ in a particular hour i. Let j be the number of data points over which Areas A and B are evaluated. In addition, let the following equations allow the energy accounting depend on the capacity reserved by a particular plant:

$E_\alpha^k = (\alpha_k / \alpha)*(Area(A))/j$ *(energy created by holding out inc reserve on plant k)*

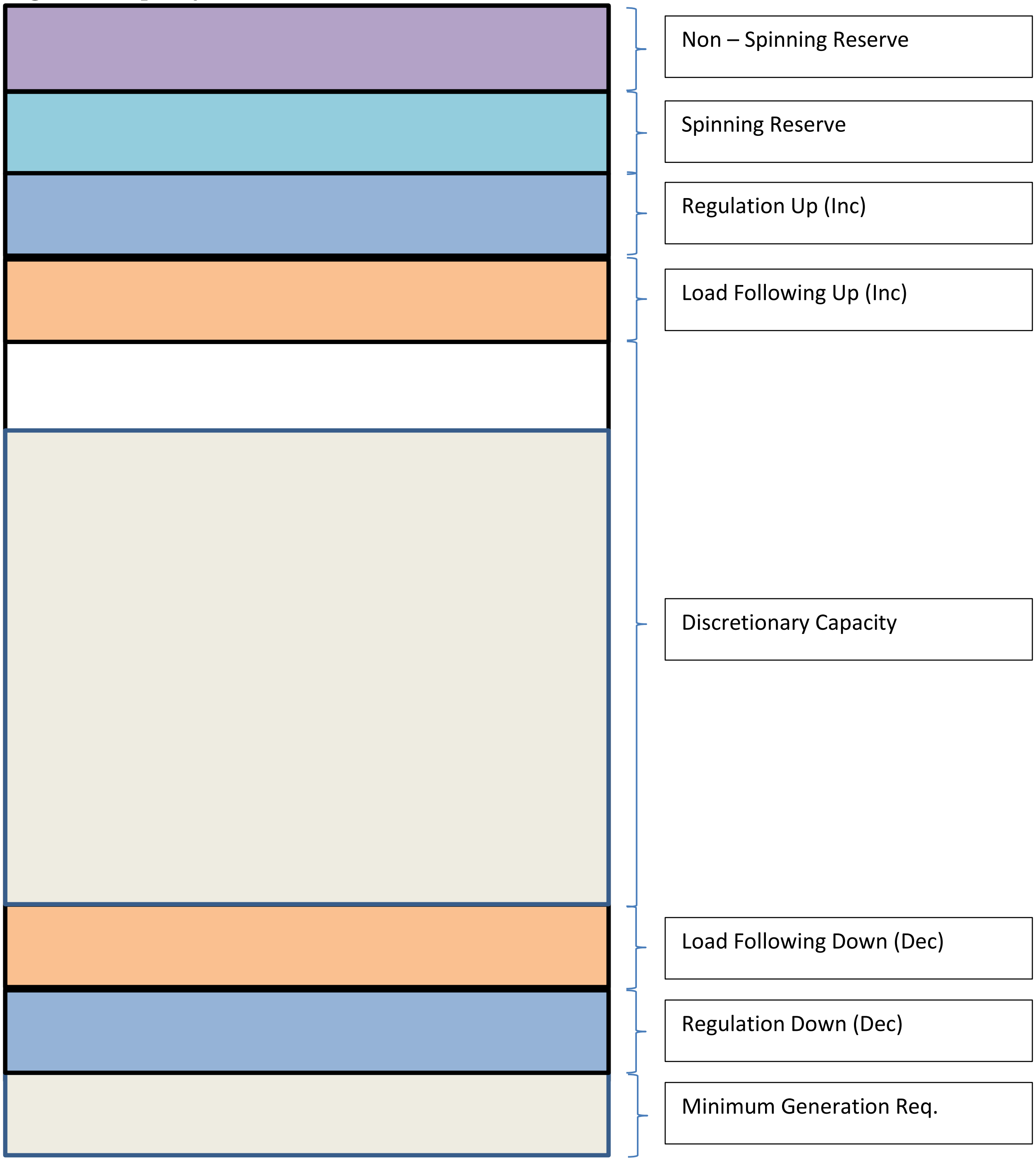
$E_\beta^k = (\beta_k / \beta)*(\beta*j - Area(B))/j$ *(energy created by holding out DEC reserve on plant k)*

In this case, α_k and β_k will be determined be the model, but Area(A), Area(B), α and β will computed outboard and input into the model for each time increment (hourly, sub-hourly).

When the model considers what percentage of the reserve requirements (regulation, load following, spinning, and non-spinning reserves) should be assigned to the plant also must consider other range limitations: minimum generation levels and discretionary energy dispatch. A plant's minimum generation is required to provide almost all reserves (non-spinning can be provided without minimum generation in some cases). The cost of this minimum generation is often the hurdle for a plant's provision of reserves.

In Figures 3 and 4 below, a plant's operating range is assigned all of the discussed reserve components, and minimum generation and discretionary energy. Note that the plant has some unused discretionary range because that is theoretically possible, however in practice, if the plant is generally dispatched for discretionary energy production it is usually because it is in the money and thus would use all of its discretionary range.

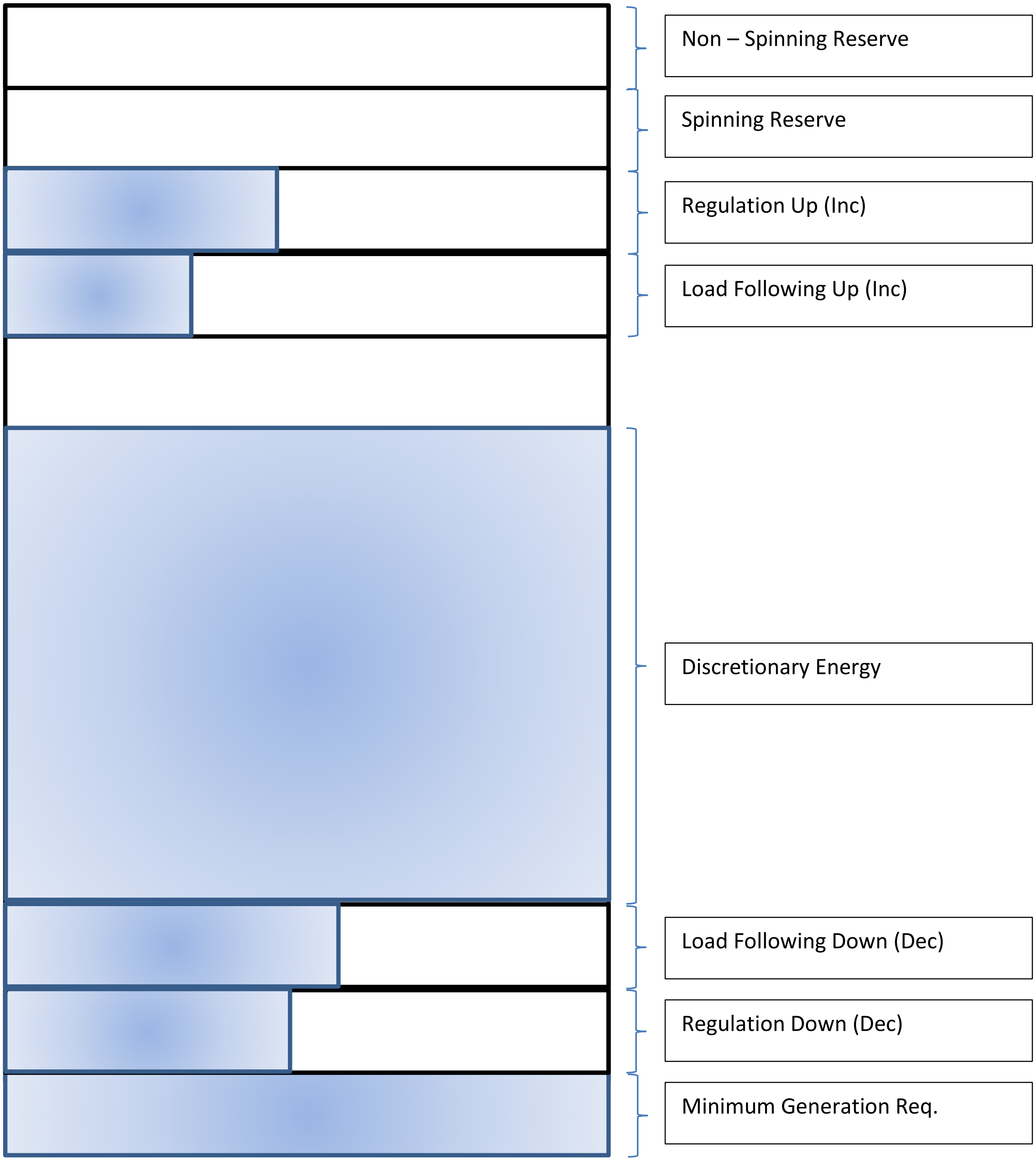
Figure 3: Capacity Reservation on a Generator[5]



[5] Note that this does not necessarily represent the energy produced by reserving a range of the generator for capacity purposes, for more detail on the associated energy see Figure 4 below.

Figure 4: Example of Energy Produced by allocating capacities as in Figure 3

- Add up the blue blocks to get the energy associated with the capacity ranges in Figure 3



Energy production is equal to the capacity provision of the discretionary range that is selected by economic dispatch and the minimum generation requirement[6]. In contrast, there is no energy production directly connected to the provision of contingency reserves (spinning and non-spinning)[7]. The load following capacity reservation[8] is required to cover the largest deviation by the ten-minute average data from the average energy produced over the appropriate dispatch time period. The regulation capacity reservation[9] is required to cover the largest deviation of the one-minute data from the ten-minute average data. By definition, the energy associated with providing those load following and regulation reserves (INC or DEC) must be less than the capacity reserved to meet that requirement. Another way of thinking about this is that for every bit of range of the plant that is reserved for contingency reserves, load following and/or regulation there is foregone opportunity for the plant to have used that range to produce baseload generation over the ENTIRE dispatch period.

iii. MODELING TOOLS

System Optimization

PGE has developed an economic dispatch model to estimate operating costs for the PGE system. This is the principal model used in the Wind Integration Study. The model has a cost minimization objective function and a set of equations/inequalities which detail constraints on the operation of PGE's system. This model was constructed using three commercially available software products: GAMS, Gurobi, and Microsoft Excel. GAMS is used to program/compile the objective function and operating constraint equations. Gurobi is used to solve the resulting constrained optimization problem. Excel (and associated VBA code) is used for data input, reporting model results, and overall model control.

GAMS is a high-level modeling system for mathematical programming and optimization. It consists of a language compiler and a set of integrated high-performance solvers. GAMS is tailored for complex, large-scale modeling applications, and facilitates the construction of large maintainable models that can be quickly adapted to new situations.

The Gurobi Optimizer is a state-of-the-art solver for linear programming (LP), quadratic programming (QP), and mixed-integer linear/quadratic programming (MILP and MIQP). It was designed to exploit modern multi-core processors. For MILP and MIQP models, the Gurobi Optimizer incorporates the latest methods including cutting planes and powerful solution heuristics. Models benefit from advanced presolve methods to simplify models and reduce solve times.

Aurora Model

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[6] In other words, the entire capacity of the range reserved is dispatched over the entire dispatch period.

[7] In the model there is no energy produced even though a portion of the plant is reserved for contingency reserves. In real operation, these reserves will be dispatched only during regional contingencies, and once the contingency situation has been stabilized they need to be re-allocated and maintained without associated generation.

[8] The way load following is defined in the Wind Integration Model.

[9] The way regulation is defined in the Wind Integration Model.

PGE relies on the AURORAxmp Electric Market Model in its IRP for developing the long-term forecast of wholesale electricity prices and for portfolio analysis, as detailed in Chapter 9 of PGE's 2013 Integrated Resource Plan. AURORAxmp is a model that simulates electricity markets by NERC (North American Electric Reliability Corporation) area, detailing: 1) resources by geographical area, fuel, and technology; 2) load by area; and 3) transmission links between areas. As stated in the IRP, PGE uses it to conduct fundamental supply-demand analysis in the Western Electric Coordinating Council (WECC). AURORAxmp is also used to forecast 2018 hourly electricity prices for the Pacific Northwest. These hourly electric prices and the corresponding gas prices, were then input into the Wind Integration Model.

iv. Data Assumptions

Plants Available for Integration

As noted in Section II.ii, above, PGE has a varied mix of generating resources but only a subset of these resources has the capability to provide the Dynamic Capacity required for wind integration. Specifically, we do not use the following thermal resources as part of our modeling:

Port Westward (excluding the duct burner) – plant technology was not designed to provide Dynamic Capacity.

Boardman – this baseload coal plant has a limited dynamic range. It is not allowed to provide dynamic capacity products until a Wear and Tear study better quantifies the risks of operating the plant more flexibly.

Colstrip – PGE does not directly control the operation of this baseload coal plant.

As described in Section V.ii above, for resources that are able to provide ancillary services, only the portion not used for discretionary energy production is available for Dynamic Capacity. A summary of PGE's resources and their specific ancillary services capabilities is provided in Table 1, below.

Table 1: PGE's 2018 Portfolio (does not include Tucannon River or Biglow Canyon Wind Farms)

	Reserve Type	Mid-C	Round Butte	Pelton	Westside Hydro	Boardman	Colstrip	Port Westward	Port Westward Duct Burner	Coyote	Beaver – Simple Cycle	Beaver Combined Cycle	Carty	Carty Duct Burner	Port Westward 2	Distributed Standby Generation
Energy		X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Capacity	Load Following	X	X	X					X	X	X	X		X	X	
	Regulation	X	X	X							X				X	
	Spinning Reserve	X	X	X					X	X	X	X		X	X	
	Non-Spinning Reserve	X	X	X					X	X	X	X		X	X	X

Fuel Prices

PGE relies on independent third-party sources to project fuel prices. Specifically, to be consistent with our IRP methodology, Wood-Mckenzie provided reference, high and low case gas forecasts for 2018. Variable transportation costs are summed with gas commodity price to compute the delivered cost of the fuel, which, along with variable O&M, is used in the dispatch decision. PGE used the most recent available fuel forecast, which was May 2013.

Regional Wholesale Electric Prices

As in the Wind Integration Study Phase 2, PGE used AURORAxmp to generate the wholesale electricity prices used in the wind integration model for the dispatch of PGE generating resources. AURORAxmp simulates the fundamentals of supply and demand in the WECC and is the model used in PGE's 2013 IRP. Macroeconomic assumptions and modeling setup are those described in the

2013 IRP draft (as filed in November 2013) with minor changes not materially affecting electricity prices:

Carbon regulation

It was assumed that no specific carbon regulation is in place by 2018.

Wind shapes

Wind shapes for the WECC are those of the default 2012 AURORAxmp data base. EPIS (the developer of the Aurora market model) developed wind shapes for each area in the WECC using this NREL data. These were calculated by averaging the three years of NREL data (2004-2006), selecting sites/areas as typical of a region, computing a typical-week wind generation for every region and month with hourly detail (168 hours for each month), and reintroducing some of the variability in hourly generation lost in averaging .

For new plants in the Pacific Northwest, PGE computed a typical hourly shape (8760) representing the aggregate wind generation in the BPA balancing authority. We chose 2011 as the year that best fits the historical behavior of wind in the PNW and used the computed hourly shape from the BPA wind generation in 2011 to model any other generic wind plant in the PNW.

Resulting electric prices

The resulting average 2018 wholesale electricity price is $41.26 per MWh ($46.83 on-peak and $30.12 off-peak). In the Pacific Northwest, prices tend to peak in winter, when PNW load peaks, and in July-August, when California's load is peaking. Spring is typically a low price season, because of the abundance of hydro. Hydro is a major driver of prices in the Pacific Northwest. For modeling purposes we assume average hydro conditions.

Loads and Load Forecast Error

For Phase 4 of the Wind Integration Study, PGE projected its 2018 load data by employing a three-step process using 2005 actual load and 2005 Day-Ahead and Hour-Ahead load forecast data. The wind data is based on 10-minute intervals for the necessary Within-Hour granularity.

<u>Step 1. Realign Days of Week</u>
PGE developed the 2018 load data from 2005 load data by first aligning the 2005 actual load data days of the week with the 2018 days of the week. Because January 1, 2005 fell on a Saturday and January 1, 2015 falls on a Monday, we used the first Monday of January 2005 (January 3rd, 2005) for Monday, January 1st, 2018. Tuesday, January 4th, 2005 was then used for Tuesday, Jan. 2nd, 2018, and so on. This step is important because the load and wind data must correspond to the same days for consistency in deriving the "load net wind" concept.

<u>Step 2. Escalate 2005 to 2018</u>
The realigned 2005 data was then scaled up to 2018 levels by an escalation factor equal to the percentage increase from PGE's 2005 average annual actual load to PGE's 2018 average annual

forecast load. The realigned and scaled data was then used to develop the projected 2018 real-time load data in the model.

Step 3. Develop Hour-Ahead and Day-Ahead Forecast Loads
PGE's 2018 Hour-Ahead and Day-Ahead forecast load data was derived by summing the 2018 forecasted-actual load data (derived in steps 1 and 2 above) with the corresponding 2018 Hour-Ahead or Day-Ahead load forecast error data. Specifically, the 2018 Hour-Ahead and Day-Ahead load forecast error data was created by: 1) taking the difference between the respective forecasted and actual 2005 loads, and then realigning to the matching day of the week, and 2) scaling the actual 2005 Hour-Ahead and Day-Ahead forecast errors in the same way the 2005 actual load data was escalated to 2018 forecast load data (described in step 2, above).

Water Year

PGE selected 2005 hydro flows for use in the wind integration model as a proxy for 2018 hydro flows. Of the three years (2004-2006) of NREL wind data used in the Western Wind and Solar Integration Study (from which EnerNex derived the wind energy data), 2005 was nearest to a normal hydro year for the Pacific Northwest. PGE did not use a 3-year hydro average of those years because the resulting hourly averages would mask the interactive effect of localized weather on hydro flows and wind speeds. The inputs of the wind integration model are temporally aligned to try to capture the effect of weather creating volatility in loads, wind, and hydro, and the resulting effect on the system trying to provide the Dynamic Capacity to meet the reserve needs of such volatility.

Specific hydro data used in the wind integration model includes:

- Mid-Columbia hydro energy – this is treated as one resource in the model, so historical (2005) flows from Chief Joseph were used.
- Deschutes hydro project inflows – USGS daily average inflows from 2005 were the assumed inflows for Round Butte.
- Hourly energy for PGE's run-of-river hydro – PGE historical PSAS (Power Scheduling and Accounting System) data from 2005 was used as proxy hourly energy data for Oak Grove, North Fork, Sullivan, Faraday, River Mill, and PGE's portion of Portland Hydro Project. (These hydro facilities do not provide ancillary services for wind integration.)

Bid/Ask Pricing

The wind integration model assumes virtually unlimited access to the energy market in the Day-Ahead and Hour-Ahead schedules. When the model chooses to purchase or sell energy in the Day-Ahead or Hour-Ahead stages to balance generation to load net of wind, there is an assumed bid/ask spread that affects the economics of using the market to meet load.

The Bid/Ask treatment is the same as in Phase 2 of the Wind Integration Study[10].

[10] See pp. 29-30 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"

General constraints for Hydro

The hydro modeling methodology is the same as in Phase 2 of the Wind Integration Study[11], and all hydro data is consistent with the Phase 2 study, except PGE's contractual shares of the Mid-Columbia system are decreased in 2018 to reflect the expiration of the Wells contract.

General Constraints for Thermal Plants Providing Ancillary Services

In Phase 4 of the Wind Integration Study, Beaver and Port Westward Duct Burner are available to provide ancillary services as in Phase 2[12]. In addition, 50 MW per hour of intra-hour movement will be allowed on Coyote Springs (natural gas combined cycle cogeneration plant), per PGE's current understanding of the BPA's Dynamic Transfer Capability (DTC) business practice and best assumption of long term availability of DTC from Coyote. The 50 MW of range provided by the duct burner at PGE's future CCCT at Carty Reservoir is also available to provide some ancillary services. The 12 reciprocating engines at PGE's future Port Westward 2 plant are available to provide all ancillary services and are free to move between the min generation (8 MW, emissions constrained) and max generation (18 MW) although the number of engines available in any hour is determined by the designated scheduled outage rate.

Constrained Gas Supply Enhancement

In Phase 2, the wind integration model had no gas supply constraints limiting its nomination of gas to be burned in the day-ahead, hour-ahead and real-time economic dispatches. This modeling simplification over represented, in the Wind Integration Model, the flexibility the PGE system had to supply gas to Beaver, Port Westward and Coyote. Thus, to better represent the system operations, in Phase 4 of the Wind Integration Study, gas supply constraints have been applied to the operations governing Beaver (simple and combined cycle), Coyote, Port Westward (baseload and duct firing), Carty (baseload and duct firing), and Port Westward 2.

In actual operations, there are multiple ways that the gas desk can change the supply of gas after it has been nominated on a day-ahead basis. When there is a market, a portion of nominated gas can be sold at a couple different times after it is nominated. However, our model currently is not set up to capture the time windows in which renomination is available. Due to time constraints, renominating gas will have to be saved for a future enhancement to the model.

The other major way that gas is constrained, but has some flexibility is utilizing storage and/or drafting and packing the pipeline. This constraint is a daily accounting to ensure that a plant has not underused its nomination, and is thus storing unused gas in the pipeline (packing the gas, since it is a compressible fluid); or, overused its nomination, and is thus using more gas than allotted off the pressurized pipe (drafting the gas within appropriate pressure limits).

Beaver and Port Westward 2 can be fueled from a gas storage facility so are allowed a broader range of flexibility within the injection and withdrawal limits of the facility. This gas storage facility has

[11] See pp. 30-32 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"
[12] See pp. 32-33 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"

an annual maintenance cycle; during this period, the change of gas supply for Beaver and Port Westward 2 dispatch changes after the day-ahead nomination is limited by the drafting/packing limits of the gas pipeline.

Economic Feathering of Wind

In Phase 2 of the Wind Integration Study, the wind output was a static input for each stage (Day-Ahead, Hour-Ahead and Real-Time), and the model had no choice on how the wind plant actually dispatched. This was a simplifying assumption for the Phase 2 study that would underrepresent system flexibility in certain rare situations, since when there is wind blowing, the generation (determined by rotation speed) from the plant can be reduced/stopped by pitching the blades of the wind plant (feathering). PGE's wind plants all have feathering capability (albeit different capabilities between the Vestas and Siemens units), so it makes sense to incorporate that aspect into the optimization.

One of the potential benefits of feathering wind is that it can reduce the additional reserve burden on the system due to wind. PGE does not currently have the methodology refinement required to adjust intra-scheduling period reserves (Load Following, Regulation) dynamically as the wind generation changes. However, the spinning and non-spinning reserve requirements can be dynamically reduced with any feathered generation in the model.

In Phase 4 of the Wind Integration Study, the model can make the decision to feather based on the cost of losing the wind generation. The production tax credit, renewable energy credit, and increased wear and tear cost to the plant caused by feathering wind are explicitly defined as inputs to the model. Replacement energy for the feathered wind generation is implicitly calculated in the model. These are all part of the variable cost calculation considered by the model when determining to feather wind.

V. Modeling Approach

During Phase 2 of the Wind Integration Study, with the assistance of two external consultants, PGE developed a mixed integer programming model to assess the incremental operating (non-capital) costs of integrating wind resources into PGE's system. The model is a "constrained optimization model" with an objective function to minimize total system operating costs given a set of operational constraints. These operational constraints include plant dispatch requirements (minimum plant up-times, minimum plant generation requirements, etc.) and system requirements (Contingency Reserves [Spinning and Non-Spinning], Regulation INC/DEC, Load Following INC/DEC, etc.). The model allocates the total system requirements (e.g., total Spinning Reserve requirements) to the individual generators to minimize overall system costs. Currently, the model optimizes plant dispatch and system operation for a single year (2018). Given the heavy computational requirements, each of the 52 weeks is run separately on an hourly basis although functions for reserve requirements are developed from 10-minute data.

Phase 4 of the Wind Integration Study considers wind integration cost for three gas price sensitivities - reference, high, and low cases. In order to accurately represent system operation, the model is run in three stages corresponding to Day-Ahead, Hour-Ahead, and Within-Hour. At each stage, PGE's system is optimized subject to the operational constraints relevant at that stage. Commitments made in prior stages (e.g., purchase or sale commitments) are carried forward to the next stage as constraints. Total system operating costs at the third stage are used in assessing the costs of wind integration.

The model incorporates explicit reserves (reserved generation capacity) to address:

1) The Hour-Ahead uncertainty of wind INC/DEC;
2) Generation resource requirements for Within-Hour Load Following INC/DEC for wind; and
3) Generation resource requirements for Within-Hour Regulation INC/DEC for wind.

In addition, implicitly, spinning and non-spinning reserves are assigned economically within to generators per the level dictated by portfolio dispatch.

As in Phase 2, no reserves are specified in the model to address Day-Ahead wind uncertainty.

Details of Modeling Approach and Results

As discussed above, the costs of wind integration are identified by comparing total system operating costs, from a model run that incorporates the system requirements for wind integration, to total system operating costs, from a model run that excludes the system requirements for wind integration.

In Phase 4, to capture the system operation costs associated with integrating wind[13] for each of the three gas price sensitivities six model runs are required per Table 2 below. For example the system operation cost for wind integration in the reference gas case requires Run 1 (PGE integrates wind and load) and Run 1 (PGE integrates load only) described in Table 2. The difference between those runs is the systems operations cost associated with the self-integration of wind in the reference gas price case. Similarly, the differences between Runs 3 and 4, and Runs 5 and 6, are the increased system operation costs associated with self-integration of wind in the high and low gas cases respectively.

[13] As mentioned above, "PGE's estimated self-integration costs are exclusive of the necessary investment required in software automation tools, generation control systems, communications/IT infrastructure, and the potential need for personnel additions to manage the self-integration of variable energy resources."

Table 2: Descriptions of the Six Model Runs Required

Note that PGE integrates load in all the runs, the delineation of "PGE integrates" refers specifically to wind.

Identification	Description
RUN 1	**PGE integrates Regulation, Load Following, Hour-Ahead and Day-Ahead Uncertainty (Reference Gas Price)**
RUN 2	**PGE doesn't Integrate Load Following, Regulation, Hour-Ahead and Day-Ahead Uncertainty (Reference Gas Price)**
RUN 3	**PGE integrates Regulation, Load Following, Hour-Ahead and Day-Ahead Uncertainty (High Gas Price)**
RUN 4	**PGE doesn't Integrate Load Following, Regulation, Hour-Ahead and Day-Ahead Uncertainty (High Gas Price)**
RUN 5	**PGE integrates Regulation, Load Following, Hour-Ahead and Day-Ahead Uncertainty (Low Gas Price)**
RUN 6	**PGE doesn't Integrate Load Following, Regulation, Hour-Ahead and Day-Ahead Uncertainty (Low Gas Price)**

vi. Calculation for Reserves and Uncertainty

The wind integration model accounts for three categories of reserves: Regulation, Load Following (including forecast error), and Contingency Reserves. The Contingency Reserve requirement is defined by the WECC (i.e., 5% for hydro and wind, and 7% for thermal resources) with requirements split equally between Spinning and Non-Spinning Contingency Reserves. The model simulates the different reserve requirements as hourly constraints for resource scheduling and dispatch across each of the three time horizons: Day-Ahead scheduling, Hour-Ahead scheduling and Real Time dispatch (Within-Hour). In Phase 2 of the Wind Integration Study, EnerNex provided PGE with a methodology for estimating regulation and load variability parameters for Day-Ahead, Hour-Ahead and Real Time (Within-Hour) scheduling, as well as the Hour-Ahead forecast error. However, PGE currently does not explicitly set aside reserves for Day-Ahead forecast error for either load or wind generation. Specific modeling for the reserves, by category and time frame, are described below.

Reserve Requirement Calculation

The reserve requirements for regulation, load following and forecast error for the Phase 4 study are calculated using the same methodology described in the Phase 2 study[14]. The only difference in reserve calculation is described in detail in Section V.ii: Increasing and Decreasing Reserve Requirement Model Enhancement above.

Day-Ahead Scheduling

In Day-Ahead scheduling, reserve predictions must be made for load variability and regulation for both load and wind generation. The Day-Ahead load forecast is input with a forecast error, but the model does not explicitly hold back reserves to cover the forecast error.

Hour-Ahead Scheduling

For Hour-Ahead scheduling, reserve predictions for the load variability and regulation from the Day-Ahead Scheduling step must be recalibrated to account for the Hour-Ahead load and wind generation forecast. Since PGE explicitly holds back reserves for forecast error in Hour-Ahead scheduling, additional reserves are calculated as follows:

- Reserves to cover the load forecast error are derived from historical PGE information (i.e., 2005 load data escalated to 2018 levels)
- Additional reserves held to cover the wind generation Hour-Ahead forecast error are determined by the EnerNex methodology described in the Phase 2 Study[15].

Plant dispatch is recalibrated from the Day-Ahead schedule to reflect the different reserve, wind generation, and load requirements.

Real-Time Dispatch (Within-Hour)

The forecast error reserve obligations that were established in the preceding Hour-Ahead scheduling step are released (when possible) in the Real Time (Within-Hour) dispatch step, and the reserve requirements for load variability and regulation are recalibrated. Plant dispatch is also recalibrated from the Hour-Ahead schedule to reflect different reserve, wind generation, and load requirements. Consequently, in each stage of the simulation, (i.e., Day-Ahead, Hour-Ahead and Within-Hour), the calculated reserve requirements for Regulation, Load Following, and Contingency Reserves are factored into the model's optimization of dispatching generation, capacity, and market resources.

[14] See pp. 40-42 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"
[15] See p. 42 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"

VI. Summary and Conclusions

i. *Cost Summary*

PGE estimates the additional system operation costs incurred to self-integrate almost 717 MW of wind in 2018 would be $3.99 per MWh (in 2018$) at the reference gas price. PGE's estimate of the additional system operation costs to self-integrate the 717 MW in 2018 at the high gas price case is $4.24 per MWh, and at the low gas price case is $3.57 per MWh. It is again important to note that the aforementioned estimated self-integration cost estimates are exclusive of the necessary investment required in software automation tools, generation control systems, communications/IT infrastructure, and the potential need for personnel additions to manage the self-integration of variable energy resources. These results are summarized in Table 3 below.

Table 3: System Operation Costs for PGE Self-Integrating Wind with Gas Price Sensitivities

Identifier	**Cost Saving For PGE**	**Run Delta Measures:**	**Cost ($/MWh)**
A	RUN 2 – RUN 1	Cost saving for Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation (Cost of wind integration at **Reference Gas Price**)	$3.99
B	RUN 4 – RUN 3	Cost saving for Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation (Cost of wind integration at **High Gas Price**)	$4.24
C	RUN 6 – RUN 5	Cost saving for Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation (Cost of wind integration at **Low Gas Price**)	$3.57

ii. *Conclusions*

PGE believes that Phase 4 of the Wind Integration Study accurately simulates the constraints associated with existing conditions and available resources to estimate the costs attributed to the self-integration of 717 MW of wind generation in 2018. The study has been subject to regular and rigorous reviews from the TRC and major participants in PGE's 2013 IRP, Docket No. LC 56. The TRC considers this study to be technically sound and have provided their unanimous endorsement. Regional stakeholders and PGE's Wind Integration Study Project Team have participated in three detailed public presentations regarding the intricacies of the study. Stakeholders have been provided the opportunity to examine, in detail, the methodology of the study and the results. They have also had the opportunity to comment on the methodology and make recommendations. In short, Phase 4 of the Wind Integration Study has been vetted in accordance with Commission Order No. 10-457.

As shown in the results in Table 4 below, the change in wind integration cost has a direct significant relationship to the price of gas. However, the larger overall effect is due to the net addition of balancing resources and wind diversity. There may be some threshold of gas prices where the effect on system operation cost due to wind integration is more drastic, but this study did not bear evidence to that threshold.

Table 4: Comparison of Gas Plant Portfolio Changes, Gas Price Sensitivities, WI Phase costs[16]

Study Name	Study Year	Gas Plants Capable of Providing Reserves	Plants fueled by Sumas	Plants fueled by AECO	Annual Average Sumas Gas Price	Annual Average AECO Gas Price	Wind Integration Cost
Wind Integration Study Phase 2	2014	Beaver, PW Duct Firing	Beaver, Port Westward	Coyote	$ 5.23	$ 5.17	**$ 11.04**
Wind Integration Study Phase 2	2014	Beaver, PW Duct Firing, **Proxy Port Westward 2**	Beaver, Port Westward, **Proxy Port Westward 2**	Coyote	$ 5.23	$ 5.17	**$ 9.15**
Wind Integration Study Phase 4 (reference)	**2018**	Beaver, PW Duct Firing, **Port Westward 2, Coyote, Carty Duct Firing**	Beaver, Port Westward, **Port Westward 2**	Coyote, **Carty**	$ 5.28	$ 4.89	$ 3.99
Wind Integration Study Phase 4 (high)	**2018**	Beaver, PW Duct Firing, **Port Westward 2, Coyote, Carty Duct Firing**	Beaver, Port Westward, **Port Westward 2**	Coyote, **Carty**	$ 6.05	$ 5.62	$ 4.24
Wind Integration Study Phase 4 (low)	**2018**	Beaver, PW Duct Firing, **Port Westward 2, Coyote, Carty Duct Firing**	Beaver, Port Westward, **Port Westward 2**	Coyote, **Carty**	$ 4.24	$ 3.89	$ 3.57

All evidence points to wind regime diversity between Biglow and Tucannon River as the single most influential factor in the cost estimate decrease from Phase 2 to Phase 4. In the Phase 2 study, the most reasonable site for the next available tranche of wind had a much higher correlation with Biglow than the Tucannon River Wind Project acquired in the 2011 RFP. Thus, the regulation and load following reserve requirements fell slightly and the forecast error dropped considerably. This

[16] Note that the **bold** resources differentiate from the Wind Integration Phase 2 Base Case.

significant reduction in reserve requirements seems to be highly dependent on spatial and temporal diversity between wind sites.

The advent of more available gas balancing resources as was also seen in Phase 2 seems to have a significant mitigating effect on wind integration cost; however, these effects are highly portfolio dependent. Other changes between Phase 2 and Phase 4 that appear to have significant effect on the cost are follows:

(1) Reduction in PGE's contractual share of the Mid-C likely raises system operating costs.
(2) Addition of gas fueling constraints likely raises system operating costs.
(3) Revised understanding of BPA's dynamic transfer constraint which allows some generation movement at Coyote and Carty Duct Firing likely decreases costs.
(4) The model's ability to feather wind when system constraints leave the portfolio flexibility short likely decreases costs.
(5) Ability for the model to assign INC and DEC reserve requirements to units individually allows PGE's portfolio to provide reserves more efficiently and likely decreases costs.

iii. Dynamic Dispatch Program

For PGE to self-integrate wind, join a future energy imbalance market or adopt a hybrid system integration solution, investment is required in software automation tools, generation control systems, and communications/IT infrastructure. There is also the potential need for personnel additions to manage the self-integration of variable energy resources. In addition, to be prepared for a future where units will be used more flexibly, PGE has contracted an in-detail study on the wear and tear costs of increased cycling of PGE's units and the installation of automatic generation control (AGC) systems on the thermal units that will be sent within-hour balancing signals. PGE has currently folded all these efforts into a Dynamic Dispatch Program that will be completed in phases over the next few years.

iv. Future Potential Remediation

Energy Imbalance Market

Currently, PGE is participating in the region's Energy Imbalance Market (EIM) feasibility assessments. An EIM is a hybrid of a bilaterally based market and a centrally cleared market model that seeks to redispatch in real-time, according to transmission availability, the flexible capacity made available to it by market participants. In an EIM, parties must enter the market with sufficient resources to stand-alone, in terms of energy and capacity to meet load and balancing requirements, as the market does not provide flexible reserve capacity to participants. EIM participants demonstrate their resource sufficiency through a combination of scheduled market purchases and identified resource plans for their owned assets. Whether for intentional, or market instructed deviations where a more economic regional redispatch is sought, market participants will either pay or be paid for the difference between their actuals and schedules (i.e., their energy imbalance, paid to or by the EIM) for each EIM flow period.

PGE is actively participating in the formative discussions of two main regional efforts: the Northwest Power Pool Members EIM and the California Independent System Operator EIM proposal with PacifiCorp. While outcomes of each effort are currently unknown, and noting that PGE has limited ability to influence the ultimate outcome of these processes, PGE expects that some form of an EIM has the potential to be made available to entities in the Pacific Northwest within the next few years.

PGE will consider modifying a future Wind Integration Study to calculate system costs should PGE have the opportunity to participate in an EIM. However, it should be noted that wind integration costs for an entity operating within an EIM would be highly dependent on market structures that have not yet been finalized for either of the two main efforts and that the current system operation model may need to be significantly enhanced to accurately represent these market structures.

Additional Flexible Generation

As stated earlier, the cost for wind integration is dependent on the characteristics of the system available to provide the moment-to-moment movement that is required to keep generation and system load in balance. If additional flexible resources are added to the PGE system, then the cost to provide wind integration will likely decrease.

v. Next Steps for PGE's Wind Integration Study

Because variable generation resources place unique demands on system operation and reliability, PGE reiterates that understanding the physical needs and costs of wind integration is an ongoing effort. While PGE has not yet formulated a formal list of next steps, or tried to prioritize them, the following items are presented for further consideration. PGE's Wind Integration Study Project Team welcomes suggestions and feedback from stakeholders regarding prioritization or other study items may not be listed.

Phase 4 incorporated some the changes suggested in Phase 2 including the following:

- Evaluate impact of natural gas price variability
- Assess impact of transmission and gas supply constraints
- Evaluate impact of additional flexible gas generation resources
- Delineate between INC/DEC reserves
- Cost effects of feathering wind

Future Phases of PGE's Wind Integration Study may include:

- Evaluating the net impact of moving to sub-hourly scheduling;
- Evaluating the net impact of developing and operating a regional energy imbalance market;

- Estimating the value of adding additional flexible gas generation;
- Estimating how wind integration costs change with a higher or lower amount of variable resources to integrate;
- Better understanding the impact of a poor water year;
- Exploring the impact of changes to scheduled maintenance outages.

The PGE Wind Integration Study Project Team will continue to evaluate and improve its modeling tools and software, as needed, and will also continue to monitor the industry for Wind Integration Study best practices.

Attachment 1

The Technical Review Committee (TRC), operating under the principles established by the Utility Variable-Generation Integration Group (UVIG) and available at http://variablegen.org/wp-content/uploads/2009/05/TRCPrinciplesJune2012.pdf, wishes to congratulate you and the entire study team on completing the PGE Wind Integration Study Phase IV. The TRC endorses the study methodology, execution, and the final results presented to the TRC. The results naturally depend on the assumptions concerning balancing area and regional grid operating practices and scheduling opportunities which remain in a state of flux in the Pacific Northwest. We have enjoyed working together on this project and feel it has advanced the state of the art in wind integration studies.

Thanks Again

Brendan Kirby

Charlie Smith

Michael Goggin

Michael Milligan

Bob Zavadil

Appendix E

PGE IRP Meeting Agendas

Appendix E: IRP Meeting Agendas

Public Meetings

1st Public Meeting - April 3, 2013

- IRP process overview
- Updates since 2009 IRP
- Current status of RFPs
- New topics and content for 2013 IRP
- Load forecast
- Resource need through 2020
- Customer Focus: Resource Preferences / Demand-side Resources
    - Customer Attitudes & Preferences - Definitive Insights
    - Energy Efficiency Resource Assessment - Energy Trust of Oregon
    - An Assessment of PGE's Demand Response Potential - The Brattle Group
    - PGE Demand Response Strategy and Actions
    - Smart Electric Water Heater Program

2nd Public Meeting - May 28, 2013

- Introduction
- Follow-up from first IRP Public Meeting
- E3 – "PGE Low Carbon IRP Portfolios"
- Automated Demand Response RFP Update
- Flexible capacity: demand and supply
- Supply-side resources
- Gas: prices, price ranges, supply, and transport
- CO2 costs and PTC & ITC assumptions
- Wholesale electric market prices
- Proposed portfolio analytics

3rd Public Meeting - August 29, 2013

- Introduction
- Updated load-resource balance
- Portfolios and Futures

- Portfolio results
- Portfolio observations
- Risk and uncertainty
- Loss of load probability
- PGE Wind Integration Study: Phase 4
- Transmission project update
- Appendix: Capacity contribution of central station solar PV

4th Public Meeting - October 7, 2013

- Gas transport/storage -- acquisition strategy
- Automated Demand Response update
- Distributed solar preliminary technical potential
- Colstrip 3 & 4 update
- Load/Resource Balance update
- Potential study/research Action Plan items for next IRP
- Final IRP Portfolio results
- Loss of Load Probability results
- Parking lot items follow-up

Technical Workshops

1st Technical Workshop - May 17, 2013

- Demand for Flexible Capacity

2nd Technical Workshop - June 25, 2013

- Portfolios and Action Plan
- Wind Capacity Factor

3rd Technical Workshop - August 8, 2013

- Wind Integration Study

Appendix F

PGE IRP Carbon Reduction Candidate Portfolios Scope of Work

E3 Final Report - "PGE Low Carbon IRP Portfolios"

Priority Recommendations - the Environmental Group

Scope of Work for Development of Candidate Carbon Reduction Resource Portfolios

Portland General Electric Integrated Resource Plan – 2013

Introduction
Portland General Electric Company (PGE) and a group of stakeholders[1] ("the Group") are seeking consulting assistance in developing a limited number of carbon reduction resource portfolio options ("Carbon Portfolio Options") for evaluation in PGE's 2013 Integrated Resource Plan (IRP) process.

Background
In 2010, the Oregon Public Utility Commission (OPUC) acknowledged PGE's 2009 IRP action plan, in which PGE agreed to cease coal combustion operations at its Boardman Generation Facility in Boardman, Oregon by no later than the end of 2020. In exchange for the Group's support of PGE's Boardman proposal, PGE agreed, in its next IRP, to work with the Group to develop a limited number of Carbon Portfolio Options to meet its anticipated electric resource requirements, including the replacement of Boardman coal generation, while seeking to achieve the best combination of expected costs and associated risks for PGE and its customers and also reduce the carbon footprint of the company's resource portfolio over time. PGE also committed to allocate sufficient funding, not to exceed $50,000 without PGE's prior approval, to secure technical consulting services on a one-time basis to assist in developing and evaluating the Carbon Portfolio Options. One or more suppliers of these services may be selected.

This process represents a commitment by PGE to work with the Group and other IRP stakeholders to develop and evaluate carbon emission reduction candidate portfolios that support Oregon's efforts to reduce greenhouse gas emissions while operating within the OPUC's least-cost/least-risk paradigm. Under this paradigm, cost is defined as the expected Net Present Value Revenue Requirement of the total PGE resource portfolio and risk is defined as potential cost variability. Performance ranking and subsequent selection of a "preferred portfolio" and IRP Action Plan from the candidate portfolios (including the Carbon Portfolio Options) will be driven by the objective of achieving the best combination of total portfolio cost and risk for PGE and its customers.

PGE and the Group recognize that, consistent with the OPUC's IRP Guidelines, any proposal for the replacement of Boardman coal generation in 2020 will likely be beyond the actionable range of the 2013 IRP Action Plan. Nonetheless, PGE and

[1] Citizens' Utility Board, Northwest Energy Coalition, Oregon Environmental Council, Renewable Northwest Project, and Angus Duncan.

the Group agreed to proceed with the one-time consulting services as part of the 2013 IRP process.

IRP Process

Stakeholder involvement in PGE's development of the IRP consists of a series of workshops open to all interested parties, along with opportunities for written comment and input regarding the key components of the IRP. PGE will initiate a limited number of workshops to collaboratively develop the Carbon Portfolio Options. Such workshops are expected to begin Q3 2012.

State of Oregon Greenhouse Gas Reduction Goals

The Oregon Legislature, in 2009, adopted non-binding goals for reduction of greenhouse gas (GHG) emissions attributable to Oregonians. These goals are not sector-specific, so electric utilities (for example) may reduce their GHG emissions on a slower or faster pace. The overall State GHG goals may provide context for the Carbon Portfolio Options.

Deliverables: Resource Portfolio Options/Scenarios

Specific features of the Carbon Portfolio Options will be developed in consultations with the Group, PGE and other participants in the IRP process. The consultant will then be expected to assist with evaluation of the Carbon Portfolio Options analytical results for cost, risk, reliability and other IRP performance factors. Carbon Portfolios Options will be evaluated against other portfolios developed during the IRP process and in accordance with PGE's IRP methodologies and OPUC IRP principles and guidelines.

A limited number of Carbon Portfolio Options will be identified. Candidate portfolios will reflect the estimated annual CO2 emissions of the portfolio resources based on the IRP planning horizon of 20 years, which for PGE's 2013 IRP will be 2034.

In addition to generating resource options, candidate Carbon Portfolio Options may consider commercially available storage technologies and transmission options, as well as increased levels of demand management, energy efficiency, and vehicle electrification beyond the base case assumptions.

Consultant Qualifications

The preferred consultant will be familiar with IRP processes and procedures, preferably as they are practiced in Oregon; and with modeling tools, and analytical methodologies that PGE plans to employ in the prospective IRP.

The preferred consultant will have knowledge of, or demonstrate access to, expertise concerning technically feasible and commercially available supply and demand-side resource options available during the IRP planning period, including prevailing and advanced generation, storage, and transmission technologies and operating practices.

The preferred consultant will have demonstrated, in other work products and within other proceedings, an understanding of the technologies and strategies that can potentially be assembled into a candidate carbon reduction portfolio that is also competitive on cost, risk, and reliability criteria.

The preferred consultant will have a working knowledge of PGE's resource base, load requirements and other operating circumstances, and of the Western Electricity Coordinating Council, the Bonneville Power Administration and the Pacific Northwest context within which PGE operates.

Energy+Environmental Economics

PGE Low Carbon IRP Portfolios

May 28, 2013

Arne Olson, Partner
Jim Williams, Chief Scientist
Amber Mahone, Senior Consultant
Nick Schlag, Consultant

BACKGROUND

Energy and Environmental Economics, Inc.

- E3 has operated at the nexus of energy, environment, and economics since it was founded in 1989
- E3 advises utilities, regulators, government agencies, power producers, energy technology companies, and investors on a wide range of critical issues in the electricity and natural gas industries
- Offices in San Francisco, CA and Vancouver, B.C.
- 30 professional staff in economics, engineering & policy

Project Objectives

+ **E3 was hired by Portland General Electric (PGE) to assist PGE and a group of stakeholders in the development of a low carbon resource portfolio for PGE's 2013 Integrated Resource Plan (IRP)**
+ **E3's primary task was to develop, in consultation with the stakeholder group and PGE, one or more potential low carbon portfolios for PGE to evaluate using its IRP tools in 2013**
+ **The stakeholder group included five parties:**
  - Bonneville Environmental Foundation
  - Citizens' Utility Board of Oregon
  - Northwest Energy Coalition
  - Oregon Environmental Council
  - Renewable Northwest Project

Contents

1. **Context for a low carbon portfolio**
   - Policy
   - Backcasting & downscaling
2. **Analysis of low-carbon resource options**
   - Efficiency
   - Renewables
   - Potential displacement of PGE's 20% ownership in Colstrip units 3 & 4 late next decade
3. **Development of candidate portfolios**
4. **Specifying a low-carbon future**
5. **Identifying future research needs**

Energy+Environmental Economics

POLICY CONTEXT FOR A LOW CARBON PORTFOLIO

What Might a Low Carbon Future Look Like?

+ Oregon House Bill 3543 (2007)

- By 2010, arrest the growth of Oregon's greenhouse gas (GHG) emissions and begin to reduce GHG
- By 2020, achieve GHG levels that are 10% below 1990 levels.
- By 2050, achieve GHG gas levels that are at least 75% below 1990 levels

+ Senate Bill 101 (2009)

- Every even-numbered year, develop estimates to reach GHG goals by 2020 of 10% below 1990 (above) and 15% below 2005 levels
- Because PGE's portfolio in 1990 was dominated by the Trojan nuclear plant and hydro, the stakeholder group agreed that a 2005 baseline would be appropriate for PGE's carbon targets

+ Possibility of an international, US, or WECC-wide carbon reduction policy

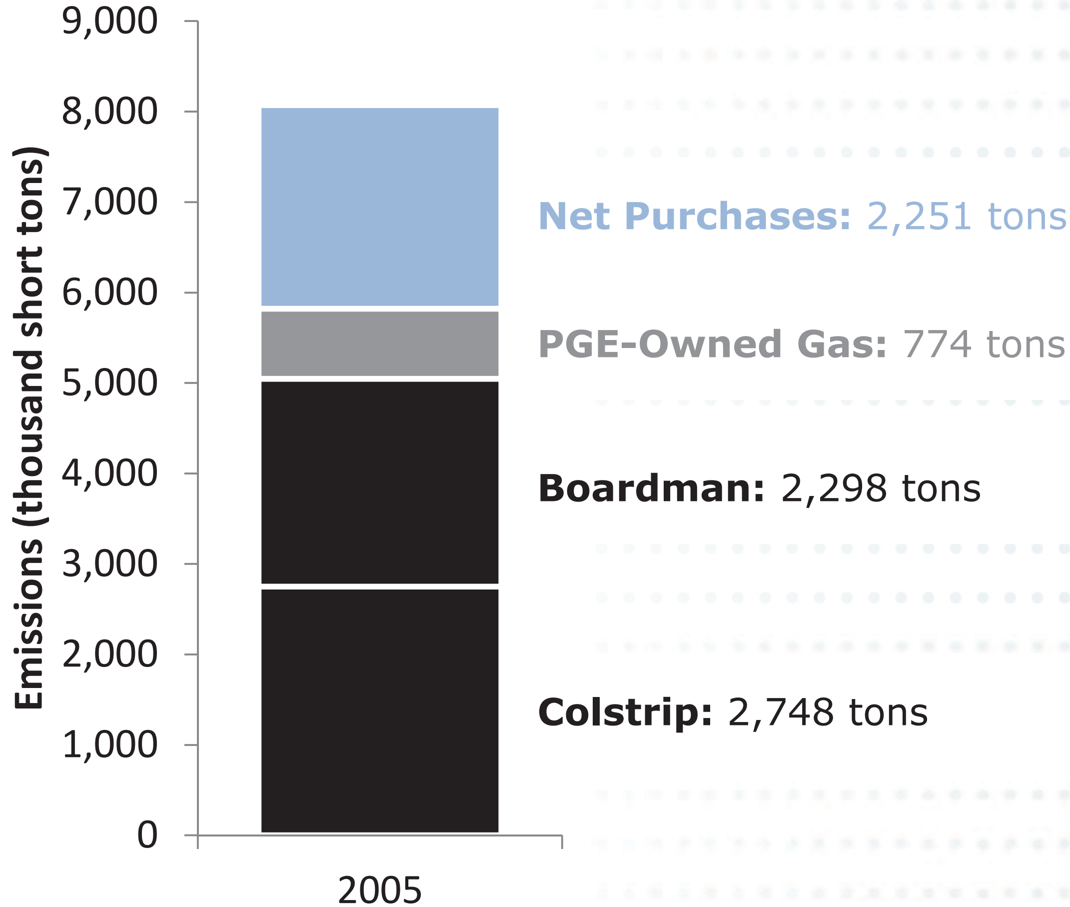
- IPCC goals
- Waxman-Markey Bill: past legislation in U.S. House

Framework for Portfolio Development

- **At the kickoff meeting, stakeholders agreed that applying the principles of backcasting and downscaling would provide a useful framework for developing portfolios**
  - **Backcasting:** working backwards from a long-term carbon reduction goal to determine necessary near-term actions and investments
  - **Downscaling:** zooming in from the state's long-term carbon goals to determine emissions targets specific to PGE
- **This process establishes a glide path for GHG emissions reduction for PGE**

2005 Portfolio Emissions

- **In 2005, PGE actual generation and purchases created approximately 8 million tons of carbon dioxide emissions to meet retail load**
- **Implied long term targets:**
  1. By 2020: **6.9 million tons** (15% below 2005 levels)
  2. By 2050: **1.6 million tons** (80% below 2005 levels)



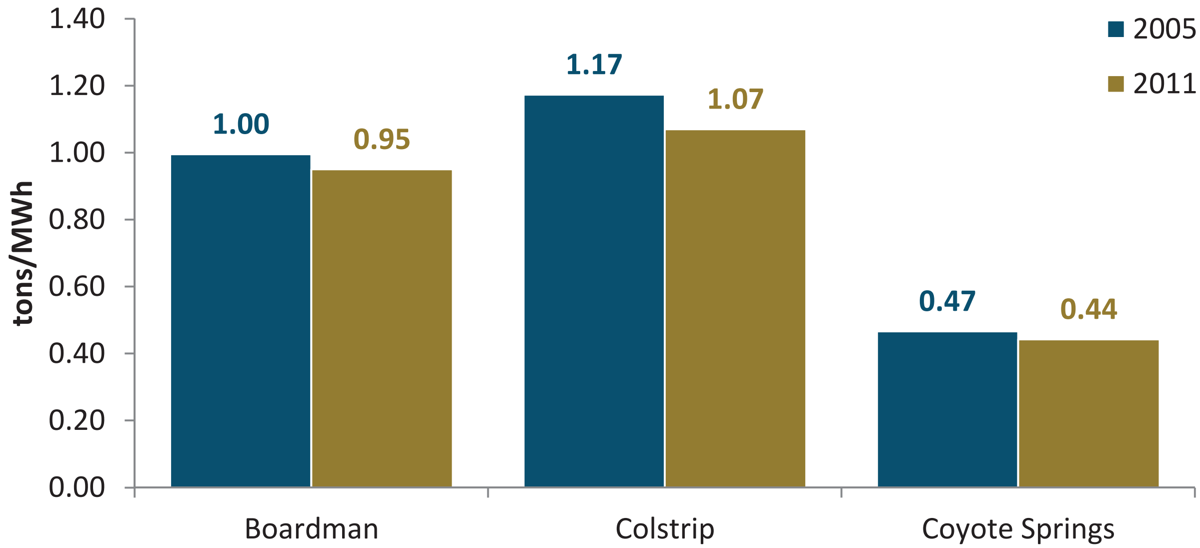
Loss of Mid-C Hydro Contracts

- Unlike many utilities in the Northwest, PGE faces a unique challenge in the expiration of **146 aMW** of hydro contracts over the next decade, compounding the challenge of decarbonization
- Not only will PGE have to meet growth and displace fossil generation with low-carbon power, but it must replace the load historically served by these non-emitting resources as well

Contract	Annual Energy (aMW)	Contract Expiration Date
Hydro Contract A	5	9/30/2015
Hydro Contract B	30	12/31/2015
Hydro Contract C	10	8/31/2017
Hydro Contract D	16	8/1/2018
Hydro Contract E	85	8/31/2018
Total	**146**	

Improving Plant Efficiencies

+ **Since 2005, PGE has improved operational efficiency and reduced emissions rates at its coal plants and the Coyote Springs gas plant:**

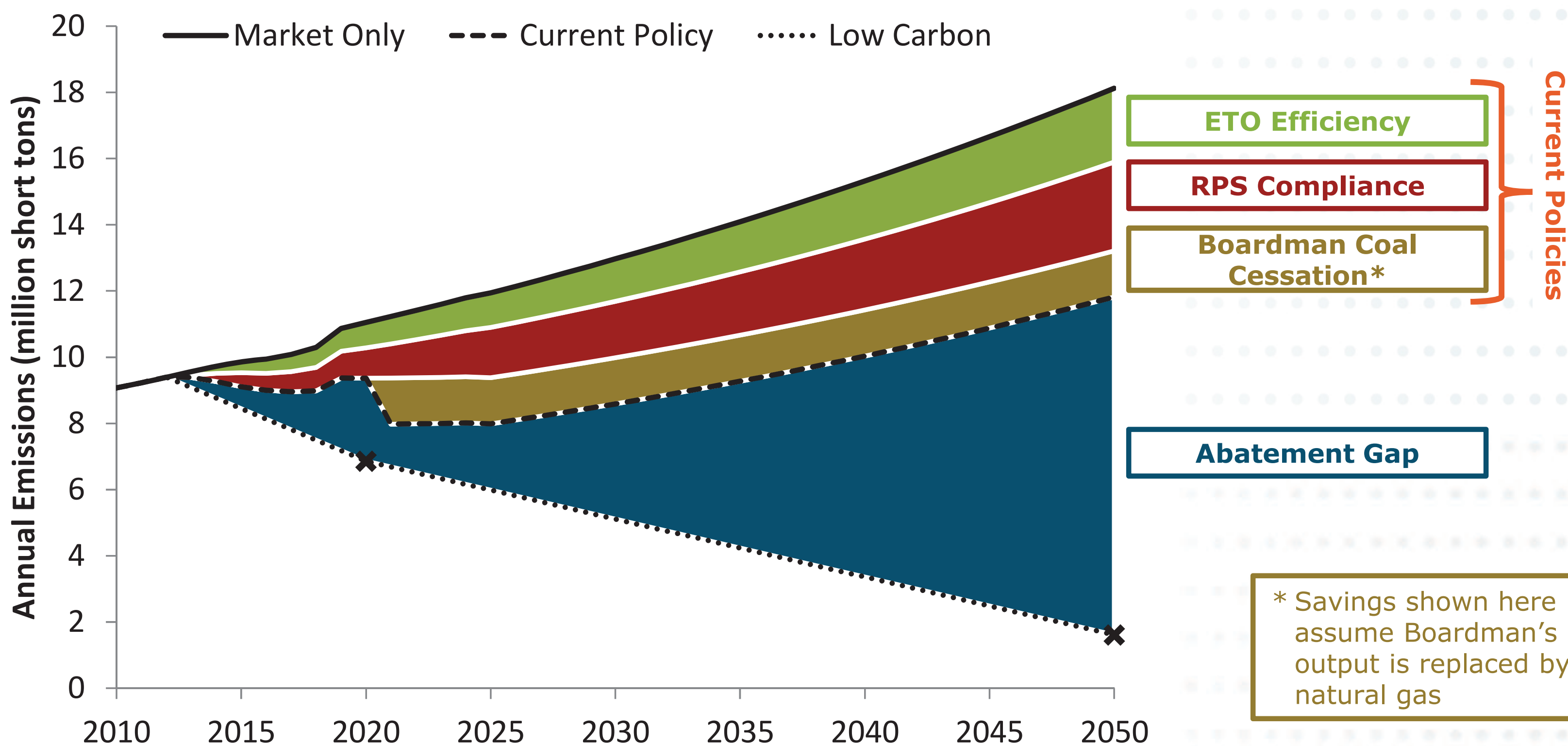


Current Strategies

- **Due to an Oregon RPS and action plans developed in past IRPs, PGE has committed to several emissions abatement strategies over the coming decade:**
  1. **Customer energy efficiency:** PGE originated the initiative via SB 838 to expand funding from customers to acquire all achievable cost-effective energy efficiency identified by the Energy Trust of Oregon (ETO)
  2. **Plant energy efficiency:** PGE has undertaken efficiency upgrades at its coal, gas, and hydro plants, resulting in more output without new emissions
  3. **Renewable compliance:** PGE supported and helped design Oregon's RPS, which targets meeting 25% of PGE's retail sales with qualifying renewable generation by 2025; PGE is well ahead of the current 5% target and intends to remain in physical compliance with the 2015 15% target
  4. **Boardman 2020 Plan:** as a result of analysis in its 2009 IRP, PGE committed to a cessation of coal-based operations at the plant by December 31, 2020
  5. **Solar Standards:** while still small, PGE has implemented tariffs for net metering and feed-in tariffs to encourage customer solar PV
  6. **"Buy-down" of gas heat rates:** PGE paid one-time fees to Oregon's Climate Trust to "buy down" the heat rates of Coyote & Port Westward; the Climate Trust purchases offsets on PGE's behalf

Long-Term Emissions Trajectories

- By 2050, these PGE current strategies could be expected to save just over **six million tons** of GHG emissions per year
- Achieving long-term targets, however, will require PGE to intensify its emissions reductions strategies significantly



* Savings shown here assume Boardman's output is replaced by natural gas

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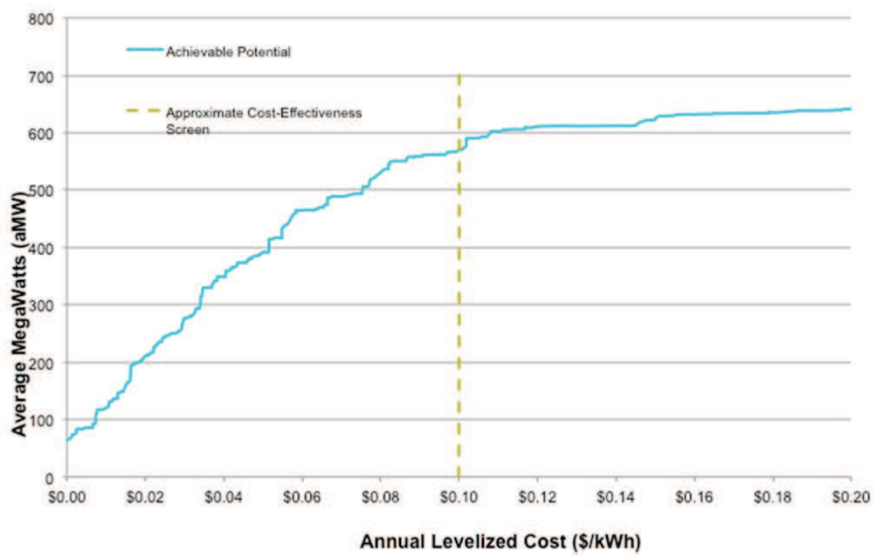
RESOURCE OPTIONS FOR LOW CARBON PORTFOLIO

Filling the Gap

- **E3 has evaluated three primary options to fill this "abatement gap":**
  1. Increased energy efficiency
  2. Increased procurement of renewables
  3. Potential displacement of PGE's 20% ownership in Colstrip units 3 & 4 late next decade
- **A combination of strategies will be needed to get on a pathway to long-term carbon reductions**
- **This analysis uses a target of 80% emissions reduction relative to 2005 by 2050**
  - This is an economy-wide target that may not necessarily apply pro-rata to regions and/or utilities

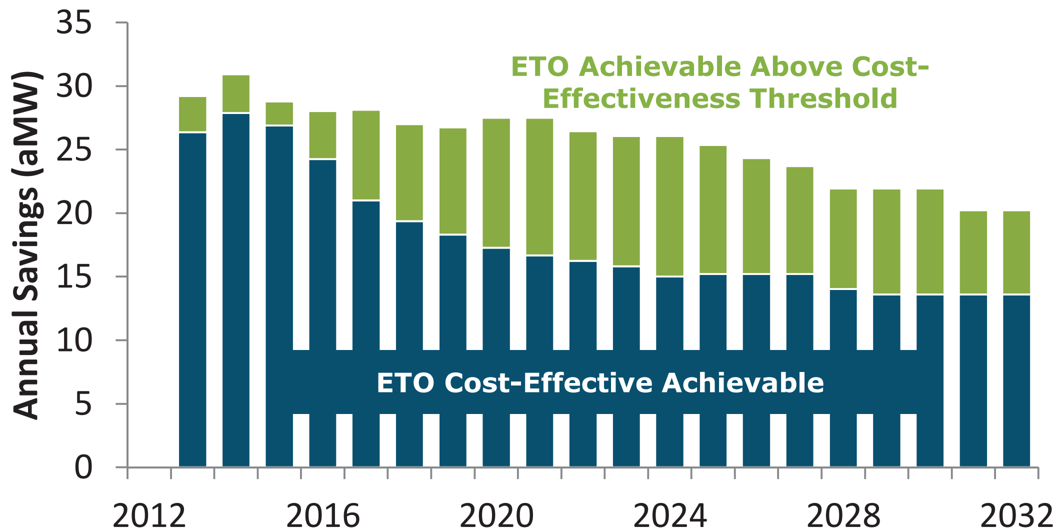
Energy Efficiency

+ **Under current practices, PGE's IRP portfolios assume the acquisition of all achievable cost-effective energy efficiency associated with commercially available technologies as forecast by the Energy Trust of Oregon (ETO)**
    - ETO EE potential also includes newly commercial technologies such as ductless heat pumps, water heater heat pumps, and LED lighting
+ **In the context of a carbon-constrained world, it is useful to consider how the role of energy efficiency might be expanded in long-term planning exercises**
    - Commercialization of new technologies may expand the supply curve
    - Implicit valuation of carbon will shift the cost-effectiveness threshold
+ **Accordingly, E3 has explored whether additional opportunities for efficiency should be considered in a low carbon portfolio**



ETO Energy Efficiency

- In addition to quantifying achievable *cost-effective* energy efficiency, ETO also estimates the total achievable energy efficiency without economic constraints
- This quantity is a useful reference point in low-carbon resource planning because the cost-effectiveness screen used by ETO does not capture the implicit high value of carbon reductions in a low-carbon world



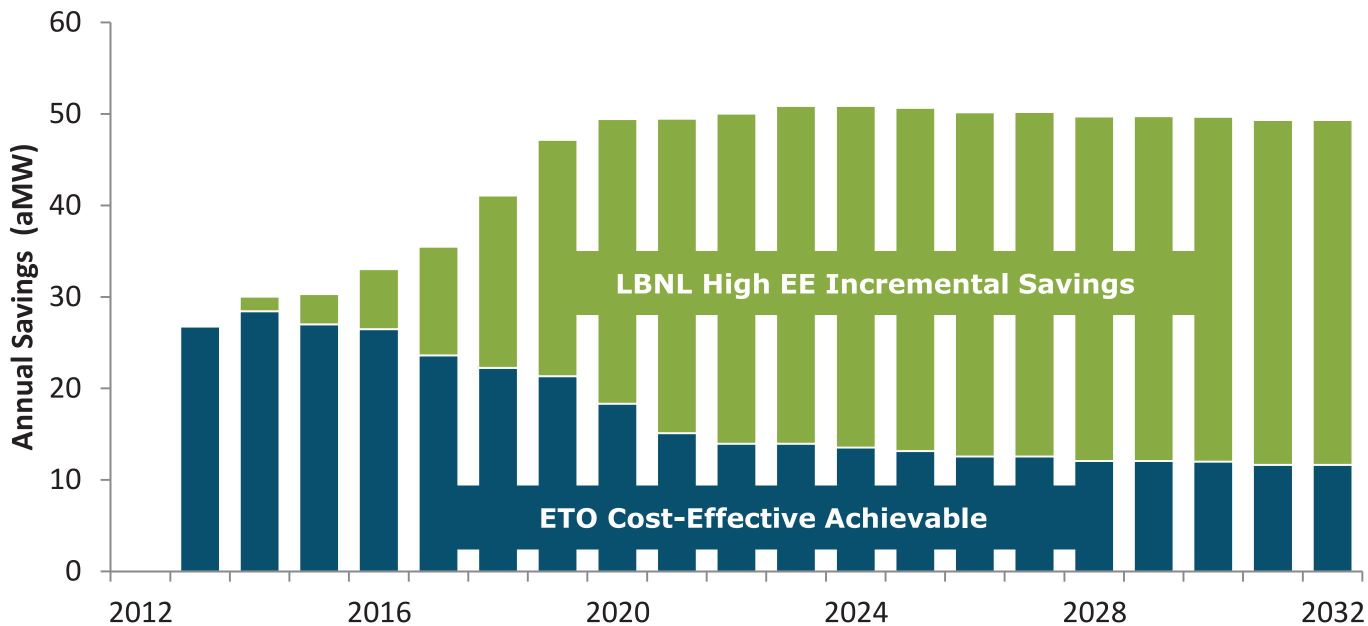
ITRON/LBNL High EE Case

- **As an input to WECC's 20-year transmission planning process, LBNL has worked with Itron to develop several load forecasts for each balancing authority in the WECC:**
  1. **Reference Case:** incorporates levels of efficiency consistent with utilities' IRPs (i.e. ETO assumptions for PGE)
  2. **High DSM Case:** assumes that by 2032, the *average* efficiency of each of 31 end uses has reached the level of today's best available technology (*no explicit screen for measure cost-effectiveness*)
- **This forecast provides a second useful reference point that could be quickly adapted in a top-down manner to provide an efficiency input to this IRP:**

Incremental efficiency (2032)	=	**Reference Case Load** (2032)	–	**High DSM Case Load** (2032)

Incremental Efficiency in High EE Case

- **The additional efficiency in the LBNL High DSM load forecast would represent a transformative expansion to ETO's traditional efficiency programs**
  - Nearly flattens load growth from today to 2032



Review of High EE Savings Assumptions

- **ETO has reviewed end-use assumptions for a number of substantial savings sources and concluded assumptions are reasonable and consistent with an emerging technology perspective on efficiency**
- **ETO provided valuable end-use specific comments:**
  - **Commercial ventilation (18% of savings):** not an end-use where efficiency programs have traditionally focused, but there are opportunities to reduce consumption through separation of ventilation and space conditioning
  - **Commercial lighting (10%):** High EE assumptions may be conservative, as emerging LED applications will provide the opportunity for savings above any of today's commercial technologies
  - **Residential space heat (8%):** ductless mini-split heat pumps may be the mechanism to realize the hypothetical savings in this end use
  - **Residential DHW (0%):** potential savings are understated, as High EE case does not assume conversion to near-commercial heat pump water heaters

Cost of Incremental Energy Efficiency

- LBNL recently released a report on projected EE program costs in the United States
- Findings indicate increasing marginal costs of achieving higher levels of efficiency; the generic cost curve below illustrates this effect but may not line up with PGE's expected EE costs

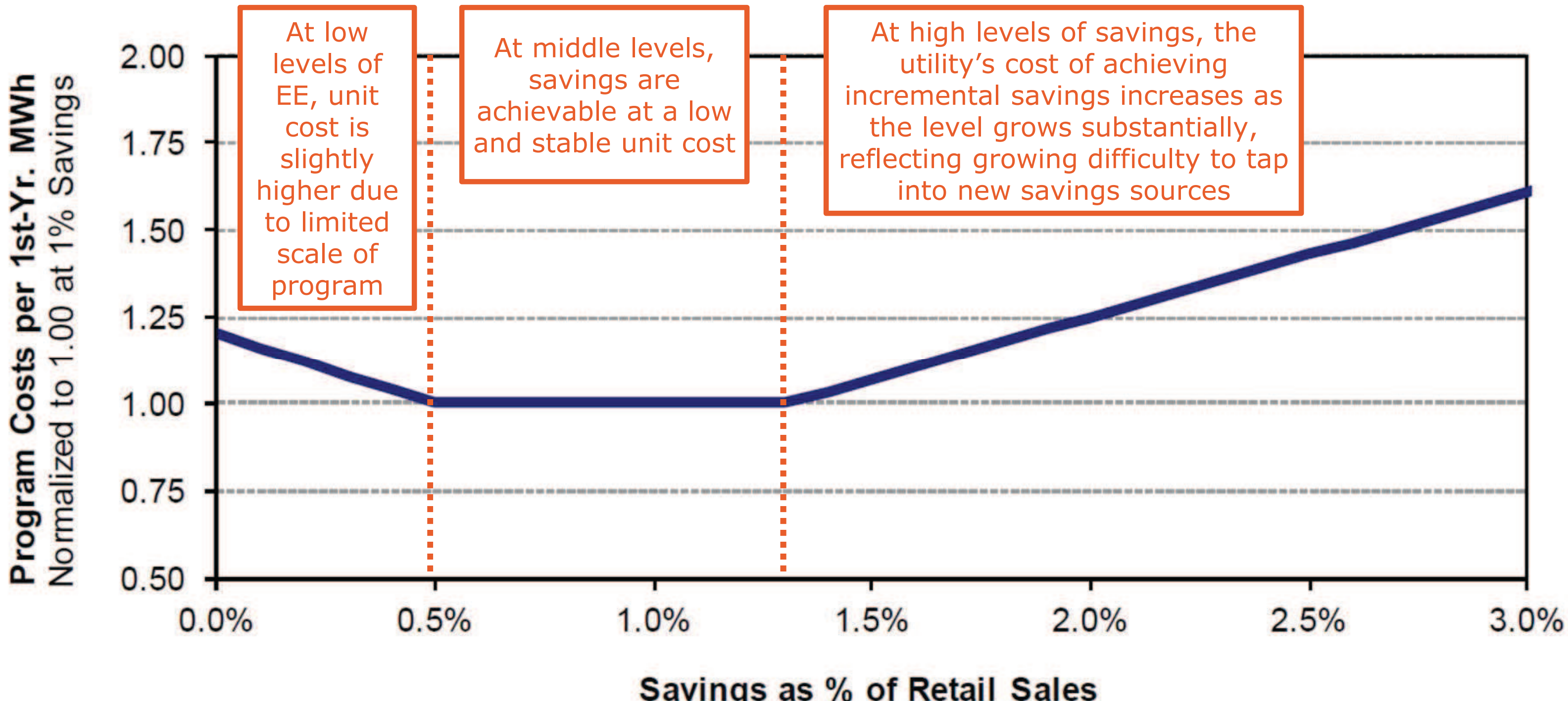


Figure source: *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025*

Energy Efficiency – Next Steps

- Because of the uncertainty associated with the possible existence of additional energy efficiency beyond the amounts currently included in PGE's IRP portfolios, more work is needed to understand this resource
- The stakeholder group, the ETO, and PGE have discussed working together over the next 2 years to further examine the EE potential for the subsequent IRP

Renewable Resources

+ **PGE's second major option for carbon emission reductions is further investment in renewable resources, which include:**
  - Local wind
    - Without new transmission (e.g. Gorge)
    - With new transmission (e.g. Steens Mountains)
  - Remote wind
    - Montana wind (in combination with Colstrip displacement)
    - Wyoming wind (with new interregional transmission line)
  - Solar photovoltaics
    - Distributed (e.g. rooftop)
    - Central station
  - Local biomass and geothermal

Availability of Columbia Gorge Wind

+ **While substantial development has occurred in the Columbia River Gorge, a large amount of potential remains**
  - WREZ study (2009) identifies over 5,500 MW of wind resource available for development in the Columbia River Gorge
  - NREL Western Wind data set suggests potential may be larger (10-15 GW)
  - Both data sets are dated and don't capture the fact that recent improvements in turbine technology have made more sites with low wind speed suitable for development
+ **In a low carbon future, competition for wind in the Gorge may constrain PGE's ability to develop this resource in significant quantities**
  - PGE represents just under 15% of WA/OR total loads
  - PGE will compete with other WA/OR utilities—as well as California utilities—for resources in the Gorge
+ **E3 has assumed that 2,000 MW of Gorge Wind would be available for PGE development**
  - Well-aligned with PGE's wind-heavy portfolios in the 2009 IRP
  - Represents a reasonable fraction of identified local potential
  - However, Gorge wind has little seasonal and diurnal diversity, presenting greater operational and cost challenges for integration and meeting peaking needs

Assumed Availability of Other Wind Resources

- **To the extent that future IRPs conclude that it isn't least cost/least risk for PGE to fill its need with Gorge wind only, it will have to seek alternative resources**
- **E3 assumes that the quantity of other resources available to PGE is constrained by transmission:**
  - The amount of **Montana** wind that can be developed upon the displacement of Colstrip without new transmission needed is assumed to equal PGE's share of Colstrip (296 MW), equivalent to about 120 aMW at an assumed 40% capacity factor
  - Wind in the **Steens Mountain** region of Oregon can be accessed by building new transmission (likely 230 kV, which would provide 800 MW)
  - Wind in **Wyoming** can be delivered to Portland through the construction of a new 500 kV transmission line, which would allow for 1,500 MW of wind

Limits on Biomass and Geothermal Availability

- **Biomass potential is limited by the availability of fuels**
  - NWPCC Sixth Power Plan identifies **203 MW** of biomass potential in Oregon due to supply constraints
  - 2009 IRP assumed **50 MW** of biomass would be available to PGE, an assumption that E3 has carried forward in this analysis.
- **Geothermal options are limited by the number of sites with sufficient thermal gradients for development**
  - 2009 IRP identified **380 MW** of in-state potential but included no more than **50 MW** in any single portfolio
  - NWPCC Sixth Power Plan relies on a 2008 USGS report, which identifies **595 MW** of resource in Oregon with 95% confidence
  - WREZ identifies **832 MW** of geothermal in areas near PGE's service territory
  - E3 has conservatively assumed that **120 MW** of the identified and undeveloped Oregon biomass and geothermal resources are available to PGE
- **For reference, PGE's recently concluded renewables RFP, yielded bids for about 65 MW each of biomass and geothermal**
  - None of the projects made it to the short list

Solar PV Resource Options

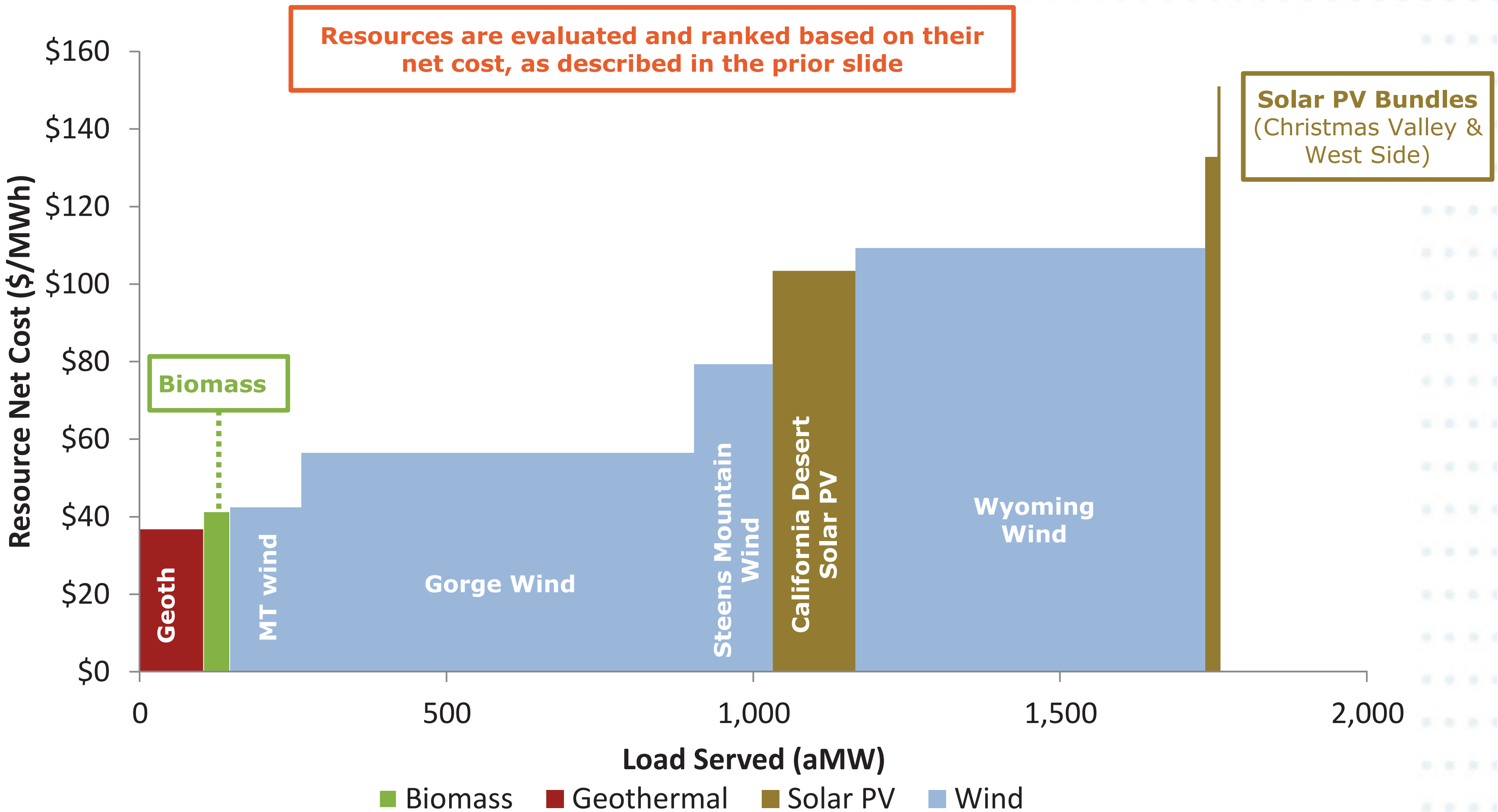
- **In the past few years, the costs of solar PV have declined substantially, presenting PGE with another possible resource alternative**
- **E3 has considered several solar PV options in its screening analysis of renewables:**
  - **Christmas Valley:** a reasonable quality solar resource that would not require substantial new transmission to serve PGE's loads. (PGE has recently entered into a PPA for the output from a 2.4 MW solar PV facility in that location.)
  - **Distributed:** local PV installed at or near loads in Portland, both ground-mounted and rooftop
  - **California Desert:** installed at a high quality resource site in California and wheeled to PGE loads through the CAISO

Net Cost Approach to Portfolio Development

- **In other portfolio design exercises, E3 has compared the "net costs" of new resources to generate a least-cost portfolio of resources**
  - In addition to a resource's direct cost of generation, net cost considers the costs imposed by and benefits associated with a new resource on the system

Formulation of Net Cost	
	Levelized cost of energy
+	Transmission cost
+	Integration (operating) cost
+	Fixed cost of integrating resources
-	Energy value
-	Capacity value
=	**Net cost**

Renewable Supply Curve



*** Montana wind assumes availability of transmission line currently dedicated to Colstrip 3&4**

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Displacing Colstrip

- **PGE is a minority owner in Colstrip units 3 & 4, which provide its customers with approximately 250 aMW of power each year**
- **PGE's share of Colstrip will become the single largest source of emissions in PGE's portfolio after 2020**
  - Accounted for approximately one third of the emissions attributed to PGE's 2005 resource portfolio
- **PGE has already committed to cessation of coal operations at Boardman by the end of 2020, but to achieve a 2030 emissions reduction target, displacing Colstrip by 2030 is necessary**

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DEVELOPMENT OF CANDIDATE PORTFOLIOS

Tradeoff Between Efficiency and RPS

+ **With the limited number of options available for carbon emissions reductions, there is an implicit tradeoff between efficiency and renewables in a carbon-constrained world**

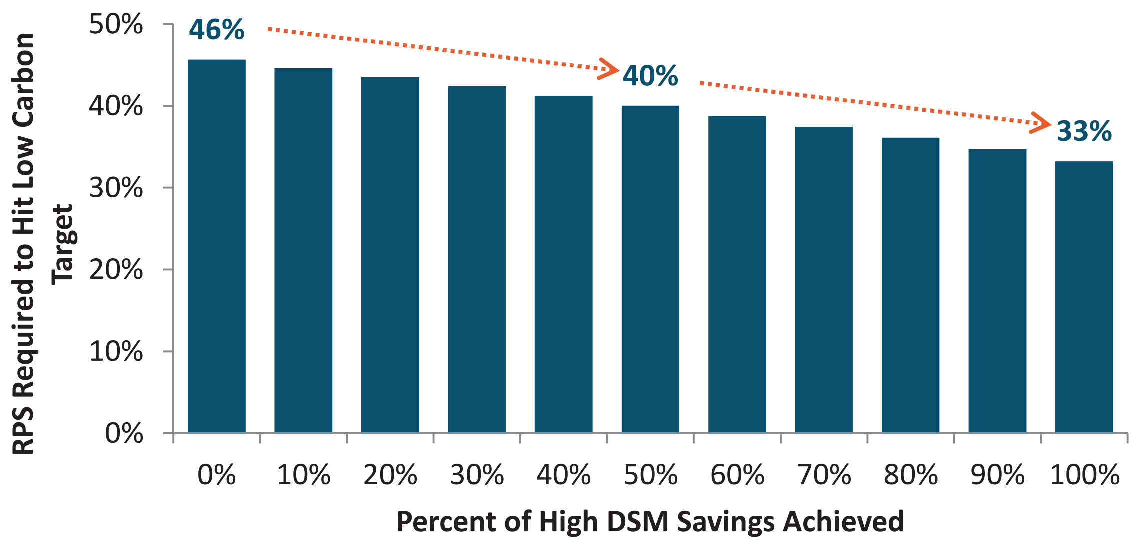
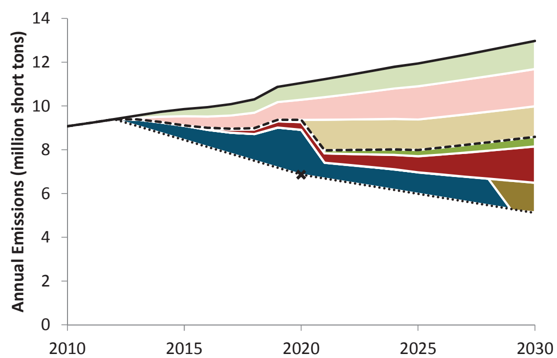
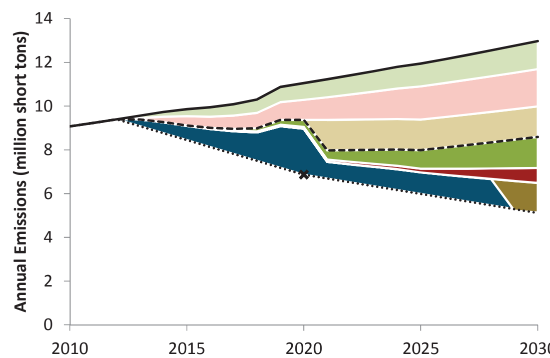


Figure based on load & resource mix in 2030; assumes Colstrip is fully displaced

+ **Due to uncertainties in the achievability of high levels of efficiency captured by LBNL's High DSM Case forecast, E3 has developed two low carbon portfolios as sensitivities on various carbon reduction strategies**

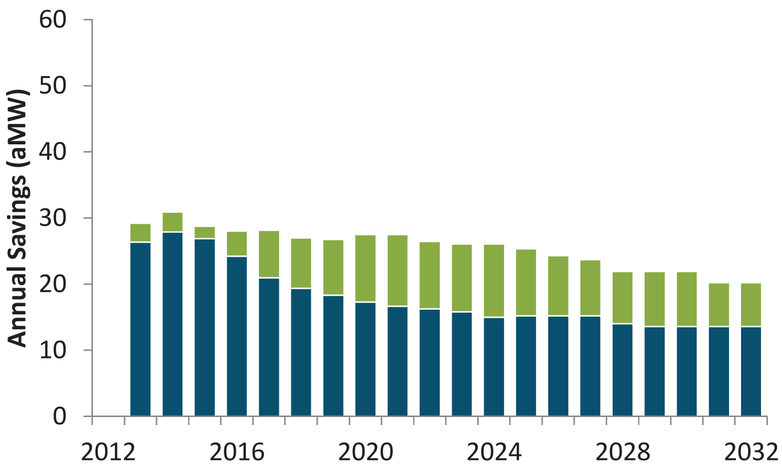
Two Low Carbon Portfolios

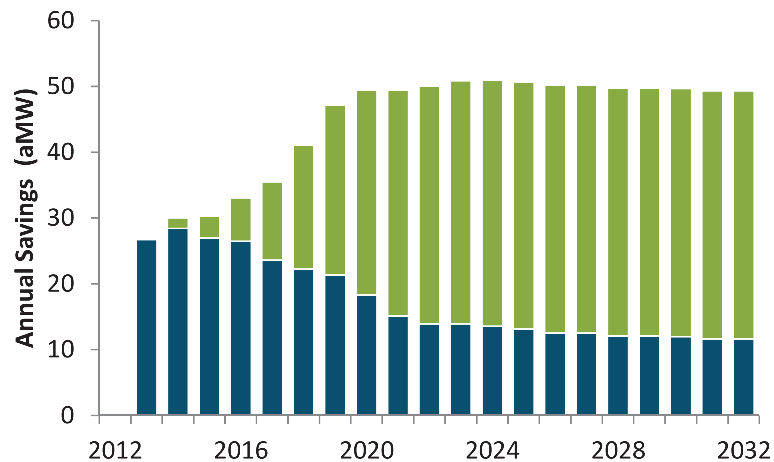
- **E3 recommends studying two Low Carbon Portfolios to highlight both the effects of decarbonizing with renewable investment and the possible impact of achieving transformative levels of efficiency**
- **Both portfolio meet the same carbon target for 2030, putting PGE on a glide path to longer term reduction goals by 2050**

Assumption	Portfolio #1	Portfolio #2
Energy Efficiency	ETO **Total Achievable** Potential	ETO Cost-Effective Achievable + **LBNL High DSM** savings
Renewables	**42%** RPS by 2030 (85% by 2050)	**33%** RPS by 2030 (75% by 2050)
Colstrip	Fully displaced by **2028**	Fully displaced by **2028**
Resulting Carbon Abatement		

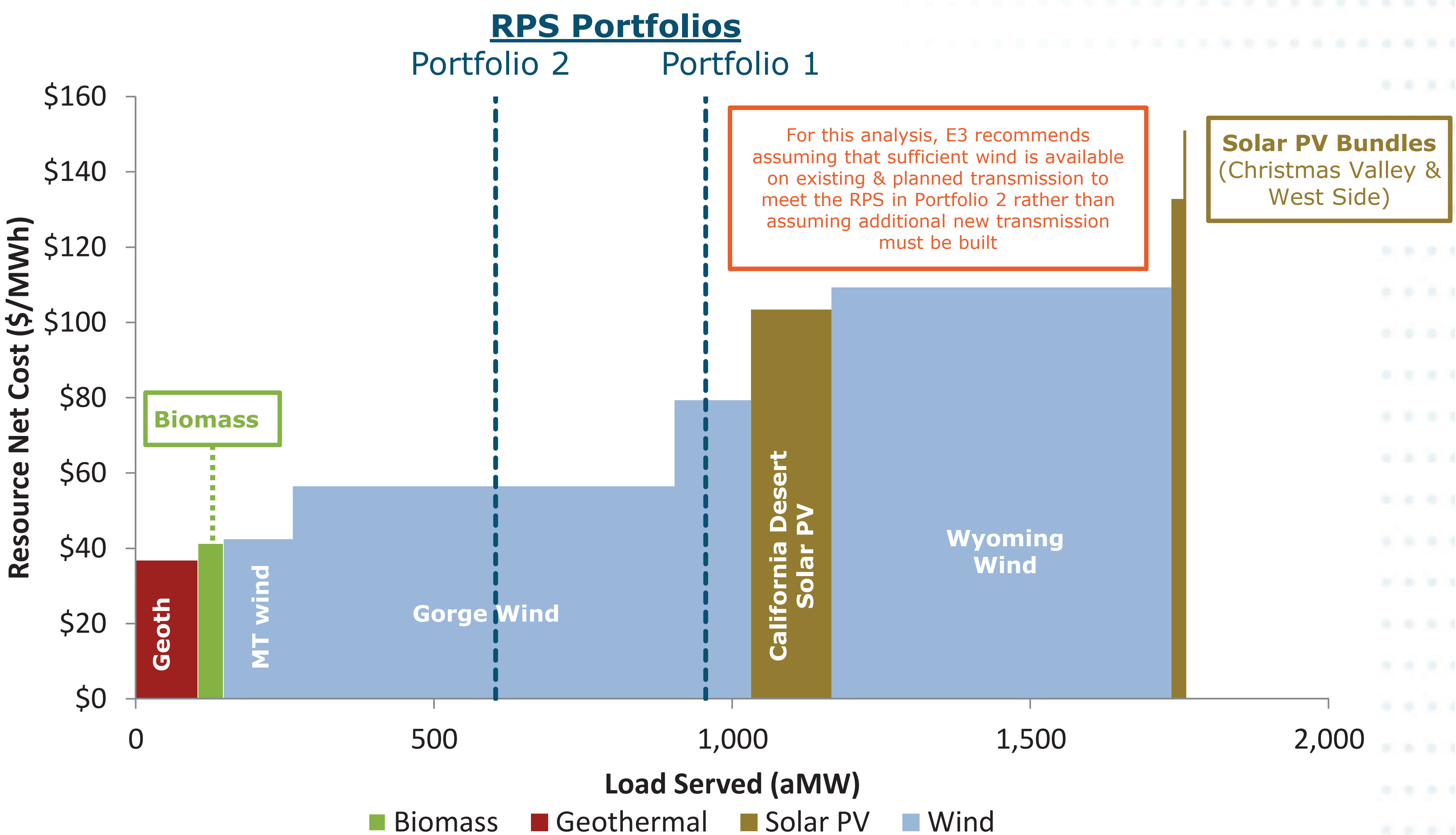
Efficiency Deployment

- The low carbon portfolios assume that ETO's achievement of energy efficiency savings exceeds its current projections by a substantial margin
- In <u>Portfolio 1</u> (ETO total achievable efficiency), incremental efficiency nearly offsets the decline in annual achievement in ETO's base case
- In <u>Portfolio 2</u> (ETO cost-effective achievable + full LBNL High EE savings), ETO achieves efficiency at a historically unprecedented level



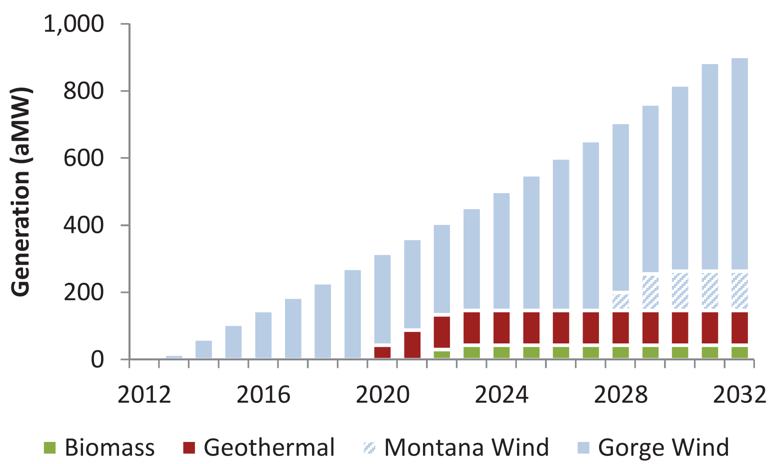


Deriving RPS Portfolios from the Supply Curve

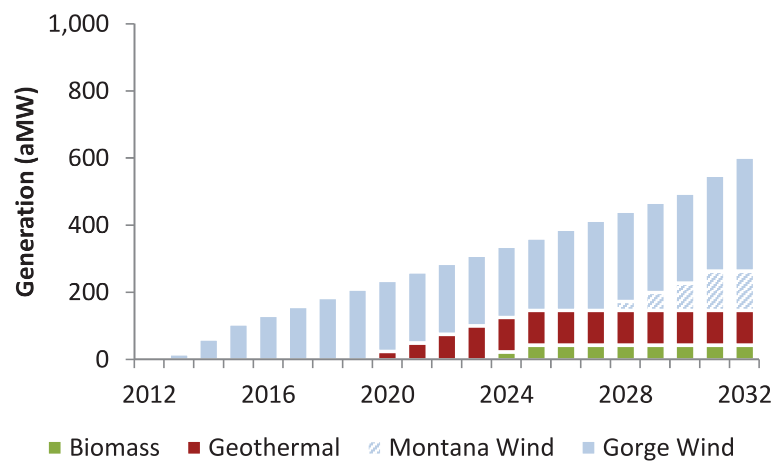


Renewable Portfolio Investments

- **The renewable resources included in each portfolio draw from the same pool—local biomass and geothermal, Gorge wind, and Montana wind—but differ in their magnitude of reliance on Gorge Wind**
- **Portfolio 1 assumes PGE will add about 2,000 MW of wind in the Columbia River Gorge by 2032**

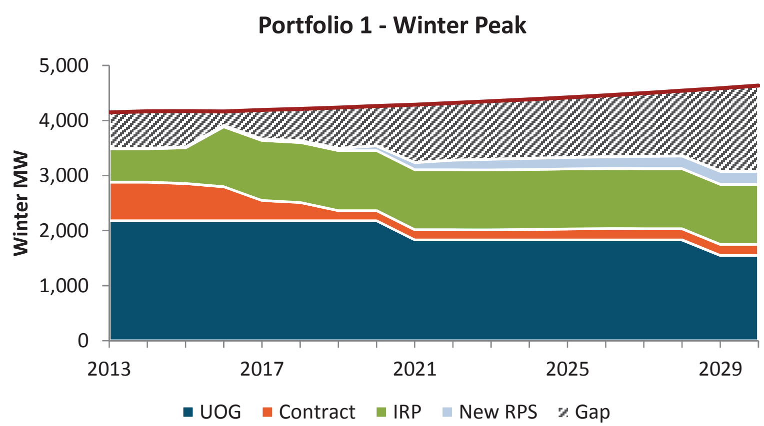


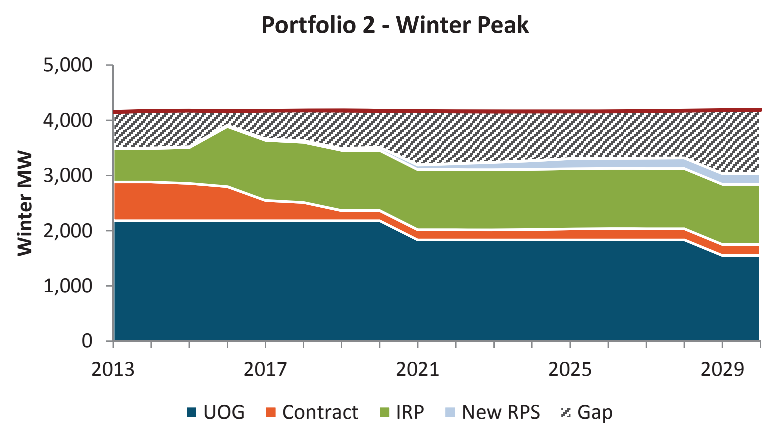
- **Portfolio 2 contains a more balanced mix, with roughly half of 2032 additional renewables in the Gorge**



Winter Capacity Balance

- Because wind power provides relatively little reliable capacity (~5% of nameplate), portfolios that rely heavily on wind power create large reliability-driven needs for new capacity
- This deficit is largest in Portfolio 1, in which PGE invests heavily in wind resources in the Gorge
- Portfolio 1 deficit: 1,550 MW by 2030
- Incremental efficiency in Portfolio 2 mitigates some of this deficit, as efficiency reduces peak demand
- Portfolio 2 deficit: 1,150 MW by 2030





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SPECIFYING A LOW-CARBON FUTURE

Distinction between Portfolios and Futures

+ **To develop an action plan that is robust in the face of future uncertainty, PGE's IRP process examines the performance of each candidate "portfolio" against a range of potential "futures"**
  - **Portfolio:** a mix of resources which will meet PGE's future energy and capacity needs
  - **Future:** a set of input assumptions for the behavior of a set of variables (e.g. gas prices, carbon prices) over the planning horizon

Table 10A-3: Portfolios, Futures and Scenarios

Future / Portfolio	Future 1	Future 2	Future 3	Future 4
Portfolio 1	Scenario 1,1	Scenario 1,2	Scenario 1,3	Scenario 1,4
Portfolio 2	Scenario 2,1	Scenario 2,2	Scenario 2,3	Scenario 2,4
Portfolio 3	Scenario 3,1	Scenario 3,2	Scenario 3,3	Scenario 3,4
Portfolio 4	Scenario 4,1	Scenario 4,2	Scenario 4,3	Scenario 4,4

+ **While E3's scope focused on developing assumptions for a portfolio, defining a low carbon future is important for that portfolio to have any coherence in the IRP process**

Why Create a Low Carbon "Future"?

- **In the near term, most of PGE's renewable procurement will allow PGE to maintain physical compliance with Oregon's RPS policy**
- **In the long term, continued investment in renewables above current statutory requirements must be motivated by:**
  1. Legislative mandates for carbon abatement (e.g. mandatory GHG goals), or
  2. The presence of a clear economic benefit to PGE ratepayers to pursue a low carbon portfolio
- **Defining a future based on (1) does not fit well with Oregon's current IRP framework, as other portfolios could not be easily compared against the Low Carbon Portfolio because of their non-compliance with goals**
- **Therefore, E3 recommends comparing the Low Carbon Portfolio against others in the context of a future in which the value of achieving emissions reductions is high enough to justify investment in low carbon resources**

Calculating an Implied Carbon Price

- **How high will carbon prices have to be to prompt investment in renewables above statutory requirements in the long run?**

$$\text{Implied Carbon Value } [\$/\text{ton}] = \frac{\text{Net Renewable Cost } [\$/\text{MWh}]}{\text{Avoided Emissions } [\text{tons}/\text{MWh}]}$$

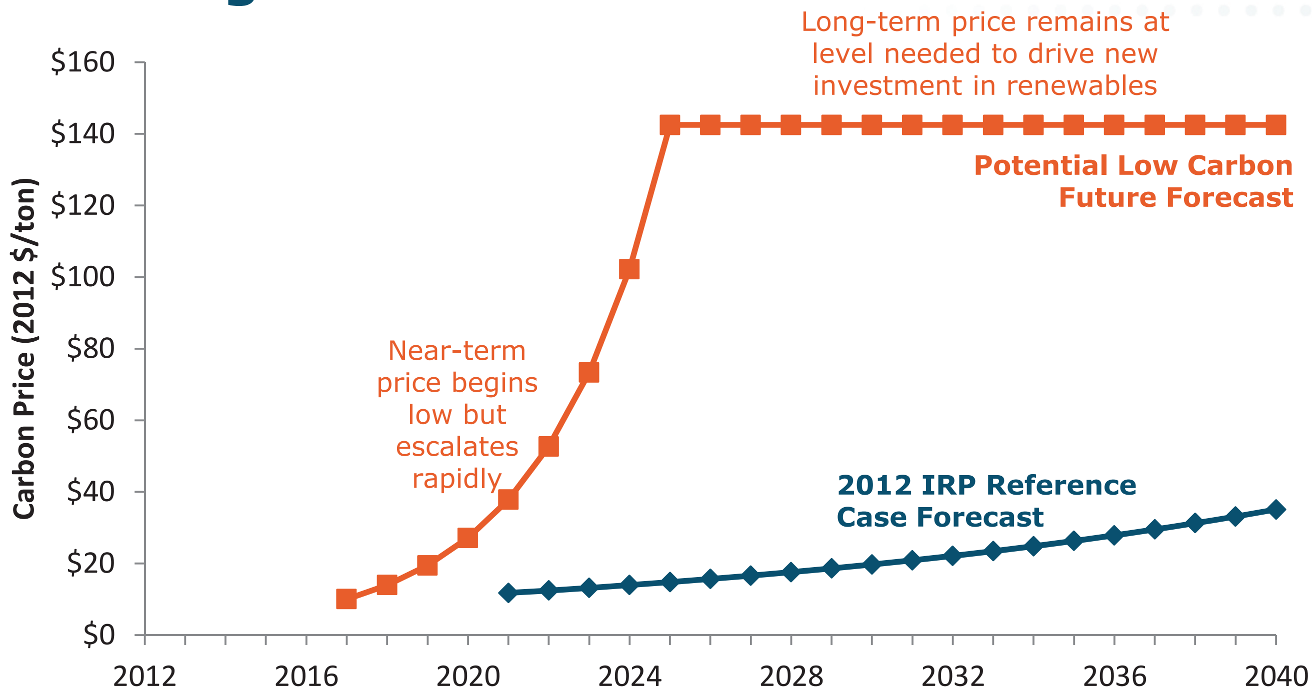
- **PGE's marginal renewable investment cost implies a high cost of carbon**
  - When the PTC expires, the ***net cost*** of Gorge wind will rise to **$64/MWh**
  - Each MWh of renewable generation displaces approximately **0.45 short tons** of carbon emissions
  - The value of carbon implied by this investment is **$142/short ton**

Gorge Wind Net Cost in 2030 (2012 $/MWh)		
	Delivered LCOE	$91.75
+	Transmission from BPA	$5.73
+	Integration	$9.33
-	Energy Value	-$38.74
-	Capacity Value	-$3.96
=	**Net Cost**	**$64.10**

Assumptions:
- Energy & capacity values based on PGE avoided cost as filed in Schedule 201 (Qualifying Facility 10 MW or Less Avoided Cost Power Purchase Information)
- Capacity factor of 31% for marginal resource

Carbon Price Trajectory

+ **Carbon price for a Low Carbon future would escalate from a low value in the near term to the level required to sustain investment in carbon-free technologies**



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SUMMARY OF RESEARCH NEEDS

Identifying Future Research Needs and Issues

- **In addition to providing technical assistance on low carbon portfolio development, E3 agreed to help identify issues and uncertainties that PGE should consider in its future evaluations of low carbon portfolios**
- **These outstanding questions, which could not be addressed in E3's scope, span a wide range of issues that PGE would have to address to realize a low carbon portfolio:**
  - Cross-sectoral implications of economy-wide low carbon targets
  - Technical and economic barriers to the development and acquisition of low carbon resources
  - Regulatory hurdles that may impede progress to carbon emissions reductions

Summary of Future Research Needs

Category	Key Questions
Economy-Wide Targets	1. Will the electric sector be forced to bear a larger share of emissions reductions in an economy-wide strategy? 2. How will the burden of electric sector GHG emissions reductions be allocated among Oregon utilities? 3. How much electrification load could PGE expect to see under an economy-wide GHG reduction plan?
Energy Efficiency	4. How much energy efficiency, beyond what is identified in ETO's supply curve, is or may become available to PGE over the IRP time horizon? 5. At what increased level of program funding can PGE expect to achieve these increased savings? 6. How can non-programmatic energy efficiency impacts be better captured in load forecasting? 7. How should ETO's cost-effectiveness screening for efficiency treat the probability of a carbon price under a low carbon future? 8. Is there an energy efficiency substitution effect that results in increased CO2 emissions elsewhere in the economy?
Renewables	9. How does integration cost change at different penetrations and with different amounts of intermittent resource diversity?

Summary of Future Research Needs (cont)

Category	Key Questions
Renewables (cont)	10. At what wind penetration would PGE need to build new flexible capacity to balance intra-hour variability of variable resources? 11. What would be the impact of an EIM or other regional initiatives on PGE's integration cost and flexibility needs? 12. How much wind in the Columbia River Gorge can PGE expect to be able to develop? 13. How will transmission affect PGE's ability to develop wind in the Columbia River Gorge? 14. What is the cost of transmission upgrades or RAS arming needed to achieve the full rating of the MT-NW path if Colstrip were to be displaced? 15. What is the cost of building new transmission to Steens Mountain or Wyoming? 16. Should PGE consider including solar PV generation located in a favorable location and wheeling the power to its system via CAISO?
Conventional Resources	17. Would any of PGE's prospective resource investments be at risk of stranding in a Low Carbon future?
Regulatory Issues	18. What near-term actions could be justified by the anticipation of much more stringent carbon regulations in the future?

Electricity's Role in an Economy-Wide Low Carbon World (1)

1. How will the carbon reductions required of the electric sector compare to economy-wide targets?

- **Many studies that focus exclusively on the electric sector in a low carbon world assume that it will have to meet the same reduction goals as the economy as a whole**
  - i.e. if economy wide target is 80% below 2005 levels, assume electric sector reduces emission to 80% below 2005 levels
- **In contrast, most economy-wide studies conclude that the electric sector will have to bear an outsize share of the emissions reductions, as opportunities in other sectors are limited**
  - Notwithstanding a major technological breakthrough, applications of biofuels are constrained by limits on supply
  - Future efforts to study the implications of low carbon portfolios should consider the implications of economy-wide targets on the reductions required of the electric sector

Summary of Economy-Wide GHG Studies
(% reduction relative to reference year by 2050)

Study	Economy-Wide Target	Electric Sector Reductions
Williams, et al.	80%	86%
SPSC Low Carbon	80%	80%
European Climate Foundation	79-82%	93-99%

Studies Cited:

Williams, J., et al. "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science* (2012).

SPSC Low Carbon Case, WECC 20-Year Transmission Planning Process

European Climate Foundation, "Power Perspectives 2030: On the Road to a Decarbonised Power Sector," 2012.

Electricity's Role in an Economy-Wide Low Carbon World (2)

2. How will the burden of electric sector GHG emissions reductions be allocated among Oregon utilities?

- **In addition to determining the appropriate share of GHG emissions reductions to require of the electric sector, policymakers will also have to choose how to allocate that responsibility within the electric sector**
- **Because utilities have different fuel mixes as starting points, they have different opportunities to reduce emissions relative to their baseline portfolios**
- **This analysis has assumed that PGE must meet the same reduction as the economy-wide target, but there are other ways that responsibility might be allocated**
  - e.g. uniform emissions intensity targets (tons/MWh) across utilities

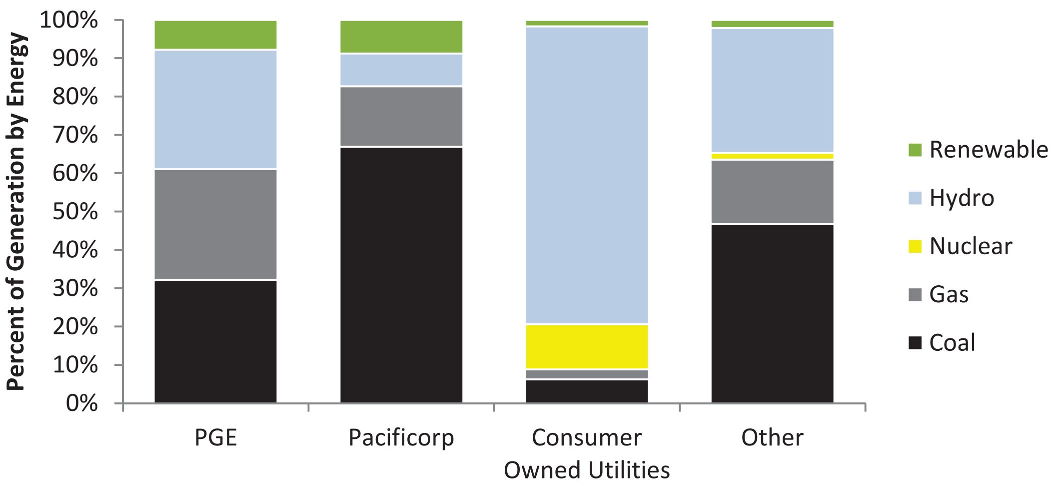
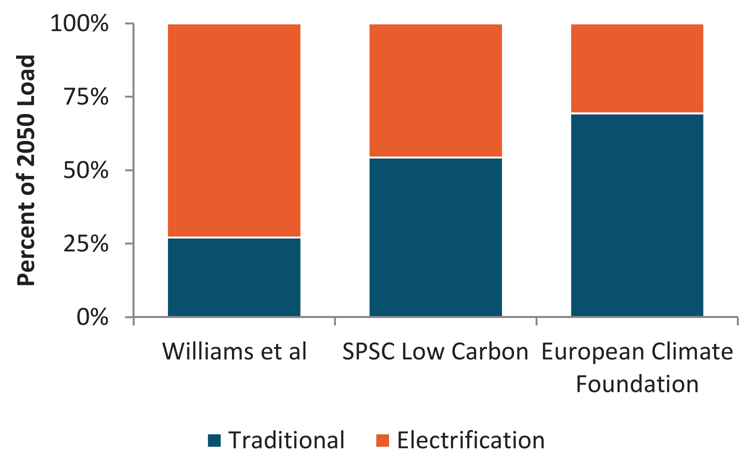


Figure Source: *data from Oregon Department of Energy; based on fuel mix disclosure reports for 2010*

Electrification in an Economy-Wide Decarbonization Effort (3)

3. How much electrification load could PGE expect to see under an economy-wide GHG reduction plan?

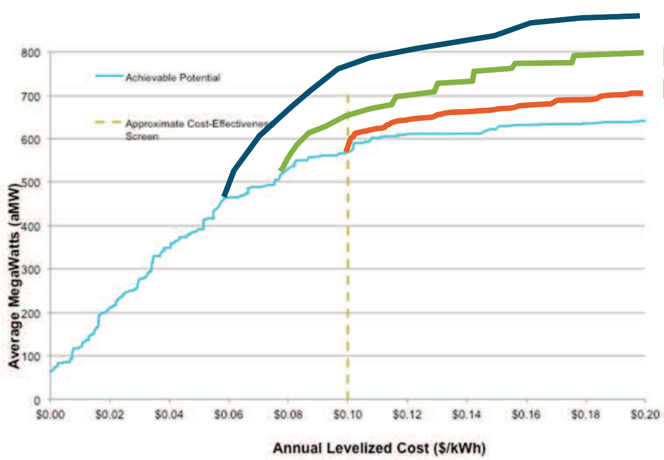
+ **While E3's current analysis assumed no cross-sectoral mitigation strategies, many studies agree that electrification will be key to achieving deep long-term GHG reductions**
  - This is another consequence of the limited opportunities for abatement outside of the electric sector
  - Transitioning end uses traditionally served by fossil-fuel combustion to low-carbon electricity presents a large opportunity for abatement but will intensify the challenge faced by the electric sector, which will have to decarbonize **while serving additional loads not traditionally planned for**
+ **Addressing this question requires understanding:**
  - The potential growth of the market for electric vehicles
  - Possibilities for fuel switching among residential and commercial end-uses
+ **For such a measure to be viable, utilities would have to receive credit/allowances for the emissions reductions**



Quantifying Incremental Efficiency Potential (4)

4. How much energy efficiency, beyond what is identified in ETO's supply curve, is or may become available to PGE over the IRP time horizon?

- **Assumptions based on the High EE case provide an interesting scenario from an academic perspective but would need support from more concrete feasibility assessments to allow PGE to act upon them**
- **E3 has presented a framework under which emerging technology opportunities could be incorporated into ETO's traditional supply curve approach to efficiency**
  - As with commercially available technologies currently included in the supply curve, this approach would involve identifying and characterizing emerging efficiency opportunities



- **Opportunities could be classified based on their probability of realization as a commercial technology, allowing for incorporation of such technologies into the IRP framework with an acknowledgement of the risk associated with them**

Costs of Aggressive Efficiency Programs (5)

5. At what increased level of program funding can PGE expect to achieve these increased savings?

- **Determining the cost of funding an efficiency program that would achieve the same level of savings as the High EE case is a challenging exercise since the case is not built on the same measure-level data that ETO uses**
- **E3 has used a generic relationship between program costs and savings levels established in a recent LBNL study that shows increasing marginal costs at higher savings levels, which is not ideal:**
  - PGE has historically invested in efficiency at a much higher level than other utilities in the United States and has achieved a large share of the "low hanging fruit" savings that are available to others
  - As a result, the cost function—based on data from utilities around the US—may have a different shape for PGE
- **As a result, the cost-effectiveness of incremental efficiency as an emissions abatement strategy is a *planning assumption* more than it is an *analytical result***
- **Developing a measure-based approach to identifying emerging opportunities such as that on the prior slide would allow for improved estimates of program funding costs**

Cost-Effectiveness Screening in a Low Carbon Future (6)

6. How should ETO's supply curve cost-effectiveness screening treat the probability of a carbon price under a low carbon future?

- ETO currently screens cost-effectiveness of efficiency based on PGE's avoided costs, which currently include no explicit consideration for a future carbon price
- Under a low carbon future, ignoring the value of efficiency opportunities just beyond this threshold will inflate the costs of reducing emissions
- PGE and ETO should consider how placing an explicit value on emissions reductions would impact its cost-effectiveness threshold for EE
- A second cost-effectiveness screening incorporating a carbon price provides another means of distinguishing efficiency as a resource in a low carbon future

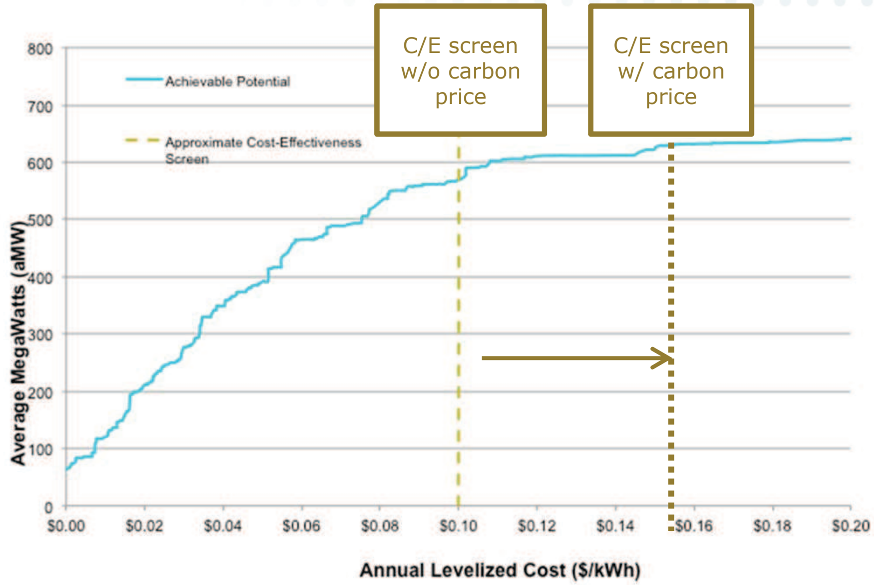


Figure is illustrative only and shows the impact of carbon pricing on cost-effectiveness screening of energy efficiency

Non-Programmatic Efficiency (7)

7. How can non-programmatic energy efficiency impacts be better captured in load forecasting?

- **Like most utilities, PGE forecasts future loads using a top-down model based on the historical relationship between macroeconomic and population indicators and loads**
  - As a result, increasing stringency of codes and standards is not explicitly accounted for in the load forecast
  - At the same time, it is challenging for ETO's efficiency assessment to account for savings through non-programmatic channels
- **In the future, incorporating end-use detail into the load forecast development would allow for explicit adjustments for future changes to codes and standards, improving the accuracy of the load forecast**

Examples of Increasing Federal Standards
• By 2014, federal standards will require general purpose lighting to provide 45 lumens per watt
• Water heaters larger than 55 gallons will be required to utilize heat pumps

EE Substitution Effects (8)

8. Is there a substitution effect for energy efficiency that results in increased CO_2 emissions elsewhere in the economy?

+ **Several studies have found that the adoption of increasingly efficient technologies can cause behavior changes that partially offset the carbon reductions that improvement in efficiency might have otherwise enabled**
  - One example: a person who purchases a fuel-efficient vehicle may drive more than they would have using a less efficient vehicle
+ **Determining whether this effect is real—and to what extent it should be considered in a utility's resource planning for carbon reductions—is a challenging exercise**
  - However, ignoring this impact could result in an overvaluation of energy efficiency as a measure to reduce carbon emissions

Characterizing the Cost of Renewable Integration (9)

9. How does integration cost change at different penetrations and with different amounts of intermittent resource diversity?

+ **Integration costs refer to the increase in system dispatch costs associated with the need to carry increased levels of reserves to accommodate the intra-hour variability and the uncertainty of renewables**
+ **Because integration costs are very difficult to quantify, many studies, including PGE's prior IRPs, assume that the unit cost of integration ($/MWh) for intermittent technologies such as wind and solar PV does not change as penetrations increase**
+ **However, there is growing concern in the industry that the unit cost of integration will begin to increase as higher and higher penetrations are achieved**
+ **As higher penetrations are reached, understanding the marginal cost of integration and how portfolio diversity affects its magnitude could become instrumental in informing utilities' choices of low cost resources to add to their portfolios**
+ **A closely related question is how the GHG impacts of renewable additions will change at varying levels of penetrations**
    - E3's analysis has assumed a 1-for-1 substitution of renewable generation for gas generation
    - However, as penetrations increase, operators will have to utilize less efficient, fast ramping gas resources to provide sufficient reserves to balance variable renewables, which could result in lower GHG reduction efficiency associated with renewable resources

Understanding the Need for Flexible Resources (10)

10. At what wind penetration would PGE need to build new flexible capacity solely to balance intra-hour variability of intermittent resources?

- **One of the major concerns in California as the state approaches its 33% RPS is whether there will be enough flexible generation resources available to meet all of the ramps and reserve requirements resulting from high penetrations of intermittent resources**
- **With PGE's small size and its past and future loss of flexible hydro contracts, it will have to consider the need for flexible resource additions to balance its growing variable energy portfolio**
- **One of the major questions that PGE will have to confront is what type of flexible capacity acquisitions will provide the best complement to its renewable portfolio:**
  - Combined cycle
  - Combustion turbine
  - Demand response
  - Internal combustion engines
  - Storage
  - Smart grid applications

How Cooperation Among Entities Impacts Costs of Integration (11)

11. What would be the impact of an EIM or other regional initiatives on PGE's integration cost and flexibility needs?

- **Over the past several years, there has been growing interest in the possibility of establishing an Energy Imbalance Market in the WECC**
  - Two recent (2011) studies of benefits of implementing an EIM over a WECC footprint (but excluding CAISO and AESO): one funded by WECC and the other by Public Utilities Commission EIM group
  - CAISO and Pacificorp recently joined in an MOU to implement such an EIM with the express goals of improving dispatch efficiency and reducing integration costs
- **From PGE's perspective, participating in such a regional initiative could result in benefits to ratepayers whose magnitude could be increased in a low carbon portfolio:**
  - **Reduced reserves cost:** by pooling its loads and renewables with neighboring BAs to take advantage of diversity and by sharing flexible resources to provide reserves more efficiently, PGE could reduce the cost of carrying reserves to balance its increasing penetrations of renewable resources (i.e. its integration costs)
  - **Reduced renewable curtailment:** participating in a larger pool through an EIM would reduce the likelihood of PGE's needing to curtail valuable renewable generation during periods of overgeneration

Gorge Wind Potential (12)

12. How much wind in the Columbia River Gorge can PGE expect to be able to develop?

+ **E3's assessment of wind potential in the Columbia River Gorge relies heavily on the NREL Western Wind Dataset, which has some shortcomings in this context:**
  - It is admittedly not a comprehensive estimate of resource potential, and the data set's broad scope (the entire Western US) may result in a lack of accuracy in such local geography
  - Its resource assessment is now slightly outdated, as improvements in wind turbine technologies—especially performance at low wind speeds—have expanded the possibilities for site selection
+ **Competition among utilities in the Northwest to develop local wind resources in a low carbon future may limit PGE's access to the available potential**
  - Competition for the best renewable resources could be expected to increase in a low carbon future
  - How will this competition for high quality renewables affect regional trends in resource development?

Transmission Challenges in the Columbia River Gorge (13)

13. To what extent will the lack of transmission availability constrain development of otherwise viable resources in the Gorge?

+ **E3's analysis suggests that developing wind in the Gorge is one of the lowest cost renewable resource options available to PGE as long as no major additional investments in new transmission are needed**
+ **Transmission from the Gorge to Portland's load center on BPA's system may be limited due to the substantial wind development in the region over the past several years**
+ **Cascade Crossing could provide relief, providing a new path for east-side resources.**
  - Single circuit 500 kV: ~800 MW for wind after Boardman shuts down
+ **Nonetheless, PGE should continue to monitor the situation to understand what upgrades may be needed to continue development in the region and, as a result, whether other resource options may present more cost-effective opportunities**

Accessing Montana Wind on Colstrip Transmission (14)

14. In the event of a Colstrip displacement, what technical steps will be necessary to maintain the path rating to allow PGE to access high capacity factor Montana wind?

+ **E3's analysis has assumed that the ratings of paths that PGE currently uses to deliver Colstrip's generation to its loads could be sustained at minimal cost to PGE in the event of Colstrip's displacement, allowing PGE to acquire roughly 120 MWa of high quality wind resources along this corridor**
+ **Maintaining the path ratings from Montana to Oregon may require additional investments in transmission infrastructure or the introduction of new RAS arming schemes to avoid WECC-wide reliability issues in the event of a contingency**
  - Maintaining the path rating in the absence of a single large coal plant at the end of the line may prove challenging

Costs of Major New Transmission (15)

15. What is the magnitude of new investment that will be necessary to access wind in locations that are currently inaccessible to PGE because of transmission constraints?

+ **The assumptions in E3's analysis suggest that the costs of new transmission are prohibitively high for PGE to consider developing remote wind resources while local renewable resources are available**
  - Based on NWPCC 6th Power Plan assumed transmission costs from Wyoming to Oregon
  - Capacity factor for Wyoming wind is assumed to be 38%
+ **There are, however, a number of reasons that E3 would recommend PGE continue to evaluate such remote wind resources as an option in its IRPs:**
  1. E3's experience suggests that there may be higher quality wind resources available for development in Wyoming with new transmission—up to capacity factors of 45%—in which case Wyoming wind would look much more competitive even with new transmission investment required
  2. Potential supply of local resources may prove shorter than assumed here, in which case investment in major new transmission to develop renewables may be unavoidable
  3. Reaching the 2030 goals that these portfolios target is only a waypoint on a trajectory to deeper carbon reductions by 2050, which will require further resource development
  4. With the potential challenges facing PGE with regard to integration, there may be substantial benefits to adding diversity to its portfolio of resources by including generation linked to a different wind regime—a benefit that has not been considered in this screening
  5. Pacificorp's planned Gateway expansion will reinforce existing east-to-west corridors, and may provide opportunities for other utilities to transport high-quality Wyoming wind to loads in the PNW

California Solar Resource Options (16)

16. Should PGE consider including solar PV generation located in a favorable location (e.g. Southern California) and wheeling the power to its system via CAISO?

+ **While the assumptions on resource cost and value in the IRP indicate that California solar PV is higher on the renewable supply curve than PGE will need to look to achieve low carbon targets, there are a number of reasons that PGE may want to continue to evaluate this resource option:**

    1. The costs of solar PV resources have dropped precipitously in the past several years, and if cost reductions continue in the future, the economics of PV relative to Gorge wind could shift;
    2. Historically, power has flowed along the California-Oregon Intertie from North to South throughout much of the year, suggesting that wheeling power from California to Portland should not be constrained by congestion or a lack of transmission and could reduce real power losses; and
    3. Diversifying its renewable portfolio among multiple technology types could provide PGE benefits that have not been explicitly accounted for in this analysis (e.g. reduced integration costs), and the complementarity of solar and wind production profiles could reduce the challenges associated with serving load under high penetrations of renewables

Risk of Stranded Assets (17)

17. Would any of the gas resources that PGE may consider in the development of an Action Plan be at risk of stranding in a Low Carbon future?

- **In a carbon-constrained future, utilization of gas-fired resources may be limited by emissions targets, which could result in underutilization of new investments in a low carbon future**
  - Gas investments that may present an apparent low-cost solution to serving loads in the near future could result in higher costs for ratepayers if their use is limited in the future
- **As gas resources have an expected useful lifetime that spans several decades, it is critical to consider how the constraints of a low carbon future might impact the lifecycle economic impacts of its investment decisions**
  - This could be achieved through the calculation of a value-at-risk analysis, whereby PGE could calculate the incremental cost to its ratepayers of investing in infrastructure that becomes underutilized in the event of a low carbon constraint on the portfolio

Balance Between Near- and Long-Term Strategies (18)

18. Are there any near-term actions that PGE should consider taking with the prospect of a low-carbon future on the horizon?

- While long-term carbon targets often appear to be a long distance in the future, the multi-decade lifetime of new investments requires utilities to plan near-term investments carefully to facilitate the achievement of these goals and allow for flexibility in resource development
- Utilities must continue to balance their focus on near-term investment decisions with a considerations of their long-term implications with respect to carbon dioxide emissions reduction

Energy+Environmental Economics

Thank You!

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Priority Recommendations from PGE Low Carbon Scenario Analysis [developed by the Environmental Group; based on E3 analysis and suggested subjects for further evaluation.] March 15, 2013			
	Area	Recommendations	Suggested additional parties to involve
I	2013 IRP	PGE should defer any significant resource acquisitions pursuant to this 2013 IRP, relying instead on short-term and medium-term purchases if needed, to preserve its future options to acquire lower carbon resources and to avoid the opportunity cost of committing to a new large fossil-fueled resource.	ODOE, OPUC, NCPPC
II	Next Steps	PGE should continue collaborative efforts with other relevant parties to complete research in the areas recommended below over the next two to three years.	
	IIa. Improve long-term PGE/ETO Energy Efficiency (EE) Supply Curve	PGE should seek to confirm the low/medium/high probability LBNL EE supply curves identified by E3; in particular: • Leverage NWCPPC backcasting EE supply analysis to have a tool for validating predictions of EE technology maturation and delivery potentials • Identify EE technologies within the low/medium/high probability range and evaluate for potential contributions over the planning horizon (even if it is still “emerging technology” at front end of IRP period) • Evaluate opportunities for EE penetration gains through new	ETO, NCPPC, LBNL

		behavioral, financing and other delivery mechanisms
		• Evaluate opportunities for technology availability through new Federal and State efficiency standards (e.g., appliances, lighting, motors, etc.)
		• Evaluate new incentive and regulatory tools that could enlarge the EE supply curve or accelerate technology/delivery movement through:
		    o Attributing higher carbon displacement value
		    o Attributing higher system operations value for load-center EE resources, especially those with dispatchable Demand Response capability	

	IIb. Enlarge PGE Renewable Energy Supply Curve	• Evaluate potential for utility scale solar (≥ 10 MW) costs to descend during the IRP 20 year window (as wind did from 2000-2012), and reserve flexibility to acquire such resources during the planning period • Complete and evaluate the closed-loop biomass fuel supply demonstration at the Boardman facility; evaluate forest-fuel recovery and other biomass technology and fuel options. • PGE should fully evaluate and cost out the option of terminating Colstrip early and reassigning the associated transmission assets to developing eastern slope Rocky Mountain wind for its energy and diversity value to the utility. • Evaluate wind options outside the Columbia River corridor development area for resource value, diversity value, cost to access, cost to integrate (see “Colstrip,” above; and	NREL, LBNL, BPA, NCPPC, ODOE, ETO

		"integration supply curve, below) • Evaluate and address access, regulatory or business issues required to capture the geothermal resources in the supply curve • Evaluate new incentive and regulatory tools that could enlarge the RE supply curve or accelerate technology/delivery movement (e.g., through attributing higher carbon displacement value)	

	IIc. Enlarge PGE Renewable Energy Integrating Tools/Resources Supply Curve[1]	• Evaluate the range, availability and marginal cost curves of supply side and demand response flexibility options that may become available to support variable generating resources
		  ○ Load-center and "mine-mouth" supply-side: fast-ramp SCGT; CAES; advanced materials batteries, etc.
		  ○ Load-center demand-side: load-cycling demand response; plug-in electric vehicles
		• Evaluate where adding transmission capacity and/or links could offer PGE system flexibility added value
		• Participate in developing and enlarging a Western Energy Imbalance Market mechanism
			WECC, BPA, WAPA, CAISO, NCPPC, NREL, Batelle, LBNL,

[1] NOTE: The E3 analysis cautions that new integrating capabilities may impose increasing marginal costs on PGE and other utilities. While this may be the case, it is at least equally likely that increased demand for such capabilities will stimulate innovation and declining unit cost curves (as have wind and solar generating technologies, and many control technologies). The already identified potential for PEV's to provide load center storage capability is one example.

Appendix G

Characterization of Supply Side Options

by Black & Veatch for PGE

Characterization of Supply Side Options - Wind Energy

by Black & Veatch for PGE

Cost and Performance Data for Power Generation Technologies

by Black & Veatch for NREL

FINAL REPORT

CHARACTERIZATION OF SUPPLY SIDE OPTIONS

B&V PROJECT NO. 178601
B&V FILE NO. 90.0000

PREPARED FOR

Portland General Electric

22 FEBRUARY 2013

BLACK & VEATCH
Building a world of difference.

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1.0 Introduction

Black & Veatch has prepared this report to characterize supply-side options (SSOs) to be considered in upcoming Integrated Resource Planning (IRP) activities to be conducted by Portland General Electric (PGE). The SSOs characterized in this report include:

- Integrated Gasification Combined Cycle (IGCC) with Carbon Capture
- 1x0 General Electric (GE) LMS100PA Combustion Turbine
- 6x0 Wartsila 18V50SG Reciprocating Engines
- Solar Photovoltaic (10 MW Fixed Tilt)
- Biomass Combustion (25 MW Bubbling Fluidized Bed)
- Geothermal (20 MW Binary System)
- Pumped Storage Hydroelectric (500 MW Closed Loop)
- Battery Storage (10 MW, 10 MWh Lithium Ion Battery)
- Battery Storage (25 MW, 25 MWh Lithium Ion Battery)

Each of these technology options is described in the following sections, including a brief technology overview and characterization of the performance and cost parameters of each SSO. A full matrix of cost and performance parameters for the nine requested SSOs is provided as Appendix A.

2.0 Design Basis and General Assumptions

2.1 DESIGN BASIS FOR SUPPLY SIDE OPTIONS

To develop technical performance and cost characteristics, Black & Veatch established design basis parameters for each of the SSOs under consideration. For each SSO, design basis parameters are summarized in Table 2-1.

Table 2-1 Design Basis for Supply Side Options

SUPPLY-SIDE OPTION	MAJOR EQUIPMENT	DUTY	NET CAPACITY (MW)	CAPACITY FACTOR (%)	PRIMARY FUEL
IGCC w/ Carbon Capture	Gasifier: Entrained Flow Combustion Turbine: GE 7F Syngas Carbon Capture: Physical Solvent Emissions Control: N_2 Injection, SCR Heat Rejection: Wet Cooling Tower	Baseload	475	80%	Coal
1x0 GE LMS100 PA	Combustion Turbine: LMS100 PA Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Peaking	100	5%	Natural Gas
6x0 Wartsila 18V50 SG	Recip. Engine: Wartsila 18V50 SG Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Peaking	110	5%	Natural Gas
Solar PV	PV Module: Trina TSM-PA14 Insolation Data Site: Redmond, OR	As-Available	10	22%	n/a
Biomass Combustion	Boiler: Bubbling Fluidized Bed Emissions Control: SNCR, Fabric Filter Heat Rejection: Wet Cooling Tower	Baseload	25	85%	Wood
Geothermal	System: Binary Geothermal System Heat Rejection: Air-Cooled Condenser	Baseload	20	85%	n/a
Pumped Storage Hydro	System: Closed Loop	Storage	500	n/a	n/a
Battery Storage	Battery: Lithium Ion Max. Discharge Period: 60 minutes	Storage	25	n/a	n/a
Battery Storage	Battery: Lithium Ion Max. Discharge Period: 60 minutes	Storage	10	n/a	n/a

2.2 GENERAL SITE ASSUMPTIONS

In addition to the design basis parameters shown in Table 2-1, general site assumptions employed by Black & Veatch for these SSOs include the following:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- The plant will not be located on environmentally or culturally sensitive lands. The project site will require neither mitigation nor remediation.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- Potable, Service and Fire water will be supplied from the local water utility.
- Wastewater disposal will utilize local sewer systems.
- Cooling water, if required, will be treated sewage effluent or groundwater. Allowances for pipeline costs are included in the owner's cost.
- Costs for transmission lines and switching stations are included as part of the owner's cost estimate.

2.3 CAPITAL COST ESTIMATING ASSUMPTIONS

Assumptions associated with capital cost estimates developed by Black & Veatch include the following:

- Capital cost estimates were developed on an engineer, procure, and construct (EPC) basis. The EPC capital cost estimates presented in this document include both direct and indirect costs.
- EPC capital cost estimates are presented as "overnight" costs and do not include any allowances for escalation, financing fees, interest or other general Owner's cost items.
- A recommended allowance for Owner's costs has been provided for each technology, separately from the EPC capital cost estimates. Potential Owner's costs are listed in Table 2-2.
- All capital cost estimates are presented in 2012 dollars.

Table 2-2 Potential Owner's Costs for Power Generation/Storage Projects

Project Development • Site selection study • Land purchase/rezoning for greenfield sites • Transmission/gas pipeline right-of-way • Road modifications/upgrades • Demolition • Environmental permitting/offsets • Public relations/community development • Legal assistance • Provision of project management	**Owner's Contingency** • Owner's uncertainty and costs pending final negotiation • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreements (i.e., interconnection contract costs) **Owner's Project Management** • Preparation of bid documents and the selection of contractors and suppliers • Performance of engineering due diligence • Provision of personnel for site construction management
Spare Parts and Plant Equipment • Combustion turbine materials, gas compressors, supplies, and parts • Steam turbine materials, supplies, and parts • Boiler materials, supplies, and parts • Balance-of-plant equipment/tools • Rolling stock • Plant furnishings and supplies	**Taxes/Advisory Fees/Legal** • Taxes • Market and environmental consultants • Owner's legal expenses • Interconnect agreements • Contracts (procurement and construction) • Property
Plant Startup/Construction Support • Owner's site mobilization • O&M staff training • Initial test fluids and lubricants • Initial inventory of chemicals and reagents • Consumables • Cost of fuel not recovered in power sales • Auxiliary power purchases • Acceptance testing • Construction all-risk insurance	**Utility Interconnections** • Natural gas service • Gas system upgrades • Electrical transmission • Water supply • Wastewater/sewer **Financing (included in fixed charge rate)** • Financial advisor, lender's legal, market analyst, and engineer • Loan administration and commitment fees • Debt service reserve fund

2.3.1 Direct Cost Assumptions

Assumptions regarding direct costs within the capital cost estimates include the following:

- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on a turnkey EPC contracting philosophy.
- Permitting and licensing are excluded from EPC costs. These items should be included in the owner's cost estimate.

2.3.2 Indirect Cost Assumptions

Indirect costs within the capital cost estimates are assumed to include the following:

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts.

Indirect costs are assumed to exclude the following:

- Initial inventory of spare parts for use during operation. These items are assumed to be included in the owner's costs.
- Allowance for funds used during construction and financing fees. These costs should be included in the Owner's overall cost estimate.

2.4 NON-FUEL OPERATION & MAINTENANCE COST ESTIMATING ASSUMPTIONS

Assumptions associated with non-fuel operations and maintenance (O&M) cost estimates developed by Black & Veatch include the following:

- Non-fuel O&M cost estimates were developed as representative estimates based on (1) previous Black & Veatch experience with projects of similar design and scale, and (2) relevant vendor information available to Black & Veatch.

- Non-fuel O&M cost estimates were categorized into Fixed O&M and Non-fuel Variable O&M components.
  - Fixed O&M costs include labor, routine maintenance and other expenses (i.e., training, property taxes, insurance, office and administrative expenses).
  - Non-fuel Variable O&M costs include outage maintenance, parts and materials, water usage, chemical usage and equipment.
  - Non-fuel Variable O&M costs exclude the cost of fuel (e.g., coal, natural gas or woody biomass). Depending upon the SSO, fuel may or may not be required.
- All Non-fuel O&M cost estimates are presented in 2012 dollars.

2.5 ADDITIONAL FINANCIAL PARAMETER ASSUMPTIONS

In addition to capital and O&M cost parameters, PGE requested characterization of the other financial parameters, including escalation of capital costs (over an extended term); capital expenditures and maintenance accruals; and decommissioning costs.

2.5.1 Escalation of Capital Costs (over an Extended Term)

Capital costs for electric power plants have become driven by the current market conditions for commodities, equipment, and construction. As a result, they have become extremely volatile. This volatility makes the application of simple escalation rates over an extended term difficult. Historical power plant capital costs for conventional generation in the United States have been driven by two major events since the late 1990s. The first was the large boom in the combined cycle market that occurred in the late 1990s and the early 2000s. The second major event was the large boom in coal fueled units during the 2000s. Other significant events also contributed to the conventional power plant cost escalation during this period including the boom in proposed nuclear plant construction, the boom in air quality control equipment installation on coal units, and the international conventional generation construction market. An example of this volatility was a 55 percent increase in the capital cost of F class combined cycles entering service in 2000 compared to 1999. Similarly, combined cycles experienced a 60 percent increase in capital cost in the mid- to late 2000s. During the period from 2000 to 2011, however, combined cycle capital costs also decreased in certain years by as much as 13 percent.

On the other hand, evolving technologies such as solar and wind have seen significant reductions in costs during this period in spite of pressure on the EPC market for conventional resources. These market trends are difficult to accurately forecast. As such, Black & Veatch generally employs the expected general inflation rate as a proxy for long-term escalation for planning studies. While there may be periods where market pressures cause short-term fluctuations in capital costs, the general outlook of Black & Veatch regarding capital costs is (1) conventional alternatives will be steady, and (2) renewable alternatives such as solar and wind will slow in their decreasing prices and become steady.

2.5.2 Capital Expenditures/Maintenance Accruals

Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). For example, the operation of a geothermal facility typically requires the drilling of new supply wells at regular intervals during the lifetime of the power project, and depending on the extent of charge/discharge cycling, battery energy storage systems may require periodic replacement of batteries.

Typically, Black & Veatch does not provide estimates of the costs associated with these activities as capital expenditures or maintenance accruals separately from other O&M costs. In instances where these periodic costs are necessary (for the SSOs under consideration in this report), these costs have been included in the relevant O&M costs associated with specific technology options. For these SSOs, the periodic system/equipment replacement requirements are noted in the technology-specific assumptions.

2.5.3 Decommissioning Costs

A fixed amount of money is accrued each year over the book life of the asset to cover the cost of decommissioning the asset. For all SSOs except Pumped Storage Hydro, the site would be returned to a Brownfield condition at the end of its book life. For Pumped Storage Hydro, it is assumed that powerhouse equipment would be decommissioned and salvaged, and the facility/reservoirs would be retired in place, with the site secured as appropriate (e.g., reservoirs drained, additional security fencing installed, and signs posted).

The fixed amount was determined using a sinking fund factor based on the book life of the asset and an assumed interest rate of 6 percent. The future amount was estimated based on a percentage of the current total capital requirement of the asset. The percentage was based on recent decommissioning cost estimates for similar scope of decommissioning for similar assets.

3.0 Conventional Generation Options

Of the SSOs considered in this effort, three are classified as conventional generation options. These include:

- Integrated Gasification Combined Cycle (IGCC) with Carbon Capture
- 1x0 GE LMS100PA Combustion Turbine
- 6x0 Wartsila 18V50SG Reciprocating Engines

These conventional SSOs and their performance and cost characteristics are defined below.

3.1 INTEGRATED GASIFICATION COMBINED CYCLE WITH CARBON CAPTURE

3.1.1 Technology Overview

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 for the endothermic gasification reactions.

Entrained flow gasifiers have been operating successfully on solid fuels since the mid-1980s to produce chemicals, and since the mid-1990s, to produce electricity in four 250 to 300 MW IGCC plants located in Europe (two units) and the United States (two units). At this time, based upon their characteristics and level of development, entrained flow gasifiers are the best choice for high capacity gasification for power generation.

Entrained flow gasifiers use oxygen to produce syngas heating values in the range of 250 to 300 Btu/scf (on an HHV basis). Oxygen is produced in a cryogenic air separation unit (ASU) by compressing air; cooling and drying the air; removing CO_2 from the air; chilling the feed air with product oxygen and nitrogen; reducing the air pressure to provide autorefrigeration and liquefy the air at -300 °F; and separating the liquid oxygen and liquid nitrogen by distillation. Air compression consumes a significant amount of power, between 13 and 17 percent of the IGCC gross power output.

The oxygen produced from the ASU is fed to the gasifier along with coal and fluxant (if needed) to produce raw syngas. The raw syngas is cooled, and then cleaned by various treatments, including filtration, scrubbing with water, catalytic conversion, and scrubbing with solvents to remove various sulfur and nitrogen containing compounds (H_2S, COS, ammonia (NH_3), and hydrogen cyanide (HCN)). The clean syngas used as CTG fuel contains hydrogen, CO, carbon dioxide (CO_2), water, and low concentrations of hydrogen sulfide (H_2S) and carbonyl sulfide (COS).

A representative IGCC process flow diagram (excluding carbon capture) is shown in Figure 3-1.

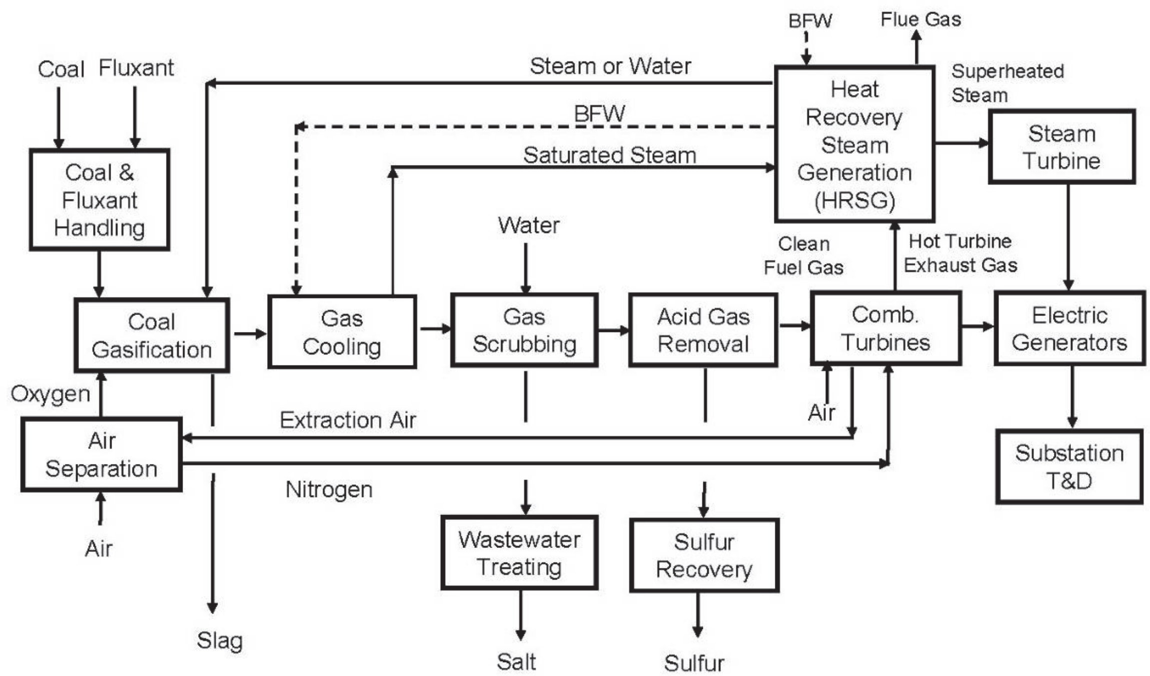


Figure 3-1 Typical IGCC Process Flow Diagram

When adding carbon capture to an IGCC plant, the CO in the syngas may be shifted with water to form CO_2 and hydrogen by the water-gas shift reaction. The H_2S and CO_2 are then removed with acid gas removal (AGR). A physical solvent is used to absorb the CO_2 from the hydrogen-rich syngas. Regeneration of the solvent produces a CO_2 stream suitable for enhanced oil recovery or other underground storage.

Coal-based operating experience of IGCC systems has been focused almost exclusively on bituminous coals (e.g., Pittsburgh No. 8 and Illinois No. 6), and there is also extensive experience with petcoke. Subbituminous (i.e., Powder River Basin [PRB]) coals have been tested only in a limited fashion, but due to the nature of the US coal market and the abundance of PRB coal, there is strong interest in using it for IGCC applications. The assumed fuel for this study is PRB.

Presently, leading technology suppliers for entrained flow gasification processes associated with IGCC configurations include the following:

- General Electric (GE)
- Phillips 66 (P66)
- Shell
- Siemens

One of the primary differences between these gasification technologies is in the feeding system: dry feed versus wet (slurry) feed systems. GE and P66 technologies employ wet feed systems, while Shell and Siemens technologies employ dry feed systems.

Dry-feed gasification processes are better suited for high moisture fuels (e.g., PRB, the assumed design fuel for this study), as these processes minimize the moisture added to the gasifier (beyond the inherently high moisture of the fuel). Because these dry-feed processes are better suited for PRB, the Shell process was selected as the likely gasification technology for this characterization.

Entrained flow gasification processes may offer the potential to co-fire biomass fuels, but the extent to which this may be possible is largely dependent upon the feed system of the technology. Wet feed systems (e.g., GE and P66) would limit biomass co-firing to a range of 0 to 5 percent (by weight) of the total fuel stream. Dry feed systems (e.g., Shell and Siemens) may be able to co-fire biomass in the range of 10 to 30 percent (by weight) of the total fuel stream, with system design modifications required to achieve the upper end of this range. Biomass has been reportedly used as a successful co-feed for the Shell gasification process employed at Nuon Power's 235 MW (net) IGCC power plant located in Buggenum, The Netherlands, with biomass representing up to 30 percent (by weight) of the fuel input to the gasifier. Biomass used at Buggenum has included pre-milled waste wood, dried sludge from biotreaters, paper mill wastes, and chicken manure. In order for successful co-firing, the biomass should be (1) relatively dry and (2) pre-milled or easily millable to a size comparable to coal powder.

3.1.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a baseload IGCC plant with carbon capture and compression. Relevant assumptions employed in the development of performance and cost parameters for the IGCC plant include the following:

- The IGCC facility would have a net generation capacity of 495 MW and a capacity factor of approximately 80 percent.
- The IGCC facility is based on the Shell gasification technology.
- Major equipment for the IGCC system (with carbon capture) includes:
  - (2) GE 7F Syngas combustion turbines
  - (2) Shell entrained flow gasifiers
  - (1) Condensing steam turbine generator
  - (1) Acid gas removal system
  - (1) Cooling tower
  - (1) Air separation unit
- Carbon capture equipment is designed and sized for CO_2 capture efficiency of 90 percent.
- CO_2 transportation and sequestration are not included in the overnight EPC capital cost.

3.2 1X0 GE LMS100PA

3.2.1 Technology Overview

The LMS100PA is an intercooled aeroderivative CTG with two compressor sections and three turbine sections. Compressed air exiting the low-pressure compressor section is cooled in an air-to-water intercooler heat exchanger prior to admission to the high-pressure compressor section. A compressed air and fuel mixture is combusted in a single annular combustor. Hot flue gas then enters the two-stage high-pressure turbine. The high-pressure turbine drives the high-pressure compressor. Following the high-pressure turbine is a two-stage intermediate pressure turbine, which drives the low-pressure compressor. Lastly, a five-stage low-pressure turbine drives the electric generator. Major intercooler components include the inlet and outlet scrolls and associated ductwork to/from the intercooler and the intercooler. NO_x emissions are minimized utilizing water injection.

Many of the major components from the LMS100 are based on engine applications with extensive operating hours. The low-pressure compressor section is derived from the first six stages of GE's MS6001FA heavy-duty CTG compressor. The high-pressure compressor is derived from GE's CF6-80C2 aircraft engine and strengthened to withstand a pressure ratio of ~41:1. The single annular combustor is derived from GE's LM6000 aeroderivative and CF6-80C aircraft engines. The high-pressure turbine is derived from GE's LM6000 aeroderivative and CF6-80E2 aircraft engines.

Key attributes of the GE LMS100PA include the following:

- High full- and part-load efficiency.
- Minimal performance impact at hot-day conditions.
- High availability.
- 50 MW/min ramp rate.
- 10 minutes to full power.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 850 psig.
- Dual fuel capable.

The LMS100 is available in a number of configurations. Major variations include an intercooler heat rejection to atmosphere using dry cooling methods and dry low emissions (DLE) in lieu of water injected combustion for applications when water availability is limited.

3.2.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a simple cycle natural gas-fired GE LMS100PA combustion turbine facility. Relevant assumptions employed in the development of performance and cost parameters for the LMS100PA facility include the following:

- The power plant would consist of a single GE LMS100PA CTG, located outdoors in a weather-proof enclosure.

- To reduce NO_x and CO emissions, a selective catalytic reduction (SCR) system with oxidation catalyst would be utilized. The SCR system would include purge/tempering air for startup and when CTG exhaust temperature approaches the operational limits of the SCR catalyst.
- Intercooler heat is rejected to atmosphere by way of a wet mechanical draft cooling tower.
- A generation building would house electrical equipment, engine controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- Natural gas compressors would be housed in a prefabricated weather-proof enclosure.

3.3 6X0 WARTSILA 18V50SG

3.3.1 Technology Overview

The 18V50SG is a turbocharged, four-stroke spark-ignited natural gas engine. Unlike dual fuel reciprocating engines, the SG does not require liquid pilot fuel during startup and to maintain combustion. The 18V50SG utilizes 18 cylinders in a "V" configuration. Each cylinder has a bore diameter of 500 millimeters (19-11/16 inches) and a stroke of 580 millimeters (22-13/16 inches). Each engine operates at a shaft speed of 514 revolutions per minute. Individual cylinder computer controls and knock sensors for precise control of the combustion process, enabling the engine to operate more efficiently while minimizing emissions. The 18V50SG is based on the smaller 20V34SG model, with almost 400 engines in operation to date.

For this characterization, it is assumed that engine heat is rejected to the atmosphere by way of a mechanical draft cooling tower. In locations with limited water resources, an air-cooled heat exchanger may be employed as an alternative to a mechanical draft cooling tower. An 18V50SG power plant utilizing air cooled heat exchangers would require very little makeup water as the engines do not typically utilize inlet cooling for power augmentation or water injection for NO_x reduction.

Key attributes of the Wartsila 18V50SG include the following:

- High full- and part-load efficiency.
- Minimal performance impact at hot-day conditions.
- 10 minutes to full power.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 75 psig.
- Not dual fuel capable.

While the 18V50SG does not provide dual fuel capability, the diesel variation of the engine, the 18V50DF model, does provide dual fuel capability. In diesel mode, the main diesel injection valve injects the total amount of light fuel oil as necessary for proper operation. In gas mode, the combustion air and the fuel gas are mixed in the inlet port of the combustion chamber, and ignition is provided by injecting a small amount of light fuel oil (less than one percent by heat input). The injected light fuel oil ignites instantly, which then ignites the air/fuel gas mixture in the combustion chamber. During startup, the 18V50DF must operate in diesel mode until the engine is up to speed; once up to speed, the unit may operate in gas mode.

Wartsila offers a standard, pre-engineered six-engine configuration for the 18V50SG and the 18V50DF, sometimes referred to as a “6-Pack”. The 6-Pack configuration has a net generation output of approximately 100 MW and ties the six engines to a single bus and step-up transformer. This configuration provides economies of scale associated with the balance of plant systems (e.g., step-up transformer and associated switchgear) and reduced engineering costs.

3.3.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a simple cycle (6x0) natural gas-fired Wartsila 18V50SG reciprocating engine facility. Relevant assumptions employed in the development of performance and cost parameters for the 18V50SG facility include the following:

- The facility would consist of six Wartsila 18V50SG reciprocating engines, arranged as slide along units and co-located in a common engine hall.
- The engine hall would be one of a number of rooms within a generation building. The generation building would also include space for water treatment, electrical equipment, engine controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- An SCR system with oxidation catalyst would be utilized to minimize NO_x and CO emissions.
- Engine heat is rejected to atmosphere by way of a common wet mechanical draft cooling tower.

3.4 TECHNICAL AND FINANCIAL PARAMETERS FOR CONVENTIONAL GENERATION OPTIONS

Technical parameters for conventional energy options considered for PGE are summarized in Table 3-1, while cost and financial parameters for conventional energy options considered for PGE are summarized in Table 3-2 and Table 3-3.

Table 3-1 Technical Parameters for Conventional Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	LAND REQUIRED (ACRES)	NET PLANT HEAT RATE (BTU/ kWh)	MINIMUM TURNDOWN CAPACITY (%)	RAMP RATE (MW/MIN)	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE PATTERN (WEEKS/YR)	EQUIVALENT FORCED OUTAGE RATE (%)
Integrated Gasification Combined Cycle (w/ CO_2 Capture)	475(1)	80(2)	60	11,900(1)	25	10	6.5	3-3-3-3-3-4	13
1x0 LMS100	100	5	10	9,000	30	50	0.5	1-10	1.6
6x0 Wartsila 18V50	110	5	7	8,400	7	12	0.4	2-3-2-3-2-4	3.2

(1) When operating with a CO_2 capture efficiency of 90%, the IGCC w/ CO_2 Capture facility would provide a net capacity of 475 MW and a net plant heat rate (NPHR) of approximately 11,900 Btu/kWh. When operating in a mode without CO Capture, the IGCC facility would provide a net capacity of 560 MW and an NPHR of approximately 9,000 Btu/kWh.

(2) IGCC w/ CO_2 Capture capacity factor assuming 100 percent utilization and based on expected long term plant availability after the first several years of operation. Plant availability is expected to be 70-75 percent for the first five years of operation.

Table 3-2 Financial Parameters for Conventional Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	BOOK LIFE (YEARS)	EPC PROJECT DURATION[1] (MONTHS)	EXPENDITURE PATTERN	OVERNIGHT EPC CAPITAL COST ($000, 2012$)	OWNER'S COST ALLOWANCE (%)	OVERNIGHT TOTAL CAPITAL COST ($000, 2012$)
Integrated Gasification Combined Cycle (w/ CO_2 Capture)	475	80	35	59	See Appendix B	2,900,000	20	3,480,000
1x0 LMS100	100	5	25	24	See Appendix B	107,000	25	133,750
6x0 Wartsila 18V50	110	5	25	24	See Appendix B	145,000	25	181,250

(1) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD).

Table 3-3 Financial Parameters for Conventional Generation Options – Continued

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	FIXED O&M COSTS ($/kW-YEAR)	NON-FUEL VARIABLE O&M COST ($/MWh)	DECOMMISSIONING ACCRUAL[1] (2012$)	LONG-TERM CAPITAL COST ESCALATION RATE[2]
Integrated Gasification Combined Cycle (w/ CO_2 Capture)	495	80	64.9	11.4	5,500,000	General Inflation
1x0 LMS100	100	5	12.7	3.6	150,000	General Inflation
6x0 Wartsila 18V50	110	5	15.7	8.6	185,000	General Inflation

(1) Accrual collected annually over the book life of the asset to decommission the facility and return the site to a Brownfield condition.
(2) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

4.0 Renewable Generation Options

Renewable SSOs considered for this effort include:

- Solar Photovoltaic (10 MW Fixed Tilt)
- Biomass Combustion (25 MW Bubbling Fluidized Bed)
- Geothermal (20 MW Binary System)

These renewable SSOs and their performance and cost characteristics are defined in the following sections.

4.1 SOLAR PHOTOVOLTAIC

4.1.1 Technology Overview

Photovoltaic (PV) systems convert sunlight directly into electricity. The conversion of sunlight into electricity (known as the photovoltaic effect), is achieved with semiconductor materials. There are three main types of commercially available PV technologies to date. These are: crystalline Silicon (c-Si) modules, thin-film modules and concentrating PV systems. The most widely used technology is c-Si, which is also the technology with the longest operational history, dating back to over 30 years.

The c-Si modules are made up of individual solar cells connected electrically in series. The cells are then encapsulated with a polymer material (typically EVA) that protects them from moisture. The flat sheet of encapsulated cells is mounted on a rectangular back pane sheet made of Teflon or similar material. On the front of the encapsulant there is a flat sheet of transparent glass that allows the transmission of sunlight. The glass is built with optical properties suited for this application and mechanical properties that will withstand hail and other shocks. All these layers are mechanically supported by an aluminum frame.

The amount of power produced by PV modules depends on the technology used and the intensity of the solar radiation incident on the material.

There are two main c-Si technologies, mono-crystalline (m-Si) and poly-crystalline (p-Si). Mono-crystalline cells are manufactured by growing single crystal ingots, which are then sliced into thin cell-sized material. Commercial modules built with m-Si cells have efficiencies between 15.5 to 20 percent. Polycrystalline cells have reduced production costs, but provide a lower efficiency of 14 to 15.8 percent. The thermal response (power output as a function of temperature) of m-Si modules is also better than p-Si modules.

Thin film technology was able to significantly reduce module's price in the past few years. However, c-Si prices in the last year have reduced the price gap difference, leaving a minimal margin between both technologies. Thin film technologies have a lower efficiency (approximately 7 percent to approximately 13 percent) although the thermal response is significantly better than the m-Si modules. Currently, most thin-film modules are made of two different semiconductors alloys: Cadmium Telluride (CdTe) and Copper Indium Gallium Selenide (CIGS). Thin film modules have similar warranties to crystalline modules, but due to the limited operating experience there is some uncertainty regarding their degradation (of performance) over time.

Concentrating PV systems (CPV) make use of highly efficient cells (over 35 percent). The cost per unit area of these cells is significantly higher when compared with c-Si cells or thin film modules. However, the use of concentration reduces the material requirements and typical CPV cells have a surface area of one square centimeter. For most commercial cases, a CPV system requires to be installed in regions with high solar resource and clear skies to be cost effective. These regions tend to be arid, desert like areas like the southwest of the United States. There are few commercial CPV installations worldwide

To calculate the expected energy output of a PV system the most important input is the solar resource. A typical solar resource metric is the total amount of solar radiation incident on a horizontal plane and measured in kWh/m^2 on a yearly basis. Because this metric captures the radiation incident from all angles on this plane, it is referred to as Global Horizontal Irradiance, or GHI.

There are few data sources available for the United States. The National Renewable Energy Laboratories (NREL) has compiled three main datasets that are publicly available, which are TMY2, TMY3 and TGY. There are also private companies that sell data sets based on satellite image data. The data sets are compiled as a Typical Meteorological Year (TMY) with hourly values, for a total of 8760 data points per TMY. The TMY data set is meant to be representative of a typical year and is compiled from several years of measured data, using a specific algorithm that filters out atypical records and takes into account the inter-annual variability observed in the series. In general, inter-annual variability is less than 3 percent for most US locations.

For the specific location under review (Redmond, Oregon) the typical GHI (from TMY2 file) is 1,620 kW/m^2. In comparison, typical GHI for the southwest United States is approximately 2,100 kW/m^2.

4.1.2 Technology-Specific Assumptions

Cost and performance have been developed for a utility-scale PV system. The utility-scale PV system is assumed to be a 10 MWac system using crystalline Silicon modules mounted at a fixed tilt. Relevant assumptions employed in the development of performance and cost parameters for the 10 MW utility-scale solar PV system include the following:

- The PV system model was developed with PVsyst software version 5.60. PVsyst is an industry standard modeling tool for PV systems developed by the University of Geneva in Switzerland.
- The specific commercial equipment selected for the purposes of conceptual design, system modeling and cost estimates is representative of Tier-1 manufacturers. The remaining balance of systems equipment and materials were assumed to be typical for this type of projects. The specific equipment used in this study does not imply a recommendation on the part of Black & Veatch to select or engage with any of these vendors.

- The model was based on a conceptual system design with the characteristics listed in Table 4-1.

Table 4-1 Solar PV Conceptual System Design Parameters for Performance Modeling

PARAMETER	VALUE
System DC Rating (MW dc)	12.47
System AC Rating (MW ac)	10.08
System DC voltage (V)	1000
Module nominal power (W)	300 (Trina TSM-PA14)
Modules per string	18
Total number of modules	41,580
Inverter nominal power (KW ac)	720 (SMA SC 720CP-US)
Number of inverters	14
Tilt (degrees)	27
Surface area (acres)	52
Acres / MW ac	5.2

- The solar resource data selected was the TMY2 data set from NREL for Redmond/Bend.
- The model included typical losses due to wiring, module mismatch and others, as well as estimated soiling based on the average weather patterns observed in Redmond. Shading losses were considered minimal.
- The EPC costs model assumed the main characteristics listed below:
- The site is relatively flat and is a single parcel of a regular shape. Minimal grading is required. There is minimal vegetation to be removed. No drainage works were assumed to be required on this site.
  - The foundations for the mounting structures are hot dip galvanized I-beams installed as driven piles.
  - The geological conditions are assumed to be optimal for driven piles. The soils are solid/hard, well compacted and with medium density. These conditions allow for shorter driven piles with strong frictional forces in the long term to ensure minimal displacement of the pile. Assuming soft soils or hard rock would have increased project cost. The soils are assumed to be non-corrosive.
- The installation is assumed to be performed by an experienced solar integrator. An experience solar integrator provides:

- Efficient design and construction processes.
- Most economical equipment pricing from vendors.

- The interconnection is at distribution voltage with no step-up transformer required.
- The AC collector station is next to the point of interconnection.

4.2 BIOMASS COMBUSTION

4.2.1 Technology Overview

Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially 100 years ago. In many respects, biomass power plants are similar to coal plants. When burning biomass, pressurized steam is generated in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. Boiler systems used in biomass combustion include stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Newly constructed biomass-fired generation facilities likely employ either a stoker boiler or a fluidized bed boiler. Advanced technologies, such as integrated biomass gasification combined cycle and biomass pyrolysis, are under development but have not achieved widespread commercial operation at utility scales.

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating values of the fuels, biomass plants are less efficient than modern fossil fuel plants. Also, because of added transportation costs, biomass is generally more expensive than conventional fossil fuels on a $/MBtu basis. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target the use of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that both fuel harvesting and collection practices are sustainable and do not adversely affect the environment. Biomass projects that collect thinning from forests to reduce the risk of forest fires are increasingly seen as a way to restore a positive balance to forest ecosystems while avoiding catastrophic and polluting uncontrolled forest fires.

Unlike coal or natural gas, biomass may be viewed as a carbon-neutral power generation fuel. While carbon dioxide (CO_2) is emitted during biomass combustion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Furthermore, biomass fuels contain little sulfur compared to coal and, therefore, produce less sulfur dioxide (SO_2). Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury (Hg), cadmium, and lead.

While biomass fuels offer certain emissions benefits relative to coal and natural gas, biomass combustion facilities typically require technologies to control emissions of nitrogen oxides (NO_x), particulate matter (PM), and carbon monoxide (CO) to meet state and or federal regulatory requirements.

4.2.2 Technology-Specific Assumptions

For this PGE IRP effort, Black & Veatch developed performance and cost parameters for a biomass facility employing a Bubbling Fluidized Bed (BFB) boiler, with a net generation output of 25 MW. Relevant assumptions employed in the development of performance and cost parameters for the 25-MW biomass energy facility include the following:

- The primary fuel for the biomass facility will be woody biomass, with an average moisture content of 40 percent and an as-received heating value of 5,100 Btu/lb (HHV).
- The facility will have an average annual capacity factor of 85 percent.
- The facility will have a wood fuel yard sufficiently sized to store 30 days of woody biomass fuel.
- Air quality control equipment includes Selective Non-Catalytic Reduction (SNCR) systems for NO_x control, sorbent injection for acid gas control, and a fabric filter for particulate matter (PM) control.

4.3 GEOTHERMAL

4.3.1 Technology Overview

Geothermal power is produced by using steam or a secondary working fluid in a Rankine Cycle to produce electricity. Geothermal energy was first used to make electricity at the beginning of the 20th century. In 1904, Prince Piero Conti, owner of the Larderello fields in Italy, attached a generator to a natural-steam-driven engine which lit four light bulbs. This experiment led to the installation of the world's first geothermal power plant in 1911, with a capacity of 250 kilowatts. The government of New Zealand was the first significant producer of geothermal electricity, with the ~150-MW Wairakei power plant, which began operating in 1958. Shortly thereafter, the first power plants were installed at The Geysers in California, USA. By 1975, the Larderello fields were capable of producing about 400 MW of power. By the mid-1980s, The Geysers' output had peaked at about 1,600 MW, after which it declined to its present output at about 850 MW.[1] Today, roughly 70 geothermal power facilities are in operation in over 20 countries around the world. There is a

[1] Sanyal, S. K. (2011) Fifty Years of Power Generation at The Geysers - The Lessons Learned. Proceedings, Thirty-sixth Workshop on Geothermal Reservoir Engineering, Stanford University, January 31 - February 2, 2011, SGP-TR-191.

natural concentration of geothermal resources in regions characterized by volcanism, active tectonism, or both. For example, Indonesia and The Philippines have many large, high-temperature geothermal resources; about 10,000 MW of geothermal capacity are installed worldwide.[2]

The most commonly used power generation technologies are direct steam (or dry steam), single-flash, dual-flash, and binary systems. In addition, efforts are underway to develop "enhanced geothermal" projects. The choice of technology is driven primarily by the temperature and quality of the steam/liquid extracted from the geothermal resource area. These geothermal technologies are classified as follows:

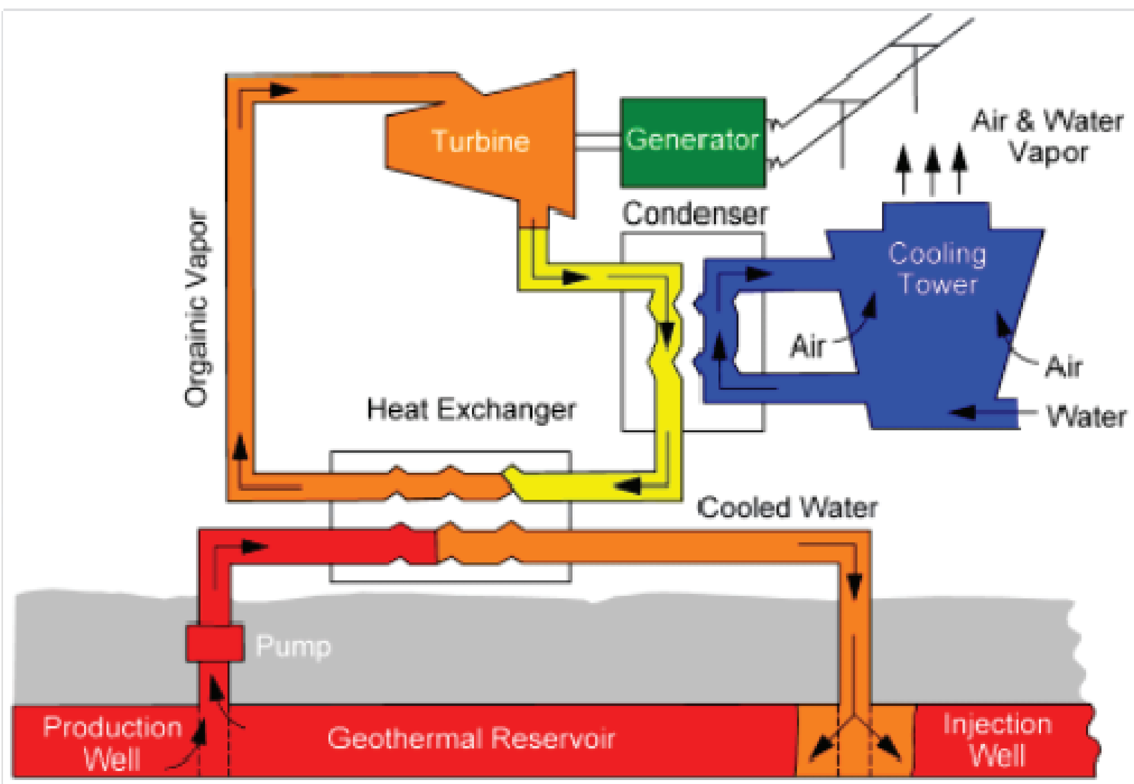
- Direct steam: For geothermal resources that provide slightly superheated steam, direct-steam technologies may be employed. Superheated steam (with temperatures exceeding 350°F [177°C]) is gathered from the geothermal reservoir (via production wells) to drive a condensing steam turbine-generator. Following expansion in the steam turbine, the brine is scrubbed as necessary to remove acid gases and other contaminants, and re-injection wells are employed to return the geothermal brine to the geothermal reservoir.
- Single-Flash or Double-Flash: Flash systems are used in high temperature (i.e., greater than 350°F [177°C]) liquid-dominated geothermal reservoirs. Upon extraction from the geothermal reservoir, the geothermal fluid is a pressurized two-phase mixture of liquid brine and steam. This two-phase mixture is routed to a separator, where the pressure of the mixture is reduced, causing the fluid to flash into steam. This steam is then expanded in steam turbine generator. Double-flash systems flash the separated brine a second time. In double-flash systems, the lower temperature steam may be expanded through a separate steam turbine, or the steam may be introduced into the high-pressure turbine through a second admission port. As in direct steam systems, the spent brine is scrubbed and re-injected into the geothermal reservoir.
- Binary: Binary cycle systems are employed for development of liquid-dominated geothermal reservoirs that do not have temperatures sufficiently high enough to flash steam (i.e., less than 350°F [177°C]). In a binary system, a secondary fluid is employed to capture thermal energy of the brine and operate within a Rankine Cycle. Additional details regarding binary geothermal systems are discussed below.
- Enhanced geothermal (or "hot dry rock"): For geologic formations with high temperatures but without the necessary subsurface fluids or permeability, fluid may be injected to develop geothermal resources. Typically, the geologic structure must be hydraulically fractured to achieve a functional geothermal resource. While enhanced geothermal projects are currently being demonstrated around the world

[2] R.Bertani. (2010). Geothermal Power Generation in the World, 2005-2010 update report. Proceedings of the World Geothermal Congress. Bali, Indonesia.

(including the Newberry Volcano EGS demonstration near Bend, Oregon), this technology is not yet considered commercial.

Considering the temperatures associated with geothermal resource areas located in Oregon, it is anticipated that geothermal developments would utilize either binary geothermal systems or enhanced geothermal systems. Because of the technical and cost uncertainty associated with enhanced geothermal systems, Black & Veatch has selected binary geothermal options for this characterization and has developed performance and cost parameters for a 20-MW (net) binary geothermal facility.

In a binary plant, the thermal energy in the geothermal brine is transferred in a heat exchanger to a secondary working fluid for use in a fairly conventional Rankine cycle, as shown in Figure 4-1. The brine itself does not contact moving parts of the power plant, thus minimizing the potential of equipment fouling (e.g., scaling, corrosion or erosion). Binary plants may be especially advantageous for low brine temperatures (i.e., less than about 350°F [177°C])) or for brines with high dissolved gases or high corrosion or scaling potential.



Source: Colorado Department of Natural Resources

Figure 4-1 Binary Geothermal System

Most binary plants operate on pumped wells and geothermal fluid remains in the liquid phase throughout the plant, from production wells through the heat exchangers to the injection wells. Dry cooling is typically used with a binary plant to avoid the necessity for make-up water required for a wet cooling system. Dry cooling systems generally add 5 to 10 percent to the cost of the power plant compared to wet cooling systems. Because of chemical impurities, the waste geothermal fluid is not generally suitable for cooling tower make-up. There is a wide range of candidate working fluids for the closed power cycle. The working fluid of the binary system is generally selected to achieve good thermodynamic match to the particular geothermal temperature. The optimal fluid would provide a high utilization efficiency with safe and economical operation.

4.3.2 Technology-Specific Assumptions

Relevant assumptions employed in the development of performance and cost parameters for the 20-MW (net) geothermal energy facility include the following:

- The geothermal energy facility would employ a binary geothermal system with dry cooling methods (rather than a wet cooling tower) to minimize water requirements.
- The facility will have an average annual capacity factor of 85 percent.
- To extract and re-inject geothermal brine, the facility would utilize 5 supply wells and 5 return wells.
    - Capital costs estimated by Black & Veatch include the cost of well development.
    - Variable O&M costs estimated by Black & Veatch include costs associated with development of 1 new supply well every 5 years. When drilling replacement wells, it is assumed that 1 out of every 5 supply wells is dry (i.e., does not provide sufficient flow and is unusable), and well replacement costs include costs associated with drilling of dry wells.
- The geothermal project would require 20 acres of land, and this land would be leased for the lifetime of the project. Land lease costs for the geothermal facility are included in the Variable O&M costs estimated by Black & Veatch.

4.4 TECHNICAL AND FINANCIAL PARAMETERS FOR RENEWABLE GENERATION OPTIONS

Technical parameters for renewable energy options considered for PGE are summarized in Table 4-2, while cost and financial parameters for renewable energy options considered for PGE are summarized in Table 4-3 and Table 4-4.

Table 4-2 Technical Parameters for Renewable Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	LAND REQUIRED (ACRES)	HEAT RATE (BTW/ kWh)	MINIMUM TURNDOWN CAPACITY (%)	RAMP RATE (MW/MIN)	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE PATTERN (WEEKS/YR)	EQUIVALENT FORCED OUTAGE RATE (%)
Solar PV	10	22	52	N/A	N/A[1]	N/A	0.00[2]	2	N/A
Biomass Combustion	25	85	25	13,250	25	1.3	0.5[2]	3-3-3-3-3-8	7.5
Geothermal	20	85	20	N/A	10	3.0	0.05[2]	3-3-3-3-3-8	6.0

(1) If it is necessary to curtail solar power output, the inverter is capable of curtailing 100% of the power output.

(2) For Solar PV, it is assumed that rainfall will be sufficient to make panel washing unnecessary. No other water consumption required for operation of Solar PV facility. For Biomass Combustion, water consumption includes makeup water for cooling tower, makeup water for steam cycle, and service water for facility. For Geothermal, water consumption includes service water for facility.

Table 4-3 Financial Parameters for Renewable Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	BOOK LIFE (YEARS)	EPC PROJECT DURATION(1) (MONTHS)	EXPENDITURE PATTERN	OVERNIGHT EPC CAPITAL COST ($000, 2012$)	OWNER'S COST ALLOWANCE (%)	OVERNIGHT TOTAL CAPITAL COST ($000, 2012$)
Solar PV	10	22	25	3	See Appendix B	24,500	12	27,440
Biomass Combustion	25	85	25	36	See Appendix B	148,700	25	185,900
Geothermal	20	85	30	48	See Appendix B	146,000	20	175,200

(1) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD).

Table 4-4 Financial Parameters for Renewable Generation Options – Continued

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	FIXED O&M COST ($/kW-YEAR)	NON-FUEL VARIABLE O&M COST ($/MWh)	DECOMISSIONING ACCRUAL(1) (2012$)	LONG-TERM CAPITAL COST ESCALATION RATE(2)
Solar PV	10	22	18.0	2.6	100,000	General Inflation
Biomass Combustion	25	85	220	9.3	530,000	General Inflation
Geothermal	20	85	205	21.4	300,000	General Inflation

(1) Accrual collected annually over the book life of the asset to decommission the facility and return the site to a Brownfield condition.
(2) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

5.0 Energy Storage Options

Energy Storage options considered for this effort include:

- Pumped Storage Hydroelectric (500 MW Closed Loop)
- Battery Storage (10 MW, 10 MWh Lithium Ion Battery)
- Battery Storage (25 MW, 25 MWh Lithium Ion Battery)

These energy storage options and their performance and cost characteristics are defined in the following sections.

5.1 PUMPED STORAGE HYDROELECTRIC

5.1.1 Technology Overview

A pumped storage hydroelectric facility requires a lower and upper reservoir. During times of minimal load demand, excess low cost energy is used to pump water from a lower reservoir to an upper reservoir. When energy is required (during a high value or a peak electrical demand period), water in the upper reservoir is released through a turbine to produce electricity. The pumping and generating is typically accomplished by a reversible pump turbine / motor generator.

In addition to providing electricity at times of peak power demand, applications for pumped storage hydroelectric projects include:

- Providing transmission system support
- Energy storage for less dependable renewable resources such as wind and solar energy.

Pumped storage projects may be categorized as either open- loop or closed-loop pumped storage projects. The Federal Energy Regulatory Commission (FERC) defines these classifications as follows:

- Open-loop pumped storage projects are continuously connected to a naturally-flowing water feature.
- Closed-loop pumped storage projects are not continuously connected to a naturally-flowing water feature.

For open-loop pumped storage systems, acquisition of environmental approvals has become increasingly challenging, due to the need to develop a lower reservoir on an active river or existing lake. To mitigate this issue, many recent pumped storage developments have proposed closed-loop systems, which often utilize existing features such as abandoned quarries or underground mines as the lower reservoir of the pumped storage system. This allows the pumped storage project to be developed and operated off-stream, reducing environmental impacts and also reducing costs associated with development of the lower reservoir.

5.1.2 Technology-Specific Assumptions

Black & Veatch developed performance and cost parameters for a pumped storage hydroelectric project capable of providing 500 MW of energy output. Relevant assumptions employed in the development of these performance and cost parameters include the following:

- The pumped storage project is assumed to have a maximum output of 500 MW, with a maximum discharge period of 40 hours (i.e., maximum energy storage capacity of 20,000 MWh).
- The facility would employ two reversible pump turbines, each rated at approximately 2,200 cubic feet per second (cfs). These reversible pump turbines are assumed to be located in an aboveground powerhouse near the lower reservoir. Two steel penstocks, each with a diameter of 14 feet, would be located between the inlet/outlet of the upper reservoir and the pump turbine units.
- The lower reservoir of the pumped storage hydroelectric project is either an abandoned quarry, an underground mine or a similar existing feature. Therefore, the project is a closed-loop pumped storage project.
- Upper Reservoir design parameters:
  - Elevation: 2500 ft above mean sea level (ft msl)
  - Active Water Storage Capacity: 14,500 acre-feet
  - Active Water Storage Depth: 50 ft
- Lower Reservoir design parameters:
  - Elevation: 1000 ft msl
  - Active Water Storage Capacity: 14,500 acre-feet
  - Active Water Storage Depth: 50 ft
- Gross Head design parameters:
  - Average Gross Head: 1500 ft
  - Maximum Gross Head, (Generating or Pumping): 1550 ft
  - Minimum Gross Head, (Generating or Pumping): 1450 ft
- Distance from Upper Reservoir to Lower Reservoir: 1500 ft (i.e., distance/head ratio of 1.0)
- Fixed O&M costs include the cost of major overhaul of the reversible pump turbines in Year 15 of the project's life.

5.2 BATTERY ENERGY STORAGE

5.2.1 Technology Overview

Batteries are electrochemical cells that convert chemical energy into electrical energy. This conversion is achieved via electrochemical oxidation-reduction (redox) reactions occurring at the electrodes of the batteries. The batteries of interest for this report are secondary batteries that can be recharged (i.e., the redox reaction can be reversed). The main components of a battery are the positive electrode (cathode), the negative electrode (anode) and the electrolyte. The resulting potential, or voltage, of the battery is based on the composition of the electrodes and the redox reactions that occur at the electrodes.[3]

Battery energy storage systems employ multiple (up to several thousand) batteries and are charged via an external source of electrical energy. The battery energy storage system discharges this stored energy to provide a specific electrical function. Examples of these functions, as defined by the Energy Storage Association (ESA), are as follows:

- Spinning Reserve: the use of energy storage to supply generation capacity that is online and dispatchable within 10 minutes.
- Non-Spinning Reserve: a resource that follows spinning reserve dispatch during loss of generation or transmission events and usually required to respond within 10-15 minutes.
- Capacity Firming: the use of energy storage to fill in capacity (power) when variable energy resources, such as solar and wind, fall below their rated output.
- Voltage Support: the use of energy storage to manage and supply reactive power on the grid at or near a power factor of 1.
- Frequency Regulation: the use energy storage to maintain grid system frequency with a resource that is capable of responding within seconds.
- Ramping Service: using energy storage ramping to offset excessive ramping of other generating facilities, often variable energy resources such as solar or wind.

The size of a battery energy storage system is based on two parameters: power, usually in kW or MW, and energy, usually in kWh or MWh. The energy storage capacity of a battery designates how long a given energy storage system can discharge at a given power. Other parameters relevant for energy storage systems are:

- Ramp-rate: how quickly an energy storage system can change its power output, typically in MW/ min
- Response time: how quickly an energy storage system can reach its rated power (constrained by power conversion system)
- Round-trip efficiency: the amount of energy discharged from an energy storage system relative to the amount required for charging
- Discharge duration: how long a battery can be discharged at a given power
- Charge/Discharge rate (C-rate): how quickly the battery can charge or discharge relative to a one-hour charge or discharge (for example, a 2C rate charges or discharges in 30 minutes)

Operational parameters associated with battery energy storage technologies include:

[3] Linden's Handbook of Batteries. Edited by Thomas B. Reddy.

- State-of-charge (SOC): how much energy is stored in an energy storage system relative to the maximum energy storage capacity. In general, maximum lifetime of battery systems occurs when the SOC is maintained between 10 and 80 percent.
- Depth of discharge (DoD): how discharged an energy storage system is relative to the maximum energy storage capacity.
- Cycles-to-failure (CtF): the number of cycles at 100 percent DoD until the battery's energy storage capacity is degraded to 80 percent of its original capacity.

Battery types employed within battery energy storage systems include lithium-ion (Li-ion), lead-acid and flow batteries. Because Li-ion battery systems appear to be the prevalent battery technology for battery energy storage projects presently under development,[4] this section will focus on Li-ion battery technology.

Various Li-ion battery systems are installed around the world, including projects in the United States. The 32 MW Laurel Mountain Project in West Virginia and other projects in Chile and China employ Li-ion systems. PGE also employs a 5 MW Li-Ion system at the Salem Smart Power Center (SSPC) as part of the Pacific Northwest Smart Grid Demonstration. According to the DOE Energy Storage Database, the United States installed (or under construction) capacity of Li-ion is about 56 MW.[5]

A summary of representative performance parameters for battery energy storage systems employing Li-ion batteries is provided in Table 5-1.

5.2.2 Technology-Specific Assumptions

Black & Veatch developed performance and cost parameters for 10-MW and 25-MW battery energy storage systems, each capable of discharging at their rated power for 1 hour. Relevant assumptions employed in the development of these performance and cost parameters include the following:

- The battery storage system is assumed to have a 20 year service lifetime. Assuming one (complete) discharge of the battery energy per day, it is anticipated that the battery energy storage modules employed within the system will provide 20 years of operation. No capacity additions (i.e., periodic battery replacement) were included in estimates of either capital costs or O&M costs.
- Service contracts for long-term battery maintenance (provided by the OEM) are included in the fixed O&M costs.
- Energy storage capacity is based on charge and discharge rate of 1C.

[4] 2020 Strategic Analysis of Energy Storage in California prepared for the California Energy Commission and by the University of California, Berkeley School of Law, University of California, Los Angeles, and the University of California, San Diego. November 2011.
[5] DOE Energy Storage Database (beta). Sandia National Laboratories. http://www.energystorageexchange.org/

Table 5-1 Representative Performance Parameters for Lithium Ion Energy Storage Systems

PARAMETER	VALUE
Commercial Availability	Commercial
Facility Power Rating, MW	0.1 to 32
Module Power Rating, MW	0.1 to 4
Facility Energy Capacity, MWh	0.1 to 25
Module Energy Capacity, MWh	0.1 to 2
Ramp Rate, MW/min	Note (1)
Response Time(2)	20 to 120 ms
Round-Trip Efficiency, %	75 to 90
Discharge Duration, hours	0.25 to 4
Charge/Discharge Rate, C(3)	1C to 6C

(1) Li-ion systems are able to ramp up from an idle status to full rated capacity in less than 1 second.

(2) Amount of time system takes to reach rated power.

(3) Charge/discharge rate is conventionally expressed in terms of "C-rate". Under this convention, a system with a charge/discharge rate of 2C could be fully charged or discharged in 30 minutes (1/2 hour), while a system with a charge/discharge rate of 6C could be fully charged or discharged in 10 minutes (1/6 hour).

5.3 TECHNICAL AND FINANCIAL PARAMETERS FOR ENERGY STORAGE OPTIONS

Technical parameters for energy storage options considered for PGE are summarized in Table 5-2, while cost and financial parameters for energy storage options considered for PGE are summarized in Table 5-3 and Table 5-4. Additional parameters specific to energy storage options are shown in Table 5-5.

Table 5-2 Technical Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	LAND REQUIRED (ACRES)	NET PLANT HEAT RATE (BTW/ kWh)	MINIMUM TURNDOWN CAPACITY (%)	RAMP RATE (MW/MIN)	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE PATTERN (WEEKS/YR)	EQUIVALENT FORCED OUTAGE RATE (%)
Pumped Storage Hydro	500	N/A	600	N/A	20	160	N/A	2	N/A
Battery Storage – Spinning Reserve	25	N/A	0.7	N/A	0	Note [1]	N/A	2	N/A
Battery Storage – Spinning Reserve	10	N/A	0.3	N/A	0	Note [1]	N/A	2	N/A

[1] Li-ion systems are able to ramp up from an idle status to full rated capacity in less than 1 second.

Table 5-3 Financial Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	BOOK LIFE (YEARS)	EPC PERIOD (MONTHS)	EXPENDITURE PATTERN	OVERNIGHT EPC CAPITAL COST ($000, 2012$)	OWNER'S COST ALLOWANCE (%)	OVERNIGHT TOTAL CAPITAL COST ($000, 2012$)
Pumped Storage Hydro	500	N/A	30	60	See Appendix B	1,000,000	25	1,250,000
Battery Storage – Spinning Reserve	25	N/A	20	15	See Appendix B	48,050	12	53,820
Battery Storage – Spinning Reserve	10	N/A	20	15	See Appendix B	21,250	12	23,800

Table 5-4 Financial Parameters for Energy Storage Options – Continued

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	FIXED O&M COSTS ($/kW-YEAR)	NON-FUEL VARIABLE O&M COST ($/MWh)	DECOMISSIONING ACCRUAL(1) (2012$)	LONG-TERM CAPITAL COST ESCALATION RATE(3)
Pumped Storage Hydro	500	N/A	5.3	0.3	115,000	General Inflation
Battery Storage – Spinning Reserve	25	N/A	6	N/A	50,000	General Inflation
Battery Storage – Spinning Reserve	10	N/A	10	N/A	50,000	General Inflation

(1) Accrual collected annually over the book life of the asset to decommission the facility. For Battery Storage options, site would be returned to a Brownfield condition. For Pumped Storage Hydro, it is assumed that powerhouse equipment would be decommissioned and salvaged, and facility/reservoirs would be retired in place, with site secured as appropriate (e.g., reservoirs drained, additional security fencing installed, and signs posted).

(2) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

Table 5-5 Additional Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	ENERGY CAPACITY (MWh)	DISCHARGE PERIOD (HOURS)	ROUND TRIP EFFICIENCY (%)	CYCLE LIFE – FOR BATTERY OPTIONS (CYCLES)
Pumped Storage Hydro	500	N/A	20,000	40	77	N/A
Battery Storage – Spinning Reserve	25	N/A	25	1	85	7,000 to 10,000[1]
Battery Storage – Spinning Reserve	10	N/A	10	1	85	7,000 to 10,000[1]

(1) Cycle life assumes a typical cycle of charge to 100% SOC and discharge to 80% DoD.

Appendix A. Supply Side Option Parameters (Full Table)

No.	Option	Design Basis Parameters: Option Design Basis	Duty	Net Capacity (MW)	Capacity Factor (%)	Primary Fuel	Technical/Performance Parameters: Land Required (acres)	Net Plant Heat Rate (Btu/kWh)	Minimum Turndown Capacity (%)	Range of Potential NPHR Improvements (%)	Ramp Rate (MW/min)	Water Consumption (mgd)	Scheduled Maint. Pattern (weeks/yr)	Equiv. Forced Outage Rate (%)
1	Integrated Gasification Combined Cycle (w/ CO2 Capture)	Gasifier: Dry Feed Entrained Flow Combustion Turbine: GE 7F Syngas Carbon Capture: Physical Solvent (90% Capture) Emissions Control: N_2 Injection, SCR Heat Rejection: Wet Cooling Tower	Baseload	475[(1)]	80%[(2)]	Coal (Powder River Basin)	60	11,900[(1)]	25%	Note [(3)]	10	6.48	3-3-3-3-3-4	13%
2	1x0 LMS100	Combustion Turbine: LMS100 PA Duct Firing: None Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Peaking	100	5%	Natural Gas	10	8,950	30%	Note [(3)]	50	0.48	1-10	1.6%
3	6x0 Wartsila 18V50	Recip. Engine: Wartsila 18V50 SG Heat Rejection: Air-cooled radiators Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Peaking	110	5%	Natural Gas	7	8,370	7%	Note [(3)]	12	0.42	2-3-2-3-2-4	3.2%
4	Solar PV -- Fixed Tilt	PV Module: Trina TSM-PA14 Insolation Data Site: Redmond, OR	As-Available	10	22%	n/a	52	n/a	n/a	Note [(3)]	n/a	0.00	2	n/a
5	Biomass Combustion	Boiler: Bubbling Fluidized Bed Emissions Control: SNCR, Fabric Filter Heat Rejection: Wet Cooling Tower	Baseload	25	85%	Wood	25	13,250	25%	Note [(3)]	1.3	0.53	3-3-3-3-3-8	7.5%
6	Geothermal -- Binary	System: Binary Geothermal System Heat Rejection: Air-Cooled Condenser	Baseload	20	85%	n/a	20	N/A	10%	Note [(3)]	3	0.05	3-3-3-3-3-8	6%
7	Pumped Storage Hydro	System: Closed Loop	Storage	500	n/a	n/a	600	n/a	20	Note [(3)]	160	n/a	2	n/a
8	Battery Storage -- Frequency Regulation	Battery: Lithium Ion Max. Discharge Period: 60 minutes	Storage	25	n/a	n/a	0.7	n/a	0%	Note [(3)]	Note [(8)]	n/a	2	n/a
9	Battery Storage -- Frequency Regulation	Battery: Lithium Ion Max. Discharge Period: 60 minutes	Storage	10	n/a	n/a	0.3	n/a	0%	Note [(3)]	Note [(8)]	n/a	2	n/a

NOTES:

(1) When operating with a CO2 capture efficiency of 90%, the IGCC w/ CO2 Capture facility would provide a net capacity of 475 MW and a net plant heat rate (NPHR) of approximately 11,900 Btu/kWh. When operating in a mode without CO Capture, the IGCC facility would provide a net capacity of 560 MW and an NPHR of approximately 9,000 Btu/kWh.

(2) IGCC w/ CO_2 Capture capacity factor assumes 100 percent utilization and is based on expected long term plant availability after the first several years of operation. Plant availablity is expected to be 70 - 75 percent for the first 5 years of operation.

(3) For all of the SSOs under consideration for the PGE study, Black & Veatch anticipates no significant improvements in efficiency in either the near- or long-term.

(4) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD). Some excluded activities are permitting and EPC specification development.

(5) Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). In instances where these periodic costs are necessary (for the SSOs under consideration in this report), these costs have been included in the relevant O&M costs associated with specific technology options.

(6) Decommissioning Accrual collected annually over the book life of the asset to decommission the facility. For all SSOs except Pumped Storage Hydro, the site would be returned to a Brownfield condition at the end of its book life. For Pumped Storage Hydro, it is assumed that powerhouse equipment would be decommissioned and salvaged, and the facility/reservoirs would be retired in place, with the site secured as appropriate (e.g., reservoirs drained, additional security fencing installed, and signs posted).

(7) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

(8) Li-ion systems are able to ramp up from an idle status to full rated capacity in less than 1 second.

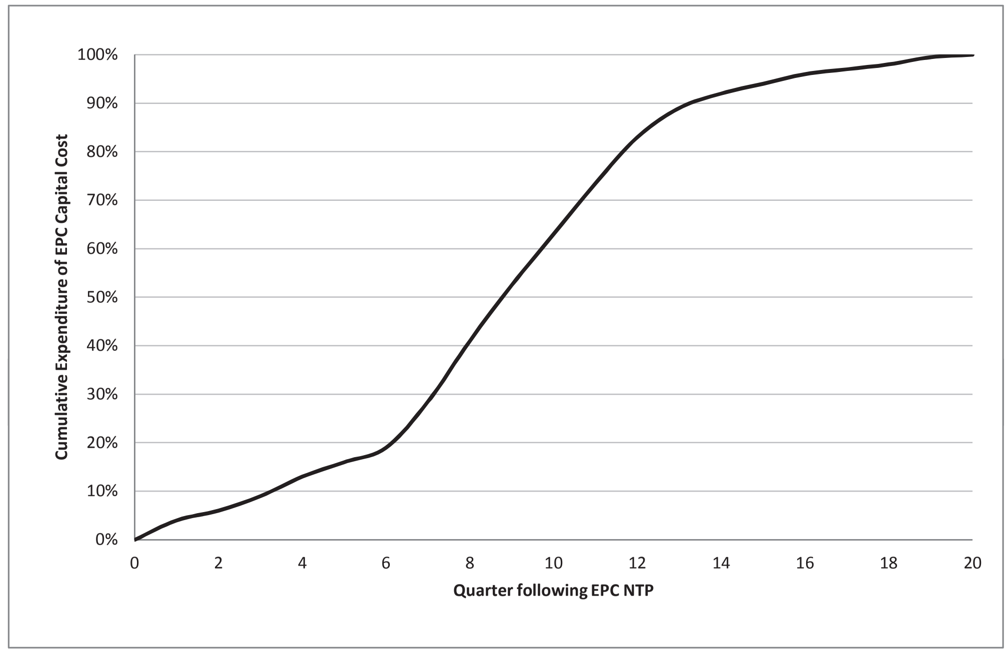
(9) Cycle life assumes a typical cycle of charge to 100% SOC and discharge to 80% DoD.

		Financial Parameters											Energy Storage Parameters			
No.	Option	Book Life (years)	EPC Period[4] (months)	Expenditure Pattern (by month/qtr)	Overnight EPC Capital Cost ($000, 2012$)	Owner's Cost Allowance (%)	Overnight Total Capital Cost ($000, 2012$)	Fixed O&M Cost ($/kW-year)	Variable O&M Cost ($/MWh)	Capital Additions/ Maint. Accrual ($/yr)	Decom-missioning Accrual[6] ($000/yr)	Capital Cost Escalation Rate[7]	Energy Capacity (MWh)	Discharge Period (hours)	Round Trip Efficiency (%)	Cycle Life -- for Battery Options (cycles)
1	Integrated Gasification Combined Cycle (w/ CO2 Capture)	35	59	See Appendix B	2,900,000	20%	3,480,000	64.9	11.4	Note [5]	5,500	General Inflation	n/a	n/a	n/a	n/a
2	1x0 LMS100	25	24	See Appendix B	107,000	25%	133,750	12.7	3.6	Note [5]	150	General Inflation	n/a	n/a	n/a	n/a
3	6x0 Wartsila 18V50	25	24	See Appendix B	145,000	25%	181,250	15.7	8.6	Note [5]	185	General Inflation	n/a	n/a	n/a	n/a
4	Solar PV -- Fixed Tilt	25	3	See Appendix B	24,500	12%	27,440	18.0	2.6	Note [5]	100	General Inflation	n/a	n/a	n/a	n/a
5	Biomass Combustion	25	36	See Appendix B	148,700	25%	185,900	220.0	9.3	Note [5]	530	General Inflation	n/a	n/a	n/a	n/a
6	Geothermal -- Binary	30	48	See Appendix B	146,000	20%	175,200	205.0	21.4	Note [5]	300	General Inflation	n/a	n/a	n/a	n/a
7	Pumped Storage Hydro	30	60	See Appendix B	1,000,000	25%	1,250,000	5.3	0.3	Note [5]	115	General Inflation	20,000	40	77	n/a
8	Battery Storage -- Frequency Regulation	20	15	See Appendix B	48,050	12%	53,820	6.0	N/A	Note [5]	50	General Inflation	25	1	85	7,000 to 10,000[9]
9	Battery Storage -- Frequency Regulation	20	15	See Appendix B	21,250	12%	23,800	10.0	N/A	Note [5]	50	General Inflation	10	1	85	7,000 to 10,000[9]

Appendix B. SSO Expenditure Patterns

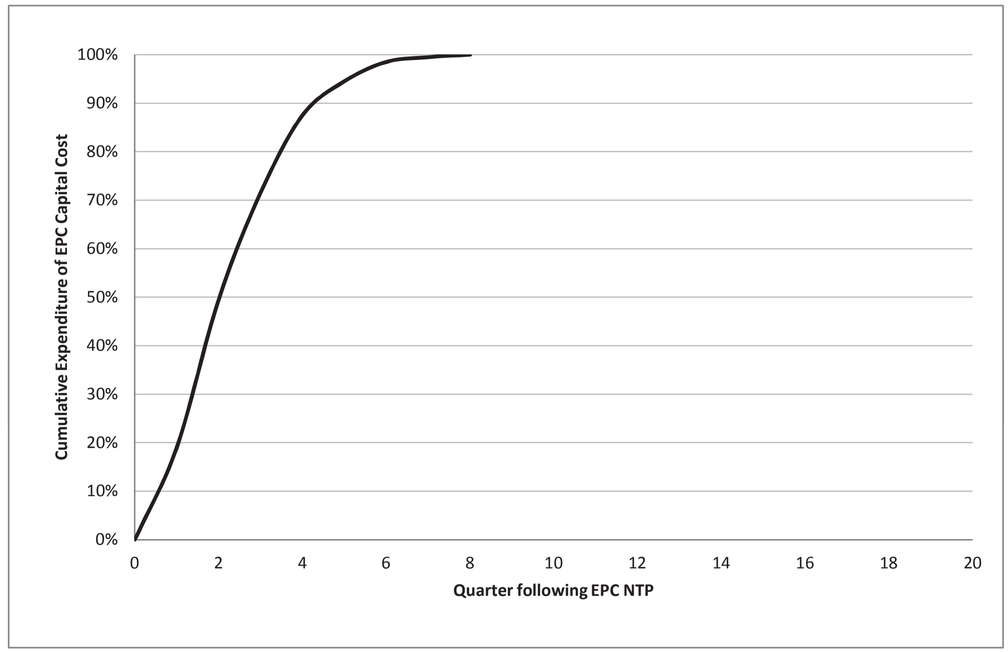
Expenditure Pattern for EPC Capital Cost
Supply Side Option: 465 MW IGCC w/ Carbon Capture

Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	4.0%	4.0%
1	2	2	2.0%	6.0%
1	3	3	3.0%	9.0%
1	4	4	4.0%	13.0%
2	1	5	3.0%	16.0%
2	2	6	3.0%	19.0%
2	3	7	9.5%	28.5%
2	4	8	12.5%	41.0%
3	1	9	11.5%	52.5%
3	2	10	10.5%	63.0%
3	3	11	10.5%	73.5%
3	4	12	9.5%	83.0%
4	1	13	6.0%	89.0%
4	2	14	3.0%	92.0%
4	3	15	2.0%	94.0%
4	4	16	2.0%	96.0%
5	1	17	1.0%	97.0%
5	2	18	1.0%	98.0%
5	3	19	1.5%	99.5%
5	4	20	0.5%	100.0%



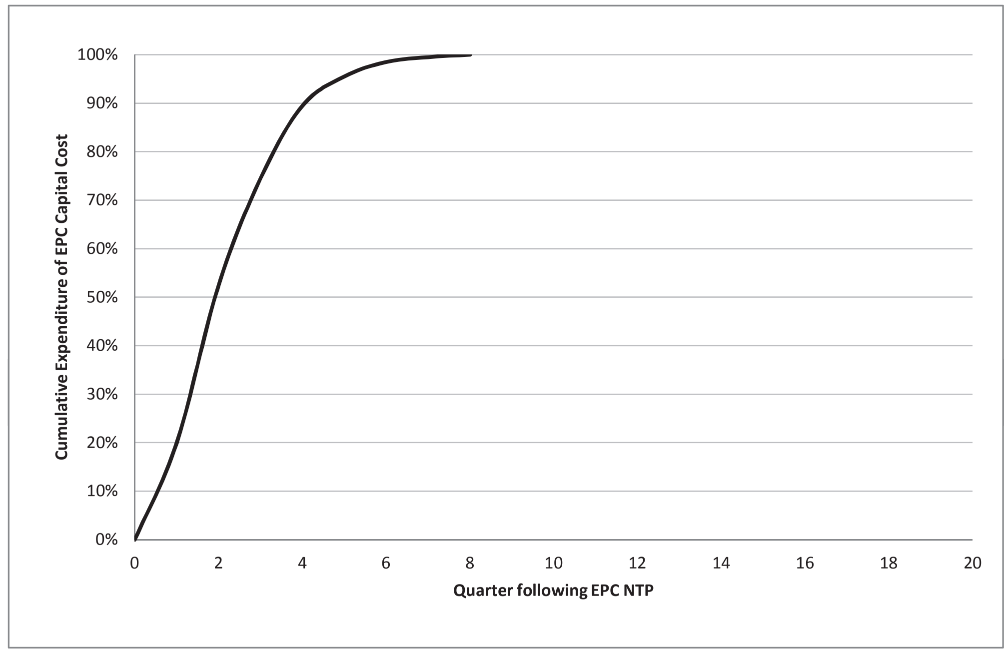
Expenditure Pattern for EPC Capital Cost
Supply Side Option: 1x0 MW GE LMS100PA

Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	19.0%	19.0%
1	2	2	30.5%	49.5%
1	3	3	22.0%	71.5%
1	4	4	16.0%	87.5%
2	1	5	7.0%	94.5%
2	2	6	4.0%	98.5%
2	3	7	1.0%	99.5%
2	4	8	0.5%	100.0%
3	1	9	0.0%	100.0%
3	2	10	0.0%	100.0%
3	3	11	0.0%	100.0%
3	4	12	0.0%	100.0%
4	1	13	0.0%	100.0%
4	2	14	0.0%	100.0%
4	3	15	0.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	100.0%



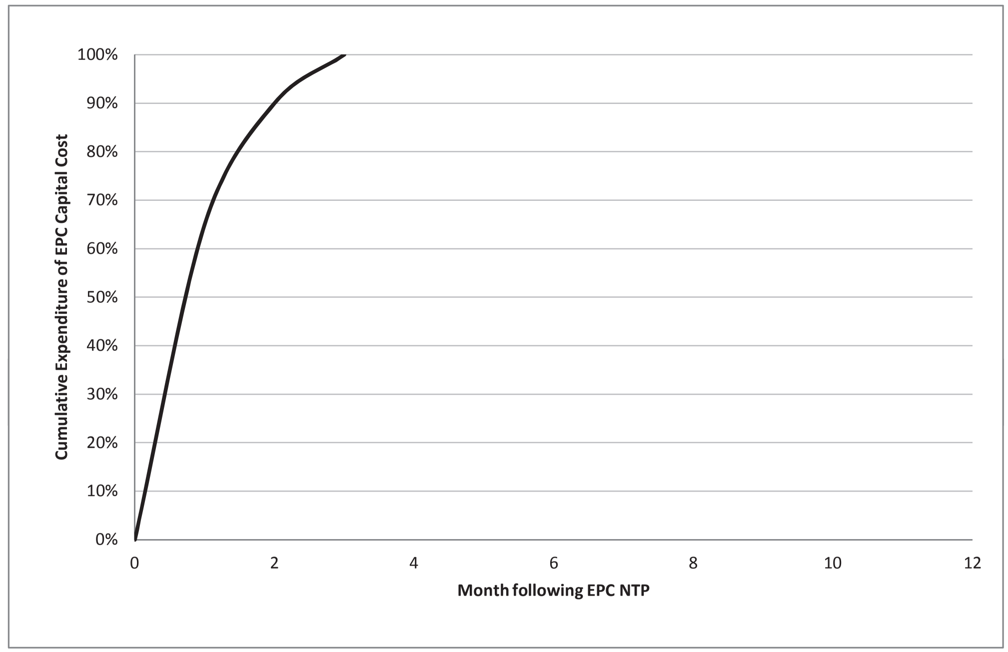
Expenditure Pattern for EPC Capital Cost
Supply Side Option: 6x0 Wartsila 18V50SG

Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	20.0%	20.0%
1	2	2	32.5%	52.5%
1	3	3	22.0%	74.5%
1	4	4	15.0%	89.5%
2	1	5	6.0%	95.5%
2	2	6	3.0%	98.5%
2	3	7	1.0%	99.5%
2	4	8	0.5%	100.0%
3	1	9	0.0%	100.0%
3	2	10	0.0%	100.0%
3	3	11	0.0%	100.0%
3	4	12	0.0%	100.0%
4	1	13	0.0%	100.0%
4	2	14	0.0%	100.0%
4	3	15	0.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	100.0%



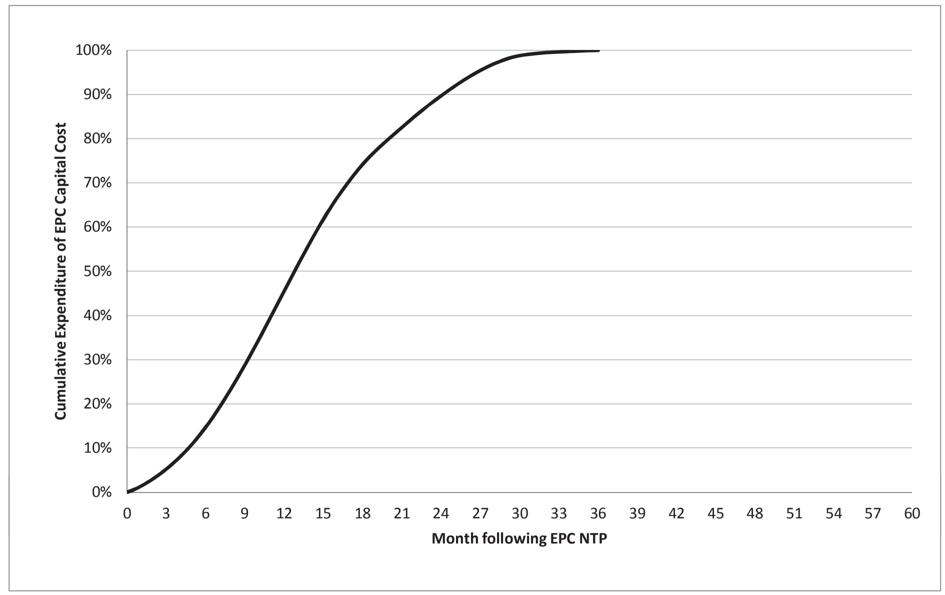
Expenditure Pattern for EPC Capital Cost
Supply Side Option: 10 MW Solar PV

Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	65.0%	65.0%
1	2	2	25.0%	90.0%
1	3	3	10.0%	100.0%
1	4	4	0.0%	100.0%
1	5	5	0.0%	100.0%
1	6	6	0.0%	100.0%
1	7	7	0.0%	100.0%
1	8	8	0.0%	100.0%
1	9	9	0.0%	100.0%
1	10	10	0.0%	100.0%
1	11	11	0.0%	100.0%
1	12	12	0.0%	100.0%
2	1	13	0.0%	100.0%
2	2	14	0.0%	100.0%
2	3	15	0.0%	100.0%
2	4	16	0.0%	100.0%
2	5	17	0.0%	100.0%
2	6	18	0.0%	100.0%
2	7	19	0.0%	100.0%
2	8	20	0.0%	100.0%



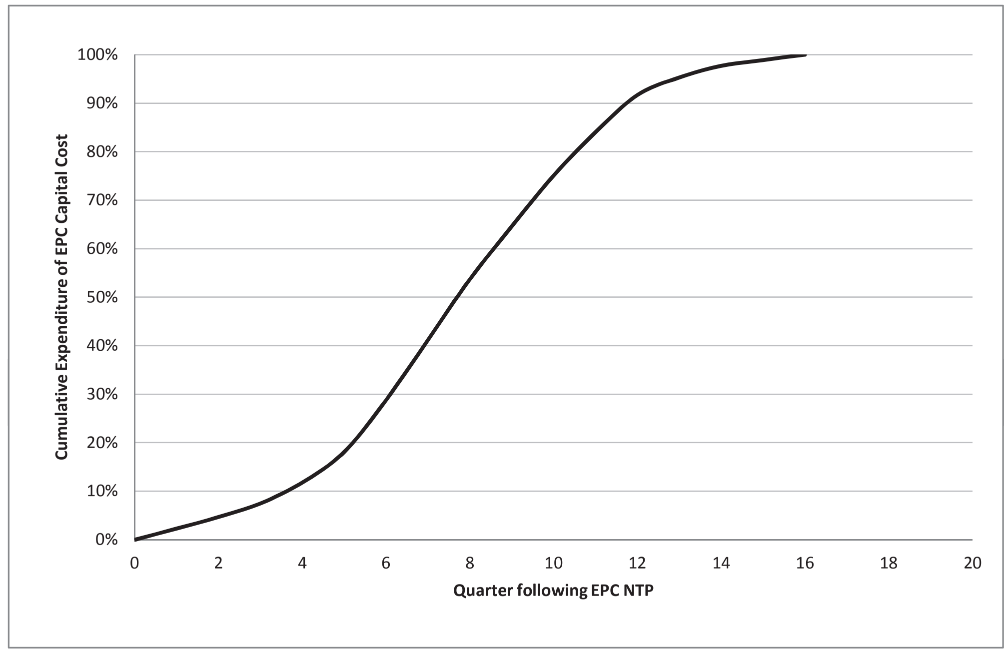
Expenditure Pattern for EPC Capital Cost
Supply Side Option: 25 MW Biomass Combustion (BFB)

Year	Quarter	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	1.2%	1.2%
1	2	2	1.9%	3.1%
1	3	3	2.2%	5.3%
1	4	4	2.6%	7.9%
1	5	5	3.2%	11.0%
1	6	6	3.7%	14.7%
1	7	7	4.3%	19.0%
1	8	8	4.7%	23.7%
1	9	9	5.1%	28.8%
1	10	10	5.4%	34.2%
1	11	11	5.6%	39.8%
1	12	12	5.7%	45.5%
2	1	13	5.6%	51.2%
2	2	14	5.5%	56.6%
2	3	15	5.2%	61.8%
2	4	16	4.6%	66.4%
2	5	17	4.1%	70.5%
2	6	18	3.7%	74.2%
2	7	19	3.0%	77.3%
2	8	20	2.7%	80.0%
2	9	21	2.6%	82.6%
2	10	22	2.5%	85.1%
2	11	23	2.4%	87.5%
2	12	24	2.2%	89.7%
3	1	25	2.1%	91.8%
3	2	26	1.9%	93.8%
3	3	27	1.7%	95.5%
3	4	28	1.4%	96.9%
3	5	29	1.1%	98.0%
3	6	30	0.8%	98.8%
3	7	31	0.4%	99.2%
3	8	32	0.2%	99.5%
3	9	33	0.2%	99.6%
3	10	34	0.1%	99.8%
3	11	35	0.1%	99.9%
3	12	36	0.1%	100.0%



Expenditure Pattern for EPC Capital Cost
Supply Side Option: 20 MW Geothermal

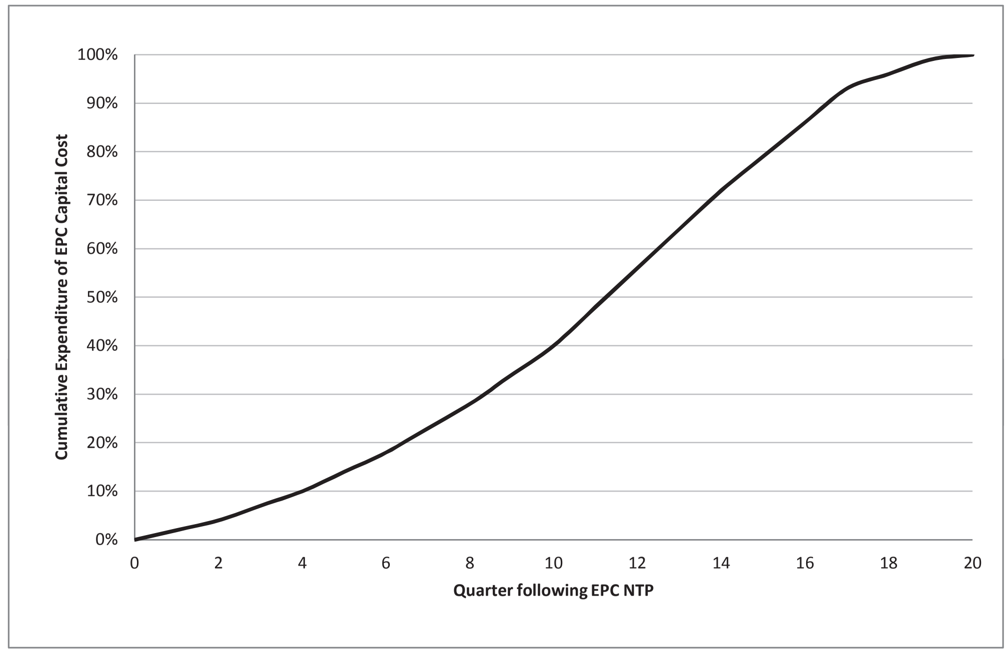
Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	2.3%	2.3%
1	2	2	2.4%	4.7%
1	3	3	2.8%	7.5%
1	4	4	4.3%	11.8%
2	1	5	6.3%	18.1%
2	2	6	10.7%	28.8%
2	3	7	12.4%	41.2%
2	4	8	12.5%	53.7%
3	1	9	10.9%	64.6%
3	2	10	10.5%	75.1%
3	3	11	8.9%	84.0%
3	4	12	7.7%	91.7%
4	1	13	3.6%	95.3%
4	2	14	2.4%	97.7%
4	3	15	1.2%	98.9%
4	4	16	1.1%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 500 MW Pumped Storage Hydro

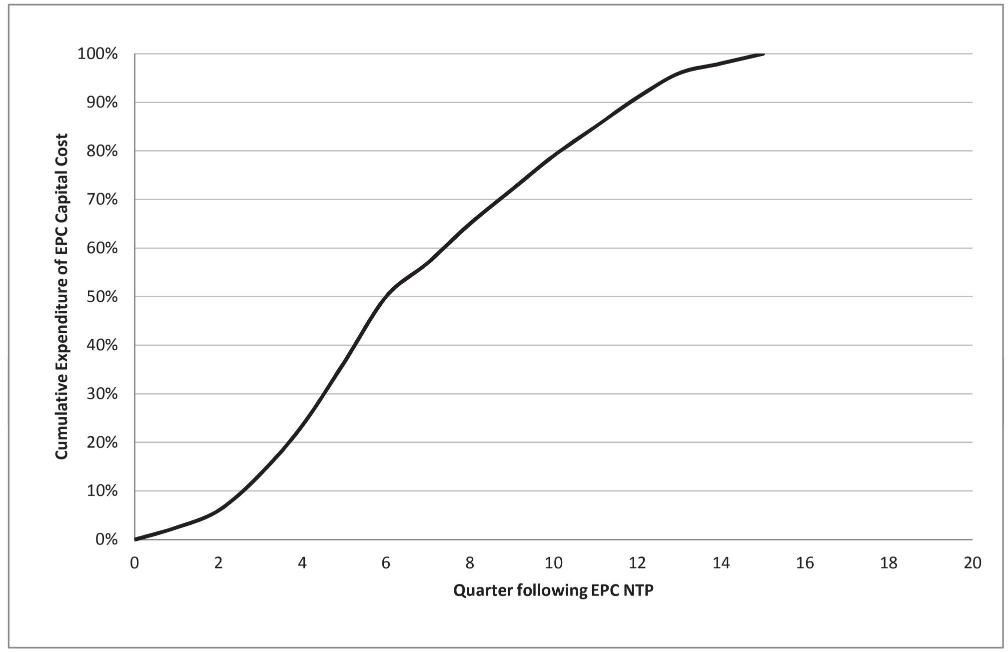
Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	2.0%	2.0%
1	2	2	2.0%	4.0%
1	3	3	3.0%	7.0%
1	4	4	3.0%	10.0%
2	1	5	4.0%	14.0%
2	2	6	4.0%	18.0%
2	3	7	5.0%	23.0%
2	4	8	5.0%	28.0%
3	1	9	6.0%	34.0%
3	2	10	6.0%	40.0%
3	3	11	8.0%	48.0%
3	4	12	8.0%	56.0%
4	1	13	8.0%	64.0%
4	2	14	8.0%	72.0%
4	3	15	7.0%	79.0%
4	4	16	7.0%	86.0%
5	1	17	7.0%	93.0%
5	2	18	3.0%	96.0%
5	3	19	3.0%	99.0%
5	4	20	1.0%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 25 MW Li-Ion Battery Energy Storage

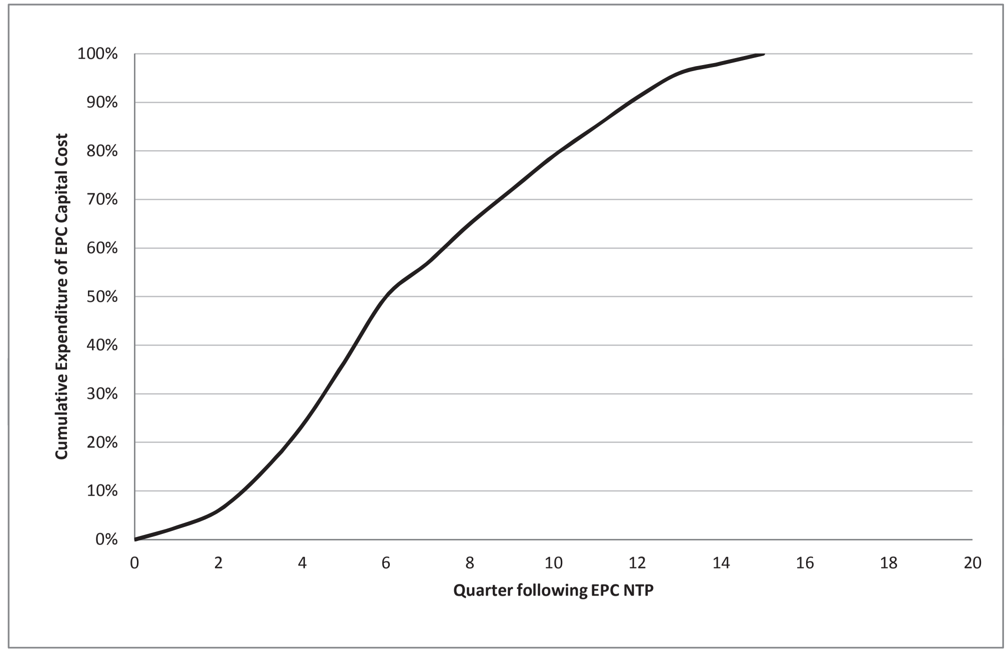
Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	2.5%	2.5%
1	2	2	3.5%	6.0%
1	3	3	7.5%	13.5%
1	4	4	10.0%	23.5%
2	1	5	13.0%	36.5%
2	2	6	13.5%	50.0%
2	3	7	7.0%	57.0%
2	4	8	8.0%	65.0%
3	1	9	7.0%	72.0%
3	2	10	7.0%	79.0%
3	3	11	6.0%	85.0%
3	4	12	6.0%	91.0%
4	1	13	5.0%	96.0%
4	2	14	2.0%	98.0%
4	3	15	2.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 10 MW Li-Ion Battery Energy Storage

Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	2.5%	2.5%
1	2	2	3.5%	6.0%
1	3	3	7.5%	13.5%
1	4	4	10.0%	23.5%
2	1	5	13.0%	36.5%
2	2	6	13.5%	50.0%
2	3	7	7.0%	57.0%
2	4	8	8.0%	65.0%
3	1	9	7.0%	72.0%
3	2	10	7.0%	79.0%
3	3	11	6.0%	85.0%
3	4	12	6.0%	91.0%
4	1	13	5.0%	96.0%
4	2	14	2.0%	98.0%
4	3	15	2.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	100.0%



FINAL REPORT

CHARACTERIZATION OF SUPPLY SIDE OPTIONS – WIND ENERGY

B&V PROJECT NO. 178601
B&V FILE NO. 90.0000

PREPARED FOR

Portland General Electric

29 APRIL 2013

BLACK & VEATCH
Building a world of difference.

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Legal Notice

This report was prepared for Portland General Electric ("Client") by Black & Veatch ("Consultant"). In performing the services, Consultant has made certain assumptions or forecasts of conditions, events, or circumstances that may occur in the future. Consultant has taken reasonable efforts to assure that assumptions and forecasts made are reasonable and the basis upon which they are made follow generally accepted practices for such assumptions or projections under similar circumstances. Client expressly acknowledges that actual results may differ significantly from those projected as influenced by conditions, events, and circumstances that actually occur.

1.0 Introduction

Black & Veatch has prepared this update to a report issued February 22, 2013, to characterize supply-side options (SSOs) to be considered in upcoming Integrated Resource Planning (IRP) activities to be conducted by Portland General Electric (PGE). The SSOs characterized in this update include:

- Wind Farm (100 MW, 80 meter hub-height, 3-bladed horizontal axis machine)
- Wind Farm (300 MW, 80 meter hub-height, 3-bladed horizontal axis machine)

Both of these technology options are considered for four representative sites in the following states:

- Montana
- Oregon
- Washington
- Wyoming

The technology options and representative sites are described in the following sections, including a brief technology overview and characterization of the performance and cost parameters of each SSO. A full matrix of cost and performance parameters for the requested SSOs is provided as Appendix A.

2.0 Design Basis and General Assumptions

2.1 DESIGN BASIS FOR SUPPLY SIDE OPTIONS

To develop technical performance and cost characteristics, Black & Veatch established design basis parameters for each of the SSOs under consideration. For each SSO, design basis parameters are summarized in Table 2-1.

Table 2-1 Design Basis for Supply Side Options

SUPPLY-SIDE OPTION	MAJOR EQUIPMENT	DUTY	NET CAPACITY (MW)	CAPACITY FACTOR (%)	PRIMARY FUEL
Wind Farm	63 1.6 MW Wind Turbine Generators	As-Available	100	Varies based on site	n/a
Wind Farm	188 1.6 MW Wind Turbine Generators	As-Available	300	Varies based on site	n/a

2.2 GENERAL SITE ASSUMPTIONS

In addition to the design basis parameters shown in Table 2-1, general site assumptions employed by Black & Veatch for these SSOs include the following:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- The plant will not be located on environmentally or culturally sensitive lands. The project site will require neither mitigation nor remediation.
- Spread footings are assumed for all equipment foundations.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- Potable, Service and Fire water will be supplied from the local water utility.
- Wastewater disposal will utilize local sewer systems.
- Costs for transmission lines and switching stations are included as part of the owner's cost estimate.

2.3 REPRESENTATIVE SITE DESCRIPTIONS

Each state was evaluated for likely site characteristics based on estimated wind speed, topography, proximity to existing transmission, and federal land restrictions. Representative sites were created to base production and cost estimates on realistic parameters for each state. A brief description of each representative site's physical characteristics and expected wind speed is provided below.

2.3.1 Oregon

A representative site in Oregon consists of flat plains (2% - 4%) and rolling hills (4% – 8% grade) along steep ridgelines (15% - 35% grade). Access would be moderately difficult along these ridgelines. Vegetation on the plains and hills is moderate, generally consisting of grasslands or farmland. The average 80 meter wind speed in the area is between 6.0 meters per second and 6.5 meters per second.

2.3.2 Montana

A representative site in Montana consists of moderate terrain with rolling hills (4% – 8% grade) sloping up gradually to a sudden drop-off along steep ridgelines (15% - 30% grade). Access is estimated to be fairly simple if approached on the side with a gradual incline. Vegetation on the hills is moderate to low, generally consisting of grasslands or farmland. The average 80 meter wind speed in the area is between 8.0 meters per second and 9.0 meters per second.

2.3.3 Washington

A representative site in Washington consists of rolling hills (4% – 8% grade) with some isolated peaks in the area. Access would be moderately difficult given the hilly surroundings. Vegetation on the plains and hills is moderate, generally consisting of grasslands or farmland. The average 80 meter wind speed in the area is between 6.5 meters per second and 7.0 meters per second.

2.3.4 Wyoming

A representative site in Wyoming consists of flat plateaus (1% - 4% grade) and rolling hills (4% – 8% grade) sloping up to a drop-off along fairly steep ridgelines (5% - 13% grade). Access would be relatively easy in the plateaus and hills. There are also some isolated peaks in the area. Vegetation on the plains and hills is low, consisting of grasslands. The average 80 meter wind speed in the area is between 8.5 meters per second and 9.0 meters per second.

2.4 CAPITAL COST ESTIMATING ASSUMPTIONS

Assumptions associated with capital cost estimates developed by Black & Veatch include the following:

- Capital cost estimates were developed on an engineer, procure, and construct (EPC) basis. The EPC capital cost estimates presented in this document include both direct and indirect costs.
- EPC capital cost estimates are presented as "overnight" costs and do not include any allowances for escalation, financing fees, interest or other general Owner's cost items.

- A recommended allowance for Owner's costs has been provided for each technology, separately from the EPC capital cost estimates. Potential Owner's costs are listed in Table 2-2.
- All capital cost estimates are presented in 2012 dollars.

Table 2-2 Potential Owner's Costs for Power Generation/Storage Projects

Project Development • Site selection study • Land leasing and rezoning for greenfield sites • Transmission right-of-way • Road modifications/upgrades • Demolition • Environmental permitting/offsets • Public relations/community development • Legal assistance • Provision of project management	**Owner's Contingency** • Owner's uncertainty and costs pending final negotiation • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreements (i.e., interconnection contract costs) **Owner's Project Management** • Preparation of bid documents and the selection of contractors and suppliers • Performance of engineering due diligence • Provision of personnel for site construction management
Spare Parts and Plant Equipment • Wind turbine generator materials, supplies, and parts • Balance-of-plant equipment/tools • Rolling stock • Plant furnishings and supplies	**Taxes/Advisory Fees/Legal** • Taxes • Market and environmental consultants • Owner's legal expenses • Interconnect agreements • Contracts (procurement and construction) • Property
Plant Startup/Construction Support • Owner's site mobilization • O&M staff training • Initial test fluids and lubricants • Initial inventory of chemicals and reagents • Consumables • Auxiliary power purchases • Acceptance testing • Construction all-risk insurance	**Utility Interconnections** • Natural gas service • Electrical service • Water supply **Financing (included in fixed charge rate)** • Financial advisor, lender's legal, market analyst, and engineer • Loan administration and commitment fees • Debt service reserve fund

2.4.1 Direct Cost Assumptions

Assumptions regarding direct costs within the capital cost estimates include the following:

- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on a turnkey EPC contracting philosophy, but with owner purchase of wind turbines.
- Permitting and licensing are excluded from EPC costs. These items should be included in the owner's cost estimate.

2.4.2 Indirect Cost Assumptions

Indirect costs within the capital cost estimates are assumed to include the following:

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts.

Indirect costs are assumed to exclude the following:

- Initial inventory of spare parts for use during operation. These items are assumed to be included in the owner's costs.
- Allowance for funds used during construction and financing fees. These costs should be included in the Owner's overall cost estimate.

2.5 OPERATION & MAINTENANCE COST ESTIMATING ASSUMPTIONS

Assumptions associated with operations and maintenance (O&M) cost estimates developed by Black & Veatch include the following:

- O&M cost estimates were developed as representative estimates based on (1) previous Black & Veatch experience with projects of similar design and scale, (2) market reports including summaries of wind project operating costs across the United States, and (3) relevant vendor information available to Black & Veatch.

- O&M cost estimates were reviewed, and although in all costs were considered to be Fixed O&M. Fixed O&M costs include labor, routine maintenance and other expenses (i.e., training, property taxes, insurance, office and administrative expenses).
- O&M cost estimates are presented in 2012 dollars.

2.6 ADDITIONAL FINANCIAL PARAMETER ASSUMPTIONS

In addition to capital and O&M cost parameters, PGE requested characterization of the other financial parameters, including escalation of capital costs (over an extended term); capital expenditures and maintenance accruals; and decommissioning costs.

2.6.1 Escalation of Capital Costs (over an Extended Term)

Evolving technologies such as solar and wind have seen significant reductions in costs during the past two decades in spite of pressure on the EPC market for conventional resources. These market trends are difficult to accurately forecast. As such, Black & Veatch generally employs the expected general inflation rate as a proxy for long-term escalation for planning studies. While there may be periods where market pressures cause short-term fluctuations in capital costs, the general outlook of Black & Veatch regarding capital costs is (1) conventional alternatives will be steady, and (2) renewable alternatives such as wind will slow in their decreasing prices and become steady.

2.6.2 Capital Expenditures/Maintenance Accruals

Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). Typically, Black & Veatch does not provide estimates of the costs associated with these activities as capital expenditures or maintenance accruals separately from other O&M costs. In instances where these periodic costs are necessary (for the SSOs under consideration in this report), these costs have been included in the relevant O&M costs associated with specific technology options. For these SSOs, the periodic system/equipment replacement requirements are noted in the technology-specific assumptions.

2.6.3 Decommissioning Costs

A fixed amount of money is accrued each year over the book life of the asset to cover the cost of decommissioning the asset. For all SSOs the site would be returned to a Brownfield condition at the end of its book life. The fixed amount was determined using a sinking fund factor based on the book life of the asset and an assumed interest rate of 6 percent. The future amount was estimated based on a percentage of the current total capital requirement of the asset. The percentage was based on recent decommissioning cost estimates for similar scope of decommissioning for similar assets.

3.0 Renewable Generation Options

Renewable SSOs considered for this effort include:

- Wind Farm (100 MW, 63 80 meter hub-height, 3-bladed horizontal axis machines)
- Wind Farm (300 MW, 188 80 meter hub-height, 3-bladed horizontal axis machines)

These renewable SSOs and their performance and cost characteristics are defined below.

3.1 WIND FARM

3.1.1 Technology Overview

Wind energy technology has made major advancements since the production of wind turbines in the early 1980's. Three decades of technological progress has resulted in today's wind turbines being a cutting edge technology. A modern, single wind turbine has the ability to produce nearly two hundred times more electricity annually and at less than half the cost per kWh than its equivalent twenty years ago. The wind power sector now includes some of the world's largest energy companies.

Although wind turbines have advanced significantly in design, their basic operating principles have remained virtually unchanged. Figure 3-1 from the U.S. Department of Energy shows the typical layout of equipment in a wind turbine nacelle. Almost all of these subsystem elements have counterparts in conventional electric generation systems but differ greatly in their implementation. The prime mover in wind turbines consists of power extracted from the wind, which is converted to rotational mechanical energy by means of the aerodynamic properties of the turbine blades. This rotational energy is then transmitted to the generator rotor through a drive train. This may be by means of a gear box to a 4 or 6 pole generator, or directly to a low-speed multi-pole generator. Turbines typically rotate at between 10 and 20 RPM at rated power. In order to operate efficiently, the orientation of the wind turbine is always kept facing the oncoming wind by means of the yaw mechanism. The turbine's controller has autonomous control of most all of its functions including the operation of various switches, hydraulic pumps, valves, and motors. The control system operates within various parameters and will commence simple or even emergency procedures in response to pre-programmed settings.

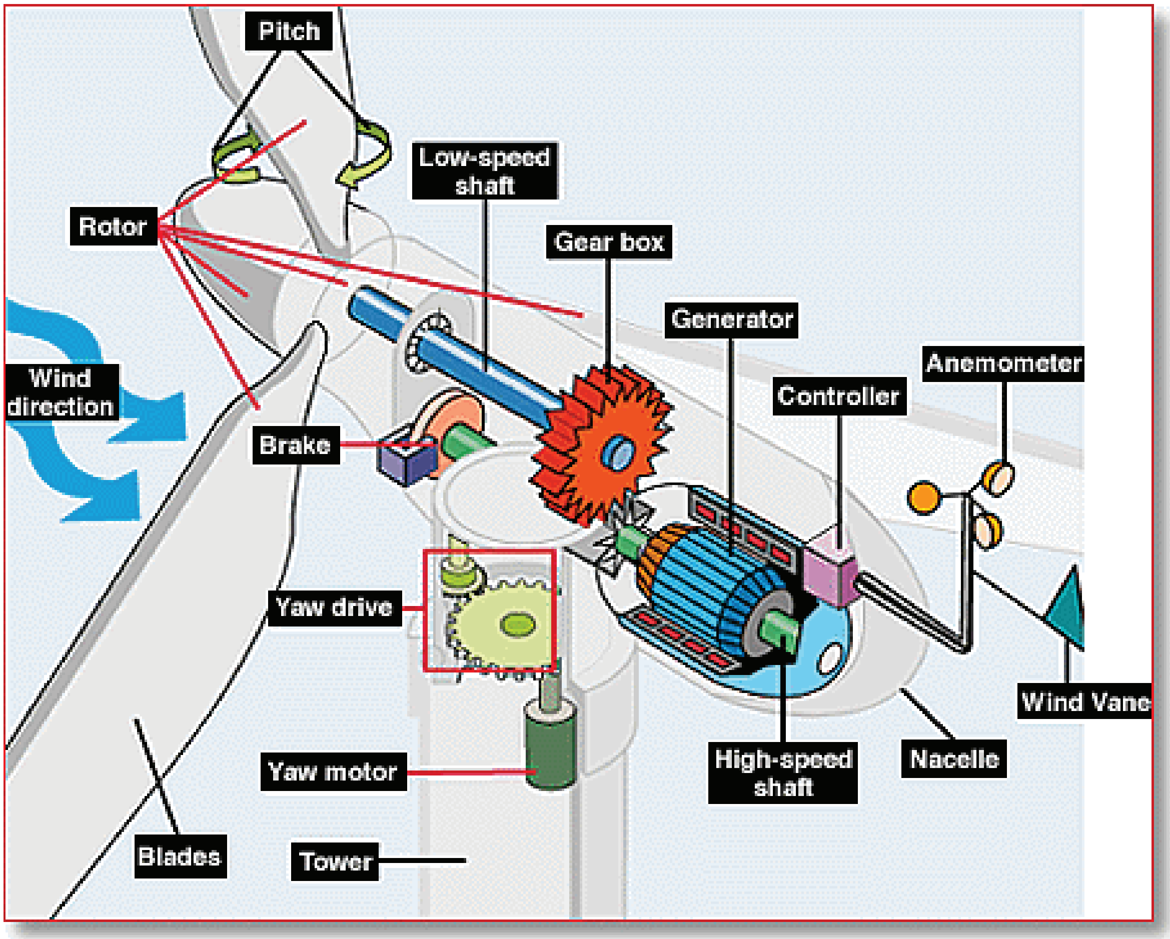


Figure 3-1 Wind Turbine Components

The technology employed in large commercial wind turbines for electromechanical energy conversion deviates somewhat from conventional generation equipment. In lieu of synchronous generators, induction machines are used in most commercial-scale wind turbine designs, typically connected to the grid via sophisticated power electronics that alter the fundamental behavior of the induction machines in both steady-state and dynamic operation. Others use synchronous designs with permanent magnet excitation, but are connected to the grid through a rectifier and power converter. In response to the advancing demands for power quality, remote data acquisition, and fault response capabilities, turbine manufacturers are implementing higher reliability systems to accommodate these explicit grid connection requirements.

3.1.2 Wind Farm Configuration

A wind farm typically consists of many individual wind turbines spread across a large area. The overall shape and size of a wind farm varies with each individual project, but they are typically arranged in several rows or cluster of turbines. Wind resource, terrain, land cover, land ownership, residences, environmental restrictions, and existing road networks all influence the final configuration of a wind project. Although a large amount of land is required for development and construction of a wind project, most of the land is undisturbed by the project and can remain in use for its original purpose. This makes large wind projects highly compatible with agricultural activities, with some exceptions such as aerial application of pesticides and fertilizers.

Wind turbines generally are mounted to relatively shallow octagonal inverted tee spread footing foundations, typically between 50 and 60 feet across, with anchor bolts embedded into a smaller circular pedestal 10-15 feet across, to which the turbine tower is mounted. Depending on the specific configuration of the wind turbine generators, a small transformer may be mounted adjacent to the turbine base, inside the base of the turbine tower, or in the turbine nacelle. This transformer converts power from the typical 600 V generating voltage to the 35 kV class collection system voltage (typically 34.5 kV in the US).

Permanent gravel access roads are generally built to each individual wind turbine location. For a project developed in open ranch land or on rolling hills a network of new access roads is often built from turbine to turbine. The roads may follow existing roads with improvements and modifications, or may be entirely new build. For a project developed in relatively flat cultivated farmland with a gridded road network individual turbine access roads may be short straight roads connected to the public roads rather than a turbine to turbine network.

A central collection substation is generally built within the overall footprint of a wind farm. This collection substation includes the main power transformer, which converts the collection system voltage to the voltage of the interconnection transmission line. From this collection substation wind farm is interconnected to the grid. The interconnection point may be adjacent to the substation if it is built along the interconnecting transmission line, or the project may construct a new transmission line and interconnection switchyard adjacent to the interconnecting transmission line. Each turbine is connected electrically into groups of 8-15, and power is brought back to the collection substation. The collection lines may follow access road routes, or may be trenched directly from turbine to turbine. Often collection lines follow the access road routes when a new wind farm specific access road network is built, and are trenched directly from turbine to turbine when the access roads connect back to a gridded public road network.

Although each turbine is fully capable of autonomous operation, all turbines are linked together to a project control system (SCADA). The central SCADA system can monitor and control the project as needed, included recording of all project operating data and implementation of curtailment controls as needed.

In addition to the turbines, access roads, collection system, and substation, wind projects typically include an operations and maintenance (O&M) facility. This facility is often a pre-engineered building and warehouse, with offices, conference rooms, restrooms and showers, storage, and warehousing.

3.1.3 Wind Resource and Energy Generation

To calculate the expected energy output of a wind farm the most important input is the wind resource. Wind resource information for this update is from estimates developed for the U.S. Department of Energy by AWS Truepower, LLC. Using a high-resolution grid, 80 meter annual average wind speeds were mapped for the United States. The model used a spatial resolution of 2.5 km that was interpolated to a finer scale.

Wind speeds are presented in the AWS map as ranges. For this update, average annual 80 meter wind speeds for each site were selected based on the mid-point of each range. Using the mid-point wind speeds, the sites were assumed to be Class III or Class II locations. A common machine for Class III sites is the GE 1.6-100, and for Class II sites the GE 1.6-82.5 is often utilized. These two machines were chosen because they are seen in sites throughout the United States similar to the ones under consideration in this update, and because these two turbines are based on the same technologies and design platforms. The power curves for both machines were adjusted to account for the impact of the site air density. Air density was estimated based on annual temperatures for each state collected from representative airport data and pressure derived from site elevation and a hub-height of 80 meters. The wind speed ranges, wind speeds chosen for each site, assumed class, chosen turbine, and air density for the site are shown in Table 3-1 below.

Table 3-1 Estimated 80 meter annual average wind speeds

STATE OF SITE	WIND SPEED RANGE	MID-POINT	WTG CLASS	CHOSEN WTG	AIR DENSITY
Oregon	6.0 m/s – 6.5 m/s	6.25 m/s	Class III	GE 1.6-100	1.14
Montana	8.0 m/s – 9.0 m/s	8.5 m/s	Class II	GE 1.6-82.5	1.11
Washington	6.5 m/s – 7.0 m/s	6.75 m/s	Class III	GE 1.6-100	1.12
Wyoming	8.5 m/s – 9.0 m/s	8.75 m/s	Class II	GE 1.6-82.5	1.02

3.1.4 Technology-Specific Assumptions

Cost and performance have been developed for a two utility-scale wind farm scenarios. The utility-scale wind farms are assumed to have nameplate capacities of roughly 100 MW and 300 MW, composed of 63 1.6 MW machines and 188 1.6 MW machines, respectively. Relevant assumptions employed in the development of performance and cost parameters for these two utility-scale wind farms include the following:

- Wind turbines would be spaced sufficiently to prevent significant wake losses caused by neighboring turbines. A common distance is ten rotor diameters in the direction of the predominant wind direction, and four rotor diameters in the direction perpendicular to the predominant wind direction.
- The site does not have unusually turbulent flows or other environmental conditions that might impact the functionality or cause damage to the wind turbines.

- A Weibull curve fit based upon the mean wind speed with a standard Raleigh distribution is assumed to accurately represent the wind characteristics of each site.
- The model included typical losses due to wakes, availability, environmental impacts, electrical losses, maintenance and other sources of loss. Losses were assumed to be greater for the 300 MW case, as more rows would probably be needed to fit 188 turbines on a given site. This would result in higher wake losses due to deep array effects, which have been accounted for in Table 3-3.

Table 3-2 Project Losses for 100 MW cases

LOSS ESTIMATE	LOSS	FACTOR
Topographic	1%	99%
Wake	6%	94%
Availability	4%	96%
Power Curve	2%	98%
Grid	1%	99%
Electrical	2%	98%
Columnar	0%	100%
Contamination	1%	99%
Icing	2%	98%
Model	1%	99%
Hysteresis	0%	100%
Total	18.75%	81%

Table 3-3 Project Losses for 300 MW cases

LOSS ESTIMATE	LOSS	FACTOR
Topographic	1%	99%
Wake	10%	90%
Availability	4%	96%
Power Curve	2%	98%
Grid	1%	99%
Electrical	2%	98%
Columnar	0%	100%
Contamination	1%	99%
Icing	2%	98%
Model	1%	99%
Hysteresis	0%	100%

Total	22.20%	78%

- The EPC costs model assumed the main characteristics listed below:
  - There is minimal vegetation to be removed.
  - Both the GE 1.6-100 and the GE 1.6-82.5 are installed using the 80 meter hub-height configuration and have the same costs for BOP/erection, but different costs by turbine.
  - The BOP costs are assumed to be the same regardless of turbine type, but will be impacted by the average site slope. The impact of site slope are accounted for by applying the multipliers shown in Table 3-4 to BOP/erection costs and switchyard costs:

Table 3-4 Slope multipliers to BOP/erection costs and switchyard

SLOPE	MULTIPLIER
Slope < 4%	1.00
4% < slope < 8%	1.16
8% < slope < 16%	1.22
slope > 16%	1.55

  - BOP costs will also be impacted slightly by the difficulty of approach to a site. A gradually increasing slope with existing roads will be easier to access than a region with abrupt changes in grade and no existing roads. Table 3-5 shows the additional multipliers applied to the BOP costs based on ease of access.

Table 3-5 Ease of access multipliers to BOP/erection costs

EASE OF ACCESS	MULTIPLIER
Simple	1.00
Moderate	1.04
Difficult	1.08

  - Owner's costs are assumed to be 10% of direct costs and Finance costs are assumed to be 5% of direct costs, shown as Owner's Cost Allowance in Table 3-7.
- The installation is assumed to be performed by an experienced contractor. An experienced contractor provides:
  - Efficient design and construction processes.
  - Most economical equipment pricing from vendors.

- The AC collector station is next to the point of interconnection.

3.2 TECHNICAL AND FINANCIAL PARAMETERS FOR RENEWABLE GENERATION OPTIONS

Technical parameters for renewable energy options considered for PGE are summarized in Table 3-6, while cost and financial parameters for renewable energy options considered for PGE are summarized in Table 3-7 and Table 3-8.

Table 3-6 Technical Parameters for Renewable Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	LAND REQUIRED (ACRES) (1)	HEAT RATE (BTW/ kWh)	MINIMUM TURNDOWN CAPACITY (%)(2)	RAMP RATE (MW/MIN)	WATER CONSUMPTION (MGD) (3)	SCHEDULED MAINTENANCE PATTERN (WEEKS/YR) (4)	EQUIVALENT FORCED OUTAGE RATE (%)
Oregon Site Wind Farm	100	31	24,900	N/A	N/A	N/A	0.0	N/A	N/A
Oregon Site Wind Farm	300	30	73,510	N/A	N/A	N/A	0.0	N/A	N/A
Montana Site Wind Farm	100	41	16,950	N/A	N/A	N/A	0.0	N/A	N/A
Montana Site Wind Farm	300	39	50,030	N/A	N/A	N/A	0.0	N/A	N/A
Washington Site Wind Farm	100	35	24,900	N/A	N/A	N/A	0.0	N/A	N/A
Washington Site Wind Farm	300	34	73,510	N/A	N/A	N/A	0.0	N/A	N/A
Wyoming Site Wind Farm	100	41	16,950	N/A	N/A	N/A	0.0	N/A	N/A
Wyoming Site Wind Farm	300	39	50,030	N/A	N/A	N/A	0.0	N/A	N/A

(1) For the 100 MW case it is assumed that the 63 turbines spaced at 4 x 10 diameters and are arranged in 3 rows. For the 300 MW case it is assumed that the 188 turbines spaced at 4 x 10 diameters and are arranged in 6 rows. Class III and Class II sites have rotor diameters of 100 meters and 82.5 meters, respectively.

(2) If it is necessary to curtail wind power output, the inverter is capable of curtailing 100% of the power output.

(3) For Wind, it is assumed that rainfall will be sufficient to make panel washing unnecessary. No other industrial water consumption required for operation of wind facility.

(4) Maintenance is performed on a continuous, rolling schedule throughout the year. Each individual turbine will be offline for roughly 100 hours during maintenance, but the entire farm will not be offline at any point during the maintenance cycle, except for 1-2 days when substation maintenance is performed.

Table 3-7 Financial Parameters for Renewable Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	BOOK LIFE (YEARS)	EPC PROJECT DURATION[1] (MONTHS)	EXPENDITURE PATTERN	OVERNIGHT EPC CAPITAL COST ($000, 2012$)	OWNER'S COST ALLOWANCE (%)	OVERNIGHT TOTAL CAPITAL COST ($000, 2012$)
Oregon Site Wind Farm	100	31	25	12	See Appendix B	209,100	15	240,470
Oregon Site Wind Farm	300	30	25	12	See Appendix B	627,300	15	721,400
Montana Site Wind Farm	100	41	25	12	See Appendix B	191,920	15	220,710
Montana Site Wind Farm	300	39	25	12	See Appendix B	575,760	15	662,120
Washington Site Wind Farm	100	35	25	12	See Appendix B	209,100	15	240,470
Washington Site Wind Farm	300	34	25	12	See Appendix B	627,300	15	721,400
Wyoming Site Wind Farm	100	41	25	12	See Appendix B	182,000	15	209,300
Wyoming Site Wind Farm	300	39	25	12	See Appendix B	546,000	15	627,900

(1) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD).

Table 3-8 Financial Parameters for Renewable Generation Options – Continued

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	CAPACITY FACTOR (%)	FIXED O&M COST ($/kW-YEAR)	NON-FUEL VARIABLE O&M COST ($/MWh)	DECOMISSIONING ACCRUAL[1] ($000, 2012$)	LONG-TERM CAPITAL COST ESCALATION RATE[2]
Oregon Site Wind Farm	100	31	40	0.0	1,240	General Inflation
Oregon Site Wind Farm	300	30	40	0.0	3,713	General Inflation
Montana Site Wind Farm	100	41	40	0.0	1,240	General Inflation
Montana Site Wind Farm	300	39	40	0.0	3,713	General Inflation
Washington Site Wind Farm	100	35	40	0.0	1,240	General Inflation
Washington Site Wind Farm	300	34	40	0.0	3,713	General Inflation
Wyoming Site Wind Farm	100	41	40	0.0	1,240	General Inflation
Wyoming Site Wind Farm	300	39	40	0.0	3,713	General Inflation

(1) Accrual collected annually over the book life of the asset to decommission the facility and return the site to a Brownfield condition. Estimate is a net cost offset by the salvage of each turbine.

(2) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

Appendix A. Supply Side Option Parameters (Full Table)

		Design Basis Parameters					Technical/Performance Parameters							
No.	Option	Option Design Basis	Duty	Net Capacity (MW)	Capacity Factor (%)	Primary Fuel	Land Required (acres)[1]	Net Plant Heat Rate (Btu/kWh)	Minimum Turndown Capacity (%) [2]	Range of Potential NPHR Improvements (%)	Ramp Rate (MW/min)	Water Consumption (mgd) [3]	Scheduled Maint. Pattern (weeks/yr) [4]	Equiv. Forced Outage Rate (%)
1	Oregon Site Wind Farm	63 1.6 MW Wind Turbine Generators	As-Available	100	31	N/A	24,900	N/A	N/A	N/A	N/A	0	N/A	N/A
2	Oregon Site Wind Farm	188 1.6 MW Wind Turbine Generators	As-Available	300	30	N/A	73,510	N/A	N/A	N/A	N/A	0	N/A	N/A
3	Montana Site Wind Farm	63 1.6 MW Wind Turbine Generators	As-Available	100	41	N/A	16,950	N/A	N/A	N/A	N/A	0	N/A	N/A
4	Montana Site Wind Farm	188 1.6 MW Wind Turbine Generators	As-Available	300	39	N/A	50,030	N/A	N/A	N/A	N/A	0	N/A	N/A
5	Washington Site Wind Farm	63 1.6 MW Wind Turbine Generators	As-Available	100	35	N/A	24,900	N/A	N/A	N/A	N/A	0	N/A	N/A
6	Washington Site Wind Farm	188 1.6 MW Wind Turbine Generators	As-Available	300	34	N/A	73,510	N/A	N/A	N/A	N/A	0	N/A	N/A
7	Wyoming Site Wind Farm	63 1.6 MW Wind Turbine Generators	As-Available	100	41	N/A	16,950	N/A	N/A	N/A	N/A	0	N/A	N/A
8	Wyoming Site Wind Farm	188 1.6 MW Wind Turbine Generators	As-Available	300	39	N/A	50,030	N/A	N/A	N/A	N/A	0	N/A	N/A

NOTES:

(1) For the 100 MW case it is assumed that the 63 turbines spaced at 4 x 10 diameters and are arranged in 3 rows. For the 300 MW case it is assumed that the 188 turbines spaced at 4 x 10 diameters and are arranged in 6 rows. Class III and Class II sites have rotor diameters of 100 meters and 82.5 meters, respectively.
(2) If it is necessary to curtail wind power output, the inverter is capable of curtailing 100% of the power output.
(3) For Wind, it is assumed that rainfall will be sufficient to make panel washing unnecessary. No other water consumption required for operation of wind facility.
(4) Maintenance is performed on a continuous, rolling schedule throughout the year. Each individual turbine will be offline for roughly 100 hours during maintenance, but the entire farm will not be offline at any point during the maintenance cycle, except for 1-2 days when substation maintenance is performed.
(5) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD).
(6) Accrual collected annually over the book life of the asset to decommission the facility and return the site to a Brownfield condition. Estimate is a net cost offset by the salvage of each turbine.
(7) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

		Financial Parameters											Energy Storage Parameters			
No.	Option	Book Life (years)	EPC Period[5] (months)	Expenditure Pattern (by month/qtr)	Overnight EPC Capital Cost ($000, 2012$)	Owner's Cost Allowance (%)	Overnight Total Capital Cost ($000, 2012$)	Fixed O&M Cost ($/kW-year)	Variable O&M Cost ($/MWh)	Capital Additions/ Maint. Accrual ($/yr)	Decom-missioning Accrual[6] ($000/yr)	Capital Cost Escalation Rate[7]	Energy Capacity (MWh)	Discharge Period (hours)	Round Trip Efficiency (%)	Cycle Life -- for Battery Options (cycles)
1	Oregon Site Wind Farm	25	12	See Appendix B	209,100	15	240,470	40	0	N/A	1,240	General Inflation	N/A	N/A	N/A	N/A
2	Oregon Site Wind Farm	25	12	See Appendix B	627,300	15	721,400	40	0	N/A	3,713	General Inflation	N/A	N/A	N/A	N/A
3	Montana Site Wind Farm	25	12	See Appendix B	191,920	15	220,710	40	0	N/A	1,240	General Inflation	N/A	N/A	N/A	N/A
4	Montana Site Wind Farm	25	12	See Appendix B	575,760	15	662,120	40	0	N/A	3,713	General Inflation	N/A	N/A	N/A	N/A
5	Washington Site Wind Farm	25	12	See Appendix B	209,100	15	240,470	40	0	N/A	1,240	General Inflation	N/A	N/A	N/A	N/A
6	Washington Site Wind Farm	25	12	See Appendix B	627,300	15	721,400	40	0	N/A	3,713	General Inflation	N/A	N/A	N/A	N/A
7	Wyoming Site Wind Farm	25	12	See Appendix B	182,000	15	209,300	40	0	N/A	1,240	General Inflation	N/A	N/A	N/A	N/A
8	Wyoming Site Wind Farm	25	12	See Appendix B	546,000	15	627,900	40	0	N/A	3,713	General Inflation	N/A	N/A	N/A	N/A

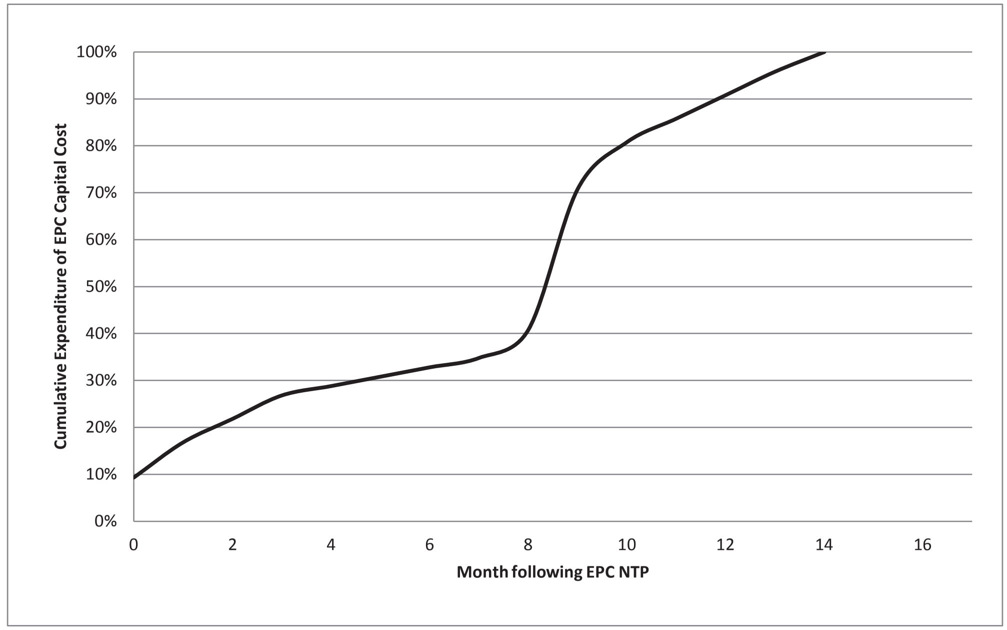
Appendix B. SSO Expenditure Patterns

Expenditure Pattern for EPC Capital Cost

Supply Side Option: 100 MW & 300 MW Wind Farms

Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%) (1)
		0	0.0%	9.3%
1	1	1	7.5%	16.8%
1	2	2	5.0%	21.8%
1	3	3	5.0%	26.8%
1	4	4	2.0%	28.8%
1	5	5	2.0%	30.8%
1	6	6	2.0%	32.8%
1	7	7	2.0%	34.8%
1	8	8	6.0%	40.8%
1	9	9	30.0%	70.8%
1	10	10	10.0%	80.8%
1	11	11	5.0%	85.8%
1	12	12	5.0%	90.8%
2	1	13	5.0%	95.8%
2	2	14	4.2%	100.0%

(1) Expenditures prior to EPC NTP account for roughly 9% of the total Capitol Costs



COST REPORT

COST AND PERFORMANCE DATA FOR POWER GENERATION TECHNOLOGIES

Prepared for the
National Renewable Energy Laboratory

FEBRUARY 2012

BLACK & VEATCH
Building a world of difference.

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1 Introduction

Black & Veatch contracted with the National Renewable Energy Laboratory (NREL) in 2009 to provide the power generating technology cost and performance estimates that are described in this report. These data were synthesized from various sources in late 2009 and early 2010 and therefore reflect the environment and thinking at that time or somewhat earlier, and not of the present day.

Many factors drive the cost and price of a given technology. Mature technologies generally have a smaller band of uncertainty around their costs because demand/supply is more stable and technology variations are fewer. For mature plants, the primary uncertainty is associated with the owner-defined scope that is required to implement the technology and with the site-specific variable costs. These are site-specific items (such as labor rates, indoor versus outdoor plant, water supply, access roads, labor camps, permitting and licensing, or lay-down areas) and owner-specific items (such as sales taxes, financing costs, or legal costs). Mature power plant costs are generally expected to follow the overall general inflation rate over the long term.

Over the last ten years, there has been doubling in the nominal cost of all power generation technologies and an even steeper increase in coal and nuclear because the price of commodities such as iron, steel, concrete, copper, nickel, zinc, and aluminum have risen at a rate much greater than general inflation; construction costs peak in 2009 for all types of new power plants. Even the cost of engineers and constructors has increased faster than general inflation has. With the recent economic recession, there has been a decrease in commodity costs; some degree of leveling off is expected as the United States completes economic recovery.

It is not possible to reasonably forecast whether future commodity prices will increase, decrease, or remain the same. Although the costs in 2009 are much higher than earlier in the decade, for modeling purposes, the costs presented here do not anticipate dramatic increases or decreases in basic commodity prices through 2050. Cost trajectories were assumed to be based on technology maturity levels and expected performance improvements due to learning, normal evolutionary development, deployment incentives, etc.

Black & Veatch does not encourage universal use solely of learning curve effects, which give a cost reduction with each doubling in implementation dependent on an assumed deployment policy. Many factors influence rates of deployment and the resulting cost reduction, and in contrast to learning curves, a linear improvement was modeled to the extent possible.

1.1 ASSUMPTIONS

The cost estimates presented in this report are based on the following set of common of assumptions:

1. Unless otherwise noted in the text, costs are presented in 2009 dollars.
2. Unless otherwise noted in the text, the estimates were based on on-site construction in the Midwestern United States.
3. Plants were assumed to be constructed on “greenfield” sites. The sites were assumed to be reasonably level and clear, with no hazardous materials, no standing timber, no wetlands, and no endangered species.
4. Budgetary quotations were not requested for this activity. Values from the Black &Veatch proprietary database of estimate templates were used.
5. The concept screening level cost estimates were developed based on experience and estimating factors. The estimates reflect an overnight, turnkey Engineering Procurement Construction, direct-hire, open/merit shop, contracting philosophy.

6. Demolition of any existing structures was not included in the cost estimates.
7. Site selection was assumed to be such that foundations would require cast-in-place concrete piers at elevations to be determined during detailed design. All excavations were assumed to be "rippable" rock or soils (i.e., no blasting was assumed to be required). Piling was assumed under major equipment.
8. The estimates were based on using granular backfill materials from nearby borrow areas.
9. The design of the HVAC and cooling water systems and freeze protection systems reflected a site location in a relatively cold climate. With the exception of geothermal and solar, the plants were designed as indoor plants.
10. The sites were assumed to have sufficient area available to accommodate construction activities including but not limited to construction offices, warehouses, lay-down and staging areas, field fabrication areas, and concrete batch plant facilities, if required.
11. Procurements were assumed to not be constrained by any owner sourcing restrictions, i.e., global sourcing. Manufacturers' standard products were assumed to be used to the greatest extent possible.
12. Gas plants were assumed to be single fuel only. Natural gas was assumed to be available at the plant fence at the required pressure and volume as a pipeline connection. Coal plants were fueled with a Midwestern bituminous coal.
13. Water was assumed to be available at the plant fence with a pipeline connection.
14. The estimates included an administration/control building.
15. The estimates were based on 2009 costs; therefore, escalation was not included.
16. Direct estimated costs included the purchase of major equipment, balance-of-plant (BOP) equipment and materials, erection labor, and all contractor services for "furnish and erect" subcontract items.
17. Spare parts for start-up and commissioning were included in the owner's costs.
18. Construction person-hours were based on a 50-hour workweek using merit/open shop craftspersons.
19. The composite crew labor rate was for the Midwestern states. Rates included payroll and payroll taxes and benefits.
20. Project management, engineering, procurement, quality control, and related services were included in the engineering services.
21. Field construction management services included field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control. Also included was technical direction and management of start-up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services.
22. Engineering, procurement, and construction (EPC) contractor contingency and profit allowances were included with the installation costs.
23. Construction management cost estimates were based on a percentage of craft labor person-hours. Construction utilities and start-up utilities such as water, power, and fuel were to be provided by the owner. On-site construction distribution infrastructures for these utilities were included in the estimate.
24. Owner's costs were included as a separate line item.
25. Operational spare parts were included as an owner's cost.
26. Project insurances, including "Builders All-Risk" insurance, were included in the estimates as an owner's cost.
27. Construction permits were assumed to be owner's costs.

28. The estimates included any property, sales or use taxes, gross receipt tax, import or export duties, excise or local taxes, license fees, value added tax, or other similar taxes in the owner's costs.
29. Costs to upgrade roads, bridges, railroads, and other infrastructure outside the site boundary, for equipment transportation to the facility site, were included in the owner's costs.
30. Costs of land, and all right-of-way access, were provided in the owner's Costs.
31. All permitting and licensing were included in the owner's costs.
32. All costs were based on scope ending at the step-up transformer. The electric switchyard, transmission tap-line, and interconnection were excluded.
33. Similarly, the interest during construction (IDC) was excluded.
34. Other owner's costs were included.

In some cases, a blended average technology configuration was used as the proxy for a range of possible technologies in a given category. For example, a number of concentrating solar power technologies may be commercialized over the next 40 years. Black & Veatch used trough technology for the early trajectory and tower technology for the later part of the trajectory. The costs were meant to represent the expected cost of a range of possible technology solutions. Similarly, many marine hydrokinetic options may be commercialized over the next 40 years. No single technology offering is modeled.

For technologies such as enhanced geothermal, deep offshore wind, or marine hydrokinetic where the technology has not been fully demonstrated and commercialized, estimates were based on Nth plant costs. The date of first implementation was assumed to be after at least three full-scale plants have successfully operated for 3–5 years. The first Nth plants were therefore modeled at a future time beyond 2010. For these new and currently non-commercial technologies, demonstration plant cost premiums and early financial premiums were excluded. In particular, although costs are in 2009 dollars, several technologies are not currently in construction and could not be online in 2010.

The cost data presented in this report provide a future trajectory predicted primarily from historical pricing data as influenced by existing levels of government and private research, development, demonstration, and deployment incentives.

Black & Veatch estimated costs for fully demonstrated technologies were based on experience obtained in EPC projects, engineering studies, owner's engineer and due diligence work, and evaluation of power purchase agreement (PPA) pricing. Costs for other technologies or advanced versions of demonstrated technologies were based on engineering studies and other published sources. A more complete discussion of the cost estimating data and methodologies follows.

1.2 ESTIMATION OF DATA AND METHODOLOGY

The best estimates available to Black & Veatch were EPC estimates from projects for which Black & Veatch performed construction or construction management services. Second best were projects for which Black & Veatch was the owner's engineer for the project owner. These estimates provided an understanding of the detailed direct and indirect costs for equipment, materials and labor, and the relationship between each of these costs at a level of detail requiring little contingency. These detailed construction estimates also allowed an understanding of the owner's costs and their impact on the overall estimate. Black & Veatch tracks the detailed estimates and often uses these to perform studies and develop estimates for projects defined at lower levels of detail. Black & Veatch is able to stay current with market conditions through due diligence work it does for financial institutions and others and when it reviews energy prices for new PPAs. Finally, Black & Veatch also prepares proposals for projects of a similar nature. Current market insight is used to adjust detailed estimates as required to keep them up-to-date. Thus, it is an important part of the company's business model to stay current with costs for all types of projects. Project costs for site-specific engineering studies and for more generic engineering studies are frequently adjusted by adding, or subtracting, specific scope items associated with a particular site location. Thus, Black & Veatch has an understanding of the range of costs that might be expected for particular technology applications. (See Text Box 1 for a discussion of cost uncertainty bands.)

Black & Veatch is able to augment its data and to interpret it using published third-party sources; Black & Veatch is also able to understand published sources and apply judgment in interpreting third-party cost reports and estimates in order to understand the marketplace. Reported costs often differ from Black & Veatch's experience, but Black & Veatch is able to infer possible reasons depending upon the source and detail of the cost data. Black & Veatch also uses its cost data and understanding of that data to prepare models and tools.

Though future technology costs are highly uncertain, the experiences and expertise described above enable Black & Veatch to make reasonable cost and performance projections for a wide array of generation technologies. Though technology costs can vary regionally, cost data presented in this report are in strong agreement with other technology cost estimates (FERC 2008, Kelton et al. 2009, Lazard 2009). This report describes the projected cost data and performance data for electric generation technologies.

Text Box 1. Why Estimates Are Not Single Points

In a recent utility solicitation for (engineering, procurement and construction) EPC and power purchase agreement (PPA) bids for the same wind project at a specific site, the bids varied by 60%. More typically, when bidders propose on the exact scope at the same location for the same client, their bids vary by on the order of 10% or more. Why does this variability occur and what does it mean? Different bidders make different assumptions, they often obtain bids from multiple equipment suppliers, different construction contractors, they have different overheads, different profit requirements and they have better or worse capabilities to estimate and perform the work. These factors can all show up as a range of bids to accomplish the same scope for the same client in the same location.

Proposing for different clients generally results in increased variability. Utilities, Private Power Producers, State or Federal entities, all can have different requirements that impact costs. Sparing requirements, assumptions used for economic tradeoffs, a client's sales tax status, or financial and economic assumptions, equipment warranty requirements, or plant performance guarantees inform bid costs. Bidders' contracting philosophy can also introduce variability. Some will contract lump sum fixed price and some will contract using cost plus. Some will use many contractors and consultants; some will want a single source. Some manage with in-house resources and account for those resources; some use all external resources. This variation alone can impact costs still another 10% or more because it impacts the visibility of costs, the allocation of risks and profit margins, and the extent to which profits might occur at several different places in the project structure.

Change the site and variability increases still further. Different locations can have differing requirements for use of union or non-union labor. Overall productivity and labor cost vary in different regions. Sales tax rates vary, local market conditions vary, and even profit margins and perceived risk can vary.

Site-specific scope is also an issue. Access roads, laydown areas,[1] transportation distances to the site and availability of utilities, indoor vs. outdoor buildings, ambient temperatures and many other site-specific issues can affect scope and specific equipment needs and choices.

Owners will also have specific needs and their costs will vary for a cost category referred to as Owner's costs. The Electric Power Research Institute (EPRI) standard owner's costs include 1) paid-up royalty allowance, 2) preproduction costs, 3) inventory capital and 4) land costs. However, this total construction cost or total capital requirement by EPRI does not include many of the other owner's costs that a contractor like Black & Veatch would include in project cost comparisons. These additional elements include the following:

- **Spare parts and plant equipment** includes materials, supplies and parts, machine shop equipment, rolling stock, plant furnishings and supplies.
- **Utility interconnections** include natural gas service, gas system upgrades, electrical transmission, substation/switchyard, wastewater and supply water or wells and railroad.
- **Project development** includes fuel-related project management and engineering, site selection, preliminary engineering, land and rezoning, rights of way for pipelines, laydown yard, access roads, demolition, environmental permitting and offsets, public relations, community development, site development legal assistance, man-camp, heliport, barge unloading facility, airstrip and diesel fuel storage.
- **Owner's project management** includes bid document preparation, owner's project management, engineering due diligence and owner's site construction management.

[1] A laydown yard or area is an area where equipment to be installed is temporarily stored.

- **Taxes/ins/advisory fees/legal** includes sales/use and property tax, market and environmental consultants and rating agencies, owner's legal expenses, PPA, interconnect agreements, contract-procurement and construction, property transfer/title/escrow and construction all risk insurance.

- **Financing** includes financial advisor, market analyst and engineer, loan administration and commitment fees and debt service reserve fund.

- **Plant startup/construction support** includes owner's site mobilization, operation and maintenance (O&M) staff training and pre-commercial operation, start-up, initial test fluids, initial inventory of chemical and reagents, major consumables and cost of fuel not covered recovered in power sales.

Some overlap can be seen in the categories above, which is another contributor to variability - different estimators prepare estimates using different formats and methodologies.

Another form of variability that exists in estimates concerns the use of different classes of estimate and associated types of contingency. There are industry guidelines for different classes of estimate that provide levels of contingency to be applied for the particular class. A final estimate suitable for bidding would have lots of detail identified and would include a 5 to 10% project contingency. A complete process design might have less detail defined and include a 10 to 15% contingency. The lowest level of conceptual estimate might be based on a total plant performance estimate with some site-specific conditions and it might include a 20 to 30% contingency. Contingency is meant to cover both items not estimated and errors in the estimate as well as variability dealing with site-specific differences.

Given all these sources of variability, contractors normally speak in terms of cost ranges and not specific values. Modelers, on the other hand, often find it easier to deal with single point estimates. While modelers often conveniently think of one price, competition can result in many price/cost options. It is not possible to estimate costs with as much precision as many think it is possible to do; further, the idea of a national average cost that can be applied universally is actually problematic. One can calculate a historical national average cost for anything, but predicting a future national average cost with some certainty for a developing technology and geographically diverse markets that are evolving is far from straightforward.

Implications

Because cost estimates reflect these sources of variability, they are best thought of as ranges that reflect the variability as well as other uncertainties. When the cost estimate ranges for two technologies overlap, either technology could be the most cost effective solution for any given specific owner and site. Of course, capital costs may not reflect the entire value proposition of a technology, and other cost components, like O&M or fuel costs with their own sources of variability and uncertainty, might be necessary to include in a cost analysis.

For models, we often simplify calculations by using points instead of ranges that reflect variability and uncertainty, so that we can more easily address other important complexities such as the cost of transmission or system integration. However, we must remember that when actual decisions are made, decision makers will include implicit or explicit consideration of capital cost uncertainty when assessing technology trade-offs. This is why two adjacent utilities with seemingly similar needs may procure two completely different technology solutions. Economic optimization models generally cannot be relied on as the final basis for site-specific decisions. One of the reasons is estimate uncertainty. A relatively minor change in cost can result in a change in technology selection. Because of unknowns at particular site and customer specific situations, it is unlikely that all customers would switch to a specific technology solution at the same time. Therefore, modelers should ensure that model algorithms or input criteria do not allow major shifts in technology choice for small differences in technology cost. In addition, generic estimates should not be used in site- specific user-specific analyses.

2 Cost Estimates and Performance Data for Conventional Electricity Technologies

This section includes description and tabular data on the cost and performance projections for "conventional" non-renewable technologies, which include fossil technologies (natural gas combustion turbine, natural gas combined-cycle, and pulverized coal) with and without carbon capture and storage, and nuclear technologies. In addition, costs for flue gas desulfurization2 (FGD) retrofits are also described.

2.1 NUCLEAR POWER TECHNOLOGY

Black & Veatch's nuclear experience spans the full range of nuclear engineering services, including EPC, modification services, design and consulting services and research support. Black & Veatch is currently working under service agreement arrangements with MHI for both generic and plant specific designs of the United States Advanced Pressurized Water Reactor (US-APWR). Black & Veatch historical data and recent market data were used to make adjustments to study estimates to include owner's costs. The nuclear plant proxy was based on a commercial Westinghouse AP1000 reactor design producing 1,125 net MW. The capital cost in 2010 was estimated at 6,100$/kW +30%. We anticipate that advanced designs could be commercialized in the United States under government-sponsored programs. While we do not anticipate cost savings associated with these advanced designs, we assumed a cost reduction of 10% for potential improved metallurgy for piping and vessels. Table 1 presents cost and performance data for nuclear power. Figure 1 shows the 2010 cost breakdown for a nuclear power plant.

[2] Flue gas desulfurization (FGD) technology is also referred to as SO_2 scrubber technology.

Table 1. Cost and Performance Projection for a Nuclear Power Plant (1125 MW)

Year	Capital Cost ($/kW)	Fixed O&M[a] ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR[b] (%)	FOR[c] (%)	Min. Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	6,230	–	–	–	–	–	–	5.00	5.00
2010	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2015	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2020	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2025	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2030	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2035	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2040	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2045	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2050	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00

[a] O&M = operation and maintenance
[b] POR = planned outage rate
[c] FOR = forced outage rate

All costs in 2009$

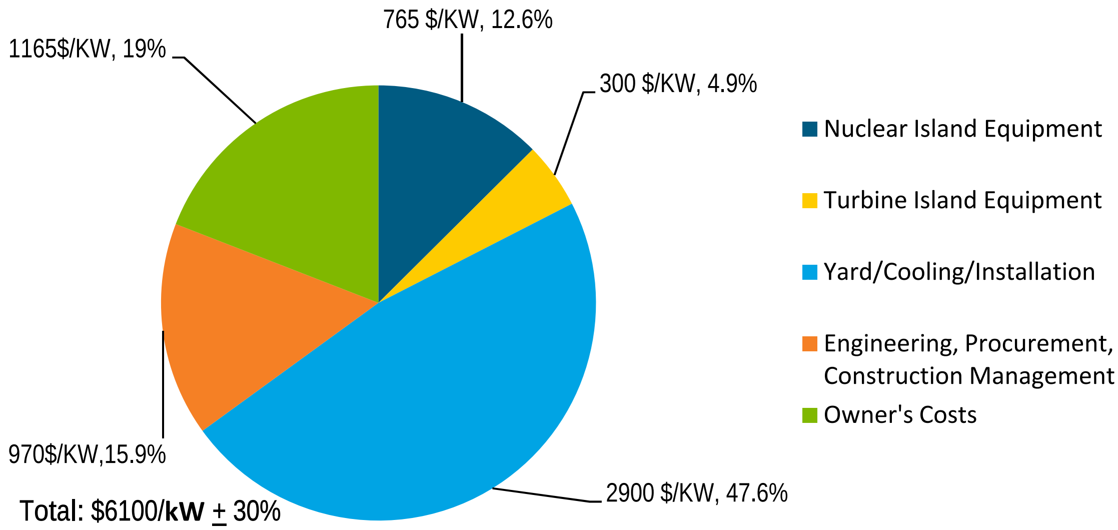

Figure 1. Capital cost breakdown for a nuclear power plant

The total plant labor and installation is included in the Yard/Cooling/ Installation cost element. The power plant is assumed to be a single unit with no provision for future additions. Switchyard, interconnection and interest during construction are not included. Owner's costs are defined in Text Box 1 above.

2.2 COMBUSTION TURBINE TECHNOLOGY

Natural gas combustion turbine costs were based on a typical industrial heavy-duty gas turbine, GE Frame 7FA or equivalent of the 211-net-MW size. The estimate did not include the cost of selective catalytic reduction (SCR)/carbon monoxide (CO) reactor for NOx and CO reduction. The combustion turbine generator was assumed to include a dry, low NOx combustion system capable of realizing 9 parts per million by volume, dry (ppmvd) @ 15% O2 at full load. A 2010 capital cost was estimated at 651 $/kW ±25%. Cost uncertainty for this technology is low. Although it is possible that advanced configurations will be developed over the next 40 years, the economic incentive for new development has not been apparent in the last few decades (Shelley 2008). Cost estimates did not include any cost or performance improvements through 2050. Table 2 presents cost and performance data for gas turbine technology. Table 3 presents emission rates for the technology. Figure 2 shows the 2010 capital cost breakdown by component for a natural gas combustion turbine plant.

Table 2. Cost and Performance Projection for a Gas Turbine Power Plant (211 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min. Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	671	–	–	–	–	–	–	–	–	–
2010	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2015	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2020	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2025	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2030	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2035	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2040	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2045	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2050	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20

Table 3. Emission Rates for a Gas Turbine Power Plant

SO_2 (Lb/mmbtu)	NOx (Lb/mmbtu)	PM10 (Lb/mmbtu)	CO_2 (Lb/mmbtu)
0.0002	0.033	0.006	117

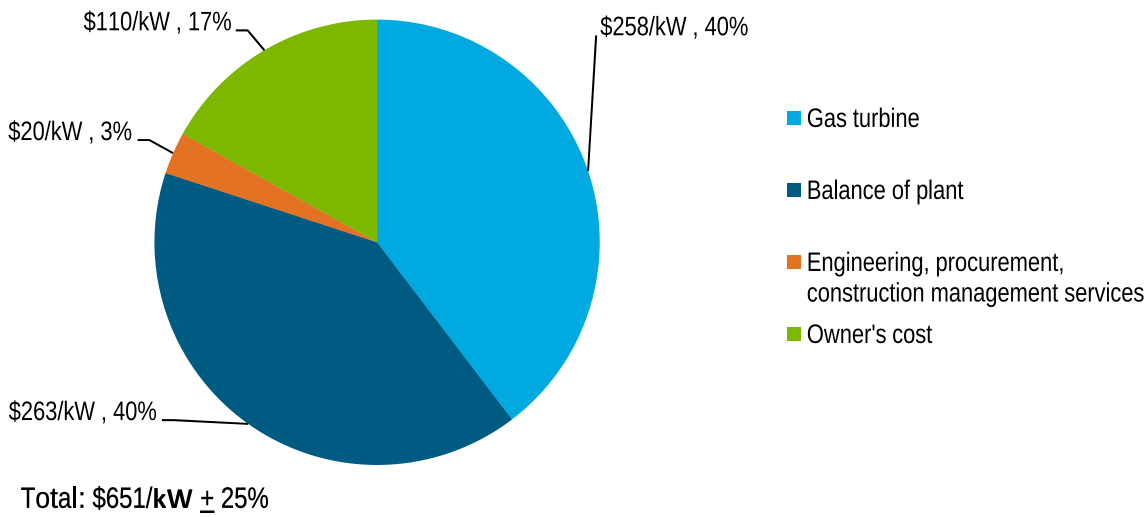

Figure 2. Capital cost breakdown for a gas turbine power plant

2.3 COMBINED-CYCLE TECHNOLOGY

Natural gas combined-cycle (CC) technology was represented by a 615- MW plant. Costs were based on two GE 7FA combustion turbines or equivalent, two heat recovery steam generators (HRSGs), a single reheat steam turbine and a wet mechanical draft cooling tower. The cost included a SCR/CO reactor housed within the HRSGs for NOx and CO reduction. The combustion turbine generator was assumed to include dry low NOx combustion system capable of realizing 9 ppmvd @ 15% O_2 at full load.

2010 capital cost was estimated to be 1,230 $/kW +25%. Cost uncertainty for CC technology is low. Although it is possible that advanced configurations for CC components will be developed over the next 40 years, the economic incentive for new development has not been apparent in the last few decades. The cost estimates did not include any cost reduction through 2050. Table 4 presents cost and performance data for combined-cycle technology. Table 5 presents emission data for the technology. The 2010 capital cost breakdown for the combined-cycle power plant is shown in Figure 3.

Table 4. Cost and Performance Projection for a Combined-Cycle Power Plant (580 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min. Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	1250	–	–	–	–	–	–	–	–	–
2010	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2015	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2020	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2025	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2030	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2035	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2040	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2045	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2050	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50

Table 5. Emission Rates for a Combined-Cycle Power Plant

SO_2 (Lb/mmbtu)	NO_X (LB/mmbtu)	PM10 (Lb/mmbtu)	CO_2 (Lb/mmbtu)
0.0002	0.0073	0.0058	117

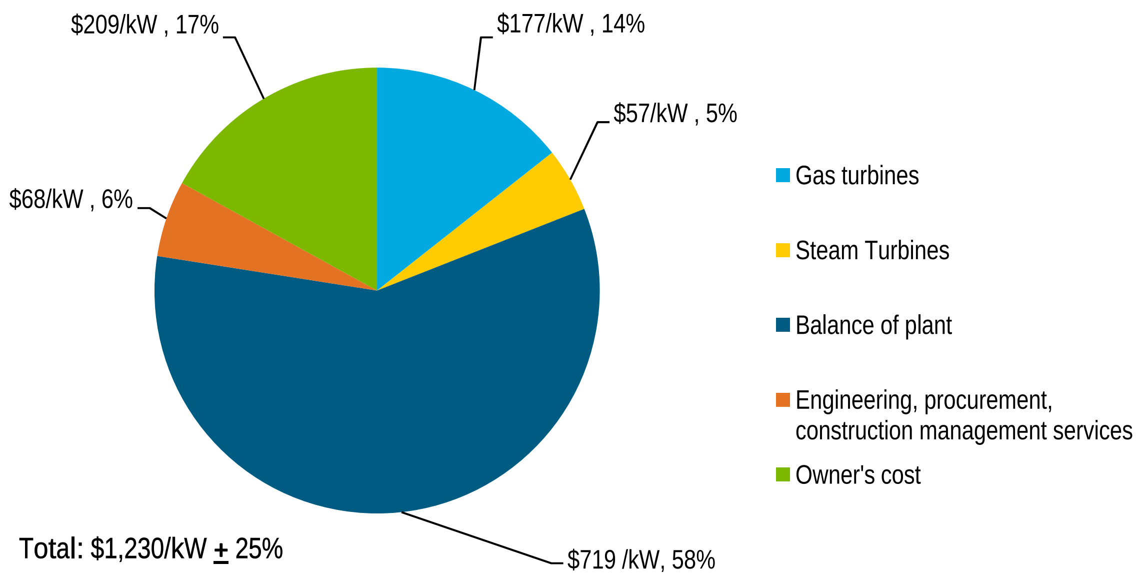

Figure 3. Capital cost breakdown for a combined-cycle power plant

2.4 COMBINED-CYCLE WITH CARBON CAPTURE AND SEQUESTRATION

Carbon capture and sequestration (CCS) was added to the above CC. Black & Veatch has no EPC estimates for CCS since it is not commercial at this time. However, Black & Veatch has participated in engineering and cost studies of CCS and has some understanding of the range of expected costs for CO2 storage in different geologic conditions. The CC costs were based on two combustion turbines, a single steam turbine and wet cooling tower producing 580 net MW after taking into consideration CCS. This is the same combined cycle described above but with CCS added to achieve 85% capture. CCS is assumed to be commercially available after 2020. 2020 capital cost was estimated at 3,750$/kW +35%. Cost uncertainty is higher than for the CC without CCS due to the uncertainty associated with the CCS system. Although it is possible that advanced CC configurations will be developed over the next 40 years, the economic incentive for new gas turbine CC development has not been apparent in the last decade. Further, while cost improvements in CCS may be developed over time, it is expected that geologic conditions will become more difficult as initial easier sites are used. The cost of perpetual storage insurance was not estimated or included. Table 4 presents cost and performance data for combined-cycle with carbon capture and sequestration technology. Table 5 presents emission data for the technology.

Table 6. Cost and Performance Projection for a Combined-Cycle Power Plant (580 MW) with Carbon Capture and Sequestration

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Const. Schedule (Months)	POR (%)	FOR (%)	Min Load (%	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	3860	–	–	–	–	–	–	–	–	–
2010	–	–	–	–	–	–	–	–	–	–
2015	–	–	–	–	–	–	–	–	–	–
2020	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2025	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2030	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2035	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2040	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2045	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2050	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50

Table 7. Emission Rates for a Combined-Cycle Power Plant with Carbon Capture and Sequestration

SO_2 (Lb/mmbtu)	NOx (LB/mmbtu)	PM10 (Lb/mmbtu)	CO_2 (Lb/mmbtu)
0.0002	0.0073	0.0058	18

2.5 PULVERIZED COAL-FIRED POWER GENERATION

Pulverized coal-fired power plant costs were based on a single reheat, condensing, tandem-compound, four-flow steam turbine generator set, a single reheat supercritical steam generator and wet mechanical draft cooling tower, a SCR, and air quality control equipment for particulate and SO2 control, all designed as typical of recent U.S. installations. The estimate included the cost of a SCR reactor. The steam generator was assumed to include low NOx burners and other features to control NOx. Net output was approximately 606 MW.

2010 capital cost was estimated at 2,890 $/kW +35%. Cost certainty for this technology is relatively high. Over the 40-year analysis period, a 4% improvement in heat rate was assumed. Table 8 presents cost and performance data for pulverized coal-fired technology.

Table 9 presents emissions rates for the technology. The 2010 capital cost breakdown for the pulverized coal-fired power plant is shown in Figure 4.

Table 8. Cost and Performance Projection for a Pulverized Coal-Fired Power Plant (606 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min Load (%)	Spin Ramp Rate (%/min)
2008	3040	–	–	–	–	–	–	–	–
2010	2890	3.71	23.0	9,370	55	10	6	40	2.00
2015	2890	3.71	23.0	9,370	55	10	6	40	2.00
2020	2890	3.71	23.0	9,370	55	10	6	40	2.00
2025	2890	3.71	23.0	9,000	55	10	6	40	2.00
2030	2890	3.71	23.0	9,000	55	10	6	40	2.00
2035	2890	3.71	23.0	9,000	55	10	6	40	2.00
2040	2890	3.71	23.0	9,000	55	10	6	40	2.00
2045	2890	3.71	23.0	9,000	55	10	6	40	2.00
2050	2890	3.71	23.0	9,000	55	10	6	40	2.00

Table 9. Emission Rates for a Pulverized Coal-Fired Power Plant

SO_2 (Lb/mmbtu)	NO_x (Lb/mmbtu)	PM10 (Lb/mmbtu)	Hg (% removal)	CO_2 (Lb/mmbtu)
0.055	0.05	0.011	90	215

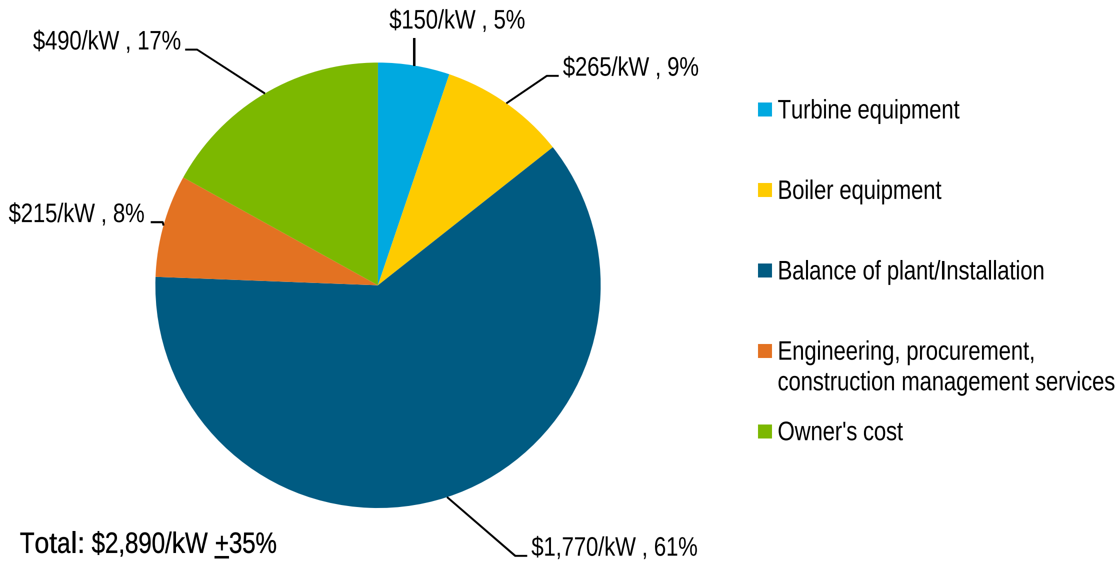

Figure 4. Capital cost breakdown for a pulverized coal-fired power plant

2.6 PULVERIZED COAL-FIRED POWER GENERATION WITH CARBON CAPTURE AND SEQUESTRATION

Black & Veatch is a leading designer of electric generating stations and the foremost designer and constructor of coal-fueled power generation plants worldwide. Black & Veatch's coal-fueled generating station experience includes 10,000 MW of supercritical pulverized coal-fired power plant projects.

The pulverized coal-fired power plant costs were based on a supercritical steam cycle and wet cooling tower design typical of recent U.S. installations, the same plant described above but with CCS. Net output was approximately 455 MW. CCS would be based on 85% CO2 removal. CCS was assumed to be commercially available after 2020. 2020 capital cost was estimated at 6,560$/kW -45% and +35%. Cost uncertainty is higher than for the pulverized coal-fired plant only due to the uncertainty associated with the CCS.

We assumed a 4% improvement in heat rate to account for technology potential already existing but not frequently used in the United States. The cost of perpetual storage insurance was not estimated or included. Table 8 presents cost and performance data for pulverized coal-fired with carbon capture and sequestration technology.

Table 911 presents emissions rates for the technology.

Table 10. Cost and Performance Projection for a Pulverized Coal-Fired Power Plant (455 MW) with Carbon Capture and Sequestration

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min Load (%)	Spin Ramp Rate (%/min)
2008	6890	–	–	–	–	–	–	–	–
2010	–	–	–	–	–	–	–	–	2.00
2015	–	–	–	–	–	–	–	–	2.00
2020	6560	6.02	35.2	12,600	66	10	6	40	2.00
2025	5640	6.02	35.2	12,100	66	10	6	40	2.00
2030	5640	6.02	35.2	12,100	66	10	6	40	2.00
2035	5640	6.02	35.2	12,100	66	10	6	40	2.00
2040	5640	6.02	35.2	12,100	66	10	6	40	2.00
2045	5640	6.02	35.2	12,100	66	10	6	40	2.00
2050	5640	6.02	35.2	12,100	66	10	6	40	2.00

Table 11. Emission Rates for a Pulverized Coal-Fired Power Plant with Carbon Capture and Sequestration

SO_2 (Lb/mmbtu)	NO_x (Lb/mmbtu)	PM10 (Lb/mmbtu)	Hg (% removal)	CO_2 (Lb/mmbtu)
0.055	0.05	0.011	90	32

2.7 GASIFICATION COMBINED-CYCLE TECHNOLOGY

Black & Veatch is a leading designer of electric generating stations and the foremost designer and constructor of coal-fueled power generation plants worldwide. Black & Veatch's coal-fueled generating station experience includes integrated gasification combined-cycle technologies. Black & Veatch has designed, performed feasibility studies, and performed independent project assessments for numerous gasification and gasification combined-cycle (GCC) projects using various gasification technologies. Black & Veatch historical data were used to make adjustments to study estimates to include owner's costs. Special care was taken to adjust to 2009 dollars based on market experience. The GCC estimate was based on a commercial gasification process integrated with a conventional combined cycle and wet cooling tower producing 590 net MW. 2010 capital cost was estimated at 4,010$/kW-+35%.. Cost certainty for this technology is relatively high. We assumed a 12% improvement in heat rate by 2025. Table 812 presents cost and performance data for gasification combined-cycle technology.

Table 913 presents emissions rates for the technology. The Black & Veatch GCC estimate is consistent with the FERC estimate range.

Table 12. Cost and Performance Projection for an Integrated Gasification Combined-Cycle Power Plant (590 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	4210	–	–	–	–	–	–	–	–	–
2010	4010	6.54	31.1	9,030	57	12	8	50	5	2.50
2015	4010	6.54	31.1	9,030	57	12	8	50	5	2.50
2020	4010	6.54	31.1	9,030	57	12	8	50	5	2.50
2025	4010	6.54	31.1	7,950	57	12	8	50	5	2.50
2030	4010	6.54	31.1	7,950	57	12	8	50	5	2.50
2035	4010	6.54	31.1	7,950	57	12	8	50	5	2.50
2040	4010	6.54	31.1	7,950	57	12	8	50	5	2.50
2045	4010	6.54	31.1	7,950	57	12	8	50	5	2.50
2050	4010	6.54	31.1	7,950	57	12	8	50	5	2.50

Table 13. Emission Rates for an Integrated Gasification Combined-Cycle Power Plant

SO_2 (Lb/mmbtu)	NO_x (Lb/mmbtu)	PM10 (Lb/mmbtu)	Mercury (% Removal)	CO_2 (Lb/mmbtu)
0.065	0.085	0.009	90	215

2.8 GASIFICATION COMBINED-CYCLE TECHNOLOGY WITH CARBON CAPTURE AND SEQUESTRATION

Black & Veatch is a leading designer of electric generating stations and the foremost designer and constructor of coal-fueled power generation plants worldwide. Black & Veatch's coal-fueled generating station experience includes integrated gasification combined-cycle technologies. Black & Veatch has designed, performed feasibility studies, and performed independent project assessments for numerous gasification and IGCC projects using various gasification technologies. Black & Veatch historical data were used to make adjustments to study estimates to include owner's costs. The GCC was based on a commercial gasification process integrated with a conventional CC and wet cooling tower, the same plant as described above but with CCS. Net capacity was 520 MW. Carbon capture, sequestration, and storage were based on 85% carbon removal. Carbon capture and storage is assumed to be commercially available after 2020. 2020 capital cost was estimated at 6,600 $/kW +35%. The cost of perpetual storage insurance was not estimated or included. Table 814 presents cost and performance data for gasification combined-cycle technology integrated with carbon capture and sequestration.

Table 915 presents emissions rates for the technology.

Table 14. Cost and Performance Projection for an Integrated Gasification Combined-Cycle Power Plant (520 MW) with Carbon Capture and Sequestration

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/KWh)	Construction Schedule (Months)	FOR (%)	POR (%)	Min Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	6,930	–	–	–	–	–	–	–	5.00	2.50
2010	–	–	–	–	–	–	–	–	5.00	2.50
2015	–	–	–	–	–	–	–	–	–	–
2020	6,600	10.6	44.4	11,800	59	12.0	8.00	50	5.00	2.50
2025	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50
2030	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50
2035	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50
2040	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50
2045	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50
2050	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50

Table 15. Emission Rates for an Integrated Gasification Combined-Cycle Power Plant with Carbon Capture and Sequestration

SO_2 (Lb/mmbtu)	NOx (Lb/mmbtu)	PM10 (Lb/mmbtu)	Hg (% Removal)	CO_2 (Lb/mmbtu)
0.065	0.085	0.009	90%	32

2.9 FLUE GAS DESULFURIZATION RETROFIT TECHNOLOGY

Flue gas desulfurization (FGD) retrofit was assumed to be a commercial design to achieve 95% removal of sulfur dioxide and equipment was added to meet current mercury and particulate standards. A wet limestone FGD system, a fabric filter, and a powdered activated carbon (PAC) injection system were included. It is also assumed that the existing stack was not designed for a wet FGD system; therefore, a new stack was included. Black & Veatch estimated retrofit capital cost in 2010 to be 360 $/kW +25% with no cost reduction assumed through 2050. Table 16 presents costs and a construction schedule for flue gas desulfurization retrofit technology.

Table 16. Cost and Schedule for a Power Plant (606 MW) with Flue Gas Desulfurization Retrofit Technology

Year	Retrofit Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)
2008	371	–	–	–
2010	360	3.71	23.2	36
2015	360	3.71	23.2	36
2020	360	3.71	23.2	36
2025	360	3.71	23.2	36
2030	360	3.71	23.2	36
2035	360	3.71	23.2	36
2040	360	3.71	23.2	36
2045	360	3.71	23.2	36
2050	360	3.71	23.2	36

Text Box 2. Cycling Considerations

- Cycling increases failures and maintenance cost.
- Power plants of the future will need increased flexibility and increased efficiency; these qualities run counter to each other.
- Higher temperatures required for increased efficiency mean slower ramp rates and less ability to operate off-design. Similarly, environmental features such as bag houses, SCR, gas turbine NOx control, FGD, and carbon capture make it more difficult to operate at off-design conditions.
- Early less-efficient power plants without modern environmental emissions controls probably have more ability to cycle than newer more highly-tuned designs.
- Peak temperature and rate of change of temperature are key limitations for cycling. Water chemistry is an issue.
- The number of discrete pulverizers is a limitation for pulverized coal power plants and the number of modules in add-on systems that must be integrated to achieve environmental control is a limitation.

<u>The ramp rate for coal plants is not linear as it is a function of bringing pulverizers on line as load increases.</u> A 600-MW pulverized coal-fired unit (e.g., Powder River Basin) can have six pulverizers. Assuming an N+1 sparing philosophy, five pulverizers are required for full load so each pulverizer can provide fuel for about 20% of full load.

From minimum stable load at about 40% to full load, it is the judgment of Black & Veatch, based on actual experience in coal plant operations, that the ramp rate will be 5 MW/minute at high loads. This is about 1%/minute for a unit when at 500 MW.

<u>The ramp rate for a combined-cycle plant is a combination of combustion turbine ramp rate and steam turbine ramp rate.</u> The conventional warm start will take about 76 minutes from start initiation to full load on the combined cycle. The combined ramp rate from minute 62 to minute 76 is shown by GE to be about 5%/minute for a warm conventional start-up.

GE shows that the total duration of a "rapid response" combined-cycle start-up assuming a combustion turbine fast start is 54 minutes as compared to a conventional start duration of 76 minutes for a warm start. The ramp rate is shown by GE to be slower during a rapid start-up. The overall duration is shorter but the high load combined ramp rate is 2.5%.

After the unit has been online and up to temperature, we would expect the ramp rate to be 5%.

3 Cost Estimates and Performance Data for Renewable Electricity Technologies

This section includes cost and performance data for renewable energy technologies, including biopower (biomass cofiring and standalone), geothermal (hydrothermal and enhanced geothermal systems), hydropower, ocean energy technologies (wave and tidal), solar energy technologies (photovoltaics and concentrating solar power), and wind energy technologies (onshore and offshore).

3.1 BIOPOWER TECHNOLOGIES

3.1.1 Biomass Cofiring

From initial technology research and project development, through turnkey design and construction, Black & Veatch has worked with project developers, utilities, lenders, and government agencies on biomass projects using more than 40 different biomass fuels throughout the world. Black & Veatch has exceptional tools to evaluate the impacts of biomass cofiring on the existing facility, such as the VISTA™ model, which evaluates impacts to the coal fueled boiler and balance of plant systems due to changes in fuels.

Although the maximum injection of biomass depends on boiler type and the number and types of necessary modifications to the boiler, biomass cofiring was assumed to be limited to a maximum of 15% for all coal plants. For the biomass cofiring retrofit, Black & Veatch estimated 2010 capital costs of 990 $/kW -50% and +25%. Cost uncertainty is significantly impacted by the degree of modifications needed for a particular fuel and boiler combination. Significantly less boiler modification may be necessary in some cases. Black & Veatch did not estimate any cost improvement over time. Table 17 presents cofiring cost and performance data. In the present convention, the capital cost to retrofit a coal plant to cofire biomass is applied to the biomass portion only3. Similarly, O&M costs are applied to the new retrofitted capacity only. Table 17 shows representative heat rates; the performance characteristics of a retrofitted plant were assumed to be the same as that of the previously existing coal plant. Many variations are possible but were not modeled. Table 18 shows the range of costs using various co-firing approaches over a range of co-firing fuel levels varying from 5% to 30%. Emissions control equipment performance limitations may limit the overall range of cofiring possible.

[3] For example, retrofitting a 100 MW coal plant to cofire up to 15% biomass has a cost of 100 MW x 15% x $990,000/MW = $14,850,000.

Table 17. Cost and Performance Projection for Biomass Cofiring Technology

Year	Capital Cost ($/kW)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-Yr)	Heat Rate (Btu/KWh)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	1,020	–	–	–	–	–	–
2010	990	0	20	10,000	12	9	7
2015	990	0	20	10,000	12	9	7
2020	990	0	20	10,000	12	9	7
2025	990	0	20	10,000	12	9	7
2030	990	0	20	10,000	12	9	7
2035	990	0	20	10,000	12	9	7
2040	990	0	20	10,000	12	9	7
2045	990	0	20	10,000	12	9	7
2050	990	0	20	10,000	12	9	7

Table 18. Costs for Co-Firing Methods versus Fuel Amount

Co-firing Level (%)	Fuel Blending ($/kW)	Separate Injection ($/kW)	Gasification ($/kW)
5	1000-1500	1300-1800	2500-3500
10	800-1200	1000-1500	2000-2500
20	600	700-1100	1800-2300
30	–	700-1100	1700-2200

3.1.2 Biomass Standalone

Black & Veatch is recognized as one of the most diverse providers of biomass (solid biomass, biogas, and waste-to-energy) systems and services. From initial technology research and project development, through turnkey design and construction, Black & Veatch has worked with project developers, utilities, lenders, and government agencies on biomass projects using more than 40 different biomass fuels throughout the world. This background was used to develop the cost estimates vetted in the Western Renewable Energy Zone (WREZ) stakeholder process and to subsequently update that pricing and adjust owner's costs.

A standard Rankine cycle with wet mechanical draft cooling tower producing 50 MW net is initially assumed for the standalone biomass generator.4 Black & Veatch assumed the 2010 capital cost to be 3,830 $/kW -25% and +50%. Cost certainty is high for this mature technology, but there are more high cost than low cost outliers due to unique fuels and technology solutions. For modeling purposes, it was assumed that gasification combined-cycle systems displace the direct combustion systems gradually resulting in an average system heat rate that improves by 14% through 2050. However, additional cost is likely required initially to achieve this heat rate improvement and therefore no improvement in cost was assumed for the costs. Table 19 presents cost and performance data for a standalone biomass power plant. The capital cost breakdown for the biomass standalone power plant is shown in Figure 5.

[4] "Standalone" biomass generators are also referred to as "dedicated" plants to distinguish them from co-fired plants.

Table 19. Cost and Performance Projection for a Stand-Alone Biomass Power Plant (50 MW Net)

Year	Capital Cost $/kW	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-Yr)	Heat Rate (Btu/KWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Minimum Load (%)
2008	4,020	–	–	–	–	–	–	–
2010	3,830	15	95	14,500	36	7.6	9	40
2015	3,830	15	95	14,200	36	7.6	9	40
2020	3,830	15	95	14,000	36	7.6	9	40
2025	3,830	15	95	13,800	36	7.6	9	40
2030	3,830	15	95	13,500	36	7.6	9	40
2035	3,830	15	95	13,200	36	7.6	9	40
2040	3,830	15	95	13,000	36	7.6	9	40
2045	3,830	15	95	12,800	36	7.6	9	40
2050	3,830	15	95	12,500	36	7.6	9	40

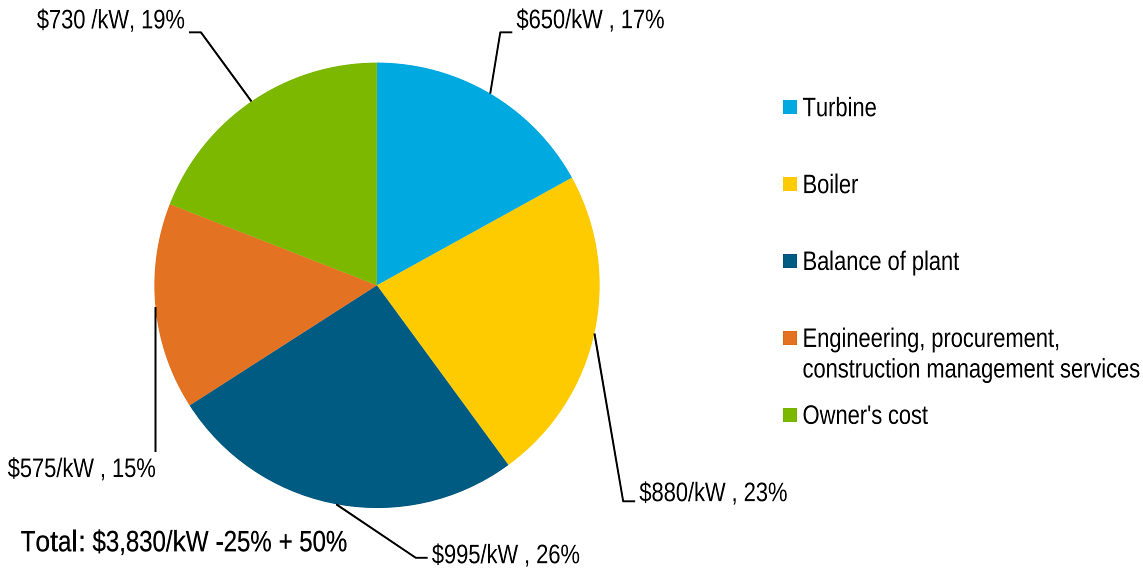

Figure 5. Capital cost breakdown for a standalone biomass power plant

3.2 GEOTHERMAL ENERGY TECHNOLOGIES

Hydrothermal technology is a relatively mature commercial technology for which cost improvement was not assumed. For enhanced geothermal systems (EGS) technology, Black & Veatch estimated future cost improvements based on improvements of geothermal fluid pumps and development of multiple, contiguous EGS units to benefit from economy of scale for EGS field development. The quality of geothermal resources are site- and resource-specific, therefore costs of geothermal resources can vary significantly from region to region. The cost estimates shown in this report are single-value generic estimates and may not be representative of any individual site. Table 20 and Table 21 present cost and performance data for hydrothermal and enhanced geothermal systems, respectively, based on these single-value estimates.

Table 20. Cost and Performance Projection for a Hydrothermal Power Plant

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	6,240	–	–	–	–	–
2010	5,940	31	0	36	2.41	0.75
2015	5,940	31	0	36	2.41	0.75
2020	5,940	31	0	36	2.41	0.75
2025	5,940	31	0	36	2.41	0.75
2030	5,940	31	0	36	2.41	0.75
2035	5,940	31	0	36	2.41	0.75
2040	5,940	31	0	36	2.41	0.75
2045	5,940	31	0	36	2.41	0.75
2050	5,940	31	0	36	2.41	0.75

Table 21. Cost and Performance Projection for an Enhanced Geothermal Systems Power Plant

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	10,400	31	0	36	2.41	0.75
2010	9,900	31	0	36	2.41	0.75
2015	9,720	31	0	36	2.41	0.75
2020	9,625	31	0	36	2.41	0.75
2025	9,438	31	0	36	2.41	0.75
2030	9,250	31	0	36	2.41	0.75
2035	8,970	31	0	36	2.41	0.75
2040	8,786	31	0	36	2.41	0.75
2045	8,600	31	0	36	2.41	0.75
2050	8,420	31	0	36	2.41	0.75

The capital cost breakdown for the hydrothermal geothermal power plant is shown in Figure 6.

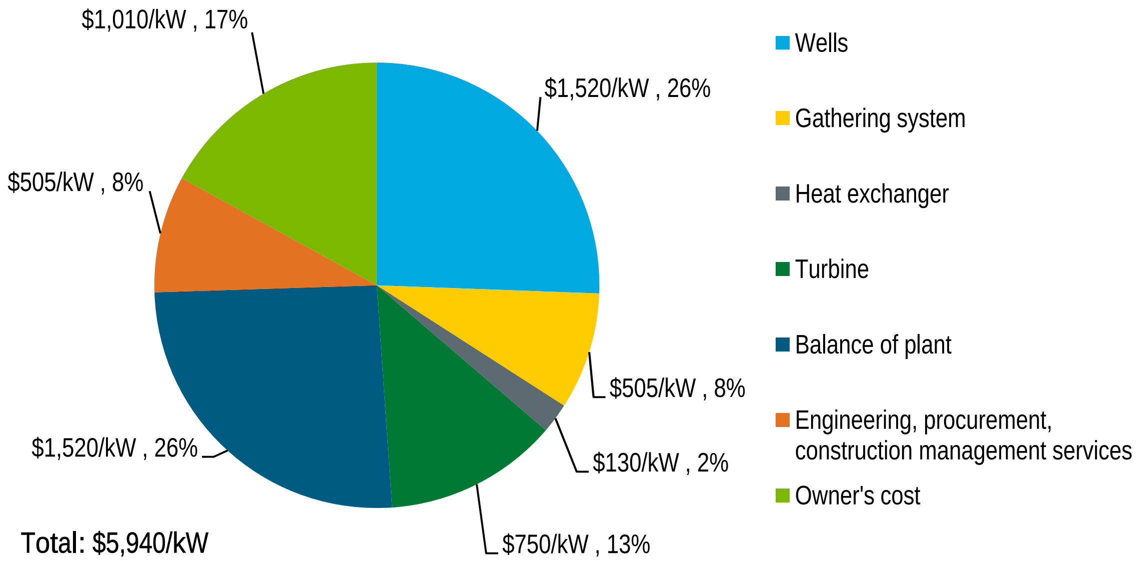

Figure 6. Capital cost breakdown for a hydrothermal geothermal power plant

The capital cost breakdown for the enhanced geothermal system power plant is shown in Figure 7.

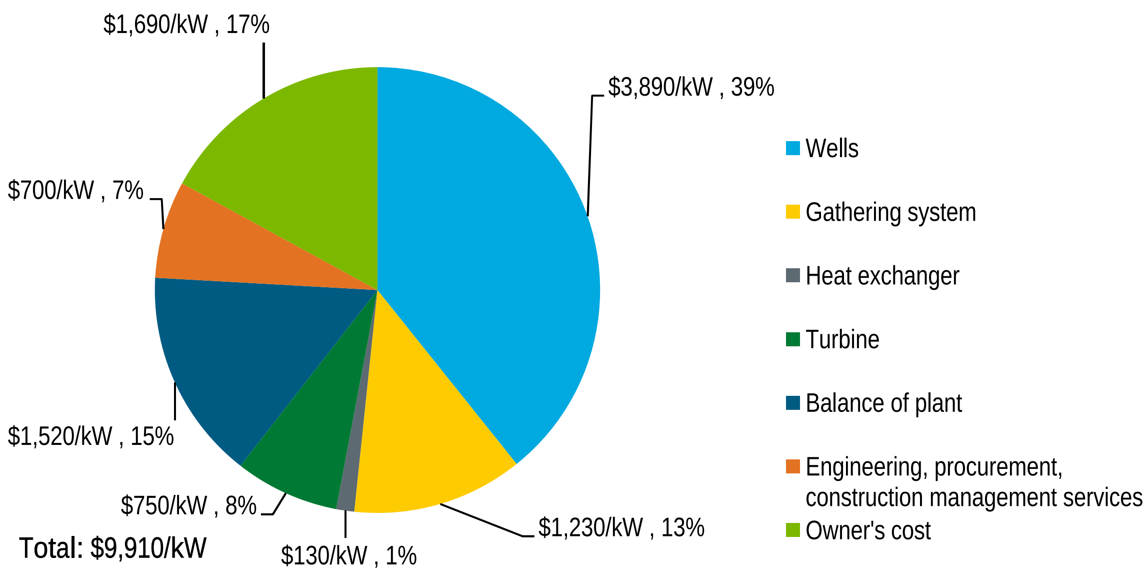

Figure 7. Capital cost breakdown for an enhanced geothermal system power plant

Enhanced geothermal system cost reductions will occur primarily in the wells, turbine, and BOP categories over time.

3.3 HYDROPOWER TECHNOLOGIES

Nearly 500 hydropower projects totaling more than 50,000 MW have been served by Black & Veatch worldwide. The Black & Veatch historical database incorporates a good understanding of hydroelectric costs. Black & Veatch used this historical background to develop the cost estimates vetted in the WREZ (Pletka and Finn 2009) stakeholder process and to subsequently update that pricing and adjust owner's costs as necessary.

Similar to geothermal technologies, the cost of hydropower technologies can be site-specific. Numerous options are available for hydroelectric generation; repowering an existing dam or generator, or installing a new dam or generator, are options. As such, the cost estimates shown in this report are single-value estimates and may not be representative of any individual site. 2010 capital cost for a 500 MW hydropower facility was estimated at 3,500 $/kW +35%. Table 22 presents cost and performance data for hydroelectric power technology.

Table 22. Cost and Performance Data for a Hydroelectric Power Plant (500 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	3,600	–	–	–	–	–
2010	3,500	6	15	24	1.9	5.0
2015	3,500	6	15	24	1.9	5.0
2020	3,500	6	15	24	1.9	5.0
2025	3,500	6	15	24	1.9	5.0
2030	3,500	6	15	24	1.9	5.0
2035	3,500	6	15	24	1.9	5.0
2040	3,500	6	15	24	1.9	5.0
2045	3,500	6	15	24	1.9	5.0
2050	3,500	6	15	24	1.9	5.0

The capital cost breakdown for the hydroelectric power plant is shown in Figure 8.

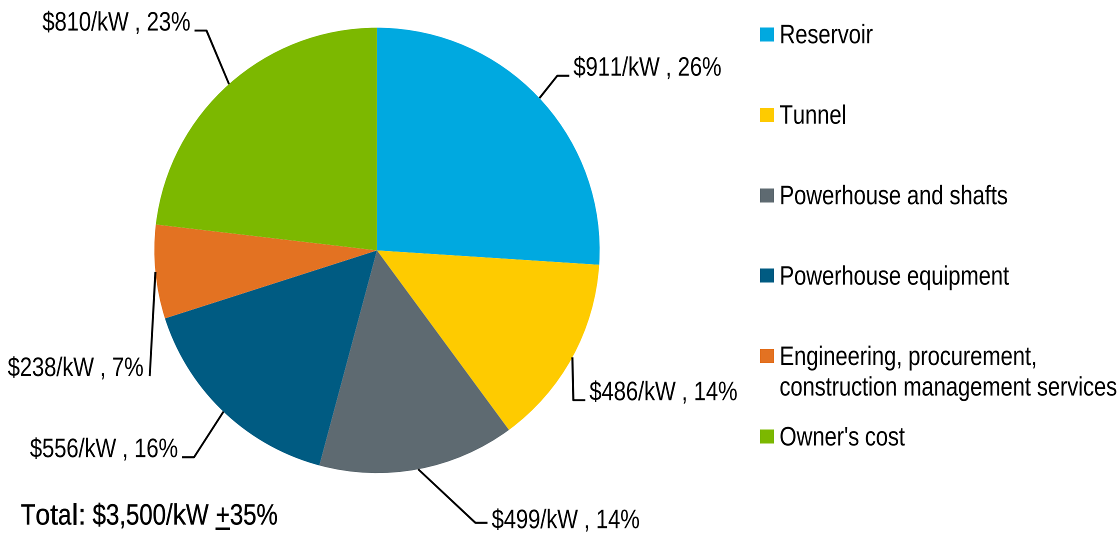

Figure 8. Capital cost breakdown for a hydroelectric power plant

Hydroelectric power plant cost reductions will be primarily in the power block cost category over time.

3.4 OCEAN ENERGY TECHNOLOGIES

Wave and tidal current resource assessment and technology costs were developed based on European demonstration and historical data obtained from studies. A separate assessment of the hydrokinetic resource uncertainty is included in Appendices A and B, informed by a Black & Veatch analysis that includes an updated resource assessment for wave and tidal current technologies and assumptions used to develop technology cost estimates. Wave capital cost in 2015 was estimated at 9,240 $/kW – 30% and +45%. This is an emerging technology with much uncertainty and many options available. A cost improvement of 63% was assumed through 2040 and then a cost increase through 2050reflecting the need to develop lower quality resources. Tidal current technology is similarly immature with many technical options. Capital cost in 2015 was estimated at 5,880 $/kW - 10% and + 20%. A cost improvement of 45% was assumed as the resource estimated to be available is fully utilized by 2030. Estimated O&M costs include insurance, seabed rentals, and other recurring costs that were not included in the one-time capital cost estimate. Wave O&M costs are higher than tidal current costs due to more severe conditions. Table 23 and

Table 24 present cost and performance for wave and tidal current technologies, respectively. The capital cost breakdown for wave and current power plants are shown in Figure 9 and Figure 10, respectively.

Table 23. Cost and Performance Projection for Ocean Wave Technology

Year	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2015	9,240	474	24	1	7
2020	6,960	357	24	1	7
2025	5,700	292	24	1	7
2030	4,730	243	24	1	7
2035	3,950	203	24	1	7
2040	3,420	175	24	1	7
2045	4,000	208	24	1	7
2050	5,330	273	24	1	7

Table 24. Cost and Performance Projection for Ocean Tidal Current Technology

Year	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2015	5,880	198	–	–	–
2020	4,360	147	24	1.0	6.5
2025	3,460	117	24	1.0	6.5
2030	3,230	112	24	1.0	6.5
2035	–	112	24	1.0	6.5
2040	–	112	24	1.0	6.5
2045	–	112	24	1.0	6.5
2050	–	112	24	1.0	6.5

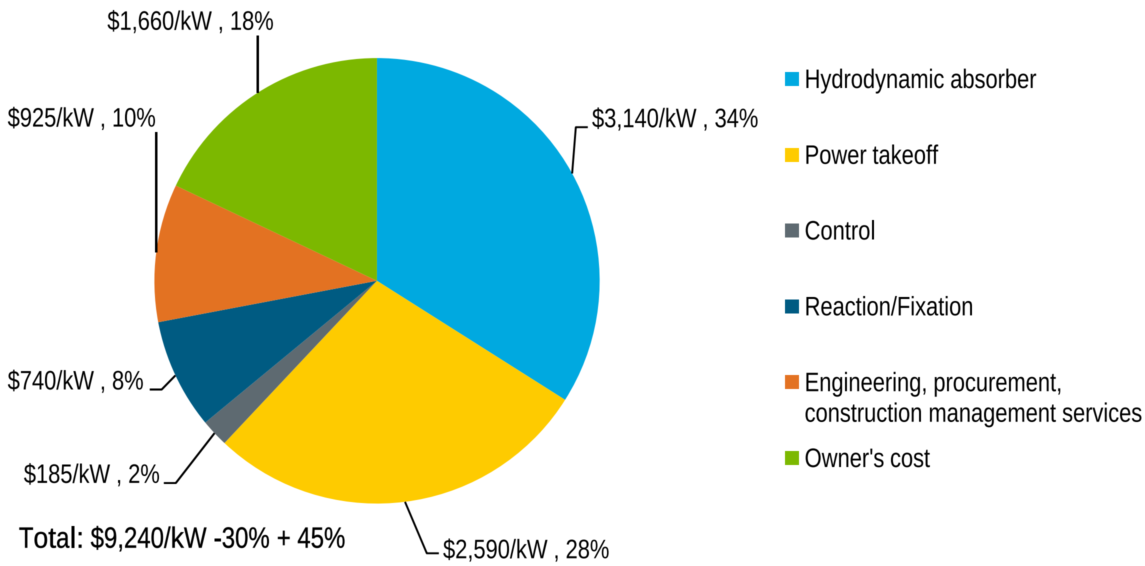

Figure 9. Capital cost breakdown for an ocean wave power plant

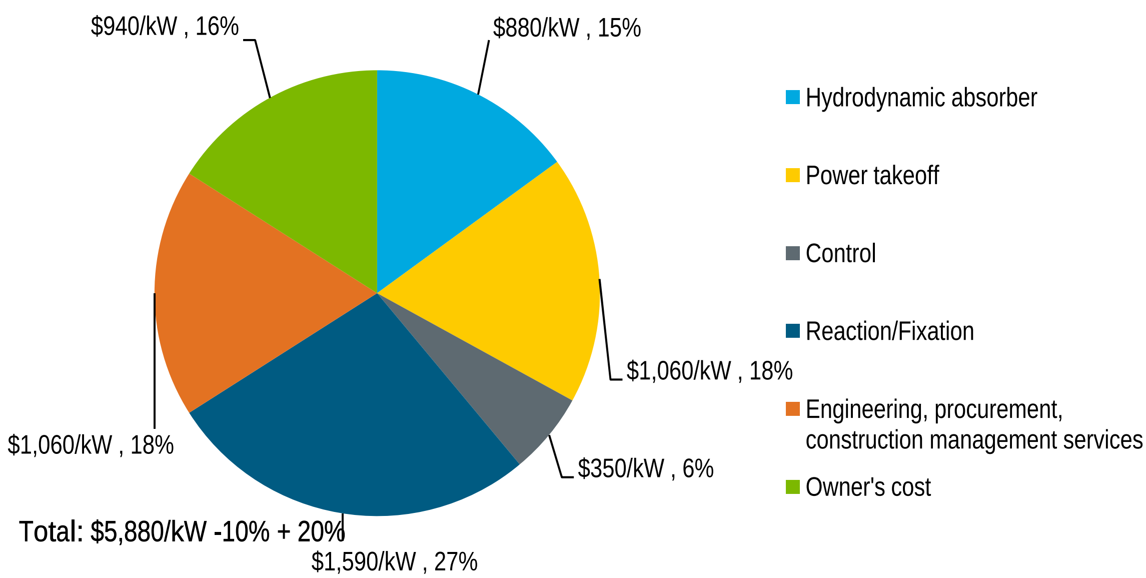

Figure 10. Capital cost breakdown for an ocean tidal power plant

Appendices A and B highlight the uncertainty associated with estimates of wave and tidal energy resources. They form the basis for the estimates above.

3.5 SOLAR ENERGY TECHNOLOGIES

3.5.1 Solar Photovoltaic Technologies

Black & Veatch has been involved in the development of utility scale solar photovoltaic (PV) systems, including siting support, interconnection support, technology due diligence, and conceptual layout. Specifically Black & Veatch has performed due diligence on more than 200 MW of utility scale PV projects for lenders and owners as well as assisted in the development of more than 1,500 MW of projects for utilities and developers. Black & Veatch has been the independent engineer for 35 distributed PV projects totaling 16 MW in California and an independent engineer for two of the largest PV systems in North America. It has also reviewed solar PV new PPA pricing and done project and manufacturer due diligence investigations. This background was used to develop the cost estimates vetted in the WREZ stakeholder process and to subsequently update that pricing and adjust owner's costs.

Estimates for a number of different residential, commercial and utility options ranging from 40 KW (direct current (DC)) to 100 MW (DC) are provided. The capital costs were assumed to have uncertainties of +25%. Cost uncertainty is not high for current offerings but over time, a number of projected, potential technology improvements may affect costs for this technology. Choosing the non-tracking utility PV with a 100-MW (DC) size as a representative case, a 35% reduction in cost was expected through 2050. Table 25 presents cost and performance data for a wide range of PV systems. Table 25 includes 2008 costs to illustrate the impact (in constant 2009 dollars) of the commodity price drop that occurred between 2008 and 2010. For most generation technologies, the decline in commodity prices over the two years results in a 3%–5% reduction in capital cost. As seen in Table 25, the drop in PV technology costs is significantly greater. For PV, the 2008 costs were based on actual market data adjusted to 2009 dollars. Over these two years, PV experienced a drastic fall in costs, due to technology improvements, economies of scale, increased supply in raw materials, and other factors. The capital cost breakdown for the PV power plant (non-tracking Utility PV with a 10 MW (DC) install size) is shown in Figure 11. Note that 100-MW utility PV systems representing nth plant configurations are not available in 2010.

Table 25. Cost and Performance Projection for Solar Photovoltaic Technology

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
Residential PV with a 4 kW (DC) install size						
2008	7690	–	–	–	–	–
2010	5950	0	50	2.0	2.0	0.0
2015	4340	0	48	1.9	2.0	0.0
2020	3750	0	45	1.8	2.0	0.0
2025	3460	0	43	1.7	2.0	0.0

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2030	3290	0	41	1.6	2.0	0.0
2035	3190	0	39	1.5	2.0	0.0
2040	3090	0	37	1.5	2.0	0.0
2045	3010	0	35	1.4	2.0	0.0
2050	2930	0	33	1.3	2.0	0.0
Commercial PV with a 100 kW (DC) install size						
2008	5610	–	–	–	–	–
2010	4790	0	50	6.0	2.0	0.0
2015	3840	0	48	5.7	2.0	0.0
2020	3340	0	45	5.4	2.0	0.0
2025	3090	0	43	5.1	2.0	0.0
2030	2960	0	41	4.9	2.0	0.0
2035	2860	0	39	4.6	2.0	0.0
2040	2770	0	37	4.4	2.0	0.0
2045	2690	0	35	4.2	2.0	0.0
2050	2620	0	33	4.0	2.0	0.0
Non-Tracking Utility PV with a 1-MW (DC) Install Size						
2008	4610	–	–	–	–	–
2010	3480	0	50	8.0	2.0	0.0
2015	3180	0	48	7.6	2.0	0.0
2020	3010	0	45	7.2	2.0	0.0
2025	2880	0	43	6.9	2.0	0.0
2030	2760	0	41	6.5	2.0	0.0
2035	2660	0	39	6.2	2.0	0.0
2040	2570	0	37	5.9	2.0	0.0
2045	2490	0	35	5.6	2.0	0.0
2050	2420	0	33	5.3	2.0	0.0
Non-Tracking Utility PV with a 10-MW (DC) Install Size						
2008	3790	–	–	–	–	–
2010	2830	0	50	12.0	2.0	0.0

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2015	2550	0	48	11.4	2.0	0.0
2020	2410	0	45	10.8	2.0	0.0
2025	2280	0	43	10.3	2.0	0.0
2030	2180	0	41	9.8	2.0	0.0
2035	2090	0	39	9.3	2.0	0.0
2040	2010	0	37	8.8	2.0	0.0
2045	1940	0	35	8.4	2.0	0.0
2050	1870	0	33	8.0	2.0	0.0
Non-Tracking Utility PV with a 100-MW (DC) Install Size						
2008	3210	–	–	–	–	–
2010						
2015	2357	0	48	17.1	2.0	0.0
2020	2220	0	45	16.2	2.0	0.0
2025	2100	0	43	15.4	2.0	0.0
2030	1990	0	41	14.7	2.0	0.0
2035	1905	0	39	13.9	2.0	0.0
2040	1830	0	37	13.2	2.0	0.0
2045	1760	0	35	12.6	2.0	0.0
2050	1700	0	33	11.9	2.0	0.0
1-Axis Tracking Utility PV with a 1-MW (DC) Install Size						
2008	5280	–	–	–	–	–
2010	3820	0	50	10.0	2.0	0.0
2015	3420	0	48	9.5	2.0	0.0
2020	3100	0	45	9.0	2.0	0.0
2025	2940	0	43	8.6	2.0	0.0
2030	2840	0	41	8.1	2.0	0.0
2035	2750	0	39	7.7	2.0	0.0
2040	2670	0	37	7.4	2.0	0.0
2045	2590	0	35	7.0	2.0	0.0
2050	2520	0	33	6.6	2.0	0.0

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
1-Axis Tracking Utility PV with a 10-MW (DC) Install Size						
2008	4010	–	–	–	–	–
2010	3090	0	50	14.0	2.0	0.0
2015	2780	0	48	13.3	2.0	0.0
2020	2670	0	45	12.6	2.0	0.0
2025	2560	0	43	12.0	2.0	0.0
2030	2380	0	41	11.4	2.0	0.0
2035	2380	0	39	10.8	2.0	0.0
2040	2300	0	37	10.3	2.0	0.0
2045	2230	0	35	9.8	2.0	0.0
2050	2170	0	33	9.3	2.0	0.0
1-Axis Tracking Utility PV with a 100-MW (DC) Install Size						
2008	3920	–	–	–	–	–
2010						
2015	2620	0	48	13.3	2.0	0.0
2020	2510	0	45	12.6	2.0	0.0
2025	2410	0	43	12.0	2.0	0.0
2030	2310	0	41	11.4	2.0	0.0
2035	2230	0	39	10.8	2.0	0.0
2040	2160	0	37	10.3	2.0	0.0
2045	2090	0	35	9.8	2.0	0.0
2050	2030	0	33	9.3	2.0	0.0

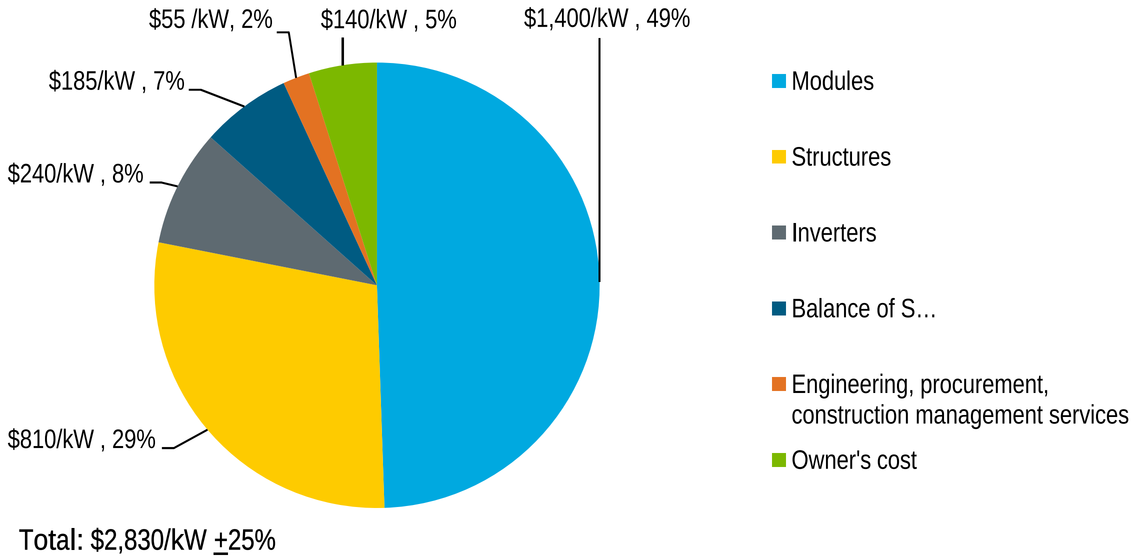

Figure 11. Capital cost breakdown for a solar photovoltaic power plant

Appendix C presents further breakdowns for photovoltaic costs.

3.5.2 Concentrating Solar Power Technologies

Black & Veatch has participated in numerous concentrating solar power (CSP) pilot plant and study activities since the 1970s. The company has been the independent engineer for CSP projects and has performed due diligence on CSP manufacturers. Black & Veatch has also reviewed costs in new CSP purchase agreements. This historical knowledge and recent market data was used to develop the cost estimates vetted in the WREZ stakeholder process and to subsequently update that pricing and make adjustments to owner's costs.

Multiple CSP options were represented, including CSP without storage and CSP with storage. The CSP without storage option was assumed to be represented by trough systems for all years. For the CSP option with storage, the cost data represented trough systems until 2025, after which, tower systems were represented. These model assumptions do not represent CSP technology choice predictions by Black & Veatch. The location assumed for costing of CSP systems is the Southwest United States, not the Midwest as used for other technologies. All CSP systems were based on dry-cooled technologies. The cost and performance data presented here were based on 200-MW net power plants. Multiple towers were used in the tower configuration.

Black & Veatch estimated capital costs to be 4,910 $/kW -35% and +15% without storage and 7,060 $/kW -35% and +15% with storage for 2010. There is greater downside potential than upside cost growth due to the expected emergence of new technology options. New CSP technologies are expected to be commercialized before 2050, and 30%-33% capital cost improvements were assumed for all systems through 2050. Table 26 and Table 27present cost and performance data for CSP power plants without and with storage, respectively. For the with storage option, trough costs were represented in years up to and including 2025; tower costs were provided after 2025. Capital cost breakdown for the 2010 CSP plants with storage are shown in Figure 12 and Figure 13 for trough and tower systems, respectively.

Table 26. Cost and Performance Projection for a Concentrating Solar Power Plant without Storagea

Year	Capital Cost ($/kW)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-Yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	5,050	–	–	–	–	–
2010	4,910	0	50	24	0	6
2015	4,720	0	50	24	0	6
2020	4,540	0	50	24	0	6
2025	4,350	0	50	24	0	6
2030	4,170	0	50	24	0	6
2035	3,987	0	50	24	0	6
2040	3,800	0	50	24	0	6
2045	3,620	0	50	24	0	6
2050	3,430	0	50	24	0	6

[a] Concentrating solar power dry cooling, no storage, and a solar multiple of 1.4.

Table 27. Cost and Performance Projection for a Concentrating Solar Power Plant with Storagea

Year	Capital Cost ($/kW)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-Yr)	Construction Schedule (months)	POR (%)	FOR (%)
2008	7280	–	–	–	–	–
2010	7060	0	50	24	0	6
2015	6800	0	50	24	0	6
2020	6530	0	50	24	0	6
2025	5920	0	50	24	0	6
2030	5310	0	50	24	0	6
2035	4700	0	50	24	0	6
2040	4700	0	50	24	0	6
2045	4700	0	50	24	0	6
2050	4700	0	50	24	0	6

[a] Concentrating solar power dry cooling, 6-hour storage, and a solar multiple of 2.

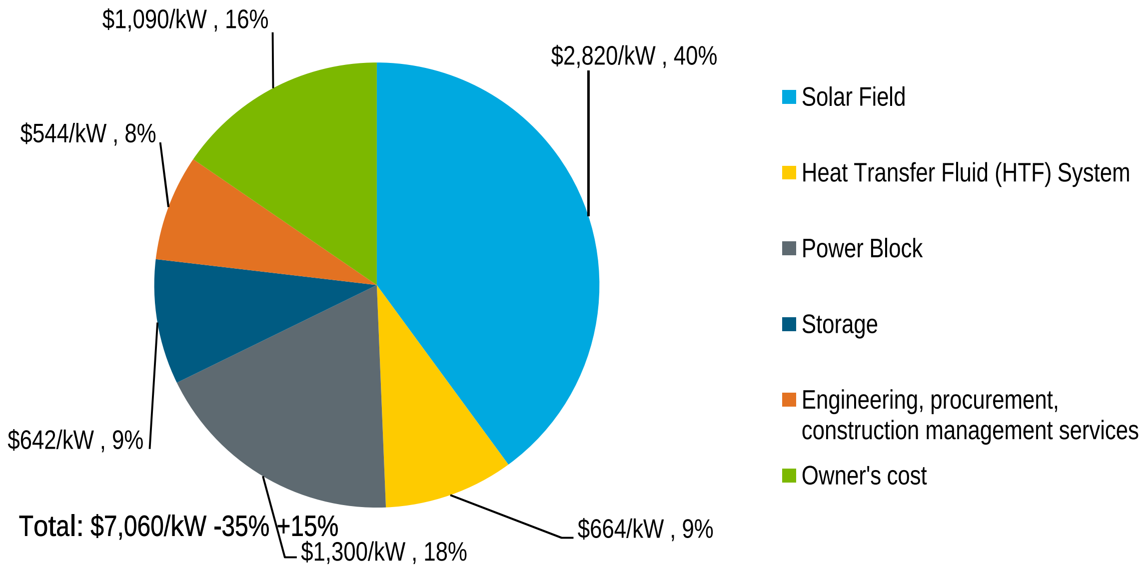

Figure 12. Capital cost breakdown for a trough concentrating solar power plant with storage

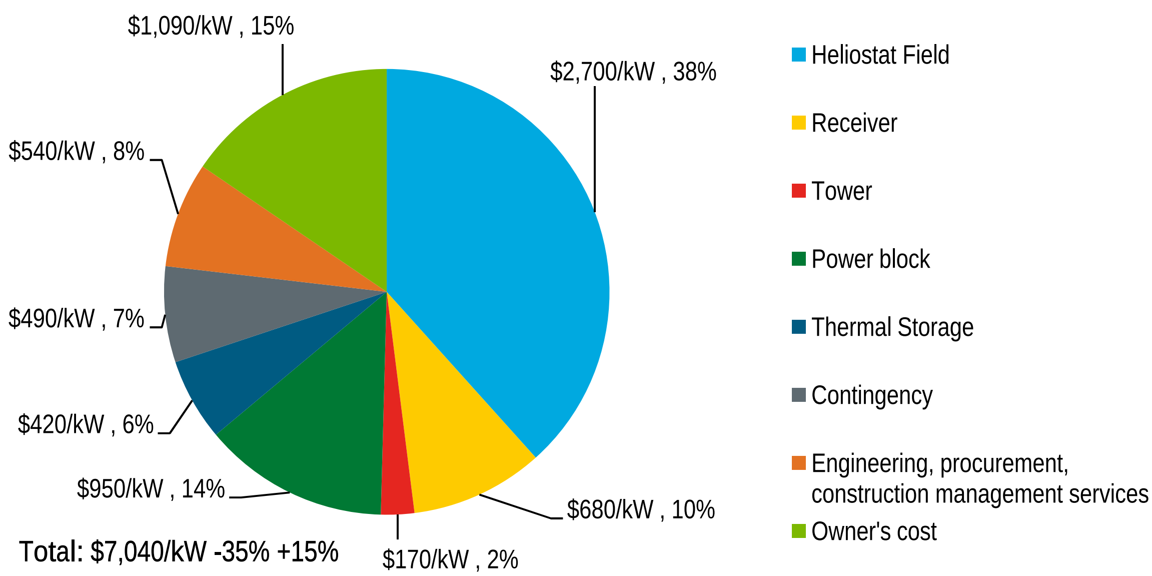

Figure 13. Capital cost breakdown for a tower concentrating solar power plant with storage

3.6 WIND ENERGY TECHNOLOGIES

Black & Veatch has experience achieved in 10,000 MW of wind engineering, development, and due diligence projects from 2005 to 2010. In addition, significant understanding of the details of wind cost estimates was obtained by performing 300 MW of detailed design and 300 MW of construction services in 2008. Black & Veatch also has reviewed wind project PPA pricing. This background was used to develop the cost estimates vetted in the WREZ stakeholder process and to subsequently update that pricing and adjust owner's costs. Costs are provided for onshore, fixed-bottom offshore and floating-platform offshore wind turbine installations. These cost and performance estimates are slightly more conservative than estimates identified in O'Connell and Pletka 2007 for the "20% Wind Energy by 2030" study. Improvements seen since 2004 to 2006 have been somewhat less than previously estimated as the technology more fully matures. Additional improvement is expected but at a slightly slower pace. There is both increased cost and increased performance uncertainty for floating-platform offshore systems.

3.6.1 Onshore Technology

Black & Veatch estimated a capital cost at 1,980 $/kW +25%. Cost certainty is relatively high for this maturing technology and no cost improvements were assumed through 2050. Capacity factor improvements were assumed until 2030; further improvements were not assumed to be achievable after 2030.

3.6.2 Fixed-Bottom Offshore Technology

Fixed-bottom offshore wind projects were assumed to be at a depth that allows erection of a tall tower with a foundation that touches the sea floor. Historical data for fixed-bottom offshore wind EPC projects are not generally available in the United States, but NREL reviewed engineering studies and published data for European projects. Black & Veatch estimated a capital cost at 3,310 $/kW +35%. Cost and capacity factor improvements were assumed to be achievable before 2030; cost improvements of approximately 10% were assumed through 2030 and capacity factor improvements were assumed for lower wind classes through 2030.

3.6.3 Floating-Platform Offshore Technology

Floating-platform offshore wind technology was assumed to be needed in water depths where a tall tower and foundation is not cost effective/feasible. Black & Veatch viewed the floating-platform wind turbine cost estimates as much more speculative. This technology was assumed to be unavailable in the United States until 2020. Fewer studies and published sources exist compared with onshore and fixed-bottom offshore systems. Black & Veatch estimated a 2020 capital cost at 4,200 $/kW +35%. Cost improvements of 10% were assumed through 2030 and capacity factor improvements were assumed for lower wind classes until 2030.

Table 28 through Table 33 present wind cost and performance data, including capacity factors, for onshore, fixed-bottom offshore, and floating-platform offshore technologies. Capital cost breakdowns for these technologies are shown in Figure 14 through Figure 16.

Table 28. Cost and Performance Projection for Onshore Wind Technology

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	2,060	–	–	–	–	–
2010	1,980	0	60	12	0.6	5
2015	1,980	0	60	12	0.6	5
2020	1,980	0	60	12	0.6	5
2025	1,980	0	60	12	0.6	5
2030	1,980	0	60	12	0.6	5
2035	1,980	0	60	12	0.6	5
2040	1,980	0	60	12	0.6	5
2045	1,980	0	60	12	0.6	5
2050	1,980	0	60	12	0.6	5

Table 29. Capacity Factor Projection for Onshore Wind Technology

	Capacity Factor (%)				
Year	Class 3	Class 4	Class 5	Class 6	Class 7
2010	32	36	41	44	46
2015	33	37	41	44	46
2020	33	37	42	44	46
2025	34	38	42	45	46
2030	35	38	43	45	46
2035	35	38	43	45	46
2040	35	38	43	45	46
2045	35	38	43	45	46
2050	35	38	43	45	46

Table 30. Cost and Performance Projection for Fixed-bottom Offshore Wind Technology

Year	Capita Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	3,410	–	–	–	–	–
2010	3,310	0	100	12	0.6	5
2015	3,230	0	100	12	0.6	5
2020	3,150	0	100	12	0.6	5
2025	3,070	0	100	12	0.6	5
2030	2,990	0	100	12	0.6	5
2035	2,990	0	100	12	0.6	5
2040	2,990	0	100	12	0.6	5
2045	2,990	0	100	12	0.6	5
2050	2,990	0	100	12	0.6	5

Table 31. Capacity Factor Projection for Fixed-bottom Offshore Wind Technology

	Capacity Factor (%)				
Year	Class 3	Class 4	Class 5	Class 6	Class 7
2010	36	39	45	48	50
2015	36	39	45	48	50
2020	37	39	45	48	50
2025	37	40	45	48	50
2030	38	40	45	48	50
2035	38	40	45	48	50
2040	38	40	45	48	50
2045	38	40	45	48	50
2050	38	40	45	48	50

Table 32. Cost and Performance Projection for Floating-Platform Offshore Wind Technology

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2020	4,200	0	130	12	0.6	5
2025	4,090	0	130	12	0.6	5
2030	3,990	0	130	12	0.6	5
2035	3,990	0	130	12	0.6	5
2040	3,990	0	130	12	0.6	5
2045	3,990	0	130	12	0.6	5
2050	3,990	0	130	12	0.6	5

Table 33. Capacity Factor Projection for Floating-Platform Offshore Wind Technology

	Capacity Factor (%)				
Year	Class 3	Class 4	Class 5	Class 6	Class 7
2020	37	39	45	48	50
2025	37	40	45	48	50
2030	38	40	45	48	50
2035	38	40	45	48	50
2040	38	40	45	48	50
2045	38	40	45	48	50
2050	38	40	45	48	50

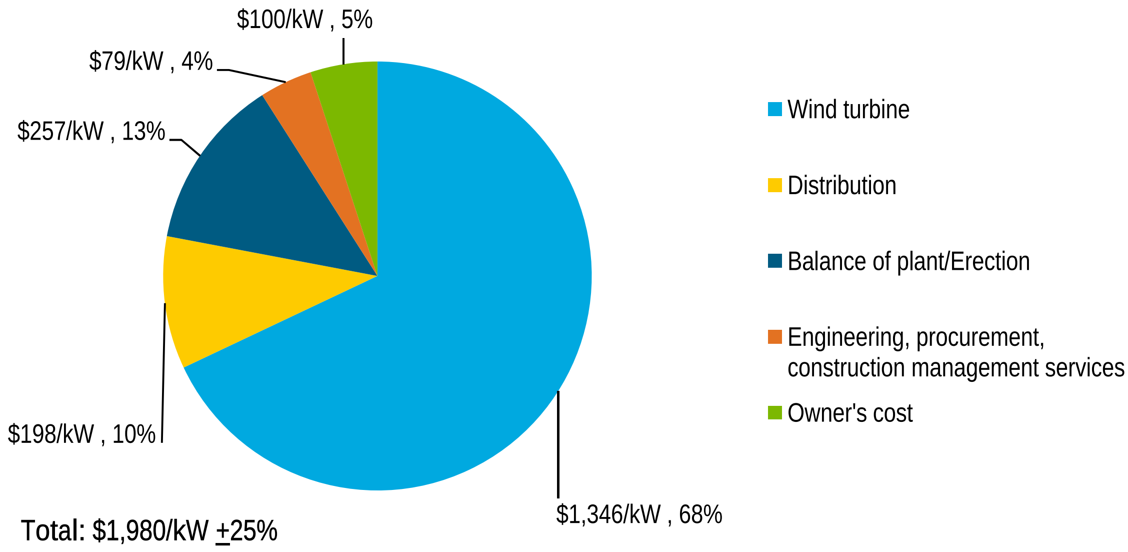

Figure 14. Capital cost breakdown for an onshore wind power plant

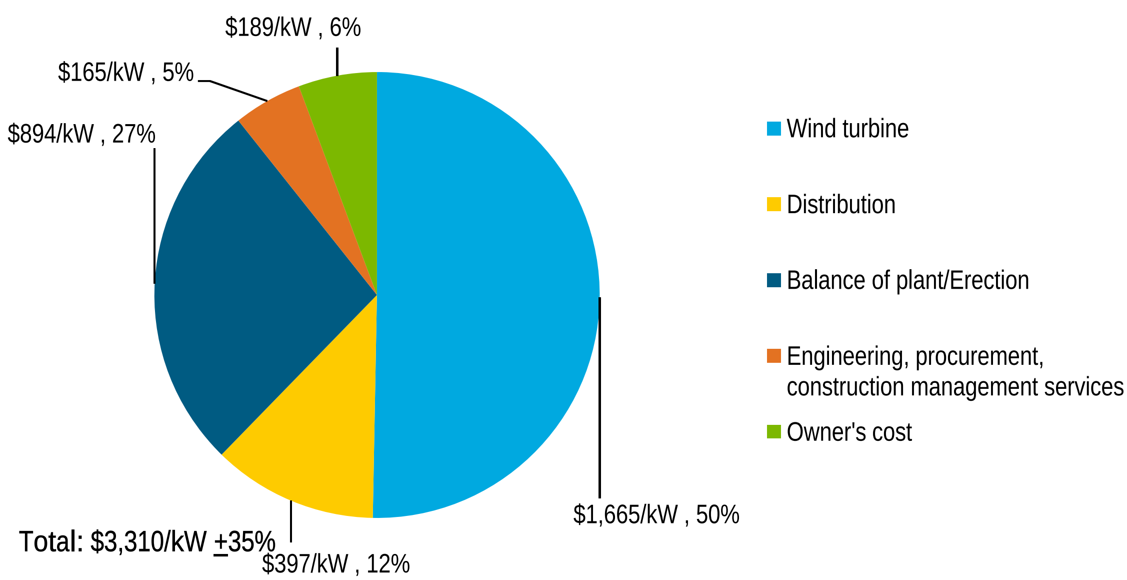

Figure 15. Capital cost breakdown for a fixed-bottom offshore wind power plant

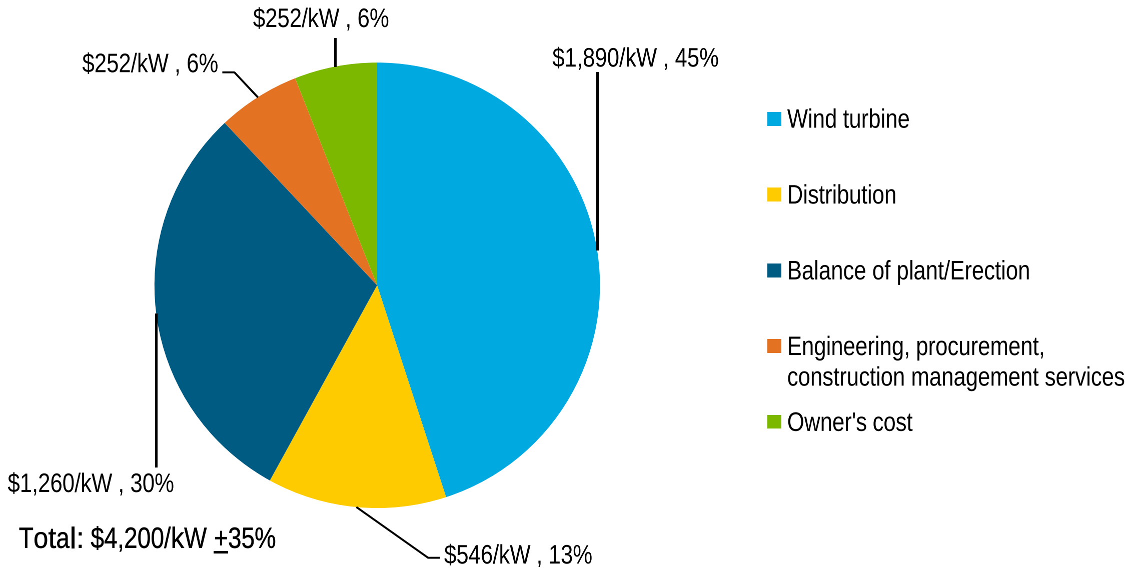

Figure 16. Capital cost breakdown for a floating-platform offshore wind power plant

4 Cost and Performance Data for Energy Storage Technologies

Selecting a representative project definition for compressed air energy storage (CAES) and pumped-storage hydropower (PSH) technologies that can then be used to identify a representative cost is extremely difficult; one problem is that a very low cost can be estimated for these technologies if the best circumstances are assumed (e.g., use of existing infrastructure). For example, an assumption can be made for CAES that almost no below ground cost is contributed when building a small project that can be accommodated by an abandoned gas well of adequate size. For PSH, one can assume only two existing reservoirs need to be connected with a pump and turbine at the lower reservoir. These low cost solutions can be compared to high cost solutions; for CAES, excavation of an entire cavern out of hard rock could be assumed, and for PSH construction of new reservoirs and supply of pump/turbine and interconnections between reservoirs could be assumed. These scenarios are entirely different from possible low cost or mid-cost options. While this situation makes identifying a representative, or average, project difficult, this selection must be made before the discussion of costs can be opened. The design options and associated costs for CAES and PSH are unlimited. History is no help because circumstances are now different from those that existed when the previous generation of pumped hydropower was built and because there are not a large number of existing CAES units to review. Another issue with PSH is that transmission has been equally challenging with cost and environmental issues limiting pumped options.

No CAES or PSH plants have been built recently. Further, in the case of PCH, the Electric Power Research Institute has indicated, “scarcity of suitable surface topography that is environmentally acceptable is likely to inhibit further significant domestic development of utility pumped-hydro storage.”5

Black & Veatch initially selected point estimates for CAES and PSH with ranges around points that can capture a broad range of project configuration assumptions. The disadvantage of the storage estimates initially selected is that they might not adequately reflect the very lowest cost options that may eventually be available. However, the advantage is that they are examples of what real developers have recently considered for development; developers have considered projects with these costs and descriptions to be worthy of study. They are not the least cost examples that could someday be available for consideration by developers, but they are recent examples of site and technology combinations that developers actually have had available for consideration. In addition, the PSH example is of relatively small capacity that may be suitable in a larger number of locations; it is not a less expensive, larger capacity system that may not be as available in many parts of the country. Lastly, because Black & Veatch views the costs as mid-range, they may be considered reasonably conservative. Black & Veatch recognizes that it could have chosen lower cost cases, but the cases initially shown here are representative of projects that developers have actually recently considered.

[5] Pumped Hydroelectric Storage, http://www.rkmaonline.com/utilityenergystorageSAMPLE.pdf

4.1 COMPRESSED AIR ENERGY STORAGE (CAES) TECHNOLOGY

A confidential CAES in-house reference study for an independent power producer has been used for the point estimate, and the range was based on historical data. A two-unit recuperated expander with storage in a solution-mined salt dome was assumed for this estimate. Approximately 262 MW net with 15 hours of storage was assumed to be provided. Five compressors were assumed to be included. A 2010capital cost was estimated at 900 $/kW -30% + 75%. No cost improvement was assumed over time . Table 34 presents costs and performance data for CAES. Table 535 presents emission data for the technology.

Table 34. Cost and Performance Projection for a Compressed Air Energy Storage Plant (262 MW)

Year	Heat Rate (Btu/kWh)	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-year)	Round-Trip Efficiency	FOR (%)	POR (%)	Construction Schedule (Months)	Min. Load (%)	Spin Ramp Rate (%/min.)	Quick Start Ramp Rate (%/min.)
2008	4910	927	–	–	–	–	–	–	–	–	–
2010	–	–	–	–	–	–	–	–	–	–	–
2015	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2020	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2025	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2030	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2035	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2040	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2045	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2050	4910	900	1.55	11.6	1.25	3	4	18	50	10	4

Table 35. Emission Rates for Compressed Air Energy Storage

SO_2 (lb/ hr)	NO_X (lb/hr)	Hg Micro (lb/hr)	PM10 (lb/hr)	CO_2 (kpph)
3.4	47	0	11.6	135

The capital cost breakdown for the CAES plant is shown in Figure 17.

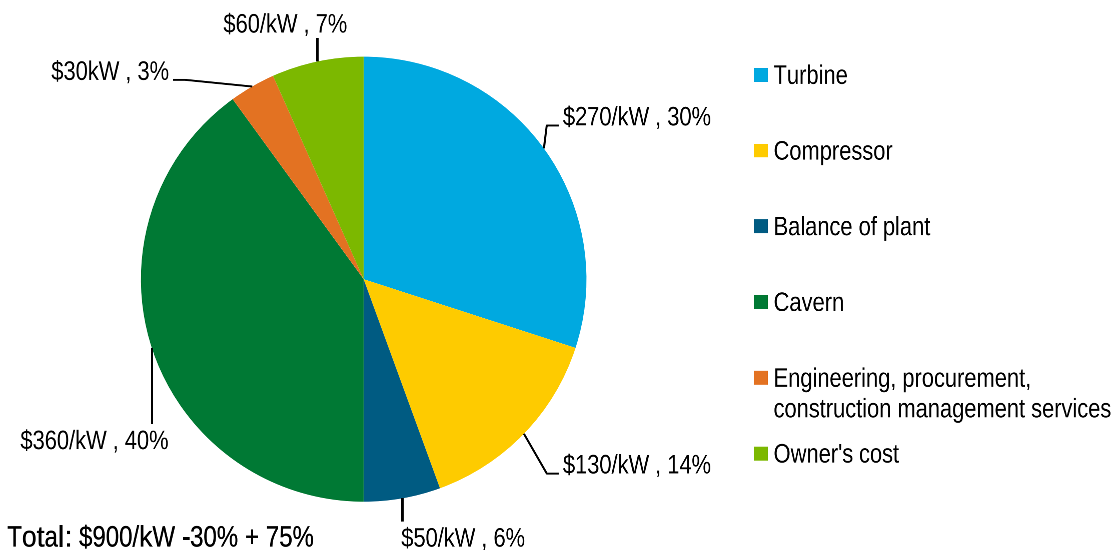

Figure 17. Capital cost breakdown for a compressed air energy storage power plant

CAES plant cost savings will occur in all cost categories over time.

4.2 PUMPED-STORAGE HYDROPOWER TECHNOLOGY

A confidential in-house reference study for an independent power producer was used for the point estimate, and the range was established based on historical data. The PSH cost estimate assumed a net capacity of 500 MW with 10 hours of storage. A 2010 capital cost was estimated at 2,004 $/kW +50%. Appendix D provides additional detail on cost considerations for PSH technologies. This is a mature technology with no cost improvement assumed over time.. A list of current FERC preliminary licenses indicates an average size between 500 and 800 MW. Cost and performance data for PSH are presented in Table 36.

Table 36. Cost and Performance Projection for a Pumped-Storage Hydropower Plant (500 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Round-Trip Efficiency (%)	FOR (%)	POR (%)	Construction Schedule (Months)	Min. Load (%)	Spin Ramp Rate (%/min.)	Quick Start Ramp Rate (%/min.)
2008	2297	–	–	–	–	–	–	–	–	–
2010	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2015	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2020	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2025	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2030	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2035	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2040	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2045	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2050	2230	0	30.8	0.8	3.00	3.80	30	33	50	50

The capital cost breakdown for the pumped-storage hydropower plant is shown in Figure 18.

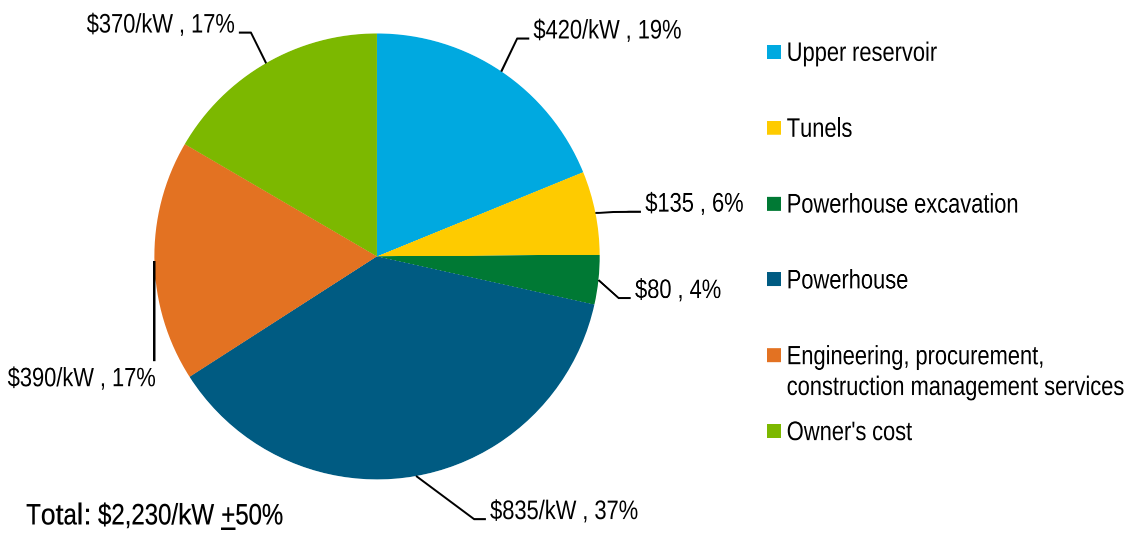

Figure 18. Capital Cost breakdown for a pumped-storage hydropower plant

Pumped hydroelectric power plant cost savings will occur primarily in the powerhouse category over time.

4.3 BATTERY ENERGY STORAGE TECHNOLOGY

A confidential in-house reference study for an independent power producer has been used for the point estimate, and the range has been established based on historical data. The battery proxy was assumed to be a sodium sulfide type with a net capacity of 7.2 MW. The storage was assumed to be 8.1 hours. A capital cost is estimated at 3,990 $/kW (or 1,000 $/kW and 350 $/kWh) +75%. Cost improvement over time was assumed for development of a significant number of new battery options. Table 37 presents cost and performance data for battery energy storage. The O&M cost includes the cost of battery replacement every 5,000 hours.

Table 37. Cost and Performance Projection for a Battery Energy Storage Plant (7.2 MW)

(Year)	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Round-Trip Efficiency (%)	FOR (%)	POR (%)	Construction Schedule (Months)	Min. Load (%)	Spin Ramp Rate (%/sec)	Quick Start Ramp Rate (%/sec)
2008	4110	–	–	–	–	–	–	–	–	–
2010	3990	59	25.2	0.75	2.00	0.55	6	0	20	20
2015	3890	59	25.2	0.75	2.00	0.55	6	0	20	20
2020	3790	59	25.2	0.75	2.00	0.55	6	0	20	20
2025	3690	59	25.2	0.75	2.00	0.55	6	0	20	20
2030	3590	59	25.2	0.75	2.00	0.55	6	0	20	20
2035	3490	59	25.2	0.75	2.00	0.55	6	0	20	20
2040	3390	59	25.2	0.75	2.00	0.55	6	0	20	20
2045	3290	59	25.2	0.75	2.00	0.55	6	0	20	20
2050	3190	59	25.2	0.75	2.00	0.55	6	0	20	20

The capital cost breakdown for the battery energy storage plant is shown in Figure 19.

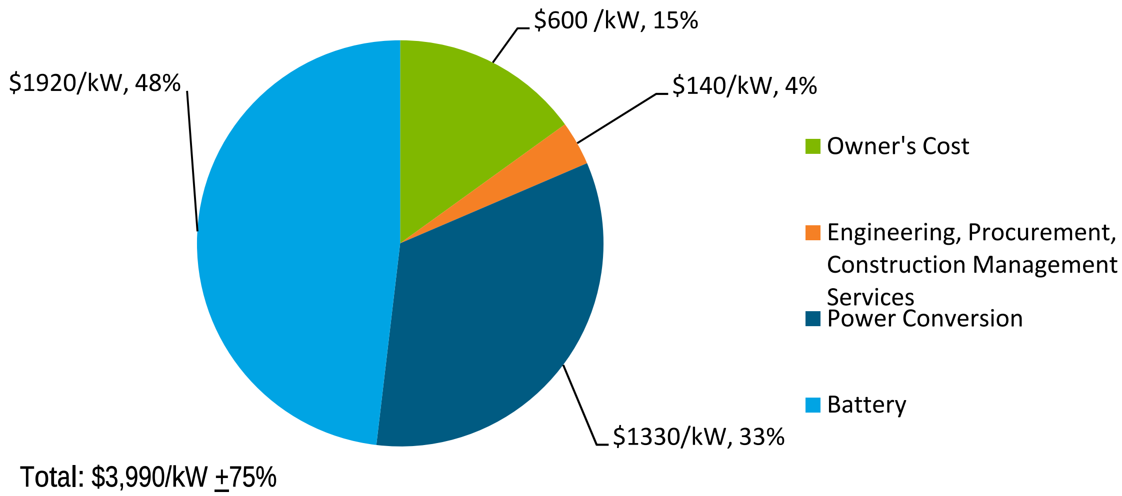

Figure 19. Capital Cost Breakdown for a Battery Energy Storage Plant

Battery energy storage plant cost reductions will occur primarily in the battery cost category over time.

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Appendix A. Energy Estimate for Wave Energy Technologies

RESOURCE ESTIMATE

This appendix documents an analysis of the wave energy resource in the United States and provides the basis for information presented in Section 0 above.

Coastline of the United States

Using Google Earth, Black & Veatch sketched a rough outline of the East and West Coasts of the United States, and divided each into coastal segments to match the available wave data, as described in Figure A-1 and Table A-1. The states of Alaska and Hawaii were not included.

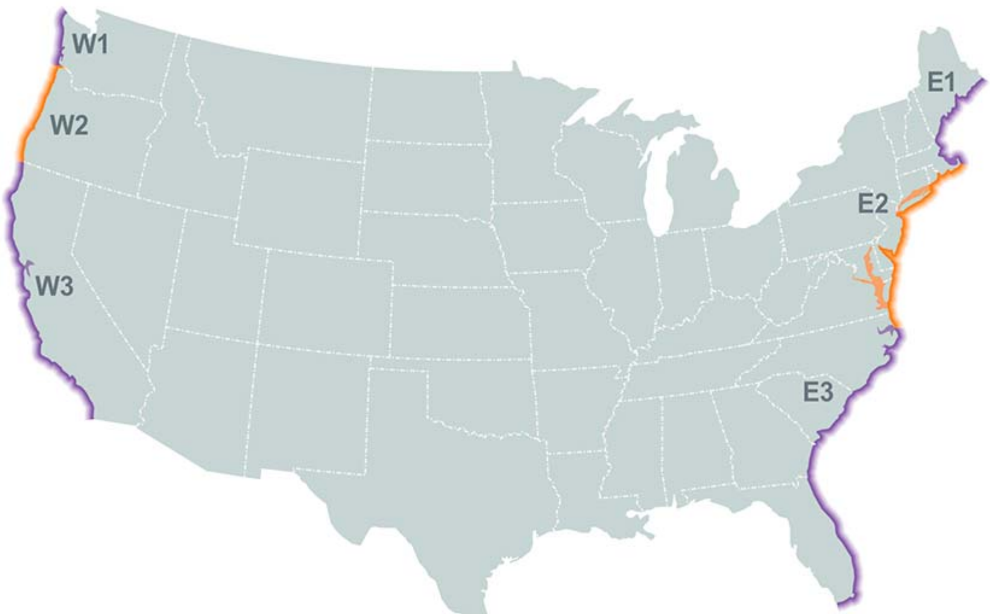


Figure A-1. Designated Coastal Segments

W1: Neah Bay, WA (26.5 kW/m @ ? m)
W2: Coquille, OR (21.2 kW/m @ 64 m)
W3: San Francisco, CA (20 kW/m @ 52 m)
E1: Portland, ME(4.9 kW/m @ 19 m)
E2: Middle (13.8 kW/m @ 74 m)
E3: South East (kW/m @ m)

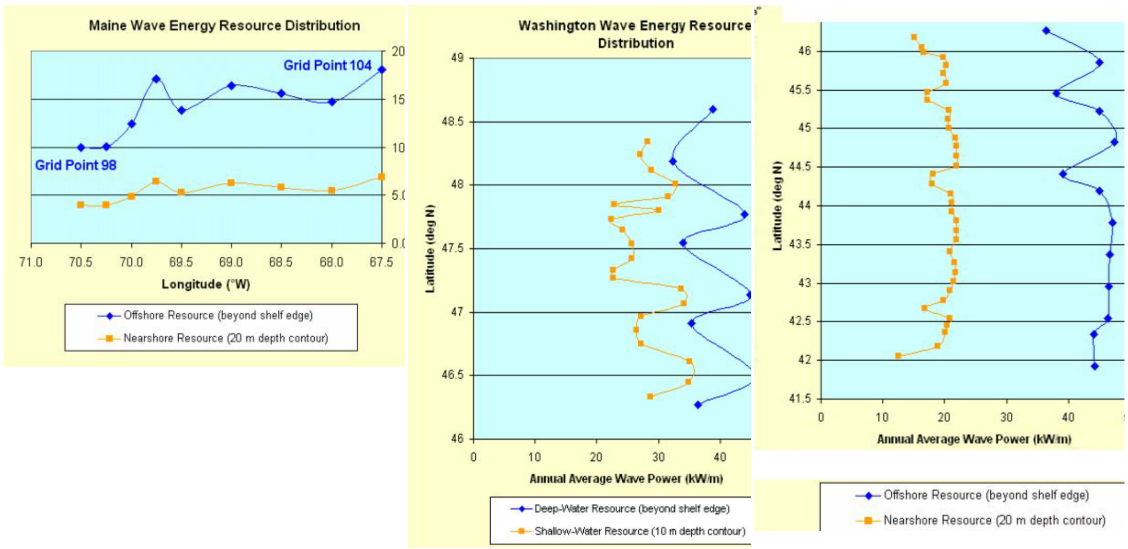
Table A-1. Length of Coastlines in United States

Coastal Segment	Coastline Length (km)	Description
W1	238	Washington
W2	492	Oregon
W3	1322	California
West Total	**2052**	
E1	465	Maine–Massachusetts
E2	942	Massachusetts–North Carolina
E3	1390	North Carolina–Florida
East Total	**2797**	

Wave Energy Resource

Wave energy resource data for West Coast sites (Washington, Oregon, and California) and northern East Coast sites (Maine and Massachusetts) were extracted from several relevant reports (EPRI n.d.).

In addition to data from a small number of specific buoys, EPRI (n.d.) contained annual average power for sites along the coasts of selected states, as shown on Figure A-2. These data were used to estimate the wave energy resource for the contiguous United States.



Maine (E1)
(Hagerman et al. 2004a)

Washington (W1)
(Hagerman et al. 2004b)

Oregon (W2)
(Hagerman et al. 2004c)

Figure A-2. Wave Flux for Maine, Washington, and Oregon

In addition to the EPRI data, wave flux results (in kW/m), from Kane (2005, Table 8) were also used to estimate California's wave energy resource as shown in Figure A-3. Most sites assessed in Kane are deeper than 100 m, but approximately 3 of the 10 sites are from shallower buoys, including Del Norte (60 m), Mendocino (82 m), and Santa Cruz (13 m, 60-80 m).

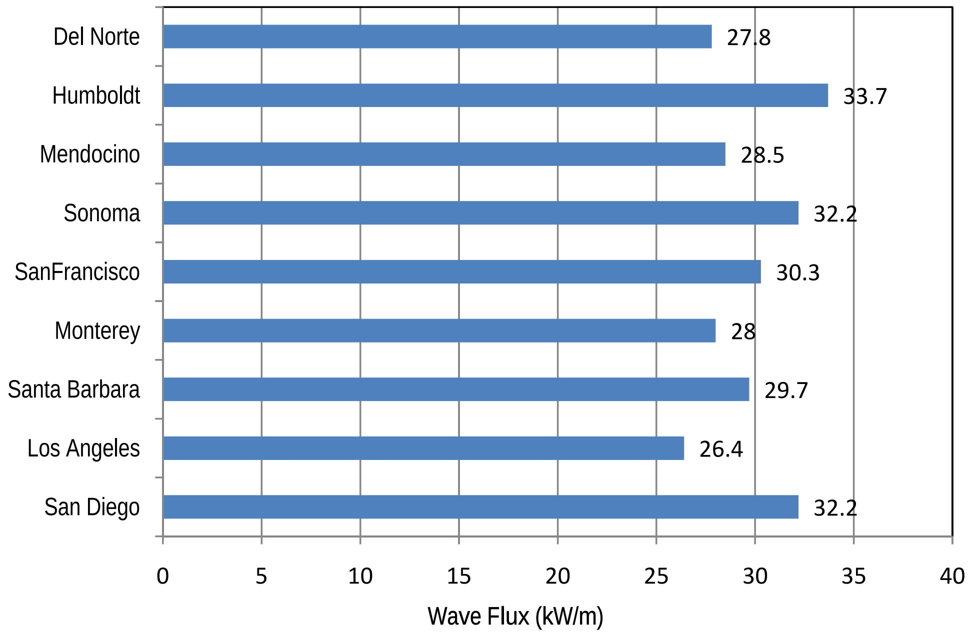


Figure A-3. Wave Flux for California

(Coastal segment W3, Figure A-1) (Kane 2005, Table 8)

The available data were used to estimate an average wave energy resource for each coastal segment. As a spot check, the EPRI (n.d.) cites 20 kW/m wave flux at 52-m depth at the San Francisco site, which approximately matches the 30 kW/m cited by Kane (2005, Table 8) for San Francisco at a deep site. Consequently, both studies were used with relative confidence. No wave resource data were found for the central (E2, Figure A-1) and southern (E3) East Coast.

Normalizing to 50-m Depth

All wave resources were normalized to a 50-m depth contour. This depth is believed to represent for the next 10 years the average depth targeted by most wave energy developers, and is the basis for the cost estimates presented below. Within the next 50 years, exploiting the wave energy resource at greater depths will likely be possible. While more energy may be available at deeper sites, it might not be as commercially exploitable, as the wave direction would be more variable and grid connection costs would increase significantly.

The wave energy data presented above are sourced from deep water off the continental shelf. Results from a study by Queen's University Belfast & RPS Group (Folley et al. 2009) were used to estimate the resource at 50-m depth. Using wave data and modeling for the European Marine Energy Centre (EMEC) site in Scotland, Folley et al. calculated the gross (omni-directional), net (directionally resolved), and exploitable (net power less than four times the mean power density) for a number of site depths. Figure A-4 shows the results from this study.

Given the lack of other available data, Black & Veatch assumed the EMEC results apply to the United States and used them to estimate gross power at 50-m depth from U.S. offshore wave data from the previously mentioned sources (taken to be offshore – all directions). By multiplying the U.S. offshore data by 23.5/41 (as read from Figure A-4), the wave flux was normalized to 50-m depth.

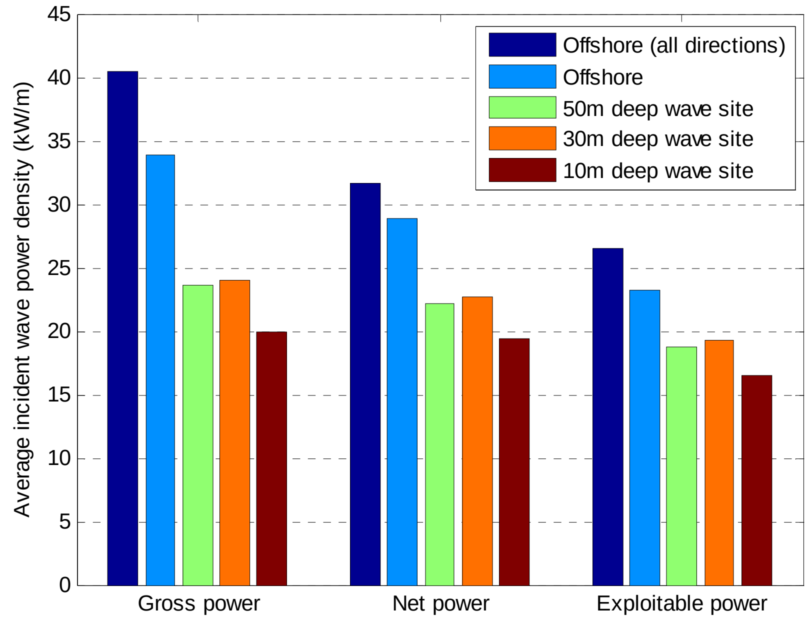


Figure A-4. Gross v. Exploitable Power at Varying Sea Depths

(Folley et al. 2009, p. 7)

However, the particular site conditions at the EMEC site might mean these conclusions are not applicable to all sites. Local bathymetry can create high and low resource areas, and the seabed slope is relatively steep at the EMEC site, which reduces the distance between deep and shallow sites and the energy dissipated between them. It is, for example, clear from Figure A-2 that the wave energy resource dissipation from offshore to near shore is much higher in Oregon than it is in Washington.

Additional studies are needed to establish the validity of this relationship for the U.S. coastline, but it is believed to be a reasonable first estimate.

Directionality

Black & Veatch was not able to locate directional wave data for U.S. sites; a directionality of 0.9, which has historically been used for UK wave energy sites, was therefore assumed for the *Base Case*.

A *Pessimistic Scenario* (low-deployment) and an *Optimistic Scenario* (high deployment) were developed to reflect the uncertainty in the U.S. wave resource. In the *Pessimistic Scenario* and the *Optimistic Scenario*, factors of 0.8 and 1.0 respectively were applied to reflect the fact that at some sites the wave resource is more focused than at others (particularly in shallower waters) and that some wave devices are able to cope with directionality more efficiently than others (e.g., point absorbers).

Spacing

The spacing between the devices was not considered in the estimate of the wave energy resource, as the resource study is based on available wave energy per wave front. Hence, no farm configuration was considered for the wave devices, and energy available is based only on a percentage of extraction from the available resource.

Conversion from Absorbed Power to Electrical Power

A wave energy converter efficiency of 70% from the absorbed power to the electrical power generated at shore was generally assumed, as 70% is the typical value used for wave devices. In the *Pessimistic Scenario*, efficiency of 60% is assumed and 80% is assumed in the *Optimistic Scenario*.

Exploitable Coastline

In the *Base Case*, 50% of the coastline length was estimated to be exploitable. In the *Optimistic Scenario*, the full length of coastline was considered exploitable, reflecting the fact that if a site would not be suitable for development at 50 m in the next few years, it might be exploitable at deeper or shallower waters in the next 50 years. Under the *Pessimistic Scenario,* 25% of the coastline was considered exploitable.

Extractable Energy from the Wave Resource

Clearly, the whole energy resource cannot be extracted from the wave front without impacting the environment and the project economics. Black & Veatch did not consider environmental issues and set the criteria for extractable wave energy on the economical cut-off point. As a wave energy project is believed to be uneconomical for wave resource lower than a 15 kW/m threshold, the percentage of extractable power compared to the available resource was set to ensure the available wave resource does not drop below this economic threshold.

Wave Energy Regime

The wave resource was classified into wave energy regimes as shown in Table A-2.

Table A-2. Wave Energy Regime Classification

Wave Energy Regime	Wave Flux at 50-m Depth (kW/m)
Very Low	< 15
Low	15–20
Medium	20–25
High	> 25

The wave energy resource (in kW/m) data were reviewed for each site, and a split in the resource was estimated (Table A-3). For example, because approximately 10 of the 13 data points for the W2 (Oregon) coastline have a wave energy resource above 25 kW/m, 75% of the resource was estimated as high," with the remainder being estimated as "medium."

Table A-3. Wave Energy Regime Split

	Very Low	Low	Medium	High
W1	–	–	100%	0%
W2	–	–	25%	75%
W3	–	100%	–	–
E1	100%	–	–	–
E2	100%	–	–	–
E3	100%	–	–	–

Coastal segment E1 (Figure A-1), with a peak average offshore wave energy resource of less than 20 kW/m, corresponding to an equivalent wave energy resource of less than 11 kW/m at 50 m, was classified as "very low" and was not counted in the wave resource estimate. Coastal segments E2 and E3 were both assumed to have a milder wave regime than E1, and therefore to also fall into the "very low" category and were not included in the resource estimate.

Wave Energy Mean Annual Resource

By multiplying the average wave energy resource (at 50 m depth) for each segment by the coastal length, and the wave energy regime split (Table ATable -3), the U.S. wave energy resource was estimated for the Base Case as shown in Table A-4. This estimate does not construe any device capacity factors but does take into account the directionality, efficiencies, and exploitable percentage explained above. The values are given in MW, and hence they represent mean annual electrical power.

Table A-4. Mean Annual U.S. Wave Energy Resource (MW)—*Base Case*

Coastal Segment	Low	Medium	High	Total
W1	–	707	–	707
W2	–	476	1,429	1,905
W3	1,539	–	–	1,539
West Total	1,500	1,200	1,400	4,100
East Total	–	–	–	–
TOTAL	1,500	1,200	1,400	4,100

As explained above, the mean annual U.S. wave energy resource for the *Pessimistic* and *Optimistic Scenarios* are shown in Table A-5 and Table A-6 respectively, consistent with the directionality, the spacing, and the percentage of coastline exploitable assumptions for these Scenarios described above.

Table A-5. Mean Annual U.S. Wave Energy Resource (MW)—*Pessimistic Scenario*

Coastal Segment	Low	Medium	High	Total
W1	–	269	–	269
W2	–	181	544	726
W3	586	–	–	586
West Total	600	500	500	1,600
East Total	–	–	–	–
TOTAL	600	500	500	1,600

Table A-6. Mean Annual U.S. Wave Energy Resource (MW)—*Optimistic Scenario*

Coastal Segment	Low	Medium	High	Total
W1	–	1,795	–	1,795
W2	–	1,210	3,629	4,838
W3	3,908	–	–	3,908
West Total	3,900	3,000	3,600	10,500
East Total	–	–	–	–
TOTAL	3,900	3,000	3,600	10,500

Capacity Factor

The U.S. wave resource is smaller than the UK resource. Black & Veatch based its cost estimates on UK-based technologies designed mostly for UK sites. The rated power and power matrix that is being used in this cost estimate was developed for an average UK site of approximately 30 kW/m, which is higher than for any U.S. site. Typically, technology developers would change the rated power conditions and tuning of their device to match a lower power resource site, however, in this analysis the technologies have not been optimized for the different site conditions.

Table A-7 shows the capacity factors that were applied in the cost estimates for the different resource bands. As explained above, these are lower than they would be if the device were optimized specifically for a U.S. site rather than for a UK site, but this is not expected to make a significant difference to the results, bearing in mind the other potential uncertainties in the analysis.

Table A-7. Capacity Factors for the Different Resource Bands in the United States

Resource Band	Representative Site	Capacity Factor
Low (15 kW/m –20 kW/m)	Massachusetts	15%
Medium (20 kW/m–25 kW/m)	Oregon	20%
High (25 kW/m–30 kW/m)	UK	25%

Installed Capacity Limits in the United States

The values in Tables A-4 to A-6 are annual average power generation as they were calculated from the annual wave energy resource available from the wave front. To estimate the corresponding installed capacity, the values stated above were divided by the capacity factors given in Table A-7. Clearly, major uncertainties are inherent to the wave resource in the United States, and hence the total wave energy resource ranges from 9,000 MW to 55,000 MW electrical installed capacity (including efficiencies), as shown in Table A-8 and Figure A-5.

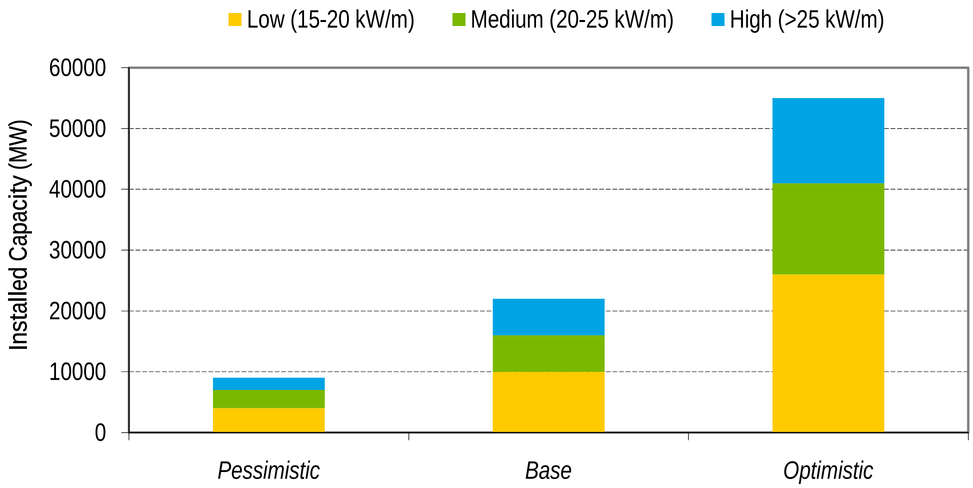


Figure A-5

Table A-8. U.S. Wave Energy Resource (MW)—Installed Capacity Summary for all Scenarios

Scenario	Low Band (15-20 kW/m)	Medium Band (20-25 kW/m)	High Band (>25 kW/m)	Total
Pessimistic	4,000	3,000	2,000	9,000
Base Case	10,000	6,000	6,000	22,000
Optimistic	26,000	15,000	14,000	55,000

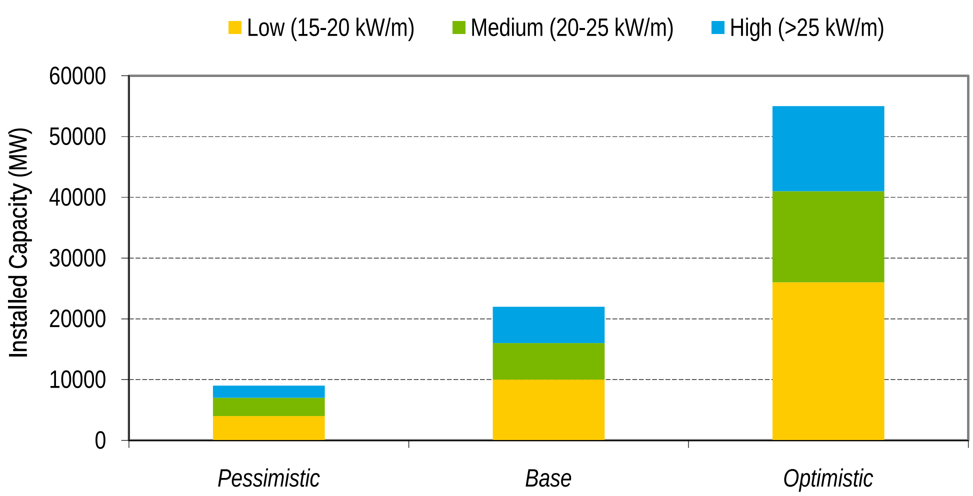


Figure A-5. Wave resource estimate for different scenarios

COST OF ENERGY ESTIMATE

To forecast the future cost of energy of wave power in the United States, a number of key assumptions must be made. Initially, a deployment scenario must be generated to forecast the potential growth of the industry; a starting cost of energy must be determined based on the current market costs; and, a learning rate or curve is required to reflect potential reductions in the cost of energy with time. This section details Black & Veatch's methods to determine a future forecast of the potential economics of the wave power industry in the United States.

Given the relative uncertainties due to the early stage of the wave power market, an *Optimistic Scenario*, a *Base Case*, and a *Pessimistic Scenario* were considered for the deployment rates, cost of electricity, and learning rates. The *Base Case* represents Black & Veatch's most likely estimate, while the *Optimistic* and *Pessimistic Scenarios* represent the potential range of the primary uncertainties in the analysis.

Wave Deployment Estimate

Global Deployment

Global deployment is required to drive the learning rate of a technology; therefore, Black & Veatch developed an assumption for the deployment of wave energy converters globally to 2050. This estimate was made identifying the planned short term (to 2030) future deployments of the leading wave energy converter technologies. The growth rate from 2020 to 2030 was then used as a basis to estimate the growth to 2050. This growth rate was decreased annually by 1% from 2030 and each subsequent year in order to represent a natural slowing of growth that is likely to occur. The year 2030 was chosen as the start date for the slowdown as this would represent approximately 20 years of high growth, which is reasonable based on slowdowns experienced in other industries (e.g., wind) that have reflected resource and supply chain constraints.

Not all developers are likely to prove successful, and naturally, not all planned installations will proceed. As such, weighting factors were applied to reflect the uncertainty related to both the developers' potential success and their projects' success.

Deployment in the United States

Deployment in the United States has been based on the growth rate of global deployment. The current installed capacity and the planned installed capacity for 2010 in the United States were calculated. These starting values were then used in combination with the global growth rate to determine the scenarios for U.S. deployment to 2050. The growth rates for the *Optimistic Scenario*, the *Base Case*, and the *Pessimistic Scenario* were based on 25% of high, 16% of base, and 8% of low global deployment scenarios respectively and therefore each was assigned a unique growth rate. The total resource installed capacities estimates for the scenarios calculated above were applied. Figure A-6 shows the results of the analysis.

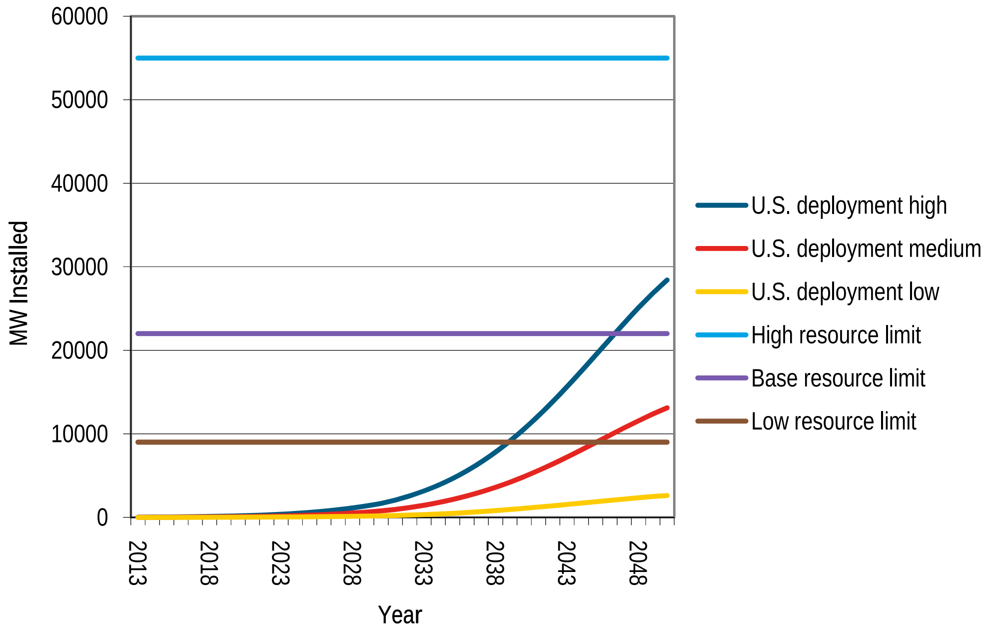


Figure A-6. Deployment Scenarios for Wave Power in the United States to 2050

The analysis shows that the United States could install to approximately13 gigawatt (GW) by 2050 in the *Base Case* with an *Optimistic* deployment scenario of approximately 28.5 GW; the *Pessimistic* deployment scenario installed 2.5 GW by 2050; none of the scenarios reaches its respective deployment limit. The growth rates vary among the deployment scenarios; these different rates are the major contributing factor to the large variance among the scenarios and reflect the current lack of understanding of the U.S. resource and the early stage of development of the wave energy converter industry.

Deployment Assumption

Given the relatively low energy density of U.S. wave resource sites, it was assumed that 1) developers would aim to maximise project economics for early projects and would thus deploy only at sites in the high-band wave resource, 2) that when this is exhausted, the medium-band resource sites would be exploited, and 3) that the low resource sites would be used only after the medium-band resource was exhausted. It is also assumed that the effects of the learning curve will make the medium- and low-resource sites more feasible in the future. This order of exploitation is a key assumption used throughout the cost modelling and will naturally result, as seen below, in distinct offsets in cost of electricity projections at the points of transition between the resource bands.

Deployment Constraints

The deployment growth is limited only by the resource constraints. It was assumed that all other factors impacting deployment would be addressed, including but not limited to: financial requirements, supply chain infrastructure, site-specific requirements, planning, and supporting grid infrastructure.

Learning

To form a judgment as to the likely learning rates that can reasonably be assumed for the coming years, it is appropriate to first consider empirical learning rates from other emerging renewable energy industries. This section provides an overview of learning experience from similar developing industries, suggests applicable learning rates for wave technology, and considers scenarios for future generation costs. Figure A-7 shows learning rate data for a range of emerging renewable energy technologies.

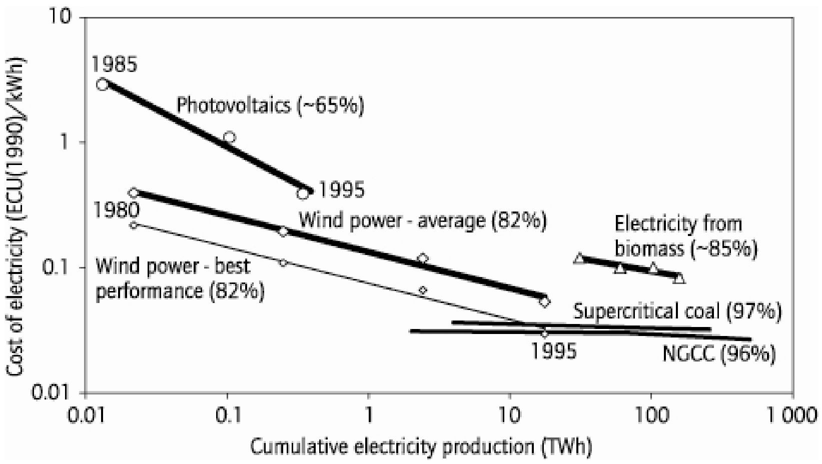


Figure A-7. Learning in Renewable Energy Technologies

(IEA 2000)

Cost and cumulative capacity are observed to exhibit a straight line when plotted on a log-log diagram; mathematically, this straight line indicates that an increase by a fixed percentage of cumulative installed capacity gives a consistent percentage reduction in cost. For example, the progress ratio for photovoltaics during 1985–1995 was approximately 65% (learning rate approximately 35%), and the progress ratio for wind power between 1980 and 1995 was 82% (learning rate 18%).

Any discussion as to the likely learning rates that may be experienced in the wave energy industry will be subjective. The closest analogy for the wave industry has been assumed to be the wind industry. A progress ratio as low as wind energy (82%) is not expected for the wave industry for the following reasons:

- In wind, much of the learning was a result of doing "the same thing bigger" or "upsizing" rather than "doing the same or something new." This upsizing has probably been the single most important contributor to cost reduction for wind, contributing approximately 7% to the 18% learning rate.[6] Most wave energy devices (particularly resonant devices) do not work in this way. A certain size of device is required for a particular location to minimize the energy cost, and simply making larger devices does not reduce energy costs in the same way. Nevertheless, wave devices can benefit from the economies of scales of building farms with larger devices and larger numbers of devices.

[6] See, for example, Coulomb and Neuhoff 2006, which calculates an 11% learning rate for wind excluding learning due to "upsizing."

- Unlike wind in which the market as mostly adopted a single technical solution (3-bladed horizontal-axis turbine), there are many different technology options for wave energy devices and there is little indication at this stage as to which technology is the best solution. This indicates that learning rate reductions will take longer to realize when measured against cumulative industry capacity.

The learning rates for wave energy converters have been developed as per the above discussion and are presented in Table A-9. The learning rates for the United States were assumed to be 1% less than what would be expected in the UK, as the energy densities of the perspective sites are lower (which suggests that there may be less room for cost improvement).

Table A-9. Learning Rates

Scenario	Learning Rate
Optimistic	15%
Base Case	11.5%
Pessimistic	8%

Cost of Energy

Cost Input Data

Black & Veatch used its experience in the wave energy converter industry to develop a cost of electricity for a first 10-MW farm assuming 50 MW installed globally, which effectively represents the cost of the initial commercial farm; these costs are presented in Table A-10. The costs presented are considered an industry average covering both off-shore and near-shore wave technologies. Learning rates were applied to the cost of electricity only after the 50 MW of capacity was installed worldwide.

Table A-10. Cost Estimate for a 10-MW Wave Farm after Installation of 50 MW

Resource	Costs	Costs ($ million)		Performance (%)		Cost of Electricity(c/kWh)
		Capital	Operating (annual)	Capacity Factor	Availability	
High-band Resource (25-30 kW/m)	*Pessimistic*	73	4.6	23%	88%	69
	Base Case	62	3.9	25%	92%	50
	Optimistic	50	3.4	28%	95%	37
Medium-band Resource (20-25 kW/m)	*Pessimistic*	77	4.8	18%	88%	91
	Base Case	66	4.1	20%	92%	67
	Optimistic	53	3.5	22%	95%	49
Low-band Resource (15-20 kW/m)	*Pessimistic*	81	5.0	14%	88%	127
	Base Case	68	4.4	15%	92%	94
	Optimistic	56	3.8	17%	95%	69

The *Pessimistic* and *Optimistic Scenarios* were generated to indicate the uncertainties in the analysis.

General Assumptions

These general assumptions were used for this analysis:

- Project life: 20 years
- Discount rate: 8%.
- Device availability: 90% in the Base Case, 92% in the *Optimistic Scenario*, and 88% in the *Pessimistic Scenario*.

Also, the cost of electricity presented is in 2008 dollars and future inflation has not been accounted for.

Cost of Energy

The cost of electricity directly depends on the learning curve and the deployment rate. Figure A-8 shows the cost of electricity forecast for the *Base Case* learning rate and the *Base Case* deployment scenario (Table A-9 and Figure A-6 respectively) based on the *Optimistic, Base Case*, and *Pessimistic* costs (Table A-8). The *Optimistic* and *Pessimistic* curves in the figure represent the upper and lower cost uncertainty bands for the *Base Case* deployment assumption and learning rate.

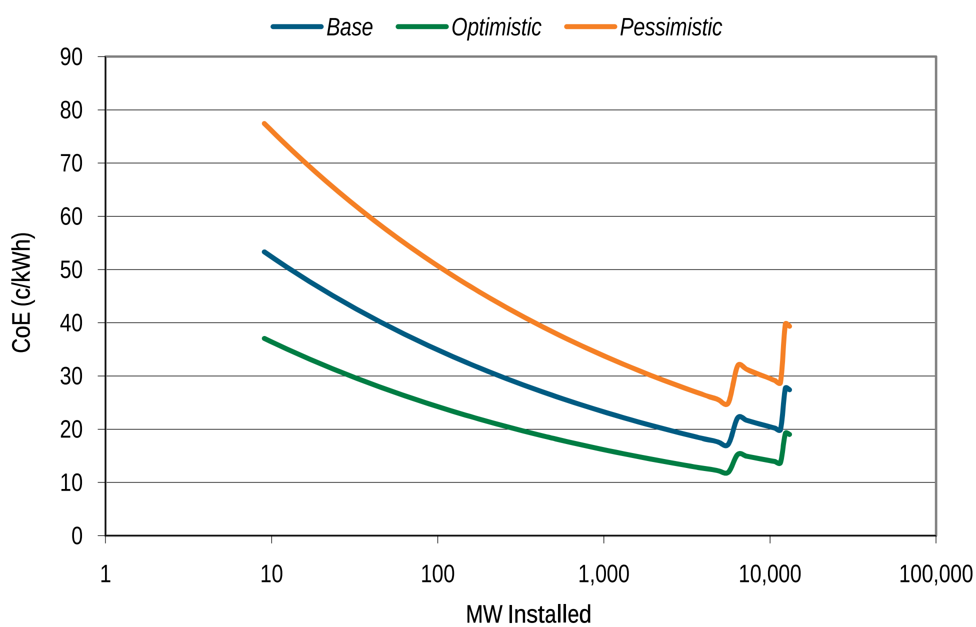


Figure A-8. Cost of energy projection with installed capacity for *Base Case* deployment and learning rates

The *Base Case* cost of energy falls to 17c/kWh after approximately 5.5GW is installed however, the cost of electricity then increases as the best sites have been exploited and is 27c/kWh after 13GW is installed (2050). The two spikes in the graph show the effect of moving from the high-band resource to the medium- band resource and from the medium-band to the low- band resource.

Figure A-9 shows the *Optimistic* deployment scenario and learning rates with the *Optimistic*, *Base Case*, and *Pessimistic* costs. These assumptions have a considerable effect on the cost of electricity, with the *Optimistic* cost of electricity reducing to a low point of approximately 8c/kWh (*Base Case* 12c/kWh) after approximately 14 GW is installed before rising as the high-band resource is exhausted and the medium-band resource is used; the cost of electricity then falls to approximately 9c/kWh (*Base Case* 13c/kWh) after 28.5 GW is installed. Sufficient resource is considered to be available so that the low-band resource is not required by 2050.

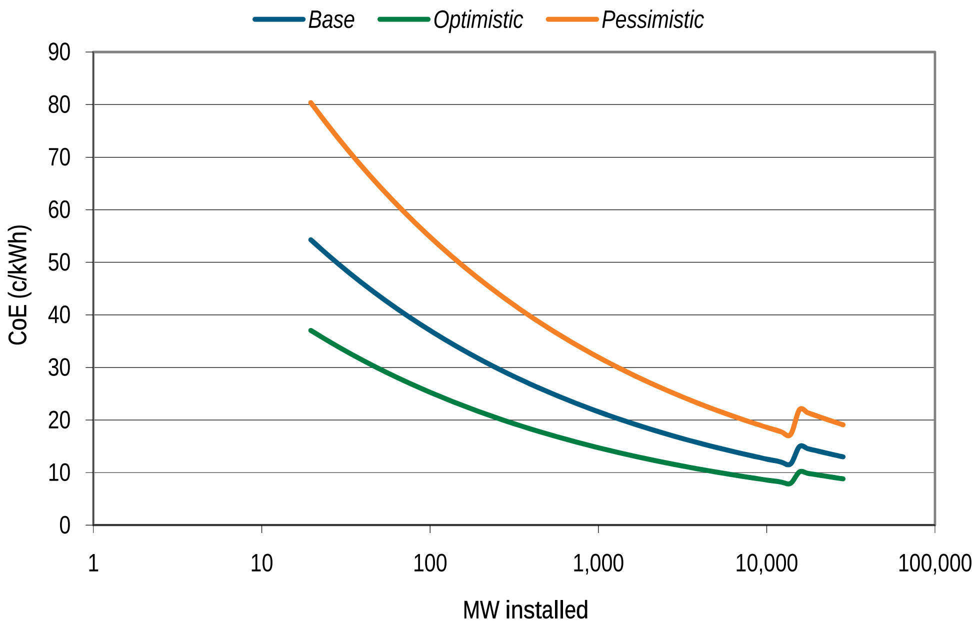


Figure A-9. Cost of energy (projection with installed capacity for *Optimistic* deployment and learning rates

Figure A-10 shows the *Pessimistic* deployment and learning rates with the *Optimistic*, *Base Case*, and *Pessimistic* costs. In this scenario, there are no high-band resource sites; therefore, the analysis starts from the medium-band resource before moving to the low-band resource. The *Pessimistic* cost of electricity falls to a low point of approximately 34c/kWh (*Base Case* 24c/kWh) after approximately 2GW is installed; the installations then require the low-band resource where the cost of electricity finishes on 42c/kWh (*Base Case* 31c/kWh) after 2.5GW is installed.

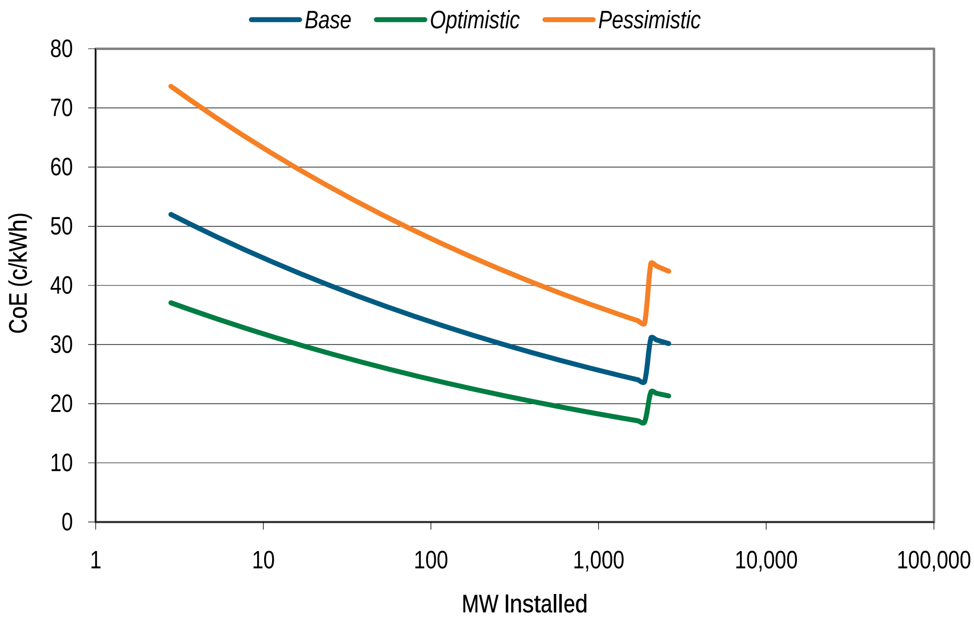


Figure A-10. Cost of energy (c/kWh) over projection with installed capacity for *Pessimistic* deployment and learning rates

Capital and Operating Costs

The capital costs for the *Base Case*, *Optimistic*, and *Pessimistic Scenarios* and the *Base Case* operating expenditure costs to 2050 are shown in Table A-11. As stated above, developers were assumed to install first at sites in the high-band resource, then at sites in medium-band resources, and finally at sites in the low-band resource; in Table A-11, the costs highlighted in green, orange, and red correspond to a high, medium and low resource bands, respectively. The construction schedule and outage rates relate to the *Base Case*. The data in Table A-11 relate directly to the costs projected in Figure A-8; the *Base Case* overnight costs were taken from the *Base Case* (middle) curve in Figure A-8; the low overnight costs were taken from the best case (lower curve) of the *Optimistic Scenario* (Figure A-9); and, the high overnight costs were taken from the worst case (upper curve) of the *Pessimistic Scenario* (Figure A-10).

Table A-11. Capital and Operating Costs to 2050

Year	*Base Case* Capacity Factor (%)	*Base Case* Overnight Cost ($/kW)	*Optimistic* Overnight Cost —High Deployment/ Learning Rate	*Pessimistic* Overnight Cost —Low Deployment/ Learning Rate	*Base Case* Fixed O&M ($/kW-Yr)	Construction Schedule (Months)	Planned Outage Rate (%)	Forced Outage Rate (%)
2008								
2010	25%	14,579	11,400	18,482	741	24	1%	7%
2015	25%	9,336	6,252	13,558	474	24	1%	7%
2020	25%	7,030	4,283	11,308	357	24	1%	7%
2025	25%	5,756	3,282	9,886	292	24	1%	7%
2030	25%	4,782	2,564	8,714	243	24	1%	7%
2035	25%	3,989	2,015	7,746	203	24	1%	7%
2040	25%	3,451	1,662	7,059	175	24	1%	7%
2045	20%	4,094	1,888	6,603	208	24	1%	7%
2050	15%	5,379	1,727	8,318	273	24	1%	7%

The data for the *Base Case* and *Optimistic Scenarios*— which assume the same (*Base Case*) cost of electricity starting point in 2015, along with the estimated cumulative installed capacity in the United States—are also presented in Table A-12. The following results are taken from the mid cases of the *Base Case* and *Optimistic Scenarios*).

Table A-12. Capital and Operating Costs to 2050 (Same Starting Costs—Middle Cases)

	Base Case			*Optimistic Scenario*		
Year	MW Installed (in U.S.)	*Base Case* Overnight Cost ($/kW)	*Base Case* Fixed O&M ($/kW-yr)	MW Installed (in U.S.)	*Base Case* Overnight Cost ($/kW)	*Base Case* Fixed O&M ($/kW)
2008	–	–	–	–	–	–
2010	–	–	–	–	–	–
2015	5	9,336	474	11	9,336	474
2020	19	7,030	357	41	6,397	325
2025	37	5,756	292	80	4,902	249
2030	140	4,782	243	304	3,830	195
2035	371	3,989	203	804	3,009	153
2040	670	3,451	175	1,452	2,482	126
2045	881	4,039	205	1,910	2,804	142
2050	735	5,379	273	1,592	2,565	130

Data Confidence Levels

The uncertainty associated with the resource data is discussed in the resource estimate section above. The greatest uncertainty for resource estimates stems from the fact that the available data is located mostly in very deep regions that would not be suitable for installation of wave energy devices. As a consequence, the data were extrapolated to shallower regions. This major uncertainty for the West Coast resource could be reduced by using hydrodynamic models to estimate the wave energy resource at different depths[7]. The total lack of data for the middle (E2, Figure A-1) and lower (E3) East Coast of the United States also adds uncertainty to the resource and cost estimates. However, because the wave energy resource is believed to be relatively small in these regions, the U.S. resource assessment could be improved by investigating the remaining areas (E1, Figure A-2) to confirm that the wave energy resource is not significant on the East Coast.

The cost data provided in this report were based on Black & Veatch's experience working with leading wave technology developers, substantiated by early prototype costs and supply chain quotes. These data are believed to represent a viable estimate of future costs; however, the industry is still in its infancy; and therefore these costs are in the main estimates. This uncertainty is reflected in the relatively large error bands.

The deployment scenarios were based on potential installations globally deemed realistic; however, they are a forecast and therefore subject to significant uncertainty. Deployment will ultimately be driven by numerous variables, including financing, grid constraints, government policy, and the strength of the supply chain.

Summary

The deployment analysis indicates that approximately 12.5 GW of wave generation could be installed in the United States by 2050 in the *Base Case* with approximately 27 GW by 2050 under an Optimistic (high-deployment) scenario, and 2.5 GW by 2050 under a Pessimistic (low-deployment) scenario. None of the scenarios reach their respective resource ceilings.

The cost of electricity analysis estimates a 17c/kWh cost of electricity for *Base Case* assumptions after approximately 5GW is installed (2050 *Base Case* installed capacity); after approximately 13 GW is installed the cost of electricity is 27c/kWh. In the *Optimistic Scenario* (deployment rate, learning rate, and costs)), the cost of electricity is estimated to be as low as 9c/kWh after approximately 28.5GW is installed (2050). In the *Pessimistic Scenario*, the cost of electricity after approximately 2.5GW is installed (2050) is estimated at 42c/kWh.

[7] Not only the mean wave power (kW/m) must be assessed, but the yearly wave occurrence data to produce Hs/Te scatter diagrams must also be assessed, as these are crucial to apply to device performance to estimate capacity factors.

Appendix B. Energy Estimate for Tidal Stream Technologies

This appendix documents an analysis of the tidal energy resource in the United States and provides the basis for information presented in Section 0 above.

RESOURCE ESTIMATE

Raw Resource Assessment

Black & Veatch sourced tidal stream energy data from existing EPRI tidal stream energy literature (EPRI n.d.) for West Coast sites (Washington and California) and northern East Coast sites (Maine and Massachusetts). The results are summarized in Table B-1 for the contiguous United States.

Table B-1. Raw Resource Assessment Summary

State	Site	Depth (m)	Mean Annualised Power Density (kW/m^2)	Cross-section Area (m^2)	Mean Annualised Available Power (MW)
Massachusetts	Blynman Canal	2	0.93	18.2	0.02
	Muskeget Channel	25	0.95	14000	13.3
	Woods Hole Passage	4	1.32	350	0.5
	Cape Cod Canal	11	2.11	1620	3.4
	Lubec Narrows	6	5.5	750	4.1
Maine	Western Passage	55 to 75	2.2	16300	35.9
	Outer Cobscook Bay	18 to 36	1.64	14500	23.8
	Bagaduce Narrows	3 in Narrow 18 to 24 off Castine	1.94	400	0.8
	Penobscot River	18 to 21	0.73	5000	3.7
	Kennebec River entrance	9 to 20	0.44	990	0.4
	Piscataqua River	10 to 14	1.48	2300	3.4
Washington	Washington	42	1.7	62600	106.4
California	California	90	3.2	74100	237.1

The sites highlighted in Table B-1 were retained after considering depth and resource constraints. Only sites of depth greater than approximately 20 m and power density greater than 1 kW/m^2 were believed to be suitable for commercial tidal stream energy extraction. In any case, the sites not highlighted have a negligible contribution to the total)

Based on an understanding that EPRI focused its research on the most promising states, no other data than that from EPRI were reviewed and therefore the potential tidal stream resource for other locations was not assessed directly. . A cursory investigation of the U.S. coastline revealed other potentially suitable sites such as Long Island Sound, Chesapeake Bay, and Rhode Island. Assumptions about the total U.S. potential are discussed in the resource limits section below.

To estimate the amount of energy that might be actually produced from tidal energy converters (TECs), three significant impact factor (SIF)[8] values were applied to all sites corresponding to the three different scenarios as follows: 10% SIF was applied to the *Pessimistic Scenario*, 20% SIF to the *Base Case*, and 50% to the *Optimistic Scenario*. The extractable power results are summarized in Table B-2.

Table B-2. Extractable Resource Assessment Summary

State	Sites	Extractable Power (MW)		
		Pessimistic Scenario	*Base Case*	*Optimistic Scenario*
Massachusetts	Muskeget Channel	1	3	7
Maine	Western Passage	4	7	18
	Outer Cobscook Bay	2	5	12
Washington	Washington	11	21	53
California	California	24	47	119
Total		42	83	208

The total extractable resource varies from approximately 40 MW to 200 MW (approximately 80 MW for the *Base Case*).

Resource Limits

To account for yet to be discovered sites, a coefficient was applied to the three total values obtained in the raw resource assessment section above. The results are shown in Table B-3.

Table B-3. Estimated Resource Limits

	Extractable Power (MW)		
	Pessimistic Scenario	*Base Case*	*Optimistic Scenario*
Total	42	83	208
Multiplier	1	2	10
Grand Total	42	167	2082

[8] In 2004 and 2005, as part of the UK Marine Energy Challenge (MEC), Black & Veatch defined a "significant impact factor" (SIF) to estimate the tidal resource extractable in the United Kingdom, representing the percentage of the total resource at a site that could be extracted without significant economic, environmental, or ecological effects.

As there are significant uncertainties associated with the resource data associated with these estimates, and it is possible that the mean annualized power density and resource in the California and Washington sites might have been over-estimated in the EPRI studies, a factor of one was applied on the resource in the *Pessimistic Scenario*. In the *Base Case* and *Optimistic Scenario*, this possibility of overstatement of the potential of know sites was assumed to be significantly smaller than the potential of undiscovered sites; a factor of 2 was assumed in the *Base Case* and a factor of 10was applied in the *Optimistic Scenario*. Based on these assumptions, the total estimated resource for the contiguous United States. is close to the total estimated UK resource.

To derive estimates of the cost of tidal stream energy, the sites were split into three categories based on their raw power density: 3% of the sites identified earlier present a power density of less than 1.5 kW/m^2, 57% present a power density greater than 2.5 kW/m^2, and the remaining present a power density comprised between 1.5 kW/m^2 and 2.5 kW/m^2. Given the small number of sites, the factors applied to account for undiscovered sites, and Black & Veatch's experience, these figures were modified to be consistent with a more likely distribution, as shown in Table B-4.

Table B-4. Resource Bands

Resource	Proportion of Total Extractable Resource
% Low-band resource (<1.5kW/m2)	10%
% Medium-band resource (>1.5kW/m2 ; <2.5kW/m2)	50%
% High-band resource (>2.5kW/m2)	40%

COST OF ENERGY ESTIMATE

Tidal Stream Deployment Estimate

Global and U.S. Deployments

Global deployment is required to drive the learning rate of a technology. An assumption was developed for the deployment of TECs globally to 2050. This estimate was made by identifying the planned short term (to 2030) future deployments of the leading TEC technologies. The growth rate from 2020 to 2030 was then used as a basis to estimate the growth to 2050. This growth rate was decreased annually by 1% from 2030 and each subsequent year in order to represent a natural slowing of growth that is likely to occur. The year 2030 was chosen as the start date for the slowdown as this would represent approximately 20 years of high growth, which is reasonable based on slowdowns experienced in other industries (e.g., wind) that have reflected resource and supply chain constraints.

Not all developers are likely to prove successful, and naturally, not all planned installations will proceed. As such, weighting factors were applied to reflect the uncertainty related to both the developers' potential success and their projects' success.

Deployment of commercial tidal farms in the United States was assumed to be a certain percentage of the growth rate of this global deployment projection (Table B-4), consistent with the total resource ceilings identified above.

Table B-4. U.S. Contribution to Global Tidal Stream Deployment

Scenario	Proportion of World Deployment
Optimistic	30%
Base Case	20%
Pessimistic	10%

For the *Base Case*, the first 10-MW farm was estimated to be installed after approximately 50 MW had been installed worldwide. The different deployments scenarios obtained are shown in Figure B-1.

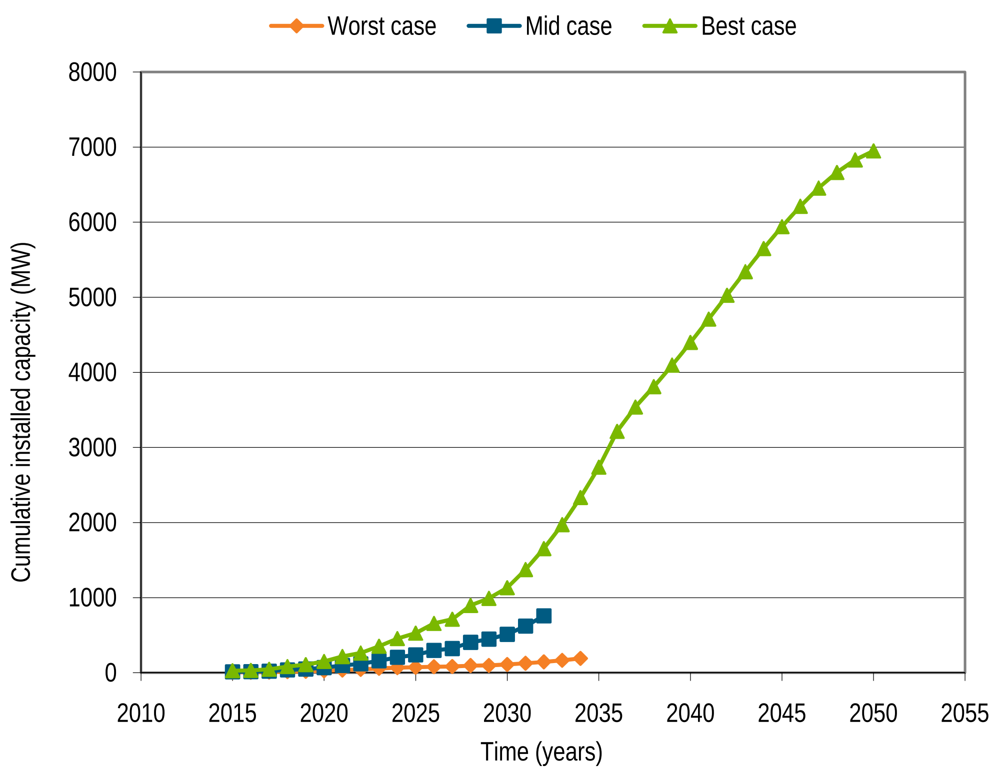


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Figure B-1. Deployment scenarios for tidal stream power (continental waters) in the United States to 2050

In the *Base Case* and *Pessimistic Scenario* cases, the resource ceilings were reached between 2030 and 2035, whereas in the *Optimistic Scenario* the resource ceiling was not reached even in 2050.

Deployment Assumptions

Given the relatively low energy density of U.S. tidal resource sites, it was assumed that 1) developers would aim to maximise project economics for early projects and would thus deploy only at sites in the high-band wave resource, 2) that when this is exhausted, the medium-band resource sites would be exploited, and 3) that the low resource sites would be used only after the medium-band resource was exhausted. It is also assumed that the effects of the learning curve will make the medium- and low-resource sites more feasible in the future.

Deployment Constraints

The deployment growth is only limited by the resource constraints. It was assumed that all other factors impacting deployment are addressed, including but not limited to: financial requirements, supply chain infrastructure, site-specific requirements, planning, and grid infrastructure.

Learning

To form a judgment as to the likely learning rates that can reasonably be assumed for the coming years, it is appropriate to first consider empirical learning rates from other emerging renewable energy industries. This section provides an overview of learning experience from similar developing industries, suggests applicable learning rates for tidal stream technology, and considers scenarios for future generation costs. Figure A-7 (Appendix A) shows learning rate data for a range of emerging renewable energy technologies.

Cost and cumulative capacity are observed to exhibit a straight line when plotted on a log-log diagram; mathematically, this straight line indicates that an increase by a fixed percentage of cumulative installed capacity gives a consistent percentage reduction in cost. For example, the progress ratio for photovoltaics over the period 1985 to 1995 was approximately 65% (learning rate approximately 35%) and that for wind power between 1980 and 1995 was 82% (learning rate 18%).

Any discussion as to the likely learning rates that might be experienced by the tidal stream industry will be subjective. The closest analogy for the tidal stream industry has been assumed to be the wind industry. A progress ratio as low as wind energy (82%) is not expected for the tidal stream industry for the following reasons:

- In the wind power industry, much of the learning was a result of doing “the same thing bigger” or “upsizing” rather than “doing the same or something new.” This upsizing has probably been the single most important contributor to cost reduction for wind, contributing approximately 7% to the 18% learning rate.[9] Tidal turbines, like wind turbines, will benefit from increasing rotor swept areas until the maximum length of the blades, limited by loadings, is reached. However, unlike for wind power, the ultimate physical limit on rotor diameter can also be imposed by cavitation or limited water depth, the latter being particularly important for the relatively shallow sites of (25–35 m) that are likely to be developed in the near-term.
- Much of the learning in wind power occurred at small scale with small-scale units (<100 kW), often by individuals with very low budgets. Tidal stream on the other hand requires large investments to deploy prototypes and therefore requires a smaller number of more risky steps to develop, which tends to suggest that the learning will be slower (and the progress will be ratio higher).
- Tidal stream technology development is still in its infancy, and learning rates are often higher during this period of technology development, offsetting the points in (2).

[9] See, for example, http://www.electricitypolicy.org.uk/pubs/wp/eprg0601.pdf, which calculates an 11% learning rate for wind excluding learning due to ‘upsizing’.

The likely range of learning rates for the tidal energy industry in the United States is believed to be between 7% and15% (progress ratios of 85%–93 %) with a mid range value of 11%.

Cost of Energy

An in-house techno-economic model was used by Black & Veatch to derive A cost of electricity was developed for a first 10-MW farm installed in the three-band resource environment discussed in the resource limits section above, assuming this installation occurred after 50 MW of capacity had been installed worldwide. The cost of electricity presented is considered an industry average for horizontal-axis axial-flow turbines. The learning rate range specified above was used to derive the future cost of electricity.

General Assumptions

As described above, the resource data used in the techno-economic analysis were sourced from EPRI (n.d.). The three resource cases were modelled and derived from the Muskeget Channel site (approximately 1 kW/m^2) and from the sites in Washington and California (respectively approximately 2 kW/m^2 and 3 kW/m^2). The current velocity distributions from the real sites were slightly modified to exactly match the generic resource mid-bands (1 kW/m^2, 2 kW/m^2, and 3 kW/m^2). These general assumptions were used for this analysis:

- Depth: 40 m for all three generic sites considered
- Project life: 25 years
- Discount rate: 8%.
- Device availability: 92.5% in the Base Case, 95% in the *Optimistic Scenario*, and 90% in the *Pessimistic Scenario*.

The cost of electricity presented is in 2009 dollars and future inflation has not been accounted for. The exchange rate used to convert any costs from GBP to USD was: 1 GBP = 1.65 USD.

Cost Results

The estimated cost of electricity is presented in Table B-5. Learning rates were only applied to the cost of electricity only after the 50 MW of capacity was installed worldwide.

Table B-5. Cost Estimate for a 10-MW Tidal Farm after Installation of 50 MW

Resource	Costs	Costs ($ million)		Performance (%)		Cost of Electricity (c/kWh)
		Capital	Operating (annual)	Capacity Factor	Availability	
High-band Resource	*Pessimistic*	69	2.5	22%	90.0%	45.0
	Base Case	59	2.0	26%	92.5%	35.8
	Optimistic	54	1.5	30%	95.0%	29.3
Medium-band Resource	*Pessimistic*	74	2.6	19%	90.0%	55.0
	Base Case	63	2.1	23%	92.5%	44.4
	Optimistic	58	1.6	26%	95.0%	35.9
Low-band Resource	*Pessimistic*	127	4.3	21%	90.0%	84.3
	Base Case	104	3.5	25%	92.5%	66.9
	Optimistic	96	2.6	29%	95.0%	55.0

Black & Veatch's techno-economic model is run in such a way that the technology (rated power of the devices) matches the resource, hence the range of capacity factors obtained in Table B-5. The *Pessimistic* and *Optimistic Scenarios* were generated to indicate the uncertainties in the analysis.

The supply curves obtained after applying the learning rates to the cost of electricity from Table B-5 are shown in Figures B-2, B-3, and B-4.

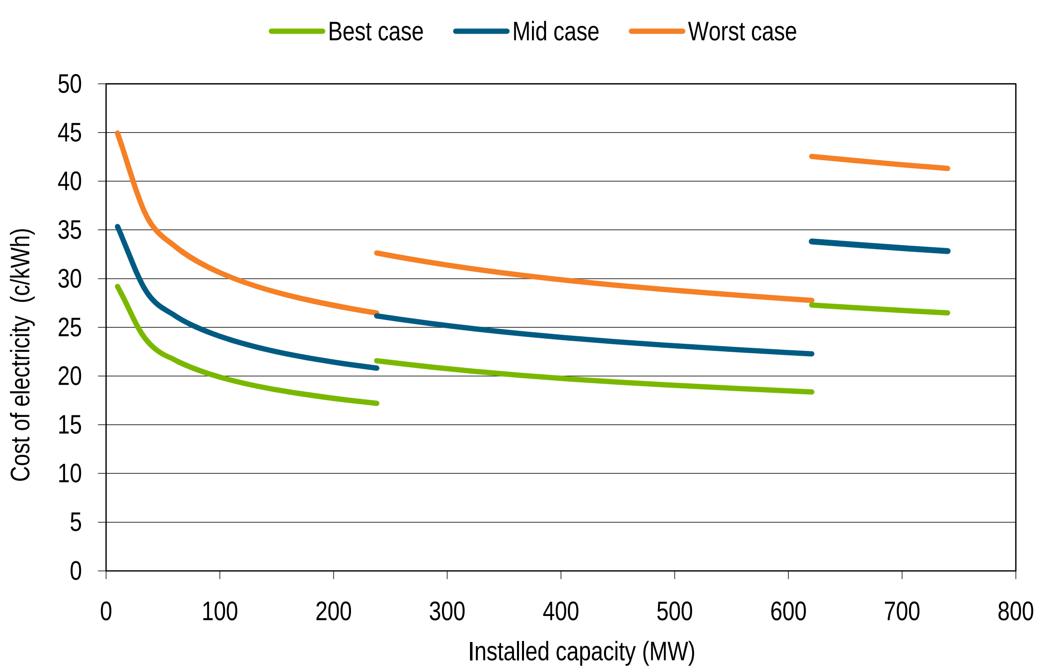


Figure B-2. Supply curve for a *Base Case* resource ceiling and an 11% learning rate

From a *Base Case* of approximately 35c/kWh, the cost of electricity dropped to approximately 20c/kWh after approximately 250 MW were installed. At that point, the most energetic sites had been exploited and the medium-band resource sites start to be exploited, hence the offset in the curve. After these additional 350 MW of medium-band resource sites had been exploited, the *Base Case* cost of electricity lies slightly above the previous 20c/kWh level. The late exploitation of the low-band resource brought the cost of electricity back to the original levels (approximately 35c/kWh in the *Base Case*).

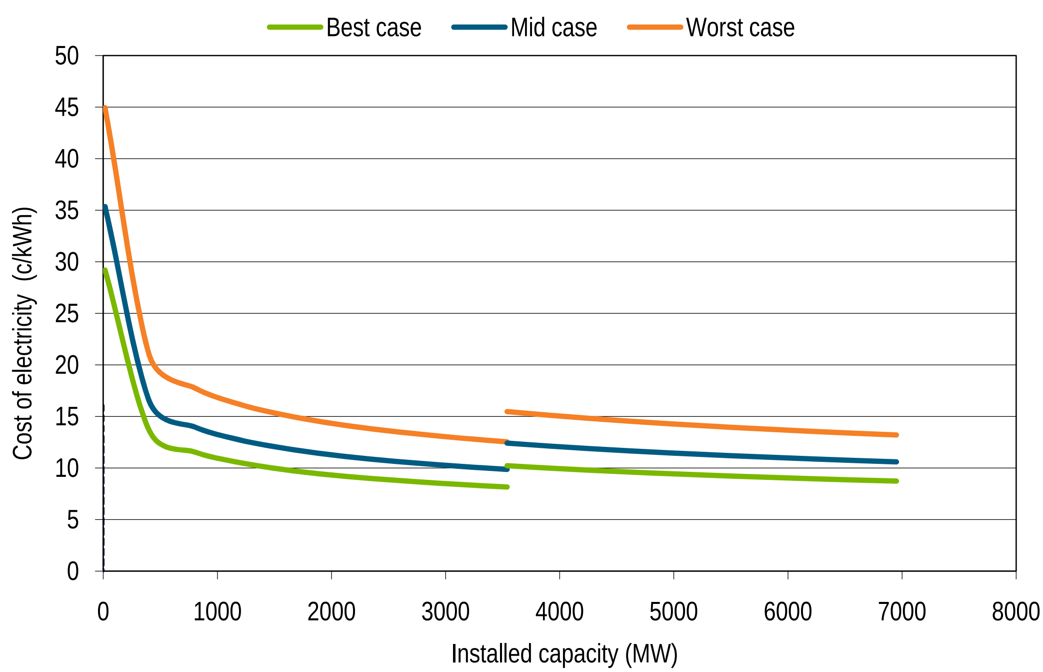


Figure B-3. Supply curve for an *Optimistic* resource ceiling and a 15% learning rate

From a *Base Case* of approximately 35c/kWh, the cost of electricity dropped to approximately 10c/kWh after approximately 3,500 MW had been installed. At that point, the most energetic sites had been exploited and the medium-band resource sites start to be exploited, hence the offset in the curve. After these extra 3,500 MW of medium resource sites had been exploited, the *Base Case* cost of electricity was back at the previous 10c/kWh level.

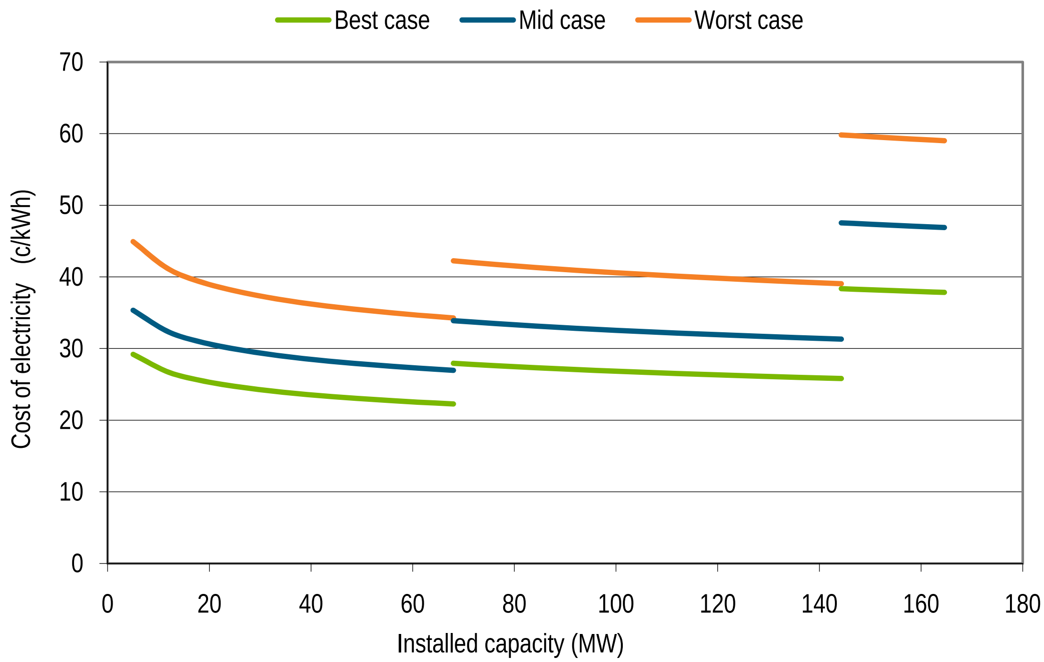


Figure B-4. Supply curve for a *Pessimistic* resource ceiling and a 7% learning rate

From a *Base Case* of approximately 35c/kWh, the cost of electricity dropped to approximately 27c/kWh after approximately 70 MW had been installed. At that point, the most energetic sites had been exploited and the medium-band resource sites start to be exploited, hence the offset in the curve. After these extra 90 MW of medium-band resource sites had been exploited, the *Base Case* cost of electricity reaches approximately 30c/kWh level. The late exploitation of the low-band resource took the cost of electricity to the highest levels reached in this analysis (approximately 48c/kWh in the *Base Case*).

Capital and Operating Costs

The capital costs for the *Base Case*, *Optimistic* and *Pessimistic Scenarios* and the *Base Case* operating costs to 2050 are shown in Table B-6. As stated above, developers were assumed to install first at sites in the high-band resource, then at sites in medium-band resources, and finally at sites in the low-band resource. In Table B-6, the costs highlighted in green, orange, and red correspond to a high, medium, and low resource bands, respectively. The construction schedule and outage rates relate to the *Base Case*. The data in Table B-6 relate directly to the costs projected in Figures B-2 through B-4. The *Base Case* overnight costs were taken from the *Base Case (*middle curve) of Figure B-2; the low overnight costs were taken from the best case (lower curve) of the *Optimistic Scenario* (Figure B-3); and, the high overnight costs were taken from the worst case (upper curve) of the *Pessimistic Scenario* (Figure B-4). In Table B-6, in the base and high overnight cost scenarios, the low-band resource sites were exploited between 2030 and 2035 and hence no red colored cells are visible.

Table B-6. Capital and Operating Costs to 2050

Year	*Base Case* Capacity Factor	*Base Case* Overnight Cost ($/KW)	*Optimistic* Overnight Cost—High Deployment/ Learning Rate ($/KW)	*Pessimistic* Overnight Cost—Low Deployment/ Learning Rate ($/KW)	*Base Case* Variable O&M ($/MWh)	*Base Case* Fixed O&M $/KW-Yr	Heat Rate (Btu/KWh)	Construction Schedule (Months)	Planned Outage Rate (%)	Forced Outage Rate (%)
2008	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-
2015	26%	5,940	5,445	6,930	-	198	-	24	1%	6.5%
2020	26%	4,401	3,293	5,843	-	147	-	24	1%	6.5%
2025	26%	3,498	2,524	5,661	-	117	-	24	1%	6.5%
2030	23%	3,267	1,962	5,381	-	112	-	24	1%	6.5%
2035		-	1,611	-	-	-	-	24	1%	6.5%
2040		-	1,540	-	-	-	-	24	1%	6.5%
2045		-	1,434	-	-	-	-	24	1%	6.5%
2050		-	1,376	-	-	-	-	24	1%	6.5%

The data for the *Base Case* and *Optimistic Scenario* are also presented in Table B-7 with the same starting points, along with the estimated cumulative installed capacity in the United States. The following results were taken from the middle cases of the *Base Case* and *Optimistic Scenario* (Figures B-2 and B-3).

Table B-7. Capital Expenditure Cost and Operating Expenditure Costs to 2050 (Same Starting Costs—Middle Cases)

Base Case				*Optimistic Scenario*			
Year	MW Installed (in U.S.)	*Base Case* Overnight Cost ($/kW)	*Base Case* Fixed O&M ($/kW-Yr)	Year	MW Installed (in U.S.)	*Base Case* Overnight Cost ($/kW)	*Base Case* Fixed O&M ($/kW-Yr)
2008				2008			
2010				2010			
2015	10	5,940	198	2015	15	5,940	198
2020	61	4,401	147	2020	131	3,591	120
2025	238	3,498	117	2025	407	2,753	92
2030	493	3,267	112	2030	1,190	2,140	71
2035	-	-	-	2035	2,756	1,758	59
2040	-	-	-	2040	4,297	1,672	57
2045	-	-	-	2045	5,813	1,557	53
2050	-	-	-	2050	6,950	1,494	51

Data Confidence Levels

The uncertainty associated with the resource data is discussed in the resource estimate section above. The U.S. resource assessment could be improved by investigating the remaining coastline that has not yet been investigated and by using hydrodynamic modeling on the most promising sites.

The cost data provided in this report were based on Black & Veatch's experience working with leading tidal stream technology developers, substantiated by early prototype costs and supply chain quotes. These data are believed to represent a viable current estimate of future costs; however, the industry is still in its infancy and therefore these costs are in the main estimates.. This uncertainty is reflected in the relatively large error bands.

The deployment scenarios were based on potential installations globally deemed realistic; however, they are a forecast and therefore are subject to significant uncertainty. Deployment will ultimately be driven by numerous variables including financing, grid constraints, government policy, and the strength of the supply chain.

Summary

The analysis estimates a 20c/kWh cost of electricity for *Base Case* assumptions after 250 MW is installed; after 720 MW is installed (*Base Case* total resource ceiling), the cost of electricity is estimated to be 34c/kWh due to the late exploitation of the low-band resource. In the *Optimistic Scenario* (deployment rate, learning rate, and costs), the cost of electricity is estimated to be as low as 10c/kWh after 7 GW is installed (2050 resource level). In the *Pessimistic Scenario,* the cost of electricity after 180 MW is installed (*Pessimistic* Scenario total resource ceiling) is estimated at 48c/kWh.

The cost of tidal stream energy extraction in the United States cannot be further investigated until a full national resource assessment is completed.

Appendix C. Breakdown of Cost for Solar Energy Technologies

This appendix documents capital cost breakdowns for both photovoltaic and concentrating solar power technologies, and provides the basis for information presented in Sections 0 above.

SOLAR PHOTOVOLTAICS

Figure C-1 and Table C-1 show capital cost ($/W) projection for a number of different residential, commercial and utility options ranging from 40 KW (direct current (DC)) to 100 MW (DC), assuming no owner's costs and no extra margin. Table C-2 breaks these costs down by component.

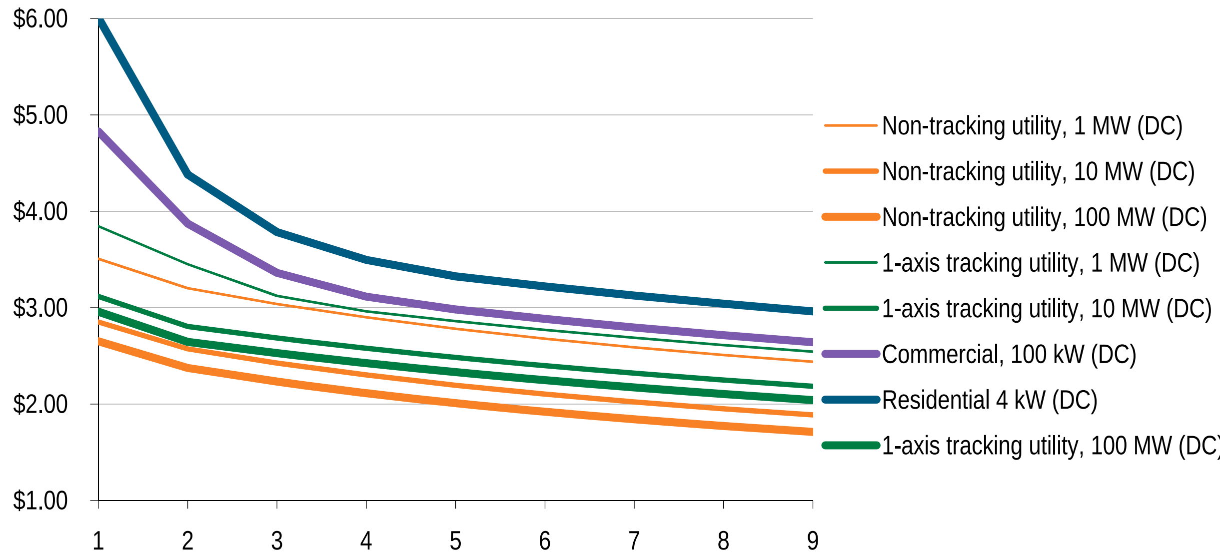


Figure C-1. Capital cost projection for solar photovoltaic technology

Table C-1. Solar Photovoltaics Capital Costs ($/W) by Type and Size of Installation

	Utility PV Non-Tracking			Utility PV 1-Axis Tracking			Commercial PV	Residential PV
	1 MW (DC)	10 MW (DC)	100 MW (DC)	1 MW (DC)	10 MW (DC)	100 MW (DC)	100 kW (DC)	4 kW (DC)
2010	$3.19	$2.59	$2.41	$3.50	$2.83	$2.69	$4.39	$5.72
2015	$2.91	$2.34	$2.16	$3.14	$2.55	$2.40	$3.52	$4.17
2020	$2.76	$2.21	$2.03	$2.84	$2.44	$2.30	$3.06	$3.60
2025	$2.64	$2.09	$1.92	$2.69	$2.34	$2.20	$2.83	$3.33
2030	$2.53	$2.00	$1.83	$2.60	$2.26	$2.12	$2.71	$3.17
2035	$2.43	$1.91	$1.75	$2.52	$2.18	$2.04	$2.62	$3.07
2040	$2.35	$1.84	$1.67	$2.44	$2.11	$1.98	$2.54	$2.98
2045	$2.28	$1.77	$1.61	$2.37	$2.05	$1.91	$2.47	$2.90
2050	$2.22	$1.72	$1.56	$2.31	$1.99	$1.86	$2.40	$2.82

Table C-2. Solar Photovoltaics Capital Cost ($/W) Breakdown by Type and Size of Installation—No Owner's Costs, No Extra Margin

	Non-Tracking Utility		1-Axis tracking Utility		Commercial		Residential	
Year	1 MW (DC)	10 MW (DC)	100 MW (DC)	1 MW (DC)	10 MW (DC)	100 MW (DC)	100 kW (DC)	4 kW (DC)
2010	$3.19	$2.59	$2.41	$3.50	$2.83	$2.69	$4.39	$5.72
2015	$2.91	$2.34	$2.16	$3.14	$2.55	$2.40	$3.52	$4.17
2020	$2.76	$2.21	$2.03	$2.84	$2.44	$2.30	$3.06	$3.60
2025	$2.64	$2.09	$1.92	$2.69	$2.34	$2.20	$2.83	$3.33
2030	$2.53	$2.00	$1.83	$2.60	$2.26	$2.12	$2.71	$3.17
2035	$2.43	$1.91	$1.75	$2.52	$2.18	$2.04	$2.62	$3.07
2040	$2.35	$1.84	$1.67	$2.44	$2.11	$1.98	$2.54	$2.98
2045	$2.28	$1.77	$1.61	$2.37	$2.05	$1.91	$2.47	$2.90
2050	$2.22	$1.72	$1.56	$2.31	$1.99	$1.86	$2.40	$2.82
2010								
Overnight EPC	**$3.19**	**$2.59**	**$2.41**	**$3.50**	**$2.83**	**$2.69**	**$4.39**	**$5.72**
Modules	$1.68	$1.47	$1.42	$2.20	$1.80	$1.75	$2.33	$3.00
Balance of system (BOS)	$0.73	$0.51	$0.49	$0.56	$0.49	$0.49	$0.66	$0.76
Labor, engineering, and construction	$0.67	$0.51	$0.40	$0.65	$0.47	$0.38	$1.27	$1.77
Shipping	$0.10	$0.10	$0.10	$0.08	$0.06	$0.06	$0.13	$0.19
Module efficiency	9.5%	9.5%	9.5%	15.0%	15.0%	15.0%	15.0%	15.0%
Ground coverage ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%

	Non-Tracking Utility		1-Axis tracking Utility		Commercial		Residential	
Year	**1 MW (DC)**	**10 MW (DC)**	**100 MW (DC)**	**1 MW (DC)**	**10 MW (DC)**	**100 MW (DC)**	**100 kW (DC)**	**4 kW (DC)**
2015								
Overnight EPC	**$2.91**	**$2.34**	**$2.16**	**$3.14**	**$2.55**	**$2.40**	**$3.52**	**$4.17**
Modules	$1.45	$1.27	$1.23	$1.88	$1.56	$1.51	$2.00	$2.19
BOS	$0.75	$0.51	$0.50	$0.57	$0.51	$0.50	$0.63	$0.73
Labor, engineering, and construction	$0.62	$0.46	$0.34	$0.60	$0.42	$0.33	$0.76	$1.07
Shipping	$0.09	$0.09	$0.09	$0.08	$0.06	$0.06	$0.12	$0.18
Module efficiency	11.0%	11.0%	11.0%	16.0%	16.0%	16.0%	16.0%	16.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2020								
Overnight EPC	**$2.76**	**$2.21**	**$2.03**	**$2.84**	**$2.44**	**$2.30**	**$3.06**	**$3.60**
Modules	$1.33	$1.17	$1.13	$1.60	$1.47	$1.42	$1.65	$1.76
BOS	$0.74	$0.50	$0.49	$0.57	$0.50	$0.50	$0.58	$0.68
Labor, engineering, and construction	$0.61	$0.45	$0.33	$0.59	$0.41	$0.32	$0.72	$0.99
Shipping	$0.08	$0.08	$0.08	$0.08	$0.06	$0.06	$0.12	$0.17
Module efficiency	12.0%	12.0%	12.0%	17.0%	17.0%	17.0%	17.0%	17.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2025								
Overnight EPC	**$2.64**	**$2.09**	**$1.92**	**$2.69**	**$2.34**	**$2.20**	**$2.83**	**$3.33**
Modules	$1.23	$1.08	$1.04	$1.47	$1.39	$1.34	$1.50	$1.61

	Non-Tracking Utility		1-Axis tracking Utility		Commercial		Residential	
Year	**1 MW (DC)**	**10 MW (DC)**	**100 MW (DC)**	**1 MW (DC)**	**10 MW (DC)**	**100 MW (DC)**	**100 kW (DC)**	**4 kW (DC)**
BOS	$0.73	$0.50	$0.48	$0.56	$0.50	$0.49	$0.57	$0.67
Labor, engineering, and construction	$0.60	$0.44	$0.32	$0.58	$0.40	$0.31	$0.65	$0.88
Shipping	$0.08	$0.08	$0.08	$0.07	$0.06	$0.06	$0.11	$0.16
Module efficiency	13.0%	13.0%	13.0%	18.0%	18.0%	18.0%	18.0%	18.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2030								
Overnight EPC	**$2.53**	**$2.00**	**$1.83**	**$2.60**	**$2.26**	**$2.12**	**$2.71**	**$3.17**
Modules	$1.14	$1.00	$0.96	$1.39	$1.32	$1.27	$1.42	$1.53
BOS	$0.73	$0.49	$0.48	$0.56	$0.49	$0.49	$0.57	$0.67
Labor, engineering, and construction	$0.59	$0.43	$0.32	$0.58	$0.40	$0.31	$0.62	$0.82
Shipping	$0.07	$0.07	$0.07	$0.07	$0.05	$0.05	$0.10	$0.16
Module efficiency	14.0%	14.0%	14.0%	19.0%	19.0%	19.0%	19.0%	19.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2035								
Overnight EPC	**$2.43**	**$1.91**	**$1.75**	**$2.52**	**$2.18**	**$2.04**	**$2.62**	**$3.07**
Modules	$1.07	$0.93	$0.90	$1.33	$1.25	$1.21	$1.35	$1.45
BOS	$0.72	$0.49	$0.47	$0.55	$0.49	$0.48	$0.56	$0.66
Labor, engineering, and construction	$0.58	$0.43	$0.31	$0.57	$0.39	$0.30	$0.61	$0.81
Shipping	$0.07	$0.07	$0.07	$0.07	$0.05	$0.05	$0.10	$0.15

	Non-Tracking Utility		1-Axis tracking Utility		Commercial		Residential	
Year	1 MW (DC)	10 MW (DC)	100 MW (DC)	1 MW (DC)	10 MW (DC)	100 MW (DC)	100 kW (DC)	4 kW (DC)
Module efficiency	15.0%	15.0%	15.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2040								
Overnight EPC	**$2.35**	**$1.84**	**$1.67**	**$2.44**	**$2.11**	**$1.98**	**$2.54**	**$2.98**
Modules	$1.00	$0.88	$0.84	$1.26	$1.19	$1.15	$1.29	$1.38
BOS	$0.72	$0.48	$0.47	$0.55	$0.48	$0.48	$0.56	$0.66
Labor, engineering, and construction	$0.57	$0.42	$0.30	$0.57	$0.39	$0.30	$0.60	$0.79
Shipping	$0.06	$0.06	$0.06	$0.06	$0.05	$0.05	$0.10	$0.14
Module efficiency	16.0%	16.0%	16.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2045								
Overnight EPC	**$2.28**	**$1.77**	**$1.61**	**$2.37**	**$2.05**	**$1.91**	**$2.47**	**$2.90**
Modules	$0.94	$0.82	$0.79	$1.20	$1.14	$1.10	$1.23	$1.32
BOS	$0.71	$0.48	$0.46	$0.55	$0.48	$0.47	$0.55	$0.66
Labor, engineering, and construction	$0.57	$0.41	$0.30	$0.56	$0.38	$0.29	$0.60	$0.79
Shipping	$0.06	$0.06	$0.06	$0.06	$0.05	$0.05	$0.09	$0.14
Module efficiency	17.0%	17.0%	17.0%	22.0%	22.0%	22.0%	22.0%	22.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%

	Non-Tracking Utility		1-Axis tracking Utility		Commercial		Residential	
Year	1 MW (DC)	10 MW (DC)	100 MW (DC)	1 MW (DC)	10 MW (DC)	100 MW (DC)	100 kW (DC)	4 kW (DC)
2050								
Overnight EPC	**$2.22**	**$1.72**	**$1.56**	**$2.31**	**$1.99**	**$1.86**	**$2.40**	**$2.82**
Modules	$0.89	$0.78	$0.75	$1.15	$1.09	$1.05	$1.17	$1.26
BOS	$0.71	$0.47	$0.46	$0.54	$0.48	$0.47	$0.55	$0.65
Labor, engineering, and construction	$0.56	$0.41	$0.29	$0.56	$0.38	$0.29	$0.59	$0.78
Shipping	$0.06	$0.06	$0.06	$0.06	$0.04	$0.04	$0.09	$0.13
Module efficiency	18.0%	18.0%	18.0%	23.0%	23.0%	23.0%	23.0%	23.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%

CONCENTRATING SOLAR POWER

Tables C-3 and C-6 show performance and cost for trough systems in 2010 and 2050. Tables C-4 and C-5 show performance and cost for tower systems in 2010 and 2050.

Table C-3. Solar Trough Performance for 2010 and 2050

Parameter	2010		2050	
	Without Storage	With Storage	Without Storage	With Storage
Plant size (MW)	200	200	200	200
Design direct normal irradiance (DNI) W/m^2	950	950	950	950
Solar multiple	1.4	2	1.4	2
Storage (hours)	0	6	0	6
Solar to thermal efficiency	0.6	0.6	0.65[a]	0.65
Thermal to electric efficiency	0.37	0.37	0.37	0.365[b]
Design thermal output (MWth-hours)	541	541	541	548
Required aperture (m^2)	1327643	1896633	1225517	1774721
Thermal storage (MWth-hours)	0	3243	0	3288

[a] Improved reflectivity, receiver
[b] Parallel storage penalty

Table C-4. Solar Trough Capital Cost Breakdown for 2010 and 2050

Cost Assumptions	2020		2050	
	Without Storage	With Storage	Without Storage	With Storage
Solar field ($/m^2)	300	300	195[a]	195
Heat transfer fluid (HTF) system ($/kWe)	500	500	375[b]	375
Power block ($/kW$_e$)	975	975	900	900
Storage ($/kWh$_{th}$)	0	40	0	30
Contingency	10	10	10	10[c]
Solar field and site ($)	398,293,030	568,990,043	238,975,818	346,070,656
HTF and power block ($)	295,000,000	295,000,000	255,000,000	255,000,000
Storage ($)	0	129,729,730	0	97,479,452
Total with contingency ($)	762,622,333	1,093,091,750	543,373,400	768,406,119
Direct Costs ($/kW)	3,813	5,465	2,717	3,842
Engineering, procurement, construction (%)	10	10	10	10
Owners costs (%)	20	20	20	20
Indirect costs (%)	30	31	30	30
Total Cost ($/kW)	4,957	7,135	3,532	4,995

[a] Reduced material, installation
[b] Lower pressure drop, advanced HTF
[c] slightly higher temperature

Table C-5. Solar Tower Plant Parameters 2010 and 2050

Plant Parameters	2010	2050
Storage (hours)	6	6
Capacity factor (5)	40	41
Collector field aperture (m^2)	1147684	1081000[a]
Receiver surface area (m^2)	847	677.6[b]
Plant capacity (MW$_e$)	100	100
Thermal storage (hours)	6	6
Thermal to electric efficiency	0.425	0.425
Tower height (m)	228	228
Design thermal output (MW$_{th}$)	235	235
Thermal storage (kWh$_{th}$)	1411765	1411765

[a] Better reflectivity, less spillage; Better availability, less receiver heat loss
[b] Higher flux levels; better coatings

Table C-6. Solar Tower Capital Cost Breakdown for 2010 and 2050

Assumption	2010		2050	
Capacity factor	40%		41%	
Heliostat field	235 $\$/m^2$ aperture	$269,705,740	235 $\$/m^2$ aperture	$167,555,000
Receiver	80000 $\$/m^2$ receiver	$67,760,000	50000 $\$/m^2$ receiver	$33,880,000
Tower	901500 0.01298 $\$/m^2$ aperture	$17,387,382	901500 0.01298 $\$/m^2$ aperture	$17,387,382
Power block	950 $\$/kW_e$	$95,000,000	875 $\$/kW_e$	$87,500,000
Thermal storage	30 $\$/kWh_{th}$	$42,352,941	18 $\$/kWh_{th}$	$25,764,706
Total direct costs		$492,206,063		$332,087,088
Total with contingency	10%	$541,426,669	10%	$365,295,797
Indirect costs				
EPC	10%		10%	
Owners	20%		20%	
Total Direct and Indirect Costs	30%	$704,017,098	30%	$474,884,535
Total Cost ($/kW)		$7,040		$4,749

Appendix D. Technical Description of Pumped-Storage Hydroelectric Power

This appendix presents a generic technical description and characteristics of a representative 500 MW pumped-storage hydroelectric (PSH) plant that has as its primary purpose energy storage.

DESIGN BASIS

Pumped storage is an energy storage technology that involves moving water between an upper and lower reservoir. The system is charged by pumping water from the lower reservoir to a reservoir at a higher elevation. To discharge the system's stored energy water is allowed to flow from the upper reservoir through a turbine to the lower reservoir. The overall efficiency of the system is determined by the efficiency of the equipment (pump/turbine, motor generator) as well as the hydraulic and hydrologic losses (friction and evaporation) which are incurred. Overall cycle efficiencies of 75%–80% are typical.

Most often, a pumped storage system design utilizes a unique reversible Francis pump/turbine unit that is connected to a motor/generator. Equipment costs typically account for 30%–40% of the capital cost with civil works making up the vast majority of the remaining 60%–70%.

The configuration of the pumped-storage plant used in this report is described as follows:

1. The 500-MW pumped-storage project will operate on a daily cycle with energy stored on a 12-hour cycle and generated on a 10-hour cycle. Approximately 322 cycles per year would be assumed.
2. For purposes of this evaluation, the energy storage requirement is equal to 500 MW for 10 hours or 5,000 megawatt hours of daily peaking energy.
3. The lower reservoir is assumed to exist and a site for a new upper reservoir can be found that has the appropriate characteristics.
4. For evaluation purposes, the pumping and generating head is based on the average difference in the upper and lower reservoir levels. The reality is that the heads in both pumping and generating modes will constantly fluctuate during their respective cycles. This fluctuation must be designed
5. This evaluation is based on an average net operating head (H) for both pumping and generating cycles of 800 feet.
6. The distance from the outlet of the upper reservoir to the outlet of the lower reservoir is assumed to be 2,000 feet resulting in an L/H ratio of 2.5, which is excellent by industry standards.
7. The calculated generating flow assuming a 0.82 generating efficiency is 9,000 cubic feet per second (cfs).
8. The active water storage in the reservoirs required for this flow over the 10 hours generating cycle is 7,438 acre-feet. Adding 10 percent for inactive storage yields a total reservoir storage requirement of about 8,200 acre-feet.
9. The lower reservoir is assumed to be an existing reservoir that can afford a fluctuation of 7,438 acre-feet without environmental or other fluctuation issues.

STUDY BASIS DESCRIPTION AND COST

Based on the above project sizing criteria, the following reconnaissance-level project design and associated capital cost was estimated:

1. Assuming an upper reservoir depth of 100 feet yields a surface area of 82 acres. Using a circular reservoir construction results in a 2,132-foot diameter and a circumference of 6,700 ft. The assumed dam would be a gravity type constructed using roller-compacted concrete (RCC). Other types such as concrete-faced rock fill, concrete arch, or embankment are possible depending on site conditions. The total volume of RCC is estimated at 670,000 cubic yards (cy). At a cost of $200/cy, RCC would cost roughly $134 million. The following are other upper reservoir estimated costs:

   A. Reservoir clearing: $10 million

   B. Emergency spillways: $5 million

   C. Excavation and grout curtain: $20 million

   D. Inlet/Outlet structure and accessories: $20 million

   The total reservoir cost is roughly $189 million.

2. The tunnels from the lower reservoir to powerhouse and from powerhouse to upper reservoir would include 20-foot diameter access tunnel (assumed to be 1,000 ft long) and 2x20 foot diameter penstock and draft tube tunnels (total of 4,200 ft long). Other tunnels and shafts for ventilation and power lines would be required. About $60 million is assumed for tunneling.
3. The powerhouse would be constructed underground and be approximately 100 feet and 200 feet for a 2x250 MW pump turbine unit. The excavation of the powerhouse would cost approximately $35 million.
4. At an estimate cost of $750 per installed kW, the powerhouse structures, equipment, and balance of plant would cost about $375 million.
5. The total estimate construction cost is therefore:

   A. Upper reservoir: $189 million

   B. Tunnels: $60 million

   C. Powerhouse excavation: $35 million

   D. Powerhouse: $375 million

   Total: $659 million

6. The following additional technical assumptions have been made for this option:

   A. The site features geological formations ideal for upper reservoir and underground development.

   B. A relatively flat 82-acre site is required for the upper reservoir. A total site area, including underground rights is about 200 acres.

   C. The site is on land where no existing human-made structures exist.

   D. No offsite roads are included.

E. The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.

F. Construction power and water is assumed to be available at the site boundary.

G. No consideration was given to possible future expansion of the facilities.

H. A 345-kV generator step-up (GSU) transformer is included. Transmission lines and substations/switchyards are not included in the base plant cost estimate. An auxiliary transformer is included.

I. Provision for protection or relocation of existing fish and wildlife habitat, wetlands, threatened and endangered species or historical, cultural, and archaeological artifacts is not included.

J. The upper reservoir will be capable of overtopping due to accidental over-pumping. A service spillway equal to the pumping flow is assumed.

OTHER COSTS AND CONTINGENCY

The following are potential additional costs:

1. Plant location is assumed to be where land is not of significant societal value, with a cost of $5,000 per acre or $1 million total.
2. Transmission and substation are assumed to be adjacent to the site and is a major siting factor.
3. Project management and design engineering at 5% of construction cost or $33 million.
4. Construction management and start-up support at 5% of construction cost of $33 million.
5. A contingency of $109 million (15%) is assumed.

Total: $176 million.

Based on the total Construction Cost of $659 million and the above Other Costs and Contingency of $176 million, the total capital cost is estimated to be $835 million, or roughly 1,670 $/kW. A 20% addition for owner's costs of the type described in Text Box 1 in section 1.2 above yields a cost of 2,004 $/kW that is comparable to the other cost estimates provided.

OPERATING AND MAINTENANCE COST

Operating and maintenance costs are dependent on the mode of operation. For hydroelectric plants, the following are the typical annual operating and maintenance costs:

1. Routine Maintenance and spare parts: $500,000
2. Personnel wages (20 total @$65,000): $1.3 million

    A. One plant manager

    B. Two administrative staff

    C. Eight operators

    D. Two maintenance supervisors

    E. Seven maintenance and craft

3. Personnel burden @ 40% of wages: $520,000

4. Staff supplies @ 5% of wages: $65,000

   Total: $2.385 million per year

Hydroelectric plants typically operate for 5-10 years without significant major repair or overhaul costs. For evaluation purposes, a major overhaul reserve available at year 10 of $100 per installed kilowatt or $50 million is assumed. When spread over a 10-year period, the annual major overhaul cost is $5 million per year.

CONSTRUCTION SCHEDULE

A PSH project is a major civil works infrastructure project that would take many years to develop but would provide a project life that exceeds that of the other renewable technologies evaluated in this report. Project life can be expected to be at least 50 years. Many hydropower projects constructed in the early 1900s are still in service today. The development of an impound project would have the following estimated milestone schedule:

1. Permitting, design, and land acquisition: 2-4 years
2. Equipment manufacturing: 2 years
3. Construction: 3 years

   Total: 7-9 years

OPERATING FACTORS

A hydroelectric plant can be designed to provide the following operating factors:

1. Normal start-up and shutdown time for a PSH project is less than 1-5 minutes depending on the status of the water passages. If the unit is watered to the wicket gates and plant auxiliaries are running, unit start-up time is only a function of wicket gate opening to bring the unit up to speed and synchronize.
2. A PSH unit can be tripped off instantaneously as long as the turbine is designed to operate at runaway until the wicket gates are closed. This would be an emergency case.
3. A PSH plant can load follow and provide system frequency/voltage control.
4. Pumped-storage hydroelectric plants can black-start assuming a small emergency generator is provided for unit auxiliaries and field flashing.
5. A major feature of PSH is its ability to operate as spinning or non-spinning reserve, change from pumping to generating within 20 minutes, synchronous condensing, and it can be designed to meet grid system operator certification of these benefits.

Appendix H

Customer Attitudes & Preferences Relating to PGE's IRP

by Definitive Insights for PGE

DEFINITIVE INSIGHTS

Customer Attitudes & Preferences Relating to PGE's Integrated Resource Plan

Relevant Insights from Residential, General Business, & Key Business Customers

For Definitive Insights:

David C. Lineweber, Ph.D.
Sabrina Lomeu
John Whaley

This Discussion Covers Two Recent Customer Research Efforts

- **Preferences Relating to IRP Issues:**
  - Explored issues within Residential, General Business, and Key Business customers regarding their views on the resource mix they think is most appropriate to meet future energy needs.
    - This research was commissioned to strengthen PGE's understanding of Customer concerns and to provide input into the 2013 IRP process
    - This research aligns closely with similar customer research conducted in 2006.
  - Primary objective was to quantify customer support for various energy resources under consideration for inclusion in the 2013 IRP
    - Conventional Coal, Next Generation Coal, Next Generation Nuclear, Natural Gas, Renewables (Solar, Wind, Geothermal, Biomass), Energy Conservation
- **Residential Customer Attitudes And Actions Relating to Energy Efficiency**:
  - What do customers say they have done, and are doing, in this arena?
  - What more would they be willing to do, and under what circumstances?

DEFINITIVE INSIGHTS

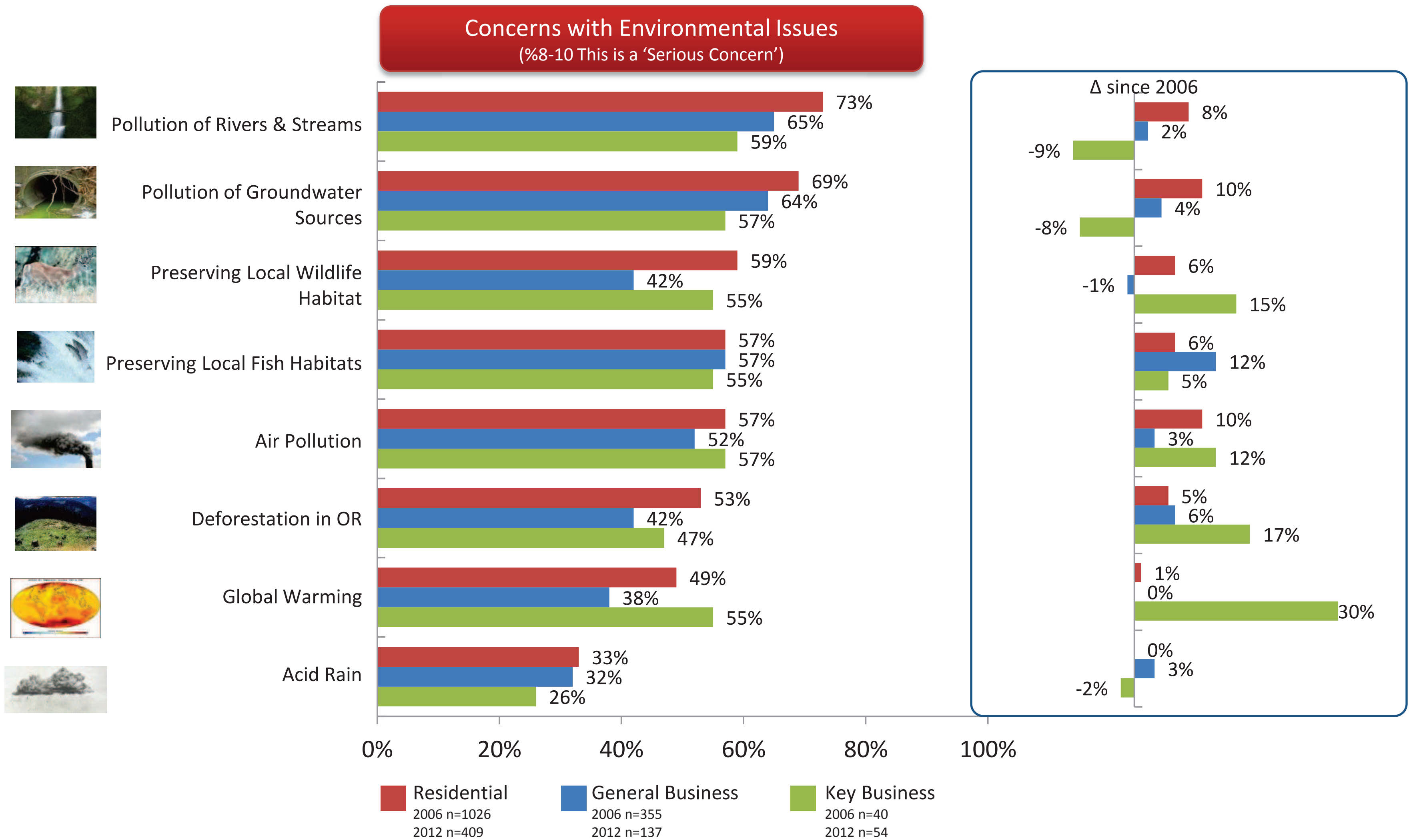
Methodology

- **IRP Customer Research**
  - Customers Completed Surveys Online
    - **502** Residential ; **198** General Business; and **54** Key Business Customers
    - Surveys were completed from July – September 2012
    - Respondents were incented for their participation
  - Invitation & Screening
    - Residential and General Business Customers: Screening / invitation completed via phone
    - Key Business Customers: Invited via email to complete screener / survey online
- **Energy Efficiency Research**
  - Online survey of 763 PGE residential customers invited by email to complete the survey during late 2012

Key Topics & Takeaways

- **Context for Resource Preferences**
  - All customer classes continue to say that environmental issues are a concern
- **Overall Resource Preferences**
  - All customer classes continue to express strong stated preferences for renewables and EE & conservation
- **Preferences for Resource Mix**
  - There is a preference for a resource mix that is NOT highly dependent on one or two sources
  - Stated preferences for greener options continue, even when this means 5% or 10% higher rates for everyone
- **So, What Will Residential Customers Do To Contribute to EE & Conservation?**
  - Residential customers support PGE EE efforts (mostly) and say they are interested in it themselves
    - Though, this is where political differences have a big impact
  - Residential customers also say they have already done a lot, and try pretty hard to manage energy use

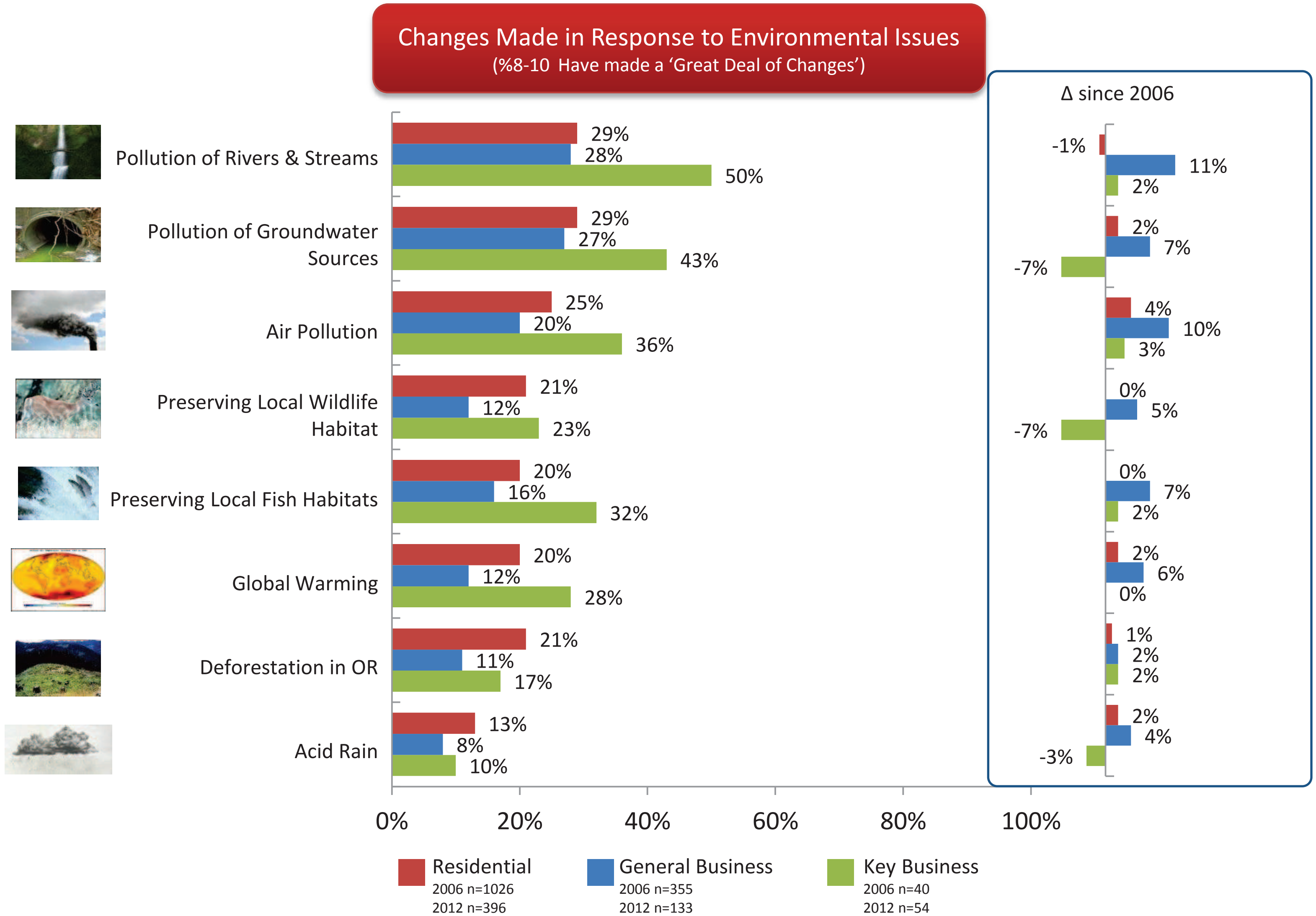
Concerns with Local Environmental Issues Tend to Be Highest, But Global Warming Is Also Important



DEFINITIVE INSIGHTS

S15/S29 (2006); S10/S27 (2012): How serious a concern would you say each of the following global environmental issues is for you as a resident of Oregon? 0=Not at all serious concern; 10=Extremely serious concern.

Most Customers (Excepting Some Key Businesses) Have Not Done Much In Response To These Concerns

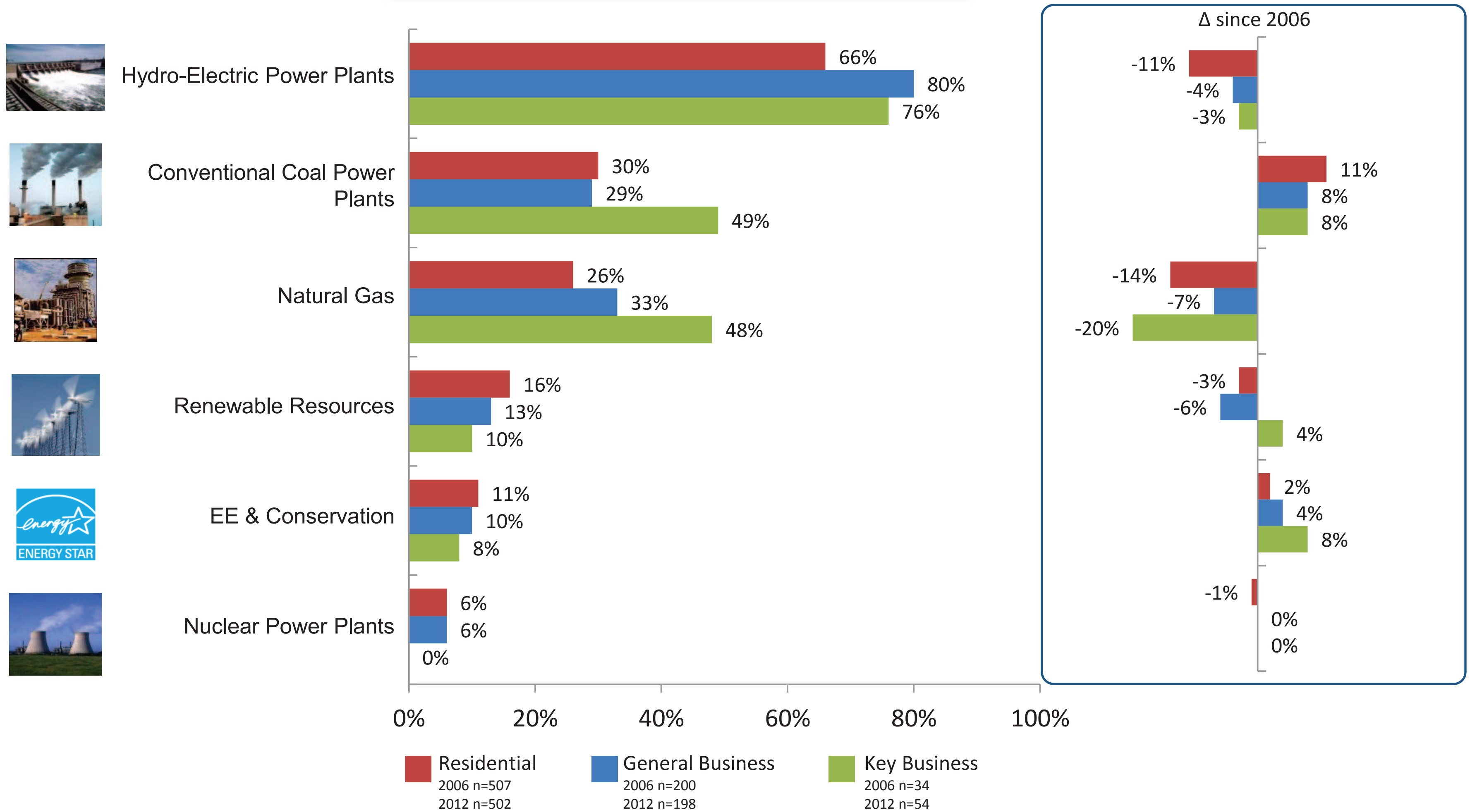


DEFINITIVE INSIGHTS

S16/S30 (2006); S11/S28 (2012): To what degree have you made changes in the way you buy or use products and services in response to each of the environmental issues just discussed? 0=Little or no change; 10=A great deal of change.

Customers Most Often Assume That Hydro is Central to the PGE Power Supply

Opinions of Resource that Accounts for Greatest/2nd Greatest Proportion of PGE's Power Supply



DEFINITIVE INSIGHTS

Q5/6: Which one of these resources do you think currently accounts for the greatest/second greatest proportion of PGE's power supply?

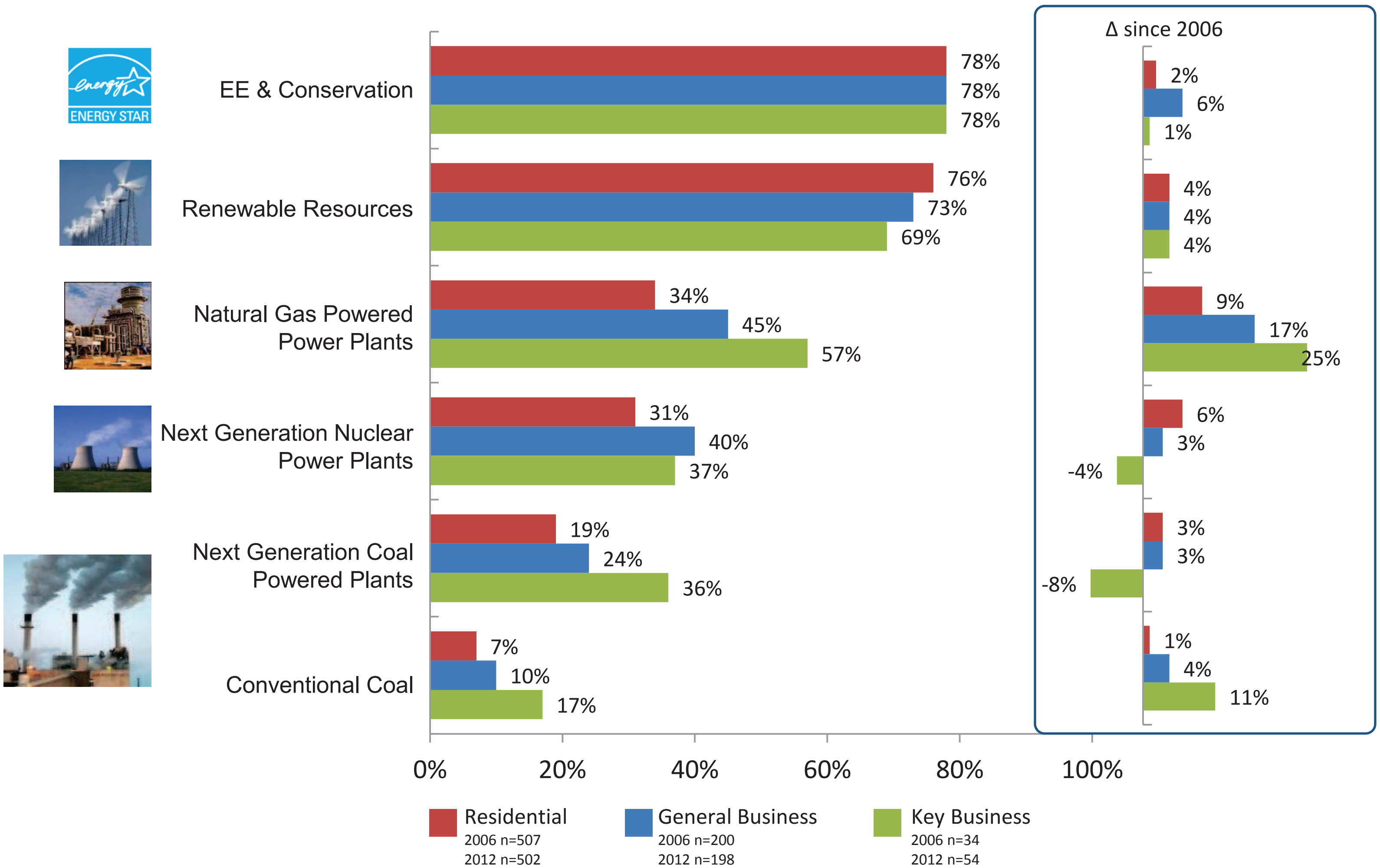
Overall Customer Resource Preferences

DEFINITIVE INSIGHTS

Customers Across All Customer Classes Continue to Say That They Prefer EE / Conservation & Renewables

Preference for Conventional Resources Before Resource Descriptions

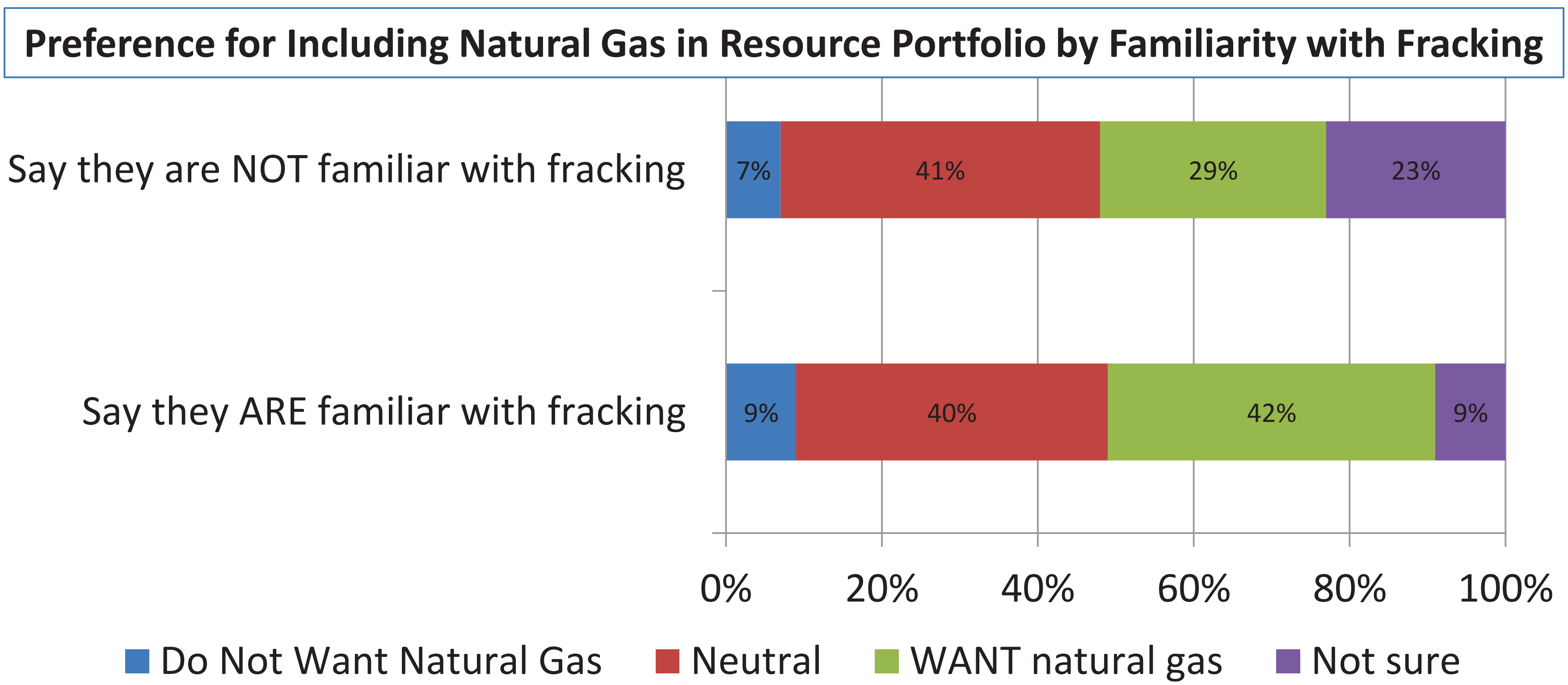
(Preference for Including Conventional Resources in a Long-Term energy supply plan for Oregon (% 8-10) **before** resource description)



Q4 (2006 &2012). Please tell us how much you prefer that each type of resource be included in a future energy plan for Oregon. 0=Definitely do not want this resource included in such a plan, 10=Definitely want this resource included in such a plan.

Natural Gas Preferences & Fracking

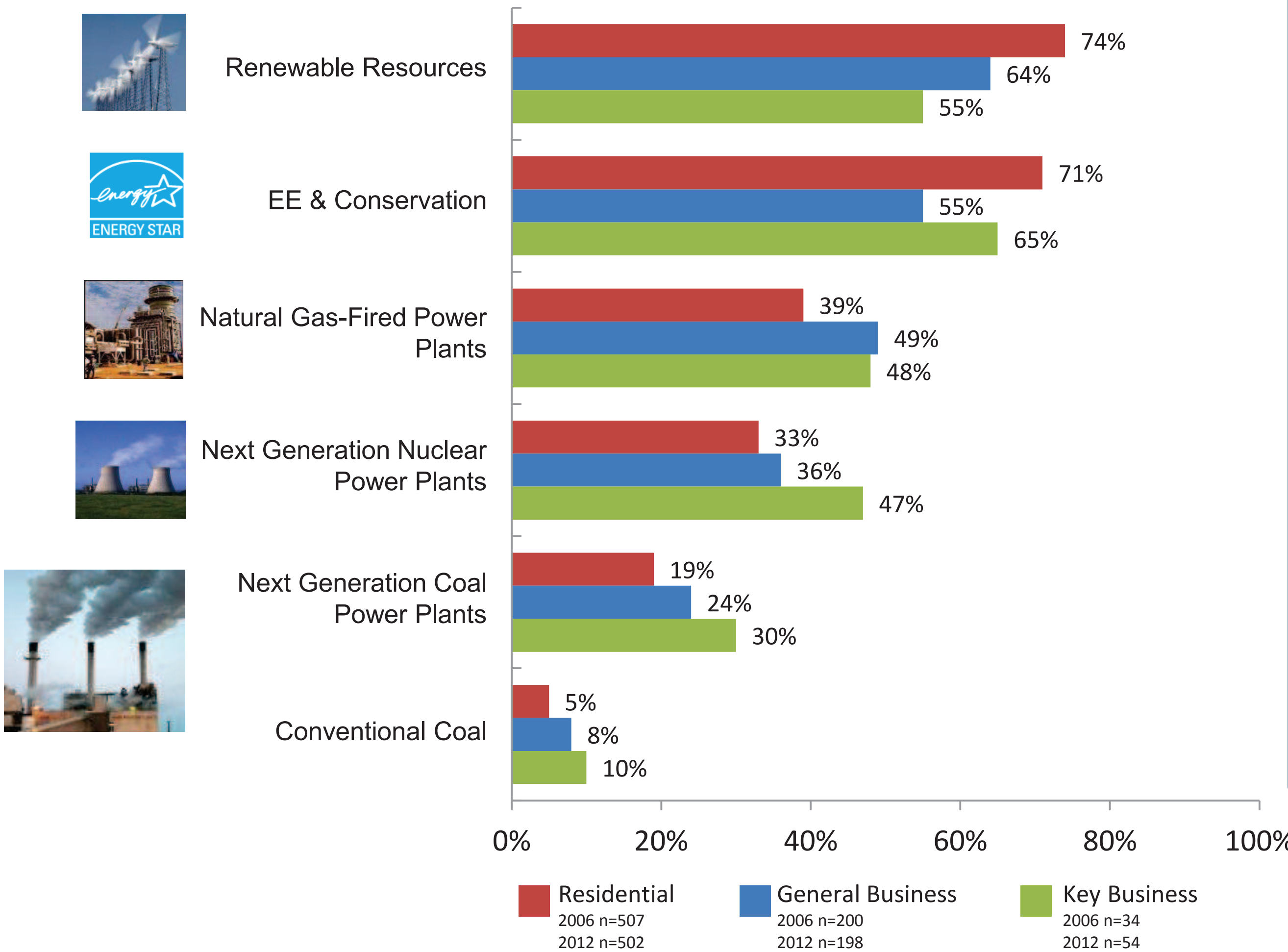
- Customers who say they are familiar with fracking are slightly more positive toward natural gas, though not dramatically so

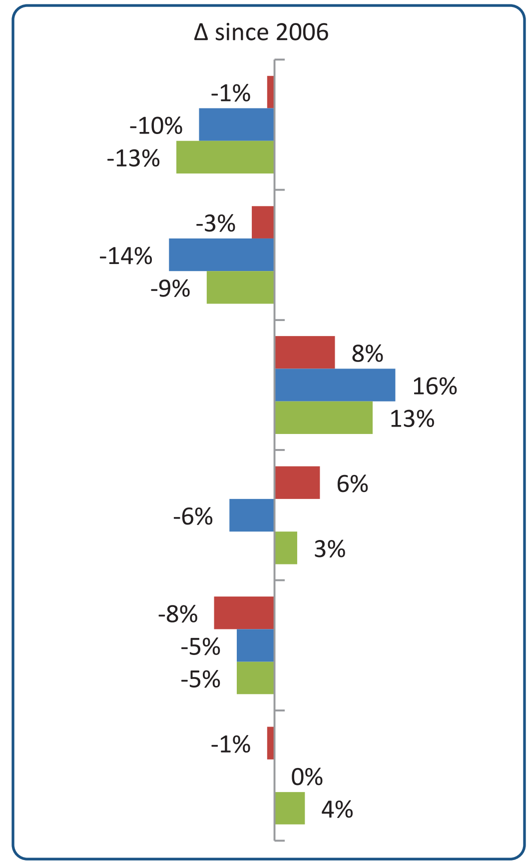


DEFINITIVE INSIGHTS

And Customers Retain the Same Preferences, Regardless of the Cost of Those Resources

Resources Customers Definitely Want PGE to Include
(Given cost, price stability, environmental impact, and reliability and no matter resource cost)



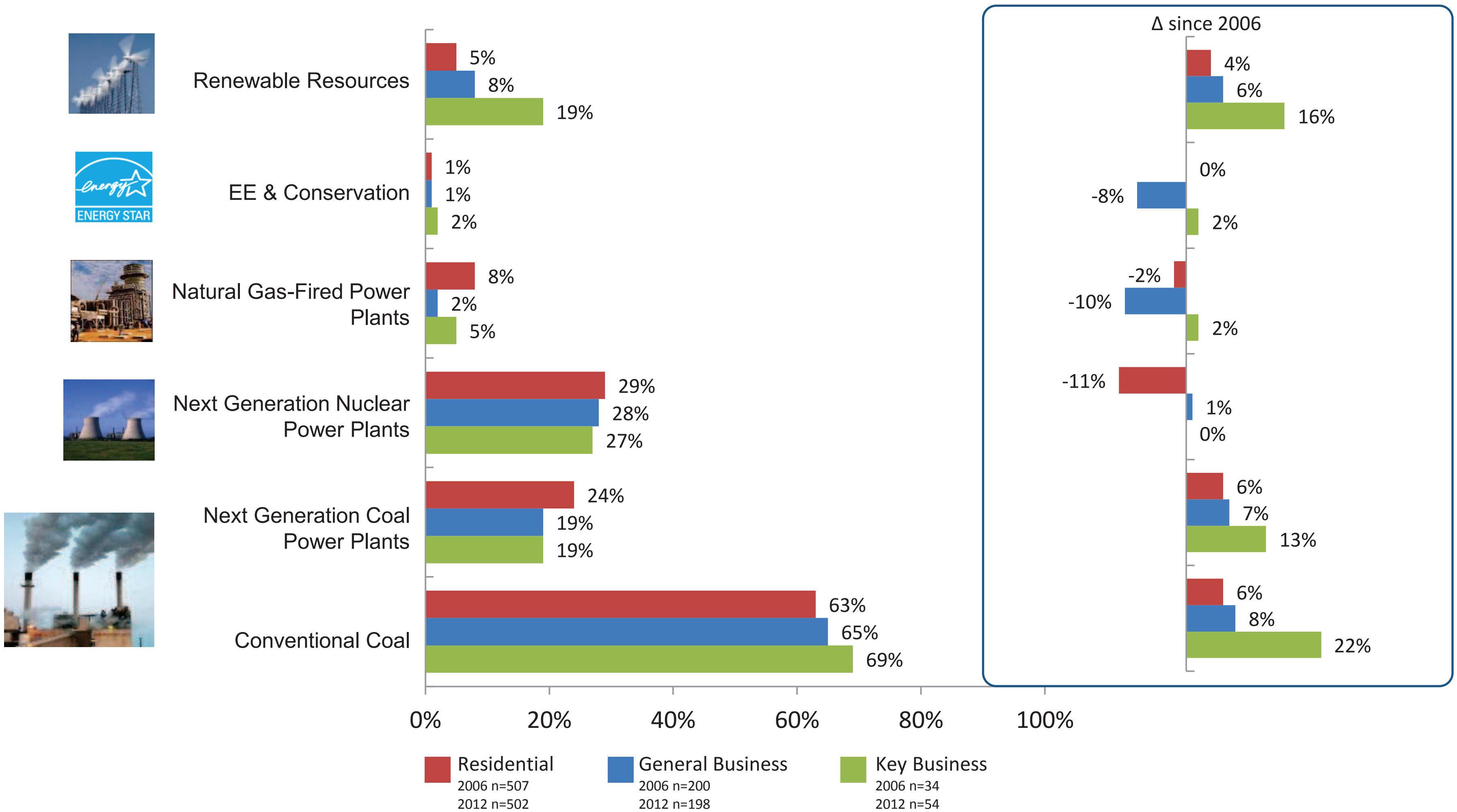


DEFINITIVE INSIGHTS

Q15 (2006) Q19 (2012) Which of these resources would you definitely want PGE to include in a future electricity supply plan regardless of how expensive it was relative to other options?

When The Question is Flipped (What Do You Not Want Regardless of How Cheap It Is?): Coal is The "Winner"

Resources Customers do NOT Want PGE to Include
(Given cost, price stability, environmental impact, and reliability and no matter resource cost)

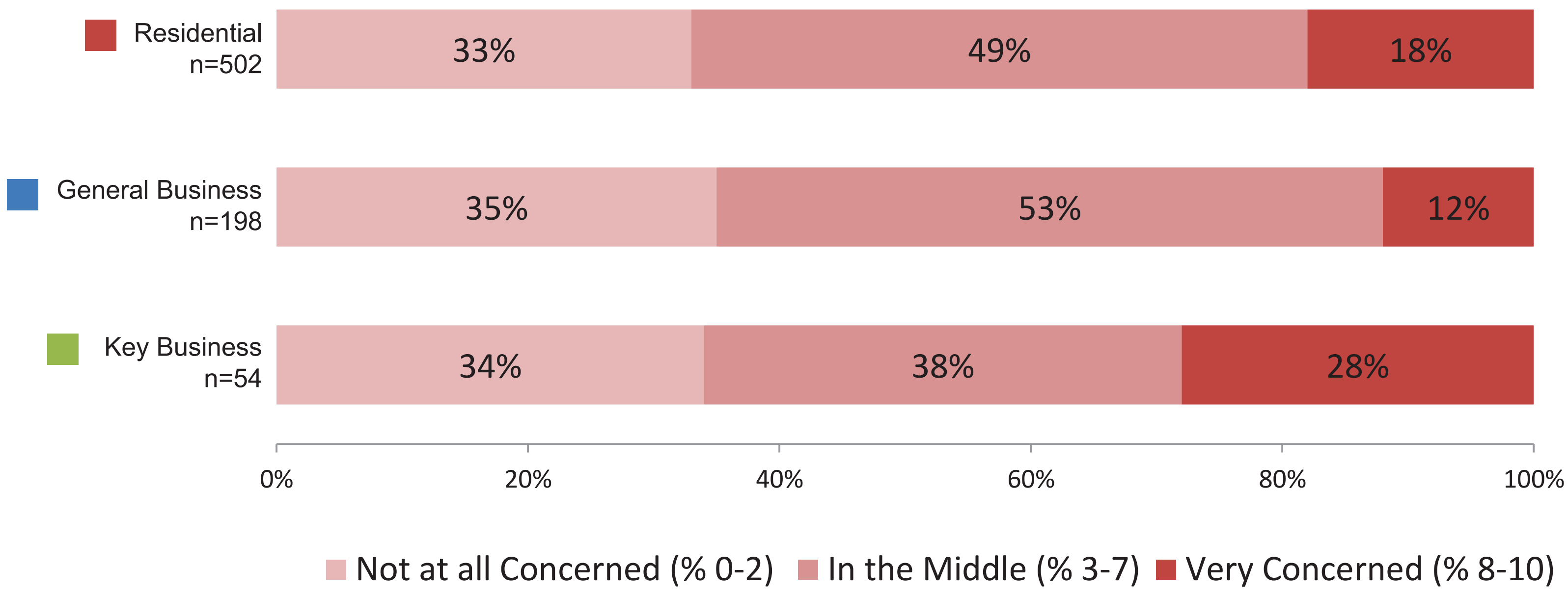


Q16 (2006) Q20 (2012) Which of these resources would you definitely NOT want PGE to include in a future electricity supply plan regardless of how expensive it was relative to other options?

DEFINITIVE INSIGHTS

Key Business Customers More Often Express Concerns with The Negative Impacts of Renewables

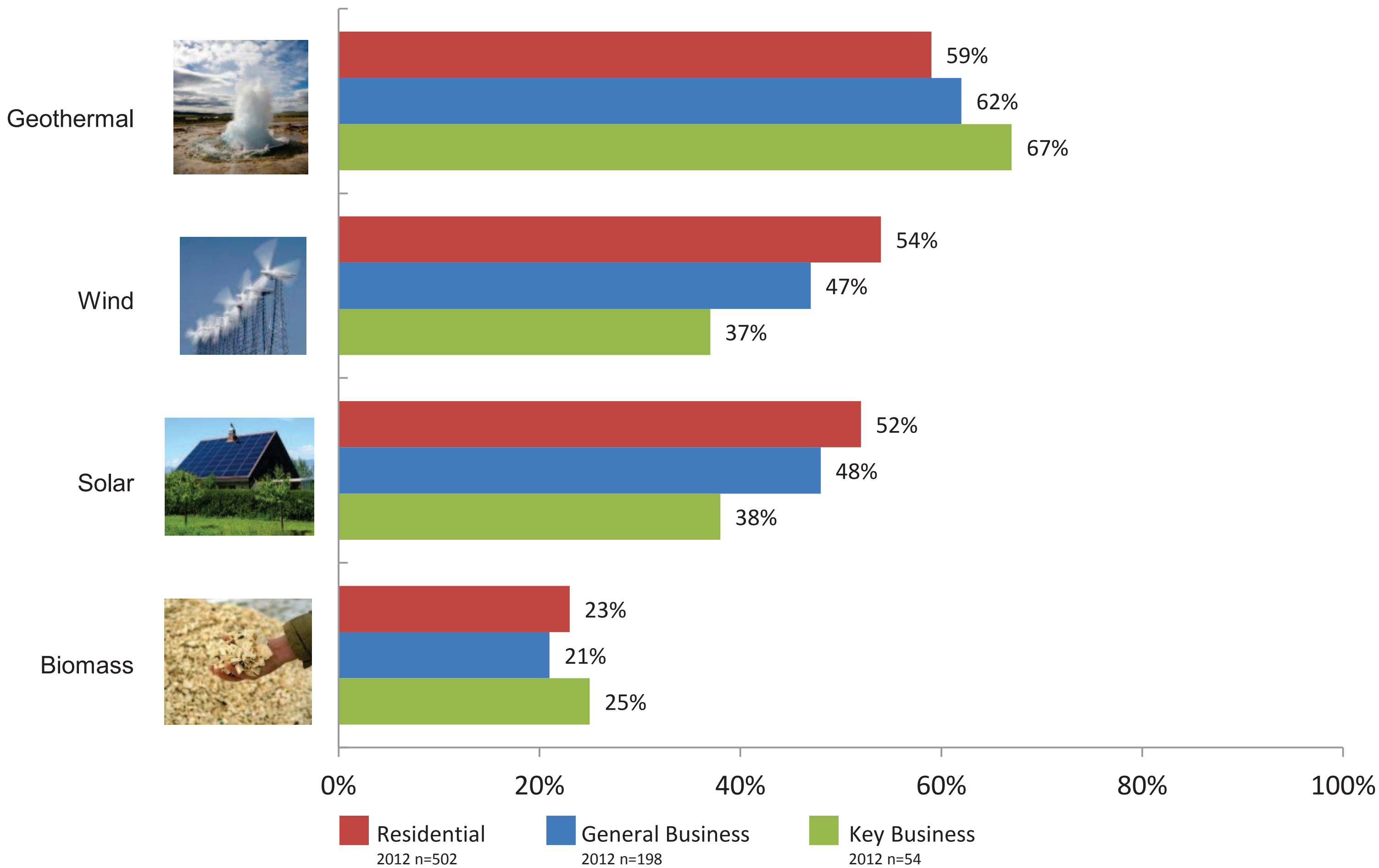
Concern About Potential Negative Impacts of Renewable Resources



Q64. While many people support the use of renewable resources, other people are concerned that renewable resources do have negative impacts (visual impacts from wind turbines, for example, or the acreage needed for solar farms. How concerned are you about any potential negative impacts from renewable resources?

Geothermal is the Most Preferred Specific Renewable Resource, While Biomass is Least Preferred

Preference for **Renewable** Resources After Resource Descriptions
(Preference for Including Renewable Resources in a Long-Term energy supply plan for Oregon (% 8-10) **after** resource description)

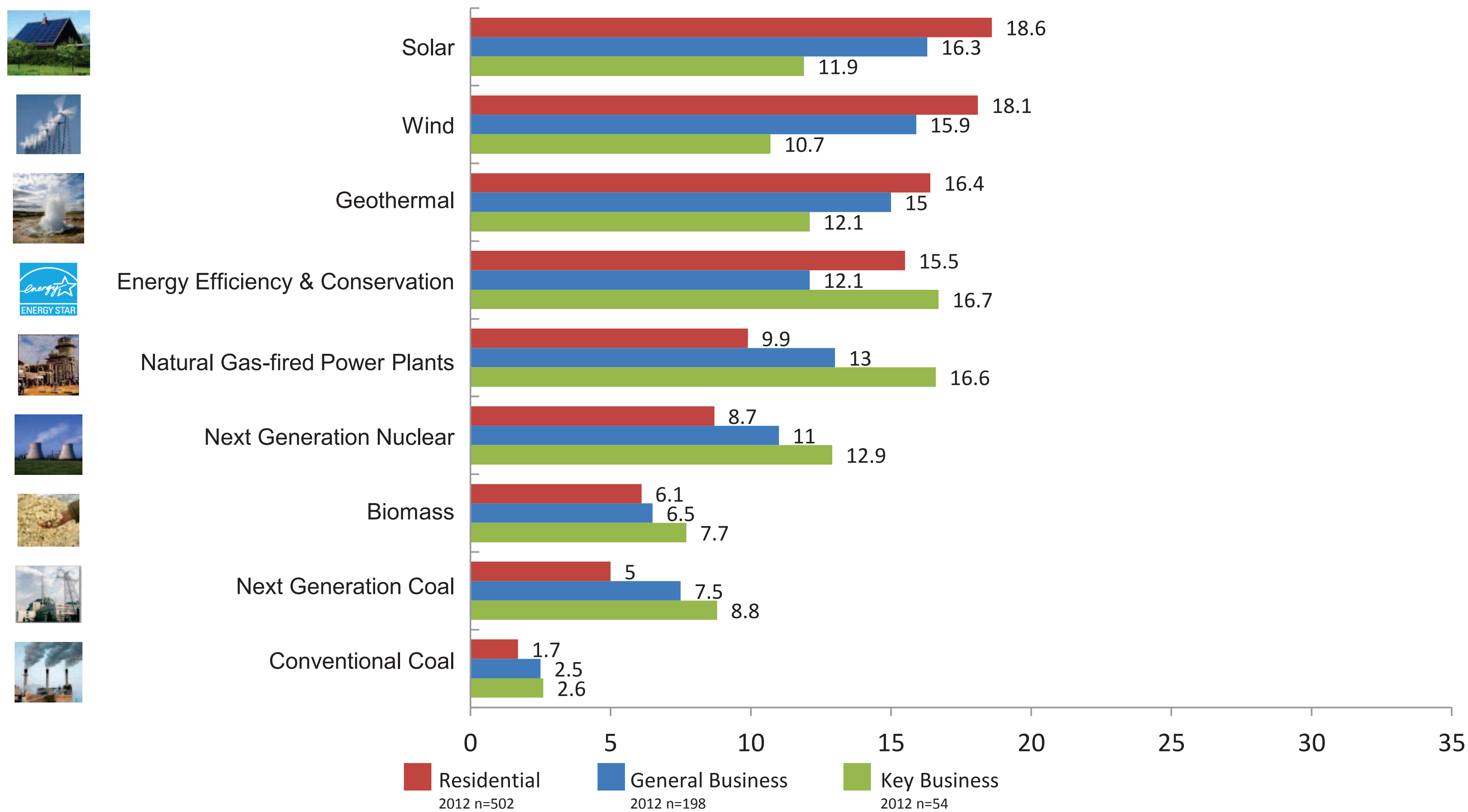


DEFINITIVE INSIGHTS

Q43A-Q43D (2012 Only) Given these factors, please rate (resource) in terms of the extent to which you would prefer that renewables be part of PGE's long-term energy supply plans. 0=Definitely do not want this resource included in such a plan, 10=Definitely want this resource included in such a plan.

Customers Want A Diverse Energy Supply Portfolio, But Composed Mostly of Renewables And EE & Conservation

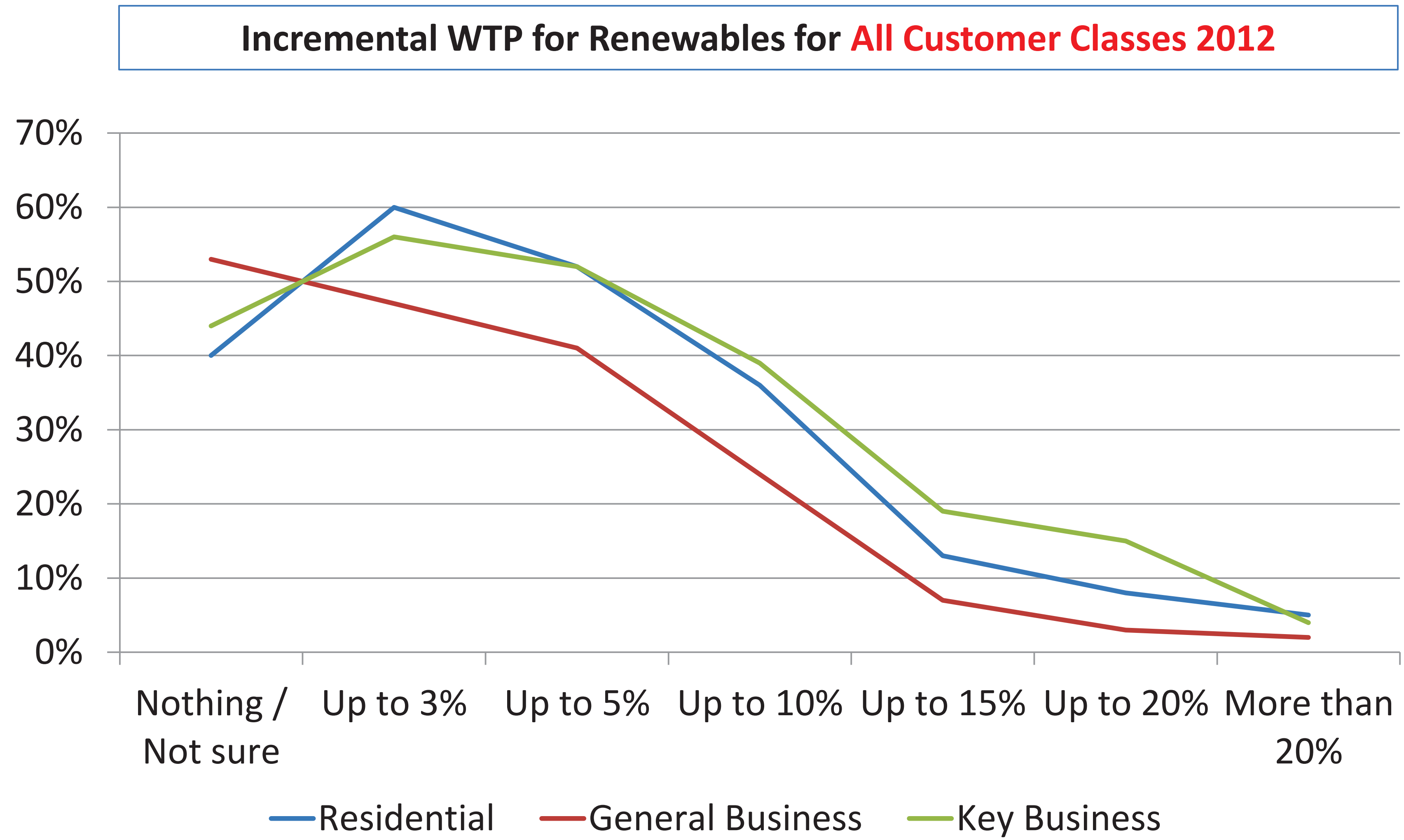
'Perfect' Energy Supply Plan – Including Specific Renewables
100 Points Allocated Across Nine Resources, Given Equal Prices
(Mean Points Allocated)



DEFINITIVE INSIGHTS

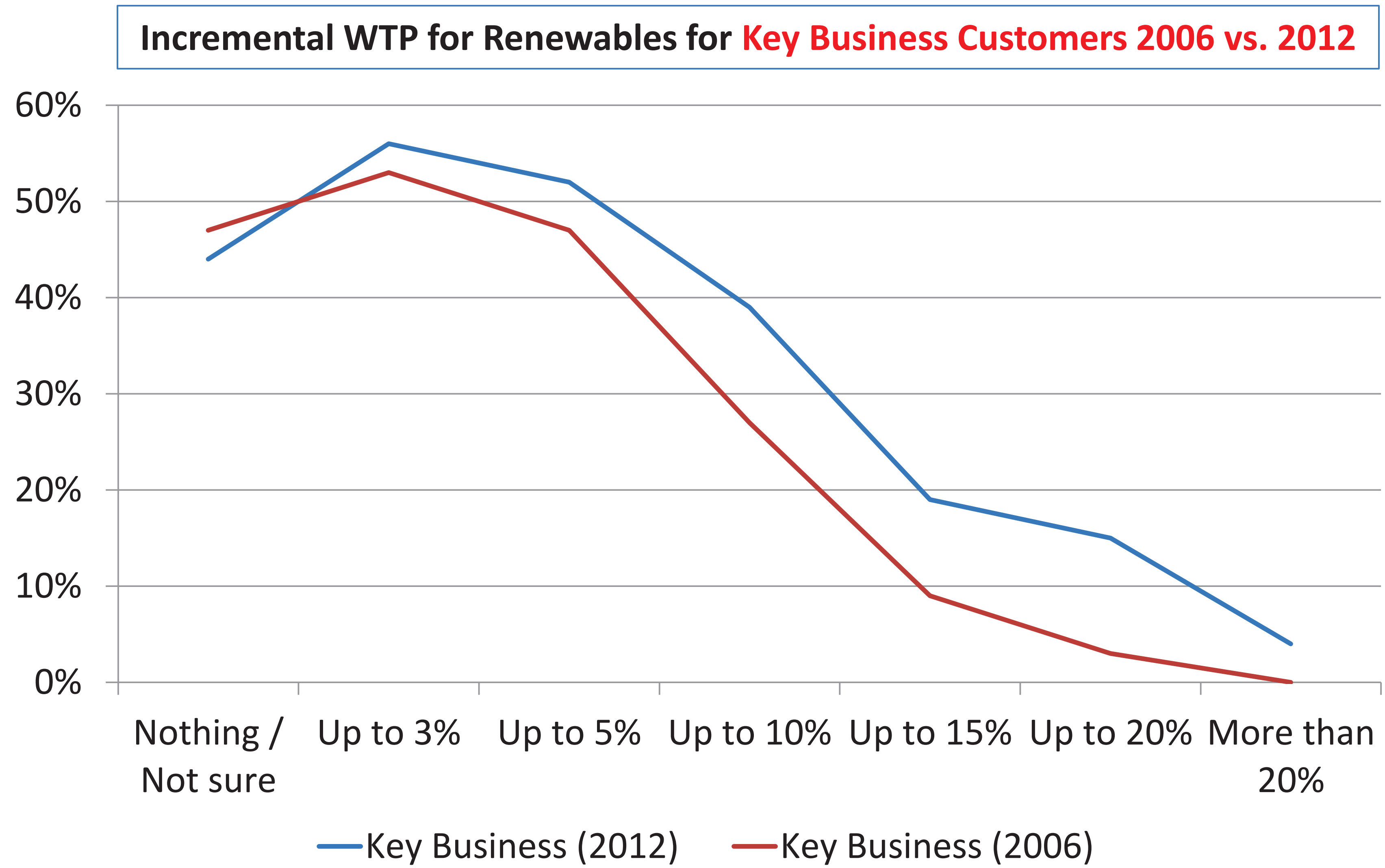
Q43E (2012 only): Please allocate 100 'points' across the different energy resources below in a way that indicates which resources you would most like to see developed, given what you now know about these resources. (note: max of 40 allotted to any single resource)

Customers Continue To Say They Will Pay More for Renewable Resources Themselves



DEFINITIVE INSIGHTS

And Key Business Customers Have Trended To Say They Will Also Pay More Since 2006



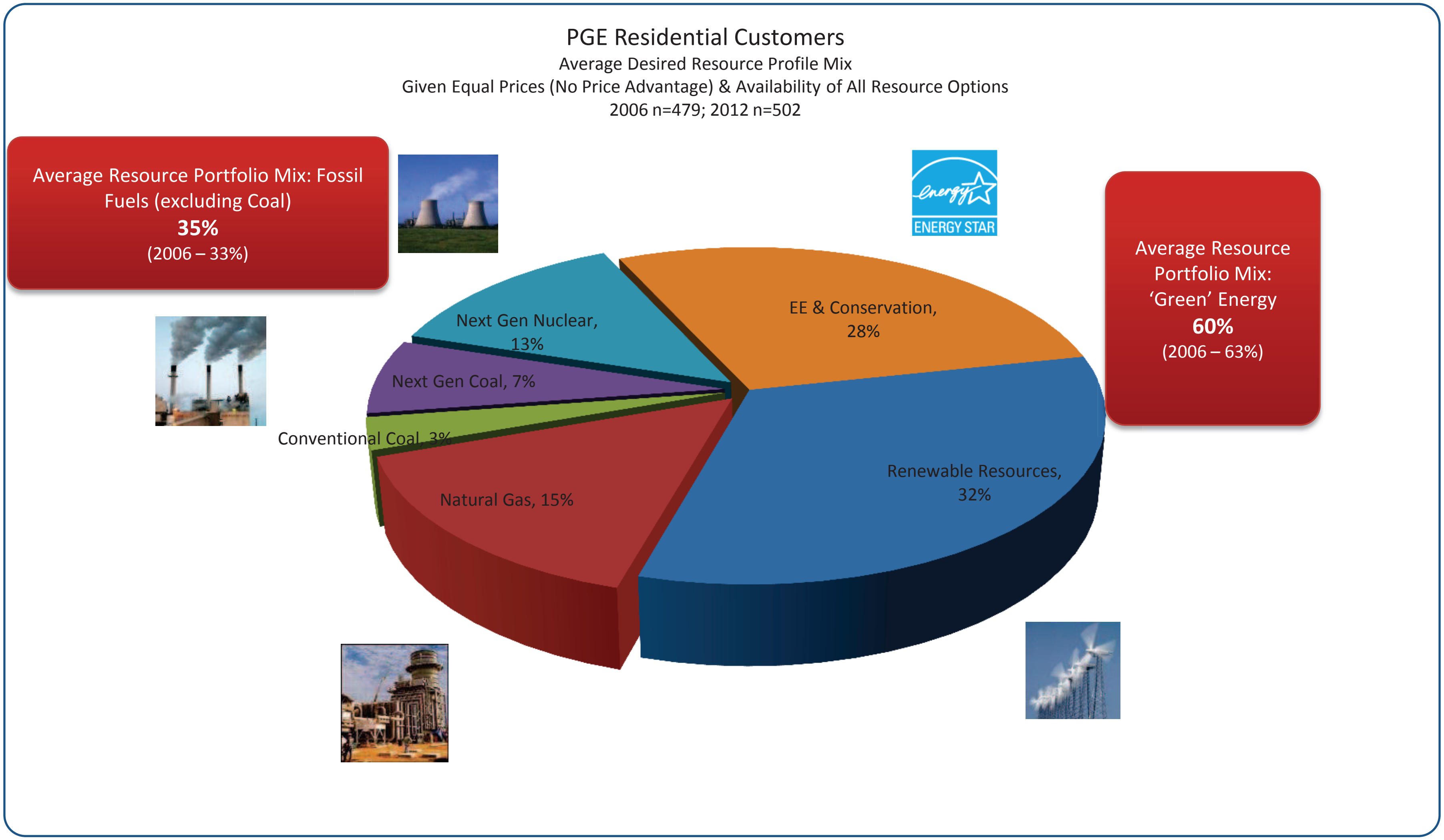
DEFINITIVE INSIGHTS

Understanding Customer Preferences for Resource Mix

DEFINITIVE INSIGHTS

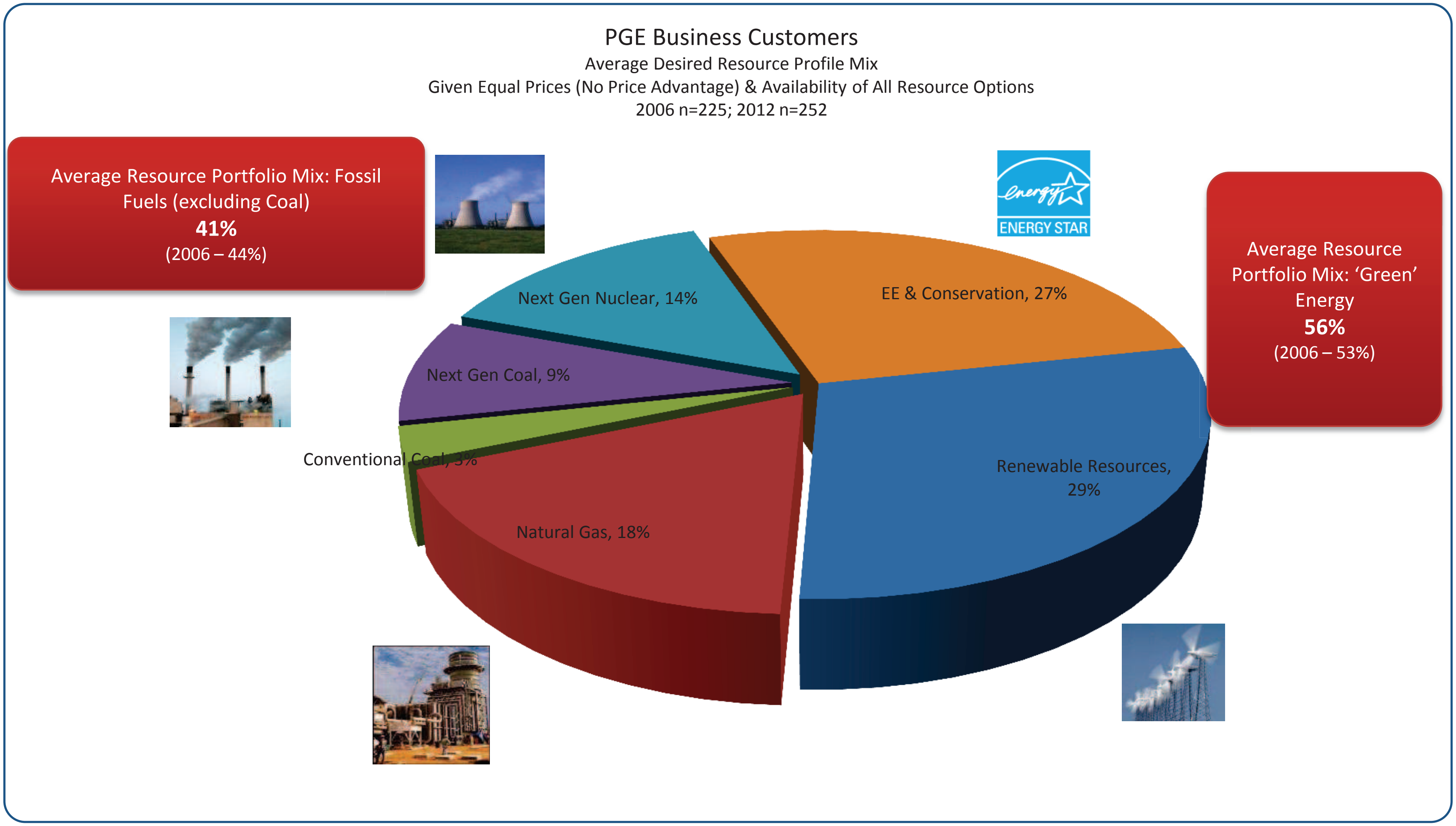
18

When Residential Customers Outline Their Preferred Resource Mix , Non-Green Options Make Up 35% of The Supply



19

For Business Customers, Non-Green Options Make Up 41% of the Resource Mix



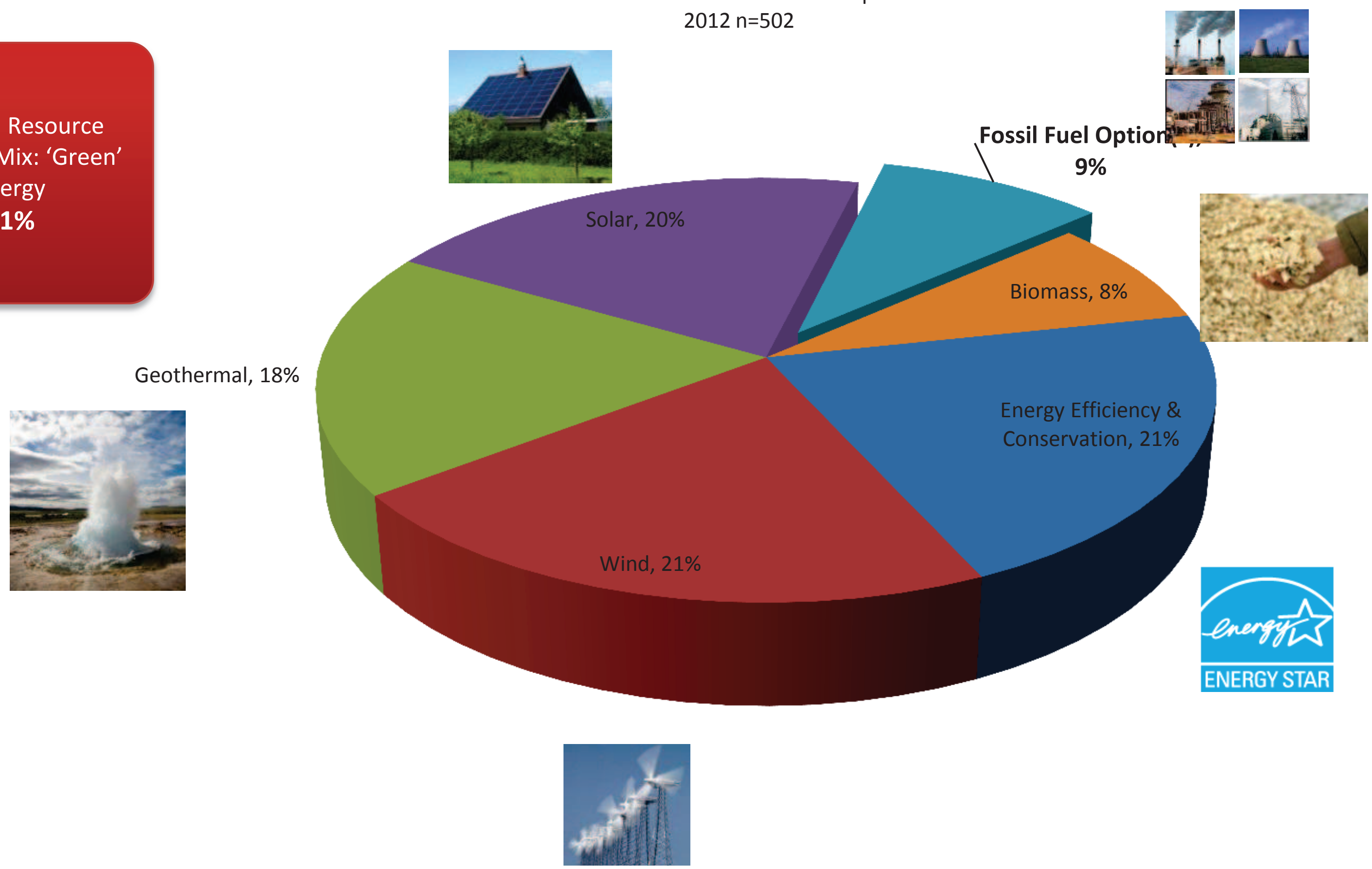
When Residential Customers Can Choose From Among One Fossil Fuel + All Available 'Green' Options, The Fossil Options Gets 9%

PGE Residential Customers

Average Desired Resource Profile Mix Given Equal Prices (No Price Advantage) & Availability of One Conventional Resource (from among Con. Coal, Next Gen Coal, Nat. Gas) AND ALL Renewable Resource Options

2012 n=502

Average Resource Portfolio Mix: 'Green' Energy
91%



Poisson Regression Results – Q44-Q53

DEFINITIVE INSIGHTS

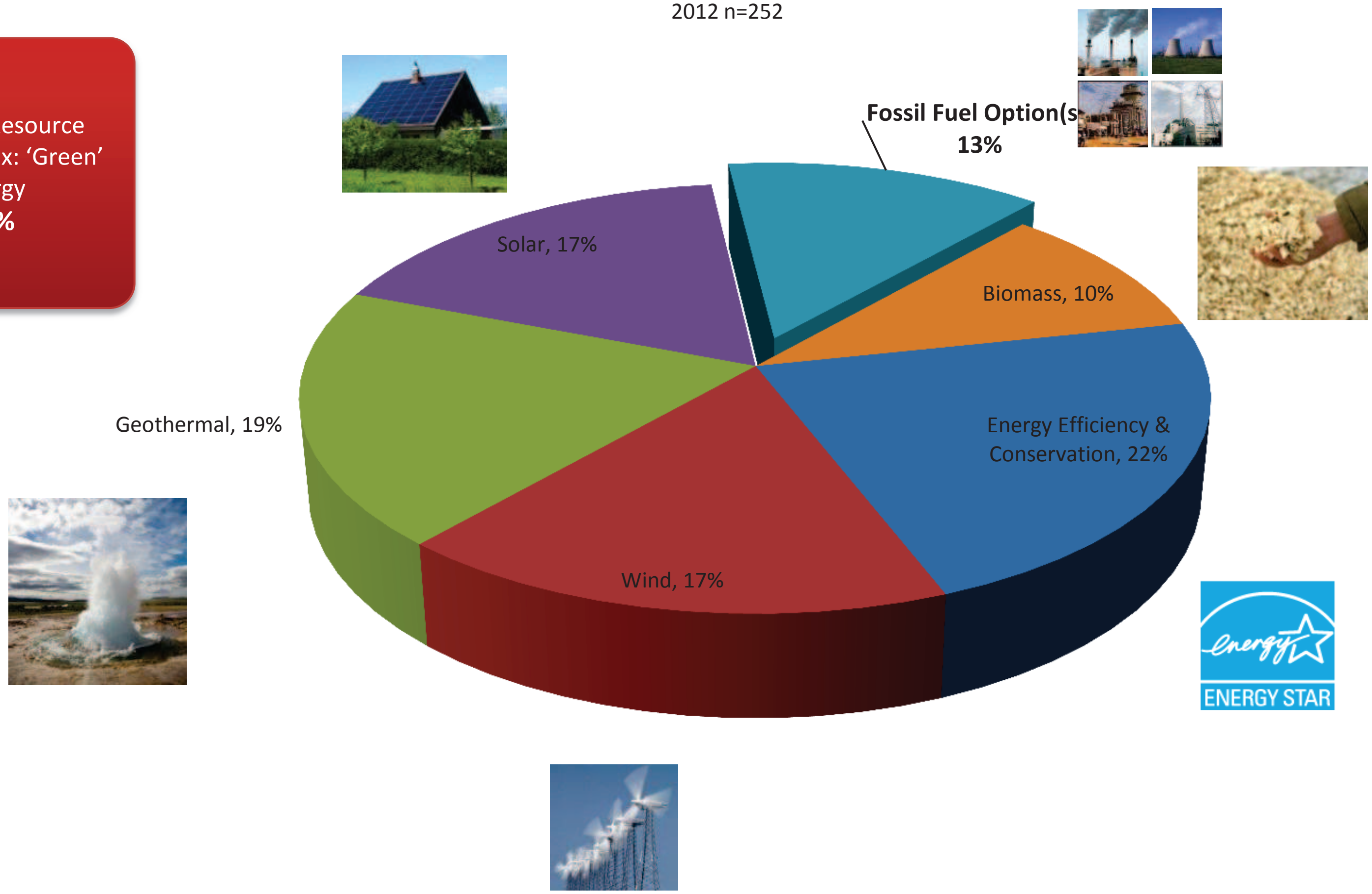
When Business Customers Have the Same Choices Their Responses Are Very Similar

PGE Business Customers

Average Desired Resource Profile Mix Given Equal Prices (No Price Advantage) & Availability of One Conventional Resource (from among Con. Coal, Next Gen Coal, Nat. Gas) AND ALL Renewable Resource Options

2012 n=252

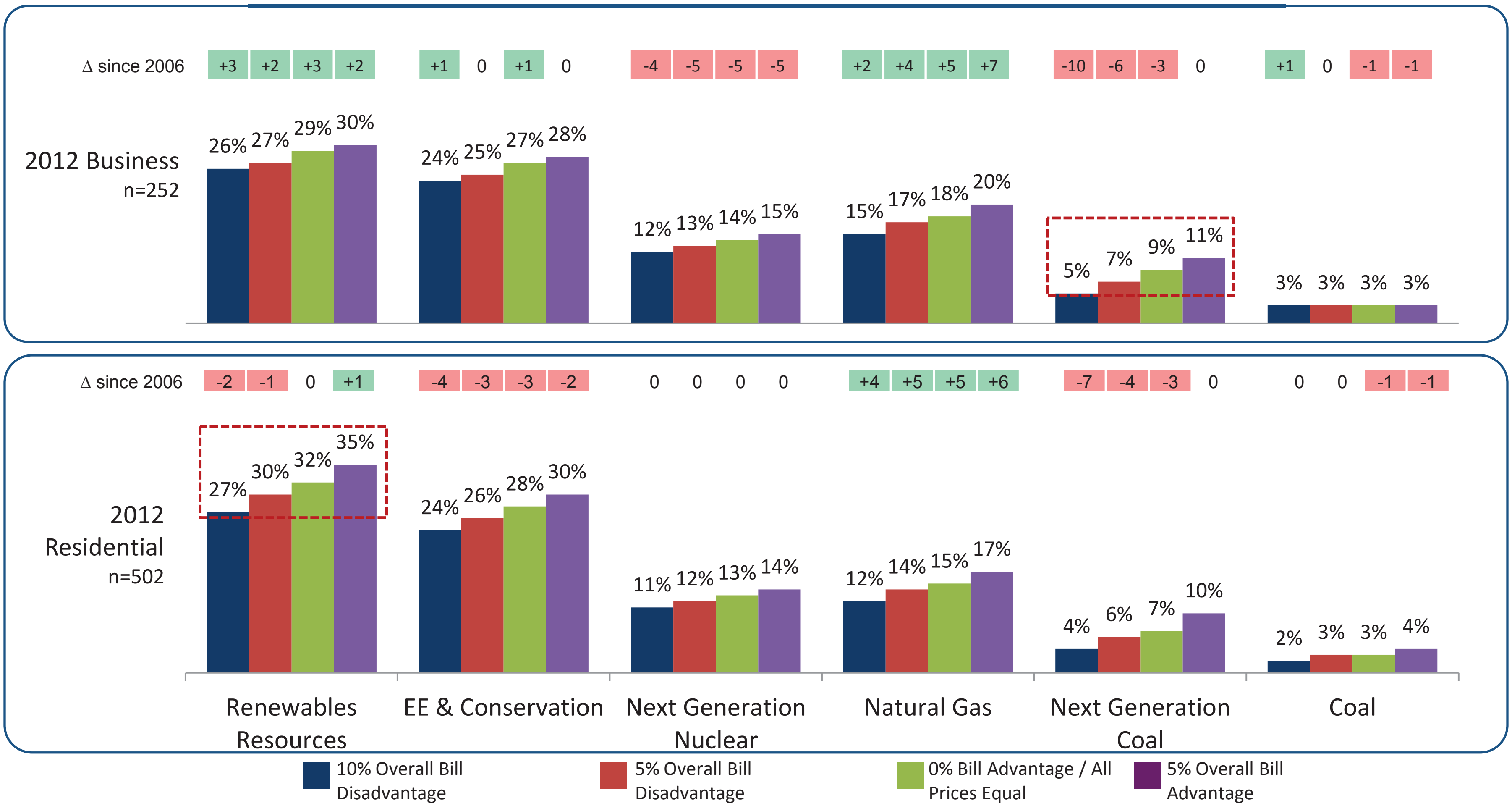
Average Resource Portfolio Mix: 'Green' Energy
87%



Poisson Regression Results – Q44-Q53

Customers Are Only Slightly Sensitive to Bill Impacts: When A Given Resource Would Increase Bills, Preference Share Goes Down – A Bit

PGE Customers - Average Expected Increase in Desired Portfolio Mix Given Change in Price
Assumes All Resources Available & Price of All Other Options Equal



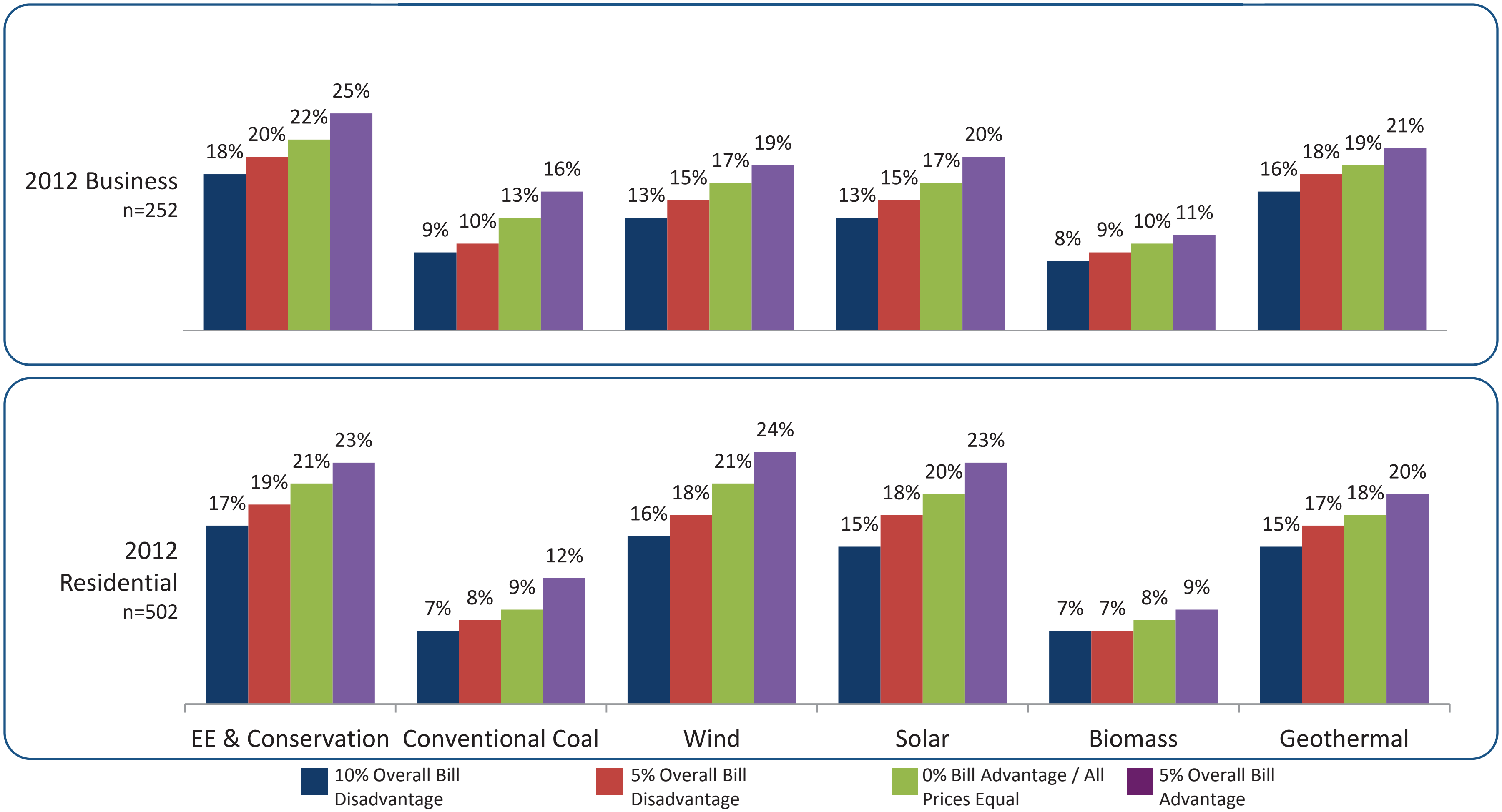
[1] *The summary measure for the relationship between the prices of each resource present in a given scenario is called "price advantage" in this analysis. The price advantage of a given resource option is dependent not on the absolute value of the prices of competing resource options, but rather the differences in these prices. That is, looking at just two energy resources priced at $100 and $150 dollars respectively, we could say that the first resource has a $50 price advantage. Similarly, if the two energy resource options were priced at $50 and $100, the first option still has just a $50 price advantage. Conversely, the second option has a $50 price* disadvantage.

DEFINITIVE INSIGHTS

A19,20,21,22,23,24,25,26,27,28,29,30,31,32,32b, 32d (2006) Q24,26,29,30,32 (2012)

Similar – Small Levels of Price Sensitivity – Are Seen For Green Resource Options

Average Expected Increase in Desired Portfolio Mix Given Change in Price
Assumes All Resources Available & Price of All Other Options Equal



[1] *The summary measure for the relationship between the prices of each resource present in a given scenario is called "price advantage" in this analysis. The price advantage of a given resource option is dependent not on the absolute value of the prices of competing resource options, but rather the differences in these prices. That is, looking at just two energy resources priced at $100 and $150 dollars respectively, we could say that the first resource has a $50 price advantage. Similarly, if the two energy resource options were priced at $50 and $100, the first option still has just a $50 price advantage. Conversely, the second option has a $50 price* disadvantage.

DEFINITIVE INSIGHTS

Q44,46,48,50,52 (2012)

So, What Will RESIDENTIAL Customers Do To Contribute to Energy Efficiency & Conservation?

DEFINITIVE INSIGHTS

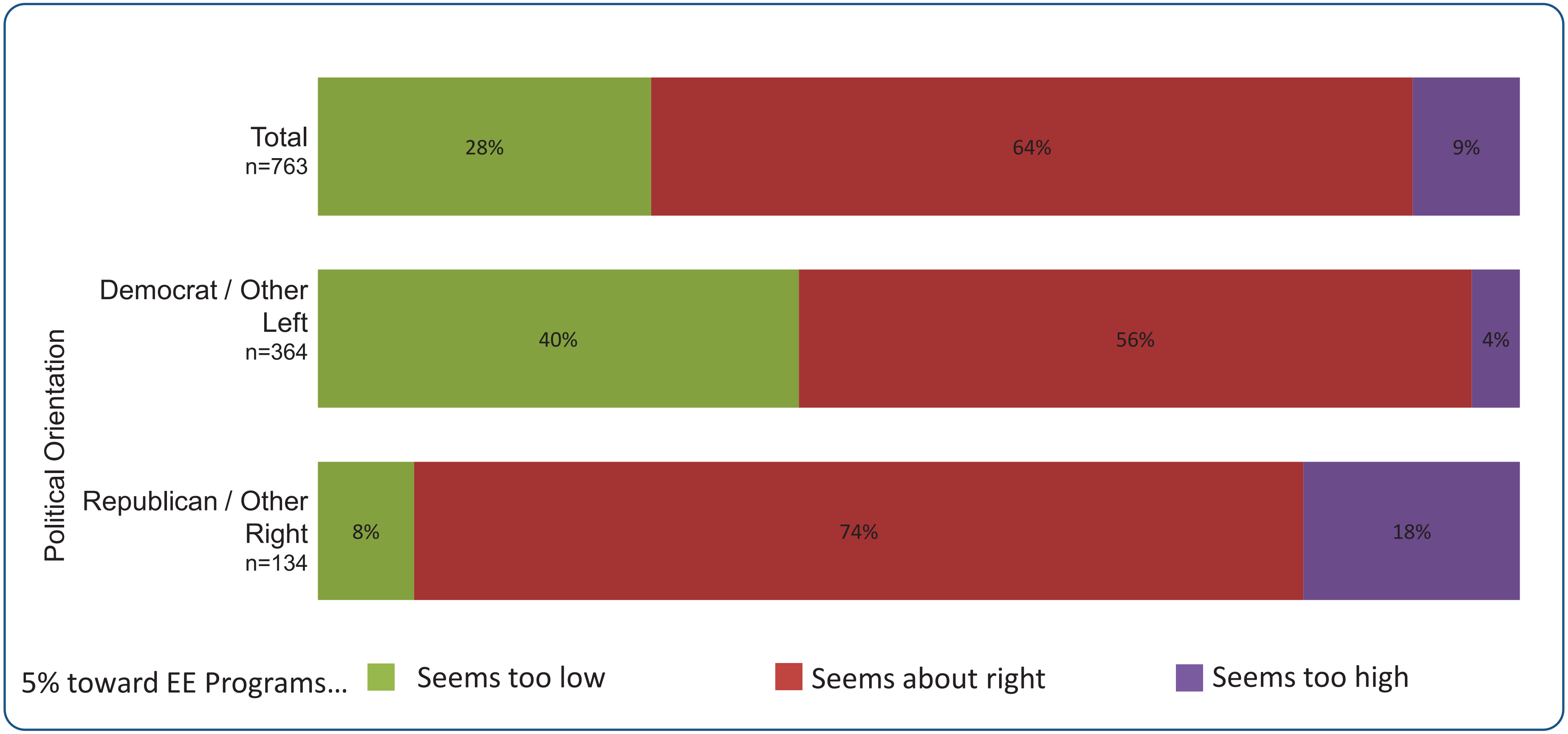
Summary: What Do RESIDENTIAL Customers Say They Will Do?

- Residential customers express support for PGE EE actions and charges (mostly) and say they are interested in pursuing EE themselves
  - This is where political differences have a big impact, however
- Residential customers say they have already done a lot, and try pretty hard to manage energy use
  - As a result, they don't think that new programs would make a lot of difference
  - In fact, they don't think that current programs (like rebate programs) make that much of a difference

DEFINITIVE INSIGHTS

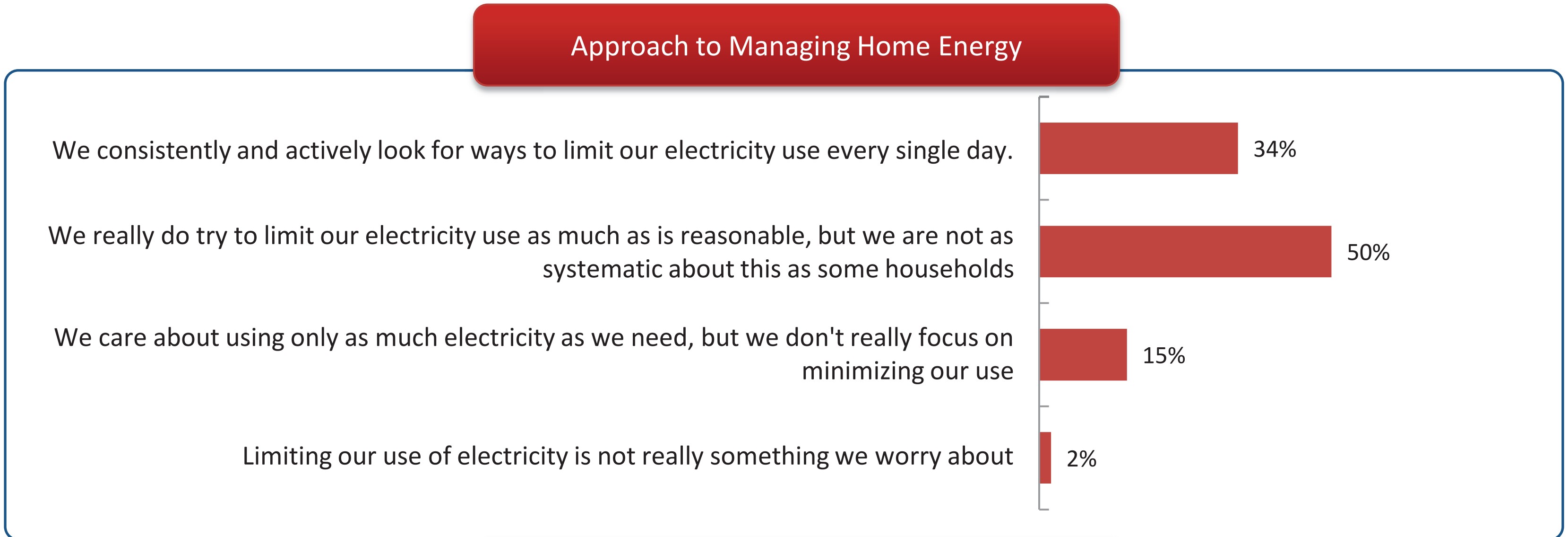
Most Residential Customers Support EE Bill Charges

About 5% of Residential Bill Goes to EE Programs, this amount…



(Q38) Currently, under Oregon law, about 5% of the average residential customer's bill goes to programs to promote greater energy efficiency. Which of the following statements best describes your thinking about this?

And Most Say They Actively Try And Limit Their Home Energy Use on A Day-To-Day Basis; Most Say They Already Try to Purchase EE Equipment As Often As Possible

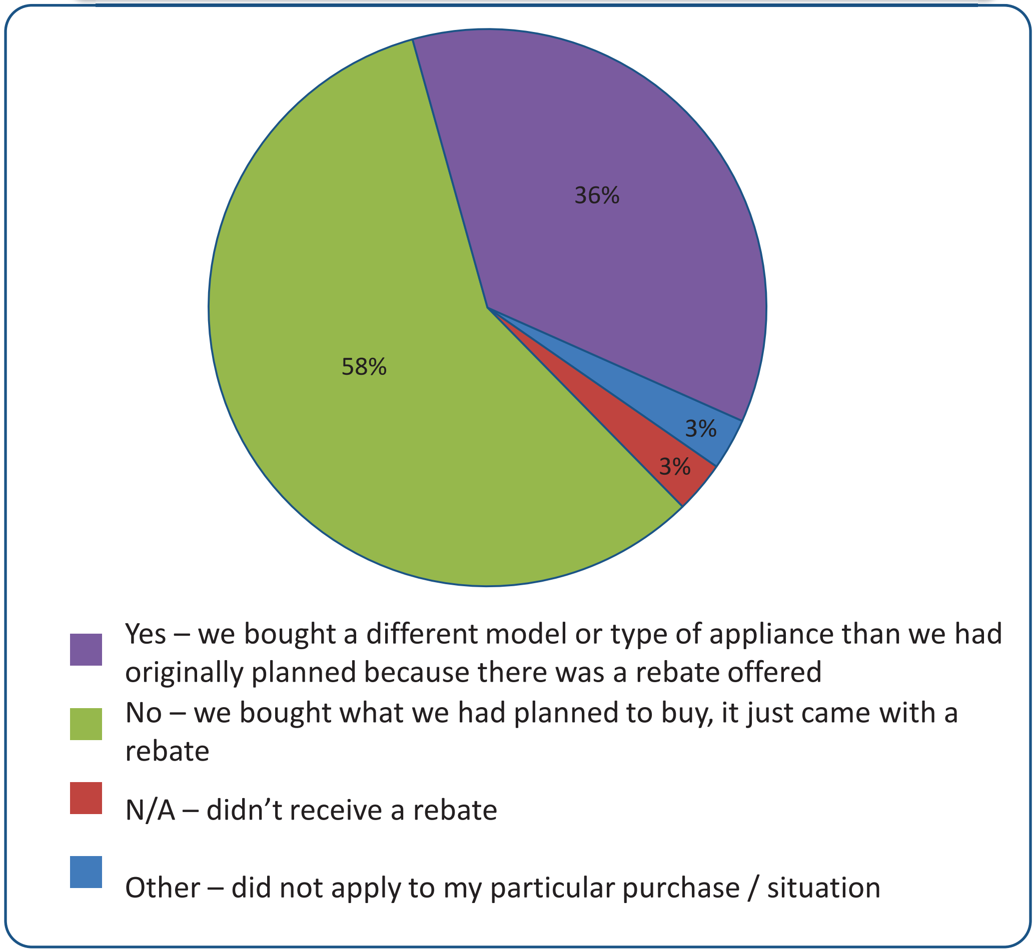


DEFINITIVE INSIGHTS

(Q8) Thinking of your entire household, which of the following best describes your household's overall approach to managing energy use around your home on a day-to-day basis?
(Q10) Which of the following best describes your household's approach to buying new appliances, light bulbs, or other electricity using devices?

As A Result, Many Say That Current Programs Do Not Much Affect Their Behavior

Impact of Rebate on Purchase
(Base: those who received a rebate, or some other type of financial incentive; n=307)



DEFINITIVE INSIGHTS

(Q23) Thinking about the last rebate you received, did you purchase a different appliance or other energy-related measure than you had planned to buy specifically in order to receive the rebate?

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Summary Takeaways

- **Context for Resource Preferences**
  - All customer classes continue to say that environmental issues are a concern
- **Overall Resource Preferences**
  - All customer classes continue to express strong stated preferences for renewables and EE & conservation
- **Preferences for Resource Mix**
  - There is a preference for a resource mix that is NOT highly dependent on one or two sources
  - Stated preferences for greener options continue, even when this means 5% or 10% higher rates for everyone
- **So, What Will Residential Customers Do To Contribute to EE & Conservation?**
  - Residential customers support PGE EE efforts (mostly) and say they are interested in it themselves
  - Residential customers say they have already done a lot, and try pretty hard to manage energy use – and they think this limits how much you can incent them to do more

DEFINITIVE INSIGHTS

Appendix I

PNUCC Memo Regarding Proposed EPA CO_2 Standards

Attachment C

Bringing the Power of good ideas Together.

Memorandum

To: **The Power and Natural Gas Planning Taskforce**

From: **Tomás Morrissey**

Date: **October 10, 2013**

Subject: **Proposed September 2013 EPA Standards for CO2 Emissions from New Power Plants**

Background and Proposed Rule

In 2009 EPA Administrator Jackson signed a rule deeming greenhouse gases a threat to public health under section 202(a) of the Clean Air Act.[1] On September 20, 2013, the EPA proposed standards to limit CO2 emissions from new power plants.[2] Please keep in mind that the standards are proposed and may change before they are finalized.

The proposed standards are:

- New coal plants must meet one of two standards. In a one year period they must emit less than 1,100 lbs CO2/MWh on average *or* over a seven year period they must emit less than 1,050 lbs CO2/MWh on average.
    - This effectively prohibits the construction of new coal plants that do not feature carbon capture and sequestration technology.
- Larger new natural gas plants must emit less than 1,000 lbs CO2/MWh on average over a one year period. Smaller new natural gas plants must emit less than 1,100 lbs CO2/MWh over a one year period.[3]

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[1] EPA. "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Final Rule." Federal Register, Vol. 74, No. 239, Page 66496. December 2009.
[2] The rule can be found at: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf
[3] The EPA defines a the size limit for a small plant as having "a heat input rating that is less than or equal to 850 MMBtu/h" which roughly translates to a 100 MW unit. See page 88 of the rule for more details.

101 S.W. Main Street, Suite 1605 Portland, OR 97204-3224

Attachment C

One key exemption to the proposed standards:

- The standards only "apply to a facility if the facility supplies more than one-third of its potential electric output and more than 219,000 MWh net electric output to the grid per year" on a three year rolling average basis.[4]
    - This provision effectively excludes new peaking units from the proposed rules.

Impact on the Northwest Power Industry

These proposed rules will likely have no immediate impact on the Northwest power industry. Although the rules make it very difficult to construct new coal fired generation the Northwest is not planning any new coal builds at this time. New baseload gas units should be able to meet the 1,000 lbs CO2/MWh restriction without extra costs and new peaking units will likely be exempt from the rule. The rule will set a precedent of EPA CO2 regulation in the electric power sector. The EPA is expected to issue CO2 regulations that apply to existing power plants in upcoming years.

Appendix J

PGE WECC Resource Expansion Details

Appendix J: PGE WECC Resource Expansion Details

Table J-1 details the long-term resource additions by area in the Western Electricity Coordinating Council (WECC). The period of the analysis is 2014-2033. All areas with an RPS standard contain a significant percentage of renewable resources in their incremental resource mix.

Table J-2 shows resources added in the WECC by technology.

Table J-1: Resource Added by Area (Nameplate MW, 2014-2033)

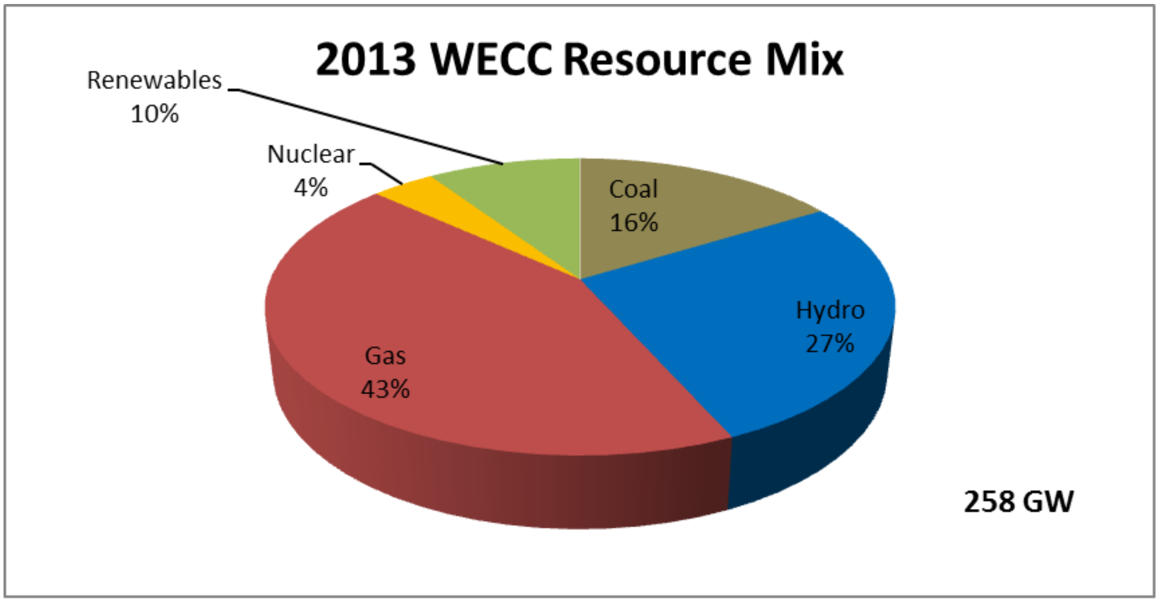
	Aurora Selections	RPS Resources	Total	RPS Percentage
Arizona	(8,670)	2,472	(6,199)	NA
Canada-Alberta	18,024		18,024	0%
Canada-British Columbia	6,920		6,920	0%
California	16,690	14,209	30,899	46%
Colorado	3,273	3,342	6,615	51%
Idaho South	4,550	-	4,550	0%
Montana	10,074	421	10,495	4%
Nevada	6,493	2,465	8,958	28%
New Mexico	5,210	957	6,167	16%
Pacific Northwest	789	4,215	5,003	84%
Utah	695		695	0%
Wyoming	(351)	1,969	1,618	NA
Total			**93,744**	

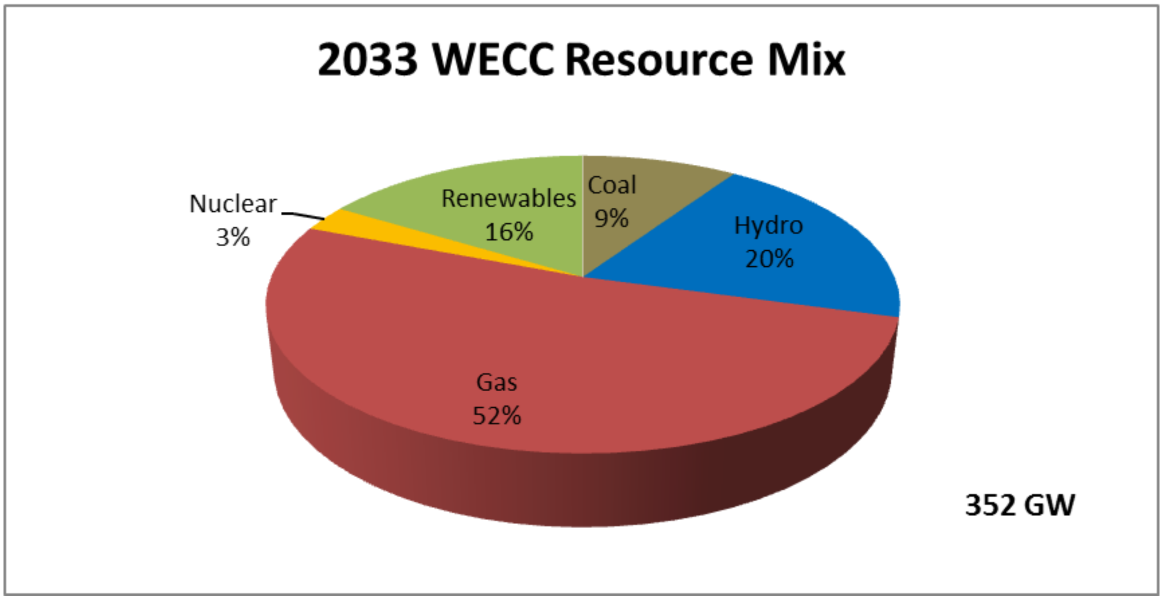
Table J-2: Cumulative Resource Additions by Technology, Nameplate (MW)

	MW
RPS Renewables	30,049
Other Renewables	3,040
CCCT - Gas	74,260
SCCCT/Peakers - Gas	(4,923)
Coal	(8,682)
Total (2014-2033)	**93,744**

Figure J-1 shows the WECC resources by technology in 2013 and then by 2033, after the AURORAxmp resource expansion. Capacity by 2033 increased by almost 40% compared to the current levels.

Figure J-1: WECC Resource Mix by Technology, 2013 and 2033





Tables J-1 and J-2 and Figure J-1 summarize net resource changes. They include both additions and retirements. The summary figure of approximately 94 GW over the 20-year period ending in 2033 is the net of 110 GW of additions and 16 GW of retirements. Figure 9-2 in the IRP provides detail for both additions and retirements. Retirements are comprised of coal plants, which become subject to carbon taxes in 2023, and older, less efficient, simple cycle combustion turbines. These retirements occur primarily in the Southwest. For example, Table J-1 shows that retirements are greater than additions in Arizona over the analysis period.

Table J-3 shows the long-term annual average electricity prices resulting from our WECC expansion in AURORAxmp.

Table J-3: WECC–Long-Term Annual Average Electricity Prices (Nominal $ per MWh)

	Alberta	Arizona	British Columbia	CA-NP15+	CA-PG&E-ZP26+	CA-SP15+	Colorado	IdahoSouth	Mexico-BajaCANorth	Montana	Nevada North	Nevada South	NewMexico	PNW	Utah	Wyoming
2014	56.95	34.76	47.11	40.9	39.24	40.72	34.91	34.38	39.05	31.4	37.56	37.23	32.88	33.45	34.66	30.23
2015	49.13	35.3	41.7	41.51	39.79	41.3	34.94	33.83	39.88	31.65	37.89	37.55	33.56	33.76	35.09	30.1
2016	46.54	36.5	42.79	42.67	40.92	42.48	36.38	35.19	40.71	32.73	39.12	38.79	34.98	34.89	36.27	31.35
2017	49.31	39.87	47.09	46.63	44.81	46.35	39.55	37.92	44.47	35.7	42.69	42.48	37.93	37.95	39.68	34.06
2018	54.1	43.8	52.83	50.84	48.99	50.61	43.29	41.21	49.27	39.18	46.93	46.81	41.43	41.54	43.61	37.29
2019	56.64	47.04	55.58	54.4	52.6	54.29	46.68	44.42	53.74	41.89	50.57	50.43	44.54	44.3	47.05	40.25
2020	58.05	48.54	57.91	55.34	53.55	55.37	47.97	45.3	55.8	42.3	50.71	51.35	46.01	44.8	48.07	41.15
2021	56.36	48.17	58.57	54.96	53.09	54.76	47.86	45.17	56.47	39.87	50.24	50.55	46.25	45.13	47.7	40.87
2022	58.29	51.27	60.87	58.31	56.36	57.89	51.13	47.99	60.89	41.53	52.25	53.45	49.28	47.75	50.49	43.48
2023	64.87	65.56	69.81	73.41	71.23	72.73	66.68	61.9	61.2	49.96	66.83	67.82	65.01	60.57	64.91	57
2024	64.16	67.11	70.79	75.2	72.95	74.19	68.81	64.01	62.78	50.16	68.33	69.03	67.08	63.52	66.37	58.89
2025	63.58	68.53	71.17	76.91	74.73	75.38	70.15	64.89	65.83	50.59	69.48	69.04	69.04	64.72	67.68	60.13
2026	63.11	70.17	71.85	77.55	75.73	76.42	72.83	67.07	64.88	52.16	70.63	69.58	73.34	66.28	69.49	62.63
2027	62.68	71.59	71.94	78.02	76.3	77.28	73.89	67.67	70.17	52.48	71.91	70.63	75.63	66.93	70.74	63.93
2028	61.73	73.26	71.97	78.41	76.66	77.75	74.74	68.06	65.79	52.82	72.35	70.78	77.92	67.51	72.26	65.07
2029	63.27	75.79	74.5	81.37	79.54	80.52	76.61	71.42	71.96	54.9	75.35	73.4	78.2	70.63	75.9	68.11
2030	64.66	79.04	75.53	83.26	81.54	82.76	79.2	73.43	82.15	56.58	77.67	75.45	79.59	72.77	78.87	70.81
2031	66.37	82.14	78.45	86.25	84.48	85.52	82.47	76.33	73.59	60.87	80.67	77.84	80.97	76.1	82.73	74.28
2032	66.96	84.09	80.48	88.63	86.84	87.81	85.1	78.9	79.54	60.58	83.29	80.03	81.24	78.69	85.4	77.33
2033	67.44	86.12	82.32	90.28	88.61	89.7	87.75	80.81	85.91	63.71	85.69	81.85	83.01	80.66	88.74	80.15

Appendix K

PGE Load-Resource Balance Details

Appendix K: PGE Load-Resource Balance Details

Figure 3-4 **Annual energy LRB**

(MWa)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Coal	639	639	639	639	639	639	639	256	256	256
Gas	581	581	793	944	944	944	944	944	944	944
Hydro	488	487	456	452	418	349	349	349	321	321
Renewables	179	237	278	278	278	278	278	278	278	278
EE	34	69	99	124	147	166	184	200	216	230
Non-Hydro Contracts	113	109	86	19	19	67	67	19	19	19
Total Resources	**2,034**	**2,121**	**2,350**	**2,456**	**2,444**	**2,443**	**2,461**	**2,046**	**2,034**	**2,049**
Load and Reserves	**2,224**	**2,254**	**2,308**	**2,364**	**2,422**	**2,469**	**2,522**	**2,573**	**2,625**	**2,676**
Surplus or (Deficit)	**(190)**	**(133)**	**43**	**93**	**23**	**(26)**	**(61)**	**(527)**	**(591)**	**(627)**

Figure 3-5 **Winter capacity LRB**

(MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Coal	756	756	756	756	756	756	756	296	296	296
Gas	1,184	1,184	1,414	1,855	1,855	1,855	1,855	1,855	1,855	1,855
Hydro	1,140	1,130	1,072	922	886	739	739	739	664	664
Renewables	43	43	57	57	57	57	57	57	57	57
EE	47	93	128	158	183	205	223	240	256	272
Non-Hydro Contracts	229	213	209	109	109	67	67	9	9	9
Demand Response	28	35	45	45	45	45	46	49	53	58
DSG	97	104	110	116	122	122	122	122	122	122
Total Resources	**3,524**	**3,557**	**3,790**	**4,018**	**4,013**	**3,846**	**3,866**	**3,368**	**3,313**	**3,334**
Load and Reserves	**3,753**	**3,793**	**3,823**	**3,935**	**4,010**	**4,063**	**4,126**	**4,156**	**4,215**	**4,277**
Surplus or (Deficit)	**(229)**	**(236)**	**(32)**	**83**	**3**	**(217)**	**(261)**	**(789)**	**(902)**	**(943)**

Figure 3-6 **Summer capacity LRB**

(MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Coal	756	756	756	756	756	756	756	296	296	296
Gas	1,099	1,313	1,754	1,754	1,754	1,754	1,754	1,754	1,754	1,754
Hydro	1,028	1,028	970	820	784	637	637	637	562	562
Renewables	57	71	71	71	71	71	71	71	71	71
EE	46	90	124	153	177	198	216	233	249	265
Non-Hydro Contracts	229	213	209	109	109	67	67	9	9	9
Demand Response	28	35	45	45	45	45	46	49	53	58
DSG	97	104	110	116	122	122	122	122	122	122
Total Resources	**3,340**	**3,609**	**4,039**	**3,824**	**3,819**	**3,651**	**3,670**	**3,172**	**3,117**	**3,138**
Load and Reserves	**3,632**	**3,654**	**3,721**	**3,791**	**3,870**	**3,934**	**4,012**	**4,057**	**4,131**	**4,209**
Surplus or (Deficit)	**(292)**	**(45)**	**318**	**33**	**(51)**	**(283)**	**(341)**	**(885)**	**(1,014)**	**(1,071)**