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V. Denise Saunders
Associate General Counsel

July 3, 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:

Enclosed for filing in the above-referenced docket are an original and five (5) copies of **Portland General Electric Company's ("PGE") Reply Comments**. PGE also includes the following Attachments:

- Attachment A – PGE's 2011 IRP Update, Chapter 3;
- Attachment B - PGE's 2011 IRP Update, Chapter 4;
- Attachment C – PGE's First Supplemental Response to OPUC Data Request No. 039; and
- Attachment D – Initial Solar Break Even Analysis.

Please note that the original signature page will be forwarded to the OPUC next week.

This filing is being made by electronic mail with the Filing Center and simultaneously served upon the Service List for LC 56.

Thank you in advance for your assistance.

Sincerely,

/s/V. Denise Saunders

V. DENISE SAUNDERS
Associate General Counsel

VDS:qal
Enclosures
cc: LC 56 Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **Portland General Electric Company's Reply Comments and Attachments A through D** to be served by electronic mail to those parties whose email addresses appear on the attached service list from OPUC Docket No. LC 56.

Dated at Portland, Oregon, this 3rd day of July, 2014.

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OPUC DOCKET # LC 56

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. LC 56

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY's 2013 Integrated Resource Plan.	**REPLY COMMENTS**

I. Introduction

Pursuant to the ALJ Prehearing Conference Memorandum dated April 30, 2014, Portland General Electric Company ("PGE" or "the Company") submits these comments in response to the five parties[1] that filed comments respecting PGE's 2013 Integrated Resource Plan ("IRP"). We appreciate the interest parties have shown in our IRP and their generally supportive tone. Many of these parties participated in some or all of PGE's five IRP Public Meetings and workshops conducted over the past fourteen months. We have benefitted from their collaboration and suggestions as we assess increasingly complex resource planning issues. Their collective contributions have improved our 2013 IRP and resulting Action Plan, and their comments provide helpful suggestions to enhance and inform the next IRP.

The comments submitted to the Oregon Public Utility Commission ("OPUC" or "Commission") indicate that OPUC Staff believe that PGE's 2013 IRP "has demonstrated an overall compliance with the basic elements of least cost planning."[2] Other parties make a similar statement, or are silent about compliance with the Commission's Guidelines. We address the specific issues raised by the parties in these Reply Comments. We note that many of the issues are considered at length in our previous responses to data requests, which we will separately incorporate into the record of this IRP docket. In addition, some of the issues raised by parties can also be addressed prospectively as potential enhancements to our next IRP.

II. Discussion of Staff and Intervenor Comments

A. Compliance with OPUC IRP Guidelines

OPUC Order No. 07-002 (as modified in Order No. 07-047 and Order No. 08-339) established thirteen broad guidelines to govern the IRP process. Of those

[1] OPUC Staff (Staff), Citizens' Utility Board (CUB), Renewable Northwest (RNW), Oregon Department of Energy (ODOE), Small Business Utility Advocates (SBUA).
[2] Staff's Opening Comments at Section I, ¶3.

thirteen, the opening comments of Staff and intervenors focus on four guidelines, which we address below.

1) Guideline 1

Guideline 1 requires that resources be compared on a consistent and comparable basis, including both cost and associated risk and uncertainty.

a) Parties' Positions

Staff suggests that PGE's 2013 IRP does a "fairly comprehensive" job of identifying and describing all potential resources. However, Staff believes that the 2013 IRP has not met Guideline 1, as it did not analyze all known resources via portfolio analysis.[3] In particular, Staff's comments assert that supply-side storage resources and demand response ("DR") resources are excluded from the analysis.[4]

Staff is not convinced that the assumed resource costs are accurate for generic PV solar and biomass projects. For solar PV in particular, Staff is concerned that solar resource costs assumed in the IRP do not adequately reflect the declining solar prices seen in the marketplace. Staff believes that solar costs will continue to trend down, and that PGE's IRP should forecast future solar resource costs.[5]

Staff suggests that PGE make use of additional professional research to inform these assumptions, beyond the Black & Veatch consultant report used in this IRP to develop generic resource costs.[6]

Staff has other concerns regarding resource assessments, however these additional issues are not characterized as guideline deficiencies. Those concerns are detailed below in Section C.

The Citizen's Utility Board ("CUB") believes that action items in PGE's 2013 IRP are "mostly consistent with the IRP guidelines set forth in Order No. 07-047."[7] The other parties do not comment on compliance with IRP Guideline 1.

b) PGE's Response

PGE believes that the 2013 IRP complies with Guideline 1. All known resources, including DR and energy storage, were evaluated on a consistent and comparable basis.

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[3] Staff's Opening Comments, Section III, ¶¶ 1-2.
[4] *Id.* at ¶2.
[5] *Id.* at Section IV(g)(i), ¶1.
[6] *Id.* at ¶4.
[7] CUB's Opening Comments at p. 2.

Demand Response

With regard to DR, Staff provides no supporting evidence, cites, or other documentation to support its assertion that PGE has not adequately considered DR. In fact, the maximum amount of DR that PGE and its automated DR contractor have identified as cost-effectively available is in *every* portfolio.

Further, PGE made a considerable effort to identify DR resource potential and forecast additional cost effective DR. In Chapter 4 of the 2013 IRP, PGE describes the DR potential study, our assessment and forecast of PGE's two firm DR programs, and the status of our three non-firm DR programs. Arguably, PGE's assessment of the availability and cost of DR is more extensive than the assessment for any other resource.

As described in Chapter 4.2 of the IRP, in late 2012, PGE invited DR industry expert, The Brattle Group ("Brattle"), to conduct a demand response assessment. This study had several goals, one of which was to inform Automated Demand Response ("ADR") RFP bidders of the potential resource within the PGE service territory. The study was also intended to provide guidance for PGE's future DR programs. PGE and Brattle looked at all potential participation scenarios for all known types of DR. Drawing on best practices from the other utilities which Brattle tracks, PGE mapped our potential participation rates. We then looked at the internal costs of each of those types of DR, as well as the resource they provide, in order to come up with a cost effectiveness assessment for each of those models. Because PGE put a high priority on demand-side options, this information (as well as the Energy Trust of Oregon energy efficiency forecast) was shared in PGE's first IRP public meeting.[8]

Energy Storage

In the second IRP public meeting (held May 28th, 2013), PGE presented the supply side resources it proposed to include in its analysis and explained why other resources were not being considered.[9]

Energy storage resources are considered in the IRP, although not in portfolio analysis.[10] Specifically, the IRP evaluates several energy storage technologies. Please refer to section 8.7 of PGE's IRP filing, which addresses battery, thermal, pumped hydro, and compressed air energy storage

[8] These presentations are available for download at PGE's IRP website: http://www.portlandgeneral.com/irp.

[9] "May 28 Stakeholder Presentation" at p. 21: http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/may_28_presentation.pdf

[10] At the May 28, 2013 Public Meeting, PGE presented the types of supply-side resources that it proposed to include in the portfolio analysis and discussed the reasons why energy storage resources would not be considered.

technologies.[11] Energy storage can be used primarily as a means of providing short-term up and down ramping capability. Given the increasing need for flexible capacity to support the growing penetration of variable energy resources, PGE is actively pursuing opportunities to evaluate storage technologies. Deployment and operation of our 5 MW dedicated Salem Smart Power project[12] and the thermal energy storage pilot at the Boardman plant are examples of PGE's efforts to test different types of storage devices and gain experience in this area.[13]

At the time that the candidate portfolios for the 2013 IRP were constructed, PGE believed that it was premature to include battery storage as an energy or capacity resource for portfolio analysis because of unknowns and uncertainties regarding costs and key performance factors, including scalability, cycling efficiency, and resource life. This decision was also based on our assessment that the cost of energy storage resources was not competitive with other alternatives that could provide similar capacity and flexibility benefits, namely gas-fired generation. In addition, without improved portfolio modeling technology, energy storage analysis cannot fully quantify the distinctive attributes of energy storage.

We believe that our assessment of storage resources in Chapter 8 of the IRP complies with Guideline 1 and that our reasoned decision to exclude certain emerging and uncertain resources such as batteries from portfolio analysis does not constitute a failure to meet the Commissions requirements. At the same time we also recognize that technology in this area is maturing rapidly and related performance and cost information for storage devices is becoming more reliable. Therefore, we expect to include additional resources such as batteries in the portfolio analysis for our next IRP.

PGE notes that, for various reasons (largely related to technology maturity and uncertainty, extreme high resource cost or legislative / regulatory mandates), we also did not include nuclear, IGCC with capture and sequestration, hydrokinetic energy, offshore wind, high-altitude wind generators, and other known resources in IRP portfolio analysis. To avoid discrepancies in this area in future IRPs we encourage Staff and stakeholders to identify any concerns early in the public process and work with the Company to reach joint agreement as to which resources should be in included in portfolio analysis.

<u>Resource Costs</u>

PGE relied on Black & Veatch to help assess resource costs for the 2013 IRP. Black & Veatch is a leading global provider of engineering and construction services for the power generation sector. Accordingly, they provide a high

[11] PGE's 2013 IRP at pp. 153-156.
[12] *Id.* at p. 154.
[13] *Id.* at p. 156.

degree of expertise and knowledge with regard to cost and performance estimation for all types of power generation technologies. For these reasons PGE selected Black & Veatch to provide such research for the IRP and believes that the estimates provided reasonably represent generic resource costs. At the same time, PGE is willing to consider recommendations for additional sources of resource cost and performance information for future IRPs. However, in PGE's experience such professional research typically costs several thousands of dollars and ultimately may not provide additional insights beyond those represented in the Black & Veatch work. PGE asks stakeholders to clarify whether they recommend the Company make additional expenditures for this type of research and will support PGE's recovery of such study costs through rates.

PGE notes that the cost of biomass[14] is very situationally dependent. Without knowing whether particular opportunities are available, PGE could only reliably represent the cost for a purpose-built biomass plant with a secure, third-party source for fuel. This was not meant to indicate that the market might not bring lower-cost alternatives. PGE continues to actively pursue its own unique opportunity, which would synergistically lever off of existing facilities and transmission.

Regarding PV solar costs, PGE agrees with Staff that such costs continue to trend downward. To address this issue we asked our generation research consultant Black & Veatch to provide us with a solar cost forecast. They were unable to meet this request due to the high degree of uncertainty regarding the future pace of technology / materials developments and process improvements that drive solar costs and the trajectory of those costs over time, particularly in the longer term. PGE welcomes suggestions from Staff and other stakeholders about how to reliably forecast solar resource costs across the planning horizon for future IRPs.

In response to Staff's comments regarding solar costs in the Draft IRP and in their Opening Comments, we include as Attachment D to these Reply Comments summarized results from a trigger point analysis which covers both central station and distributed solar resources. This analysis indicates that for either of these solar resources, installed costs would have to be less than $600 per kW to be cost competitive. This figure includes total generation resource costs. Hence the cost for solar panels per se would have to be substantially less than $600 per kW for solar generation to become competitive with a gas-fired, combined-cycle combustion turbine.

We base our utility-scale analysis on the Christmas Valley site in Lake County, which projects a 23% net capacity factor. However, this relatively

[14] Staff's comments on the cost of PV solar and biomass, do not appear to indicate that these are Guidelines compliance issues.

high capacity factor is partially off-set by higher wheeling, line losses, and site costs. Our distributed solar analysis is based on Portland area data. Transmission is avoided, which lowers costs. However, this is off-set by a significantly lower capacity factor of only 12%.

While our analysis indicates that solar is currently very expensive relative both to other energy resources in general and to other renewables, we will, in our next IRP, revisit cost assumptions for all resources, including solar and other renewables.

2) Guideline 7

Guideline 7 requires that IRPs evaluate demand response resources on par with other resources to meet energy, capacity and transmission needs.

a) Parties' Positions

Staff's comments indicate that PGE's IRP does not fully comply with Guideline 7. Staff asserts that PGE has not fully assessed the potential for DR in this IRP.[15] Staff requests greater detail regarding PGE's DR activities. In particular, Staff would like to know about PGE's contract with EnerNOC, PGE's use of advance metering infrastructure for DR, and PGE's assessment of DR's capabilities and barriers.[16]

Staff has additional concerns with regard to how "PGE anticipates using the demand response from an operational point of view."[17] Staff suggests that PGE's approach to demand response is too focused on utility dispatch and does not contemplate 'customer-centric' programs.

The comments submitted by other parties do not question PGE's compliance with IRP Guideline 7.

b) PGE's Response

PGE believes the 2013 IRP meets the requirements of Guideline 7. The potential for demand response was evaluated in detail through the Brattle study discussed above and on pages 58-67 of the IRP. PGE's Response to OPUC Staff Data Request No. 15, Confidential Attachment 015-A, also provides the complete DR assessment performed by The Brattle Group in 2012. Chapters 5 and 6 of the 2012 Brattle report provide detailed explanations of PGE's demand response potential including cost efficacy for multiple programs. The Brattle Group is a well-respected energy consulting

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[15] Staff's Opening Comments, Section III, ¶ 3.
[16] Staff's Opening Comments, Section IV(d)(ii), ¶¶ 3-5.
[17] *Id.* at ¶2.

firm that has worked with clients across the U.S. on demand response issues.[18] By investing in industry leading research, specifically on demand response in PGE's territory, PGE has evaluated demand response on par with alternative resources, as required by Guideline 7.

In addition, as reported in our 2014 Smart Grid Report, we are actively engaged on the residential direct load control front as well.[19] PGE is in contract negotiations with a summer residential AC demand response provider for a 2015-2016 pilot. In addition, we are actively pursuing "smart" water heater standards that will enable future residential direct load control programs.[20]

Additional information pertaining to PGE's evaluation of demand response activities is included in PGE's responses to Staff data requests in this proceeding. PGE's Response to OPUC Staff Data Request No. 24 discusses the EnerNOC contract. PGE's Response to OPUC Staff Data Request No. 27 addresses the use of advanced metering infrastructure with demand response programs. PGE's Response to OPUC Staff Data Request No. 19 assesses barriers to demand response.

Staff indicates that it is also concerned with how we are using DR resources from an operational point of view and notes that it appears that PGE's vision for demand response is "dispatch-oriented not customer-centric." Staff does not elaborate, leaving PGE unable to respond without a clear understanding of the concern. We will follow-up with Staff for clarification.

As discussed in this and the previous section of these Reply Comments, PGE has evaluated DR on par with, if not to a materially greater extent than, other options for meeting our needs and included DR in all its candidate portfolios.

3) *Guideline 8*

IRP Guideline 8 encompasses the treatment of environmental (e.g., emissions compliance) costs in IRP analysis. Guideline 8a, specifically, directs utilities to include expected costs for emissions compliance, as well as, "several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities."

a) Parties' Positions

Staff Comments

[18] *See, http://www.brattle.com/industry/electric-power/79-demand-response-energy-efficiency-and-the-smart-grid.*

[19] PGE's 2014 Annual Smart Grid Report was filed in OPUC Docket UM 1657 on May 30, 2014 and is incorporated by reference into these Reply Comments.

[20] PGE's IRP at pp. 61-63.

Staff states that it is continuing its investigation of whether PGE has fully satisfied Guideline 8.[21] However, Staff also "recognizes the work PGE has done to meet its obligations under IRP Guideline 8" and that the work done provides a great deal of useful information.[22] Nonetheless, Staff would like PGE to model more immediate carbon costs associated with recent EPA actions" (i.e., the Section 111(d) proposed rule).[23]

<u>CUB Comments</u>
CUB has specific concerns about how environmental policies, including EPA's proposed 111(d) regulations, will be captured in future IRPs.

Questions from Staff and CUB pertaining to Section 111(d) will be addressed in Section E below, since they do not appear to be characterized as issues of Guideline 8 compliance.

<u>ODOE Comments</u>
The Oregon Department of Energy's ("ODOE") comments propose that the CO_2 futures assessed in PGE's 2013 IRP may not adequately address the "upper reaches of credible proposals" as required by Guideline 8a.[24] In support of its proposition, ODOE provides an Organization for Economic Cooperation and Development (OECD) report, dated November 2012, in which the 2050 carbon price specified therein exceeds the "Synapse High" future used in the 2013 IRP. While ODOE supports OPUC acknowledgement of PGE's Action Plan, it requests that compliance costs in the future include proposals from:

1. The 50 U.S. states;
2. The U.S. federal government, including its treaty obligations;
3. The Canadian provinces; and
4. The Canadian federal government, including its treaty obligations.[25]

<u>RNW Comments</u>
The Opening Comments of Renewable Northwest ("RNW") do not comment on compliance with IRP Guideline 8, but RNW does identify two portfolios that appear to perform similarly to PGE's preferred portfolio, while also achieving lower levels of CO_2 emissions over the analysis time period.[26]

b) <u>PGE's Response</u>

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[21] Staff's Opening Comments, Section V, ¶1.
[22] *Id.* at Section IV(f)
[23] *Id.* at Section IV(f), ¶1.
[24] ODOE's Opening Comments at p.1.
[25] *Id.* at p. 3.
[26] RNW's Opening Comments at p. 5.

Staff

PGE believes the IRP meets the requirements of Guideline 8. While Staff briefly addresses six areas where it desires more information,[27] none of these appear to be required by, or a defect to Guideline 8. For example, since the proposed 111(d) rule was introduced in early June of this year, months after the draft issuance and subsequent filing of our IRP, we assume the requests related to the potential impact of the proposed rule are informational and not intended to be construed as a shortfall in Guideline 8 compliance. Because we believe these six areas are not integral to Guideline 8, we address them later in these Reply Comments.

Staff does not provide any information or discussion of concerns regarding PGE's compliance with the specific requirements of Guideline 8. Moreover, Staff neither raised any issues with regard to compliance with Guideline 8 at the May 28, 2013 Public Meeting (which discussed this topic in depth) nor in its comments on the Draft IRP.

ODOE

ODOE cites a 2050 CO_2 price developed by the OECD of $295 per ton (2014$) as evidence that PGE's high carbon price futures are too low.[28] However, the CO_2 price arising from PGE's trigger point analysis was approximately $565 per ton when reported on a similar basis.[29] This future assumed carbon prices starting at $115 per ton (2014$) in 2023, with a real growth rate of 6.1% through 2050 (stated in nominal terms, carbon prices were assumed to start at $136 per ton in 2023 and grow at approximately 8.1% annually as described on page 217 or PGE's 2013 IRP). All portfolios were assessed against this future, along with futures comprising five other potential carbon cost outcomes.

In addition, we document on page 118 of the IRP that PGE's Synapse high CO_2 case is a good proxy for the *high end* of the social cost of carbon as estimated by the Interagency Working Group on Social Cost of Carbon. This, we believe, represents the upper reaches of credible proposals.

While the carbon price scenarios assessed in PGE's 2013 IRP fully meet the requirements of Guideline 8a, we welcome ODOE's suggestions regarding reasonable reference points to use as guidance when developing these sensitivities for future IRPs. However, we view the suggested approach of accounting for potential regulation in all 50 U.S. states plus Canada to be both overly-burdensome and unnecessary to addressing the issue of CO_2 cost and risk for IRP.

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[27] Staff's Opening Comments, section IV(f).

[28] ODOE's Opening Comments at p. 2.

[29] The 2050 CO_2 price arising from PGE's trigger point analysis is $1,126 per ton [$136.4 * (1.0813^(2050-2023)) ~ $1,126]; adjusting for 36 years of inflation at 1.93% results in the real price in 2014$ [$1,126 * (1.0193^(2014-2050)) ~ $565].

RNW

RNW identifies two portfolios ("Diversified balanced wind/CCCT" and "Diversified Baseload gas/wind") that appear to perform similarly to PGE's preferred portfolio ("Baseload gas/RPS only"), while also achieving lower levels of CO_2 emissions over the analysis time period.[30] A key characteristic of these portfolios is the addition of 560 MW of nameplate wind beyond the amount included in the preferred portfolio (which did not add new renewables beyond RPS physical compliance). PGE's 2013 IRP acknowledges that these two portfolios perform well[31] and one of them (Diversified Baseload Gas/Wind) is among the top-three performing portfolios. As stated in the IRP, we selected the preferred portfolio because it performed best with regard to expected cost, and achieves similarly favorable risk and reliability performance when compared to the other two candidates. However, as we indicated in the IRP, we will re-examine all of the top preforming portfolios from this IRP in the next resource plan.[32]

4) *Guideline 12*

Guideline 12 requires all utilities to evaluate distributed generation (DG) on par with other resources to meet energy, capacity and transmission needs. Guideline 12 also calls for the quantification of the additional benefits of distributed generation, where possible.

a) Parties' Positions

Staff argues that the IRP fails to meet Guideline 12. Staff asserts that the IRP does not evaluate distributed resources on par with other resources and that the Company's description of distributed generation is too brief. While Staff recognizes the IRP's inclusion of the Dispatchable Standby Generation ("DSG") program, it does not consider this program a "true distributed generation program."[33]

The other parties do not comment on compliance with IRP Guideline 12.

b) PGE's Response

Distributed PV Solar

PGE believes the IRP complies with Guideline 12. We evaluate DG on par with other resources in Sections 8.3 and 8.4 and Table 8.1 of the IRP. Specifically, the IRP considers PGE's programs supporting distributed PV solar installations and evaluates the potential for solar penetration within

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[30] RNW at p. 5.
[31] PGE's 2013 IRP at p. 206.
[32] *Id.* at p. 207.
[33] Staff's Opening Comments, Section III, ¶5.

PGE's service territory.[34] We concluded that, absent a triggering event, the deployment of local distributed PV solar was likely to be gradual with regard to aggregate energy and capacity impacts.

In addition, to supplement our IRP filing and better address Staff's concern, we have performed an analysis to evaluate the cost efficacy of distributed PV solar generation.[35] (We address this in more detail below.) While we believe we have adequately evaluated DG for purposes of this IRP, PGE's proposed Action Plan item 3.c. (see page 244 of PGE's IRP filing) recommends that the Company pursue studies and research initiatives to evaluate potential business models and policies that would expand the implementation of cost-effective DG.

<u>DSG</u>

PGE believes that Staff mischaracterizes PGE's DSG program as "merely a program for providing non-spinning reserve and not a true distributed generation program."[36] Beyond providing an economic source of supplemental reserves, DSG also provides dispatchable energy as needed and when needed thereby serving as a cost hedge during times of market scarcity and extreme wholesale prices. These resources also deliver important reliability and efficiency benefits to both PGE and the host customers, providing back-up generation service for the DSG host in the event of localized system outages, while also helping PGE meet overall customer peak demand events. PGE's view is that DG, like other resources, can fill energy needs and/or capacity needs. DSG primarily provides the latter, where distributed PV solar provides the former. PGE does not think DG should be limited to evaluation only as an energy resource.

B. Compliance with Order No. 10-457

Upon acknowledgement of PGE's 2009 IRP and 2010 Addendum, the OPUC established various requirements for PGE's IRP Update and subsequent IRP planning cycle.

1) <u>Parties' Positions</u>

Staff's Comments provide the following list of requirements from Order No. 10-457 (Order):

- i. Include an updated benefit-cost analysis of Cascade Crossing.
- ii. Provide a more comprehensive treatment of Demand Response (DR) resources, including:
    - a. An estimated cost per MW of capacity savings by type and projected MW acquisitions for the next five years;

[34] PGE's 2013 IRP at pp. 139-142.
[35] *See* Attachment D.
[36] Staff's Opening Comments, Section III, ¶4.

b. A discussion of the steps it is and will be taking to evaluate DR in the next IRP; and
c. An updated action plan for assessing and acquiring DR for the next three years.

iii. Consider 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.
iv. Include a wind integration study that has been vetted by stakeholders.
v. Evaluate the use of unbundled Renewable Energy Certificates ("RECs") in its strategy for meeting the Renewable Portfolio Standards ("RPS") requirements.
vi. Evaluate alternatives to physical compliance with the RPS requirements.

The Cascade Crossing project is no longer relevant to the IRP, as Staff Opening Comments indicate. Of the remaining five requirements, Staff's Opening Comments commend PGE for our wind integration study (and subsequent updates), but assert that the remaining items (DR, CVR, RECs strategy, and RPS compliance alternatives) have not been "completely addressed" in PGE's 2013 IRP. Staff states at the end of Section II of its Opening Comments that these issues will be discussed at greater length in Section IV. However, only DR is subsequently addressed, leaving it unclear as to why Staff believes PGE has not fully complied with the Order for the other items.[37]

2) <u>PGE's Response</u>

Of these four topics (DR, CVR, RECs strategy, and RPS compliance alternatives), Order 10-457 directed us to address all except CVR in our next IRP Update and to address all the items in the subsequent IRP. PGE complied with the Order as follows:

<u>Demand Response</u>
Chapter 3, Demand Response Update, of PGE's 2011 IRP Update[38] was focused in its entirety to addressing subparts "a", "b", and "c" of the DR topic in Order No. 10-457. We subsequently included a progress update in the 2012 IRP Update. For the current IRP, as discussed above, we commissioned an updated study of DR cost-effective potential from The Brattle Group and provided the status on our current contract to acquire ADR. These were presented in stakeholder discussions and are discussed on pages 53-65 of the 2013 IRP. Each of the three items required by Order 10-457 were addressed in the 2011 IRP Update and most were also addressed and updated subsequently. The Commission, Staff, and other parties did not identify

[37] Staff's Opening Comments Section IV(g)(iii) also addresses RPS, but the discussion found there does not appear to pertain to the requirements found in Order No. 10.457.
[38] *See* Attachment A; *see also*, OPUC Docket LC 48, "PGE's 2011 IRP Update" (filed Nov. 23, 2011).

deficiencies with the Demand Response Chapter of our 2011 IRP Update, nor did we receive any such feedback in the most recent IRP public review process or in comments on the 2013 IRP Draft filing. Upon review of Order No. 10-457, we realize we should have incorporated the analysis performed in the 2011 IRP Update into this IRP filing. PGE provides that analysis as Attachment A to these Reply Comments, and, thus, incorporates Chapter 3 of the 2011 IRP Update as part of the record for this IRP.

RECs strategy and RPS compliance alternatives

Staff does not indicate what additional discussion or analysis it believes might be needed to fully comply with the RECs and RPS directives contained in Order 10-457. Chapter 4 of PGE's 2011 IRP Update, "Renewable Portfolio Standard", was focused in its entirety on addressing PGE's potential RECs strategy and RPS compliance alternatives with substantial detail and analysis.[39] The Commission, Staff, and other parties did not identify deficiencies with that chapter after the 2011 IRP Update was filed. Nothing has materially changed since that time that would alter our analysis, observations, and conclusions found in the 2011 IRP Update. However, upon further review of the Order, we realize that we should have incorporated the analysis performed in the 2011 IRP Update into this IRP filing. PGE provides that analysis as Attachment B to these Reply Comments, and, thus, incorporates Chapter 4 of the 2011 IRP Update as part of the record for this IRP.

Conservation Voltage Reduction

Staff does not indicate what additional discussion or analysis might be required to fully comply with the Order 10-457 requirements pertaining to CVR. In anticipation of this IRP, PGE devoted Chapter 5 in its 2012 IRP Update to addressing the CVR initial assessment and the subsequent two-substation full-year physical pilot with its accompanying analytics and timeline.[40] We provided a subsequent update in the 2013 IRP.[41] For the latest on this topic, we incorporate by reference and direct parties to our 2014 Smart Grid report, filed with the OPUC on May 30, 2014.[42] As with the previous topics, we received no feedback prior to Staff's Opening comments filed on June 12, 2014, that something more was desired. We have adhered to the original work plan and timeline indicated in the 2012 IRP Update, and do not think this process could have been accelerated or expanded. We have identified the steps we are taking to identify cost-effective CVR opportunities, but are unable to consider CVR as a resource for candidate portfolios until the

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[39] Because these two topics contain substantial overlap, we combined them into one discussion.

[40] *See*, OPUC Docket LC 48, PGE's 2012 IRP Update at 21 (filed Nov. 21, 2012).

[41] PGE's 2013 IRP at 66.

[42] *See*, OPUC Docket UM 1657, PGE's Annual Smart Grid Report at 8 (and Appendix D at 31) (filed May 30, 2014).

analysis is concluded. At that time, as we do with EE, we intend to develop a plan to acquire all cost-effective CVR.[43]

Summary

Staff has not provided any specific evidence or argument to support its contention that we have not fully complied with Order 10-457. The IRP process is lengthy and provides ample time for input prior to the filing of a Final IRP. We believe that future IRPs will benefit if concerns that rise to the level of potential non-compliance with Commission Orders (and Guidelines) are raised early in the process so that the utility has sufficient time to consider and address them.

C. Resource Assessment

1) Parties Positions:

Staff Comments

Staff observes that the results of PGE's flexible capacity analysis demonstrate the need to examine storage resources in greater depth.[44] Staff's comments suggest that the need for decremental capacity identified in the study could be met, in part, by energy storage resources. Staff's comments recommend that PGE evaluate energy storage resources in future candidate portfolios as a part of the Company's next IRP.[45]

For energy storage technologies, Staff indicates that battery storage technology requires specific attention. Staff would like to see cost analysis of "(v)anadium and other earth-based flow batteries."[46] Staff would like PGE to develop additional analysis regarding battery energy storage projects similar to those acquired as part of California's energy storage mandate, and more generally would like to be kept abreast of California energy storage solutions.[47]

Finally, Staff is concerned that PGE's supply-side options do not include all RPS-qualifying opportunities. Staff also suggests that PGE's next IRP needs to consider PPAs as a supply-side option to fill RPS needs.

RNW Comments

With respect to the IRP's assumed resource costs, RNW suggests that PGE engage a specialist consultant to acquire pricing information for renewables and storage. Additionally, RNW recommends that PGE solicit pricing

[43] Note that, as the 2013 IRP indicates, the opportunity may be more in demand savings than in energy savings.

[44] Staff's Opening Comments, Section IV(e), ¶1.

[45] *Id.* at Section V, ¶3

[46] *Id.* at Section IV(g)(ii), ¶1.

[47] *Id.* at Section IV(g)(ii), ¶2.

information directly from project developers and from resource manufacturers in order to acquire the most up-to-date pricing information available.[48]

RNW recommends that, in the next IRP, PGE include two additional resources in its analysis: energy storage resources and Montana wind resources with existing or upgraded transmission resources.[49]

In addition to the standard portfolio analysis that evaluates portfolios of resources with assumed costs relative to one another across the planning horizon, RNW requests an additional trigger point analysis. The additional analysis would determine at what capital cost or levelized cost of energy, a renewable resource becomes cost effective relative to those resources selected in the preferred portfolio.[50] In addition, RNW suggests that PGE should depict which portfolios do better in which futures.[51]

RNW requests that we further incorporate flexibility characteristics and values into supply modeling.[52]

RNW emphasizes that the preferred portfolio should result in an all-source RFP that is performance oriented and technology neutral.[53]

2) <u>PGE's Response</u>:

<u>Staff</u>
On Page 6 of its Opening Comments, Staff notes that PGE's flexibility study indicates a potential need for downward ramping capability. Staff then states that "this result clearly demonstrates the necessity for the Company to examine storage options in greater depth."[54] Given the growing importance of storage in a portfolio with increasing variable energy resources, as well as the emergence of storage technologies such as batteries, PGE agrees that energy storage technologies should be evaluated in more depth in the next IRP.

In response to Staff's request for PGE to follow California's energy storage mandate, PGE proposes to present our review of California's energy storage procurement activities as part of a future IRP stakeholder meeting. We will also provide analysis evaluating the costs and benefits of potential energy storage resources within PGE's system. This analysis can be based on technologies similar to those selected in the California procurement process or other suggestions from Staff, e.g., vanadium flow batteries.

[48] RNW Opening Comments at p. 2.
[49] *Id.* at p. 2.
[50] *Id.* at p. 3.
[51] *Id.* at p. 6.
[52] *Id.* at p. 7.
[53] *Id.* at p. 3.
[54] Staff's Opening Comments, Section IV(e).

While Staff is concerned that PGE's supply-side options do not include all RPS opportunities, Staff does not specifically identify what is lacking. In addition, we do not believe that this concern was raised during the public meeting process or as part of the IRP Draft comments. PGE evaluated wind, utility PV solar, geothermal, and biomass. While there may be other RPS opportunities (tidal power, off-shore wind, concentrating solar, ocean wave energy, convection towers, etc.), we believe that these technologies are either lacking commercial deployment, highly uneconomic as compared to other renewable options or are impractical for this area due to natural resource constraints. Staff acknowledges that this concern is not relevant to this IRP.[55] In order to avoid future discrepancies in this area PGE requests specific feedback from stakeholders at the beginning of the next IRP process on what additional RPS-qualifying technologies we should evaluate.

In response to Staff's suggestion that the IRP needs to specifically evaluate the role of PPAs to fill RPS needs, we refer to our evaluation and arguments in section 8.8 of the IRP (Ownership vs PPAs). As stated in the IRP, PGE continues to believe that the question of resource ownership is best addressed in the competitive bidding processes (RFP) to acquire new large resources identified in the IRP Action Plan. The RFP process provides for the evaluation and comparison of the economics and risks of specific bids and projects rather than the generic resource technologies and fuels assessed at the IRP stage. Recognizing PPA structures can take a variety of forms, and that price and risk allocation is specific to each unique project and counterparty, it is simply not practical to determine whether a PPA or ownership approach is preferred when considering RPS resource options in the IRP. In the IRP, PGE judges resource types based on their underlying operating characteristics, risks, and costs, while our RFPs allow for, and encourage, bidders to offer projects under many different structures. In fact, projects are often bid as both ownership and PPA structures allowing PGE to identify specific advantages and disadvantages of ownership vs PPA distinct from costs and risks inherent in the project itself. In addition to our assessment of ownership vs PPA in section 8.8 of the IRP, please refer to PGE's filed comments in Commission Docket UM 1182 for related discussion.

<u>RNW</u>

As discussed previously, PGE agrees that future IRPs could benefit from additional resource cost and performance research. As we stated earlier, PGE believes that acquiring additional reliable and credible research material will require increased expenditures. PGE asks stakeholders to clarify whether they support PGE's expenditure and cost recovery of additional consultant reports and studies for IRP.

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[55] *Id.* at Section IV(h), ¶1.

PGE recognizes that due to the development timeline of an IRP, resource pricing assumptions developed by a consultant and used in the IRP analysis may become stale by the time the final IRP is filed and reviewed by the Staff and Intervenors. As a result, some IRP cost assumptions may not comport with more recent anecdotal pricing information provided by developers, manufacturers, or industry trade groups. However, such differences are typically not significant absent major structural shifts in the market which do not occur frequently.

Regardless, PGE does not believe that pricing information solicited from developers and manufacturers should be used as an input into IRP resource cost assumptions for two important reasons:

- Non-binding pricing quotes are not always reliable or comprehensive, making it impossible to fairly compare across resource types. Such quotes are also often site- or project-specific, which would not represent a "generic" or repeatable resource cost estimate.
- Developers, manufacturers or other providers of anecdotal pricing data are typically not comfortable with the documentation and publication requirements associated with utility resource planning processes, making them impractical to be utilized as a publicly cited source for resource cost information in an IRP. Therefore, Soliciting proprietary pricing information from developers and manufacturers simply does not meet the accuracy or transparency standards required for IRP.

We believe the better practice is to obtain pricing information from consultants like Black & Veatch who are actively engaged in providing engineering and construction management services for the power sector, but do not have a vested commercial interest in a particular project, site, or technology. Should any of those pricing assumptions be out of step with what PGE or stakeholders believe is a reasonable assumption, additional follow-up with the IRP consultant(s) can be pursued to clarify, answer questions and adjust results as necessary.

With respect to the suggestion of modeling Montana wind, we refer to sections 11.4 and 8.6 of the IRP as well as our reply to RNW's data request No. 005. In the IRP we modeled Montana wind under the assumption of additional required transmission capacity at incremental rates. For future IRPs we are willing to consider other transmission assumptions for Montana wind resources, if such information and cost data is reasonably available and reliable.

Regarding incorporating energy storage (specifically battery storage) within the portfolio analysis, please refer to our "Energy Storage" discussion at page 3 of these Reply Comments.

Regarding additional trigger-point analysis, PGE agrees with RNWs suggestion that such an analysis to determine the price at which renewables become competitive with non-renewable resources in the preferred portfolio can be a useful sensitivity for future IRP analysis. Such an assessment will reveal how sensitive portfolio results are to variations in resource price assumptions.

We also see merit in showing how portfolios perform within a given future. While not presented exactly as RNW proposes, the IRP does provide these results. Appendix C to the 2013 IRP provides the full portfolio analysis results, including the net present value of revenue requirements (NPVRR) for each combination of portfolio and future.

With respect to RNW's suggestion to incorporate flexibility characteristics and values into supply modeling, PGE will continue refining its methods of assessing and representing portfolio capacity needs. Indeed, Our Action Plan in this IRP includes proposals for further evaluating our flexibility needs and alternatives to meet those needs, as well as assessing new methods and analytical tools for enhancing operational flexibility.

Regarding RNW's suggestions about the construct of future RFPs, PGE agrees that the RFP process should seek to acquire resources that provide the performance characteristics and attributes identified in the IRP preferred portfolio and Action Plan. We further agree in principle that the RFP should not be exclusionary with respect to resource technology or fuel types. However, as a practical matter we must also recognize that certain performance characteristics and attributes identified in the IRP preferred portfolio and Action Plan may only be achievable in an RFP by a limited number of resource types.

D. Energy Efficiency

1) Parties' Positions:

Staff Comments

Staff indicates that it has not completed reviewing PGE's Action Plan regarding EE. Staff identifies three areas of specific concern:

1. the rationale for declining energy efficiency opportunities beyond 2016, and the increasing gap between achievable and deployable measures in those years;
2. how lost opportunities affect energy efficiency acquisitions and at what cost could all lost opportunities be avoided; and

3. how PGE calculates the risk reduction value of energy efficiency.[56]

CUB Comments

CUB does not recommend acknowledgement of the IRP Action Plan with regard to EE. In CUB's view, the EE targets in the IRP are not achievable due to a funding cap for industrial customer EE.[57] PGE's industrial customers of greater than 1 MWa do not contribute funds to SB 838 energy efficiency programs. As a result, the ETO limits the amount of funding that it can allocate to large customer EE projects and programs. CUB observes that funds will be insufficient to acquire all of the industrial energy efficiency assumed in the IRP's EE acquisition assumptions.[58]

CUB recommends that energy efficiency be given a higher priority in future IRPs. In CUB's view, the EPA's draft rules regarding section 111(d) of the Clean Air Act call for an increased planning focus on energy efficiency resources.[59]

SBUA Comments

SBUA is concerned about using the total resource cost test to determine cost effective energy efficiency measures. SBUA expresses a desire to understand why EE cost-effectiveness is measure-based rather than building-based.

2) PGE's Response:

Staff

PGE has attempted to address the concerns identified by Staff via responses to earlier data requests. PGE's Response to OPUC Staff Data Request No. 002 addresses questions related to lost opportunity measures. PGE's Response to OPUC Staff Data Request No. 004 and page 55 of the 2013 IRP discuss the shape of energy efficiency acquisitions. PGE's Response to OPUC Staff Data Request No. 005 discusses the difference between all achievable and deployable measures. PGE's Response to OPUC Staff Data Request No. 053 analyzes the risk and benefits of energy efficiency. PGE will separately incorporate these data responses into the record of this IRP docket. None of these responses prompt a need for changes to the amount of EE we incorporate in the IRP.

CUB

PGE agrees with CUB that energy efficiency measures will likely be an important part of State compliance plans under the EPA's 111(d) requirements. PGE notes that the energy efficiency acquisition forecast assumed by ETO is aggressive by national standards. The energy efficiency

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[56] Staff's Opening Comments at Section IV(d)(i), ¶¶1-4.
[57] CUB's Opening Comments at p. 3.
[58] *Id.* at p. 5.
[59] *Id.* at p. 4.

targets established for Oregon in the EPA's building block 4 may be smaller than those assumed by the ETO. Nonetheless, PGE will continue to focus on planning for and acquiring all cost effective energy efficiency with our partners at ETO.

CUB recommends that EE "be given a higher priority in future IRPs." However, CUB does not elaborate on what they have in mind. We have consistently maintained that, to the degree our customers are willing to provide sufficient funding, we will, through the ETO, acquire all cost-effective EE over time using the cost-effectiveness limit formula that starts with avoided cost and includes adders to recognize avoided line losses and T&D, volatility and price risk mitigation, and a 10% adder to recognize environmental benefits. We observe in table 4-2 at page 56 of PGE's IRP that we are in the flat part of the EE supply curve.

To address concerns respecting future EE opportunities, we have proposed an action plan item to work with the ETO to explore new or emerging EE opportunities. We suggest that a useful next step would be to engage in discussions with CUB, the ETO, and other interested parties about how to improve EE assessments in future IRPs.

With respect to the funding cap on industrial customers, CUB is correct; the ETO's forecast presumes that the funding limitation on industrial energy efficiency measures is removed or similarly resolved to allow unfettered ongoing large customer EE funding. Should the funding limitation not be resolved, the ETO has estimated that 1.5-2 MWa of incremental industrial EE measures will be missed annually. The ETO is likely to reach its funding limit for PGE's industrial customers this year.

PGE is advocating in its General Rate Case testimony for a resolution that addresses the current large customer EE funding constraint. Losing cost effective energy efficiency opportunities would ultimately require acquisition of more expensive resource alternatives to meet long term energy and capacity needs.

Despite the concern raised by CUB with regard to EE funding, PGE recommends that the proposed IRP Action Plan for EE be acknowledged. It is simply not practical for the IRP to predict the outcome of future policy debates and legislative or regulatory actions with regard to ETO funding for EE. Instead the IRP has identified an Action Plan with cost effective energy efficiency acquisitions in accordance with least cost least risk IRP principles.

<u>SBUA</u>

The ETO is charged with the responsibility for identifying cost effective energy efficiency measures. It uses the total resource cost (TRC) test to rank EE measures by cost effectiveness from a societal perspective. The cost effectiveness screen compares the cost and benefits of the particular measures. The measure benefits include quantifiable non-energy benefits such as water savings from low-flow showerheads.[60]

The ETO EE evaluation is measure-based so that individual measures can be implemented up to cost-effectiveness limits. A whole building-based basket of measures seems to imply that some measures are cost effective, but others may not be.

E. Future Environmental Compliance Obligations – 111(d)

1) Parties' Positions

Staff Comments

Staff would like PGE to model more immediate carbon costs associated with the new Clean Air Act Section 111(d) rule. In addition to these modeling requests, Staff would like to see PGE model a regional carbon market mechanism; prepare a comprehensive report of its climate-change planning activities; explain in-depth how PGE is incorporating climate change risk into its planning; describe adaptation and mitigation actions PGE is taking on behalf of the Company and its customers; report on any climate change focused customer engagement activities; and fully analyze the effect of EPA's 111(d) proposed draft rule on future resource acquisitions.

CUB Comments

CUB's comments commend PGE for positioning the utility well in advance of the rulemaking. CUB believes that energy efficiency should be prioritized in system planning, given the inclusion of energy efficiency as a compliance option under the proposed rule. CUB asks PGE to discuss the proposed rule and the building blocks in its Reply Comments.

2) PGE's Response:

Regarding the potential impact of the proposed 111(d) rule, we include as Attachment C to these Reply Comments PGE's First Supplemental Response to Staff Data Response No. 039, which discusses PGE's initial assessment of the EPA's proposed rule. Given the many uncertainties of the current proposed rule, the many parties involved, and the long time line for a resolution, it is not possible to "fully analyze the effect" of [the proposed] EPA Section 111(d) rules on future resource acquisitions."

Regarding Staff's requests for additional information related to PGE's plans to engage in climate-change planning more broadly, most of these do not seem

[60] PGE's 2013 IRP at p. 56.

to pertain to the provisions in Guideline 8. They also were the subject of several earlier data requests to which we have responded.

F. Load Forecast

PGE presented its load forecast on several occasions during the public process prior to the filing of this IRP (including the first IRP Public Meeting on April 3, 2013, and the final IRP Public Meeting on March 5, 2014).

1) Parties' Positions

Staff indicates that its review of PGE's load forecasting methodology and results is not complete. Staff does, however, identify the following issues:[61]

a. The "forecast methodology has a biased positive trend, particularly in Commercial sector [sic]";
b. Staff is unsure whether the ETO forecast of EE used for IRP purposes is equivalent to the EE forecast used for load forecast purposes;
c. Staff is concerned that summer load factors may increase due to increased air conditioning load, suggesting that peak demand may rise faster than forecasted;
d. "Large industrial customers self-forecast their load. These customers tend to be overly-optimistic in energy use, particularly for out years."
e. "Load growth scenarios do not appear to test for high and low load growth, or high and low level shifts."
f. "PGE assumes 5-year flat Direct Access load, but past Direct Access load has a positive trend."

No further information was included in Staff's Comments to either support or provide context to these remarks.

2) PGE's Response

a. PGE's load forecast methodology contains no biased positive trend. There is no intentional or built-in bias.

   PGE's load forecast used for IRP analysis 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 forecast 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. The forecast relied on for IRP portfolio analysis was updated in December of

[61] Staff's Opening Comments at Section IV(a).

2013, using actual data through November 2013. The regression-based model is the basis for a five-year forecast. PGE then uses long-term historic growth rates to extend the forecast to the IRP planning horizon.

PGE's long-term load forecast methodology is based on historic long-run average growth rates over periods commensurate with the IRP planning horizon. PGE continues to believe that using a longer historical reference period as the basis for longer-term load forecasts is most appropriate. Shifting the historic period to a more recent, shorter timeframe or basing forecast assumptions on data from the most recent years would create serious flaws in a long-term load forecast. Specifically, extrapolations from the most recent decade would forecast an extension or repeat of the period's historically atypical economic environment, including the 2008 financial crisis and the "Great Recession." It would forecast that the United States and Oregon economies will remain mired in an economic slump for the next 10 – 30 years. While that scenario cannot be ruled out, longer-term historical evidence argues against it.

The economic recovery from the 2008 "Great Recession" has been slower than the recovery from past recessions. While the Pacific Northwest (and, in particular, urban centers west of the Cascades) is still expected to outpace U.S. 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, PGE has proposed, in the 2013 IRP Action Plan, conducting a third-party review of our load forecast methodology to identify potential improvements and ensure that we are employing industry best practices.

Looking more specifically to Staff's assertion that the load forecast methodology has a particular bias in the Commercial sector, Staff does not provide analysis or evidence to support this assertion. Hence, we are unable to respond.

b. The forecast of EE used for IRP purposes is equivalent to the EE forecast used for load forecast purposes.

   The ETO sends PGE its EE deployment on a regular basis. Both the IRP and the most recent load forecast are currently using the August 2013 deployment. The numbers from ETO are at the meter, but the loads used in IRP are calculated at busbar, therefore these numbers are grossed up for line losses. Because EE savings are accumulated throughout the year, the load forecast applies a quarterly ramping method that uses monthly shapes for EE acquisitions (as stipulated in UE 262). In the IRP resource tally, we use a somewhat simpler approach by assuming that the average savings in a given year is equal to half of the year-end total. The difference in the end results of the two methods is negligible for IRP purposes. However, we have since aligned our IRP resource approach to exactly match the quarterly load approach.

Additional information as to how we calculate EE in the IRP is provided in PGE's Response to OPUC Data Request 1.

c. The load forecast regressions eventually incorporate the effects of changing end uses, such as air conditioning load.

Staff expresses concern that PGE's summer peak demand may be rising faster than currently forecasted because PGE holds monthly load factors constant into future years.

While the load forecast regressions eventually incorporate the effects of changing end uses, there is considerable lag. Staff's observation that the load forecast methodology does not currently reflect gradually changing summer load factors is correct. For context, PGE's 2013 Residential Appliance Saturation Survey showed that PGE's residential customer air cooling system saturation rate increased from 72 percent in 2008 and to 82 percent in 2013. At some point in the relatively near future, air-conditioning saturation will top out and become more level, making cooling-driven changes in PGE's load factor less significant.

PGE's IRP Action Plan proposes a study of our long-term load forecast methodology. PGE will address static load factors used in the peak forecast as part of the load forecast methodology study.

d. The long-term large industrial customer forecast is reasonable.

Staff expresses concern that PGE and (a limited number of) large industrial customers tend to be too optimistic regarding their energy forecast.

Staff is correct that, in the short-term forecast (the 5-year forecast), PGE has tended to over forecast large industrial customer loads, particularly in recent years following the 2008 recession. PGE's large industrial customers face multiple sources of uncertainty, from general economic conditions, to industry specific conditions and firm-specific risks. While PGE's large customer load forecast is developed to account for both upside potential (expansions) as well as downside risk, the inherent risks are higher on the downside, because it takes longer for a customer to plan and increase capacity than to shut it down. Additionally market conditions could easily change between the planning stage and completion in the case of expansions.

However, we do not agree with Staff's contention that the large industrial customer forecast is overly optimistic, particularly in the out years. Large industrial customer information is only incorporated into PGE's short-term forecast. Beyond the short-term forecast horizon, industrial loads are forecasted based on average historic rates in the long-term forecast. These historic growth rates reflect periods of growth, but also reflect customer curtailments, closures and other declines as experienced across all industries.

e. PGE's five load growth futures included in the IRP do test for high and low load growth.

As shown on pages 186 and 187 of PGE's IRP, the futures used in PGE's 2013 IRP include reference case load growth, one-standard deviation high and low load growth, and two-standard deviation high and low load growth. These high and low load growth scenarios essentially serve as demand boundaries, or "jaws." It is PGE's position that these scenarios are sufficiently broad to capture a mid-term departure from the reference forecast caused by factors such as business cycle and/or macroeconomic fluctuations, or other long-term trends or technologies that may affect future load growth. In addition to these five scenarios specifically testing various load growth assumptions, PGE also includes a scenario based on the reference case assuming the five-year opt-out cap is reached effective immediately; we discuss this scenario further below.

The load growth sensitivities or futures at the August, 2013 IRP public meeting, at which point stakeholder feedback was solicited. While we heard no concerns expressed at that time regarding the load growth futures, we are open to discussing other approaches to assessing load growth scenarios during the public process for developing our next IRP.

f. PGE's Direct Access load assumptions are reasonable and prudent.

The decision to opt-out is the customer's option. As stated in the IRP, we employ a prudent reliability approach to maintaining resource adequacy and do not attempt to forecast the amount of additional load that will be subject to future five-year opt-out decisions.

It is also important to note that PGE's candidate portfolios tested in this IRP were designed with 100 MWa and 300 MW (through 2018, declining to 200 MW thereafter) left open for wholesale market purchases. This intentional open position creates a buffer for load forecasting (including opt-out) and resource availability variations. Additionally, PGE's scenario analysis included a future that assumed the maximum opt-out election (300 MWa) was reached beginning in 2014.

In summary, we believe the IRP adequately addresses the load forecast issues identified by Staff. To the extent Staff continues to have concerns, we suggest that they be examined as part of the third-party review of our load forecast methodology that we propose in our IRP Action Plan.

G. Natural Gas Price Forecast

PGE's reference natural gas price forecast used in the portfolio analysis for this IRP is derived from market price forward curves through 2016 and the Wood Mackenzie long-term fundamental forecast for the period 2019–2031. We transition from the market price curve to Wood Mackenzie's long-term forecast by linearly interpolating for two years (2017 and 2018). This general methodology was reviewed with stakeholders during PGE's May 28, 2013, IRP Public Meeting.

1) Parties' Positions

Staff was the only party to comment on the natural gas price forecast. Staff is concerned that the first three years in the gas forecast do not have low and high scenarios, therefore the analysis would lack exposure to price risk and be biased towards gas resources.

Staff also suggests that the gas price forecast used in this IRP was nearly one year old when the IRP was filed. PGE needs to be more up-to-date in the next IRP analysis, especially because PGE will be proposing an Action Plan that includes acquiring new resources.

2) PGE's Response

The natural gas price forecast is discussed in section 6-1 on pages 85-87 of our IRP. The gas price forecast uses a forward market curve for the first three years (2014 to 2016 in this IRP). Consequently there are no low and high cases for this near term forward curve.

Staff expresses that this lack of high and low gas prices in the first three years could bias the results toward natural gas resources. As a practical matter, the years in question, 2014 through 2016, are before any new energy resource additions in the trial portfolios. Thus, modeling higher and lower gas prices in the first three years of the portfolio analysis will not result in incremental differences between portfolios. In addition, the supposition by Staff itself indicates a bias, since it only accounts for one side of the risk – higher gas prices. Should prices land lower, then we may have had a bias away from natural gas resources.

Staff's concern that the analysis lacks exposure to price risk in the near term is unfounded. In practice, PGE negotiates gas transportation and storage in advance for gas resources that we already own and for resources that we plan to build. Therefore, in the near term the only remaining exposure is gas price, which is mitigated by a layered hedging strategy as described in section 6.4 of the IRP.

When conducting its IRP analysis, PGE uses the most recent gas price forecast available with the intent of locking down the analysis in the Draft IRP.[62] This update was shared with stakeholders at our March 11, 2014, IRP Public Meeting. Wood Mackenzie (our source for long-term gas prices) provides only semiannual updates of its long-term fundamentals forecast. The most recent forecast update available for use in the 2013 IRP analysis was issued in May 2013.It would simply not be practical to make continuous updates to the gas price forecast or fundamental changes to the IRP analysis after issuing the Draft IRP.

However, it should be noted that we provided a December gas forecast update between the filing of the Draft IRP and the Final IRP, and observed little difference between the forecasts.[63] Given the fact that gas prices declined slightly in the more recent forecast, it is highly likely that any update to the portfolio analysis with the new forecast would reinforce the performance advantage of the preferred portfolio over other candidates with lower levels of baseload gas resources. Therefore, we do not agree with Staff's assertion that the difference between forecast vintages would be significant enough to potentially impact the choice of the preferred portfolio.

H. Wind and Solar Resource Capacity Contribution

For portfolio modeling purposes in the 2013 IRP, wind resources are assigned a capacity contribution at peak load equivalent to 5% of the nameplate capacity, derived from PGE's actual hourly generation in 2011 and 2012 at Biglow Canyon Wind Farm. The generation data is paired with corresponding actual hourly loads for the same years. Capacity factors are calculated on an hourly basis, and then examined across periods of peak load hours. The result of the analysis supported using 5% of a wind resource's nameplate capacity to credit for a given portfolio's capacity. (By contrast, a peaking resource is capable of providing the portfolio with 100% of its nameplate capacity.)

The evaluation for PV solar followed a similar approach.

1) <u>Parties' Positions</u>

Staff notes that a wind or solar resource's capacity contribution at peak load is an important factor. Staff also observes that the geographic diversity of those

[62] It is not feasible to rerun the IRP analyses with an updated gas forecast, after issuance of the Draft IRP, and at the same time prepare a final IRP for filing.
[63] PGE 2013 IRP at pp. 85-87.

resources may play some role in determining a specific plant's capacity contribution. As such, Staff requests that PGE incorporate generation from all wind and solar generation resources when determining these values. [64]

ODOE appreciates PGE's work to model solar resource's capacity contribution using the ELCC methodology. ODOE encourages PGE to use the ELCC methodology in the next IRP. [65]

RNW does not provide a specific proposal with regard to the capacity contribution of variable energy resources (VERs), but rather seems to take issue with the resulting value (5%) and the data relied upon. RNW notes that VER's capacity contributions and integration rates determined in utilities' IRPs may be used in other proceedings (such as for purposes of calculating avoided costs) without specific Commission scrutiny in the IRP itself.

SBUA recommends that PGE consider a broader geographic footprint and more inclusive set of hours when calculating a renewable resource capacity contribution.

2) PGE's Response

PGE believes that the methods used in the 2013 IRP for determining capacity contribution for VERs are reasonable and appropriate. We use two years of the hourly Biglow Canyon Project actuals because Biglow Canyon is the only operating wind plant we own and 2011 was the first full year of operation for the entire three-phase project. When the Tucannon River Wind project is added, we will have another data source. PGE's analysis to-date indicates that Biglow and Tucannon exhibit a relatively low production correlation, which may favorably impact the capacity contribution. However, that diversity is measured over an entire year. We do not yet know their actual correlation during extreme winter and summer weather events. It is also problematic to use multiple generic locations where PGE may not acquire wind resources.

RNW observes that PGE will become summer peaking early next decade and our system will become more constrained in the summer prior to that point. RNW thus concludes that the capacity credit for solar PV energy can be assigned a higher value than the 5% we assigned it in this IRP. We tentatively agree in concept and believe this suggestion warrants more thought and analysis. One possibility would be to start at the 5% level (PGE is still clearly winter peaking at this time), but transition to a higher percentage over a ten year period. However, any such change would require further research and analysis to determine the appropriate capacity contribution for any future point in time and corresponding summer peak load expectation. We look

[64] Staff's Opening Comments at Section IV(c), ¶1.
[65] ODOE's Opening Comments at pp. 3-4.

forward to discussion in the next IRP planning cycle on an approach that examines the potential for identifying a higher capacity value of solar in future years.

PGE has previously expressed its concerns about the suitability of applying an "8760" approach to assess capacity contributions during peak time needs (i.e., the highest 50 load hours of the year). PGE welcomes additional conversation on the matter, but will continue to rely on the peaking methodology presently employed by the Company for IRP capacity value assumptions, until we determine that another method provides more useful insights.

III. Conclusion

As discussed above, PGE believes that the 2013 IRP meets the resource planning guidelines and is compliant with the relevant Commission orders. Although the parties have raised a number of specific concerns in their comments, we believe that such concerns have been addressed in the IRP or in data responses, are unfounded, or should be revisited prospectively in our next IRP process. We also note in our reply comments a number of areas where we either concur with suggestions made by parties for potential improvements to future IRP research and analysis, or agree that the issue is worthy of further discussion and evaluation in the next IRP process. In several cases we believe our proposed IRP Action Plan research initiatives and studies will help address issues raised by our IRP stakeholders.

We recognize that this is in many ways a limited IRP in which we do not seek acknowledgement of any major new resource additions. Rather, our Action Plan consists primarily of customer provided resources such as increased EE, additional DR, and new DSG. It also includes several enabling studies and research actions that were requested by our stakeholders. We believe that this is a comprehensive and well-considered plan founded on robust research and analysis and a collaborative and interactive public process and is a plan that positions the Company to continue to make least-cost, least-risk resource decisions for our customers.

DATED this 3rd day of July, 2014.

Respectfully submitted,

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Portland General Electric
2009 Integrated Resource Plan

2011 Integrated Resource Plan Update

November 23, 2011

3. *Demand Response Update*

In the following sections, we provide a comprehensive update of the progress in demand response (DR) procurement and programs since filing our IRP. In response to the Commission's direction in Order No. 10-457, we also address the following:

- The estimated cost per MW of capacity savings by DR type (firm vs. non-firm), and projected MW acquisitions by DR type for the next 5 years;
- A discussion of the steps PGE is taking to evaluate DR in the next IRP; and,
- An updated action plan for assessing (e.g., plans for pilots and programs) and acquiring DR for the next 3 years.

3.1 Progress in Demand Response Procurement since 2009

PGE has successfully launched several programs and pilots for the procurement of demand response (DR) resources. We identify two main types of DR:

- Firm, or non-discretionary, which are accounted for as capacity resources. We classify as "firm" the curtailment tariff and firm demand response peak capacity programs such as Automated Demand Response and the Salem Residential Pilot;
- Non-firm, which are elective and behaviorally driven and cannot therefore be relied upon to meet peak capacity needs until more is known about typical aggregate PGE participating customer response.

Firm Demand Response – Direct Load Control

Curtailment tariff

PGE filed the Schedule 77 Firm Load Reduction Pilot Program on December 23, 2008 (effective date July 9, 2009) and updated it on August 1, 2011 (effective date September 21, 2011). The pilot is offered to PGE's large non-residential customers that are able to commit to a load reduction of at least 1 Megawatt (MW) of demand at a single point of delivery. The 2009 IRP target of 10 MW per year for this schedule has been achieved. In conjunction with the tariff update, we are also increasing the expected target to 20 MW by 2015.

PGE can only initiate an event during six months of the year and each load reduction event is four hours. PGE initiates a four-hour load reduction event at its discretion by providing the participating customer with a notification. PGE may call up to twelve events per year. A minimum of one event will be called annually.

The cost estimate for 2012 is specified in the tariff[5] and is equal to a reservation credit of $3 or $6 per kW, depending on the advance notification requested. It is credited to the participating customers in January, February, March, August, September, and October regardless of whether or not a Firm Load Reduction Event was called. In addition to the reservation credit, PGE pays an energy charge equal to "the Firm Energy Reduction Amount times the lesser of the hourly Mid-Columbia Electricity Index (Mid-C) as reported by the Dow Jones or fuel cost per MWh for a Simple Cycle Combustion Turbine (SCCT)". Consequently, the cost for this program is less than that for PGE's automated demand response program (ADR – discussed below). This is appropriate because of the longer notice time associated with Schedule 77 (either four or 24 hours) as compared to ADR (10 minutes).

Firm Demand Response Peak Capacity Contracts

Automated Demand Response Pilot

In August 2008, PGE issued a request for proposal (RFP) for up to 50 MW of firm capacity to be acquired by December 1, 2012. The RFP targeted two broad customer groups:

- 25 MW for residential and small non-residential customers; and
- 25 MW for larger non-residential customers.

The proposals received for larger non-residential customers were successful and resulted in selection of a vendor and execution of a contract. We project that this program will meet the full 50 MW target by 2014, as projected in the 2009 IRP. Actual procurement in 2011 will be 5 MW through the ADR pilot, which was approved by Commission Order No. 11-182.

This program can be deployed for a limited number of hours, as its primary purpose is for peak reliability. Because ADR can respond within 10 minutes of notification, PGE could have some future potential to use the resource to address flexibility needs. However, such activities are limited because:

1) Most ADR callable hours must be available for their primary purpose of providing capacity, and

2) ADR represents decremental load only and cannot provide incremental load.

In the future, other automated demand response programs could have greater potential for helping address the challenges of variable resources. These

[5] Details are posted in the Portland General Electric web-site: http://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_077.pdf

possibilities include large-scale, direct control of appliances (see appliance market transformation, below) or use of two-way flows during electric vehicle charging (much further in the future).

The costs for this program are approximately equal to the least cost supply-side capacity alternative (i.e., an LMS100 combustion turbine) on an average levelized program basis. It is structured as follows:

- Eligible participants will be PGE's commercial and industrial customers with an annual average peak demand of 30 kW or more.
- Lighting and HVAC systems (heating, ventilation and air conditioning) are expected to be the primary sources of load reduction.

Table 3-1: Firm Demand Response Acquisitions by 2016

Year	Curtailment Tariff	Automated Demand Response Pilot		Total Demand Response
	MW	Summer (MW)	Winter (MW)	MW
2010Actual	10	-	-	10
2011	10	-	5	15
2012	20	10	10	30
2013	20	20	35	55
2014	20	50	50	70
2015	20	50	50	70
2016	20	50	50	70

Table 3-1 shows the current projected total demand response through 2016. We plan to achieve up to 70 MW by 2016 -- 10 MW more than what projected in the 2009 IRP.

Small Non-Residential Contracts

The proposals received for residential and small non-residential customers were less successful because: 1) they were not cost effective, and 2) none of the proposals included both summer and winter seasons. As a follow-up to that RFP, PGE issued a second RFP in 2010 to evaluate the potential for employing programmable communicating thermostats in a mass market residential direct load control program. This RFP was also unsuccessful because costs for the programmable communicating thermostats were too high. After PGE completes deployment of its automatic demand response and critical peak pricing pilots (discussed below), we plan to issue another residential RFP in 2012. Over time, we believe the cost of programmable communicating thermostats will decline and support the development of more successful proposals.

Water Heater Direct Load Control Pilot

PGE is developing a Water Heater Direct Load Control Pilot (the Salem Residential Pilot), which has the following characteristics:

- The pilot is implemented within the Salem Smart Grid project;
- Customers must be on the test feeders involved with the project;
- The maximum number of participants will be less than 100;
- Water heaters will respond to a radio signal;
- PGE will dispatch the water heater control via a radio signal triggered by a transactive control price signal from the Smart Grid project;
- The pilot will be operational from August of 2012 through 2014.

Because the water heater direct load control project is a very limited and non-scalable pilot within a larger smart grid demonstration project, it provides PGE with no potential MW acquisition from this initiative. Based on the results of this pilot, PGE may reevaluate the economics for expansion as a full program. Given the expectation of emerging technologies, however, PGE currently believes that the most cost-effective approach for this type of program will be through appliance market transformation, discussed in more detail below.

Non-Firm Demand Response Pricing Options

The cost of non-Firm DR programs is not easily summarized on a cost per MW basis, as the costs and demand curtailment estimates are currently uncertain. In addition, the tariff pricing options are designed to be rate-neutral. In the cases where PGE is pursuing internally-developed pilot programs, we are gaining a better understanding of costs, processes, and potential customer participation in the DR initiative proposed. Once the pilots are complete, PGE will have a better understanding of the typical aggregate cost per MW acquired for non-firm programs for a given group of participating customers.

Time-of-Day Pricing

As of January 1, 2011, PGE's long-standing Time-of-Day (TOD) tariff (for large non-residential Sch. 89 customers) was extended to Schedule 85 customers. Consequently, TOD pricing expanded from customers exceeding 1,000 kW of monthly demand to all customers with more than 201 kW of monthly demand. With completion of PGE's Advance Metering Infrastructure System (AMI – discussed below) and the increased potential for interval data, PGE plans to propose further expansion of TOD pricing to Schedule 83 (customers with monthly demand of 31-200 kW) in the future. The benefit of expanding time-of-day pricing is that it will encourage more customers to shift load based on price signals.

Time-of-Use Pricing

PGE offers a time-of-use (TOU) pricing option to residential customers and small non-residential customers with less than 30kW of demand. Time-of-use differs from time-of-day in that TOU pricing offers on-peak, mid-peak, and off-peak rates.

With the completion of AMI and expanded availability of interval data, there will be greater potential for TOU-type programs.

Critical Peak Pricing (CPP)

PGE is currently developing a CPP pilot and is scheduled to be launched November 2011.

The pilot program will employ a dynamic pricing structure, based on time-of-use rates, to encourage peak-load reduction during times of unusually high demand. The pilot is designed to accommodate up to 1,000 participants and is expected to be active from November 2011 through October 2013. Based on the results of the pilot, a residential CPP program may subsequently be made available to a broader group of customers. Until enough experience with customer response provides a reliable estimate of typical aggregate capacity savings, CPP is considered a non-firm resource.

Under the tariff, PGE will provide day-ahead notice to participants for expected critical peak day events. During a 4-hour "critical peak" period (Sundays and holidays are excluded and billed at off-peak rates), the customers' energy price will be approximately four times higher than normal. The goal is that the price signal will encourage customers to conserve energy during those hours. The pilot limits the number of times PGE can implement a CPP event to 10 times in the summer and 10 times in the winter. In order to develop the current CPP pilot in a reasonable time and cost (while retaining foundational functionality), its current design excludes enabling technology (e.g., communicating, programmable thermostats). As a condition of Commission approval for the CPP pilot, however, PGE will provide a report no later than early 2013 detailing the costs and efforts needed to implement a fully scalable CPP program upon completion of the pilot, assuming it is successful. In addition, because Phase 1 of CPP is a limited pilot, its cost is not indicative of its potential as a demand-side capacity resource.

Energy Tracker

By end-year 2011, PGE will introduce its Energy Tracker program to all customers. This represents an energy information tool that utilizes the interval data from AMI. Energy Tracker will provide customers with energy use information that can help identify-reduction and peak shifting strategies that customers may find valuable to implement. Such information includes:

- Determine how changes to a customer's end uses may impact their bill (e.g., adding/removing appliances);
- Determine energy usage trends plus how and when the most energy is used;
- View up to 24 months of historical bill data by: usage, cost (including Time of Use and Demand costs) and meter;
- Compare bills with the previous month or previous year;
- Compare their current tariff rate to other offered tariff rates and see how shifts in their usage might impact their bill; and
- View their interval data by hour, day, week, bill cycle or month.

In addition, Energy Tracker will allow customers to compare their home's energy efficiency with comparable homes in the region and provides suggestions to improve their efficiency. Finally, PGE's Customer Service Representatives (CSRs) are able to use customers' Energy Tracker data to enhance their ability to respond to energy-usage and billing-related questions.

Energy Information Service

PGE's large non-residential customers with greater than 30 kW of demand (Schedules 83, 85, and 89 customers) are currently eligible for Energy Information Service (EIS), an energy monitoring option that provides the most detailed information of any of PGE's services. As of June 2010, a total of 140 customers representing over 850 meters have signed up for EIS, which provides detailed graphs and charts depicting energy use in 15-minute intervals. By knowing when peaks occur, customers can analyze their processes and respond accordingly. In some instances, this information has helped customers know which processes they could shift to reduce peaks, or to participate in such programs as Demand Buy-Back or contract curtailment. EIS can be used to:

- Compare current operating data with historical information;
- View monthly, weekly, daily and hourly data;
- See when customer operations are using the most energy;
- Generate an "average day" profile and "peak day" profile for comparison;
- Identify abnormalities and trends in energy usage and help determine causes, such as hidden equipment problems;
- Optimize operations by adjusting energy use; and
- Monitor and track the effectiveness of energy-efficiency measures.

Appliance Market Transformation

PGE has been proactive in the effort to achieve appliance market transformation. In 2007, we established a working group along with Whirlpool and the Pacific Northwest National Laboratory that presented an award-winning paper at the Grid Interop forums. That paper addressed the potential for installing a standard interface (i.e., socket) on appliances that could accept low-cost communication devices.

In 2009, PGE worked with Whirlpool and the Electric Power Research Institute (EPRI) to define and create specifications for that socket. EPRI also recruited other utilities, appliance manufacturers, and communication device manufacturers to establish the EPRI Appliance Market Transformation Project.

In a separate but related effort (also begun in 2008), PGE was a participant in the "Home to Grid" (H2G) work group, which addresses appliance transformation. This effort is part of the National Institute of Standards and Technology (NIST) responsibilities for an overall interoperability roadmap under the Energy Independence and Security Act (EISA) of 2007. As part of this activity, PGE published two papers on appliance market transformation that allowed coordination of the principles and efforts of the EPRI and NIST projects.

Subsequently, at the request of NIST and EPRI, the Utility Smart Network Access Port (USNAP) Alliance formed to start the work of combining their specifications into a single specification. As a result of that effort, the USNAP Alliance and EPRI then created the Utility Smart Network Access Port, an interface/socket, that enables any Home Area Network standard, present and future, to use any communication method as a conduit into the home without adding additional hardware in the meter. This development has led to the following recent activities:

- In May 2011, a successful test was performed with prototype appliances containing the USNAP interface, plugged-in communication devices, and utility control software with demand response commands. "Plugfest" was attended by five appliance manufacturers, five communication device manufacturers, and several utilities including PGE. In addition, PGE submitted specifications to help define the common utility control commands;
- In June 2011, USNAP and EPRI presented the specifications for that socket to the H2G group, who recommended that the specification become a national standard. In October 2011, the Consumer Electronics Association (CEA) formally agreed to take on this work and will issue a CEA or ANSI (American National Standards Institute) standard for a low-cost modular interface/socket to communicate with appliances after they complete their process.

In addition to these efforts, The USNAP Alliance will market the new standard to appliance manufacturers and communication device manufacturers. PGE's on-going efforts will include encouraging local retailers to market appliances with this standard. With eventual incorporation of this standardized interface into appliances and the availability of low-cost communication devices, utilities will be able to efficiently coordinate appliance energy use under either direct load control or time varying price programs.

Finally, PGE plans to initiate, in late 2011, a very small pilot to install approximately five water heaters and "plug in" a Wi-Fi communication device. PGE will then use the customer's internet connection to test direct load control of the "smart" appliances. If successful, PGE will propose to expand the pilot to 100 customers in 2012/2013 to further test the system's viability. If the expanded pilot proves successful, PGE plans to propose a scalable water heater direct load control program.

Advanced Metering Infrastructure

In the 2009 IRP, PGE reported on our initial efforts to implement the Advance Metering Infrastructure (AMI) system. Since then, we have successfully achieved the following milestones:

- In August 2010, we completed meter deployment;
- In December 2010, we completed network installation;
- In June 2011, we completed all the information technology (IT) efforts to achieve the process improvements related to the AMI system, e.g., customer preferred due date, remote connects/disconnects, unaccounted for energy detection, etc.

3.2 Demand Response Evaluation Methodology and Next Steps

PGE believes that the methodology we used to evaluate DR in the 2009 IRP remains sound.

PGE will continue to evaluate demand response resources against the supply-side capacity resource alternatives, such as a simple-cycle CT. This is consistent with the discussion in Commission Order No. 05-584 and is also consistent with other PGE analyses for demand side capacity resources in recent years. For example, in Dockets UM 1514 and UE 229 (PGE's proposal for ADR approved by Commission Order No. 11-182), "the costs of ADR were compared to that of an LMS100 SCCT and found, on an average levelized program basis, to be approximately equal" (Stipulating Parties/100, page 13). PGE also estimated the benefits of a large-scale CPP program in its UE 189 scoping plan (PGE Exhibit 103) to be the avoided cost of a simple-cycle combustion turbine.

Simple-cycle combustion turbines represent the appropriate capacity benchmark because:

- They have the necessary flexibility that is not available in most other available supply-side resources;
- There currently is no liquid capacity market in the region;
- Longer-term capacity contracts can have a variety of conditions and notification times, which means they are not readily comparable; and
- In contrast, the LMS100 has 10-minute availability, similar to ADR, and therefore represents the least-cost, alternative resource.

Although the comparison is inexact, the SCCT provides the most reasonable basis for comparison. A CT can provide additional generation benefits by dispatching economically during non-critical demand periods, while demand response resources provide reduced environmental impacts and risk and diversity in PGE's capacity portfolio. DR offers reduced risk in the areas of resource development and construction as well as operational risks related to fuel prices, potential CO_2 costs, and pollution abatement. At the same time, a flexible combustion turbine offers ancillary services value that may only be achievable on the DR side through automated- / technology-enabled DR.

Steps to evaluate DR in the next IRP include:

- Update the market assessment estimate of the cost and potential for DR;
- Evaluate new pricing programs enabled by the adoption of smart meters;
- Issue a new RFP for residential peak capacity contracts; and
- Continue development of the programs and pilots described in Section 3.1 above.

3.3 Updated DR Action Plan

Our Action Plan for the next 3-yrs (to 2015) is the following:

- Pursue an ADR target of up to 50 MW by 2015;
- Issue an RFP for peak capacity contracts for residential and small non-residential customers by end-year 2012;
- Increase Schedule 77 (curtailment tariff) customers to up to 20 MW by 2015;
- Extend the time-of-day pricing option to all customers with more than 31 kW of monthly demand;
- Complete the pilots described above.

As of year-end 2011, PGE will have acquired 15 MW out of the 60 MW projected firm DR by 2015 targeted in the Action Plan. In addition, PGE has completed or is in the process of implementing the following:

- Water Heater Direct Load Control Pilot. Pilot will be operational in 2012;
- Extension of the time-of-day pricing option to all customers with more than 201 kW of monthly demand;
- Critical peak pricing pilot (November 2011);
- Phase I of the Energy Tracker to all customers (year-end 2011);
- Energy Information Service to all large non-residential customers with demand greater than 30 kW; and
- AMI system.

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4. *Renewable Portfolio Standard*

On June 6, 2007, Oregon adopted a Renewable Portfolio Standard (RPS), ORS 469A. Among the requirements of the Oregon RPS, certain electric utilities must serve at least 25% of their retail energy load with RPS qualifying renewable resources by 2025, with interim targets of 5% by 2011, 15% by 2015, and 20% by 2020. Qualifying renewable resources include the following if the resource, or an improvement to the resource, has been placed into operation on or after January 1, 1995:

- 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 from certified low-impact hydroelectric facilities.

Electric utilities can use, subject to certain limitations and independent verification, Renewable Energy Credits (RECs) or Green Tags to fulfill the RPS requirement. In meeting this requirement, the RPS identifies two classifications of RECs:

- Bundled, where the energy and REC are sourced from the same generating facility, and
- Unbundled, where the REC is purchased separately from the underlying power.

In both cases the qualified resources must be located within the boundary of the Western Electric Coordinating Council footprint (WECC).

In addition, the legislation allows for the ability of the electric utility to "bank" RECs from qualifying resources beginning January 1, 2007 for the purpose of carrying them forward for future compliance. To maintain the integrity of compliance, the origination of RECs is validated via the Western Renewable Energy Generation Information System (WREGIS). The legislation limits the maximum amount of annual RPS requirement that can be met with unbundled RECs to 20% and provides the option for electric utilities to make alternative compliance payments (ACP) instead of producing the required number of compliance RECs.

Given the above RPS provisions, PGE must meet at least 80% of each annual RPS requirement with some combination of current and banked, bundled RECs from qualifying physical resources. The practical effect of the RPS legislation is to promote the acquisition of renewable resources as the primary means of compliance, while allowing for flexibility in implementation to capture market opportunities, avoid short-term cost excursions and adapt to timing differences in securing new supply.

4.1 RPS Position and Action Plan Strategy

Our acknowledged IRP Action Plan targets the acquisition of sufficient new renewable resources to maintain physical compliance with the Oregon RPS standards. Specifically, the Action Plans seeks renewable resource additions to meet, at minimum, the 2015 RPS standard of 15%. At the time of filing the 2009 IRP, we projected a need for 122 MWa of new renewables to meet the Action Plan objectives. Due to a continued economic slowdown which has resulted in a reduced electric demand forecast for PGE, accompanied by increased customer five year opt-out elections, we now project a modestly reduced RPS need of 101 MWa.

However, due to the steep ramp of the RPS requirements over time, we also continue to forecast a significant need for qualifying renewable resources beyond 2015. Our RPS resource deficit increases to 261 MWa by 2020, 454 MWa by 2025, and 533 MWa by 2030, absent any new supply additions.

Although our Action Plan targets resource additions to maintain physical compliance with the 2015 RPS requirements, the amount of new renewable resources that we acquire to implement the Action Plan will depend on the cost and quality of bids received through our forthcoming RFP, as well as the specific characteristics of the underlying generation projects. Accordingly, we plan to issue a renewables RFP in 2012 that will seek to fulfill our IRP objectives, while remaining flexible with respect to project size and in-service date.

The following table presents our projected RPS compliance position through 2025.

Table 4-1: PGE Estimated RPS Position by Year (in MWa)

	2011	2015	2020	2025
Calculate Renewable Resource Requirement:				
PGE Retail Busbar Load net of EE	2,320	2,530	2,765	3,021
Remove 5-year Opt-Out Load	(67)	(128)	(132)	(132)
A) Net PGE Load	2,253	2,372	2,578	2,834
Renewable Resources Target Load %	5%	15%	20%	25%
B) Renewable Resources Requirement	**113**	**356**	**516**	**708**
Existing Renewable Resources at Busbar:				
Vansycle Ridge Wind	8	8	8	8
Klondike II Wind	26	26	26	26
Klondike II Stable Tariff Rate	(5)	-	-	-
Sales of RECs	-	-	-	-
Biglow Canyon Wind	161	161	161	161
Post-1999 Hydro Upgrades	9	9	9	9
Pelton-Round Butte LIH Certification	50	50	50	50
C) Total Qualifying Renewable Resources	**249**	**254**	**254**	**254**
Compliance Positions & RECs Banking:				
D) Excess/(Deficit) RECs Before New IRP Actions (C less B)	137	(101)	(261)	(454)
E) IRP Action Plan	-	101	101	101
F) Total PGE Renewable Resources (C plus E)	249	355	355	355
G) % of Load Served by RPS Renewables (F divided by A)	11%	15%	14%	13%
H) Excess/(Deficit) RECs w/IRP Actions (D plus E)	137	(0)	(160)	(353)
I) Cumulative Banked RECs After IRP Actions	**717**	**1,291**	**1,077**	**200**
J) Cumulative Non-LIH Banked RECs After IRP Actions	516	1,091	877	(214)

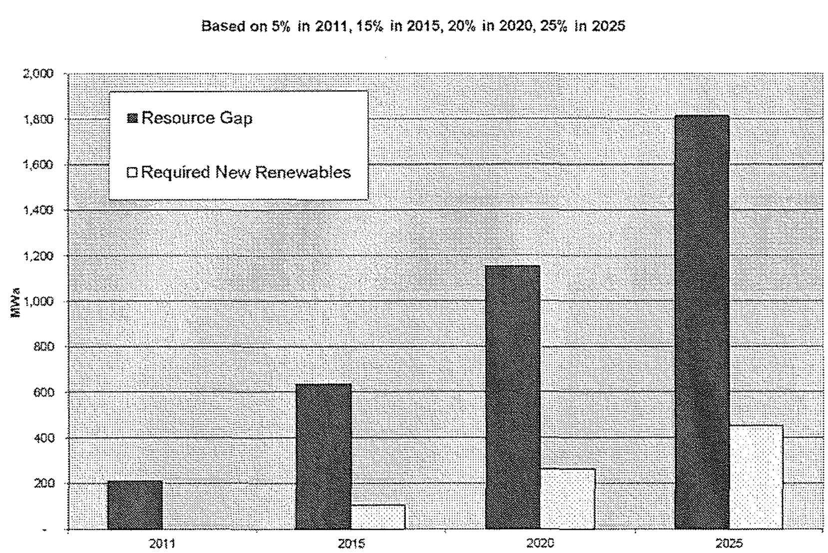
As illustrated in Table 4-1 above, our projected RPS resource deficits are significant when considered on an energy basis, and become even more challenging when converted to a nameplate generation requirement. To date, wind remains both the most available and cost-effective renewable resource. As such, it is reasonable to presume that wind will continue to provide a substantial proportion of the overall regional and PGE need for renewable energy. If we assume that our ongoing RPS needs continue to be met primarily with variable energy resources such as wind, the resulting requirement for new qualifying generation is large, and therefore suggests an implementation approach which manages to longer-term needs and cost/risk mitigation, rather than near-term compliance targets. Table 4-2 projects our future RPS requirements in terms of installed nameplate capacity for new wind generation.

Table 4-2: Wind Capacity Necessary for RPS Requirements

Time Period	Average Need (MWa)	Current Annual Generation (MWa)	Need as a % of Current Generation (%)	Shortfall (MWa)	Implied Wind Nameplate Capacity Needed (33% CF) (MW)
2011-2014	114	255	45%		
2015-2019	367	255	144%	112	339
2020-2024	536	255	210%	281	850
2025-2030	743	255	292%	488	1,480

At the same time, we also project significant future aggregate energy and capacity deficits (as discussed in more detail in Chapter 1 of this Update). This overall resource deficit exceeds our RPS renewable need through 2025 and beyond. Accordingly, qualified RPS resource additions serve the dual purpose of meeting our energy requirements and RPS obligations. This was the case for our renewable resource additions over the last several years (including Biglow Canyon Wind, Klondike Wind and new solar contracts). Figure 4-1 provides a current projection of our aggregate energy deficit alongside our RPS need at each of the upcoming RPS target change years (2015, 2020 and 2025).

Figure 4-1: Renewables Necessary to Meet RPS Requirements



4.2 Options for Achieving RPS Compliance

PGE has four primary options for achieving RPS compliance, subject to certain limitations – acquiring physical energy resources with bundled RECs, purchasing unbundled RECs, utilizing banked RECs (that result from previous REC acquisitions – both bundled and unbundled), and alternative compliance payments in lieu of physical resources or RECs. The company may also employ a mix of these strategies, either concurrently or at different points in time. Each of these strategies, as well as their potential benefits and limitations, are further discussed below:

- Physical Compliance – Means acquiring bundled RECs through the purchase of energy and associated renewable attributes from an RPS-compliant renewable generation source. Acquisition of bundled RECs can be achieved either through utility ownership or power purchase agreements. There is no limitation on the use of physical resources and bundled RECs for RPS compliance. Bundled RECs may also be banked indefinitely for future RPS compliance or monetization. For energy deficit utilities like PGE, physical compliance is particularly attractive when the costs of renewable resources are equivalent to, or lower than, the cost of non-renewable alternatives. In an environment where renewable resources are cost competitive (at or near the same cost) with non-renewable alternatives, a short utility is able to meet both its future energy requirements and its RPS obligation at a relatively small, or perhaps no additional cost. The acquisition of physical resources with bundled RECs also provides an ongoing or recurring source of supply to meet growing RPS compliance targets over time. Furthermore, utility owned resources or contract structures that provide extension rights provide access to site-specific renewable generation and RECs that may extend far beyond the initial life of the power plant and align with the long-term nature of the RPS requirement.
- Unbundled RECs – Are defined as RECs that are purchased separately from the electricity generated by a qualified renewable resource. The Oregon RPS limits the use of unbundled RECs to a maximum of 20% of the annual compliance obligation in each year. Given the relatively small proportion of unbundled RECs that may be used each year, this is not a primary strategy for achieving compliance, but instead would be used to compliment a physical resource / bundled REC strategy. In addition, unbundled RECs currently exhibit problems related to product definition and fungibility, as well as market fragmentation, lack of price transparency, and illiquidity. These structural problems increase the risk associated with reliance on unbundled RECs for RPS compliance, and further limit their practical use.

- Banked RECs –Are created when bundled or unbundled RECs are acquired or generated in advance of current RPS compliance requirements, resulting in a surplus of RECs. Banked RECs (both bundled and unbundled) may be stored indefinitely. However, unbundled RECs may only be used up to the 20% maximum per year for compliance, regardless of whether they were previously acquired and banked. There is no limitation on the amount of banked, bundled RECs that may be used for compliance. The banking provisions of the Oregon RPS provide an important flexibility mechanism for electric utilities. The RPS provisions allowed for the banking of RECs from qualified resources starting in 2007, three years prior to the first compliance year of 2011. As a result, once banked, RECs may be used as a balancing mechanism (to mitigate against timing differences in acquiring and constructing new renewable generation) or as a temporary alternative to physical supply in the event of adverse market conditions. However, the use of banked RECs is inherently limited, as banked RECs are only produced when physical supply / bundled RECs are acquired early or in surplus to current RPS obligations. They do not represent a "recurring" source of RECs for future compliance as is the case with physical renewable resources. Once banked, RECs are consumed for compliance as an alternative to physical supply, they are not replenished and deplete quickly due to growing RPS targets and increasing load. Therefore, the use of banked RECs should also not be considered a primary or long-run strategy for meeting RPS obligations.
- Alternative Compliance Payments (ACP) – Oregon legislation provides for the use of alternative compliance payments in lieu of acquiring bundled or unbundled RECs for meeting RPS obligations. However, it is clear that the ACP provision is only intended to provide a "safety valve" mechanism for extreme cases in which a utility is not able to achieve compliance through the acquisition of physical resources and/or RECs. The ACP provision is not intended to be used as a strategy for achieving RPS compliance over time. This is further evidenced by the pricing established for ACP payments, which provides an economic incentive to achieve compliance through other means. In Order No. 09-200, issued on June 12, 2009, the OPUC set the alternative minimum compliance payment at $50/MWh for the year 2011. This is the cost that a utility will incur for any REC deficits in the 2011 compliance year. The current ACP amount far exceeds the cost difference between RPS compliant resources and non-renewable generation alternatives, or any reasonable expectation for the price of unbundled RECs.

4.3 RPS Implementation: Key Factors for Strategy Development

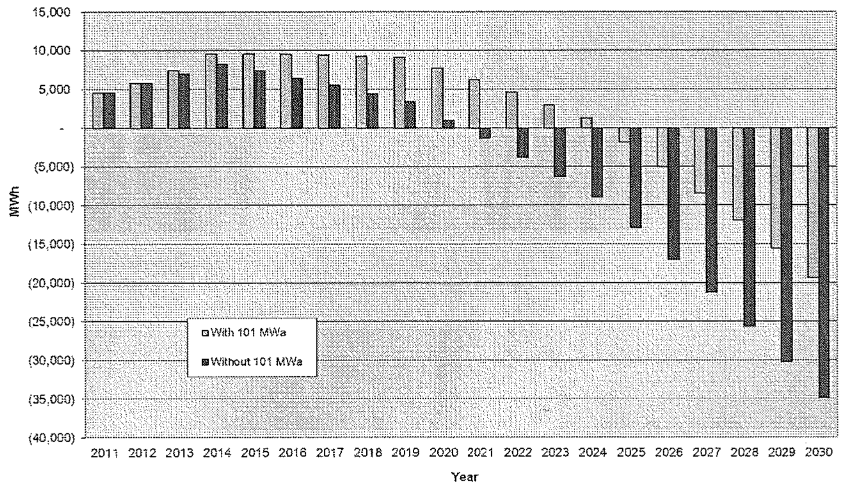
Our acknowledged Action Plan targets the procurement of additional new renewable resources to remain in physical compliance with Oregon RPS standards. More specifically, we are targeting the acquisition of additional renewable resources to be in physical compliance with, at minimum, the 15% RPS standard in 2015. As discussed in detail in our IRP (pages, 111 – 122), we believe that achieving physical compliance with the RPS provides the best balance of cost and risk for PGE and its customers, given current circumstances and future expectations – this is particularly true during the early years of RPS compliance when targets are increasing rapidly and competition amongst utilities to acquire renewable resources is high. We also recognize that the provisions of the RPS were established to incent the proliferation of new renewable resources and the achievement of long-run physical compliance. In addition, we note that the flexibility provisions in the RPS, such as acquisition of unbundled RECs, RECs banking, and the ACP are not long-term surrogates to renewable generation, but rather allow utilities to implement the RPS while minimizing significant adverse impacts to cost or reliability.

While we do not believe that unbundled or banked RECs should be the foundation or primary strategy for achieving long-run RPS compliance, they do provide valuable tools for ensuring flexibility in implementing our RPS strategy over time. Accordingly, PGE will continue to monitor signposts for future REC market development and results from upcoming competitive bidding processes to determine whether any strategy changes are warranted as we implement RPS compliance.

Further, the following key factors should be considered and monitored in developing and implementing an RPS compliance strategy:

- Growing RPS Obligations – Because future RPS requirements increase rapidly, deferring the procurement of qualified RPS resources needed for current or near term physical compliance increases the execution risk for later RPS compliance periods as compared to procuring such resources on a more measured pace over time. The "cliff" effect of such an approach could potentially have a significant adverse impact on future compliance costs and customer rates if prices for new renewables increase over time. If deficits became too large, it could also impair PGE's ability to acquire sufficient supplies to maintain RPS compliance. The graph below illustrates our rapidly growing renewable resource / REC requirement as we move beyond 2015 to the increasing compliance targets in 2020 and 2025.

Figure 4-2: Projected Cumulative REC Balance by Year (in MWa)



- Reduction or Elimination of PTC – Federal and state tax benefits are a significant driver to the cost effectiveness of renewable resources. Based on current estimates, the PTC is equal to roughly 25% of the total cost of energy from a wind project (on a utility revenue requirement basis). The Federal PTC for wind energy is currently scheduled to sunset with new wind generating facilities placed in-service by year-end 2012, and the PTC for other technologies is scheduled to sunset in 2013. If the current tax benefits are reduced or eliminated over time, the cost of renewable generation would increase considerably. The risk associated with reduction of tax benefits is both significant and increasingly likely. Given current federal and state budget deficits and growing pressure for deficit reduction, the probability of a continued extension of tax benefits at their current levels becomes more questionable. While we have not yet changed our reference case assumptions for PTC and ITC, we believe that the risk of reduction or elimination of these programs grows significantly over time. Unlike other signposts and indicators, reduced government tax incentives for renewable generation pose a potential "game changing event", where impacts would be potentially sudden and significant.
- Competition for Quality Sites – Unlike other types of electric generation that are less location specific, renewable resources are typically tied to an underlying natural resource at a specific site (e.g. wind plants are only viable when built at windy locations). Given the proliferation of RPS requirements across the Western United States and limitations on the availability of quality sites, we believe that increasing competition and the potential for resource scarcity represents a growing risk over time.

Ultimately, increased competition or reduced availability of sites could result in higher site acquisition, operating, and integration costs, and reduced capacity factors in the future. Unless offset by other developments (such as technology improvements), such supply challenges could result in substantial cost increases (on a per MWh basis) for future renewable resources. Further, constraints on available transmission continue to drive renewable generation development in areas that offer lower interconnection and transmission costs, therefore leaving for future development sites with more costly or less viable transmission access. As evidenced by the Wyoming Wind case in the IRP (2009 IRP, pages 153 to 157), incremental transmission costs to reach new and remote renewable resource areas can have a significant adverse impact on the cost of future RPS compliance. Table 4-3 provides current RPS targets for WECC states.

Table 4-3: RPS Requirement in WECC

	2010	2015	2020	2025 and after
Arizona	2.5%	5%	10%	15%
California	20%	27%	33%	33%
Colorado	5%	20%	30%	30%
Montana	10%	15%	15%	15%
Nevada	12%	20%	22%	25%
New Mexico	9%	15%	20%	20%
Oregon		15%	20%	25%
Utah				20%
Washington		8%	15%	15%

- Technology Advances – Technology innovations and improvements offer the potential to reduce manufacturing costs over time, particularly for less mature renewable resources technologies. This learning curve effect is generally driven by improved efficiency in manufacturing and production processes achieved via long-term economies of scale and increased competition. In the case of less mature renewable technologies such as solar, the benefits of economies of scale and competition continue to lower economic costs. However, for wind, any further technology-driven cost declines appear to be largely offset by the decreasing energy production capability of sites available for new construction. While it is difficult to predict the pace or degree of technology improvements for renewable generation over time, it is reasonable to presume that such improvements will occur. Since technology improvements in electric generation over time have generally been evolutionary and incremental, it seems unlikely that technology-driven cost reductions would either offset or overwhelm price impacts due to changes in aggregate supply and demand or government subsidies. Instead, technology improvements and any resulting cost reductions must be considered in conjunction with other key drivers for future cost and availability of renewable resources.

- Change in National Environmental Policy – As discussed earlier in this Update, changes in environmental policy could have a significant impact to the future cost and availability of both renewable and non-renewable resources. For instance, the passage of climate change legislation in the future would likely increase demand for renewable resources and reduce demand for fossil fuel resources, particularly for more emission-intensive generation types. At the same time, the implementation of a national RPS could have similar impacts. While it is difficult to predict the price impact of such policy changes in the long-run, it is reasonable to presume that, in the short-run, demand for new renewables would be amplified and near-term costs would increase while industry and markets adjust to the new policy.
- Integration Costs – Changes in the future cost of integrating and providing back-up capacity for variable energy renewable resources, such as wind, could have an adverse impact on the overall cost of RPS compliance over time. Currently integration costs represent a relatively small proportion of the total cost of new wind – we estimate the cost of wind integration currently to be roughly 11% of the total cost of energy for new wind generation. However, integration can become a more significant cost driver over time, particularly if a trend in cost increases or decreases develops and persists. We believe integration costs are likely to increase the future costs of renewable resources. As existing legacy regulating resources in the region (namely hydro) are consumed, it will become increasingly necessary to build new flexible thermal generation to absorb the variability of renewable resources and provide reliable back-up capacity. These new thermal generation additions are likely to provide upward pressure on the cost for integration in the long-run. At the same time, market transformations may temporarily or partially off-set some of these cost increases by improving overall regional generation and electric system efficiency. An example of this would be the development of effective sub-hourly energy trading and scheduling, or formation of capacity and ancillary services markets in the Northwest.
- Transmission Availability – The capability of the existing transmission system is decreasing due to the integration of additional resources and increased operational constraints. As a result, the potential cost of interconnecting and procuring transmission service will likely increase.

Therefore, to the extent a resource can capture existing available transmission or require only a minor system upgrade, the cost and complexity of acquiring transmission service will be reduced.

- Alternative Non-renewable Generation Costs – Changes in the cost for non-renewable generation alternatives could impact the cost effectiveness of future renewable resources. If price changes for non-renewable generation were significant, they could further influence demand and, in turn, the price for new renewables. The most obvious example of this type of scenario risk is the potential for significant changes in fuel prices for natural gas-fired generation. Over the last decade, we have seen both large increases and decreases in the current and forecasted price for gas. These fuel price changes have resulted in significant changes in the expected cost of new natural gas-fired generation, and, as a result, the relative cost-effectiveness of new renewables. Recent natural gas price reductions have resulted in lower expected costs for future gas-fired generation. While it is difficult to predict any further fundamental or structural changes in gas supply or market price, history has proven that such changes are possible.

4.4 RPS Scenario Analysis

In Order No. 10-457, the Commission directed PGE to evaluate, in its IRP Update, "the use of unbundled renewable energy credits (unbundled RECs) in its strategy to meet Renewable Portfolio Standard requirements for the entire planning period." The Commission also directed PGE to "evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/ least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources."

In assessing strategies for RPS compliance, it is important to recognize that cost estimates for building new generation resources become increasingly uncertain over time (the farther the new build occurs from today). In addition, certain RPS compliance cost factors such as future REC values are impossible to predict. While these uncertainties reduce confidence in predicting the future cost of RPS implementation strategies over long time horizons, conducting scenario analysis can be a useful tool in understanding the magnitude of potential adverse or favorable outcomes for alternative strategies, should changes in future circumstances occur. Accordingly, we address the Commission's directives in the following illustrative scenarios that test changes in costs for various RPS strategies based on potential changes in future environment and prices.

Unbundled RECS

As discussed earlier in this Update, unbundled RECs provide a potential tool to meet up to 20% of the RPS requirement each year. In situations where the projected cost of qualifying resources materially exceeds the price of non-qualifying alternatives, and Unbundled RECs are available at a price below the expected difference in cost between renewable and non-renewable generation this approach could potentially reduce compliance costs in the short-term.

Given that, through 2025, PGE's projected incremental resource needs exceed (on average) the incremental RPS requirement, we have two options for achieving compliance:

1. Rely entirely on bundled RECs (both current and banked) to meet RPS compliance.
2. Acquire bundled RECs to meet at least 80% of the RPS requirement and acquire a combination of non-qualifying electricity and unbundled RECs (up to the annual 20% annual limit) to meet the remaining need.

In order for the second strategy (acquisition of unbundled RECs in lieu of bundled RECs) to be effective, it should meet two economic tests:

1. The expected life-cycle, levelized cost for qualifying resources is higher than the like cost for non-qualifying alternatives at the time of the decision.
2. The cost of unbundled RECs is less than the cost difference between the qualifying resource and the non-qualifying alternative.

Table 4-4 illustrates the potential cost impact of pursuing a strategy with no unbundled REC purchases versus purchasing the 20% maximum each year, based on a "typically" sized renewable resource. For the example, we assume several cases with regard to unbundled REC prices:

- Unbundled REC price is equal to the cost premium for RPS renewables verses non-renewable alternative
- Unbundled REC price is less than the cost premium for RPS renewables versus non-renewable alternative
- Unbundled REC price is more than the cost premium for RPS renewables versus non-renewable alternative
- Unbundled REC prices start lower, but then rise over time.

Table 4-4: Example of Impact of Unbundled RECs on Resource Cost

Assumptions:			
Assumed "Typical" New Resource Annual Supply		50	MWa
Assumed Resource Life		20	Years
Assumed Levelized Cost of Non-Qualifying Resource		$88.00	Per MWh
Assumed Premium % for Qualifying Resources		5%	
Premium for Qualifying Resource		$4.40	per MWh
Implied Cost for Bundled RECs		$4.40	per REC
Annual RECs Generated from Qualifying Resource		438,000	
Cost Comparison of Three Cases			
	Year 1	Year 10	Year 20
Case A: Unbundled RECs are (on average over time) same price as Bundled RECs			
Cost of Unbundled RECs (per MWh)	$4.40	$4.40	$4.40
Fill minimum 80% with Bundled RECs (000s)	$1,542	$1,542	$1,542
Fill maximum 20% with Unbundled RECs (000s)	$385	$385	$385
Total cost for RECs (000s)	$1,927	$1,927	$1,927
Total Levelized Resource Cost, with RECs (000s)	$40,471	$40,471	$40,471
Case B: Unbundled RECs are (on average over time) 20% less costly than Bundled RECs			
Cost of Unbundled RECs (per MWh)	$3.52	$3.52	$3.52
Fill minimum 80% with Bundled RECs (000s)	$1,542	$1,542	$1,542
Fill maximum 20% with Unbundled RECs (000s)	$308	$308	$308
Total cost for RECs (000s)	$1,850	$1,850	$1,850
Savings of B over A (000s)	$77	$77	$77
Savings of B over A (% of A)	4%	4%	4%
Cost impact to Total Resource Cost	**0.2%**	**0.2%**	**0.2%**
Case C: Unbundled RECs are (on average over time) 20% more costly than Bundled RECs			
Cost of Unbundled RECs (per MWh)	$5.28	$5.28	$5.28
Fill minimum 80% with Bundled RECs (000s)	$1,542	$1,542	$1,542
Fill maximum 20% with Unbundled RECs (000s)	$463	$463	$463
Total cost for RECs (000s)	$2,004	$2,004	$2,004
Cost of C over A (000s)	$77	$77	$77
Cost of C over A (% of A)	4%	4%	4%
Case D: Unbundled RECs start lower but end higher than Bundled RECs			
Cost of Unbundled RECs (per MWh)	$3.52	$4.40	$5.28
Fill minimum 80% with Bundled RECs (000s)	$1,542	$1,542	$1,542
Fill maximum 20% with Unbundled RECs (000s)	$308	$385	$463
Total cost for RECs (000s)	$1,850	$1,927	$2,004
Difference of D versus A (000s)	$(77)	$-	$77

As illustrated in the examples in Table 4-4, unbundled RECs are unlikely to have a significant impact to the overall cost of RPS compliance due to their restricted use (maximum of 20% per year). Even when unbundled RECs are available for 20% less cost than bundled RECs on an ongoing basis, and are employed maximally each year, the impact to the overall cost of RPS compliance is small. More particularly, the impact to the overall fully allocated cost for the new electric generation is diminishingly small as a percentage. In short, it appears that any potential benefits from the purchase of unbundled RECs, as opposed to the acquisition of qualified resources with bundled RECs, are likely to be minor and may not off-set the hedge benefit of producing recurring and cost-certain RECs through the acquisition of RPS qualified physical resources.

Alternatives to Physical Compliance

Earlier in this chapter we discuss the primary factors and indicators that should be considered when evaluating potential strategies for achieving RPS compliance (future expectations for PTC, resource availability, technology innovations, changes in environmental policy, etc.). While predicting whether future changes in circumstances will adversely or favorably impact the availability and cost of future renewables is uncertain at best, the decision-making process about whether to acquire RPS resources today versus deferring the acquisitions is relatively straightforward. If new resources are needed to satisfy an overall energy and capacity deficit, and new renewable resources are also needed for future RPS compliance (this is PGE's expected case scenario), it would make sense to acquire new physical renewable resources as long as those resources can be acquired at a cost that is roughly equivalent to the non-renewable generation alternative. In the event that the cost for new renewable resources is not equivalent to the non-renewable generation alternative, then the following decision approach may be appropriate:

1. If you expect RPS renewable resources to be available in the future, and uncertainties are biased toward the potential for material cost increases, it would make sense to purchase physical resources now, thereby reducing the risk of increased costs to achieve long-run RPS compliance.
2. If you expect RPS renewable resources to be scarce or highly limited in availability in the future, it would make sense to purchase physical resources today, thereby avoiding scarcity premiums or alternative compliance payments in the future. Banked RECs would then also be more valuable in the future as renewable resources become more limited in availability.
3. If you expect RPS renewable resources to be available in the future, and uncertainties are biased toward the potential for material cost decreases (as compared to today's cost), it would make sense to temporarily rely on banked RECs, deferring physical renewable resource purchases.

Table 4-5 provides an illustrative example regarding the potential impacts of meeting RPS requirements under various future scenarios for tax benefits, technology developments, quality of wind sites and integration costs. The scenarios below are based on the projected cost of constructing 101 MWa of new wind generation (our current estimate of the required amount of new renewables to maintain physical compliance with RPS standards in 2015) at various points in time between 2015 and 2020. The "alternative futures" were selected to provide a sense of relative magnitude of potential change in cost for RPS compliance based on key uncertainty factors for three different implementation strategies:

- Acquire new renewable resources to maintain physical compliance with RPS standards in 2015 (our acknowledged Action Plan strategy). For this case we do not change costs under alternate futures. Instead, we assume that by acting now we can eliminate uncertainty for key cost drivers. This is a simplified assumption that recognizes the risk mitigation benefit of near-term implementation, which reduces the likelihood of experiencing significant changes in external factors that influence the cost of RPS compliance. This illustrative approach provides insights regarding the change in risk due to increased uncertainty over time.
- Acquire new renewable resources to meet 50% of our need for 2015 RPS physical compliance by 2015, and utilize banked RECs to meet the remaining RPS obligation from 2015-2020. The remaining 50% of new renewables needed to meet the 2015 RPS compliance target is added in 2020. For this case we allow costs to change under alternate futures for renewable resources procured after 2015 (resulting from the delay in implementation and increased exposure to potential cost changes).
- Acquire new renewable resources to meet 50% of our need for 2015 RPS physical compliance by 2015, and utilize banked RECs to meet the RPS obligation from 2015-2017. The remaining 50% of new renewables needed to meet the 2015 RPS compliance target is added in 2017. For this case we allow costs to change under alternate futures for renewable resources procured after 2015 (resulting from the delay in implementation and increased exposure to potential cost changes).

Table 4-5 provides useful insights regarding the potential impact of key uncertainties associated with acquiring new renewable resources to meet RPS obligations over time. While any change to the cost drivers for new renewables can have an adverse or favorable impact to RPS implementation, a few key factors appear to pose the largest potential cost impacts – erosion or loss of tax benefits for renewables, material changes in capital costs, and changes in resource quality (as measured by wind capacity factors). Each of these factors was further discussed earlier in this chapter. In particular, the potential for reduced tax benefits for renewables represents a large potential cost risk with a reasonable likelihood of occurrence due to government budget deficit concerns.

Table 4-5: Illustrative Scenarios - RPS Strategies with Varied Futures

NPVRR 2011$ (000)	Reference Case	Overnight Capital Cost 10% Less	Overnight Capital Cost 10% More	PTC Erodes to 50%	PTC Eliminated	Integration Cost 50% More	Integration Cost 50% Less	Wind Capacity Factor Declines 2.5% (nominal)	Wind Capacity Factor Increases by 2.5% (nominal)
Strategies:									
2015 In-Service Wind	$991,666	$991,666	$991,666	$991,666	$991,666	$991,666	$991,666	$991,666	$991,666
50% - 2015 & 50% - 2017	$986,253	$946,591	$1,025,914	$1,044,592	$1,102,930	$1,012,873	$959,633	$1,027,226	$951,051
50% - 2015 & 50% - 2020	$975,940	$943,420	$1,008,460	$1,023,773	$1,071,607	$997,766	$954,113	$1,009,535	$947,076
Change from 2015 Strategy:									
50% - 2015 & 50% - 2017	$(5,413)	$(45,074)	$34,249	$52,926	$111,264	$21,207	$(32,033)	$35,560	$(40,615)
50% - 2015 & 50% - 2020	$(15,726)	$(48,246)	$16,794	$32,108	$79,941	$6,100	$(37,552)	$17,869	$(44,589)
Change from Ref Case Future:									
50% - 2015 & 50% - 2017		$(39,662)	$39,662	$58,339	$116,677	$26,620	$(26,620)	$40,973	$(35,202)
50% - 2015 & 50% - 2020		$(32,520)	$32,520	$47,834	$95,667	$21,826	$(21,826)	$33,595	$(28,863)

Notes:

27-year life for wind

For delay cases, bridge contract cost based on IRP

For 2015 and 2017 in-service wind is assumed replaced with like-kind renewable resource for RFP compliance

For the reasons cited throughout this chapter (and specifically in section 1.3 above), we believe that the uncertainties associated with future RPS compliance are biased toward the potential for increasing costs to acquire new renewable resources over time. Further, the fact that RPS compliance targets grow significantly through 2025 increases the risk of deferring procurement of new renewable resources, due to the compounding effect it would have on our already large future RPS obligation. On balance, we are persuaded that our Action Plan strategy for adding renewable resources to maintain physical compliance remains the best approach for meeting RPS. This is particularly relevant for a utility like PGE that projects ongoing energy deficits, as well as RPS resource deficits. As we move forward with forthcoming supply-side RFPs and further IRP research and analysis, we will remain responsive to new information and adjust our RPS / renewable resource strategy as necessary.

Portland General Electric Company
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June 17, 2014

e-Mail / US Mail
puc.datarequests@state.or.us

Kay Barnes
Public Utility Commission of Oregon
PO Box 1088
Portland, OR 97308

RE: **LC 56 PGE First Supplemental Response to OPUC Data Request No. 039**

Attention Data Request:

Enclosed please find PGE's First Supplemental Response to the OPUC's Data Request No. 039.

If you have any questions or require further information, please call me at (503) 464-7580. Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

PGH:kr

Encl.

cc: Michael Weirich

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June 17, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 56
PGE's *First Supplemental* Response to OPUC Data Request No. 039
Dated May 20, 2014

Request:

EPA is expected to release a draft 111(d) rule on June 1st. Within 2 weeks after the release of the Rule please run a scenario showing how the rule would affect PGE's resources acquisitions through 2033. Please estimate the portion of PGE's cost of compliance with the rule and the impact on customer rates.

Response (June 4, 2014):

PGE objects to this request as being overly broad and unduly burdensome because it requires PGE to produce a new set of analyses for its trial portfolios, and because it requires speculation about rule implementation details that the State of Oregon might ultimately adopt. Without waiving objection, PGE will respond qualitatively in a supplemental response by June 16, 2014.

Supplemental Response (June 17, 2014):

On June 2, 2014 EPA issued a proposal to regulate and reduce carbon dioxide emissions from existing power plants. EPA will accept comments on the proposal for 120 days after publication in the *Federal Register* and will hold public hearings in four cities around the country to discuss its proposal. Based on the feedback it receives, EPA plans to finalize its proposal in June 2015.

In conjunction with the Edison Electric Institute and other industry parties, PGE is currently conducting an analysis of this complex proposed rule. At this time, we can make the following general observations:

- The proposed rule sets individual state goals for CO2 reductions, in the form of an emissions rate (pounds of CO2/MWh), and then requires each state to develop an individual implementation plan. Such state-level plans will not be finalized until 2016, at the earliest. Joining with other states in a regional joint effort is also an option. Under this option regional plans would be due to EPA in 2018.
- The state-level goal appears to be based on a 2012 baseline emission intensity rate with a 2030 final goal that represents a 48 percent reduction in Oregon's CO2 intensity. This is one of the highest reduction targets in the U.S.
- It will be up to each state to determine how to meet the goals EPA sets, and EPA has proposed to give the states significant flexibility in the design of their plans. We do not know exactly what PGE's obligations may be in relation to the Oregon target and do not expect to be able to finish our understanding and analysis within the time frame of this IRP review.
- The state-level baseline and reduction target appear to be based on generation within the state. For Oregon, this means that wind that is under contract to California utilities is included in Oregon's baseline and may count toward Oregon's goal rather than California's. For PGE, this may mean that our ownership in Colstrip Units 3 & 4 (Montana) would not be included in the Oregon plan, nor would our ownership in the Tucannon River Wind Farm (Washington). However, these out-of-state plants would be included in the implementation plans for Montana and Washington.
- For purposes of calculating state-by-state reduction goals, the EPA used a formula that incorporates four "building blocks" of CO2 reductions. These are:
    - Heat rate reductions for coal-fired units;
    - Displacing coal generation with gas generation;
    - Expanded use of low- and zero-carbon resources (i.e., renewables); and,
    - Expanded use of customer-side energy efficiency.
- Under the proposal, states would be able to use any, all, or none of these building blocks in their plans to demonstrate compliance with EPA's goal. State or regional plans could also include other policies to reduce carbon emissions, such as cap and trade or a carbon tax.
- It is unclear what impact actions taken by PGE to date to reduce CO2 emissions pursuant to the Renewable Portfolio Standard (e.g., the Biglow Canyon Wind Farm) and other state policies will have on our potential reduction obligations under the final rule, but it appears that under the proposed rule, actions taken prior to June 2014 provide no early action advantage to Oregon or PGE and our customers.
- Comments on the proposed 645 page rule will be due in mid-October, 120 days after the expected June 18 publication in the *Federal Register*. Like the federal regional haze process, implementation of a final rule has the potential to be a long process.

- The proposed rule raises many questions that will need to be addressed. We will work closely with the EPA, Oregon regulators, and other stakeholders to understand how Oregon's baseline and goals were determined, whether they are fair and based on appropriate assumptions, and how the proposed rule is intended to be applied.
- At this point, it is not possible to offer any cogent analysis of potential impacts to PGE's portfolio of existing and future resources until guidance regarding applicable state plans has been developed.
- Nonetheless, PGE is hopeful that commitments we have made to aggressive energy efficiency, physical compliance with the Renewable Portfolio Standard, and the discontinuation of coal operations at Boardman at year-end 2020 will help position PGE for implementation of a final 111(d) rule.

INITIAL SOLAR BREAK-EVEN ANALYSIS

PGE has performed an analysis comparing the costs and benefits of two types of solar generation: central station solar in Christmas Valley and distributed solar in Portland. Please contact PGE for additional analytic detail.

Assumptions:

- Use solar data consistent with 2013 IRP.
- Distributed solar incurs neither wheeling nor lease costs, and also avoids line losses.
- All O&M costs are embedded in fixed O&M.
- Use current Schedule 201 avoided costs to value power, inclusive of sufficiency and deficiency adjustments.
- Solar resources are assumed to deliver firm capacity value using reciprocal engine based fixed costs after Schedule 201 deficiency period begins in 2021.

Procedure:

- Step 1: Calculate value of solar generation on a per MWh basis.
  - $75/MWh (real levelized $2013) for distributed.
  - $70/MWh for central station.
- Step 2: Calculate costs of distributed and central generation on a per MWh basis.
  - $264/MWh (real levelized $2013) for distributed.
  - $175/MWh for central station.
  - Both largely function of TCM assumption of $2,797/kW ($2013) capital costs.
- Step 3: Determine the capital costs necessary to lower resources' cost to equal the resources' value.
  - $564/kW capital costs (rather than $2,797/kW) will reduce distributed solar costs from $264/MWh to $75/MWh.
  - $578/kW capital costs (rather than $2,797/kW) will reduce central station costs from $175/MWh to $70/MWh.

Conclusion:

- Capital costs would have to decrease dramatically for solar resource costs to just equal the value of these resources' output.
- Capital costs include both the cost of solar panels and "soft costs" (labor for installation, etc.), i.e. solar panel costs would have to be substantially lower than the $564 and $578 per kW "equilibrating values."