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V. Denise Saunders
Associate General Counsel

November 21, 2012

Via Electronic Filing and U.S. Mail
Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97308-2148

Re: LC 48 – PGE's 2012 IRP Update

Attention Filing Center:

In accordance with Commission Orders 10-457 and 07-002, Portland General Electric Company ("PGE") hereby submits an original and five copies of its 2012 Integrated Resource Plan ("IRP") Update in the above-captioned docket. PGE's 2009 IRP was filed with the Commission on November 5, 2009 and acknowledged (with conditions) on November 23, 2010, in Commission Order 10-457. A 2011 IRP Update was filed on November 23, 2011.

The 2012 IRP Update is being submitted for informational purposes only. PGE is not proposing changes to its 2009 IRP acknowledged Action Plan, nor are we seeking acknowledgment of a revised Action Plan. As such, no action is required by the Commission.

This is being filed by electronic mail with the Filing Center. An extra copy of the cover letter is enclosed. Please date stamp the extra copy and return to me in the envelope provided. Thank you in advance for your assistance.

Sincerely,

Quite A. Lips
for V. Denise Saunders

V. DENISE SAUNDERS
Associate General Counsel

VDS:qal
Enclosures
cc: LC 48 Service List (w/enclosures)

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PORTLAND GENERAL ELECTRIC COMPANY'S ("PGE") 2012 INTEGRATED RESOURCE PLAN ("IRP") UPDATE** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service from OPUC Docket No. LC 48.

Dated at Portland, Oregon, this 21^{st} day of November, 2012.

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Portland General Electric
2009 Integrated Resource Plan

2012 Integrated Resource Plan Update

November 21, 2012

Executive Summary

Pursuant to the Oregon Public Utility Commission's Competitive Bidding Guidelines (Guideline 3g), PGE submits this Update to its acknowledged 2009 IRP. PGE is not proposing changes to the acknowledged Action Plan or seeking acknowledgement of a revised plan. As such, this Update is an informational filing that focuses on the following elements in accordance with the Commission's Guidelines:

- An update of our Action Plan implementation activities; and
- An assessment of the impact to the Action Plan of various forecast changes.

In this 2012 IRP Update, we first focus on changes since the November 2011 IRP Update. For assessing the impact to our 2009 IRP Action Plan, we then combine these changes with those we noted in the November 2011 IRP Update to understand the cumulative change since the 2009 IRP filing.

Based on our assessment of the changes, we do not propose any material revisions to our 2009 IRP Action Plan.

<u>What has changed since PGE's 2011 IRP Update?</u>

1. PGE's Target Year for Completion of Major Resource Additions

   Our 2009 IRP Action Plan included the acquisition of resources to fulfill average annual energy needs by 2015. In the 2011 IRP Update, we assessed load and resources in both 2015 and 2016. Our assessment for both years recognized the impact to load growth from the slow economic recovery, as well as the extended regulatory approval process and schedule of our RFPs for new capacity and energy resources. In this IRP Update, we recognize that 2016 is now a more likely start year for new baseload resource additions and so we focus on that year to simplify the presentation.

2. Retail Load (Excluding Opt-out Customer Elections)

   Compared to the 2011 IRP Update, PGE's forecast annual average retail system load for 2016 has decreased an additional 55 MWa, with reductions to winter and summer peak requirements of 122 MW and 69 MW respectively. Reductions are due to a continued slower than expected economic recovery for residential and commercial customers, along with reduced output expectations for paper and solar manufacturers.

3. Large Customer Opt-out 2012 Election

   PGE continues to experience uncertainty in planning for customers that are eligible for the five-year opt-out option. In the most recent election window earlier this fall, an additional net load of 65 MWa (80 MW on peak) moved to an alternative Energy Service Supplier (ESS). Pursuant to direction given by the OPUC Staff, we do not plan for these customers even though we are the provider of last resort in case of system emergency. Thus, we incorporate this as an additional reduction to PGE's load forecast.

4. Resource Changes

   We have made adjustments to our projections for both demand-side and supply-side resources in this update:

   - Due to vendor performance issues, we are in the process of both reassessing the market and soliciting new bids for automated demand response (ADR). As a result, we now expect to have around 25 MW less of ADR available to call on during peak periods in 2016.
   - We have made various minor adjustments to the expected output of our existing generating plants, including incorporating an efficiency upgrade to the Coyote Springs natural gas plant, somewhat slower acquisition of Dispatchable Standby Generation (DSG), and modest adjustments to the Port Westward and Beaver gas-fired plants to better reflect actual performance in ambient temperature conditions.

5. Natural Gas Prices

   The natural gas price outlook for 2016 has fallen, from $5.70/ MMBtu in the 2011 IRP Update to $4.57/MMBtu in the most current gas forecast, on a levelized basis. All else being equal, the lower gas prices will cause efficient natural gas-fired units to dispatch more frequently, increasing the cost-competiveness of new gas-fired resources versus other types of new generation.

<u>Do these changes impact PGE's Action Plan?</u>

Table ES-1 summarizes the load and resource changes to 2016 (described in items 1 through 3 above) compared to our November 2011 Update. It also shows the impact of those changes on our overall supply balance outlook for 2016.

Table ES-1: Load and Resource Changes since 2011 in 2016

	Energy (MWa)	Winter Capacity (MW)	Summer Capacity (MW)
Retail System Load Reduction	55	122	69
Increased 5-year Opt-outs	65	80	84
Load Decrease since 2011 IRP Update	**120**	**202**	**154**
EE Update, Cumulative Change (with actuals)	(16)	(24)	(16)
Demand Response Acquisition	-	(25)	(25)
Dispatchable Standby Generation	-	(15)	(6)
Existing Plant Adjustments	1	(6)	(8)
Resource Decrease since 2011 IRP Update	**(15)**	**(69)**	**(55)**
Decrease in reserve requirements	-	13	10
2016 Load net of Resources, Decrease since 2011 IRP Update	**105**	**145**	**108**
2011 IRP Update Surplus/(Deficit)	38	(25)	74
Short- to mid-term market purchases	(100)	(100)	(100)
Overall Load / Resource Balance, in 2016 - Surplus/(Deficit)	**43**	**20**	**82**

As the table above illustrates, load decreases are partially off-set by forecast reductions in the output or availability of certain resources. Note that this table assumes implementation of all Action Plan items, with adjustments to demand response and DSG as noted. The net result for 2016 is a slight improvement to our energy and capacity positions, where we now project a surplus of 43 MWa in energy and a surplus of 20 and 82 MW for winter and summer capacity respectively.

Given the modest overall change in our projected Load – Resource Balance, as well as the significant ongoing need for new energy and capacity resources to meet our customer's future electricity needs, we are not proposing any material changes to the long-term acquisition components of our acknowledged IRP Action Plan. However, we do anticipate some slight differences in timing for implementing new resources, with some new resources added to our portfolio roughly one year later (in 2016), as well as the potential for modest changes in the volume of some action items. Below is a discussion of the key elements of the IRP Action Plan and the impact (if any) of the forecast and assumption changes contained in this Update:

- *Use of short-to-intermediate term purchases to hedge load uncertainty.* After implementation of the long-term resource actions from our IRP Action Plan, our portfolio is projected to be roughly in balance as of 2016 (expected resources approximately equal to expected load on an annual average basis).

Therefore, additional market purchases may not be necessary to meet our energy requirements in the short-run. However, PGE's Power Operations group continuously evaluates our portfolio and the wholesale energy markets to balance our system and reduce costs by purchasing and selling electricity to address changes in loads, resources and prices.

- *Timing and need for baseload energy.* The current forecast indicates that our portfolio will be roughly in balance as of 2016, as measured against our projected annual average energy requirement and after implementation of the Action Plan. One of the key elements of the Action Plan is the addition of a new, high-efficiency gas-fired Combined-Cycle Combustion Turbine (CCCT) of 300 – 500 MW. Absent a new baseload energy resource, we would instead be nearly 400 MWa short. Therefore, we believe that our Action Plan for new baseload energy remains valid. The Company plans to move forward with its current solicitation for new natural gas-fired generation.
- *Timing and need for RPS-qualified resources.* Our projected RPS targets are decreased modestly due to the reduced load forecast. In 2015 our RPS resource need declines by 18 MWa. Since the reduction is modest and our RPS requirements grow steadily over time, we intend to acquire the new renewable resources identified in our Action Plan. PGE is currently conducting an RFP for new Oregon RPS compliant renewable resources to satisfy this element of our Action Plan. Post-2015 RPS physical compliance will be addressed in the 2013 IRP.
- *Timing and need for flexible capacity.* We continue to project a large need for capacity to meet peak load and other contingencies. In addition, we continue to expect future declines in our hydro resource availability and increases in variable energy resources such as wind to meet RPS targets. Therefore, we are making no changes to our Action Plan for acquiring new flexible capacity resources.
- *Timing and need for seasonal capacity.* The results in Table ES-1 indicate that, for 2016, less seasonal capacity may be needed due to reduced loads and a modestly lower overall winter and summer capacity need. However, this constitutes a delay only, as our capacity requirements continue to grow rapidly after 2016, predominantly due to retirement or expiry of existing resources. Accordingly, we intend to be flexible with regard to timing and amount of new seasonal capacity resources. Our procurement decisions will be based in part on the quality and cost of resources that are being evaluated in the Company's current Energy and Capacity RFP.
- *Ongoing Action Plan Items.* Energy Efficiency and Dispatchable Standby Generation have been adjusted slightly based on newer information, as described in the body of this report.

When considering resource mix, we do not believe the updates to natural gas prices and CO2 compliance costs warrant a change to the new resources identified in our IRP Action Plan and being pursued via the current RFPs.

<u>What other content is provided in this 2012 IRP Update?</u>

This report is organized as follows:

- More detailed discussion of changes to loads and resources since the last IRP Update filing (Chapter 1);
- An update to our Action Plan implementation via the current RFPs (Chapter 2);
- Status of the Cascade Crossing transmission project (Chapter 3);
- An update on our progress toward installation of new emissions controls for implementation of the Boardman 2020 Plan (Chapter 4);
- Our work plan for identifying the distribution system Conservation Voltage Reduction (CVR) and its cost-effective potential (Chapter 5);
- Updates to regional modeling assumptions; the current outlook for a CO_2 tax, and an updated forecast of wholesale market costs (Chapter 6).

1. Load and Resources Update

1.1 Load Forecast

This update contains PGE's most recent long-term load forecast, dated September 2012. In the 2009 IRP, our planning standard was based on:

- Securing sufficient baseload energy to meet, at minimum, our annual average retail demand excluding opt-out customers. According to this standard, our projected average energy need in 2016 is 2,485 MWa (2,680 MWa projected system load less 195 MWa of opt-out load). However, we also assessed an alternative approach of targeting sufficient energy to meet our annual on-peak average retail load. This latter approach would result in the need for approximately 300 MWa more baseload energy.
- We report annual peak demand based on the highest peak hour of the winter and summer at normal (1-in-2) weather. Based on this metric, our projected 2016 winter peak load without opt-out customers is 3,959 MW and 2016 peak summer load is 3,529 MW (system load is 4,185 MW and 3,776 MW respectively, inclusive of opt-out load). However, as explained in section 3.3 of the 2009 IRP, assessing our requirement via a more robust weather standard would increase peak load estimates and resource requirements to meet the higher contingency level. For example, assuming a 1-in-5 weather event increases capacity needs by about 175 MW in summer and 255 MW in the winter for the highest hour[1].

Since our initial filing in 2009, PGE's load has been revised downward for the following reasons:

- The effect of the "Great Recession" continues to be manifest in a slower than anticipated economic rebound. The return to normal employment rates, business growth and economic activity has not yet occurred as we expected.
- One of our largest industrial customers revised its expected growth due to the economic downturn and we adjusted our loads accordingly. As discussed in our 2011 IRP update, a significant proportion of our load reductions can be attributed to revised expectations for a few major customers.

Because PGE loads are highly correlated to official Oregon state forecasts of net in-migration and economic activity, and because those fundamentals, as forecast by the State, are expected to return to longer-term pre-recession levels, PGE's forecast load growth before accounting for energy efficiency remains essentially stable compared to the forecast in the 2009 IRP, at about 50 MWa/yr. for energy, 70 MW/yr. for winter peak and about 85 MW/yr. for summer peak. The

[1] See Figure 3-8 of the 2009 IRP. Estimates are based on the 2009 IRP load forecast for 2014.

reduction in loads comes entirely from unrealized growth between 2009 and now. Lower load growth than expected since the 2011 IRP Update results in modestly lower loads by 2016.

1.2 Customer Opt-out Update

In accordance with Commission Order No. 07-002, in this IRP we remove expected 5-year opt-out load from our cost-of service load for planning purposes. Since 2009, however, customer's opt out elections have significantly reduced demand and exacerbated uncertainty around the amount of load for which we should plan.

The 2009 IRP estimated the 5-year opt-out load at 28 MWa. Since then, an additional 166 MWa of customer load has opted-out to an ESS (of which about 65 MWa was in this year's election). Our updated estimate, which is based on cumulative customer election data as of October 2012, is 195 MWa for 2016. In terms of demand, these customers represented 31 MW in 2009 and now represent 226 MW in winter and 247 MW in summer for the year 2016.

As stated in section 3.2 of the 2009 IRP, PGE has an obligation to serve as provider of last resort for all electric customers in our service territory. The increased magnitude of the 5-year opt-out load, from 28 MWa in the 2009 IRP to nearly 200 MWa today, poses a potential and substantial reliability challenge in the event of an emergency or unforeseen event that disrupted service from Energy Service Suppliers. Given the large volume of customers now receiving energy service from alternate suppliers, it would be difficult for PGE to meet its obligation to provide for these customers as well as our current retail loads in the event of an emergency or supply curtailment. Although we do not propose any change in our planning standard with this Update, we will open a discussion with stakeholders on the best approach to deal with this newly emerged risk in the next planning cycle.

1.3 Energy Efficiency Forecast and Demand Response

Energy Efficiency

The ETO provided an updated energy efficiency forecast in August 2012. This ETO update resulted in only minor changes from the figures in the 2011 IRP Update.

Table 1-1: Comparison of ETO EE forecasts for IRP (MWa)

Year	2009	2011	2012	2012 vs. 2009	Cumulative Difference
2013	35.2	24.2	23.5	(11.7)	(11.7)
2014	35.2	25.8	25.0	(10.2)	(21.9)
2015	35.2	27.4	25.1	(10.1)	(31.9)
2016	33.5	29.8	24.6	(8.9)	(40.8)
2017	31.1	23.8	22.0	(9.1)	(49.9)
2018	19.3	19.9	20.7	1.4	(48.5)
2019	15	17.0	19.9	4.9	(43.7)
2020	8.9	14.4	17.0	8.1	(35.5)
2021	8.9	13.1	14.1	5.2	(30.4)
2022	8.9	11.0	13.0	4.1	(26.3)
Total	**231.2**		**204.9**	**(26.3)**	

Table 1-1 provides a comparison of the annual incremental EE between the 2009 IRP forecast and the current forecast for 2013-2022.

As explained in the 2011 IRP Update, a chief reason for the lower energy efficiency forecast is that the ETO now takes a more conservative planning approach, committing to deliver to a "conservative" goal of at least 85% of their "stretch" goal. In the 2009 study, the base-case forecast assumed achievement of 100% of the EE stretch goal.

In addition, in the 2011 IRP Update we also incorporated an adjustment with respect to the timing for EE savings each year. In 2009, we assumed that the full ETO EE savings forecast represented the actual savings for that year. Now we assume that the savings are achieved by year-end, so we take half of the savings identified in the current year and then annualize it in the following year.

In June 2012, Governor John Kitzhaber issued a 10-year energy plan which calls for meeting 100 percent of Oregon's electricity demand growth during the next 10 years through expanded conservation and efficiency programs. Based on the ETO estimates and assumed PGE load growth, through 2016, just over half of our load growth will be offset by new EE.

Demand Response

Our automated demand response (ADR) vendor was unable to reach its initial targets, forcing PGE to terminate the contract. We have issued a new RFP and hope to have our first customers participating at this time next year. In order to attract more actionable bids, we have also reduced the minimum ADR target to 25 MW. Due to the unexpected delay and reduced target, we have lowered our

2016 expectation for ADR by 25 MW. The demand response associated with Schedule 77 is expected to grow by additional 4 MW by 2015.

More description is provided in the Demand Response section (Chapter 2).

1.4 PGE's Power Plants and Contracts Updates

PGE Plants

- Coyote Springs Turbine Upgrade. Since filing our 2011 Update, we have completed and tested work on a turbine upgrade at the Coyote Springs plant, providing improved plant efficiency. The upgrade results in an additional 7 MWa of annual energy from the plant for the same amount of fuel input.
- Beaver and Port Westward. We have updated Beaver and Port Westward energy and capacity amounts to better reflect ambient temperature conditions in which they operate, resulting in small reductions in expected energy production.
- Dispatchable Standby Generation (DSG). Acquisition of DSG, while still robust, has slowed somewhat (-15 MW) compared to the Action Plan target.
- PGE Wind Resources. PGE is comparing and analyzing the performance of the regional and national wind fleet using the empirical data on actual wind production that is now available, versus prior modeled or forecast pro-forma production. On a systemic basis, wind generation in the Northwest (including PGE projects) generally appears to be lower than anticipated when compared to project estimates used over the last decade and in our 2009 IRP. We are currently evaluating underlying causes, and whether differences are temporary or permanent. We will incorporate any updates in the 2013 IRP.

Longer-term Contracts

- Coffin Butte. PGE has entered into a contract with Coffin Butte, a qualifying facility (QF) to receive 5.7 MWa per year of landfill gas energy through September 30 2027. PGE does not receive the RECs associated with this project.
- Pelton/Round Butte. A contract for the output of a portion of the Pelton/Round Butte Hydro facilities owned by the Confederated Tribes of the Warm Springs expired in 2012. This resource change was accounted for in the 2011 IRP Update (-66 MWa, -167 MW).

1.5 2012 Update to 2016 Energy and Winter/Summer Capacity Outlooks

Table 1-2 presents our current portfolio balance for 2016 based on meeting our 2016 annual average energy needs, inclusive of the load and resource changes discussed above and the acquisition of the resources identified in our IRP Action Plan (subject to the modest timing and volume changes for some resources as discussed above).

Table 1-2: Comparison of PGE's Energy Action Plan in 2016

Annual Energy Action Plan for 2016	2009 IRP	2012 IRP Update	
	MWa	MWa	Change MWa
PGE Load Before EE Savings [1]	**2,815**	**2,680**	**(135)**
Remove 5-year Opt-Outs	(28)	(195)	(166)
Existing PGE & Contract Resources	(1,834)	(1,836)	2
PGE Resource Target	**952**	**649**	**(303)**
Resource Actions			
Thermal:			
CCCT	406	406	-
Combined Heat & Power	2	2	-
Renewable:			
ETO Energy Savings Target [1]	247	183	(64)
Existing Contract Renewal	66	-	(66)
2012 RFP Renewables	122	101	(21)
To Hedge Load Variability:			
Short and Mid-Term Market Purchases	100	-	(100)
Total Incremental Resources	**943**	**692**	**(251)**
Energy (Deficit)/Surplus	(9)	43	52
Total Resource Actions	**952**	**649**	

1 The 2009 IRP load uses PGE's March 2009 load forecast while the 2012 Update uses PGE's September 2012 forecast. The 2012 forecast has been adjusted to include 59.8 MWa of energy efficiency (EE) achieved in 2009-2011 for a correct comparison with the 2009 IRP.

Numbers may not foot due to rounding.

Figure 1-1 graphically presents the same information through 2021. We project a slight resource surplus of 43 MWa in 2016. We project a modest resource deficit of 76 MWa in 2017, which increases rapidly thereafter.

We do not propose to revise the baseload and RPS energy items in our Action Plan given that the modest 2016 surplus position becomes a deficit again after 2016, even with fulfillment of all Action Plan items from the 2009 IRP.

Figure 1-1: Energy Load Resources Balance to 2021 after Action Plan Acquisitions

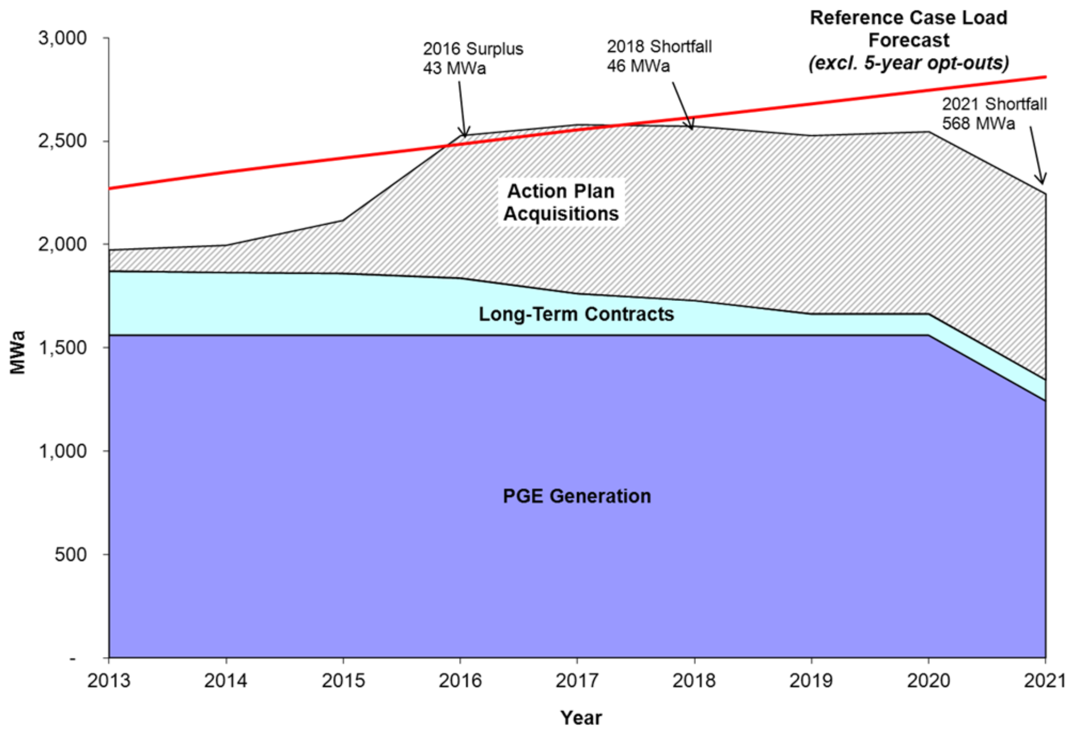


Table 1-3, Table 1-4, Figure 1-2, and Figure 1-3 highlight the effect of our load and resource updates for summer and winter capacity needs.

We project a slight winter and summer capacity surplus of 19 MW and 82 MW respectively in 2016, after assuming acquisition of most Action Plan items. (We temporarily remove 100 MW of short and mid-term market purchases until they are needed.) As in the 2009 IRP, our need for capacity includes an approximate 6% required operating reserve and a 6% planning reserve for weather and plant outage contingencies.

We revert to a short position by 2017 of 211 MW in winter and 141 MW in summer. Consequently, we believe it remains prudent to acquire the new flexible capacity resources (200 MW) identified in our Action Plan. However, the timing for acquisition of new seasonal peaking supply varies based on the type, size, and quality of the bids received in our current RFP.

Table 1-3: Comparison of PGE's Winter Capacity Action Plan: 2016 Look

January Capacity Action Plan for 2016	2009 IRP MW	2012 IRP Update MW	2012 IRP Update Change MW
PGE Load Before EE Savings [1]	**4,384**	**4,185**	**(199)**
Remove 5-year Opt-Outs	(31)	(226)	(195)
Operating Reserves [2]	205	182	(22)
Contingency Reserves[3]	249	225	(24)
Existing PGE & Contract Resources	(2,989)	(3,006)	(17)
PGE Resource Target	**1,817**	**1,360**	**(457)**
<u>Resource Actions</u>			
Thermal:			
CCCT	441	441	-
Combined Heat & Power	2	2	-
Renewable:			
Existing Contract Renewal	167	-	(167)
2012 RFP Renewables [4]	18	15	(3)
To Hedge Load Variability:	100	-	(100)
Capacity Only Resources:			
Flexible Peaking Supply	200	200	-
DSG (2010-2013)	67	52	(15)
Demand Response	60	45	(15)
Seasonally Targeted Resources:			
ETO Capacity Savings Target [4]	364	270	(95)
Bi-Seasonal Capacity	202	202	-
Winter-Only Capacity	152	152	-
Total Incremental Resources	**1,774**	**1,379**	**(395)**
Capacity (Deficit)/Surplus	(43)	19	

1 2009 IRP load used PGE's March 2009 load forecast. The IRP Update uses PGE's September 2012 forecast. The 2012 forecast is increased by 88 MW to include the EE achieved by ETO in 2009 -2012 for a correct comparison with the 2009 IRP.
2 Approx. 6% of generation; excludes reserves for action plan acquisitions.
3 6% of PGE net system load excluding 5-year opt-outs.
4 In the 2009 IRP the 1-h peak capacity contribution of wind and solar is 5% of nameplate capacity.

Numbers may not foot due to rounding.

Figure 1-2: PGE Winter Capacity Load Resource Balance

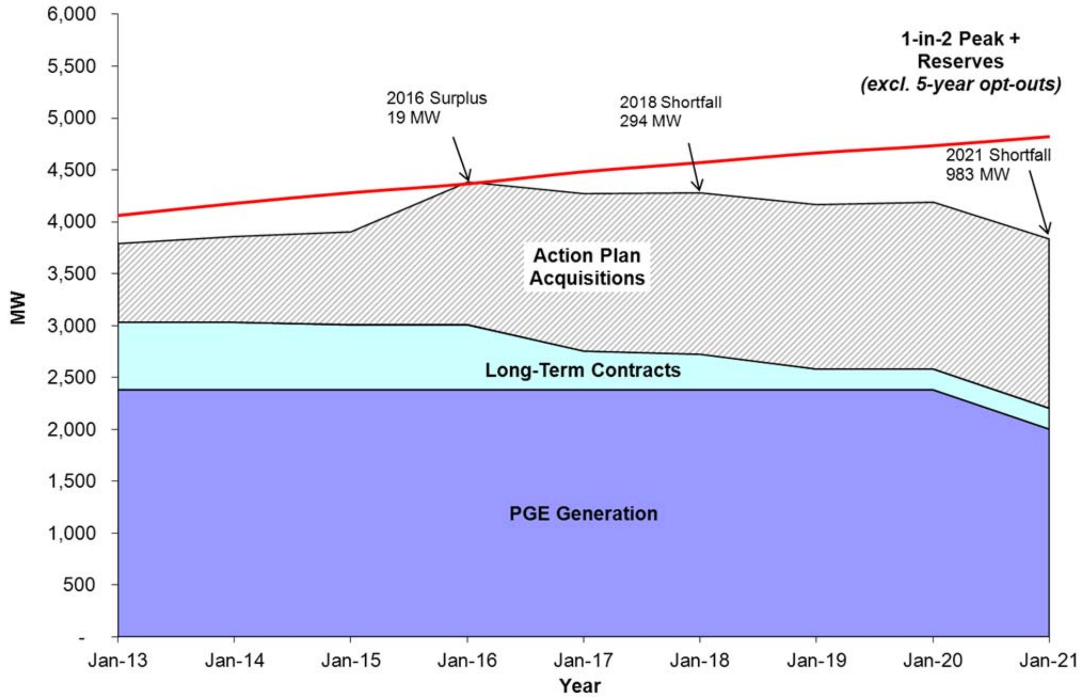


Figure 1-3: PGE Summer Capacity Load Resource Balance

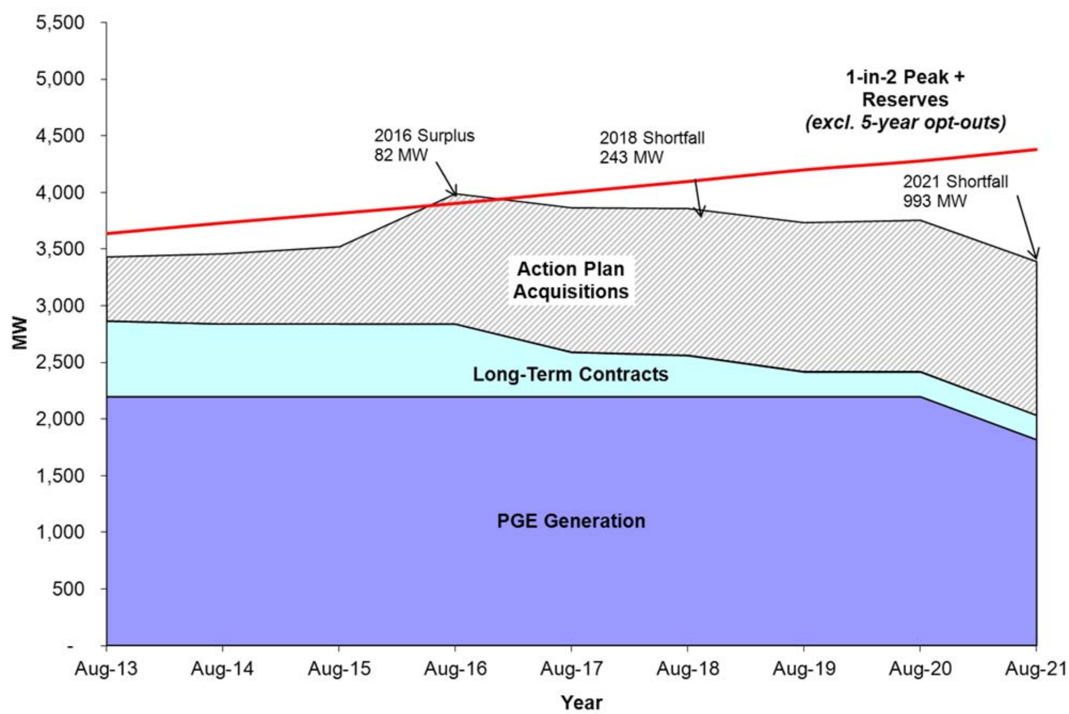


Table 1-4: Comparison of PGE's Summer Capacity Action Plan: 2016 Look

August Capacity Action Plan for 2016	**2009 IRP**	**2012 IRP Update**	
	MW	**MW**	**Change MW**
PGE Load Before EE Savings[1]	**4,003**	**3,776**	**(227)**
Remove 5-year Opt-Outs	(31)	(247)	(216)
Operating Reserves[2]	194	171	(23)
Contingency Reserves[3]	230	203	(27)
Existing PGE & Contract Resources	(2,822)	(2,838)	(15)
PGE Resource Target	**1,574**	**1,066**	**(508)**
<u>**Resource Actions**</u>			
Thermal:	441	441	-
CCCT	2	2	-
Combined Heat & Power			
Renewable:			
Existing Contract Renewal	167	-	(167)
New Renewables [4]	18	15	(3)
To Hedge Load Variability:	100	-	(100)
Capacity Only Resources:			
Flexible Peaking Supply	200	200	-
DSG (2010-2013)	67	61	(6)
Demand Response	60	45	15
Seasonally Targeted Resources:			
ETO Capacity Savings Target [4]	243	182	(62)
Bi-Seasonal Capacity	202	202	-
Winter-Only Capacity	-	-	-
Total Incremental Resources	**1,501**	**1,147**	**(353)**
Capacity (Deficit)/Surplus	(73)	82	

1 2009 IRP load used PGE's March 2009 load forecast. The IRP Update uses PGE's September 2012 forecast. The 2012 forecast is increased by 59 MW to include the EE achieved by ETO in 2009 -2012 for a correct comparison with the 2009 IRP.
2 Approx. 6% of generation; excludes reserves for action plan acquisitions.
3 6% of PGE net system load excluding 5-year opt-outs.
4 In the 2009 IRP the 1-h peak capacity contribution of wind and solar is 5% of nameplate capacity.

Numbers may not foot due to rounding.

2. Action Plan Implementation

The 2009 IRP Action Plan identified the need to acquire (1) flexible and seasonal capacity; (2) a high-efficiency combined-cycle natural gas plant (CCCT) and (3) new RPS compliant renewable resources.

PGE issued an RFP for an Independent Evaluator (IE) in late January 2011 and on April 11, 2011 the Commission issued Order No. 11-111 approving the selection of Accion Group as the IE for all of the RFPs.

PGE subsequently issued two RFPs to fulfill its requirements. The status of each RFP is described below.

2.1 Request for Proposals for Power Supply Resources

On March 22, 2011, the Commission opened Docket No. UM 1535 for PGE's issuance of a capacity RFP targeting 200 MW of flexible, year-round capacity, bi-seasonal (winter and summer) capacity of 200 MW, and 150 MW of winter-only capacity. On September 27, 2011, the Commission issued Order No. 11-371 which, among other things, directed PGE to combine the Capacity RFP with its planned baseload Energy RFP. Following the issuance of the Commission's Order, PGE worked with the IE to develop an RFP that combined our Action Plan requests for baseload energy and capacity and made PGE's sites available for EPC bids. The RFP for Power Supply Resources was filed with the OPUC on January 25, 2012.

The Commission approved PGE's final draft RFP for new energy and capacity resources in Order No. 12-215 issued on June 7, 2012. The RFP was issued on June 8, 2012. Benchmark bids were submitted on August 1, 2012. All other bids were due on August 8, 2012 but were not disclosed to PGE until completion of the scoring for the benchmark.

In response to the RFP, PGE received 32 bids representing 15 different generating projects. The bids include a mix of projects to be sold to PGE pursuant to asset purchase agreements and projects that would sell power to the utility under long term purchase agreements. The combined output of the proposed bids available for PGE to consider in each category is as follows (note that a single generating resource may be included more than once, where bidders submitted multiple configurations using that resource; total unique physical proposals are materially less than the figures below):

- Seasonal peaking resources – 1,627 MW
- Flexible capacity resources – 1,651 MW
- Baseload resources – 5,826 MW

We are currently evaluating the bids received, and are targeting to have a final short list of bids in December 2012.

2.2 Request for Proposals for Renewable Energy Resources

On June 27, 2012, the Commission opened docket UM 1613 for consideration of our RFP for Renewable Energy Resources. The renewable RFP requests approximately 100 MWa of Oregon RPS compliant resources to be online between 2013 and 2017. The minimum size requirement is 10 MW, with duration of at least ten years. The Commission approved the RFP at its September 25 public meeting. PGE issued the RFP on October 1, 2012.

The benchmark bid was submitted on October 30, 2012. Third party bids were received on November 13, 2012. Under the current schedule, we are targeting identification of the initial short list in January 2013, depending on the number and complexity of the bids. A final short list will follow thereafter, with an IE closing report expected at the end of February.

2.3 Demand Response

In the following sections, we provide an update to our demand response (DR) procurement and programs since filing our 2011 IRP update.

Progress in Demand Response Procurement since November 2011

PGE successfully launched or expanded the following programs, which continue to have the same characteristics as described in our last update:

- Curtailment Tariff –PGE currently has 16 MW participating and available for curtailment in its Schedule 77, Firm Load Reduction Pilot Program. The tariff is callable up to 48 hours per year. PGE is on track to achieve the target curtailment level of 20 MW by 2015.
- Water Heater Direct Load Control Pilot – The pilot became operational in August 2012 with 20 water heaters, and is expected to run for two years. PGE currently believes the most cost effective approach for water heater direct load control will be through appliance market transformation.
- Critical Peak Pricing (CPP) – PGE launched its CPP pilot in November 2011. PGE initially signed over 1,000 residential single-family and multi-family customers. During the first two operating seasons, PGE called 11 events: 6 during the first winter season and 5 during the first summer season. We have experienced greater attrition in the program than expected, with approximately 250 customers terminating after the first winter season and about 60 customers terminating after the first summer season. PGE has secured a third-party evaluator that will evaluate the impacts to load and survey customer attitudes regarding the pilot. The report is expected in the spring of 2013.

- Energy TrackerSM – In December 2011, PGE introduced its Energy TrackerSM program to all customers. The program provides an energy information tool that utilizes the interval data from AMI (Advanced Metering Infrastructure System). Energy Tracker provides graphical data to critical peak pricing and time of use customers to help them better manage their energy usage.

Automated Demand Response Pilot

In June 2011, Commission Order No. 11-182 approved PGE's proposal to implement an automated demand response (ADR) pilot. The pilot project was to be operated by a third-party contractor selected via a competitive bidding process, who was expected to have the pilot functioning by December 2011, with an initial procurement of 5 MW. If the pilot proved to be successful, it was expected to become a long-term program with up to 50 MW of firm seasonal capacity.

Unfortunately, PGE's ADR contractor experienced financial difficulties and was unable to meet the terms of its agreement. As a result, PGE terminated the ADR contract in early 2012. In order to continue its efforts to implement ADR, PGE issued a Request for Qualifications in August 2012 and then issued a new RFP on October 16 to establish a new ADR pilot program, which we are targeting for implementation by Q3 2013.

To help inform PGE and potential new ADR vendors, PGE also commissioned an updated study of Demand Response Potential, which was completed in November 2012. (The last study was conducted in 2008.)

When implemented, PGE expects the new ADR program to be similar to the original plan in that:

- Its callable hours can be deployed for a limited number of hours during the year, as the primary purpose is for peak reliability.
- It can respond within 10 minutes of notification.
- It represents decremental load only and cannot provide incremental load.
- Eligible participants will be PGE's commercial and industrial customers with an annual average peak demand of 30 kW or more.

3. Cascade Crossing Transmission Project

As discussed in our 2011 IRP Update, PGE has been and continues to work with other utilities to coordinate transmission planning related to the Cascade Crossing Transmission Project. It appears that these efforts could significantly affect any updates that PGE would otherwise provide to the proposal set forth in its 2009 IRP. At this time, PGE is contractually restricted from publicly disclosing the details being discussed with third parties. However, based on internal timeline targets, we expect that we will be able to provide an update on the Cascade Crossing proposal to the Commission in early 2013.

4. Boardman 2020 Plan Updates

The installation of Boardman BART III emissions controls approved by the Oregon Department of Environmental Quality (DEQ) in 2011 is proceeding on schedule. Table 4-1 summarizes PGE's achievements so far.

Table 4-1: Boardman BART III Controls

Controls	In-Service Date	Status as of October 2012
Low NOx Burners / Over Fire Air	July 2011	Installation and testing completed.
Mercury Control	July 2011	Installation and testing completed.
SO_2 Control via Dry Sorbent Injection (DSI) + Lower-sulfur Coal	July 2014	Selected contractor for engineering, procurement, and construction of DSI system. Construction and testing is on schedule.

The progress on BART implementation is detailed below.

Low NOx Burners

Installation, initial startup and performance testing of the Low NOx Burners were completed in Q3 2011. The systems are achieving the targeted reductions to NOx emissions and the boiler is operating well.

Mercury Control System (Hg)

Installation, initial startup and performance testing of the Hg System were completed in Q3 2011. Extensive tuning and work was done on the system in order to decrease sorbent and chemical usage and increase system reliability. The system is currently operating reliably, and achieving the required mercury emissions reduction.

SO2 Controls

Project Description: The SO2 control project consists of the installation of a Dry Sorbent Injection (DSI) system to reduce SO2 emissions by approximately 50% from current levels. Full-scale testing conducted at the Boardman plant in 2011 verified the proposed technology and demonstrated that required emissions limits could be achieved while maintaining compliance with the Utility Mercury Rule and with the Maximum Achievable Control Technology (MACT) rules.

Status Update: A preliminary engineering study and Engineering, Procurement and Construction (EPC) specification were developed using the 2011 test results for the DSI system. The DSI system will include a railcar unloading station, sorbent storage silos, processing equipment, and injection equipment. An EPC contractor was selected in Q2 of 2012 and engineering for the system design is being completed. Construction of the DSI system will begin in Q1 of 2013 and be completed in Q3 of 2013. System commissioning and performance testing will be completed in 2013 and 2014.

5. Conservation Voltage Reduction

PGE is following the plan described below to meet the OPUC requirement for the next IRP of "consider(ing) conservation voltage reduction (CVR) for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings" (see OPUC Order No. 10-457 at 22).

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

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

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

Based on what was learned in the CVR feasibility study, the next step, for 2013, is to develop a pilot project with hardware installation at the two substations to validate the 2012 modeled results.

Via the pilot project, the potential for CVR benefits will be evaluated for both constant CVR implementation and for peak demand shaving (kW). The pilot will determine what equipment and interfaces are recommended for constant vs. peak shaving CVR. The intent of PGE's two substation pilot is to identify and quantify additional system changes that may optimize the savings benefit of CVR.

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

- Reporting cost estimates for equipment needed to implement CVR (in dollars).
- Reporting benefits in avoided kilowatt hours and reduced kilowatts of peak demand.

- Performing cost/benefit economic analysis to move from technical potential to cost-effective potential.

PGE's plan has the following milestones:

- Substation Selection Methodology Complete
- CYMDIST Study Methodology Complete
- Verify CYMDIST Model Accuracy Complete
- Perform CYMDIST Studies Complete
- Determine Pilot Project Scope 03/01/2013
- Implement Pilot Project 07/01/2013
- Pilot Project Complete 06/30/2014
- Report Project Results & Recommendations 10/31/2014

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

6. Data & Policy Updates

In this 2012 Update, we revised modeling assumptions that are linked to third party forecasts (i.e. fuel prices) and other new information that has become available to PGE since the fall of 2011.

The sections below describe updates to:

- Fuel prices;
- Fixed gas transportation;
- WECC wind shapes
- CO_2 tax price
- Wholesale electricity price forecast.

6.1 Fuel prices, gas transportation costs

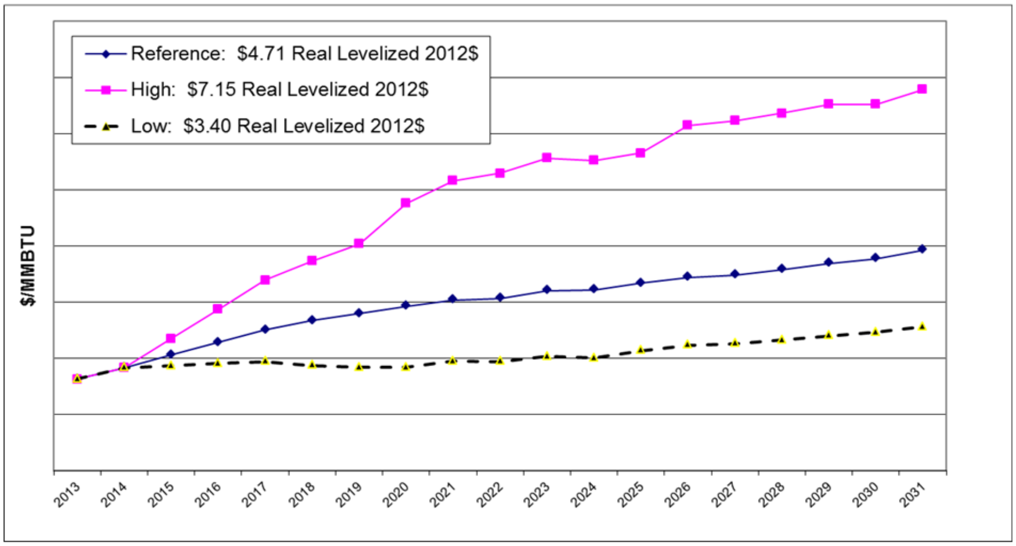
Fuel Prices

As discussed in our 2011 IRP Update, PGE relies on independent third-party sources for forecast fuel prices. For coal price forecasts, we rely on the Energy Information Administration's Annual Energy Outlook (For Boardman, we add a transportation cost).

Since our last update, after reviewing firms that specialize in fuels fundamentals, we contracted with Wood Mackenzie to provide long-term gas forecasts. Consistent with our IRP methodology, we use natural gas forward market prices for the short-term (2013-2014), and then Wood Mackenzie's long-term forecast of natural gas by hub for the longer term (2017 and beyond). We interpolate between the two sources for 2015 and 2016.

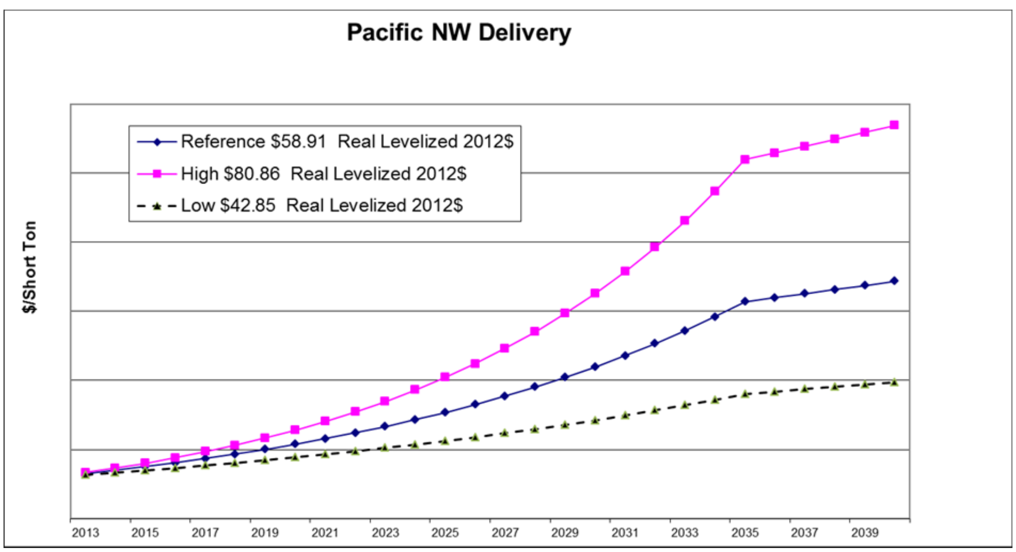
The average of Sumas and AECO prices, the gas hubs that are most relevant for the Pacific Northwest, is shown in Figure 6-1. The reference case has a real levelized average price of $4.71/MMBtu (2012$). In the high gas scenario the average price increases to $7.15/MMBtu, and in the low gas scenario the average prices decreases to $3.40/MMBtu. Although we're comparing slightly different periods (the Wood Mackenzie forecast has a five year longer forecast horizon), forecast prices have fallen again compared to the forecast presented in the 2011 IRP Update. The change in gas price from the 2011 IRP Update is a reduction of $1.13 to $4.57 (real-levelized 2012$).

Figure 6-1: Average of Sumas and AECO Natural Gas Prices Long-Term Forecast



Updated delivered coal prices (2012$) are shown in Figure 6-2 for the period 2013-2040. The real levelized reference case coal price in this Update is $58.91/ton as compared to a reference case price of $58.09 in the 2011 IRP Update for the same 2013-2040 period.

Figure 6-2: PRB 8400 Btu/lb. Low Sulphur Coal Prices



Fixed Gas Transportation Costs

In the 2009 IRP, we priced fixed gas transportation cost according to 2009 rates and an estimate of their increase due to expansion plans. For 2012, this resulted in a transportation cost to PGE's gas generation plants of $0.42 per dekatherm/day on NW Pipeline and $0.48 on Gas Transmission Northwest.

PGE has updated such costs based on the Northwest Pipeline GP FERC Gas Tariff and Gas Transmission Northwest Corporation Tariff as of March 2012. The updated 2012 estimate for fixed gas transportation costs is $0.41 per dekatherm/day on NW Pipeline for deliveries from Sumas and $0.46 per dekatherm/day on Gas Transmission Northwest for deliveries from AECO.

Starting from these 2012 rates, we then assume price escalation at inflation.

6.2 Wind Shapes for the WECC Region

PGE is currently using refined wind shapes for modeling the impact of new wind installations.

The 2009 IRP relied on the approach and estimates of the NW Council's 5th Plan filed in 2008 for modeling regional wind performance for new wind farms. This data relied on monthly shapes by area that captured seasonality based on limited empirical evidence. No attempt was made to capture wind intermittency via hourly shapes.

Since filing the IRP, the National Renewable Energy Laboratory (NREL) has published extensive data on wind regimes and resulting potential wind generation in the Western states for the years 2004 to 2006. EPIS (the developer of the Aurora market model) developed wind shapes for each area in the WECC using this NREL data. These were calculated by averaging the three years of NREL data (2004-2006), selecting sites/areas as typical of a region, computing a typical-week wind generation for every region and month with hourly detail, and reintroducing some of the variability in hourly generation lost in averaging).

This new data can now be used to simulate wind intermittency and provides a more realistic hourly pattern for wind generation during the course of the year.

6.3 Carbon Tax Update

PGE proposes to change the CO_2 tax assumption modeled in the 2011 IRP Update to reflect the apparent postponement of federal carbon regulation.

For modeling purposes, we propose to adopt a slightly adapted CO_2 compliance cost forecast developed by Wood Mackenzie, who specializes in long-term fuels fundamentals. We assume a CO_2 compliance cost beginning in 2021, based on slightly adjusted Wood Mackenzie prices.

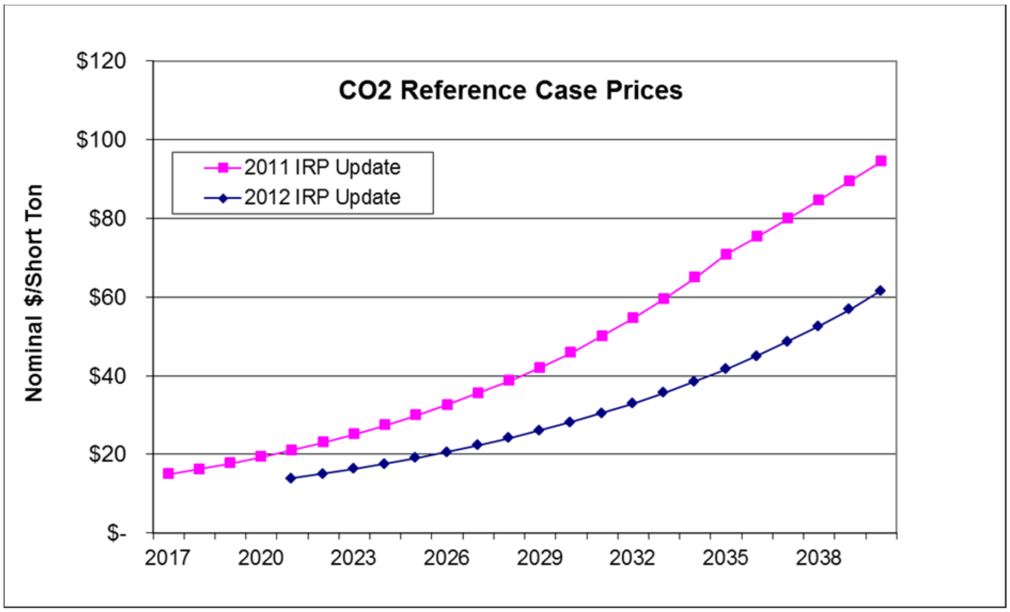
This approach conveys two advantages:

1) It allows for natural gas commodity prices to be aligned with CO_2 costs; and,

2) It relies on a third party expert that has reviewed the fundamentals of when a compliance cost is needed to continue progress in reducing utility CO_2 intensity, and what price level drives economic fuel substitution from coal to natural gas.

Figure 6-3 shows the revised CO_2 assumption in our modeling for this IRP update and the 2012 RFP as compared to the 2011 IRP Update.

Figure 6-3: CO_2 Reference Case Prices



Regarding CO_2 price, there are two primary schools of thought. The traditional approach has been to back in to a price based on achieving a schedule of nationwide, economy-wide CO_2 reductions by year. A newer approach, which has been at least partially adopted by Wood Mackenzie and others, is to impose a CO_2 compliance cost such that natural gas continues to result in reduced coal utilization within the electric sector. This approach tends to push out high-CO_2 coal (less efficient units or units facing other environmental compliance costs) quicker in favor of lower-CO_2 natural gas.

Between now and 2021, low gas prices, in conjunction with utility MATS (Mercury & Air Toxics Standards) compliance and state RPS standards, cause material displacement of coal in the U.S. electric dispatch stack. Hence, existing policy and gas prices largely substitute for new compliance costs until 2021, at which time we assume more direct federally mandated CO_2 reduction measures.

Although the start date for CO_2 reduction mandates could potentially be implemented a little sooner or a little later, PGE believes that, if federal legislation is passed by 2017, it is likely to include a transition period in which material provisions would be phased in over a few years. Shifting the start date a year or two in either direction will not have any practical impact to our model results.

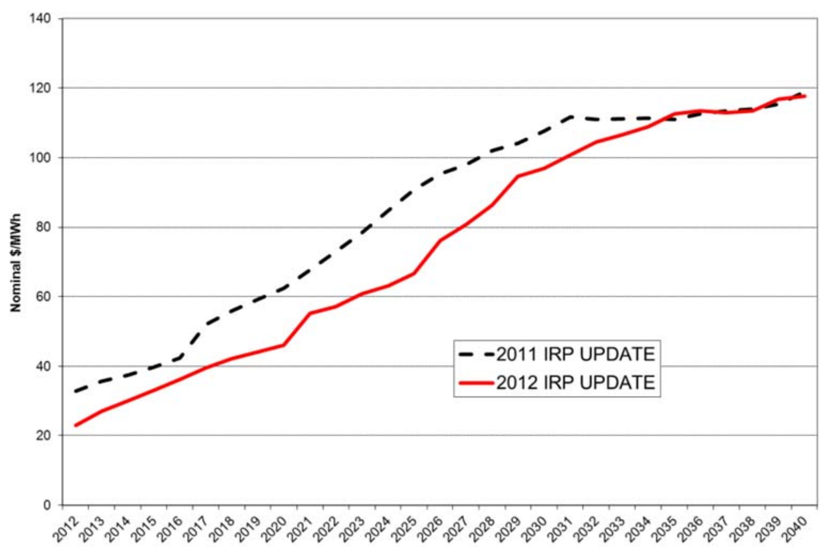
We will continue to revisit this issue as we develop the 2013 IRP. We expect further revisions to our assumptions.

6.4 Long-term Wholesale Electricity Price Forecast

PGE updated the load and resources of the WECC based on the most recent North America data base provided with AURORAxmp and incorporating updated fuel costs, hourly wind shapes, and CO2 costs described above. We then simulated long-term prices using the same methodology detailed in Chapter 10.3 of the 2009 IRP.

The resulting long-term wholesale electricity price for the Pacific Northwest is detailed in Figure 6-4. On a real levelized basis, revised prices in the Pacific Northwest are now projected at roughly $47.86/MWh (real levelized from 2012 to 2040 in 2012$) vs. $57/MWh in the 2011 IRP Update.

Figure 6-4: PGE Projected Electricity Price – Reference Case



The primary drivers of this reduction are: a) a lower forecast gas prices and b) delayed introduction of a CO_2 tax. This is offset in the longer-term by higher forecast coal prices and a changing WECC load shape. These annual average prices mask that hourly price volatility is now higher due in large part to incorporation of hourly wind shapes.