

2016 IRP Feedback & Comments

Summary of Stakeholder feedback
received during PGE's 2016 IRP Public
Process



2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
General	Passing the mic was cumbersome.	For stakeholder questions, provide a stationary microphone at a podium or mics at each table.	4/13/2015
Process	Why is schedule different on handout?	Update schedule slides to account for automation. Plan to revise and post updated slide deck to website and include summary update in 'thank you' email.	4/9/2015
Process	Is schedule firm or can the November 18th date be adjusted? (Power Council has important meeting on November 18)	Moved IRP meeting to November 20th.	4/9/2015
Process	Can the October 23rd date be adjusted? (CUB has important meeting on October 23)	Moved IRP meeting to October 21st.	4/9/2015

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Clean Power Plan	How are you assuming 111(b) resources be treated by states' 111d plans? Will PGE evaluate options with (b) resources covered under states' (d) plans as well as options with (b) resources outside states' (d) plans?	Our IRP will not impose a 111(d) constraint on the emissions from new generation facilities. New generation facilities will be limited by 111(b) standards which effectively prohibit the construction of coal plants within the power system. Rather than including new resources within 111(d) plans, PGE's IRP will deliberately study how the performance of new fossil resources could be limited by additional environmental policy. The IRP will include multiple CO2 prices, used as a proxy to reflect many potential policy outcomes. Furthermore, the IRP will include multiple PGE portfolios which both include and exclude new CCCT resources. PGE Portfolios without CCCTs would likely be selected should Oregon's final rate base goal also be applied to new generating resources.	5/26/2015
Clean Power Plan	Are you assuming Carty will be regulated by 111(b) or (d)?	The IRP will model Carty as a 111(b) resource, as it was classified in the proposed rule. Should the classification change before September, either through the final rule or agency determination, the assumption will be updated.	5/26/2015

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Clean Power Plan	How is PGE intending to model 111d credits from RE and EE? Will you have scenarios that assume RE 111d credit is imbedded in RECs as well as scenarios in which RPS and 111d compliance from RE is severable? What assumptions will you make about moving RE/EE credit between states (e.g. transferring RECs serving your load in Oregon to meet your obligations in MT)?	Renewable energy credits (RECs) will be assumed to be generated by renewable resources and made available for compliance to whichever state the power is delivered. For example, a new wind resource in Wyoming could generate RECs and 111(d) compliance instruments for Idaho compliance. For states that have both a 111(d) and RPS compliance requirement, a single REC would provide compliance credit for both the 111(d) and RPS requirement. However the credit from a single REC could not be separated to serve programs in different states. Given the complexity of modeling interstate REC ownership, PGE may have to make some simplifying assumptions within the IRP should the model complexity be greater than anticipated. Energy efficiency will be modeled to reduce load in the native state. The compliance credit will be made available to the native state in whole. As a result, interstate trading of EE credits will not be modeled.	05/26/2015
Environmental Policy	Why will climate data set be a scenario instead of a base case?	PGE to consider suggestion after vetting data.	9/25/2015
Environmental Policy	Does PGE place any type of weather weighting on load forecast?	PGE uses 15-year average weather, with rolling updates	7/15/2015

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Load Forecast Methodology	For future discussion, how is the ETO forecast in later years developed?	PGE to address questions about EE projection in the future. Refer to April 2 nd Slide 31.	7/15/2015 and 7/16/2015
Load Forecast Methodology	Comment on in-fill vs. suburban sprawl – suggestion to be cautious about moving to more standard household variables	PGE to take note.	4/8/2015
Load Forecast Methodology	Request to show load growth with and without EE.	PGE to meet this request.	8/13/2015
Load Forecast Methodology	What % of PGE service territory is within the urban growth boundary?	90% of the UGB is within PGE Service Territory UGB is 822.7 sq. mi. PGE SVC Territory is 7532.2 sq. mi. Overlap is 741.6 sq. mi.	4/8/2015
Environmental Policy	Will temperature data drive (1) increased cooling demand and (2) an acceleration of cooling device purchases?	PGE to follow-up internally with load forecast staff.	Est. 8/13/2015 (with scenarios and climate change weather discussion)

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Demand Response	How is PGE using the convergence of EE and DR programs, and avoiding over-counting benefits?	PGE is engaging the ETO on a number of DR programs, particularly with Energy Partner and the smart thermostat pilot. Our current plan is to only attribute incremental demand reductions (after EE) to the DR programs. This may change in the future if a more integrated program was offered. In either case, only measured impacts are used and therefore we should not see double counting.	Ongoing
Demand Response	What happened to the EV charging pilot?	The manufacturing of the twenty CEA-2045-equipped smart EVSEs [EV chargers] was delayed. Ten are for PGE and ten for another utility in the EPRI project. PGE now expects delivery in Q1 of 2016 and when we get them we intend to install them at employee homes and systematically test the smart features.	Q1 2016
Demand Response	What is the preferred method of evaluating the cost effectiveness of DR in Oregon?	PGE will be engaging stakeholders in 2016 as part of the larger integrated (smart) grid report process. At a high level, our preferred approach is to look at both total resource and utility cost tests when assessing cost effectiveness.	12/17/2015

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Demand Response	Would PGE provide a copy of the DR study, along with the assumptions (particularly materials supporting the basis for electric heating load control)?	PGE uploaded the final report to portlandgeneral.com	02/16/2016
Flexible Capacity Study	Rather than focusing on how renewable curtailment can reduce the trough of the duck, can PGE assess how to change the slope of the neck? (Reference- "Teaching the Duck to Fly")	Our goal is to begin exploring the potential role that energy storage may play with respect to flexibility challenges in this IRP.	12/17/2015
Flexible Capacity Study	Can the Flexible Capacity Study include a range of CO2 prices?	At this point, the flexible capacity modeling effort will likely not consider a range of CO2 prices.	12/17/2015

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Futures	Can there be discussions about the Clean Power Plan and mass vs. rate-based modeling?	PGE is willing to host detailed modeling discussions; we look forward to receiving detailed feedback regarding the specific aspects that stakeholders would like to discuss.	12/17/2015
Portfolios	How will the results of the Flexible Capacity Study inform portfolio scoring? How will REFLEX work with Aurora to help PGE insure that each type of capacity is appropriately valued?	PGE is willing to host detailed modeling discussions; we look forward to receiving detailed feedback regarding the specific aspects that stakeholders would like to discuss.	12/17/2015
Portfolios	Stakeholders would like to see portfolios that intuitively account for the geographical diversity of renewables (i.e., better examples than Gorge wind).	Our goal is for the resource portfolios tested in this IRP to include aspects of diversification benefits of renewable resources.	12/17/2015

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
PRM Study	What is PGE's definition of dependable hydro capacity or what does it mean in this context? What method was used to create PGE's estimates?	The definition is dependent on the particular capacity assessment question. PGE presented an overview of the treatment of hydro capacity in the Dec 17 Public Meeting. PGE is willing to host a more detailed technical discussion.	12/17/2015
PRM Study	When will PGE share the other portions of the reliability assessment (in addition to the statistics presented at the meeting)?	PGE plans to use the results of the PRM study in the 2016 IRP without other adjustments applied.	12/17/2015
PRM Study	How will risk adjustment measures fit in with the PRM study?	PGE plans to use the results of the PRM study in the 2016 IRP without other adjustments applied.	12/17/2015
PRM Study	What was the market import assumption?	The import assumption was 200 MW, excluding summer On-peak hours.	12/17/2015

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
PRM Study	Can PGE provide clarification on the net capacities used in winter and summer?	The plant capacities were discussed in the 12/17/15 Public meeting.	12/17/2015
PRM Study	Why does DSM not change from winter to summer?	As in the 2013 IRP, the PRM Study models the same quantity of demand response (DR) in the winter as in the summer.	12/17/2015
PRM Study	Can energy efficiency be pulled out of load forecast and shown as a capacity resource?	EE cannot be removed from load and shown as a resource in the PRM Study for this IRP cycle. PGE is willing to investigate options for future cycles, but due to the relationship between EE and load, there may be impacts to the quality of the results.	12/17/2015
Wind Integration	How does the wind integration study intersect with an EIM?	There is no explicit modeling of the EIM in the wind integration study. The study, however, does assume liquid market transactions every 15 minutes.	12/17/2015

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Clean Power Plan	Is PGE going to treat Carty as an existing resource? Can PGE provide the correspondence between PGE and EPA regarding Carty?	Yes. PGE's correspondence with EPA regarding Carty is ongoing. PGE is willing to share the letter dated September 7, 2015, with stakeholders on request.	12/17/2015
Clean Power Plan	Does PGE have a preferred state plan option?	PGE prefers a sub-category specific rate based standard.	12/17/2015
Clean Power Plan	Is there a more detailed analysis about PGE's Montana obligations with respect to Colstrip 3 and 4?	No. Detailed analysis will be performed in the 2016 IRP.	12/17/2015
Clean Power Plan	What will the new emphasis be between mass-based and rate-based futures? Does PGE know the ratio of studied mass-based vs. rate-based scenarios?	PGE will study both rate and mass based implementation plans. PGE does not yet know the ratio of mass to rate based scenarios.	12/17/2015

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Climate Study	Can the report be provided to stakeholders?	Yes. The report will be included in the 2016 IRP.	Est. 7/29/2016
Climate Study	Is the study providing information about plant cooling requirements? Transmission interruptions from wild fires? Higher temperature implications for transformers and line capacities?	No. The focus of the report is the forecasted change of temperatures in the Portland metropolitan area.	12/17/2015
2016 IRP Schedule	At the last public meeting (9/25/15), the schedule showed the draft IRP was planned to be filed at the end of Q1 and the final was to be complete by the end of Q2. Now the schedule is for a draft July 29th and final Sept 16th. What was the reasoning behind this change?	The schedule provided at the September 25th meeting was a preliminary schedule and did not include the filing of a 2013 IRP Update. The work done to complete the update, along with the time needed to finish the 2016 analysis and complete internal PGE reviews, required an adjustment to the 2016 IRP draft release and filing dates. It is important to note that the filing schedule is ahead of the December 2016 due date for the 2016 IRP.	05/16/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Load Forecast	Commercial growth rate appears to be much greater (1.3%) than residential according to the April 2015 presentation (slide 10). What part of this was smaller commercial?	PGE forecasted commercial energy growth rate of 0.9% (presented at the June 2015 load forecast workshop, slide 14) reflects growth in secondary delivery voltage service, of which small commercial (defined as service < 30 kw, PGE current rate schedule 32 in PGE UE 294/1402/page 2) has historically been approximately 21% of energy deliveries and 84% of customer count. PGE forecasts long-term energy deliveries and customer count by delivery voltage service level and does not have specific forecasted growth rates for more disaggregated customer segments.	03/09/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Load Forecast	PGE's service territory experienced stronger economic growth in 2014 and 2015 than was predicted in the economic forecast used as an input assumption for the initial 2013 IRP filing. p 18. What part of that was in the smaller commercial?	PGE tracks economic indicators such as the unemployment rate, unemployment claims, employment levels and growth by industry sector and building permits for the state of Oregon and counties within PGE service territory. PGE's source for regional economic outlook, the Oregon Office of Economic Analysis, does not provide forecasts of employment disaggregated by business size needed to determine which size groups exceeded expectations, nor does PGE track specific data on economic growth indicators by business size. The Oregon Employment Department periodically reports annual data on Oregon employment by business size which can be found online: https://www.qualityinfo.org/-/portrait-of-oregon-businesses-by-size-of-firm .	03/09/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Energy Conservation	PGE continues to work with the ETO to achieve the targeted energy efficiency savings. (IRP Update page 12). What conversations are specific to small commercial?	PGE collaborates with the Energy Trust to increase customer awareness and participation in Energy Trust small to mid-sized commercial energy efficiency programs through outreach and marketing activities. PGE has a three outreach specialists who work directly with small business customers. Outreach specialists provide small commercial customers with energy efficiency consultations and connect them with Energy Trust Trade allies. Business community outreach is supplemented with targeted marketing and through small business customer newsletters. PGE coordinates its outreach activity with Energy Trust through regular meetings. PGE and Energy Trust identified challenges in increasing Energy Trust participation rates among small business customers. In response to the challenge, Energy Trust recently created a new lighting program for small business customers which includes increased incentives and 0% interest financing. PGE is currently supporting the program through its outreach and marketing efforts.	03/09/2016
Energy Conservation	How has PGE focused on the smaller commercial customer group to realize potential in conservation through lighting (slide 40 of 140) showing lighting as highest potential for conservation (e.g. 500,000 MW cost effective potential)?	PGE primarily focuses on lighting projects in the activities described below due to the potential and cost effectiveness for lighting projects.	03/09/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Energy Conservation	How has PGE focused on the smaller commercial customer group to realize potential in conservation through lighting (slide 40 of 140) showing lighting as highest potential for conservation (e.g. 500,000 MW cost effective potential)?	PGE primarily focuses on lighting projects in the activities described below due to the potential and cost effectiveness for lighting projects.	03/09/2016
Integrated Grid	You note the large number of use cases for the Salem Smart Power project. Initially 6, now 14. The large number is interesting and implies more value to be derived from storage but any analysis/quantification of the end use cases would be valuable to present. What is the timing for having more quantifiable evaluation data available? How do the values compare relative to each other and how has this work helped you quantify values?	PGE has a project with Pacific Northwest National Laboratory, with funding received from the US Department of Energy, to model the financial benefits of the 14 identified use cases. This work will not only provide PGE an understanding of the value of various use cases to each other, but will also model the financial benefits of providing multiple simultaneous use cases, which we expect to improve the overall economics of the energy storage system. This project will begin in Q3 of 2016 and conclude in Q3-Q4 of 2017.	05/16/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Integrated Grid	You mention working with Energy Trust on the Rush Hour Rewards Pilot. Specifically, what has been/will be their role in the pilot?	Energy Trust and PGE are co-marketing the Rush Hour Rewards program with the Energy Trust's smart thermostat rebates. Both parties are providing links to the other's websites/enrollment portals. Energy Trust promotes Rush Hour Rewards on its Smart Thermostat program web page and PGE includes Energy Trust's program information on its website. This will become more important as PGE moves from simply enrolling existing thermostat owners to expanding the base of installed thermostats. Given the quantified efficiency benefits of Nest thermostats in particular (per the evaluations conducted for ETO by Apex Analytics), we feel that this collaboration is a win-win for ETO, PGE, and our customers.	03/06/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Integrated Grid	What is your estimate per household reduction for the Pricing Pilots for the estimated 3,500-7,000 customers? Why is the range of households participating so large? Which pilot has the most uncertainty in gaining targeted participation?	The uncertainty lies in the opt-in components, in particular time-of-use rates without a peak time rebate component. Preliminary results of initial enrollment show that signing up customers on these rates can be tough and often requires multiple touchpoints before getting to conversion. Additionally, our experimental design for the opt-in components requires a recruit-and-deny approach, meaning we have to over enroll each program and then assign some portion to the control group. We are targeting 3,850 participants for our opt-in rates, but this will require enrolling 6,340 all told. In addition, we will have 13,610 enrolled in opt-out Peak Time Rebates or Behavioral Demand Response.	05/06/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
DR Potential Study	Please share your evaluation of the Energy Partner Pilot. You noted overlap with energy savings and Energy Trust's work. How is energy savings realized at these sites attributed to Energy Partner quantified and reported? Is an Energy Trust program also working with these sites and if so, have interactive effects between programs been addressed?	PGE's year 1 evaluation is available upon request. The final year 2 report will be provided to staff along with our annual report 4/29/16. In general, participants in Energy Partner are industrial customers with load that is simply being shifted to a later time. For this reason, estimation of total energy impacts was not included in the scope of work for the current evaluation. Events occur only a handful of times a year for a few hours and they are not expected to have a large impact on total energy consumption at the annual level. That being said, it may be interesting for Energy Trust to look at differences in energy savings between DR and non-DR participants in their SEM evaluations in the future.	03/09/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Integrated Grid	What does “ <u>identifying</u> the system benefit of targeted peak energy usage education....” mean? Does it mean “quantifying”? If so, is the system benefit the actual capacity reduction or is the benefit quantified in dollars?	The evaluation will identify both the benefit both in terms of average peak reductions (our planning estimates are 3% of residential load for behavioral intervention alone) and the monetary value of the avoided capacity investment.	05/16/2016
DR Potential Study	In the High Case for DR Potential, do default TOU and Peak time Rebates replace the opt-in type programs in the low and base cases?	Yes, that is correct.	05/16/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
DR Potential Study	If the High Case programs are cost effective, listing the barriers to acquisition and risk factors and any specific actions that may help overcome those barriers would be helpful. The difference in potential impact is high so it will be necessary to clearly see the barriers and the magnitude of effort/costs for what it would take to overcome the barriers in order to reach that high impact level.	The biggest component that differentiates the high case from the others is the default time-variant rates. We have received feedback from several stakeholders (most recently CUB and ODOE) that they would not be comfortable moving forward with these sorts of programs. The other barrier is simply one of funding and timeline. The high case includes more aggressive participation targets and timelines that would require a rapid scaling of resources. This would be a departure from the more measured phasing-in of programs that stakeholders have seemed to favor to date.	05/16/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Resource Adequacy Study	Slide 89 (Public Meeting, 12/17/2015) states that generalizations will be made for capacity needs and capacity contributions for other years and resource combinations. Does this mean that the analysis was done for 2021 only and other years will be estimated based off the 2021 work? Please provide more description as to how this study will be used.	PGE presented data from RECAP runs for 2025 and 2030 in the 03/09/2016 meeting (Roundtable #16-1). The presentation also included capacity need values for all years of the IRP study based on interpolating/extrapolating from the RECAP runs. Interpolations and extrapolations are used to reduce the quantity of model runs that would be needed to cover every year and every combination of resources in those years.	05/16/2016
Resource Adequacy Study	Slide 72 (Public Meeting, 12/17/2015) notes that energy efficiency is in the load forecast. Does the hourly shape (binned hour and day type impacts vs hourly) of the energy savings align with the Energy Trust's updated end use load shapes from the Power Council?	The hourly shape of the energy efficiency in the load forecast is not based on the load shapes from the Power Council.	05/16/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Resource Adequacy Study	Slide 91 (Public Meeting, 12/17/2015), Please add energy efficiency to this list of modeling options for next cycle to be modeled as a resource, not a decrement to load.	PGE discussed this issue in the 12/17/2015 Public Meeting and the 03/09/2016 Round Table. It is on the list to investigate for the next IRP cycle. As discussed, due to modeling issues, it may not be practical to capture energy efficiency as a resource, but it may be possible to use different load scenarios to examine the impacts of different levels of energy efficiency.	05/16/16
Futures & Portfolios	Please clarify assumptions used for market depth for energy and capacity. Recommend limiting the amount of market purchases to a level in line with historical capabilities or justified future market depth projections to provide energy/capacity. For example, in portfolio 1, how does the 961 MW of market capacity compare to historical and estimated future market possible size?	Portfolio 1 is not intended to be representative of forward-going energy or capacity “market depth.” Rather, this portfolio serves an analytical baseline from which to judge the relative costs and risks of strategies that are intended to satisfy resource adequacy standards. The assessment of portfolio reliability occurs as an element of the portfolio scoring process.	05/16/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Futures & Portfolios	Generally, why study 2021 for ELCC and 2025 for portfolio coverage? Why the difference?	PGE is studying 2021, 2025, and 2030 for resource adequacy and renewable capacity contribution. Resource portfolio cross-sectional views have been presented at 2021 and 2025 snapshots.	05/16/2016
Futures & Portfolios	Slides 99 and 100 differentiate between Capacity and Summer or Winter capacity. Please explain the difference between the two and how they were determined. Suggest showing capacity needs by having portfolios not reach the capacity need line, not with two blocks (Capacity and either summer or winter capacity)	In PGE's December Public Meeting, we attempted to illustrate the expectation that different resource portfolios contribute to PGE's system capacity differently on a seasonal basis. For example, an incremental portfolio composed primarily of solar resources might contribute more towards system capacity in the summer than the winter, and the opposite might be true for particular wind resources. Please refer to PGE's current resource portfolios for a more streamlined representation of portfolio capacity contribution.	05/16/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Futures & Portfolios	How was this portfolio creation process illustrated in the past and is this current approach meant to be a new approach that addresses concerns from last time?	PGE's portfolio creation process was generally described verbally rather than illustrated visually, and did not consider factors such as ELCC or attempt make distinctions based on seasonal needs or capabilities. I'm unaware of any specific feedback regarding concerns surrounding the portfolio creation process in PGE's prior IRPs.	05/16/2016
Futures & Portfolios	Slide 98 (Public Meeting, 12/17/2015), portfolio 3 shows 600aMW of PNW Wind. This resource then equates to just 127 MW winter VER capacity and 235 MW summer VER capacity. Compare that to portfolio 2 where 243aMW PNW Wind equates to 98 MW winter VER capacity and 111 MW summer VER capacity. For more than 2 times the PNW Wind in energy in portfolio 3 vs portfolio 2, why is the winter capacity contribution in portfolio 3 just 30% more than in portfolio 2?	In general, a given variable resource is expected to provide diminishing marginal contribution to system capacity as increasing quantities are included in a portfolio (the last MW addition contributes less than the first MW addition).	05/16/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Futures & Portfolios	Please describe the methodology used in determining the Capacity needs vs the market needs for slides 99 and 100 (Public Meeting, 12/17/2015).	PGE needs more information to address this question.	05/09/2016
Futures & Portfolios	Consistency in labeling between all three plots would be helpful. VER should remain differentiated by type of wind and solar added (Public Meeting, 12/17/2015)	PGE's approach to estimating the capacity contribution of variable energy resources considers the portfolio of incremental variable resources and does not attempt to parse the contribution of that portfolio back to its constituents.	
Futures & Portfolios	When are scenario discussions scheduled?	PGE has presented the risk factors (Futures) that will be considered in scenario analysis at the August and December IRP Public Meetings. Feedback was sought during those discussions.	12/17/2015

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Futures & Portfolios	Please provide an exploration of how SB 1547 affects resource choices near-term.	The May 16, 2016 presentation will address this feedback.	05/16/2016
Futures & Portfolios	Discuss how later RPS obligations (2025; 2030; 2035; 2040) should influence Boardman replacement choices; as well as how these are affected by Federal tax considerations, the RPS cap on rate increases, etc.	The May 16, 2016 presentation will address this feedback.	05/16/2016
Futures & Portfolios	PGE's scenarios account for fuel cost future variability, how is the Company capturing sensitivities related to wind, solar, and storage technology cost curve variability	The May 16, 2016 presentation will address this feedback.	05/16/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Energy Storage	Why was 2021 chosen for the single-year run of the ROM? Has PGE considered running the ROM for more than a single year?	Due to the detail required to answer this and the subsequent energy storage questions, PGE and the Energy Storage Association decided to address these questions via a conference call.	10/26/2016
Energy Storage	Why was a 50 MW / 2-hour battery modeled? In many states and markets, 4 hours is the duration desired for capacity/resource adequacy functions, and that is the standard that the industry is increasingly building to? Why was a 25 MW CT considered the appropriate comparison to a 50 MW / 2-hour battery?	Due to the detail required to answer this and the subsequent energy storage questions, PGE and the Energy Storage Association decided to address these questions via a conference call.	10/26/2016
Energy Storage	Where did the model input for 81% round-trip efficiency come from? It seems low compared to what we're used to seeing for storage resources, and I recommend a sensitivity to this parameter recognizing current and forthcoming systems can be 85-90%.	Due to the detail required to answer this and the subsequent energy storage questions, PGE and the Energy Storage Association decided to address these questions via a conference call.	10/26/2016

2016 IRP: Feedback & Comments

Topic	Feedback Received	Resolution	Completed
Energy Storage	Can you please provide a reference to or copy of the Black and Veatch cost data that you used? What year was it published? I see a 50 MW/2-hr battery cost of ~\$210/kW-yr expected in 2021. Is that on a NPV basis? What is the lifetime used?	Due to the detail required to answer this and the subsequent energy storage questions, PGE and the Energy Storage Association decided to address these questions via a conference call.	10/26/2016

2016 IRP: Feedback & Comments

06/20/2015 Comments
Oregon Dept. of Energy

From: IRP Stakeholder Feedback <no-reply@wufoo.com>
Sent: Monday, June 15, 2015 11:31 AM
To: Celena Carr; Steven Corson; IRP
Subject: PGE Stakeholder Feedback Form [#5]

May we post Yes
these
comments
to the IRP
webpage?

Name * Jess Kincaid

Email jess.kincaid@state.or.us

Address *

Organization Oregon Department of Energy
*

Title Senior Policy Analyst

Public Thursday, April 2, 2015

Meeting

**Date your
comments
address**

IRP Topic(s) Request for comment on cost of carbon utilized in 2016 IRP modeling
and/or

Agenda

Items *

Respondent Comment *

RE: Request for comment on cost of carbon utilized in 2016 IRP modeling

We are submitting this informal response to your request for comment on the cost of carbon in PGE's 2016 IRP at the stakeholder meeting on April 2. During the meeting, you indicated that PGE intends to use the range of carbon prices

2016 IRP: Feedback & Comments

06/20/2015 Comments Oregon Dept. of Energy

presented in the Synapse Energy Economics 2015 Carbon Dioxide Price Forecast for PGE's 2016 IRP analysis and you asked for stakeholder reaction on that plan.

In general, the range of carbon prices in the Synapse forecast are reasonable, and we support PGE's decision to use them for IRP modeling purposes. However, we have the following comments about the Synapse forecast.

It is our understanding that Synapse based their "low" carbon price forecast on a scenario of full nation-wide cooperation on compliance with the Clean Power Plan. Because this scenario is not likely to occur, it does not seem particularly useful to use it as the basis for the "low" carbon price forecast. Nevertheless, given that EPA's own forecasts for average costs of compliance with the Clean Power Plan in 2030 (\$28/short ton) are similar to Synapse's suggested "low" price forecast (\$25/short ton in 2030), we believe this is an acceptable number for an illustrative low-end price.

In addition, we do not believe this should be the central or primary carbon cost level that PGE uses for its modeling. Rather, we feel that the Synapse report makes a compelling case that additional carbon regulation beyond the Clean Power plan is likely in the future, thus arguing for a higher carbon price forecast than the "low" range. We agree with Synapse that a "mid" and "high" price forecast better capture the other potential carbon policies that may be implemented in the future. Because of the inclusion of an estimate of science-based targets for reductions in electric sector emissions, we support PGE using the "mid" or "high" price forecasts for purposes of core scenario modeling in the 2016 IRP.

Thank you for the opportunity to comment on this topic.

2016 IRP: Feedback & Comments

11/20/2015 Comments
Absaroka Energy – Bill Pascoe

From: IRP Stakeholder Feedback [<mailto:no-reply@wufco.com>]
Sent: Friday, November 20, 2015 12:13 PM
To: Celena Carr; Steven Corson; IRP
Subject: PGE Stakeholder Feedback Form [#6]

May we post these comments to the IRP webpage?	Yes
Name *	Bill Pascoe
Email Address *	pascoeenergy@aol.com
Organization *	Absaroka Energy
Title	Consultant
Phone	(406) 328-4484
Address	 36 Star Haven Drive Absarokee, Montana 59001 United States
Check here if not related to specific meeting	
IRP Topic(s) and/or Agenda Items *	Montana Wind and Pumped Hydro in the IRP
Respondent Comment *	See attached file.
Attach a File	 ae_pgeirpcommentsattacha_112015.docx 19.05 KB • DOCX

2016 IRP: Feedback & Comments

Comments on MT Wind and Pumped Hydro in PGE 2016 IRP

Bill Pascoe – Absaroka Energy
November 20, 2015

Montana Wind in 2016 IRP

Montana vs. Gorge Wind

PGE is to be commended for including Montana wind in the 2016 IRP. However it's imperative that Montana wind be evaluated on a level playing field with other new resources, especially wind in Oregon and Washington.

Capacity Factors. Assumptions for wind projects are shown on slide #124 of the presentation for Public Meeting #2 (July 16, 2015). The 34% Gorge CF is an aggressive assumption and is based on an upper-end Gorge wind site. The 42% MT CF is for a typical MT wind site and sites with CFs in the mid-40's are readily available. Some sensitivity analysis on the CFs seems to be in order.

Capacity Value. Slides #64 & #65 from the presentation for Public Meeting #3 (August 13, 2015) show the marginal ELCC contribution from Gorge wind. Similar analysis should be conducted for MT wind. Given the seasonal and diurnal shapes of MT wind and its diversity with OR/WA wind, it is reasonable to expect that MT wind would have a greater marginal ELCC contribution. The tools developed by E3 provide PGE with an opportunity to test this hypothesis.

Flexible Capacity Requirements. Slides #66 thru #87 from the presentation for Public Meeting #3 (August 13, 2015) describe the process E3 will use to assess PGE's needs for flexible capacity including wind integration. MT wind should be included in this analysis. Given the diversity between MT wind and OR/WA wind, it is reasonable to expect that MT wind would require less flexible capacity to integrate. The tools developed by E3 provide PGE with an opportunity to test this hypothesis.

Transmission. To date, PGE has not provided any information on the assumptions that will be used for transmission costs for MT wind. These assumptions should reflect recent transmission studies performed by BPA and the Colstrip owners. Simply put, these recent studies conclude that 500-600 MW of additional transmission capacity out of Montana can be created at reasonable cost by adding series compensation to the Colstrip and BPA transmission systems. Attachment A provides specifics for a reasonable set of transmission cost scenarios.

Pumped Hydro in 2016 IRP

Capital Costs

Slide #124 of the presentation for Public Meeting #2 (July 16, 2015) shows a cost of \$2,916/kw for pumped hydro. Attachment B is a report on generation capital costs prepared by E3 Consulting for use by WECC in conducting regional transmission planning studies. Table 31 on pages 52-53 of the report shows capital cost estimates for pumped hydro from numerous sources. After stakeholder review and comment, WECC adopted E3's recommendation of \$2,400/kw for pumped hydro.

2016 IRP: Feedback & Comments

Cont'd Comments on MT Wind and Pumped Hydro in PGE 2016 IRP

Bill Pascoe – Absaroka Energy

November 20, 2015

However, pumped hydro costs are site-specific and a project at a site with outstanding physical attributes such as Absaroka Energy's Gordon Butte site in central Montana can be expected to have lower costs than a generic site. Three separate engineers' estimates for Gordon Butte come in at about \$2,000/kw for a 400 MW project with 10 hours of storage. Increasing the project capacity to 600 MW (with 7 hours of storage) reduces the cost to about \$1,800/kw.

I would also note that Slide #124 of the presentation for Public Meeting #2 shows battery costs at approximately \$1,800/kw with 2 hours of storage. The E3 report for WECC shows battery costs from various sources in Table 32 on page 53. WECC adopted E3's recommended value of \$4,500/kw for batteries with 8 hours of storage. I think it is also important to consider the useful life of batteries compared to more mature and durable technologies like pumped hydro.

Pumped Hydro vs. Flexible Gas Resources

Pumped hydro's value proposition has changed over time. In the past, pumped hydro was viewed by utilities primarily as a source of peaking capacity with the ability to shift some energy from night to day. However, as increasing amounts of intermittent resources have been added to utilities' systems, the highest value use of pumped hydro is as a fast-ramping, flexible resource capable of integrating wind energy and providing ancillary services such as regulation and load following. Below is a comparison of capital costs for pumped hydro and gas aeroderivative turbines and reciprocating engines. (Note that frame units are not included in this comparison because they are not capable of continuous, fast-ramping operation.)

Flexible Capacity Resources

Resource	Technology	Capacity (MW)	Min Load (MW)	Reg. Capacity (MW)	Installed Cost (\$MM)	Capacity Cost (\$/kw)	Reg. Cost (\$/kw)
Gordon Butte	Pumped Hydro	600	-600	1,200	\$1,100	\$1,833	\$917
Gordon Butte	Pumped Hydro	400	-400	800	\$800	\$2,000	\$1,000
NWE DGGS	Aero CTs	150	10	105	\$183	\$1,217	\$1,738
PGE PW2	Recips	220	9	211	\$319	\$1,451	\$1,513
PGE 2013 IRP	Aero CT	100	30	70	\$135	\$1,348	\$1,925
PGE 2013 IRP	Recips	110	8	102	\$181	\$1,648	\$1,777
PSE 2015 IRP	Aero CT	206	52	154	\$259	\$1,255	\$1,679
PSE 2015 IRP	Recips	220	9	211	\$352	\$1,600	\$1,668

This comparison indicates that the gas options have lower costs per kw of installed capacity. However, because pumped hydro can both generate and absorb energy its regulating range is effectively doubled and it has by far the lowest costs per kw of regulating capability.

In addition to its low costs, pumped hydro has other advantages compared to gas resources such as no fuel price risk, no carbon emissions and the ability to shift energy from night to day.

2016 IRP: Feedback & Comments

Comments on MT Wind and Pumped Hydro in PGE 2016 IRP

Bill Pascoe – Absaroka Energy
November 20, 2015

Transmission for MT Pumped Hydro

The basic information in Attachment A discussing transmission scenarios for MT wind is also applicable to transmission for MT pumped hydro.

In addition, MT pumped hydro and wind have complementary transmission needs in at least two important ways. First, the two resources could quite easily share the same dedicated transmission capacity with the pumped hydro generating at times when the wind is not producing. Second, the interconnection substation for the Gordon Butte pumped hydro project would provide a local on-ramp for extremely high quality wind in the area (45+% CF).

Colstrip Retirement Scenario in 2016 IRP

The combination of MT wind and MT pumped hydro on shared transmission would provide a carbon-free alternative for replacing Colstrip capacity and energy in Colstrip retirement scenarios in the 2016 IRP. Approximately 560 MW of MT wind (at 45% CF) and 280 MW of MT pumped hydro would provide the energy and capacity equivalent of PGE's share of Colstrip 3&4 with no carbon emissions. In addition to providing capacity, the pumped hydro would be operated to reshape the MT wind to maximize the utilization of PGE's existing transmission rights, avoid any remaining transmission congestion and maximize diurnal energy value.

Attachment A - Transmission for MT Wind

Hypothetical wind farm interconnecting at Broadview.

Broadview-Townsend (Colstrip Transmission System)

Cost w/ Colstrip Retirements: No additional investments.

Cost w/o Colstrip Retirements: NWE TSR study for Gaelectric (Attachment C) says 550 MW can be added between Broadview and Garrison with additional series compensation for \$73 million. \$47 million of this is east of Townsend. This is about \$85/kw. Assuming a 15% annual fixed charge rate this is equivalent to about \$12.80/kw-year. This is less than the PGE CTS rate of \$19.73/kw-year.

Losses: Losses for CTS are approximately 3% (PGE tariff is 3%), half between Colstrip and Broadview and half between Broadview and Garrison. Use 1.5% for Broadview to Garrison.

2016 IRP: Feedback & Comments

Comments on MT Wind and Pumped Hydro in PGE 2016 IRP

Bill Pascoe – Absaroka Energy

November 20, 2015

Townsend-Garrison (BPA Montana Intertie)

Cost w/ Colstrip Retirements: No additional investments.

Cost w/o Colstrip Retirements: NWE TSR study for Gaelectric (Attachment C) says 550 MW can be added between Broadview and Garrison for \$73 million. \$26 million of this is west of Townsend. This is about \$47/kw. Assuming a 15% annual fixed charge rate this is equivalent to about \$7.10/kw-year. This is less than the BPA MT Intertie rate of \$7.36/kw-year.

Losses: Losses are included in CTS Broadview-Garrison losses discussed above.

West of Garrison (BPA Main Grid)

Cost w/ Colstrip Retirements: No additional investments.

Cost w/o Colstrip Retirements: BPA 2011 Network Open Season studies concluded that 460 MW of TSRs could be accommodated at costs that could be rolled into the existing BPA Main Grid rate of \$17.75/kw-year. BPA 2013 Network Open Season studies confirmed the 2011 results and further concluded that an additional 160 MW of TSRs could be accommodated at costs that could be rolled into the existing BPA Main Grid rate of \$17.75/kw-year. (Additional TSRs above 620 MW would require construction of a new 500 kV line between Garrison and Ashe.)

Losses: BPA Main Grid losses of 1.9%.

2016 IRP: Feedback & Comments

Comments on MT Wind and Pumped Hydro in PGE 2016 IRP

Bill Pascoe – Absaroka Energy

November 20, 2015

MT Wind Transmission Scenarios - Hypothetical 400 MW Wind Farm Interconnecting at Broadview

Scenario	A	B	C
Description	Favorable with Colstrip Retirements	Conservative with Colstrip Retirements	No Colstrip Retirements
Broadview-Townsend (CTS)	<u>Cost</u>: None. (PGE CTS costs are sunk costs that will be recovered from PGE ratepayers whether or not the capacity is used.) <u>Losses</u>: 1.5%	<u>Cost</u>: \$19.73/kw-year (PGE CTS rate) <u>Losses</u>: 1.5%	<u>Cost</u>: \$19.73/kw-year (PGE CTS rate is higher than estimated incremental rate for series comp additions) <u>Losses</u>: 1.5%
Townsend-Garrison (BPA)	<u>Cost</u>: None. (MT Intertie rolled into BPA Main Grid or PGE MT Intertie costs are sunk costs that will be recovered from PGE ratepayers whether or not the capacity is used.) <u>Losses</u>: None. (included in CTS losses above)	<u>Cost</u>: \$7.36/kw-year (BPA MT Intertie rate) <u>Losses</u>: None. (included in CTS losses above)	<u>Cost</u>: \$7.36/kw-year (BPA MT Intertie rate is higher than estimated incremental rate for series comp additions) <u>Losses</u>: None. (included in CTS losses above)
West of Garrison (BPA)	<u>Cost</u>: \$17.75/kw-year (BPA Main Grid rate) <u>Losses</u>: 1.9% (BPA Main Grid losses)	<u>Cost</u>: \$17.75/kw-year (BPA Main Grid rate) <u>Losses</u>: 1.9% (BPA Main Grid losses)	<u>Cost</u>: \$17.75/kw-year (BPA Main Grid rate. Series comp additions rolled into existing Main Grid rate as per BPA 2011 and 2013 NOS.) <u>Losses</u>: 1.9% (BPA Main Grid losses)

2016 IRP: Feedback & Comments



Cleantech Law Partners, PC
548 Market Street, Suite 59966
San Francisco, CA 94104
www.cleantechlawpartners.com
866.233.8064

December 8, 2015

Note: PGE's responses to the SBUA's questions are provided above. The Company also had a conference call with the SBUA on April 14, 2016 to address some of the demand response questions in greater detail.

Franco Albi
Portland General Electric Co.
121 SW Salmon Street, 3WTC0306
Portland, OR 97204.

RE: LC 56 Portland General Electric 2016 Integrated Resource Plan

Dear PGE:

Thank you for this opportunity to express Small Business Utility Advocates' comments re Portland General Electric (PGE) 2016 Integrated Resource Plan:

The following comments are based on:

—Materials posted at: https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/irp.aspx

—The 2013 PGE IRP Update from November 2015
https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp_update.pdf

—DRAFT Pacific Northwest Power Plan <http://www.nwcouncil.org/energy/powerplan/7/home/>

These comments are intended to zero in on the substantial number of smaller commercial customers, by far the second most numerous rate-payer group according to the PGE General Rate Case Application. See UE 294 / PGE / Exhibit 1402 / Cody / p 2.
It is anticipated that that comments may also apply to other smaller commercial customers also.

General comments and questions:

The Draft 7th Pacific Northwest Power Plan indicates that energy efficiency consistently proved the least expensive and least economically risky resource.¹ In more than 90 percent of future conditions, cost-effective efficiency met all electricity load growth through 2035. Developing demand response capabilities is the second priority identified in the plan.

¹ For the purpose of these comments, energy efficiency and energy conservation may be interchanged, however, SBUA recognizes a distinction.

2016 IRP: Feedback & Comments



Cleantech Law Partners, PC
548 Market Street, Suite 59966
San Francisco, CA 94104
www.cleantechlawpartners.com
866.233.8064

More information specific to small business would be helpful to inform and educate these customers especially where there is potentially much to be gained by achieving potential conservation indicated. It appears that the outreach is insufficient to reach these customers, and that perhaps was part of the problem of the low success level of the Energy Partner program, for example.

In the 2013 IRP Update, the least expensive form of energy, Energy Efficiency (EE) acquisition 2013-2017 = 130 MWa. What percentage does PGE set as a goal to achieve in its second most numerous ratepayer group, that is small non-residential?

Also, in the IRP update PGE notes changes in the planning environment with respect to load forecast methodology, resource costs, fuel costs, and uncertainty regarding carbon regulation. Could the utility seek to answer the question of how each of these changes impact each of the major customer groups, such as smaller commercial?

PGE states "We know that all customer classes continue to express concern for environmental issues, strong stated preferences for renewables and EE & conservation, that there is preference for resource mix that is NOT highly dependent on one or two sources, that stated preferences for greener options continue, even when this means 5% or 10% higher rates for everyone." Also good to know more particulars on this for the small commercial.

Load forecast:

Commercial growth rate appears to be much greater (1.3%) than residential according to the April 2015 presentation (slide 10). What part of this was smaller commercial?

PGE's service territory experienced stronger economic growth in 2014 and 2015 than was predicted in the economic forecast used as an input assumption for the initial 2013 IRP filing. p 18. What part of that was in the smaller commercial?

Re Energy conservation:

July 2015 public mtg: https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2015-07-public-meeting-2.pdf

Slide 33 of 140, commercial is by far second highest to residential for potential megawatts energy conserved. It would be good to break down customer group to include smaller and larger and look more closely at the former.

2016 IRP: Feedback & Comments



Cleantech Law Partners, PC
548 Market Street, Suite 59966
San Francisco, CA 94104
www.cleantechlawpartners.com
866.233.8064

How has PGE focused on the smaller commercial customer group to realize potential in conservation through lighting (slide 40 of 140) showing lighting as highest potential for conservation (e.g. 500,000 MW cost effective potential)?

Finally, PGE continues to work with the ETO to achieve the targeted energy efficiency savings. (IRP Update page 12). What conversations are specific to small commercial?

The 2013 PGE IRP Update says PGE will provide further updates on its DR programs and pilots in the 2016 IRP. PGE has done 2 pilots and technical trial on residential side, but what on the commercial side?

From the 2013 IRP Update, re the Energy Partner ADR pilot for non-residential customers referred to on p 10. The program reached 6.7 MW at the end of winter 2015 and grew to 9.1 MW at the end of summer 2015. While the program is growing, the growth is slower than forecast. Page 11 indicates that outreach is a big part of this, or lack of outreach to businesses that are based only or mostly in the Pacific Northwest. It would be helpful to have more information including more detail as to why slower than forecast, and also was this a focus of conversation with Energy Trust?

The 2013 IRP Update says the second pilot launches in Spring 2016 and will test Time-of-Use (TOU) pricing, Peak Time Rebate (PTR), and Behavioral Demand Response (BDR). The intent of the pilot is to test a number of different possible rate designs to determine which are most attractive to customers and most successful in shifting load. The results of the pilot will inform the full-scale TOU programs that PGE rolls out to all customers. How is the pilot being applied to small commercial? How many smaller commercial (perhaps schedule 32?) will be in the pilot?

Re the BPA-PGE technology pilot to evaluate the potential to control smart water heaters via a standard (CEA-2045) communications interface. Will small commercial be part of this technology trial?

Re Renewable energy:

Discuss the growth of solar energy in the small commercial sector especially given the Slide 53 solar costs for commercial declining, the shorter payback for commercial solar, and the more flexible alternatives such as third party models enabling more funding flexibility to pay for rooftop solar. See also slide 64 use

2016 IRP: Feedback & Comments



Cleantech Law Partners, PC
548 Market Street, Suite 59966
San Francisco, CA 94104
www.cleantechlawpartners.com
866.233.8064

NREL model to calculate payback, slide 105 is 2016 case energy storage in many systems exceeding paybacks.

Re Demand Response:

Demand response seems to not be cost effective for small commercial (Public presentation August 2015 slide 106). But see slide 126 re same and showing space-heating to be cost effective, indicating the way forward for small commercial improvements. Consider slide 137-138 for research to show how demand response can be more cost effective for small commercial.

Re outreach:

See 2013 IRP Update Customer Research where PGE conducted customer completed online surveys of which 502 were Residential, 198 General Business, and 54 Key Business Customers. What distinguishes General Business from Key Business? How many surveys were sent out, how many small businesses are served approximately? Surveys were completed from July – September 2012, and respondents were incented for their participation. What was the incentive?

Please contact me or Diane Henkels, 541-270-6001 with any questions. Thank you for your courtesies.

Sincerely,

/s/ Diane Henkels

Diane Henkels
Cleantech Law Partners
Counsel for Small Business Utility Advocates
420 SW Washington St. Ste 400
Portland, OR 97204
dhenkels@cleantechlaw.com
t: 541-270-6001

2016 IRP: Feedback & Comments

12/30/2015 Comments
Absaroka Energy – Bill Pascoe

From: IRP Stakeholder Feedback <no-reply@wufoo.com>
Sent: Wednesday, December 30, 2015 3:31 PM
To: Celena Carr; Steven Corson; IRP
Subject: PGE Stakeholder Feedback Form [#11]

**May we post these comments to the IRP
webpage?** Yes

Name * Bill Pascoe

Email Address * pascoeenergy@aol.com

Organization * Absaroka Energy

Title Consultant

Phone (406) 328-4484

Address

36 Star Haven Drive
Absarokee, Montana 59001
United States

Public Meeting Date your comments address Thursday, December 17, 2015

IRP Topic(s) and/or Agenda Items * Portfolio Analysis
Slide #97 in 12/17/15 meeting presentation.

Respondent Comment * See attachment

Attach a File
 [ae_pgeirpcomments_123015.docx](#) 13.13 KB • DOCX

2016 IRP: Feedback & Comments

Comments on MT Wind and Pumped Hydro in Portfolio Analysis

Bill Pascoe – Absaroka Energy

December 30, 2015

These comments are directed toward the resource portfolios shown on Slide #98 of the December 17, 2015 public meeting presentation. It is not clear if this slide shows the portfolios that PGE plans to evaluate or if these are illustrative portfolios intended to spark discussion amount PGE and stakeholders. However, the following comments are relevant in either case.

Absaroka is heartened to see that MT wind is included in several of the portfolios. These portfolios, coupled with the inclusion of MT wind in the capacity analysis (also presented on December 17) and the flexibility analysis (now in progress), demonstrate PGE's commitment to take a serious look at MT wind in the 2016 IRP.

As always, attention to the details will result in an IRP analysis that produces the most useful information to guide future decisions. With that in mind, Absaroka asks that PGE give careful consideration to two important issues related to MT wind in the portfolio analysis.

Portfolio Construction

A primary output of the IRP process should be an objective evaluation of the relative attractiveness of PNW wind and MT wind. Comparisons of Portfolios 3 vs 4 and 5 vs 6 should provide useful insights into the effects of replacing some PNW wind with MT wind in these portfolios.

However, these portfolios (3 thru 6) may not be the lowest cost portfolios. Recent experience from Puget Sound Energy's IRP process suggests that wind may not be competitive with new gas-fired generation or market purchases given current natural gas price forecasts. In that case, new wind would be limited only to the amount needed for RPS compliance. If these assumptions prove to be correct, Portfolios 1 & 2 will likely be the lowest cost alternatives. Portfolios 1 & 2 include only PNW wind. If Portfolios 1&2 turn out to be the lowest cost alternatives and analysis of Portfolios 3 thru 6 indicates that MT wind may be lower cost than PNW wind, consideration should be given to adding portfolios similar to Portfolios 1 & 2 with MT wind replacing PNW wind.

MT Wind Blocks

Absaroka's comments dated November 20, 2015 discuss transmission alternatives for delivering MT wind. MT wind in the portfolio analysis should be sized to fit these transmission alternatives as follows:

Existing Transmission with Colstrip Retirements. PGE controls about 280 MW of firm transmission rights on the Colstrip and BPA transmission systems to deliver PGE's share of Colstrip 3&4. If portfolios are being developed that assume retirement of Colstrip 3&4 this transmission capacity would become available for delivery of other MT resources. One alternative would be 280 MW of MT wind. Another alternative would be 560 MW of MT wind combined with 280 MW of MT pumped hydro to reshape the wind energy to maximize utilization of the existing transmission rights.

Series Compensation Upgrades. Recent studies indicate that at least 450 MW of additional transmission capacity out of MT can be created at relatively low cost by increasing series compensation levels on the Colstrip and BPA transmission systems. (See Absaroka's November 20 comments for additional information.) This low-cost transmission capacity could be utilized to deliver 450 MW of MT wind or 900 MW of MT wind combined with 450 MW of MT pumped hydro to reshape the wind energy to maximize utilization of the transmission upgrades.