## 2013 Integrated Resource Plan
### Stakeholder Recommendations for Portfolio Development Cases
(As of 9/12/2012)

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<tr>
<th>Topic</th>
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<th>Recommendation</th>
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<tr>
<td><strong>Portfolio Development Cases</strong></td>
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| CO2 | Oregon Public Utility Commission (OPUC) Staff | Email to PacifiCorp, June 28, 2012 | “At a minimum [System Optimizer] needs to develop portfolios in response to the absolute best and absolute worst combination of CO$_2$ cost, natural gas cost, and load growth.”

“The start date and price for PacifiCorp’s proposed high CO$_2$ cost scenario (2018, $34 per ton of CO$_2$) are reasonable. However, the real escalation rate of 5% would result in a CO$_2$ adder of only $78 by 2035. A reasonable real escalation rate for the higher scenario would 10 percent per year. This rate would yield a CO$_2$ adder of $178 in 2035.” | In the strawman development case list distributed June 28, 2012, PacifiCorp included a number of “bookend” core and sensitivity cases expected to yield a wide range of resource selection outcomes. PacifiCorp could replace one or more of the final cases with more extreme cases if initial portfolio runs lack the expected variability. Stakeholders would be expected to help define any alternative case definitions. See Cases C-7, C-9, and C-14. Load sensitivities are captured in Cases S-1 through S-3. |
<p>| DSM | Oregon Public Utility Commission (OPUC) Staff | Email to PacifiCorp, June 28, 2012 | “At a minimum SO needs to develop portfolios in response to DSM at the technical potential level, 85% of technical potential and the % achievable recommended by the DSM consultant.” | The strawman portfolio development case list, distributed June 28, 2012, included a “high achievable” energy efficiency potential case along with cases to be developed using a base achievable potential. At the July 19 Oregon stakeholder meeting, OPUC staff clarified their intent is to see a portfolio that maximizes DSM and FOTs (avoiding new thermal generation), and agreed with PacifiCorp that a case with DSM at the technical potential was not appropriate. The Company will evaluate the need to develop this type of portfolio as a sensitivity depending upon initial portfolio results from core cases. See Case C-15. |
| <strong>Coal Plant Investment</strong> | Oregon Consumers Utility Board (CUB) | July 13 Public Input Meeting, and July 19 Oregon stakeholder | Portfolio cases should include a scenario in which the Company can avoid SCR investments over the next five years by committing to retire the coal units by a date certain such as 2021. “The portfolio I would like to see modeled is pretty simple. For each Coal | PacifiCorp requested that CUB provide a detailed case proposal to be modeled as a sensitivity analysis. CUB provided additional detail in its email dated 7/31/2012, and subsequently clarified that: 1) they would be |</p>
<table>
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<tr>
<th>CO2</th>
<th>Oregon Consumers Utility Board (CUB)</th>
<th>July 19 Oregon stakeholder input meeting</th>
<th>CO2 regulations may be event driven, leading to sudden cost shifts (“stair step trend”) rather than a smooth trend. A case that exhibits this cost behavior would be interesting from the perspective of how the SO model responds with its perfect foresight.</th>
<th>PacifiCorp requested that CUB provide a detailed case proposal to be modeled as a sensitivity analysis. No specific case definition has been provided. See Cases C-14 and C-18, which includes CO2 prices consistent with a federal hard cap on power sector emissions targeting reductions of 80% below 2005 levels by 2050, with an assumed policy start date in 2020.</th>
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<tr>
<td>Case Volume</td>
<td>Encana</td>
<td>Written comments received July 23, 2012</td>
<td>“Given that the resource plans will be further refined, Encana recommends that the Portfolio Development Cases should not attempt to simulate every possible option, but instead should be used to frame the broad resource plan boundaries.”</td>
<td>PacifiCorp’s strawman case list attempts to do this.</td>
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<tr>
<td>Stakeholder Cases</td>
<td>Encana</td>
<td>Written comments received July 23, 2012</td>
<td>Recommends the following alternate 12 core cases using a “step change in the environmental stringency” of regulations/policy mandates” and combinations of CO2, gas, and coal prices reflecting degrees of fuel risk:</td>
<td>PacifiCorp is evaluating this proposal, and would like to get feedback on it from other stakeholders. PacifiCorp has evaluated this proposal and has included a number of Core Cases (including variations of a base case) that pair different combinations of environmental policy assumptions, CO2 costs, gas prices, and coal costs. See Cases C-1 through C-14 and Case C-18.</td>
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To ensure consistency in market behavior and legal/regulatory treatment, if PacifiCorp adopts a CO₂ emission hard cap to drive a high CO₂ price, then it should apply it on a federal basis.

PacifiCorp is considering plans to use a federal cap-and-trade assumption targeting only the power sector with no use of international offsets and no use of offsets from other sectors of the U.S. economy. Shadow prices from such a scenario would be applied to the PacifiCorp system (and incorporated into gas price and power price assumptions). (Note: The shadow price can be viewed as the marginal system cost, in dollars per ton of CO₂ emitted, of complying with the hard cap.)

See Cases C-14 and C-18.
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<tr>
<th>Markets</th>
<th>Written comments received July 23, 2012</th>
<th>&quot;[T]he current FOT market caps (those consistent with the present GRID model) should be used. In other words, FOT market access should be explored in sensitivity cases, not as part of the Core Cases.&quot;</th>
<th>PacifiCorp intends to apply market caps to system balancing sales consistent with GRID practice. FOTs are traditionally limited by transmission access and/or market depth limitations. PacifiCorp would like comments from other parties on treatment of FOT availability for core and sensitivity case development.</th>
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<tr>
<td>DSM</td>
<td>Western Resource Advocates</td>
<td>July 13 Public Input Meeting</td>
<td>Recommends that PacifiCorp use DSM technical potential as a base assumption in the core cases.</td>
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<tr>
<td>CO2</td>
<td>Utah Clean Energy/Western Resource Advocates</td>
<td>July 13 Public Input Meeting</td>
<td>A high CO₂ price scenario should reflect the electricity sector’s contribution to stabilizing greenhouse gas emissions based on scientific assessments; this scenario should be paired with high natural gas prices.</td>
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<tr>
<td>Environ. Compliance (non-CO2)</td>
<td>Multiple Participants</td>
<td>June 20 Public Input Meeting</td>
<td>The Company should incorporate environmental regulations (beyond CO₂) as part of the scenario development given that System Optimizer will be allowed to optimize coal retirements for all the core cases.</td>
</tr>
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| Stakeholder Cases | Utah Clean Energy | June 20 Public Input Meeting/ written comments received July | "[G]iven that PacifiCorp serves so many states, the Company should increase the number of stakeholder-defined scenarios." | All stakeholders will review stakeholder-defined cases per the criteria listed in “2013 IRP Strawman Portfolio Development Cases” paper distributed June 28, 2012. If expanding the number of stakeholder-defined cases is
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<tr>
<th><strong>Gas Prices/Risk</strong></th>
<th><strong>Interwest Energy Alliance</strong></th>
<th><strong>Written comments received July 5, 2012</strong></th>
<th>“[W]e request that you consider sensitivities what have high natural gas prices, and separately adding a sensitivity which imposes a volatility ‘adder’ which would increase the cost of running on natural gas (under any price forecast) and other historically volatile fuels.”</th>
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<tr>
<td><strong>Coal Plant Investment</strong></td>
<td><strong>Interwest Energy Alliance</strong></td>
<td><strong>Written comments received July 5, 2012</strong></td>
<td>“[W]e recommend that a base case scenario assume[s] the retirement of any coal plant that is required or anticipated to require any upgrades or modifications for EPA regulatory compliance within the planning period, and then System Optimizer can consider alternatives.”</td>
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<tr>
<td><strong>Flex Gen</strong></td>
<td><strong>Interwest Energy Alliance</strong></td>
<td><strong>Written comments received July 5, 2012</strong></td>
<td>“[W]e ask that you consider a sensitivity which would assume an additional ‘credit’ (or arbitrarily reduced cost assumption) to reflect a preference for flexible generation resources, thus lowering the cost to consider the benefits of flexible generation, including natural gas generation which allows for quick starts. This would essentially provide a view towards the impacts of regulatory preferences for improved balancing opportunities to integrate naturally variable generation at lower cost.”</td>
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The Company has made significant updates to the updated portfolio case definitions that are responsive to stakeholder feedback/comments while maintaining a total of 19 different Core Cases.

The strawman case list included 12 cases with high gas prices. Gas price volatility is included in PaR modeling (gas prices are a stochastic variable). PacifiCorp requests that IEA clarify how a volatility adder would be developed, applied in the System Optimizer model, and justified prior to further discussion on this recommendation.

The Company notes that the portfolio case definitions are expected to result in a diverse range of resource alternatives, and that all cases will be run through PaR.

Coal retirement/replacement will be evaluated within the System Optimizer model for all core cases. The strawman case list includes scenario assumptions that are expected to result in portfolios with extensive coal retirements/fuel conversions. A case based on retiring all coal units requiring emission control investments may not be necessary.

The Company is currently considering how to address new Oregon IRP guidelines for assessing the demand and supply for flexible capacity. (See OPUC order No. 12-013, Docket No. UM 1461). Evaluating benefits and costs of flexible resources is an on-going activity identified in the IRP Action Plan. The appropriateness of using the IRP models for this purpose will be evaluated.

For the 2013 IRP, the Company will complete a flexible resource supply/demand balance for the preferred portfolio and has...
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<th>Date</th>
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<tr>
<td>Coal Prices</td>
<td>Interwest Energy Alliance</td>
<td>Written comments received July 5, 2012</td>
<td>“[W]e ask that you consider high coal prices, with ranges to be determined by stakeholder input.”</td>
<td>Both high and low coal price scenarios were included in the strawman case list distributed for the June 28, 2012 public input meeting. Company personnel most familiar with the fueling strategy are developing high and low price forecasts that will be made available to stakeholders once completed.</td>
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<tr>
<td>Coal Plant Investment</td>
<td>Oregon Citizens’ Utility Board</td>
<td>Email received July 31, 2012</td>
<td>“The portfolio I would like to see modeled is pretty simple. For each Coal Unit that has a BART-required SCR which has not yet been installed (as of 8/1/12), please model the following: 1. Assume that plant will be allowed to run 5 years past the current expected deadline for the SCR without installing the SCR or having to make significant additional capital investment, but would be required to close after operating 5 years past the current expected deadline for the SCR. 2. Assume that MATS can be met though Selective Catalytic Injection, low sulfur coal or some other measure that avoids significant capital investment. 3. As the plants are retired, replace the plants with natural gas combustion turbines.”</td>
<td>PacifiCorp is evaluating this portfolio study request. Covered above.</td>
</tr>
<tr>
<td>RPS/RECs</td>
<td>Utah Department of Public Utilities</td>
<td>Email received August 16, 2012</td>
<td>“[Please make one of the core cases an unconstrained core case where RPS is not fixed in advance from an Excel model. To the extent that the remaining core cases are not defined, then please include the unconstrained case in each of the three IRP scenarios, but if not, please make at least one core case unconstrained from fixed RPS models.”</td>
<td>The Company has incorporated throughout its updated portfolio case definitions a structure to test cost effective renewable resource additions in the absence of RPS requirements. See Core Cases C-1, C-2, C-4, C-6, C-8, C-10, and C-12.</td>
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<tr>
<td>Stakeholder Cases</td>
<td>Renewable Northwest Project</td>
<td>Written comments received August 10, 2012</td>
<td>“Upon further review, RNP supports Encana’s suggested 12 core cases proposed in the July 23rd comments. The proposal is superior because it includes bookend coal investment costs in the core cases. Stringent pollutant regulation is certainly within the reasonable bounds of uncertainty and is deserving of PaR’s increased scrutiny. Furthermore the proposal’s incremental evaluation of fuel risk is more consistent with the coal retirement”</td>
<td>PacifiCorp has evaluated this proposal and has included a number of Core Cases (including variations of a base case) that pair different combinations of environmental policy assumptions, CO2 costs, gas prices, and coal costs. See Cases C-1 through C-14 and Case C-18.</td>
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supplemental study from the 2011 IRP process, which is valuable for comparative purposes.

Despite the number of requested scenarios, RNP feels strongly that the proposal is most informative by evaluating all twelve scenarios. While it may be tempting to merge rows two and three of the proposed scenario matrix, those scenarios are necessary in order to segregate the effects from technology mandates and pollutant regulation on coal plant economics.

To limit the number of core scenarios, RNP recommends including all twelve Encana scenarios. The twelve scenarios reasonably replace core scenarios 4-9. The suggestion also replaces the need for core scenario 1. Core scenario 3 should be made a sensitivity as the performance of the 2013 business plan has already been tested for risk and likely will be similar to core scenario 2. Other scenario changes can be considered, but with four net scenario additions while simultaneously removing the need for four sensitivity scenarios (coal investment costs and federal CES), the proposal is not overly onerous.”

| Stakeholder Cases | Renewable Northwest Project | Written comments received August 10, 2012 | “RNP supports the Oregon PUC’s recommendation to model a portfolio that meets the Company’s capacity needs with a different strategy than that identified by the business plan in the 2011 process. RNP would like to see how the Company’s capacity needs could be met with pure capacity resources (SCCTs and all-tier DSM), without new resources that deliver annual surplus energy while also providing capacity (CCCTs, coal, nuclear). RNP recognizes that system optimizer measures the economics of surplus energy sales when selecting least cost portfolio solutions to meet capacity needs. However, system optimizer makes this selection given certain assumptions about the liquidity and trading price of the wholesale power market. Furthermore, this optimization is made before the PaR model can test the portfolio for market risk. For these reasons, RNP agrees with the OPUC that more diverse portfolios must be considered and believes that portfolios constrained to select low cost capacity resources provide the needed diversity.” | The Company has made significant updates to the updated portfolio case definitions that are responsive to stakeholder feedback/comments while maintaining a total of 19 different Core Cases. This includes considering a 2013 Business Plan Case as a sensitivity (See Case S-9). | See Case C-15. |

| Coal Plant Investment | Renewable Northwest Project | Written comments received August 10, 2012 | “RNP supports the specific recommendation from Oregon Citizens’ Utility Board’s July 31st comment. System optimizer logic should be adjusted to allow for avoidance of pollution control equipment should the coal unit commit to closure five years (or similar timeframe) | See Case S-4. |
| 2012 | beyond the deadline established for pollution control upgrades in the relevant Clean Air Act regulatory program. If the logic cannot be changed generally, RNP supports, at a minimum, a scenario with altered logic as this retirement strategy proved to be least cost in the Boardman case and should be examined for PacifiCorp coal units as well."

| CO2 | UCE-IDCL-PRBRC-IEA-RNP-HEAL ** | Written comments received August 20, 2012 | “We recommend using the carbon price forecasts published by Synapse Energy Economics in 2011.1 This forecast establishes a medium price of $15/ton in 2018, climbing to $50/ton by 2030. The low carbon price forecast is $15/ton in 2020, increasing to approximately $30/ton in 2030. The high carbon price starts at $15/ton in 2015, and rises to approximately $80/ton in 2030. The cited document describes the details and rationale for this comprehensive analysis of future carbon prices.”


| CO2 | UCE-IDCL-PRBRC-IEA-RNP-HEAL ** | Written comments received August 20, 2012 | “We request PacifiCorp clarify the criteria captured by the CO2 costs – Hard emission cap” attribute. This cap should apply to all PacifiCorp resources and the entire service area. How does PacifiCorp plan to implement the goals established by HB 3543 across its generation fleet? Does this attribute include a cap and trading system? If so, what carbon costs does PacifiCorp assume?

As Ceres points out, a key element of a 21st Century utility business model is managing carbon: “Failing to effectively mitigate carbon risk will lead to higher shareholder and lender risks, as well as unreasonably burdening ratepayers with higher costs.”2 The goal of any potential carbon reduction policy or scheme is to reduce greenhouse gas emissions to the level scientists indicate are necessary to avoid catastrophic consequences – reducing CO2 emissions 80% by 2050. Setting a meaningful and scientifically defensible greenhouse gas reduction target will help PacifiCorp plan for forthcoming carbon regulation and ensure that the utility is pursuing a path of

See Cases C-14 and C-18, which includes CO2 prices consistent with a federal hard cap on power sector emissions targeting reductions of 80% below 2005 levels by 2050, with an assumed policy start date in 2020. These cases are intended to also comply with Oregon’s CO2 risk guideline for developing at least one “Oregon compliant” portfolio.
environmentally responsible electricity generation. A national hard cap scenario should provide a more meaningful picture of regional/system consequences of more robust climate regulation. (See also our recommendation for Stakeholder Defined Case #5.)


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<th>Environ. Compliance (non-CO2)</th>
<th>UCE-IDCL-PRBRC-IEA-RNP-HEAL</th>
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| Written comments received August 20, 2012 | “We recommend PacifiCorp model a comprehensive suite of environmental regulations. PacifiCorp should continue to incorporate the costs of compliance with the mercury and air toxics rule. In addition, we recommend the Company also incorporate the forthcoming regulations of coal combustion residuals, cooling water intake facilities, and wastewater discharges. These final regulations will come into effect during the horizon of this planning cycle. The Electric Power Research Institute has estimated compliance costs for the proposed coal combustion residuals rules. Because one option under EPA’s proposed rule would regulate coal combustion byproducts as hazardous waste, PacifiCorp should model regulation under Subtitle C (hazardous waste) in order to provide a more cautious analysis of costs, as opposed to merely considering costs that would be incurred under a Subtitle D regulatory framework. The EPA Proposed Rule for cooling water intake structures estimates compliance costs. For power plant effluent standards, the EPA has made a preliminary estimate of compliance costs. Not including these forthcoming regulatory compliance costs in portfolio development will limit the diversity of resource portfolios and could lead to an incomplete and unnecessarily risky IRP.

We recommend using the EPA proposed Federal Implementation Plans (FIPs) as the base case for regional haze compliance. The Strawman proposal proposes using the State Implementation Plans (SIPs) to estimate a base environmental compliance scenario, while using Federal Implementation Plans for a more “Stringent EPA BART/Regional Haze” scenario. But the EPA has already rejected these SIPs as inadequate and proposed FIPs in several states, including Wyoming and Arizona. In Montana, EPA finalized a FIP on August 15. The basic compliance options and deadlines in these FIPs should also apply for Utah. It is not reasonable to assume

The Company case definitions include assumptions for regional haze, MATs, and reasonably anticipated compliance requirements for emerging regulations including CCB and cooling water intake structures. The Company’s Core Cases C-8 through C-13 will incrementally apply EPA’s current proposed FIP outcomes impacting the Company’s owned and operated or partner plants. While EPA has proposed FIP outcomes in states impacting the Company’s resources, said actions are being (or will be) highly contested and are viewed by the Company as a risk to base case planning assumptions, but not the most reasonably expected outcome.

With respect to the proposed EPA coal combustion residuals rulemaking currently anticipated to be completed in late 2012 at the earliest, with a compliance deadline of five years thereafter, or by late 2017, the Company does not believe that EPA’s proposed RCRA Subtitle C rules represent a reasonable outcome for the power generation industry and is not aware of EPA promulgating guidance on their assessment of the breadth of a Subtitle C impact on the industry and the economy as a whole. Accordingly, the Company does not consider Subtitle C compliance to be a
rejected SIPs as the base case for regional haze compliance.

In addition, we recommend that PacifiCorp apply the FIP base case to all core case scenarios. Regardless of what else happens, the Company must comply with the Clean Air Act going forward, so all portfolios must include these costs. Along with assuming the EPA FIPs as the base case, PacifiCorp should utilize the state SIPs as a less stringent case. Additionally, PacifiCorp should model a more stringent case that estimates the costs of even more robust environmental protections, including selective catalytic reduction (SCR) controls for the reduction of nitrogen oxides as recommended by conservation groups and the National Park Service.

We recommend the Company model water scarcity scenarios and the implications prolonged drought would have on electric generation. In July 2011 Black and Veatch reported that utility executives see water management “as the business issue that could have the greatest impact on the utility industry.”

We recommend the Company apply base levels of environmental compliance as a basic attribute for all cases. Regardless of the future, PacifiCorp must comply with the Clean Air Act, Clean Water Act, and other environmental laws. For regional haze, the base level should be the EPA proposed FIPs for regional haze. For mercury and air toxics standard, we recommend explicitly including these costs as a scenario attribute. We recommend sources for compliance cost information for coal combustion residuals and water quality above. It is not reasonable to model cases without factoring in these compliance costs.

4 See EPA’s proposed coal combustion residuals rule, June 21, 2010.
7 Black & Veatch “U.S. Utility Survey Respondents Believe Energy Prices Will Rise Significantly, place Emphasis on Growing Nexus of reasonable Core Case assumption, the detailed requirements and associated costs of which are largely yet undefined. While not insignificant, the Company considers Subtitle D compliance to be a better proxy compliance planning scenario for Core Case assessment.

With respect to CWA effluent guideline costs, the EPA is yet to propose its updated guidelines but has provided information regarding their estimates for potential costs of said updated under Federalism and Unfunded Mandates Reform Act (UMRA) consultations. The Company does not currently have cost estimates for its coal fleet.

Water scarcity scenarios are difficult to model, since the best measures depend on the nature, location, extent and duration of the water scarcity. The company relies heavily on water from both surface and subsurface sources and recognizes that it is a key resource in the production of electricity. In addition, the application of the underlying water law and water rights will determine the impact of the water scarcity scenario.

The company recognizes the scarcity of water in the West. To that end, the Company’s strategy has always been to acquire senior water rights such that the impact of reduced water availability would be minimized. Furthermore, the Company typically has long term storage rights at some of its facilities to manage water scarcity of longer duration. In the event the Company experienced significant,

extended, regional water scarcity, potential options may include:
- Dispatching generation resources to match water availability and water use rates.
- Operating cooling towers at higher cycles of concentration with back end water treatment systems to minimize or eliminate water discharge thereby reducing water demand.
- Installing hybrid cooling systems that would employ air cooling to reduce cooling tower evaporation losses.
- Eliminating water-based ash conveyance systems where present.
- Acquiring additional water rights.
- Employing emerging technologies to recover water from flue gas.

It should be noted that for new resources, that the Company has adopted dry cooling as its standard for capital costs and performance for new gas fired resources.

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<tr>
<th>Load Forecasts</th>
<th>UCE-IDCL-PRBRC-IEA-RNP-HEAL **</th>
<th>Written comments received August 20, 2012</th>
<th>“Given that we are seeing increasing temperatures and extreme weather events, and given that PacifiCorp’s planning cycle is 20 years, it may be imprudent, with respect to load forecasting, to model 1 in 10 and 1 in 20 peak weather incidents. We recommend the Company use a more extreme peak weather incident for purposes of modeling load forecasts.”</th>
<th>See Case S-3.</th>
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<p>| Renewables-Solar | UCE-IDCL-PRBRC-IEA-RNP-HEAL ** | Written comments received August 20, 2012 | “We recommend that the Company, instead of modeling one “solar mandate” scenario, model the utility cost of a solar incentive program in all cases. PacifiCorp explained that, in its “distributed solar mandate” scenario, the model will fix distributed solar resources and adjust the cost with incentive programs. Fixing distributed solar resources in one scenario, however, does not provide meaningful information about the selection of a distributed solar program as a utility resource. We recommend that the Company utilize solar supply curves and annual potentials for all states in the PacifiCorp system and allow the model to select distributed solar in the same manner as any other available resource. See Utah Clean Energy’s | The Company assumes that this recommendation is superseded by the joint Utah party recommendations received August 30, 2012. All cases will include Utah solar PV resources based on a utility incentive. No solar resources will be fixed in the cases. |</p>
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<tr>
<th>DSM</th>
<th>UCE-IDCL-PRBRC-IEA-RNP-HEAL **</th>
<th>Written comments received August 20, 2012</th>
<th>“We ask PacifiCorp to define the attribute “high achievable energy efficiency potential.” Second, we recommend the Company apply more than one level of DSM achievement as a potential scenario attribute. The base case should be 85% of technological potential used in the 2011 IRP and should apply to more of the core cases as described in the next section of these comments. We also recommend the Company model a scenario with higher DSM potentials/DSM best practices. This could be accomplished by increasing the ramp rates to achieve DSM resources equivalent to an annual increment of at least two percent of retail sales, similar to the rate achieved in leading states and utilities. SWEEP is conducting a study of utility DSM potential and best practices (in the Southwest) that can serve as a resource for such modeling.”</th>
<th>The Company is adopting the “2% of retail sales” recommendation from the joint Utah parties received on August 30, 2012, which will involve accelerated ramp rates.</th>
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| RPS/RECs    | UCE-IDCL-PRBRC-IEA-RNP-HEAL ** | Written comments received August 20, 2012 | “We recommend PacifiCorp remove the resource constraints of wind only, and wind and geothermal only, from the “Current state RPS rules” attribute. All current state RPS schemes allow for a broader array of technologies. Further, several states allow for unbundled Renewable Energy Credit transactions. In addition, we ask the Company to clearly identify the resource options and characteristics available to meet RPS compliance, including specifically whether both fixed and single-axis tracking utility-scale PV systems will be modeled as resources in this IRP.

Because the Company is using a spreadsheet model to select minimum RPS compliance resources for its service territory, we recommend that the Company model a “no RPS” scenario (see below), including a federal PTC extension, in order to allow System Optimizer to select a baseline level of renewable resources without fixing resources.

We ask PacifiCorp to explain the difference between the “Federal RPS and “Federal Clean Energy Standard” attributes. We also ask the Company to clearly define the criteria for each standard including compliance levels and timing.” | The Company’s updated case definitions include Core Cases both with and without RPS assumptions. In those cases with no RPS, the SO Model will be allowed to select from a broad range of renewable resource alternatives including wind, solar, and geothermal resources. Renewable resources selected in these runs will be included as a system resource for the accompanying cases that have RPS requirements, and any incremental need will be met with either wind or geothermal resources (depending upon the Core Case).

Utility scale PV resources and characteristics will be included in portfolio modeling and include both fixed and single axis tracking PV systems.

The 2013 IRP will include a discussion of RPS compliance strategies including potential use of unbundled RECs.

The Company no longer intends to model a Clean Energy Standard, but rather has |
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<th>RPS/RECs</th>
<th>UCE-IDCL-PRBRC-IEA-RNP-HEAL **</th>
<th>Written comments received August 20, 2012</th>
<th>“Furthermore, in all cases the Company should model REC revenues from renewable energy sources. Although REC markets are in constant flux, a reasonable baseline REC price of $5.00, with an escalation rate to account for inflation, will recognize the value of renewable energy attributes without speculating too much about changes in REC markets.”</th>
<th>There is no transparency in the forward REC market, and any assumed REC price would be arbitrary. For this reason, the Company does not propose valuing REC revenues in IRP modeling.</th>
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<tr>
<td>Renewables-Wind</td>
<td>UCE-IDCL-PRBRC-IEA-RNP-HEAL **</td>
<td>Written comments received August 20, 2012</td>
<td>Finally, with regard to all core cases, the Company indicated that it would not constrain renewable resources (wind in particular) based on location or timing. Will the Company also remove MW limitations on wind that were utilized in the 2011 IRP? The model should be allowed to select wind and other renewables without fixed constraints.</td>
<td>The Company will remove all maximum annual capacity constraints on wind, allowing wind to be selected up to the resource potential subject to transmission constraints.</td>
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<tr>
<td>RPS/RECs</td>
<td>UCE-IDCL-PRBRC-IEA-RNP-HEAL **</td>
<td>Written comments received August 20, 2012</td>
<td>The only difference between Cases 4 and 13 is that Case 4 has the wind-only state RPS assumption in addition to the Federal RPS assumption. Instead of modeling both Cases 4 and 13, we recommend modeling a Core Case with No RPS and the following other assumptions: medium carbon, medium gas, medium coal, and renewable PTC extension until 2020.</td>
<td>Core Cases C-1 through C-3 have varying RPS assumptions. These cases will allow the 2013 IRP to report on how a federal RPS might the allocation of renewable resources among states. Cases C-14, C-18, S-5 and S-6 assume PTCs are extended through 2020.</td>
</tr>
<tr>
<td>RPS/RECs</td>
<td>UCE-IDCL-PRBRC-IEA-RNP-HEAL **</td>
<td>Written comments received August 20, 2012</td>
<td>Please explain the scenario attribute “Constrain distrib. Solar selection to max achievable potential.” What is the geographic scope of the potential? What assumptions does PacifiCorp use to determine what is “achievable”? What is the time line for enacting and complying with the solar mandate?</td>
<td>The original intent was to fix distributed solar resources to their maximum potential in each state as indicated by the Cadmus potential study. In lieu of this assumption, the Company will adopt Utah parties’ joint recommendation to assume a utility incentive cost of $0.90 per watt (AC) plus administrative costs and let System Optimizer select the optimal resource capacity.</td>
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<tr>
<td>RPS/RECs</td>
<td>UCE-IDCL-PRBRC-IEA-RNP-HEAL **</td>
<td>Written comments received August 20, 2012</td>
<td>Case S9 – Federal Clean Energy Standard: This case does not have an assigned gas price attribute.</td>
<td>The Company no longer intends to model a Clean Energy Standard, but rather has included Cases C-14 and C-18 as surrogates for a broad range of potential future policy outcomes that might be used to reduce emissions in the U.S. power sector to 80% below 2005 levels by 2050. See Core Cases C-14 and C-18.</td>
</tr>
</tbody>
</table>
emissions in the U.S. power sector to 80% below 2005 levels by 2050. Moreover, the Company is including a Federal RPS assumption in many of its Core Cases.

| CO2 | UCE-IDCL-PRBRC-IEA-RNP-HEAL | Written comments received August 20, 2012 | “Case S12 Hard Emissions Cap: We recommend that PacifiCorp include the “high achievable energy efficiency potential” attribute in this case in addition to the “wind/solar – increased capacity factors, reduced cost” attribute.” | See Core Cases C-14, C-15 and C-18, which include increased DSM (accelerated ramp rates). Alternate wind and solar specific technology assumptions are included in Case S-10. |

| Stakeholder Cases | UCE-IDCL-PRBRC-IEA-RNP-HEAL | Written comments received August 20, 2012 | #1: High Environmental Compliance: Assume all environmental compliance rules will come into effect at the scheduled time. Also assume the rules will incorporate the most stringent compliance regime.

#2: High Fuel, High Carbon, and Clean Technology Focus: One possible policy environment is a combination of strict environmental compliance along with strong policy support for clean energy. For this core case assume: high carbon price forecast, high natural gas prices, high coal costs, stringent environmental compliance, high energy efficiency achievement, renewable PTC extension, and federal clean energy standard or RPS (pending PacifiCorp’s explanation of the difference between these attributes). With regard to the renewable PTC, please assume it will be extended until 2020.

#3: Markets and Efficiency: This case assumes PacifiCorp will maximize market transactions while addressing load through energy efficiency. This is essentially a no new generation strategy. For this case assume the following: Medium carbon, medium gas, medium coal prices, base level environmental compliance, maximum Front Office Transaction availability, maximum energy efficiency acquisition, and low load growth. Including the low load growth is essential to fully account for energy efficiency impacts.

#4 Energy Efficiency Bookend: This case examines the impact of maximizing energy efficiency acquisition compared to the reference cases. For this case assume the following: medium carbon, medium gas prices, medium coal prices, baseline environmental compliance, current state RPS rules, federal RPS, medium load, and maximum technological potential for energy efficiency, including faster ramp rates. | 1) The Company has included a range of environmental compliance Core Cases. See Cases C1 through C14, C-18, and Case S-4.

2) See Core Case C-18.

3) See Case C-15. New generation is allowed, but no new base load resources will be included.

4) See Case C-15.

5) See Cases C-14 and C-18. PacifiCorp believes that comparisons of these two portfolios with the preferred portfolio and 2013 business plan sensitivity (S-9) is sufficient for this type of acquisition path analysis. |
#5 More Stringent Carbon Reduction Portfolio: Because carbon reduction policies must enable significant greenhouse gas emissions in order to avoid catastrophic consequences (that is, at least 80% below 1990 levels by 2050), the Company should create a hard cap portfolio set to achieve no less than 80% reductions by 2050, with an interim reduction target of at least 30% by 2030. Although the Company is focusing on the short term likelihood of federal carbon policies to guide its IRP modeling, because the impacts and threatened impacts of climate change are so costly, it is critical that PacifiCorp model a scenario upon the basis of scientific consensus of a conservative estimate of necessary greenhouse gas emissions reductions. PacifiCorp should model a scenario with a hard cap that positions its fleet on a trajectory sufficient to achieve 80% reduction in greenhouse gas emissions by 2050 and at least 30% by 2030.

PacifiCorp’s planning should compare the costs of planning for and building this portfolio now with the costs of retrofitting its business plan portfolio in ten or twenty years to comply with more stringent greenhouse gas emissions limits. In order to do this, the Company must model a “foil” for its business plan portfolio.

### Coal Plant Investment

| Coal Plant Investment | UCE-IDCL-PRBRC-IEA-RNP-HEAL | Written comments received August 20, 2012 | We recommend that PacifiCorp’s coal replacement study is fully integrated into the IRP scenarios and action plan. Additionally, these broader level analyses should fully supplement, not supplant, more specific analysis carried out for each coal unit as part of the Certificate of Conveniences and Necessity permit process in Wyoming or other unit specific analyses. | Decisions on coal investments will be endogenous within the System Optimizer model for all Core Cases. PVRR(d) or “Change Cases” will focus on coal retirements or gas conversion alternatives selected within first 10 years of the planning horizon, with placeholders in the sensitivity case definitions. See Case(s) S-X. |

### Stakeholder Cases

| Stakeholder Cases | DPU-OCS-UAE-UCE-WRA-HEAL-USMag-UPSC | Written comments received August 30, 2012 | PROPOSED “STAKEHOLDER” CORE CASES

**Title:** No RPS Core Case 16

**Description:** Core case without state/federal RPS requirements. It is our intention to compare the results of this case with Base Core Case 2. In order to ensure a proper comparison, we recommend Base Core Case 2 exclude a federal RPS constraint as a scenario attribute.

**Purpose:** Determine the PVRR and Expected PVRR effect that current state RPS standards have on the selection and location of renewable resources.

**No RPS Core Case**

The Company has incorporated numerous “no RPS” Core Cases to inform portfolio selection. See Core Cases C-1, C-2, C-4, C-6, C-8, C-10, and C-12.

**Market Price Spike**

See Case C-17

**Hard Emissions Cap**

See Case C-14. The Company proposes...
<table>
<thead>
<tr>
<th>Case Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Load Forecast:</strong> Medium</td>
</tr>
<tr>
<td><strong>Carbon Price:</strong> Medium</td>
</tr>
<tr>
<td><strong>Natural Gas Price:</strong> Medium</td>
</tr>
<tr>
<td><strong>Coal Price:</strong> Medium</td>
</tr>
<tr>
<td><strong>RPS:</strong> Eliminate federal/state RPS requirements</td>
</tr>
<tr>
<td><strong>PTC:</strong> Same as Base Core Case 2</td>
</tr>
</tbody>
</table>

**Title:** Market Price Spike Core Case 17  
**Description:** Core case with sustained market price spike beginning in 2017 through 2022.

**Purpose:** Determine the effect on market reliance levels and PVRR, if a sustained market price spike occurs at the same time the regional surplus begins to disappear and coal units are either undergoing retrofit or are retired.

**Case Assumptions:**
- Price spike at market hubs for the peak/off-peak set at 50%/30% above the current high market price forecasts.
- **Timing:** 2017-2022. Explanation: The timing of the price spike would coincide with western coal plants either undergoing retrofit to comply with clean air requirements or retired.
- **Load Forecast:** Medium
- **Carbon Price:** Medium
- **Natural Gas Price:** High
- **Coal Price:** Medium
- **RPS:** Same as Base Core Case 2
- **PTC:** Same as Base Core Case 2
- **Constraints on Renewables – Same as Base Core Case 2**

**Title:** Hard Emissions Cap Core Case 18  
**Description:** Model a hard cap case that will achieve 80% reductions below 1990 levels by 2050 (30% by 2030).

**Purpose:** Provide a “bookend case” that determines the PVRR effect of having to comply with scientifically-recommended greenhouse gas reduction targets. Determine how the resulting portfolio performs in extending the PTC through 2020, after which CO2 prices would naturally provide an incentive for economic renewable resource additions.

**Third Party Transmission Pending**

**High Achievable EE**  
See Core Cases C-14, C-15 and C-18.

**Utility Cost of Dist. Solar**  
A Utah utility incentive is applied to all cases, along with a declining incentive level in line with Utah and other state program designs such as California. Based on a 20-year average (non-discounted), the residential incentive is $0.86/W (AC), while the commercial sector is $0.77/W (AC). Cadmus continues to update its solar PV potential and costs based on stakeholder feedback. The Company will distribute the updated Cadmus solar PV memo and cost information. The issue of effectively fixing 40 MW in portfolios due to application of Utility Cost Test prices should be discussed at the September 14 public input meeting.

**High EE High Renewable**  
See Cases C-14 and C-18.

The Company proposes extending the PTC through 2020, after which CO2 prices would naturally provide an incentive for economic renewable resource additions. Two RPS extension sensitivities have been added: S-5 and S-6.

**Short Term PTC Extension**  
See Core Cases C-14 and C-18, and
<table>
<thead>
<tr>
<th>Case Assumptions:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Carbon Price Assumption: Hard Cap</td>
</tr>
<tr>
<td></td>
<td>Natural Gas Price: Medium</td>
</tr>
<tr>
<td></td>
<td>Coal Price: Medium</td>
</tr>
<tr>
<td></td>
<td>RPS: Standard State Assumptions without resource type constraints</td>
</tr>
<tr>
<td></td>
<td>PTC Extension through planning horizon</td>
</tr>
<tr>
<td></td>
<td>High Achievable EE Potential with accelerated ramp rates equivalent to an average of 2% of retail sales per year.(^1)</td>
</tr>
<tr>
<td></td>
<td>Load Forecast: Medium</td>
</tr>
<tr>
<td></td>
<td>Price of system-wide distributed solar at the utility cost rather than total resource cost.</td>
</tr>
</tbody>
</table>

**Title:** 3\(^{rd}\) Party Transmission Core Case 19  
**Description:** Core case with transmission resource from Wyoming (Wyndstar/ChugWater) to the Utah/Idaho border area (Populus)  
**Purpose:** Determine the effect of purchased transmission vs. company owned to take advantage of lower upfront costs and to be able to avoid excess transmission capacity than is needed in earlier years.

**Case Assumptions:**  
- Company contracts for 900 MW of transmission capacity from a 3\(^{rd}\) Party  
- Timing: Beginning when Segment D is proposed to be in service and continuing throughout the planning horizon.  
- Cost of PPA = $12/kW-mo  
- Path ratings of other transmissions lines affected by this resource adjusted  
- Load Forecast: Medium  
- Carbon Price: Medium  
- Natural Gas Price: Medium

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\(^1\) Dr. Howard Geller, SWEEP Report. Given that we have not seen the ramp rates for the current IRP we do not have specific guidance. A report on the best practices for utility energy efficiency in the Southwest will be released by Dr. Howard Geller with the Southwest Energy Efficiency Project (SWEEP) in October. Dr. Geller has offered to help in defining the ramp rates and associated costs for the IRP modeling.
18

- Coal Price: Medium
- RPS: Same as Base Core Case
- PTC: Same as Base Core Case
- Constraints on Renewables – Same as Base Core Case

**PROPOSED CHANGES TO STRAWMAN CORE CASES**

**Redefined: High Achievable Energy Efficiency Core Case 10**
Description: In addition to assuming “high achievable energy efficiency potential,” increase energy efficiency ramp rates to 2% of retail sales per year.

Purpose: Determine the PVRR effect of maximum achievable energy efficiency at an accelerated rate of acquisition and how the resulting portfolio performs in risk analysis.

Case Assumptions:
- Carbon Price Assumption: Medium
- Natural Gas Price: Medium
- Coal Price: Medium
- RPS: Current state RPS without resource type constraints
- High Achievable EE Potential with accelerated ramp rates equivalent to 2% of retail sales per year.\(^2\)
- PTC: Same as Base Core Case 2
- Load Forecast: Medium
- Price the Utah Solar Incentive Program at the utility cost rather than total resource cost.

**Redefined: Utility Cost of Distributed Solar Core Case 11**
Description: Instead of constraining distributed solar to the maximum achievable based on the Cadmus memo, model the utility cost of a distributed resource, assuming a utility cost of $0.90 per watt(ac) incentive, plus reasonable administrative costs. Adjust Utah’s achievable potential to 40 MW per year starting in 2013.

Purpose: To determine whether the system optimizer model will select distributed solar resource based on a utility incentive cost and

\(^2\) See footnote 4.
the impact on PVRR. Determine how the resulting portfolio performs in risk analysis.

Case Assumptions:
Carbon Price Assumption: Medium
- Natural Gas Price: Medium
- Coal Price: Medium
- RPS: Current state RPS without resource type constraints
- PTC: Extension through planning horizon
- High Achievable EE Potential with accelerated ramp rates equivalent to an average rate of 2% of retail sales per year.\(^3\)
- Load Forecast: Medium
- Price of system wide distributed solar at utility cost rather than total resource cost.

Redefined: High Energy Efficiency, High Renewable Core Case 13
Description: Develop a clean-energy bookend case, consisting of a high energy efficiency, high renewable resource portfolio.

Purposes: 1) Determine carbon price associated with meeting the emissions reductions required to avert climate disaster assuming high natural gas prices; and 2) Determine PVRR impact and test the risk mitigating benefits of a clean-energy bookend case. This case is intended to meet expected resource need with as much EE and renewable energy (RE) as possible.

Case Assumptions:
- Carbon Price Assumption: Determine the carbon price consistent with a high natural gas price and 20% emissions reductions below 2005 levels by 2020, and 50% emissions reductions below 2005 levels by 2035 to achieve linear reductions of 80% below 2005 levels by 2050. Provide the annual carbon prices and use the higher of this carbon price or the high determined through the stakeholder process.
- Natural Gas Price: High
- Coal Price: Medium
- RPS: None

\(^3\) See footnote 4.
- PTC Extension through planning period
- $5.00/MWh REC Revenue Credit
- High Achievable EE Potential with accelerated Ramp Rates (same as in UCE’s high EE case)
- Load Forecast: Medium
- Price the Utah Solar Incentive Program at UC
- Remove MW and timing constraints on solar, geothermal, and wind resources.

PROPOSED SENSITIVITY CASES

We recommend one of these cases replace the “No RPS” sensitivity case and propose an additional sensitivity case.

**Title:** Short-Term Extension of PTC  
**Description:** Sensitivity case with the PTC ending in 7 years.

**Purpose:** Determine the effect on resource selection with a short-term extension of PTC.

**Case Assumptions:**
- All other assumptions the same as the Base Core Case.

**Title:** State RPS Compliance using System Optimizer  
**Description:** Sensitivity case where state RPS compliance is modeled in System Optimizer rather than using the RPS Scenario Maker.

**Purpose:** Compare the set of renewable resources for state RPS compliance selected by the RPS Scenario Maker process versus System Optimizer.

**Case Assumptions:**
- As in the 2011 IRP, RPS compliance is modeled in System Optimizer; and therefore, System Optimizer determines the set of renewable resources to meet RPS requirements.
- All other assumptions the same as the Base Core Case.
1. Proposed core case numbers do not connote agreement regarding priority of proposed cases. Rather, numbers are provided for ease of reference with the strawman matrix.
2. The term “case assumptions” here is identical to the Company’s definition of the term “scenario attributes.”

<table>
<thead>
<tr>
<th>Core Cases</th>
<th>Utah Association of Energy Users (“UAE”)</th>
<th>Written comments received August 31, 2012</th>
<th>1a. One core scenario should include a cost burden representative of at least the Gateway West transmission segment for any future Wyoming wind resources. UAE does not believe that a meaningful cost/benefit analysis can justify that segment other than as a conduit for significant additional Wyoming wind resources. The assumed cost of such resources should include all associated and required costs, including the cost of new transmission.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Core Cases</td>
<td>UAE</td>
<td>Written comments received August 31, 2012</td>
<td>2. Core case objectives. There are at least two important objectives to consider in defining core cases: 1) Represent a variety of potential futures based on a reasonable view of what is likely to happen; 2) Push scenarios to more extremes or book ends to obtain a wide variety of resources in the portfolios, in part to see how they perform in the risk analysis. Both approaches have merit and one approach does not necessarily preclude the other. A concern can arise, however, in how the core case results will be used in evaluating transmission scenarios. At a high level the concern is that targeting core cases at specific technologies may bias the transmission evaluation, especially where transmission is highly correlated to a specific technology. For example, the 2011 IRP concluded: “The modeling analysis indicates that the full Energy Gateway strategy is cost effective assuming incremental wind additions are in line with the Company’s current wind acquisition plans [Green Resource Future]. However, without the mandate for additional renewable resources [Incumbent Resource Future]...further evaluation of proposed incremental transmission...would be required”. (2011 IRP at page 82). We are concerned by the combination of too many core cases.</td>
</tr>
<tr>
<td>Coal Plant Options</td>
<td>UAE</td>
<td>Written comments received August 31, 2012</td>
<td>1b. One core scenario should incorporate PPA options for existing/stranded coal projects whose capacity may become available in the next decade due to early coal retirements or reconfiguration. UAE believes that significant coal resources in the region may become available in the not-too-distant future that may compare favorably with other resource options. Current resource planning efforts should consider the cost-effectiveness of such resources.</td>
</tr>
<tr>
<td>Core Cases</td>
<td>UAE</td>
<td>Written comments received August 31, 2012</td>
<td>A response is pending. PacifiCorp noted in a public meeting that new coal plant purchases would not be allowed under emission performance standards in Oregon, Washington, and California. PacifiCorp believes that this is a suitable topic for the risk assessment discussion planned for the October 23-24 meeting.</td>
</tr>
<tr>
<td>Federal RPS</td>
<td>UAE</td>
<td>Written comments received August 31, 2012, pg 2</td>
<td>3a. UAE questions the assumption of a federal RPS in the base and many other core cases. UAE does not believe a federal RPS remains likely in the foreseeable future.</td>
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<tr>
<td>CO2 Costs</td>
<td>UAE</td>
<td>Written comments received August 31, 2012, pg 3</td>
<td>3b. UAE does not believe that a compelling case has been made to increase the assumed CO2 cost levels. UAE questions whether a sound basis exists for the $16 and $34 values, but believes that the values used in the last IRP should again be used unless a compelling case has been made to change them. We do not believe such a case can be made in the current uncertain political environment.</td>
</tr>
<tr>
<td>Load Forecast</td>
<td>UAE</td>
<td>Written comments received August 31, 2012, pg 4</td>
<td>3c. UAE believes that load forecasts should be correlated in some manner to prices. If utility prices continue to skyrocket as in the recent past, there is little doubt but that a number of industries will be unable to continue operations within PC’s service territories.</td>
</tr>
<tr>
<td>DSM, 85% Technical Potential</td>
<td>NWEC</td>
<td>Written comments received August 31, 2012</td>
<td>We support the Company’s approach to use 85% of technical potential as the achievable potential for DSM in the 2013 IRP. This approach is an improvement over the 2011 IRP method of calculating achievable potential and provides more transparency than the undocumented assumptions used in the 2011 IRP.</td>
</tr>
<tr>
<td>Coal Analysis</td>
<td>NWEC</td>
<td>Written comments received August 31, 2012</td>
<td>We support the specific recommendation made by Oregon Citizen’s Utility Board (CUB) (July 31st comments) and Renewable Northwest Project (RNP) (August 2012 comments) that more flexibility within the IPR modeling is needed to account for flexibility on federal pollution control requirements in the event of a unit closure compromise agreement. In order to ensure that the IPR is identifying least cost, least risk approaches for all PacifiCorp customers, system optimizer logic should be adjusted to incorporate the following: For each Coal Unit that has a BART-required SCR which has not yet been installed (as of 8/1/12): 1. Assume that plant will be allowed to run 5 years past the current expected deadline for the SCR without installing the SCR or having to make significant additional capital investment, but would be required to close after operating 5 years past the current expected deadline for the SCR. 2. Assume that MATS can be met though Selective Catalytic</td>
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</table>
Injection, low sulfur coal or some other measure that avoids significant capital investment.

3. As the plants are retired, replace the plants with natural gas combustion turbines. (CUB e-mail comments, July 31, 2012).

### Energy Gateway Transmission Scenarios and Transmission Benefit Analysis

<table>
<thead>
<tr>
<th>Company</th>
<th>Comments</th>
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<tbody>
<tr>
<td>Encana</td>
<td>Written comments received July 23, 2012</td>
</tr>
</tbody>
</table>

- “[S]upports the recommendation provided during the July 13th meeting to include segments C and G within the Reference Scenario (Scenario 1). The Reference Scenario should include all segments that are highly likely (better than 90% chance) to proceed. This will make it easier to assess the impact on the (G&T) PVRR for the discretionary segments. (D, E, F and H).”

- “Encana is concerned with the proposed approach to assessing transmission benefits. In the long-run, transmission with remote generation is a substitute for local generation with local transmission. The manner in which PacifiCorp proposes to measure the transmission benefits does not allow for a proper comparison of these fundamentally different configurations.

To be more concrete, if PacifiCorp is to evaluate the benefit of, say, Segment D, the comparison needs to be against cases without Segment D – presumably other core cases when Segment D is not included. Secondly, the benefit metrics – such as line losses – need to be estimated for both the case with and without the Gateway segment, because it is fundamentally the incremental benefit/harm that is of interest.”

- The recommendation to include Segment G within the Reference Case is counter to the Utah PSC’s requirement that the reference case should only include facilities which have already received a CPCN or for which the Company has a binding contract in place. All other segments, including Segment G, will be included in the alternate transmission scenarios.

The Company decided to include Segment G (Sigurd – Red Butte) in the Reference Scenario, and has alerted Utah Commission Staff and other Utah parties on this decision.

- As discussed in detail at the July 13 workshop, for each of the five (5) Gateway scenarios which include different combinations of Energy Gateway segments, the Company will run the System Optimizer with the same set of portfolio core cases. Currently this would result in 100 different portfolios for comparison.

The intention of the proposed “dashboard” approach discussed at the July 13 workshop is to measure transmission benefits that traditional modeling does not capture. For most of the metrics discussed at the July 13 workshop, the identification and evaluation of transmission benefits requires that the benefit be estimated for both the case with and without the subject Gateway segment.

**The Company will complete its evaluation using the system benefits tool (previously**
<table>
<thead>
<tr>
<th>Source</th>
<th>Comments</th>
<th>Referred to as the “dashboard” approach for Segment G as part of the 2013 IRP.</th>
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</table>
| Encana | Written comments received July 23, 2012 | “The majority of the benefit metrics should be already included in the PVRR definition, and if not they need to be included. Specifically, the following should be included in the base PVRR:
- Incremental ATC (Wheeling revenue) – wheeling revenue should be an offset to customer paid RR.
- Energy Line Loss Savings – the cost of (energy) line losses should be included in RR.
- Capacity Line Loss Savings – the cost of (capacity) line losses should be included in RR.
- Ability to Serve WY Network Load – revenue from WY network services should be an offset to customer paid RR.
- Avoided Additional Capital Cost – all capex costs should be included in RR.

To the extent that other benefit metrics are included, they too should be compared against the cases without the segment of Gateway being evaluated. For example, if the evaluation is to consider the reliability benefit during N-1, then the benefit should only account for the incremental impact relative to the no-segment cases. If all loads can be reliably served from local generation in an N-1 scenario without Segment D, for example, then Segment D should not be assigned any incremental reliability benefit. Similarly, the "Load Loss" and "Reduced JB tripping" metrics should evaluate the incremental impact as compared against the no Gateway scenarios.

All-in-all, Encana is concerned that without a proper incremental comparison PacifiCorp will artificially over-estimate the benefits of the Gateway segments.” |
| Multiple Wyoming Stakeholders | July 12 Wyoming stakeholder input meeting | PacifiCorp agreed to consider such sensitivities. See Case S-11. |
| Utah Office of Consumer Services | Written comments received July 5, 2012 | “The Office would like the Company to model resources, including renewable resources, without a predetermined transmission topology. Based on the optimal set of resources chosen by the IRP models, the Company would then study transmission additions needed to access these resources. The Reference Case, as proposed, does not predetermine any future transmission projects beyond what is currently in-service or under construction. The 20 portfolio core cases run..." |
resources. It would be informative to see how these transmission additions compare to Energy Gateway.”

<table>
<thead>
<tr>
<th>Renewable Northwest Project</th>
<th>Written comments received August 10, 2012</th>
<th>With regard to the Company’s Transmission Benefit Analysis, RNP is very encouraged to see the Company’s progress on this difficult valuation. The methodology and proposed scope appears consistent with FERC Order 1000 and has eclipsed the progress of other regional efforts to measure transmission benefits. For this reason, RNP encourages the Company to detail its methodology in the body of its IRP for the benefit of other regional transmission planning entities.</th>
<th>The Company intends to provide the requested detail in its 2013 IRP.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Renewable Northwest Project</td>
<td>Written comments received August 10, 2012</td>
<td>In response to the Company’s specific request for feedback, RNP considers it appropriate to measure the socialized cost of outages experienced by customers. This seems intellectually consistent with the inclusion of customer benefits when determining the cost effectiveness of energy efficiency.</td>
<td>The Company intends to explore with stakeholders the potential inclusion of avoided outage costs in its benefit analysis.</td>
</tr>
<tr>
<td>Renewable Northwest Project</td>
<td>Written comments received August 10, 2012</td>
<td>“RNP supports Encana’s July 23rd written comments suggesting that Energy Gateway segment G be included in scenario 1. As mentioned by many parties at the July 13th workshop, evaluating segment G in scenario 1 is necessary to fully determine the separate benefit of segment D. RNP encourages the Company to reach a compromise with the Utah Commission to allow for this widely supported change.”</td>
<td>The Company decided to include Segment G (Sigurd – Red Butte) in the Reference Scenario, and has alerted Utah Commission Staff and other Utah parties on this decision.</td>
</tr>
<tr>
<td>Transmission Scenarios</td>
<td>UAE</td>
<td>Written comments</td>
<td>4. Transmission scenarios. UAE believes it is imperative for at least Gateway Segments D and F to be isolated in transmission scenarios so</td>
</tr>
<tr>
<td>Transmission Benefit “Dashboard”</td>
<td>UAE</td>
<td>Written comments received August 31, 2012, pg 3-4</td>
<td>5. “Dashboard” transmission benefit analysis. UAE is concerned about PC’s stated intent to attempt to quantify and incorporate perceived external benefits of transmission segments in the IRP context. Any such analysis will be fraught with complexity, uncertainty and dispute. Such an effort appears to be a pre-emptive attempt to justify construction of questionable transmission segments, as opposed to objective modeling of resource options. UAE urges PC to abandon any such effort in the context of the IRP process and to focus its limited resources instead on the complicated IRP models and issues.</td>
</tr>
<tr>
<td>Transmission Benefit</td>
<td>UAE</td>
<td>Written comments received August 31, 2012, pg 4</td>
<td>6. Specification of transmission benefits. PC should specifically list the revenues and benefits that it assumes for each Gateway transmission segment, including all assumptions, analyses and models used to derive them. These should be compared to the costs of the relevant segment and also to the “don’t build” scenario.</td>
</tr>
<tr>
<td>Contractual Transmission</td>
<td>UAE</td>
<td>Written comments received August 31, 2012, pg 4-5</td>
<td>7. Contractual transmission options. UAE is troubled that the only transmission scenarios being considered by PC are proposed PC-owned Gateway segments with astronomical price tags and questionable benefits. Ratepayers, who are impacted on a nominal basis and not a levelized basis when PC builds transmission, may be better off if PC were to contract with other entities for a level of transmission capacity legitimately needed in the near term. To the extent a legitimate need for incremental transmission capacity can be demonstrated, as compared to the option of not building such capacity, PC and the IRP should show no preference between PC-owned Gateway segments and contractual arrangements with other entities that propose to build transmission paths comparable to PC’s proposals. In order for the same to be realistic options, however, PC</td>
</tr>
</tbody>
</table>
must take steps now to respond to open seasons and otherwise express serious interest, so that PC can help shape the nature of the transmission projects and identify likely costs.

| NWEC | 8/31/2012 | Joining numerous other stakeholders, we support including Energy Gateway Segment G in Scenario 1, in part to gain a fuller understanding of the net benefits of Segment D. | The Company decided to include Segment G (Sigurd – Red Butte) in the Reference Scenario, and has alerted Utah Commission Staff and other Utah parties on this decision. |

**Resource Risk Assessment**

| Renewables-Geothermal | Renewable Northwest Project | Written comments received August 10, 2012 | The Company is not exposed to dry-hole or other drilling risks if it enters into a PPA with a third-party developer. Therefore, in the 2013 IRP the Company should allow system optimizer to select geothermal resources for all scenarios. The levelized cost of geothermal resources should be set at the high end of bids submitted to the Geothermal RFI. By assuming a high levelized price, PacifiCorp can be reasonably certain that third-party developers would assume drilling risks given the higher reward. Should system optimizer continue to see high cost geothermal resources as the least cost RPS resource given their diversity and operational characteristics, the company should include the resource in its preferred portfolio and business plan. | For all Core Cases, the Company plans to incorporate pricing derived off of bids received through the All Source Request for Proposals for a 2016 Resource in lieu of the resource capital costs specified in the supply side resource table. The associated resource costs incorporate the price premium the market is currently ascribing to geothermal development risk for projects in PacifiCorp’s service territory. The projects included in the RFI report are in the early stages of development and have pricing estimates that are speculative. |

| Renewables-Geothermal | Renewable Northwest Project | Written comments received August 10, 2012 | The Company should take one further step to measure the utility risk of self-built geothermal resources. For the geothermal RPS strategy scenario, assume geothermal resources can be developed at the average price revealed by the Geothermal RFI. To measure drilling risk, evaluate the geothermal scenario with the stochastic phase of the IRP analysis. For each stochastic run, randomly draw a new project capacity from a distribution centered around the project size selected by system optimizer. The shape of the distribution should reflect the Company’s understanding of development risk as reflected on slide 21 of the August 13th workshop. Regardless of the new capacity drawn, retain the capital investment selected by system optimizer. Some runs would capture dry-hole costs when large geothermal capital expenditures result in geothermal capacity draws with very small capacities. The upper-tail PVRR should indicate how much risk the Company faces due to dry hole risk and how that dry-hole risk compares to other risks the utility routinely takes. To limit concerns about scenario quantities, do not evaluate the geothermal scenario under all Gateway builds. | An issue with the proposed approach is that varying resource capacity in PaR would impact production costs. It is also not clear how to construct a reasonable probability distribution to represent development risk given available project information. |
| DSM | Renewable Northwest Project | Written comments received August 10, 2012 | In response to the request for feedback during the energy efficiency workshop, RNP supports including both T&D investment deferral and the risk mitigation cost adjustment in the levelized cost of energy efficiency. Doing so is conceptually sound and RNP commends the utility for quantifying this important value. | PacifiCorp has updated the risk mitigation cost adjustment based on feedback received at the June 20, 2012 public input meeting. The new approach involves (1) running PaR in stochastics mode with the 2011 IRP preferred portfolio with and without all energy efficiency resources (two Monte Carlo runs), (2) running PaR in deterministic model for 2011 IRP preferred portfolio with and without all energy efficiency resources (two deterministic runs), (3) computing the difference in the average production cost PVRR for the stochastic results as well as for the deterministic results, (4) compute the difference between the stochastic PVRR difference and deterministic PVRR difference, (5) divide by energy efficiency MWhs to get the $/MWh credit. The new credit is $7/MWh compared to $14.98/MWh used for the 2011 IRP. |
| Other | Model Results Presentation | UCE-IDCL-PRBRC-IEA-RNP-HEAL 1/ | Written comments received August 20, 2012 | In order to make the portfolio review process meaningful, output from the System Optimizer model should be distributed to stakeholders in the following forms: (a) new capacity additions and retirements by year as per previous IRPs outputs, as well as (b) total capacity by fuel type per year, (c) net generation by fuel type per year, (d) CO2, SO2, and NOx emissions by fuel type per year. Output from the Planning and Risk model should be distributed to stakeholders in the following forms: (a) PVRR of all stochastic runs for all scenarios, rather than just "average PVRR" and "95th percentile PVRR" (b) average net bulk power cost per year, by fuel type. | The Company is still evaluating reporting capabilities and limitations of the upgrade IRP models, and will determine a suitable output reporting package for both models that takes into account this request. |
| | Nominal rate impacts | UAE | Written comments received August 31, 2012, pg 5 | 8. Nominal rate impacts. In IRP/RAMPP proceedings in the past, PC prepared an evaluation of the nominal rate impacts of resource options. Such an evaluation is very informative to ratepayers and regulators, and is necessary to satisfy the Utah IRP requirement for an evaluation of rate impacts. UAE urges PC to include an evaluation of nominal rate impacts by year for each resource option. | PacifiCorp does not believe it is practical to determine rate impacts for each individual resource option given the number of portfolios being developed, nor how this would help determine which portfolio should be the designated as the preferred portfolio. |
| Reserve Margin | UAE | Written comments received August 31, 2012, pg 5 | 9. Reserve Margin. UAE supports a meaningful evaluation of cost and benefit tradeoffs of increased planning reserve margins. Reliability is critical to most UAE members, but the cost of increasing planning reserve margin is prohibitive at certain levels. UAE supports a meaningful analysis of costs and benefits of a number of levels, including reliability standards below 1 in 10 years. UAE urges PC not to select any given reserve margin - including one based on a 1 in 10 year reliability standard - without having first carefully evaluated and considered all cost and benefit tradeoffs. | PacifiCorp’s reserve margin study will explicitly examine the reliability/cost trade-off. The 1 in 10 year reliability standard would only be used if the trade-off evaluation is inconclusive. |
| Solar resources | UAE | Written comments received August 31, 2012, pg 5-6 | 10. Solar resources. UAE supports evaluation of additional solar resources in Utah and other states. However, UAE is reluctant to assume significant additional solar resources in Utah based solely on a Utility Cost Test (UCT) cost/benefit ratio in excess of 1.0. UAE recognizes that the Utah Commission has established the UCT as the primary cost effectiveness test in Utah. However, other cost/benefit measures provide very useful information and should also be considered. UAE is particularly concerned with any measure that does not produce a Ratepayer Impact Test (RIM) cost/benefit ratio that at least approaches 1.0. A significantly lower RIM ratio suggests significant cost-shifting or cross-subsidization between participants and non-participants, which is of concern to UAE, particularly in the context of large-scale solar incentives and other similar programs. | PacifiCorp notes UAE’s concern, and this should be discussed at the September 14 public input meeting. |
| Additional resource option | UAE | Written comments received August 31, 2012, pg 6 | 11. Additional resource option. The model should recognize and be able to select an additional resource consisting of coal plants that may be shut down. The additional resource would be a combined cycle plant with a simple cycle turbine added and a heat recovery boiler. This resource should have a lower capital cost than a new combined cycle plant since the existing steam turbine can be used as part of the replacement resource. | This concept is typically referred to as repowering. The Company has looked extensively at this concept for the Gadsby Plant. In almost all circumstances the concept of repowering is more expensive than to simply build a CCCT plant on the existing coal unit site. There are a number of issues with repowering including a mismatch in the size of the gas turbine(s) to the existing steam turbine resulting in a less efficient final resource. The steam turbine is designed to operate in a Rankine thermodynamic cycle and utilizes multiple extractions whereas a CCCT has a steam turbine optimized for a Brayton thermodynamic cycle. Since the gas turbine(s), heat recovery steam generator(s) and steam turbine are not
designed as a match (as in a CCCT), less efficient and more costly compromises usually result. Additionally the siting and location of the steam turbine relative to the gas turbine will require either long duct and steam runs or demolition work delaying and extending the project schedule. The primary benefit to putting a CCCT on a coal site is to use the water, air shed and transmission access. These benefits are also present with building a new CCCT on a site rather than trying to reuse a non-optimum steam turbine while working around the old boiler equipment.

Finally, repowering results in a significant loss of generation while the original equipment is being demolished. Historically very few actual repowering projects involving reuse of the steam turbine have been implemented; typically repowering translates into removing the original equipment and building a new resource on the site.

(Note that CCCTs are resource options available to the model for replacing coal unit capacity.)

I/ Organization Acronyms:

UCE = Utah Clean Energy
IDCL = Idaho Conservation League
PRBRC = Powder River Basin Resource Council
IEA = Interwest Energy Alliance
USMag = U.S. Magnesium / Roger Swenson
RNP = Renewable Northwest Project
HEAL = Healthy Environment Alliance of Utah
UAE = Utah Association of Energy Users
UPSC = Public Service Commission of Utah
WRA = Western Resource Advocates