PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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January 8, 2010

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capital Street NE, Ste. 215
Salem, OR 97301-2551

Attn: Filing Center

RE: **Docket No. LC 47**
PacifiCorp's 2008 Integrated Resource Plan ("2008 IRP")
PacifiCorp's Response to Public Utility Commission of Oregon Staff – Final Comments

Please find enclosed the original and one (1) copy of PacifiCorp's response to the Final Comments of the Public Utility Commission of Oregon Staff dated December 8, 2009.

It is respectfully requested that all formal data requests regarding this filing be provided to the Company as follows:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
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Please direct any informal inquiries to Pete Warnken, Manager Integrated Resource Planning at (503) 813-5518 or Joelle Steward, Regulatory Manager, at (503) 813-5542.

Sincerely,

Andrea L. Kelly

Andrea L. Kelly
Vice President, Regulation

cc: Service List for Docket No. LC 47

CERTIFICATE OF SERVICE

I certify that I have cause to be served the foregoing **Reply Comments** in OPUC Docket No. LC 47 by electronic mail and US mail to those parties who have not waived paper service on the attached service list.
DATED this 7th day of January, 2010.

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Response to Public Utility Commission of Oregon Staff Final Comments on PacifiCorp's 2008 Integrated Resource Plan

(Docket LC 47)

1. INTRODUCTION

PacifiCorp filed its 2008 Integrated Resource Plan ("IRP") with the Public Utility Commission of Oregon ("Commission") on May 29, 2009. As part of the IRP acknowledgment schedule, Public Utility Commission of Oregon staff ("Staff") provided final comments and recommendations on the IRP ("Staff Final Comments") on December 8, 2009. The comments addressed concerns raised by the intervenors[1] in their comments filed on October 8, 2009 and considered PacifiCorp's response to intervenor comments filed with the Commission on November 3, 2009.

PacifiCorp is pleased that Staff recommends that the Commission acknowledge the IRP, and is appreciative of the opportunity to respond to Staff's comments and the specific acknowledgment conditions viewed as needed to address the concerns raised by the parties.

In addressing the Staff Final Comments, this document first summarizes Staff's action plan additions and PacifiCorp's responses to Staff's proposed additions. The Company then turns to Staff's specific comments and acknowledgment recommendations, organized into the following topics:

- Wind Integration Cost Study
- Deferral of New Resources
- Portfolio Modeling Beyond the 10-year Action Plan Horizon
- Incorporation of Oregon's carbon dioxide ("CO_2") Reduction Goals and Coal Plant Retirement Scenarios
- Transmission Financial Analysis and Justification
- Conservation
- Demand Response Resources

2. SUMMARY AND RECOMMENDATIONS

Staff recommends adding nine new Action Items to the 2008 IRP Action Plan, most of which require modeling and analysis tied to preparation of the 2008 IRP Update. The key concern is the large number of new Action Item requirements tied to the 2008 IRP Update, which the Company plans to file with the state commissions on March 31, 2010. This date is designed to keep the IRP

[1] In addition to Staff, three parties submitted written comments: the Northwest Energy Coalition ("NWEC") and a joint submittal by the Renewable Northwest Project and Citizen's Utility Board ("RNP/CUB").

filing cycle consistent across all state jurisdictions, recognizing that PacifiCorp has already received acknowledgment orders from a number of commissions. The 2008 IRP Update will summarize the development of the 2010 business plan resource portfolio, compare that portfolio with the 2008 IRP preferred portfolio, and provide an updated action plan.

Wind Integration Cost Study: Staff recommends that the Company provide a new wind integration cost study that incorporates public input in the 2008 IRP Update. PacifiCorp agrees to perform such a study in 2010, but notes that the process proposed by Staff cannot be completed in time for the planned March 31, 2010 filing of the 2008 IRP update. PacifiCorp provides suggested modifications to Staff's proposed action item to reflect this timeline.

Deferral of New Resources: Staff recommends three new Action Items pertaining to resource assessment to support the IRP and the all-source requests for proposals ("All Source RFP") issued in early December 2009. PacifiCorp outlines reasons why two of these new Action Items are not needed, and asks Staff to clarify its expectations concerning resource assessment given the current language in Action Item 3. PacifiCorp objects to the proposed Action Item that would require the Company to demonstrate the need and timing for resources in the All-Source RFP. The proposed action item is inappropriate because a resource evaluation conducted for the All-Source RFP is outside the scope of the IRP guidelines and is already covered under the Commission's competitive bidding guidelines.

Portfolio Modeling Beyond the 10-year Action Plan Horizon: PacifiCorp agrees with Staff's recommendation to evaluate improvements to out-year capacity expansion modeling. The Company offers modifications to Staff's proposed language to account for other modeling improvement priorities planned for the next development cycle.

Incorporation of Oregon's carbon dioxide ("CO_2") Reduction Goals and Coal Plant Retirement Scenarios: Staff recommends more extensive analysis of Oregon's CO_2 reduction targets as well as coal plant retirements. PacifiCorp agrees to include this new Action Item and provides recommended edits to Staff's proposed language. PacifiCorp also summarizes recent changes to its capacity expansion model to facilitate the analysis.

Transmission: PacifiCorp agrees with Staff's recommendation to include a new Action Item pertaining to provision of on-going transmission investment analysis results in the next IRP planning cycle.

Conservation: Staff recommends two new Action Items relevant to conservation. PacifiCorp has already fulfilled the first element of Staff's first recommendation by providing a comparative assessment of its conservation assessment methodology against the Northwest Power and Conservation Council ("Council") methodology. PacifiCorp agrees with the second element of Staff's first recommendation and plans to commission a new system-wide potential study for its next IRP planning cycle that also addresses differences with respect to the Council's methodology.

However, PacifiCorp objects to Staff's recommendation to include a full distribution energy efficiency implementation plan in the 2008 IRP update. The Company questions whether an IRP proceeding is the proper forum for such an implementation plan, and proposes that such a plan be considered as part of a separate Commission proceeding to allow for a more thorough review of the issue than can be accomplished within the IRP proceeding.

Demand Response Resources: PacifiCorp responds to Staff comments regarding the Company's evaluation of the cost and amount of resources from curtailable rates, demand buybacks, and critical peak pricing programs.

3. RESPONSE TO STAFF'S COMMENTS AND RECOMMENDATIONS

3.1. Wind Integration Cost Study

Staff states that "Action item 1 of the IRP adequately incorporates sufficient acquisition targets of wind resources." However, it concurs with the other intervenors that the wind integration cost study is deficient in a number of areas and "risks over- or under-estimating the most cost-effective amount of wind to incorporate in [PacifiCorp's] portfolio of renewable resources." Two of the areas mentioned by Staff include the handling of generation output correlations between existing and new wind facilities, and the Company's assumption that all day-ahead energy imbalances are settled through market transactions. Staff therefore recommends that PacifiCorp amend its Action Plan with the following text:

In the 2008 IRP update, provide a wind integration study that has been vetted by key regional stakeholders through a public participation process.

The Company agrees to conduct an updated wind integration cost study in 2010. The Company has already started preliminary work to update the study, initially focusing on incorporating additional 10-minute wind resource data to augment its wind facility data.[2] However, such a study cannot be performed before the anticipated March 31, 2010 filing date for the 2008 IRP Update given the study's anticipated scope and Staff's requirement for an associated public process. PacifiCorp proposes to initiate a public meeting in the first quarter of 2010 to discuss with stakeholders the methodology and schedule for the study, as well as hold a final public meeting later in the year to present study results. Therefore, PacifiCorp recommends that Staff modify its proposed Action Item as follows:

~~In the 2008 IRP update, provide~~ In 2010, complete a wind integration study that has been vetted by key regional stakeholders through a public participation process.

Regarding the issue of over- or under-estimating the most cost-effective amount of wind in resource portfolios, PacifiCorp conducted a capacity expansion sensitivity analysis of the impact of changing the wind integration cost that PacifiCorp incorporates as a real-levelized component of wind resource capital costs. Such a sensitivity analysis was requested by Staff and intervenors at the IRP public workshop held September 9, 2009. For this sensitivity study, PacifiCorp used the portfolio development assumptions for case 5B_CCCT_Wet[3], a key assumption for which

[2] PacifiCorp is evaluating the "Western Dataset", developed by the 3TIER Group for the National Renewable Energy Laboratory (NREL). This simulated power output dataset, with a 10-minute, two-kilometer resolution, is supporting the Western Wind and Solar Integration Study (WWSIS), to be completed by NREL in early 2010.
[3] See IRP Table 8.37, page 236, for a description of this case.

was the use of a \$45/ton CO_2 tax. The intra-hour wind integration cost component was then reduced by 50 percent as suggested by the Renewable Northwest Project, resulting in a reduction in the wind integration cost from \$11.85/MWh[4] to \$7.11/MWh (an overall 40 percent decrease). This study thus indicates a cost-effective wind capacity expansion given a presumed significant reduction in wind integration costs with other inputs held constant. Relative to the wind additions in the original 5B_CCCT_Wet portfolio, the wind integration cost reduction resulted in a 500 MW increase in wind additions.

3.2. Deferral of New Resources

Staff recommends that Action Item no. 3 of the IRP Action Plan be modified "to more clearly explain the flexible timing of the base-load resource (2014-2016), as well as the Company's intent to further justify any resource acquisition decisions prior to the 2008 IRP update or next IRP cycle." (Staff Final Comments, page 2). Staff therefore recommends the following three additions to PacifiCorp's 2008 IRP Action Plan:

In the 2008 IRP update, evaluate the intermediate-term market purchases, taking into consideration the most current evaluation of loads, market prices and regulatory activity, in order to determine the best resource option.

In the 2008 IRP update, evaluate the continued need for the SCCT resource in 2016 given current load/price forecast, market conditions, transmission plans, and regulatory developments.

In the 2008 all-source RFP the Company will demonstrate the need and timing for the resource, taking into consideration current load/price forecasts, market conditions, transmission plans, and regulatory developments. The Company will demonstrate that additional deferral of a base load resource using cost-effective intermediate market purchases, or other alternatives is not in the best interest of customers.

PacifiCorp concurs with Staff that the IRP and All-Source RFP should sufficiently account for any benefits from relying on firm market purchases until new generation facilities are needed based on the latest assessment of load requirements, market conditions, and other factors. However, PacifiCorp believes that Staff's first two recommended action plan additions have already been considered in the IRP and are therefore unnecessary for the following reasons. First, Action Item 3 (IRP page 256) already outlines a resource strategy that focuses on evaluating cost-effective alternatives to new generation during the 2014-2016 period identified by Staff:

> In recognition of the unsettled U.S. economy, expected continued volatility in natural gas markets, and regulatory uncertainty, continue to seek cost-effective resource deferral and acquisition opportunities in line with near-term updates to load/price forecasts, market conditions, transmission plans, and regulatory developments.

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[4] The \$11.85/MWh value reflects one-year escalation of Portland General Electric's \$11.75/MWh integration cost estimate reported in 2008 dollars.

This resource strategy encompasses any major resources that may be acquired through the procurement process, and does not limit resource deferral opportunities to just firm market purchases. As a result, Action Item 3 sufficiently addresses the need to continuously assess resource need given uncertain planning conditions.

Second, investigation of intermediate-term firm market purchases, defined as purchases with a term of five to 10 years, is already accounted for in Action Item 9, Planning Process Improvements: "Continue to investigate the formulation of satisfactory proxy intermediate-term market purchase resources for portfolio modeling, contingent on acquiring suitable market data." (IRP page 258). The All-Source RFP encompasses market purchases of any duration. Any qualified intermediate-term market purchases would be evaluated on a price-screening basis and analyzed using the IRP modeling framework if selected for the bidder shortlist. Information acquired through the All-Source RFP or other sources will be used to help refine the characterization of market purchases for the next IRP.

Third, PacifiCorp explicitly accounts for the cost-effectiveness and optimal timing of market purchases and all other resources through its capacity expansion and stochastic production cost modeling. This is indeed a core objective of the IRP process as outlined in Oregon's IRP guidelines, so it is not clear why Staff would need to reiterate it in the IRP Action Plan. PacifiCorp thus asks for clarification as to why Staff believes the Action Plan needs to be augmented in this way.

Regarding the recommended addition concerning the All-Source RFP, dictating how the resource evaluation for the All-Source RFP should be performed is outside the scope of the IRP guidelines, and is not relevant to IRP acknowledgment. The All-Source RFP is governed by Oregon's competitive bidding guidelines (Order No. 06-446), and the bid evaluation methodology to be used is consistent with the IRP modeling framework as required by Section 9b of the competitive bidding guidelines.[5] For the All Source RFP, the Company will refresh the IRP models with more recent load forecast, price forecast, and transmission configuration information to ensure that resource needs and cost variables are in line with the Company's latest expectations. The Company thus recommends that Staff eliminate the third Action Plan addition listed above.

3.3. Portfolio Modeling Beyond the 10-year Action Plan Horizon

Staff agrees with the intervenors that PacifiCorp should revisit its approach for modeling the out-years of the capacity expansion simulation period. The basic concern the intervenors have in common is that with the capacity expansion model's perfect foresight, highly uncertain modeling assumptions affecting resource decisions in the out-years may unduly influence near-term resource decisions. NWEC's position is that any model that relies on perfect foresight is fundamentally flawed and should be abandoned in favor of a model that reflects the dynamic nature of investment decision-making. RNP/CUB suggests that one way to address this concern is to adopt a two-phase simulation approach where the capacity expansion model is run for the first 10 years followed by a simulation for the second 10 years with a fixed set of resources

[5] A summary of the shortlist bid evaluation methodology is included as Exhibit 1.

determined from the first 10-year run. Staff therefore makes the following Action Plan recommendation to the Commission:

For the next IRP planning cycle PacifiCorp will work with parties on developing an approach that addresses all parties concerns and can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan.

PacifiCorp agrees that investigation of alternative approaches for modeling out-year resource acquisition is desirable. Dividing a portfolio expansion plan run into two passes may actually be necessary to effectively conduct simulations with the enhanced System Optimizer model that will be placed into production for the next IRP. This custom version of the model incorporates new functionality specified by PacifiCorp. The enhanced model tracks CO_2 flows (including those from spot market activity) for load-based CO_2 emission compliance rules, and optimizes renewable resource expansion to meet individual state and federal renewable portfolio requirements. The trade-off for this new functionality is significantly longer model run-times and greater data management requirements. Testing of the model to date indicates that conducting a first 10-year run and then fixing resources for a second 10-year run significantly improves the model run time relative to a 20-year run with no fixed resources. However, PacifiCorp cautions Staff and the intervenors that such a "two-pass" modeling approach involves a trade-off with respect to the number of alternative futures (or "cases") that can be accommodated in the IRP, as well as other modeling enhancements that may be desired. For example, modeling of plant retirements and retrofit options needed for accommodating coal plant retirement scenarios involves significantly more model run-time due to the increased number of resource options and a subsequently more complex optimization problem.

Given the increasing complexity of the modeling environment, PacifiCorp cannot commit to implementing an approach "that addresses all parties concerns" before it has formulated and vetted its next IRP modeling plan and confirmed that the enhanced capacity expansion model can accommodate the demands placed on it. Therefore, the Company proposes that Staff modify the wording of its recommendation as follows:

For the next IRP planning cycle PacifiCorp will work with parties ~~on developing an~~ to investigate a capacity expansion modeling approach that reduces the influence of out-year resource selection on resource decisions covered by the IRP Action Plan. ~~addresses all parties concerns and can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan.~~

3.4. Incorporation of Oregon CO_2 Reduction Goals and Coal Plant Retirement Scenarios

Staff states that it is not satisfied with the hard cap scenario analysis conducted to meet the 2007 IRP requirement "to develop a scenario to meet the CO_2 emissions reduction goals in Oregon HB 3543." Staff recommends the following addition to the IRP Action Plan:

For the 2008 IRP update and next planning cycle, develop a more comprehensive inclusion of a hard-cap emissions standard and emission reduction plans, which includes the evaluation of the effect of the closure of coal facilities.

The enhanced System Optimizer model mentioned above will be able to simulate an Oregon-only CO_2 hard cap for all portfolios developed, whereas the version of the model available for the 2008 IRP was not able to model a hard cap unless it was applied to PacifiCorp's entire system. PacifiCorp has also been testing System Optimizer's ability to model plant retirement and retrofit resource options, and agrees to incorporate such options for the next IRP cycle. PacifiCorp's recommended edits to Staff's text are as follows:

For the ~~2008 IRP update and~~ next IRP planning cycle, incorporate an Oregon CO_2 hard cap in portfolio analysis that complies with Environmental Cost Guideline 8d and includes the closure of coal facilities as resource options. ~~develop a more comprehensive inclusion of a hard-cap emissions standard and emission reduction plans, which includes the evaluation of the effect of the closure of coal facilities.~~

3.5. Transmission Financial Analysis and Justification

Staff makes the following recommended addition to the IRP Action Plan:

For the 2008 IRP update and future IRP planning cycle the inclusion of its on-going financial analysis with regard to transmission, which includes: a comparison of alternative supply side resources, deferred timing decision criteria, the unique capital cost risk associated with transmission projects and the scenario analysis used to determine the implications of this risk on customers, and all summaries of stochastic annual production cost with and without the proposed transmission segments, and base case assumptions.

PacifiCorp agrees to continue to provide Staff with ongoing financial analysis regarding transmission as additional key segments of the Energy Gateway strategy unfold. Since PacifiCorp provided Staff with all financial analysis conducted to date, the Company recommends the following edits to Staff's new IRP Action Item:

For ~~the 2008 IRP update and~~ future IRP planning cycles include ~~the inclusion of its~~ on-going financial analysis with regard to transmission, which includes: a comparison of alternative supply side resources, deferred timing decision criteria, the unique capital cost risk associated with transmission projects and the scenario analysis used to determine the implications of this risk on customers, and all summaries of stochastic annual production cost with and without the proposed transmission segments, and base case assumptions.

3.6. Conservation

Staff provides the following recommendation regarding the analysis of conservation:

Staff recommends that PacifiCorp assess its service area-wide study against the Council study in the 2008 IRP update and commission a new system-wide potential study for its next planning cycle.

PacifiCorp provided a comparative assessment of its conservation assessment methodology against the Northwest Power and Conservation Council methodology as Exhibit 2 of the Response to Oregon Party Comments filed on November 3, 2009. PacifiCorp continues to evaluate the Council's methodology in more detail and will incorporate these findings in an updated demand side management potential study to be procured and delivered in 2010 as required by IRP Guideline 6a.

Staff also notes that the IRP does not identify any savings from distribution efficiency measures (voltage reduction), but that the Council's 6th Power Plan incorporates cost-effective achievable potential for this resource type, which was identified in a study conducted for the Northwest Energy Efficiency Alliance ("NEEA"). Staff provides the following recommendation to the Commission:

Staff recommends conditioning the action plan to require PacifiCorp to participate in Commission workshops on distribution efficiency measures, assess the costs and savings of implementing those measures, and set forth an action plan for implementation in next year's IRP update.

PacifiCorp has participated in the utility trial conducted for the NEEA potential study mentioned by Staff. PacifiCorp therefore believes that development of an action plan to investigate distribution efficiency measures is warranted. However, the Company cannot develop an implementation plan before conducting a thorough cost-benefit analysis that considers operational concerns and implementation challenges specific to its distribution system. PacifiCorp believes that the IRP is not the proper forum for development of such an action plan, and recommends that consideration of study timetables and implementation planning be handled as part of a separate Commission proceeding.

3.7. Demand Response Resources

While Staff believes that PacifiCorp has met the requirement in IRP guideline 7 to evaluate demand response resources on par with supply-side and demand-side resources, it suggests that the Company should extend its resource evaluation to cover "the cost and amount of resources from curtailable rates, demand buybacks, and critical peak pricing programs."

PacifiCorp made the commitment in Action Item 7 to continue to evaluate Class 3 DSM programs as potential firm resources for long term planning, and will also update its Class 3 DSM resource characterization as part of a new DSM resource potential study to be conducted in 2010. The Company continues to believe that price-responsive DSM evaluation needs to be handled as part of portfolio scenario analysis rather than as a firm resource.

4. CONCLUSION

PacifiCorp appreciates the opportunity to respond to Staff's Final Comments.

PacifiCorp concurs with nearly all of the analytical objectives identified by Staff in its final comments, and offers proposed modifications to Staff's Action Item language in line with the Company's planned 2008 IRP update filing schedule and development activities for the next IRP. As noted above, the key concern is the large number of new Action Item requirements tied to the 2008 IRP Update, which the Company plans to file with the state commissions on March

31, 2010. As noted in the 2008 IRP and previous public meetings, the Company's portfolio modeling supports a business plan preparation schedule culminating in plan approval in December of each year. Consequently, the modeling activities envisioned by Staff should apply to the 2010 IRP development cycle.

Exhibit 1

Final Short List Development for the All Source Request for Proposals

November 16, 2009

Introduction

This paper describes the proposed modeling approach and decision process used to develop the final conditional short list for the All Source Request for Proposals. The modeling approach has been modified and updated from that proposed in a paper submitted on January 5, 2009, based on input received during the technical conference in Docket No. 07-035-94 held on November 2, 2009.

The modeling approach consists of Steps 2 and 3 of the bid evaluation process, which would be applied after establishment of the initial short list of bidders (Step 1). These two modeling steps are:

Step 2—Portfolio Development/Optimization
Step 3—Risk Analysis
 Step 3a: Stochastic Analysis
 Step 3b: Deterministic Scenario Analysis

These modeling steps will use PacifiCorp's integrated resource planning modeling systems as well as resource portfolio evaluation principles applied for the 2008 Integrated Resource Plan and 2009 Business Plan. The key resource evaluation principle is that of resource robustness. A bid resource is considered robust if it appears in the most cost-effective resource portfolios developed under a reasonably wide range of potential futures, and after adjusting portfolio costs for sources of risk. The three-step bid evaluation process and the application of the resource robustness principle will result in a natural division of eligible proposals which will split the proposals into "top tier" and "bottom tier" groups.

IRP Evaluation process

Step 2: Portfolio Development/Optimization

Purpose
The purpose of this step is to use Ventyx Energy LLC's *System Optimizer* capacity expansion model (previously called the Capacity Expansion Model) to develop optimized portfolios[6] using the bid and benchmark resources, and based on a range of alternative cost assumptions. In addition to portfolio screening for stochastic production cost analysis, this step indicates the

[6] An optimized portfolio refers to a capacity expansion plan that minimizes the present value of revenue requirements (PVRR) over a 20-year period based on the set of input assumptions and planning reserve margin constraints. The capacity expansion plan accounts for the dispatch of both existing and future resource options, factors in amortized investment costs for generation and transmission resources, and solves for the optimal level of spot market transactions for system balancing.

frequency with which bids and benchmarks are selected under alternative futures modeled on a deterministic basis.

Methodology

The starting point for System Optimizer portfolio development is the set of preferred resources and input assumptions from PacifiCorp's 2009 business plan and the 2008 IRP. The preferred portfolio resources, developed assuming a 12 percent capacity planning reserve margin, will be removed as resource options in order to create a capacity deficit that the model must fill with combinations of bid and benchmark resources. (The model is also allowed to select a variable quantity of firm market purchases, or "front office transactions" to ensure that a specified annual planning reserve margin is maintained.) Resource additions past 2020 will be fixed for all portfolios to remove the impact of out-year resource optimization on bid/benchmark resource selection.

The System Optimizer will produce an optimized portfolio for each combination of carbon dioxide (CO_2) and natural gas price assumptions input into the model ("price scenarios"). In addition to a base case price scenario, eleven additional price scenarios will be modeled.

The price scenarios reflect CO_2 tax assumptions ranging from $8/ton to $100/ton, coupled with a range of natural gas price forecasts based on PacifiCorp's official September 30, 2009 forecast price curves. Note that all assumptions will be locked down by the Independent Evaluator ("IE") prior to the receipt of the market bids.

Figure 1 summarizes the combinations of CO_2 and natural gas price assumptions for each price scenario.

Figure 1. 2008 All Source RFP Price Scenario Summaries

Scenario	CO_2 Tax (2008$/ton)*	Natural Gas**
Base	$8	09//30/09 FPC
1	$45	Adjusted 09/30/09 FPC
2	$70	Adjusted 09/30/09 FPC
3	$100	Adjusted 09/30/09 FPC
4	$8	Low
5	$45	Adjusted Low
6	$70	Adjusted Low
7	$100	Adjusted Low
8	$8	High
9	$45	Adjusted High
10	$70	Adjusted High
11	$100	Adjusted High

*The CO_2 tax is applied starting in 2013 for all scenarios. The values listed above are in 2008$. The nominal tax for each year of the forecast period is based upon PacifiCorp's September 2009 inflation forecast.
**For scenarios with CO_2 taxes ranging from $45/ton to $100/ton, natural gas prices are adjusted to reflect changes in electric sector natural gas demand.

Projections for the price scenarios will be developed with a methodology consistent with the approach used to produce PacifiCorp's official forward price curves (FPCs). The methodology relies upon two electric sector simulation models: the Integrated Planning Model (IPM®) and Midas. IPM®, developed by ICF International, is a linear programming market simulation tool with a detailed representation of every boiler and generator in North America. The linear program's objective function determines the least cost means of meeting electric energy and capacity requirements over time. Outputs from IPM® include an internally consistent forecast of resource additions that incorporate renewable portfolio standards, electric energy and capacity prices, natural gas and coal prices, electric sector fuel consumption, and emission prices for policies administered in a cap-and-trade framework. Midas, licensed from Ventyx Energy LLC, is an hourly chronological dispatch model with a detailed representation of supply and demand variables influential to western power markets and is used to develop a long-term electricity price forecast.

The CO_2 tax assumptions used in the price scenarios are assumed to be imposed upon the entire U.S. electric sector. Given the scope of the tax, IPM® is used to simulate the overarching impact upon supply and demand dynamics that are critical to natural gas, electricity, and emission markets. Results from IPM® are then input into Midas to produce an electricity price forecast for those markets accessible to PacifiCorp's system.

All scenarios will be developed from one of three underlying natural gas price projections – either the 09/30/09 FPC, a low price forecast, or a high price forecast. For the scenarios that couple these underlying gas price forecasts with an $8/ton CO_2 tax, IPM® is used to establish a point of reference for electric sector natural gas demand. For those scenarios with higher CO_2 tax assumptions ($45/ton, $70/ton, or $100/ton), IPM® is configured with natural gas supply curves calibrated to the electric sector gas demand from the corresponding $8/ton CO_2 tax scenario. With this dynamic gas price structure in IPM®, natural gas prices are able to respond to changes in gas demand that are triggered by the costs imposed by the CO_2 tax. Consequently, each of the scenarios has a unique natural gas price forecast that is a variant of one of the three underlying projections. Figure 2 shows how scenario variables and model results flow among models.

The market price scenario results for the 2008 IRP portfolio modeling are summarized below. These market prices are provided for illustrative purposes only as they reflect outdated forward price curves. These market price scenarios will be updated based on PacifiCorp's September 30, 2009 official forward price curve and locked down with the IE prior to the receipt of the benchmark and market bids. Figure 3 shows average annual Henry Hub natural gas prices, Figures 4 and 5 show average annual electricity prices for Mid-Columbia, Figures 6 and 7 show average annual electricity prices for Palo Verde, and Figure 8 shows SO_2 allowance prices.

Figure 2. Price Scenario Modeling Framework

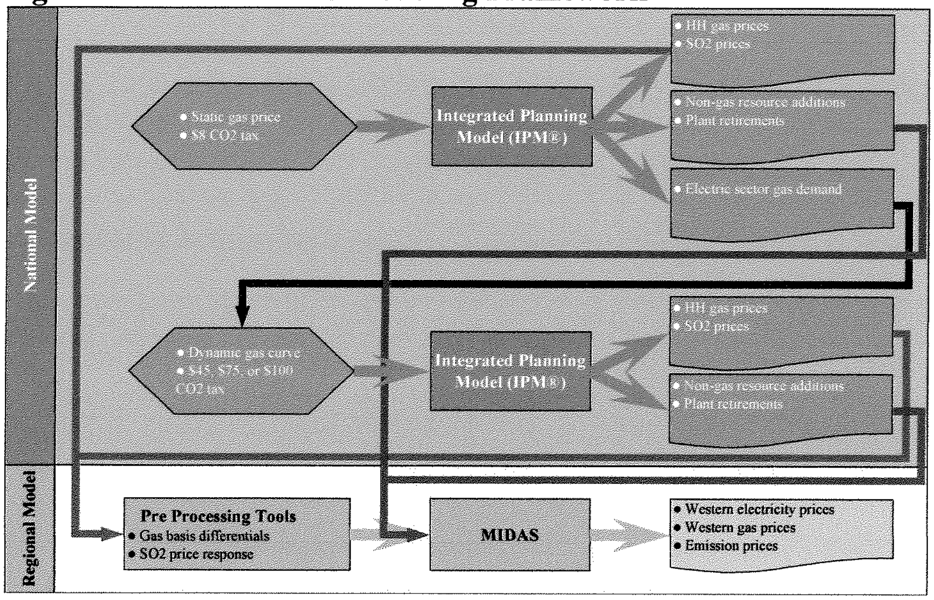


Figure 3. Average Annual Henry Hub Natural Gas Prices

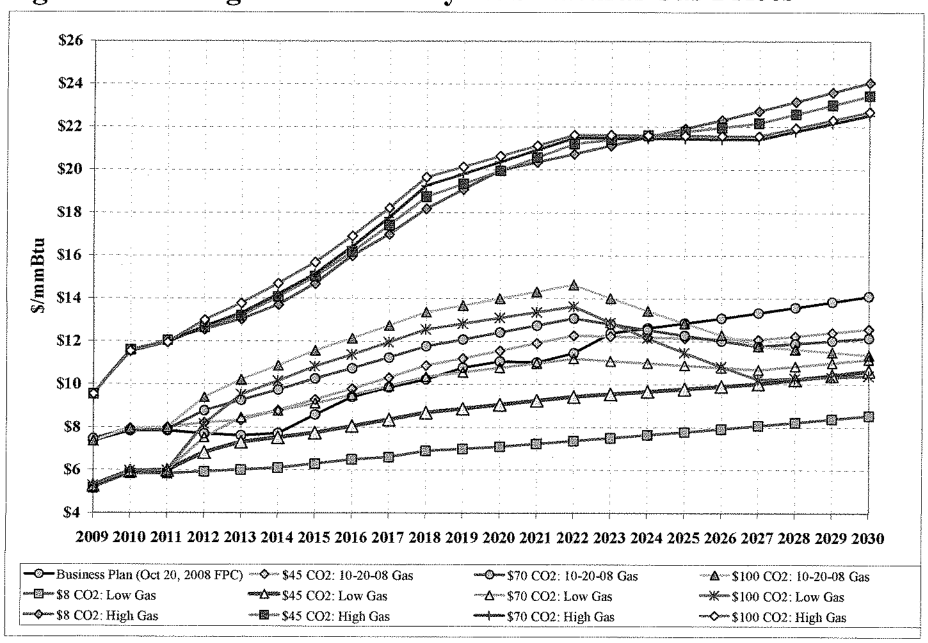


Figure 4. Mid-Columbia HLH Average Annual Electricity Prices

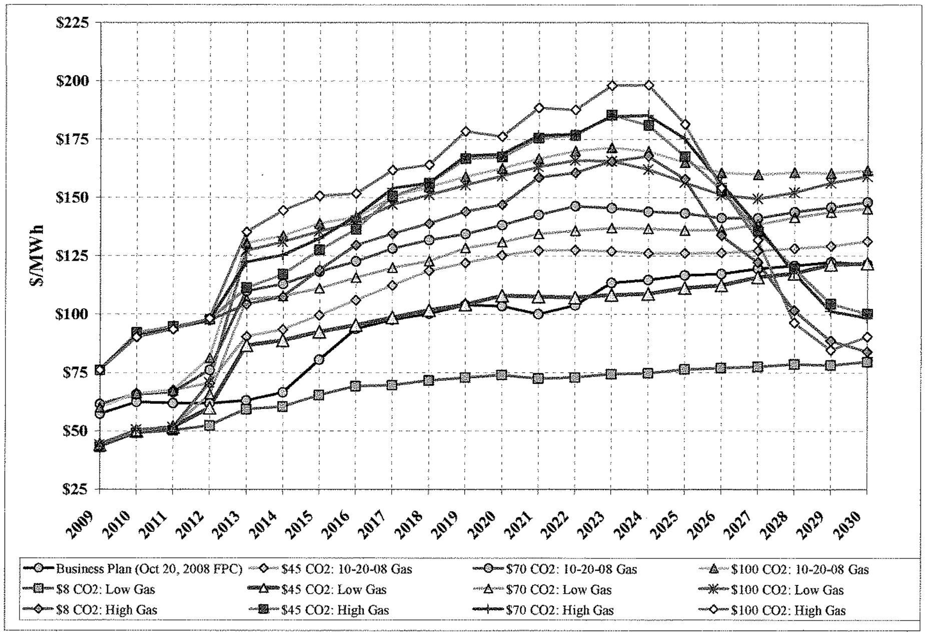


Figure 5. Mid-Columbia LLH Average Annual Electricity Prices

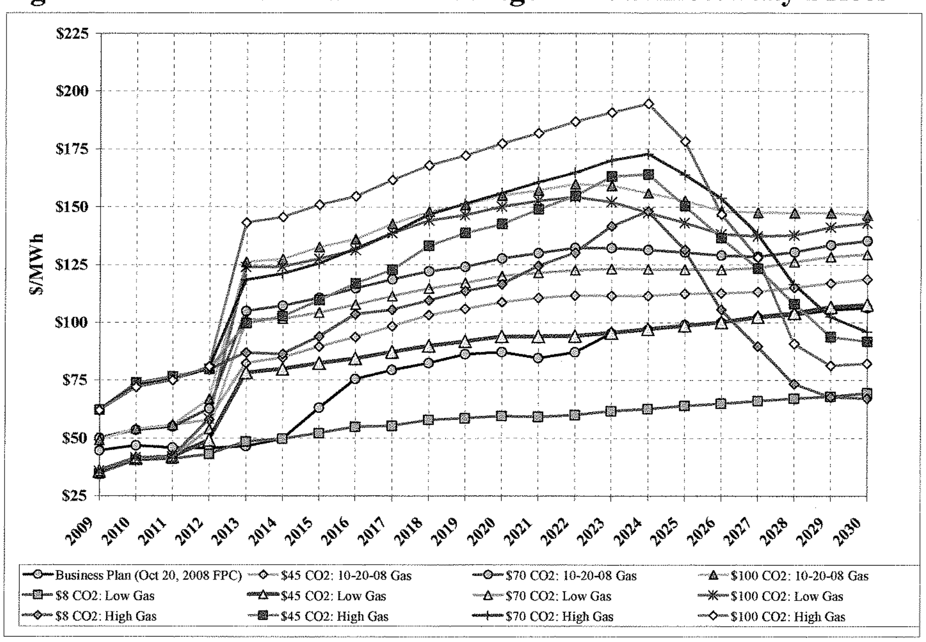


Figure 6. Palo Verde HLH Average Annual Electricity Prices

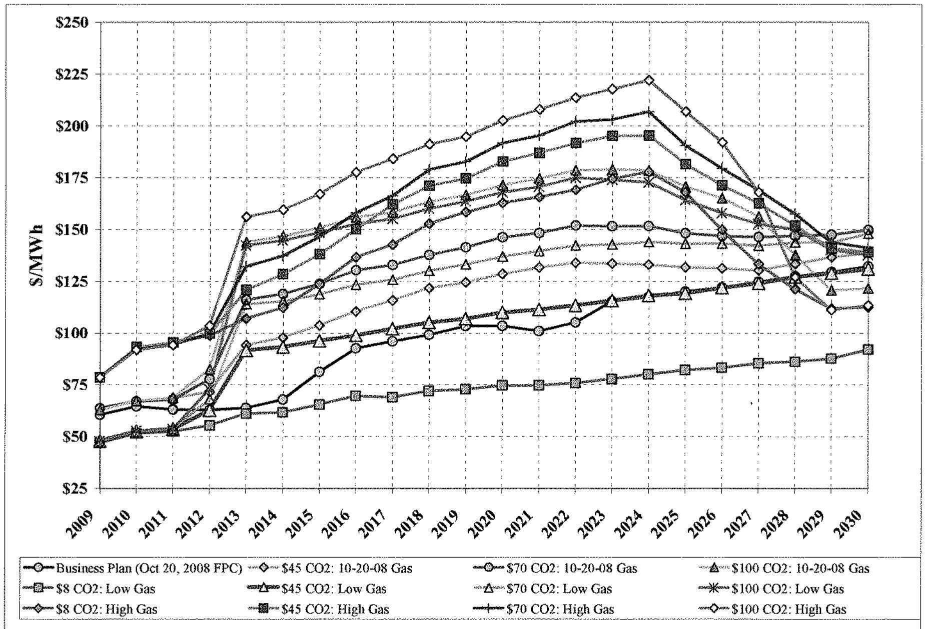


Figure 7. Palo Verde LLH Average Annual Electricity Prices

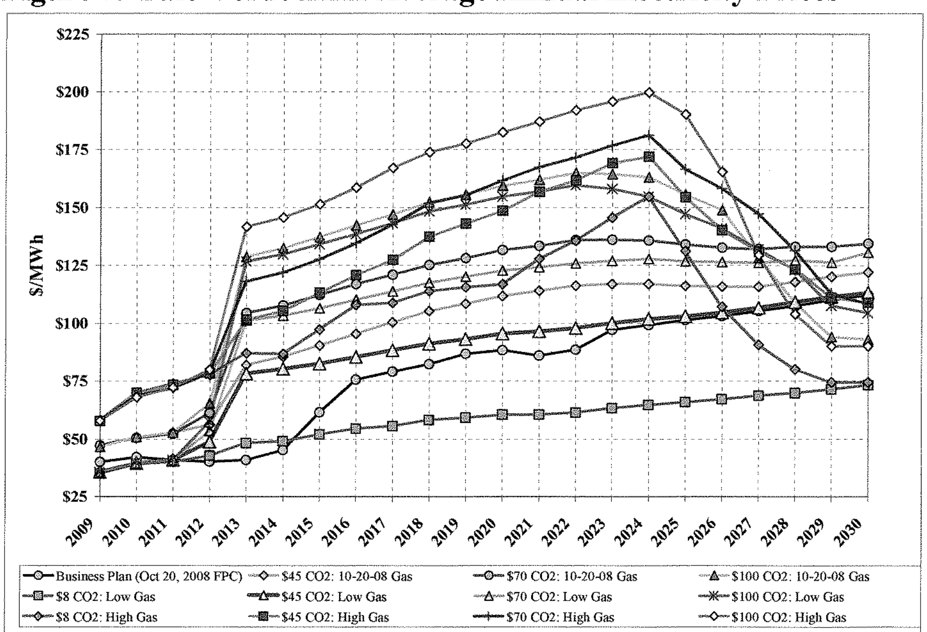
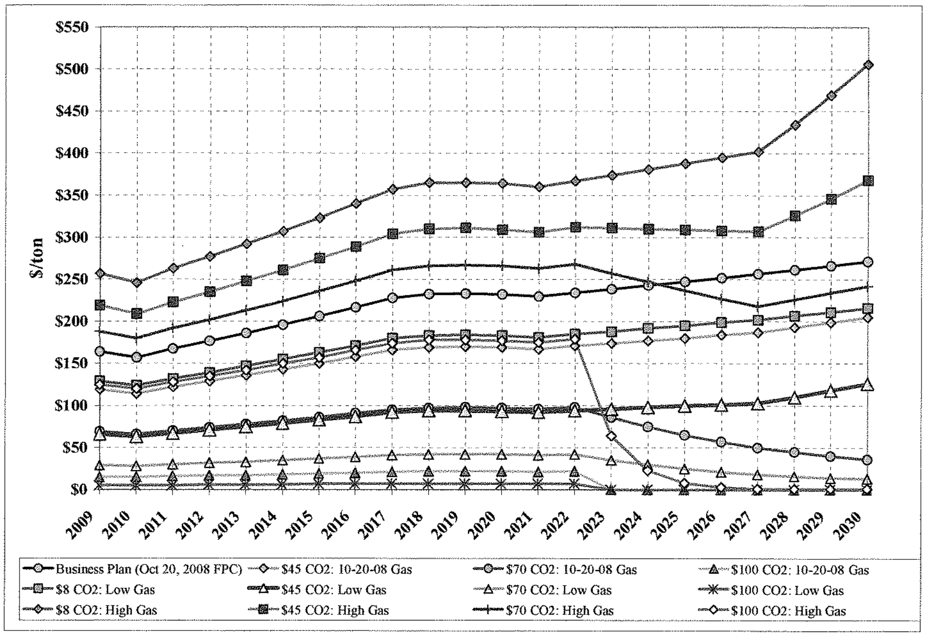


Figure 8. Average Annual SO_2 Allowance Prices



To select the System Optimizer portfolios for the stochastic production cost analysis using the Planning and Risk model, the number of cases will be condensed to groups with unique sets of bid and benchmark resources.

Step 3—Risk Analysis

Step 3a: Stochastic Analysis

Purpose

The purpose of this step is to formulate stochastic cost and risk profiles for each of the unique portfolios developed from Step 2, and then identify the bid and benchmark resources that appear consistently in the top-performing portfolios based on both cost and risk measures.

Methodology

The unique portfolios from Step 2 are simulated using Ventyx Energy LLC's Planning and Risk (PaR) production cost model in stochastics mode. The PaR simulation produces a dispatch solution that accounts for chronological unit commitment and dispatch constraints.[7] Stochastic risk is captured in the PaR production cost estimates by using Monte Carlo random sampling of five variables: loads, commodity natural gas prices, wholesale electricity prices, hydro energy availability, and thermal unit availability for new resource options. The simulation is conducted for 100 model iterations using the sampled variable values.[8] To capture CO_2 emission costs and

[7] In contrast, the System Optimizer does not model unit commitment or the holding of reserves.

[8] Based on a sample size statistical analysis conducted for the 2004 IRP, PacifiCorp determined that 100 iterations exceeded the minimum number needed to be confident (at least at a 95% confidence level) that the sampled iteration mean is close to the true iteration mean. See Appendix G, pp. 98-99, of the 2004 IRP for details on the statistical analysis.

associated dispatch impacts, simulations will be conducted using different CO_2 cost adders.[9] This model set-up is identical to the stochastic simulations conducted for the IRP.

The capital and fixed costs resulting from the System Optimizer portfolio is added to the net variable cost from the PaR simulation to derive a real-levelized PVRR. For each simulation, the stochastic cost and risk measures calculated include the following:

- Mean PVRR – Mean of the PVRR for the 100 simulation iterations
- 95th percentile PVRR – The PVRR of the iteration that represents the 95th percentile for the 100 simulation iterations.
- Customer rate impact – Levelized net present value of the year-to-year changes in the customer dollar-per-megawatt-hour price for 2014-2028.[10]
- Risk-adjusted PVRR – Calculated as the mean PVRR plus the expected value (EV) of the 95th percentile PVRR, where EV = P $(PVRR)_{95}$ x 5%.
- Variable cost standard deviation – A measure of production cost variability risk, calculated as the standard deviation of annual variable costs for the 100 simulation iterations.
- Average annual Energy Not Served – Energy Not Served (ENS) is a condition where there is insufficient generation available to meet load because of physical constraints or market conditions. The stochastic ENS results are averaged across all 100 iterations and reported on an average annual GWh basis for the 20-year simulation period.
- CO_2 emissions footprint – The amount of CO_2, in tons, attributable to generation sources (direct emissions).

The key stochastic performance measure used to assess each resource portfolio is risk-adjusted PVRR. (See Appendix A for a detailed description of risk-adjusted PVRR and the Company's rationale for selecting it as the primary portfolio evaluation measure.) Resource portfolios will be ranked according to the average risk-adjusted PVRR across three CO_2 cost levels: \$8, \$45, and \$100. In the event that the top-ranked portfolios are not materially different based on risk-adjusted PVRR (i.e., the PVRR differences among the top portfolios is less than 0.5%), then the top-ranked portfolios will be re-ordered on the basis of customer rate impact. Use of customer rate impact as a performance tie-breaker recognizes that this measure was given the second-highest importance weight for portfolio ranking for the 2008 IRP.

Individual resource bids in the top-ranked portfolio constitute the final shortlist bids. These short-listed bids will also be ranked according to their frequency of occurrence in the top four portfolios based on the ranking scheme described above.

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[9] PacifiCorp will consider for the next IRP the inclusion of CO_2 cost as a stochastic variable in the Monte Carlo simulations. Study work is needed to ensure that the gas and wholesale electricity price responses to different CO_2 cost levels is properly accounted for in the stochastic simulations. The selection of a stochastic model for CO_2 costs should also be a topic for discussion at an IRP public meeting.

[10] See page 172 of the 2008 IRP for a description of this cost measure.

Step 3b: Deterministic Scenario Analysis

Purpose
The purpose of this final step is to use the System Optimizer to determine PVRRs for the four top-performing resource portfolios under alternative case assumptions. This scenario analysis determines the range of costs that could result given a fixed set of resources under varying gas/electricity price and CO_2 cost assumptions.

Methodology
The resource portfolios will be simulated in the System Optimizer from Step 2, keeping the resources for each set fixed but allowing the System Optimizer to dispatch the resources as part of its least-cost portfolio solution.

Conclusion

PacifiCorp uses a portfolio analysis approach for bid resource evaluation consistent with its integrated resource planning process. PacifiCorp will develop 12 different portfolios using a capacity expansion optimization model that accounts for 12 combinations of key input variables reflecting alternative price scenarios. The optimizations will include the bid and Company benchmark resources as capacity options. A screening process is then applied to limit these portfolios to just those with unique sets of bids and benchmark resources.

The set of 12 optimized portfolios will be subjected to Monte Carlo production cost simulation, incorporating different CO_2 tax levels in each simulation. A measure of risk-adjusted portfolio cost that accounts for high-end risk potential will serve as the key portfolio performance measure. PacifiCorp will select resources from the top-performing portfolio for shortlist development, and will also rank the individual bids according to their frequency of occurrence in the four top-performing portfolios. This two-step ranking approach assures the Company that the shortlist bids are robust performers under a range of potential price futures, and addresses the Utah Independent Evaluator's concerns regarding portfolio ranking.[11] The final deterministic risk assessment step identifies the range of portfolio costs that result when each portfolio is subjected to different price scenarios.

As a result of the bid evaluation process, the conditional shortlist bids will be unblinded and bidders contacted by the Independent Evaluator. The shortlist bids will be required to meet the conditional requirements within 20 business days. The remaining bidders will be advised that they have not made the conditional final shortlist.

[11] Comments of Merrimack Energy as Utah Independent Evaluator Regarding the Methodology for Portfolio/Resource Selection, December 29, 2008.

APPENDIX A: RISK-ADJUSTED PVRR

The purpose of the risk-adjusted PVRR measure is to present a convenient numerical combination of two stochastic PVRR measures regularly reported for resource portfolios evaluated for the IRP and other production cost simulation studies. These two measures are the stochastic mean PVRR, and a measure of high-end cost risk: the 95th percentile PVRR. (The 95th percentile PVRR is the PVRR corresponding to the iteration out of the 100 Monte Carlo production cost iterations representing the 95th percentile.) PacifiCorp also reports a number of other stochastic risk measures such as the upper-tail mean PVRR (based on the five iterations with the highest PVRR), the production cost standard deviation, risk exposure[12] (upper-tail mean PVRR minus mean PVRR), and the 5th percentile PVRR.

The rationale behind the risk-adjusted PVRR is to have a single "risk-adjusted" cost measure for ranking portfolios that avoids the pitfalls of assigning utilities or importance weights for expected cost and high-end cost risk. Deriving such relative value indicators is a complex undertaking that needs to account for the decision-maker's attitude towards risk and uncertainty under a range of alternative futures. A simpler approach that avoids subjective weighting methods is to use the expected value of a high-cost portfolio outcome to adjust the PVRR for risk. The expected value of the 95th percentile PVRR—determined by multiplying the 95th percentile PVRR by its outcome probability, or 5 percent—serves as a reasonable and transparent risk adjustment.

Prior to adoption of the risk-adjusted PVRR measure, the only method used by the Company to combine expected and high-end cost risk concepts was to develop scatter-plot graphs showing mean PVRR versus upper-tail mean PVRR for each portfolio. This graphical method is convenient for visually showing relative portfolio performance with respect to the trade-off between expected and high-end portfolio cost outcomes. However, such graphs do not incorporate information regarding preferences for risk avoidance or cost outcome probabilities, and therefore cannot be used to directly rank portfolios. The risk-adjusted PVRR measure avoids this shortcoming.

[12] This risk measure is no longer being reported in the IRP. The 95th percentile PVRR and upper-tail mean PVRR are viewed as sufficient for capturing high-end cost risk.