Comments of the
NW Energy Coalition
on
DOCKET UE-080826: PacifiCorp's 2008 Integrated Resource Plan
July 1, 2009

The NW Energy Coalition (NWEC or "Coalition") appreciates this opportunity to comment on PacifiCorp's 2008 Integrated Resource Plan ("IRP" or "Plan"). We urge the Commission to maintain a healthy skepticism toward the Company's modeling and not confuse understanding with massive amounts of data. PacifiCorp's huge modeling effort can quickly lead the reader into a labyrinth of details, but we believe there is a fundamental conceptual flaw in how the utility conducted its analysis that calls the whole exercise into question. Until that flaw is addressed, it is difficult for anyone to know whether the Company's preferred portfolio is reasonable.

While we recognize the Commission likely will acknowledge this IRP, we urge the Commission to send a strong signal to PacifiCorp not to pursue a large CCCT in 2014 as its Action Plan suggests, because that plan is based on faulty modeling and analysis. We also provide several recommendations for what we believe are essential improvements needed in PacifiCorp's future integrated resource plans.)

I. Uncertainty is the challenge.

As it is abundantly clear from the huge changes in assumptions in the IRP just since the Company's public process began, uncertainty is the main issue facing this plan. Three fundamental assumptions were changed radically in only the past year: load growth rate, natural gas price forecast, and carbon risk. Changing any one of these assumptions in the magnitude that PacifiCorp felt it had to in order to reflect new developments would have made the task difficult, but having to deal with all three, leads us to question the fundamental approach used.

To illustrate the problem, compared to early 2008 when the planning process began, PacifiCorp's load growth forecast has declined substantially, causing a delay in acquisition of the Lake Side gas plant. Gas prices fell from more than $14/mmBTU to around $3-4 currently accompanied by a similar drop in wholesale power prices. Finally, the US House of Representatives has passed a cap and trade bill, moving the country closer to carbon regulation. These swings in key assumptions that the IRP relies on show that dealing with <u>uncertainty</u> is the fundamental issue for utility planning.

Unfortunately, this IRP is based on a static model, forcing us all to argue that our guess of future conditions is the best. But this is beside the point. Instead of planning resource decisions based on a guess about what the future will look like, we should be planning a system that is best at adapting to an uncertain future that we all know is impossible to predict.

a. Flexibility needs to be valued.

Pacific's IRP fails to value flexibility, because of the basic nature of its modeling. Although the Company may argue that its model does incorporate risk, because it tests many cases, or sample portfolios, against many futures, it misses the point. That is because the model does not reflect the more dynamic way real utilities make decisions.

The model constructs its test portfolios by "optimizing" them against <u>fixed</u> futures. For example, it constructs a portfolio that performs best under a high load growth future; another in a high gas price future; another in a low carbon-cost future; etc. Each of these portfolios (cases) is chosen to do well over a fixed 20-year-long world where assumptions never change. None must deal with a world where load growth is high for 5 years and then slows for three, accelerates for seven, etc., -- i.e., the real world! Thus, a portfolio that is flexible and retains optionality is never tested, nor is flexibility ever valued.

The model does do a limited stochastic test of each portfolio, but this is no substitute for true dynamic modeling. The stochastic test used by PacifiCorp varies assumptions such as gas prices over time, but the values all regress to the base assumption. More fundamentally, this test still does not allow the portfolio to change dynamically in response to changed conditions. So the stochastic test is of very limited value.

In real life, as opposed to this modeling behavior, if conditions changed, the utility's resource decisions would change. If the future started with a low carbon adder and then a few years out changed to a higher adder, no utility would blindly follow its original plan that had been optimized to the low carbon environment. It would shift its strategy to meet the new conditions. And, most important, having a plan that was flexible in the first place would have a higher value in being able to accomplish that shift than a plan that was unable to be changed without high costs.

b. PacifiCorp's methodology means the tail wags the dog.

One unfortunate outcome of the Company's static modeling is that resource decisions made in the later part of the 20-year planning horizon greatly influence the performance of each portfolio—despite the fact that there is little reason to think that the utility would actually blindly acquire those later resources if conditions changed significantly. Each case acquires thousands of MWs of (often different) resources in the second decade of the study horizon. And, the types of those resources are determined on day one of the plan, never to change even though in real life this would never happen.

This flaw is carried into the plan scoring. Each static plan, developed for a particular fixed future, is then tested against other futures—futures for which it wasn't designed. It's final score—mostly its cost—is an average of how it performed against these other futures.

But in real life this would not occur. A plan designed to perform well in one future that then experiences a quite different future would be modified. Its real cost over time would not be the cost of the original plan, but the cost of the modified plan. <u>And to the extent it could be modified, it would perform better.</u> This ability of a plan to be flexible is one of its most important and valuable attributes in real life. But Pacific's model never tests for it.

c. Dynamic modeling.

A much better way to model real utility behavior in the face of uncertainty is the dynamic methodology used by the Power Planning Council ("Council"). The Council model essentially tests <u>initial plans</u> that are modified over time in response to changing futures. The results of this modeling show that actions that increase flexibility, or that have economic benefits regardless of future conditions (such as aggressive conservation), turn out to be more valuable than large capital-intensive and long-lead-time resources that reduce a utility's flexibility.

Can Pacific change its modeling methodology to more closely mirror the Council's? We do not expect the Company to toss out its model at this late date. However, there is a somewhat acceptable surrogate for this that could easily be made.

PacifiCorp should modify its test portfolios (cases) in the following way. All resource decisions beyond the planning horizon—probably 8-10 years or so—should be replaced with one standard resource. This resource could be market purchases (or what Pacific calls Front Office Transactions, or FOTs) or a generic CCCT—being the same for all portfolios means the decision is not important. That is, every portfolio would look the same in its later years. By doing this, we get a much more realistic comparison of the costs of the initial resource decisions, unaffected by later decisions that will most likely change to respond to future conditions anyway.

This solution would still not correctly value the risk benefits of flexibility—something that the Council's does—but it would at least prevent resource decisions that occur after many years, and that are most likely to be changed, influencing the near-term resource decisions that must be made in the early years.

The Coalition also proposes that the Commission require that future IRPs incorporate an "inflexibility adder" or other mechanism to reflect the added risk that long-lead-time, capital intensive projects impose on the utility, if it is impossible for the Company to move to a dynamic methodology such as the Council's.

II. Other considerations that call for modification of this Plan.

The Coalition believes the scoring system is flawed. Ultimately the final decision was between two portfolios—#5 (actually portfolio "5B_CCCT_Wet) and #8B—with the former eventually being selected as the Preferred Portfolio. The key differences between the portfolios are that #8B acquires about 900 MWs (nameplate) more renewables and

260 MWs less gas. Also, #5B_CCCT_Wet acquires a sequestered coal plant toward the end of the planning horizon, a decision that need not be made now, and whose costs should not influence this decision, as we discussed above. The reasons that bring us to the conclusion that the scoring system is flawed are as follows:

a. Wind cost declines not accounted for – On p. 99, the IRP notes that, "…subsequent to completion of its 2008 IRP portfolio analysis in late 2008 and early 2009, the Company has witnessed price declines for wind turbines…. These cost declines were not incorporated in portfolio cost estimates." Since the high cost of turbines used in this IRP is 40% over the last IRP, due to tight turbine supplies that no longer exist, the failure to lower their costs disadvantaged #8 (and 8B).

b. Value of early renewable acquisition not accounted for – The Company's modeling of carbon costs did not account for auctioning or banking of allowances for which early construction of additional wind turbines would provide benefits.

c. Wind integration costs are way too high – First, we note that Pacific's estimate of $11.75 is about twice as high as the wind integration costs used by BPA and the Council. The Company came to its high cost for integration by making a number of errors in its analysis:

- PacifiCorp sets the transaction costs of rebalancing energy in the hour ahead schedule as, "…up to twenty-five percent of the per MWh energy costs," (p. 274, Appendix F) due to needing transactions in very small 1-MW increments. But Pacific fails to justify why it must go to the market for this resource when it owns multiple gas-fired units that could provide this service without incurring any transaction cost.

- The Utility calculates the cost of carrying incremental reserves to integrate wind by calculating the incremental cost of running partially loaded gas turbines, which is a reasonable assumption. However, the cost calculated--$7.51-$9.40 per MWh, depending upon CO_2 cost—is unreasonable, as a simple example shows.

  Generally speaking, for most hours, gas-fired generators are on the margin in the Western interconnect. To provide the approximately 450 MWs of reserve requirements shown in Table F.5 (p. 276, Appendix F) requires, as a simplifying assumption, that the utility run that amount of single-cycle fast reacting resources in order to provide these reserves. This incurs a cost, for without this integration requirement, the utility would instead have relied upon more efficient combined cycle units. The per-MWh cost difference between an Aero SCCT and a CCCT, due to their heat rate difference of about 2,000 BTU/kWh, is approximately $8/MWh at current gas costs of about $4/MMBTU. Applying that cost to the 450 aMW of needed reserves gives a total cost of: $8 * 450 * 8760 ≈ $31 million per year. Spreading that cost to the 2,734 MWs of wind operating at a 31%

capacity factor equals: \$31 million/(2,734 * 8760 * 31%) ≈ \$4.20/MWh, less than half of the Company's result.

- Also, the cost calculated in the previous bullet assumes that the Utility hold 450 MWs of both up regulation and down regulation at all times. But this is not how the utility would operate its system. During hours when the wind isn't blowing, there is no need for up regulation, and when the wind is blowing hard, there is little need for down regulation. Only during times of moderate wind must both up and down regulation be available, but then only for about half the full amount. Thus with some fairly simple operating protocols, the total amount of reserves needed can be reduced significantly—perhaps by a third—lowering the total cost further.

d. Scoring criteria and weightings are arbitrary and not reflective of ratepayer concerns – PacifiCorp relied upon a complicated scoring and ranking method to choose its preferred portfolio. Table 7.8, p. 175 summarizes the weighting scheme. We see problems in several areas.

- Customer Rate Impact (20% weight) measures year-to-year variability of utility costs, both up and down. Year-to-year variability of utility costs is not a valid risk metric. This kind of variability is not really a big concern for customers for a number of reasons. First of all, a downward drop in costs is a benefit, not a detriment to ratepayers, so half of the measured "risk" is really a benefit . Second, year to year cost variations are mostly a management concern. There are many ways to deal with stochastic cost changes besides yearly rate adjustments, including balancing accounts. Resource plans should not be chosen with this type of measure being given such a large weight in the scoring. Risk of concern to customers is high cost outcomes not utility cost variability year-to-year.

- Production Cost Standard Deviation (5%) is also a measure of volatility, not poor outcomes. It is not an appropriate risk measure since it assigns and counts risk as both high and low-cost iterations, even though low-cost outcomes are beneficial. It also counts as negative a distribution with very low mean but wide distribution around that mean. Standard deviation is a measure of the spread of cost outcomes (and only the production cost part of total costs), not the risk of high outcomes. The fact that standard deviation is a poor risk metric was discussed at length during the last IRP, and the parties agreed that some sort of upper-tail or 95th percentile risk measure was more appropriate. We are troubled to see it reappear in the Company's analysis.

We recommend that these two measures be dropped from the scoring completely. It is interesting to note that when the Company tested an alternative ranking (p. 228-9) that reduced the weight for Customer Rate Impact and raised the weight for CO2 Cost Exposure, a weighting we believe is justified, the ranking of the top two portfolios reversed. Therefore it is important that the Commission address this issue further to see the results of other weightings on the ranking.

- $0, $45 and $100/ton CO2 tax levels are weighted equivalently. While we favor including a $0 level to better understand the influence of carbon adders, we oppose weighting the $0 level equally with $45. There is simply no way that carbon will be ignored over the next 20 years, and assuming that there is a one-third possibility that that will be the case is irresponsible.

  While some might argue that the same reasoning applies to the $100 ton level, we could not disagree more. The science is leading us rapidly to the conclusion that the urgency and magnitude of the climate crisis is worsening. It well may result in policies such as early forced shutdown or severe dispatch limits to the Company's many coal plants that are essentially equivalent to carbon adders above $100.

- No scoring weight is given for optionality. As discussed earlier, NWEC believes that dealing with uncertainty is one of the principal challenges in planning. This conclusion is evident from the fact that at the last minute PacifiCorp needed to model a number of additional significantly different portfolios (pp. 235-240) because of changes in the load growth forecast. The new portfolios either delayed or eliminated the 544 MW 2012 Lake Side gas plant that had essentially been hard-wired into all the tested portfolios.

  The final selected portfolio, 5B_CCCT_Wet, was chosen over 5B and 8B, similar portfolios without the added gas plant, based on very small Present Value of Revenue Requirement (PVRR) differences amounting to roughly $100 million or about $8 million per year. Given the Company's overall revenue requirement, this amount is lost in the statistical noise. However, by choosing to build the plant, the decision limits PacifiCorp's options. Had the scoring valued optionality in even a small way, it is obvious that 5B or 8B would have been chosen instead. Ultimately, NWEC is convinced that portfolio #8B would be the best choice for PacifiCorp.

III. Conclusion and Recommendations.

The NW Energy Coalition is concerned that this IRP's flaws make it impossible to objectively evaluate the Company's resource options. It relies upon a static modeling methodology that creates two problems. First, it causes resource choices made in the second decade of the study to influence the performance of near-term choices, even though it is obvious that when it is time to make those later choices, the utility will not blindly stick to its original plan. Second, it fails to value resource plans that are more flexible and leave the utility with the ability to "change horses in mid-stream" if needed, at low cost.

In addition, PacifiCorp has chosen to use a ranking system that gives significant weight to measures of volatility, rather than to poor outcomes, and to a $0 carbon adder outcome that is extremely unlikely.

These flaws make it difficult for us to judge whether or not the Company's preferred portfolio is the best plan. That said, we could be somewhat less concerned with these modeling problems, except for PacifiCorp's determination in Action Item 3 to acquire a 570 MW CCCT by the summer of 2014. Except for this item, the Action Plan makes no long-term bets on large-scale fossil fuel plants, pursues DSM fairly aggressively, and steadily acquires new wind.

We are also troubled by the 2014 CCCT decision when looking at Table 8.3 (p. 189) that gives the usage factors of each resource by portfolio. We note that portfolio #5, for example, which includes the Lake Side plant, results in a gas plant utilization of only 40% over the 2013-20 period, and portfolio #8 uses its gas plants only 28% during this time. Most of the other scenarios show similarly low usage. Is it prudent to build more gas plants when the Company's existing ones run so little and the Council is predicting a large surplus in the region caused by a combination of low load growth, aggressive conservation and RPS renewables?

Given the uncertainty the Company faces in the next few years we urge the Commission to make these findings:

1. Acknowledge the Action Plan, but highlight serious skepticism for the need for item #3, the acquisition of a large CCCT in 2014. This plant could be safely delayed further through a small increased reliance on market purchases (FOTs). Delay is valuable, since it keeps options open to changes in technology, regulation, load growth and other factors.

2. Require PacifiCorp to adopt a modeling methodology for future IRPs that values flexibility and reduces the impact of later resource decisions (that are likely to be changed depending upon conditions in the future) on the selection of its preferred portfolio.

3. Direct PacifiCorp to avoid using measures of volatility, such as standard deviation or year-to-year change, as a substitute for better risk measures such as upper tail risk in future IRPs.

4. Discourage PacifiCorp from giving much weight to very low carbon adders, given emerging climate science.

Thank you,

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and you should simultaneously submit a pdf as well, plus a cover letter to David Danner, Executive Director and Secretary, WUTC simply saying that you are submitting the attached comments in Docket UE-080826 regarding PacifiCorp's Integrated Resource Plan. The whole bundle gets submitted to the Records Department at the WUTC (records@utc.wa.gov). Let me know if you want help submitting!