TO: Utah Public Service Commission
CC: PacifiCorp
FROM: U.S. Intermountain Clean Energy Application Center
DATE: March 24, 2011

The U.S. DOE Intermountain Clean Energy Application Center appreciates the opportunity to provide the following comments and recommendations on PacifiCorp's 2011 Integrated Resource Plan, in particular regarding the consideration of cogeneration and CHP.

The U.S. DOE Intermountain Clean Energy Application Center provides education, technical assistance, and policy support to promote greater adoption of clean and efficient energy generation and use through recycled energy (including cogeneration / combined heat and power (CHP), district energy, and waste heat recovery). We serve the southwestern states of Arizona, Colorado, New Mexico, Utah, and Wyoming. The center is jointly run by the Southwest Energy Efficiency Project (SWEEP) and the ETC Group. Funding is provided primarily by the U.S. Department of Energy's Industrial Technologies program, with additional funding from state energy offices and utilities throughout the intermountain region.

We support PacifiCorp's intent to ensure adequate and reliable electricity supply at a reasonable cost and in a manner consistent with the long-run public interest. As such, we appreciate cogeneration's brief inclusion in the 2011 Integrated Resource Plan and but argue that it should play a more substantial role – especially customer-sited cogeneration.

Both utility-owned and customer-owned cogeneration should be more heavily relied on in the short-, medium- and long-term to meet PacifiCorp's widening capacity deficit.

We see that cogeneration is currently included in the IRP in several ways:

- As "utility cogeneration," defined as bottoming-cycle systems contracted at customer sites
- As biomass and as anaerobic digesters (which does not have to be deployed in a cogeneration mode but often is)
- In a distributed generation section drawing from Cadmus' updated potentials study

One of the primary reasons that customer-owned cogeneration should have a larger role in meeting future load requirements is because many of the benefits accrue to the grid without much of the costs accruing to the ratebase. Although PacifiCorp's 2011 Integrated Resource Plan uses Total Resource Cost, which includes the owner's cost, this effect on the ratebase is a key point worth mentioning.

Cogeneration investors assume 100 percent of the capital risk when they install their power plant, as compared to utility investments, which spread their risk across all electric consumers. Thus, ratepayers realize all the benefits of good private sector investment decisions while bearing almost none of the risk for bad private sector investment decisions.

Seen from the perspective of resource planning, this means that a grid that maximizes customer-owned cogeneration will also realize the maximum social benefit per dollar of rate base capital investment. Note that this is true no matter what the economics of the cogeneration system are, since in virtually all cases, those investments are made with unregulated dollars.

In addition, customer-sited cogeneration typically does not require transmission from low-load areas to high-load areas as many other distributed resources do, and this too should make the cogeneration resources an attractive in resource planning.

Using cogeneration as a key resource in meeting future load growth can and should be accomplished not only through promotion of cogeneration to suitable customers but also through the removal of barriers preventing otherwise-economic installations. For instance, we would strongly support a review and revision of standby rates to ensure they reflect the actual probability of cogeneration downtime and recoup the actual, documented costs incurred by PacifiCorp to maintain the backup capacity. Additional barriers should also be addressed, such as ensuring interconnection is accomplished without delays and increasing the length of power purchase agreements to 20 years. Each of these efforts will directly contribute to increasing the amount of cogeneration and therefore decreasing the capacity gap illustrated in the IRP for future years.

Other regional utilities have and are aggressively including CHP in their integrated resource plans. For example Idaho Power's 2009 IRP states "Idaho Power's commitment to continue investigating CHP projects is evidenced by an agreement signed in November 2009 with the Idaho Office of Energy resources and Amalgamated Sugar…. The Agreement establishes the framework for a CHP feasibility study to be performed at Amalgamated Sugar's Nampa, Idaho facility that could be as large as 100 MW." We suggest that PacifiCorp could actively pursue similar efforts with large industrial customers, particularly in its Wyoming service territory (where currently no utility CHP opportunities are modeled, see below).

We have the following additional concerns, comments, and questions:

Resource Needs Assessment (Chapter 5)

- Table 5.11 on page 62 shows that electricity from QFs is not expected to increase at all on the west side, and only after 2013 on the east side. What is the basis of this assumption? Since the number of cogeneration installations is gradually increasing across the country, it may increase in PacifiCorp's territory as well. While we understand it is difficult to estimate the amount of electricity from future and prospective resources for which PacifiCorp has no control, nevertheless QFs provide a valuable resource that should be a strong part of PacifiCorp's plan for meeting future load growth.

Resource Options and Attributes: Supply-Side Tables (Chapter 6)

- Some of the cost and performance characteristics listed for large solid oxide fuel cells look overly optimistic, and from our experience, are not borne out by actual installations in the field. These numbers appear in both the East Side and West Side tables (table 6.1 and 6.2 respectively), and the tables that follow. For example, capital costs are listed there as being between $1,513 and $1,912 per kW. The capital costs data for fuel cells listed in the distributed generation section ($4,583 per kW) seem more on par with reality, and while these might be a different type and size of fuel cell, they are in the right ballpark for what we would expect.

- Wyoming does not have any utility cogeneration opportunities listed in the East Side table, but we think there may be sites or applications that have been overlooked in your analysis.

- Similarly, please review utility cogeneration opportunities in the West Side. There are likely utility cogeneration opportunities in the West Side regions, yet the entire category of utility cogeneration is omitted from the West Side table.

- "Utility cogeneration," which seems to refer to bottoming-cycle cogeneration contracted at customer sites, is included as a supply-side measure in the supply-side tables, but topping-cycle cogeneration at customer sites is not. Instead, topping cycle cogeneration seems to appear in a later distributed generation section. We suggest that they be listed and detailed in the same place.

Resource Options and Attributes: Distributed Generation (Chapter 6)

- Page 40 of the plan states that distributed resources are assumed to have a 14% administrative charge, included in their costs. We are not clear on why customer-owned cogeneration would incur this charge, considering all the costs for customer-sited cogeneration (back-up capacity, interconnection, etc.) are always passed on to the customer and not subsidized by the utility nor the ratepayers. We would appreciate an explanation of what costs are included in the 14% that are not currently paid by the customer.

- Table 6.7 lists the average capacity for a reciprocating engine in Washington as 0.01 MW (10 kW). We find this highly unlikely. Throughout the rest of the country, reciprocating engines used in cogeneration range from 0.0012 MW to 5 MW, with an average capacity of 0.59 MW and a median capacity of 0.225 MW. In Washington state, existing installed reciprocating engines range from 0.15 MW to 4.7 MW, with an average capacity of 0.96 MW and a median capacity of 0.39 MW. (Source: ICF International Combined Heat and Power Installation Database at http://www.eea-inc.com/chpdata/index.html and personal communication with ICF staff)

- Similarly, the capacity for gas turbines seems extremely low at 60 kW; in fact, that's more range of a microturbine rather than a gas turbine. The existing stock of gas turbines used for cogeneration across the country range from 0.006 MW to 100 MW, with an average capacity of 16.70 MW and a median capacity of 5.2 MW. In Washington state, existing installed reciprocating engines range from 2.83 MW to 68.0 MW, with an average capacity of19.07 MW and a median capacity of 7.52 MW. (Source: ibid)

- Table 6.7 states that gas turbines were not modeled. We are unclear why not, given that they represent a very common, reliable, practical, cost-effective, and well-understood option for cogeneration. For example, customer owned gas turbine co-generation systems operating in Utah, include a 6.5 MW system at the University of Utah and a 14 MW system at the North Salt Lake Tesoro Refinery. If the reason is because they were misrepresented as having an average capacity of 0.06 MW (as discussed above), then we respectfully request the analysis be re-done with more realistic numbers included.

- Anaerobic digesters that supply renewable fuel for cogeneration (or electric-only) quite often exceed 50 kW. Although this size might be suitable for a dairy or other small-to-medium-sized concentrated animal feeding operation (CAFO), other anaerobic digesters such as at larger CAFOs or urban wastewater treatment plants could be several hundred kilowatts, several megawatts, or more. Since we were not able to find the study on which these numbers were based, we are unable to look into the types of anaerobic digester potential sites that were included. As such, given the information we have available, we have to question the average capacity of 50 kW.

- The IRP states on page 40 that federal tax incentives are only included at a rate of 10% for anaerobic digesters and 10% for industrial biomass. It might be worth noting that systems completed by January 1, 2014 should qualify for a 30% federal investment tax credit. (Source: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=1&ee=1, confirmed with personal communication with DSIRE staff)

- Given the number of inaccurate and/or questionable data points in the distributed generation analysis as discussed above, especially in regards to the capacities, we cannot have confidence in the conclusions of the distributed generation section or how they are incorporated into the entire IRP.

Resource Options and Attributes: Resource Option Description (Chapter 6)

- The terminology used is confusing and could stand to be clarified. Page 64 states:

  > CHP are a small (10 MW or less) gas compressor heat recovery system using a binary cycle. These projects would be contracted at the customer site. They are labeled as Recovered Energy Generation (CHP) and utility cogeneration in the supply-side table.

  There are several confusing elements therein. First, the term "CHP" in common usage includes both topping cycle and bottoming cycle CHP systems, but this definition seems to only include bottoming cycle systems. Cogeneration, too, typically includes topping cycle as well as bottoming cycle but only appears to be bottoming cycle here. Next, we could not find any mention of "Recovered Energy Generation (CHP)" in the supply-side table or in the text, except for a brief mention in the list of acronyms on page 30 and in a table on book life on page 74. Further, despite saying "CHP are a small (10 MW or less) gas compressor heat recovery system using a binary cycle…" page 64 later goes on to describe small CHP as entirely different. The terminology regarding CHP and all its iterations should be carefully reviewed for consistency and clarity, and its uses in chapter 6, the supply-side section, and the distributed generation section should be given a re-write.

Additional Comments

- Although the IRP mentions an update of the 2007 demand-side management and dispersed generation potentials study, we were not able to find a copy of this updated study. We would like to review and comment on the findings of that study, to ensure that the numbers it fed into the IRP are accurate and reasonable.
- A number of states and utilities are now including CHP/cogeneration as an energy efficiency / demand-side management measure, either though a dedicated CHP program, inclusion of CHP within a larger commercial and industrial program, or as an eligible custom measure. We strongly recommend that PacifiCorp do this in both the east side and west side territories. In regards to the integrated resource plan, this would boost the total resource available through DSM.
- In the future, we would like to see biogas and waste-heat-to-power (recovered energy generation) resources included in any high-level renewable generation study (such as the one mentioned on page 30 for solar, biomass, and geothermal). Biogas is included in most state renewable portfolio standards, and waste-heat-to-power is increasingly being included as well. It’s worth noting that they both qualify for Utah’s renewable portfolio goal. In addition, biogas and waste heat are both baseload, non-intermittent resources, and as such, can provide compelling benefits to a utility in meeting an RPS while maintaining stable and predictable supply.

The U.S. DOE Intermountain Clean Energy Application Center appreciates the opportunity to file these comments.

Respectfully submitted,

Patti Case
Executive Director
U.S. DOE Intermountain Clean Energy Application Center