UTAH CLEAN ENERGY
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To: IRP Mailbox
From: Utah Clean Energy
Subject: Comments regarding 2011 IRP—August 4, 2010 Public Input Meeting
Date: August 26, 2010

Utah Clean Energy appreciates this opportunity to submit comments pursuant to the Company's invitation for comments regarding the initial Public Input Meeting for the 2011 IRP. We agree with the Public Service Commission's Standards and Guidelines for Integrated Resource Planning that "Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah."[1] We look forward to more productive information sharing as this process progresses and appreciate this opportunity to request and share information.

Demand-side Management
Slide 5 of the presentation from the last public input meeting indicates that critical peak pricing and time of use will be modeled; please explain how PacifiCorp is modeling critical peak pricing (CPP) and time of use (TOU).

Distributed Generation
Our comments regarding distributed generation refer to information provided during the public input meeting and to the updated memo from Cadmus group dated August 11, 2010, *Overview of PV Inputs and Data Sources*. For additional information, please see the comments submitted by various parties on August 4, 2010 regarding the on-site PV assumptions provided by Cadmus.

Administration Costs for PV Rebate Program
The current proposal for the administrative cost of a solar rebate program is 15% of the incremental costs, which Cadmus defined as the Total Resource Cost for solar PV. As we mentioned in our August 4 comments on the solar assumptions, 15% of the total resource cost appears to be very high as compared to other solar rebate programs (see below). We have included an excerpt from Utah Clean Energy's original comments submitted on August 4, 2010, below:

> Utah Clean Energy requests that Cadmus and PacifiCorp provide the assumptions that will be used to determine "the cost to the utility to administer a solar PV incentive program" (referenced on page 1 of the Cadmus memo) and the reasoning behind these assumptions.

[1] Procedural Issue 2, *Standards and Guidelines for Integrated Resource Planning for PacifiCorp, Utah Jurisdiction*, Docket No. 90-2035-01

In the August 4, 2010 IRP Stakeholder meeting, Cadmus and PacifiCorp indicated that the assumption for administrative costs would be 15% of the total program cost, and it would be helpful to understand the rationale behind this amount. We also suggest referencing other successful utility solar incentive programs as a comparison when determining the appropriate administrative cost assumption.

As was reported in the 2009 Annual Report, the total administrative costs of the RMP Pilot Program equal approximately 30% of the total program costs.[2] The administrative costs of such a small program are extremely high compared to the total program costs, which likely negatively impacts on the overall cost-effectiveness of the pilot program. In addition, the 2009 and 2008 Annual Reports on RMP's Pilot Program indicate that the program is consistently unable to fulfill annual allocations in the prescribed time frames, posing challenges to program administration, as noted: "Annual program allocations pose an on-going administrative burden related to communications, chronological processing requirements, etc." and "lead times on waiting list projects and timing of canceled projects both post challenges to fully allocating annual program incentives."[3] It is likely that a more expanded program, redesigned to be administratively straightforward and efficient, would benefit from economies of scale and would lower the administrative costs and burdens.

Other utility solar incentive programs across the country explicitly cap administrative costs at 5-10 percent of the total program costs;[4] for example, the Colorado Solar Incentive Program caps administrative costs at 10 percent.[5] Administrative costs in this range seem more reasonable and presumably reflect program efficiencies that any modeled utility solar program should aim to achieve.

We believe that an administration cost of 5-10% of total program costs is more reasonable and in line with the actual costs of running a solar rebate program.

Levelized cost calculations
As requested by Utah Clean Energy and other parties, we would like to see levelized cost equations and inputs. This information will be valuable in our review of this analysis.

[2] Docket No. 07-035-T14:In the Matter of the Approval of Rocky Mountain Power's Tariff P.S.C.U. No. 47, Re: Schedule 107 – Solar Incentive Program. Rocky Mountain Power. Utah Solar Incentive Program 2009 Annual Report. *Table 1. 2009 Program Installed Capacity and Expenditures*. Page 5. URL: http://www.psc.utah.gov/utilities/electric/elecindx/2006-2009/07035T14indx.html
[3] Rocky Mountain Power. Utah Solar Incentive Program 2009 Annual Report. Page 8.
[4] Communication with Chris Cook, Managing Director of SunWorks and Board of Directors of Interstate Renewable Energy Council. 26 April 2010.
[5] Matthew Baker, Commissioner, Colorado Public Utilities Commission. Presentation: *Colorado's Renewable Portfolio Standard, Making it a Success*. EUCI RPS Planning & Implementation Conference. San Francisco, CA. 15 August 2008. Slide 7.

Solar cost data
We understand that solar photovoltaic costs have dropped dramatically in the last year and it is therefore difficult to get current and accurate price information. Utah Clean Energy and a number of parties have provided comments regarding the sources and price assumptions provided in the Cadmus memo, which seem to be much higher than current market prices. Please refer to previous comments provided by stakeholders. Additionally, since our initial comments were filed, we have become aware of additional cost data and cost analysis by Lazard, dated June 2010. This information is copyrighted and as soon we obtain permission to distribute the Lazard analysis, we provide the data to the IRP team and stakeholders. For rooftop systems, the Lazard analysis showed the total capital costs ranging from $4,000 to $4,500 per kW for rooftop systems and $3,500-$4,000 per KW for utility scale and ground mount systems.

Comments on Cadmus Table 2: Comparison of Installed Costs for PV Systems in the US, revised August 11, 2010.
Table 3 indicates an inverter efficiency of 95% (therefore it is our understanding that a 1 kW AC system equals a .95 kW DC system). However, Table 2 indicates that the costs of DC systems are multiplied by a factor of 1.2 (an increase of 20% for the conversion to AC). We are unclear why, if the inverter efficiency is 95% (a 5% loss in the conversion from DC to AC), the cost is increased by 20% for the conversion from DC to AC in Table 2. Please explain the reasoning for this.

Supply-side Resources
Ramping capacity
As additional renewable resources are added to PacifiCorp's portfolio, it will be increasingly important to assess ramping requirements necessary to accommodate naturally variable renewable resources. In evaluating necessary ramping capabilities, it is important to recognize that ramp-rate is not the only relevant factor; that is, although individual units may have limited ramp-rates, the cumulative ramping capabilities across the whole system may be able to provide significant ramping capabilities. Utah Clean Energy encourages PacifiCorp to undertake an evaluation of the ramping capabilities of their current portfolio to determine the amount of additional ramping capacity.

Utility-scale solar
Utah Clean Energy requests more information regarding the solar assumptions provided at the public input meeting (slides 18-19) in order to better evaluate and comment on them. Specifically, please provide the following: capital costs assumptions; capacity factor assumptions by geographic area for different solar resource types: thin film solar PV, crystalline solar PV, solar tracking systems (both crystalline and thin film).

Proposed Portfolio Development Cases
Utah Clean Energy appreciates the opportunity to comment on the draft portfolio development case definitions and we look forward to discussing these more at the next public input meeting.

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Utah Clean Energy is interested in making sure that a representative variety of portfolios selected by the system optimizer model—not just the lowest cost portfolios—are selected to undergo subsequent risk analysis. We are concerned that the selection of certain portfolios could pre-empt the eventual risk analysis of other portfolios that might be more expensive within the system optimizer model but could perform more favorably during Planning and Risk analysis. In prior IRP proceedings, the bulk of portfolios selected for risk analysis were very similar in resource composition; for example, the portfolios did not include solar or significant amounts of risk-mitigating renewable and demand-side management resources.

To that end, we think it is important that not only least cost portfolios progress to Planning and Risk analysis, but also unique portfolios. (For example, it is likely important to send high gas price/high carbon price scenario on to PaR analysis.) Please explain how PacifiCorp will ensure that a wide range of portfolios will undergo Planning and Risk analysis.

We are additionally concerned that the initial selection of portfolio development cases, because of its limited size, is necessarily somewhat arbitrary. Utah Clean Energy recognizes that running the system optimizer model is time intensive, and therefore it is impractical to have too large a selection of development cases; however, we nevertheless request an explanation of the rationale upon which the initial set of portfolio development cases was based, in order to evaluate the appropriateness of the range of portfolio development cases presented in the July 28 Draft. A lack of time, alone, is an insufficient reason for selecting an un-representative or unlikely selection of portfolio scenarios.

For example, please explain the rationale behind including Core Cases 4, 13, and 22, which assume high carbon costs and low gas prices. In reality, it is unlikely that gas prices will remain low given increased demand for this relatively lower-carbon resource in a high carbon-cost scenario (especially if economic growth is medium or high, as is assumed in Cases 13 and 22).

Additionally, please explain why all the DSM expanded potential cases (Cases 42-47) run assuming that both gas prices and economic growth will be low.