State of Utah

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To: PURPA Work Group List, Docket File

From: Carol Revelt

Date: November 22, 2006

Re: Minutes of the November 9, 2006, Technical Conference on 2005 EPAct Amendments to PURPA – Time-Based Metering and Communications Standard - Docket 06-999-03

Attendees:

Rocky Mountain Power:	Dave Taylor, Jeff Larsen, Doug Marx, and Bill Griffith
Utah Rural Electric Association:	Mike Peterson
Utah Clean Energy:	Sara Baldwin
Utah Clean Air Coalition:	Kathy VanDame
UIEC:	Vicki Baldwin
Moon Lake Electric:	Stewart Olsen and Chad Jacobson
Smigel, Anderson & Sacks:	Scott DeBroff
Division of Public Utilities:	Judith Johnson, Andrea Coon, Sam Liu
Committee of Consumer Services:	Cheryl Murray
Public Service Commission:	Carol Revelt

On November 9, 2006, a technical conference was held in room 210 of the Heber Wells building with the purpose of discussing the time-based metering and communications standard included in the 2005 Energy Policy Act ("EPAct") amendments to the Public Utility Regulatory Policies Act ("PURPA"). During this conference an agenda, an updated draft recommendation for the fuel sources standard, and a draft recommendation for the time-based metering and communications standard were distributed, all of which are attached to this document. The following summarizes the items discussed during this technical conference.

I. Fuel Sources Standard and Fossil Fuel Generation Efficiency Standard

The Division provided a brief update on the status of the recommendations regarding the fuel sources and fossil fuel generation efficiency standards. Comments were received from various parties on the fuel sources standard; however, the Division is waiting on the Company to provide a recommendation for the fossil fuel generation efficiency standard. During this discussion the Company recommended the fossil fuel generation efficiency standard be adopted as written and that the issue would be addressed in the Company's Integrated Resource Plan (IRP). The Company also believes the standard should be addressed in terms of the total fossil fuel generation portfolio over a 10 year time period – not specific plans for individual units. The Company will provide wording which will be circulated to the group. The group agreed to submit comments on or before November 20th.

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Follow-up

- By November 20, 2006, provide to Judith comments on:
  - The proposed standard fossil fuel generation efficiency standard in light of the Company-supplied comments/information and the Division's proposed draft recommendation.
  - Should the Commission adopt the standard, decline to adopt the standard, or adopt a modified standard? If you propose to modify the standard please provide modified wording.
  - Review IRP standards and guidelines and provide comments as to whether it addresses the standard.
- Judith will the compile and circulate comments and a recommendation. Based upon the comments on the compiled document it will be determined if consensus on the issue has been reached.

II. Review of Purposes of PURPA and Language in EPAct specific to the Time-based Metering and Communications Standard.

Commission Staff provided a quick review of the three purposes of PURPA, all of which could apply to the time-based metering and communications standard: 1) conservation of energy supplied by an electric utility; 2) optimization of the efficient use of facilities and resources by electric utilities; and 3) equitable rates to consumers.

With respect to the 2005 EPAct language, the requirements for prior state actions applicable to this standard were reviewed as follows:

- Prior state actions are only applicable to this standard if:
  - the State already implemented the standard or a comparable standard;
  - the proceeding considering implementation of the standard or comparable standard was within the previous 3 years; and
  - the State's legislature voted on implementation of the standard or comparable standard within the previous three years.

III. Time-Based Metering and Communications Standard

(A) Not later than 18 months after the date of enactment each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's cost of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

(B) The types of time-based rate schedules that may be offered under the schedule referred to above include, among others –

i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such *consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;*

ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

(C) Each Electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

(E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.

(F) *Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).*

After reviewing the standard and the draft proposal, general discussion included the following:

- The Company stated that it believes it is meeting and in compliance with this standard in that they offer time-based rates to all applicable rate schedules. The Company considers seasonal rates a form of time-based rates. The time-of-day rate schedules currently available were developed during the PURPA evaluation for Standard 3 – Time of Day Rates (see Docket 81-999-03). The Company pointed out the following language in (A) of the standard, the interpretation of which could vary: "*. . . The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.*"
- Time of-day rates for residential and small commercial customers are voluntary. Time-of-day rates for customers with usage greater than 1MW are mandatory.
- The Company voiced that case studies across the country indicate there has to be a fairly substantial price differential in order for time-based metering to be effective, i.e. the Charles River Associates ("CRA") Study completed for the California Public Utilities Commission indicated that large price differentials were necessary for reductions in the 10% to 15% range (Press control and click on the following link to view the complete study: http://www.energy.ca.gov/demandresponse/documents/group3_final_reports/2005-03-24_SPP_FINAL_REP.PDF).

- The Company commented that time-of-use ("TOU") pricing must be mandatory for everyone in order to achieve major usage changes.
- Installing infrastructure (not just the meter) is a big component of the cost of smart metering. Equipping rural areas, where low densities of customers exist, with smart meters increases the system cost per unit. The company indicated that system-wide time-based metering with communications cost per meter would be approximately five times greater than the cost of a single setup.
- What is the goal of the TOU rate?
    - Match cost and usage – probably reflects marginal cost usage.
    - Better price signals which would encourage a reduction in usage during high price periods.
- The big unknown is to what extent mandatory TOU rates in the Company's service territory would result in customers changing usage behavior, especially at the residential level. Based upon the Company's current rate structure is there enough of a financial incentive to change behavior? Are there other ways to achieve the goal of reducing peak usage in Utah?
- There was quite a bit of discussion on rate Schedule 2 – Optional Time-of-Day Residential Service as follows:
    - Schedule 2 has an enrollment limitation of 1000 customers.
    - In the Company's Schedule 2 Analysis Report submitted to the Commission in December of 2005, the Company indicated that 85% of the people surveyed think that this rate schedule is important to have.
    - One person commented that the Schedule 2 program could be more effective by modifying the design of the program as it may be too confusing to customers.
    - One person commented that the Time-of-Day rate could be advertised differently – like the Blue Sky program which is very hassle free. The goal of the Blue Sky Program, however, is not to change behavior.
    - Is the time-of-use program the best was to shave the peak? It provides a price signal but do customers really change their behavior?
    - Cool-Keeper, air conditioner load control with about 60,000 customers enrolled, is a great program and is relatively hassle-free. The Company has shaved 65 MW off the daily peak with this program. During the heat wave this summer the load dropped 200 MW from Cool-Keeper and Power Forward Programs.
    - Does Cool Keeper apply to the big box stores?
    - Moon Lake representatives indicated that they require smart meters for some customer classes. Some of these customers found smart metering inconvenient and that there is a large educational component necessary for someone to change their usage.
    - One commenter speculated that those companies that could change their usage patterns in response to TOU rates have already changed them.
    - Some parties stated that TOU rates need to be mandatory – otherwise you end up with a self-selection process in that the people enrolled would have lowered their usage anyway.
- The EEI report on deciding on smart meters states that in 1985 a NE utility had 26,500 customers on time of use rates but that number dropped to 100 in 2005. Maybe people "wear out" on the program. (Press control and click on the following links to view EEI reports on smart metering:

http://www.eei.org/industry_issues/electricity_policy/federal_legislation/deciding_on_smart_meters.pdf and http://www.eei.org/industry_issues/electricity_policy/federal_legislation/responding_to_epact.pdf)

- A representative of Smigel, Anderson, and Sacks indicated that he represents two companies and is involved in 18 proceedings regarding this standard, each of which is different. He also provided the following comments:
  - PURPA was developed in 1978-1980 time frame as a reaction to energy prices.
  - Technology has evolved drastically surpassing what was available in the 1980s during the initial time-of-day rate standard assessment.
  - There are many different ways to approach this – critical peak pricing, real time pricing, day ahead, hour ahead, capacity credits for large customers, etc. Technology allows for calculating all of these prices.
  - There are different avenues for shaving the peak -- the question is "What is the right mix for each utility in a specific state?" What is the holistic picture (e.g. direct load control complemented with smart metering)? There is value in smart metering for other than just billing – i.e. disconnecting customers, knowing where system failure might occur, etc.
  - There is an educational piece associated with all of these methods – the awareness campaign and training cannot dissipate over time. There is a direct correlation with the success of program and education – i.e., it is the crafting of the program that makes it successful.
  - The major questions is "How do you develop a program and blend requirements such that the utility benefits, there is value to ratepayers for the utility to take action, and the Commission finds the proposal just and reasonable?"
  - He believes that this standard requires the commission to do something – pilot programs, promotion, curtail usage, etc.
  - Virginia has not adopted the standard. Dominion and AEP have voluntary programs.
  - Need to recognize the difference between:
    - Smart Metering – fully automated with capability for instantaneous reads – lots of registers in the system to collect data. Ability for the customer to know pricing.
    - Advanced metering – set up for one per month or daily or weekly.
    - Automated meter – meters set up with remote for drive/by readings.
- In Utah, part of PacifiCorp's metering system is local – but there are two "backbone" locations for the system – one in Salt Lake City and one in Oregon. Who would pay for smart metering with respect to the MSP if one state requires it (and possibly a modification to the backbone system) and others do not?
- Cost recovery is a big concern. There would have to be a sound business case for a system-wide smart metering initiative in order for it to be approved. The Commission would have to have the appetite to require this change for which there would be substantial costs. Historically, Schedule 6 was broken into Schedules 6 and 8 because the costs for the meters were large. On schedule 6 there are about 40,000 customers without profile meters.

- The costs for the Automated Meter Reading project were justified through “hard” benefits only, i.e., safety/liability, improvements in meter reading, efficiency, call center benefits, etc.
- The Division stated that the group should not only focus on the wording of the standard but also the spirit of the standard. Is there something other than smart metering that could accomplish the same goals? If the standard is adopted would the company need to do anything?
- There is a requirement in the Rate Case Stipulation pending before the Commission whereby commercial and industrial customers would look at the peak (Press Control and click on the following link to access the stipulation http://www.psc.utah.gov/elec/06docs/0603521/ExhibitA-Stipulation%208-25.doc.).
- There was discussion about what constitutes the analysis required by this standard. Most parties voiced the opinion that the technical conference addressed the analysis requirement. The Division talked about:
  - The purpose of the standard
  - Goals that time-based metering could help meet.
  - Benefits to reduced peak usage.
  - What could be an equivalent standard
  - Costs and benefits. This could be part of the investigation of whether or not to adopt this standard.
  - Is this the analysis or does something else need to be completed.
- One commenter indicated that the topic of how to achieve/increase customer energy efficiency is beyond what is required by PURPA and should be addressed in a separate docket.

Follow-up

- By around November 27, please provide comments to Judith on the attached draft standard recommendation – i.e. should the Commission adopt the standard, decline to adopt the standard, or adopt a modified standard? If you propose to modify the standard please provide modified wording.
- Judith will then circulate the proposed revisions to the group and request comments addressing whether we should:

IV. Future Technical Conferences

Future technical conferences addressing the new PURPA standards are scheduled as listed below, for which a Commission notice was issued on November 17, 2006. Both conferences will be held in room #401 of the Heber M. Wells Building.

1) Monday, December 18, 2006 at 1:30 p.m. – Interconnection*
2) Wednesday, January 10, 2007 at 1:30 a.m. -- Net Metering

*Patti Case requested I circulate the document at the link below dealing with a survey of interconnection rules prepared by the Regulatory Assistance Project for the Oregon Public Utilities Commission. Press Control and click on the following link to access this document http://www.oregon.gov/PUC/admin_rules/workshops/interconnection/20survey.pdf

The Commission’s Calendar can be found by clicking on the following link:

http://www.psc.utah.gov/calendar.html

Agenda

PURPA Time-Based Metering and Communications Standard
November 9, 2006

I. Short discussion on recommendations for fuel sources and energy efficiency standards
   a. Fuel Sources Standard proposed joint recommendation
   b. Energy Efficiency Standard progress – need for additional information

II. Purpose of PURPA, Time-Based Metering Standard, and Other Requirements

III. PacifiCorp's response to the discussion items as identified during the October 6, 2006, Work Group Meeting

IV. DPU response

V. Other parties response

VI. Next Technical Meetings:
   a. Interconnection: December 18 @ 1:30 p.m.
   b. Net Metering: January 10, 2007 at 1:30 p.m.

Discussion Items Identified during the October 6, 2006 Work Group Meeting

a. The purpose of the standard.
b. Address whether any current standards in place in Utah are equivalent/comparable.
c. Prior state actions (already have much of this information) and their effectiveness.
d. Recommendation regarding adoption of the standard.
e. Criteria and measurements to determine utility adherence to the standard.
f. Identify issues to be addressed in the Energy Efficiency Docket (discussed below).
g. Other considerations specific to the standard

FUEL SOURCES STANDARD RECOMMENDATONS
Working Document
November, 2006

<u>IV. PURPA Fuel Sources Standard:</u>

Each electric utility shall develop a plan to minimize dependence on one fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

Q. PURPOSE OF THE STANDARD?

A. Having diverse fuel sources reduces risk of shortages, high costs, or regulatory actions that could accrue to any of the fuels. Thus potential future costs and reliability problems could be alleviated if the utility did not depend unduly on one fuel. The standard discusses both fuels and technologies. Technologies that manage load could also be considered a source of fuel diversity. (See Reference Manual, page 51, section 4.2.3.1.2.1; Energy price risk mitigation for generators, for a discussion of the load management option.)

Q. CURRENT STANDARDS IN PLACE IN UTAH THAT ARE EQUIVALENT?

A. The IRP Standards and Guidelines, issued on June 18, 1992, as part of the order in Docket No. 90-2035-01, set out for PacifiCorp the standards and guidelines for its planning process.

We consider the Standard and Guidelines to be equivalent to the proposed standard. The following excerpt from the Standard and Guidelines address the same issues as raised by the proposed PURPA fuel source standard. The Utah standard calls for an "optimal set of resources given the expected combination of costs, risk and uncertainty". We consider the standard which calls for an optimal set of resources superior to minimizing dependence on one fuel source. Optimizing takes into account the risk of dependence on one fuel source as part of the cost and benefit analysis of the fuel source mix.

The Utah standard also addresses the part of the PURPA proposed standard that calls for generating from a diverse range of fuels and technologies including load management programs. We have provided the excerpt from the IRP Standard and Guidelines, section 4bi,ii,iii that we believe are equivalent to the PURPA standard.

1. Definition:

   Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. **The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.**

   4. PacifiCorp's future integrated resource plans will include:

      a. …

      b. An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.

i. An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.

ii. An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.

iii. The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.

Q. RECOMMENDATION REGARDING ADOPTION OF THE STANDARD.

A. We recommend that the Utah Public Service Commission find that the IRP Standards and Guidelines is an equivalent standard; therefore, the PURPA proposed standard will not be adopted for Utah. [Since the IRP S&G is for PacifiCorp only, do we want to recommend that the Commission make note that the S&Gs would apply to any electric utility under the PSCs authority?]

We also recommend that the Company specific utility IRP contain a section that explicitly details the fuel sources plan. Requiring an electric utility to produce an explicit plan derived from the IRP will keep the utility's focus on working towards the goal of a optimum diversified portfolio and allow the public and regulators to provide feedback and to monitor its progress.

We recommend that the explicit plan include both fuels and technologies. For example, coal is a fuel source but clean coal is a different technology and therefore should be treated as a separate fuel source. (Reference Manual, page 56, section 4.2.4.2.2, Regulatory risk, last paragraph, for a discussion of how technologies can impact different types of fuel sources.) Further, cost effective technologies that manage load should also be considered a source of fuel diversity.

Q. RECOMMENDED CRITERIA AND MEASUREMENTS TO DETERMINE UTILITY ADHERENCE TO THE STANDARD?

A. We recommend that an explicit 10 year plan be included in each IRP. The plan should include fuel sources in five year increments; five years before today, today, five years in the future and ten years in the future. We recommend that categories should go beyond simply stating the percentage of generation from natural gas, coal, hydro, wind and purchased power to include technologies that, for example, differentiate types of coal generation, or programs used to manage demand by cutting peak and total demand. Further, we recommend that that the plan be detailed to explain how it would be achieved and include a cost benefit analysis to support the reasons why the utility considers the plan to be optimal.

Working Document
Time-Based Metering and Communications Standard
Division of Public Utilities
November 9, 2006

I. PURPA Time-Based Metering and Communications Standard:

(A) Not later than 18 months after the date of enactment (February 8, 2007) each electric utility **shall offer each of its customer classes**, and **provide individual customers upon customer request**, a **time-based rate schedule** under which the rate charged by the electric utility varies during different time periods and **reflects the variance**, if any, in the utility's **cost of generating and purchasing electricity at the wholesale level**. The time-based rate schedule **shall enable** the electric **consumer to manage energy use and cost through advanced metering** and communications technology.

(B) The types of time-based rate schedules that may be offered under the schedule referred to above include, among others –

v) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;

vi) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

vii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

viii) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

(C) Each Electric utility subject to subparagraph (A) **shall provide each customer requesting a time-based rate with time-based meter** capable of enabling the utility and customer to offer and receive such rate, respectively.

(D) Refers to timing

(E) Applies to third-party marketers

(F) …each State regulatory **authority shall**, not later than 18 months after the date of enactment of this paragraph **conduct an investigation** in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).

II. Analysis

A. Purposes of the standard

   a. EPAct Title I purposes (as stated in the 1978 law) addressed by the standard
      i. Conservation of energy supplied by electric utilities
      ii. Optimal efficiency of electric utility facilities and resources
   b. Possible goals that time-based rates could help meet
      i. Reduced peak load demand
      ii. Increased reliability
      iii. More efficient use of current capacity
      iv. Reduced total demand
      v. Mitigated price spikes
      vi. Mitigated market power
      vii. Lower consumer bills
      viii. Reduced emissions

B. Prior state actions addressing the standards and whether they can be considered comparable

   a. This standard is different than the others regarding prior state action.
   b. "For the smart metering standard (EPAct section 1252), the prior state action by the state commission or unregulated utility must have been conducted in a proceeding considering implementation of the standard or comparable standard *within the previous three years* before enactment, or the state's legislature voted on implementation of the standard or comparable standard also with the previous three years before enactment (EPAct section 1252(i))." From Reference Manual pages 32-33

C. Costs and benefits associated with the standard
    a. Costs
        i. Investments in technology and administration to implement
        ii. Consumer education – changing consumer behavior to gain benefits
        iii. Balancing of risk, inconvenience, production interruption
    b. Benefits
        i. To the extent that it meets the goals above
    c. Analysis is required to determine whether smart metering benefits for all customers would outweigh the costs of providing.
    d. Analysis is required to determine what type of demand response meters and programs to what class of customers would be most effective in meeting the goals listed.

D. Recommendations regarding adoption of the standards
    a. An analysis could not be completed in time to determine whether smart metering benefits for all customers would outweigh the costs of providing demand response programs.
    b. Therefore we recommend it not be adopted since the standard must be implemented by February 2007.
    c. However, we recommend that a study be immediately conducted to decide if an equivalent standard should be adopted. This recommendation complies with subparagraph F.

E. Criteria and measurements to determine utility adherence to the standards if adoption is recommended
    a. To be determined by study