Office of the Secretary
Service Date
October 6, 2006

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S CONSIDERATION OF THE FIVE AMENDMENTS TO SECTION 111 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 (PURPA) CONTAINED IN THE ENERGY POLICY ACT OF 2005	)	**CASE NO. GNR-E-06-02** **NOTICE OF MODIFIED PROCEDURE** **ORDER NO. 30146**

On July 28, 2006, the Commission issued a Notice of Inquiry to consider the five "new" PURPA standards contained in the Energy Policy Act of 2005. More specifically, the Energy Policy Act (EPA) amended Section 111 of the Public Utility Regulatory Policies Act of 1978 (PURPA) by adding five new federal ratemaking standards for electric utilities. The five new PURPA standards are: net metering; fuel source diversity; fossil fuel generation efficiency; time-based metering and communications ("Smart Metering"); and interconnection services to customers with onsite generating facilities. The Commission directed the three largest electric utilities (Avista, Idaho Power and Rocky Mountain Power) to answer a series of questions set out in the initial Notice. The Notice required that the utilities serve their comments on a service list of interested persons.

The Notice also scheduled a public workshop that was convened on September 13, 2006. The purpose of the workshop was to review the utilities' responses to the questions in the Commission's Notice. The Commission also sought to determine whether there was consensus among the participants about whether the Commission: (1) had already adopted the standards; (2) should adopt the federal standards or comparable standards, if not already adopted; or (3) should not implement the federal standards. The Commission also indicated in the initial Notice that it would seek additional written comments following the public workshop. This Notice invites the second round of comments regarding the five PURPA standards.

BACKGROUND

This is not the first time that Congress has required state commissions to examine national regulatory standards. In 1978 Congress enacted PURPA to encourage the conservation of energy supplied and to promote the optimum efficiency of utility resources. Order No. 30108 at 2. The five new standards address energy efficiency, metering and customer generation.

Although the EPA requires the Commission to undertake a review of the new federal standards, the Act does not compel the Commission to adopt the standards. PURPA recognizes that nothing "prohibits any State regulatory authority . . . from making any determination that it is not appropriate to implement any such standard. . . ." Order No. 30108 at 2 *citing* 16 U.S.C. § 2621(a) (emphasis added). The EPA also recognizes that a state regulatory commission may have already implemented the new federal standards or comparable standards in prior proceedings. 16 U.S.C. § 2622(d)-(f). If a State has already reviewed a new standard – by implementing the standard/comparable standard or has considered the standard but declined implementation – then no further action is necessary. *Id.*; 16 U.S.C. § 2621(c)(1).

In undertaking our review of the five federal standards, PURPA outlines the procedural requirements that the Commission must follow. The Commission shall issue a public notice of its review proceeding and make its determination regarding each of the five standards for each regulated utility: (1) in writing; (2) based upon findings and evidence presented in the proceeding; and (3) make its findings available to the public. 16 U.S.C. § 2621(b).

THE PUBLIC WORKSHOP

The following parties attended and participated in the public workshop: Avista, Idaho Power, Rocky Mountain Power, Hunt Technologies, the Industrial Customers of Idaho Power, Distribution Control Systems, John Weber, Jay Blackhurst, and the Commission Staff. The participants reviewed each of the five federal standards and the utilities' responses to the questions set out in the Commission's Notice of Inquiry. As described in greater detail below, the participants reached consensus that the Commission has already implemented four of the five federal PURPA standards.

For purposes of this round of comments, the five federal standards are listed below as set out in the EPA and the Commission's Notice of Inquiry issued July 28, 2006. Following each standard is a brief "discussion" of the standard and the list of initial questions put to each utility. Both the discussion and the list of questions were contained in the initial Notice. *See* Order No. 30108. After the list of questions, the Commission has summarized the utilities' responses and provided a summary of the workshop discussions. The utilities' entire comments are available for public review during regular business hours at the Commission's offices and are also available on the Commission's website at www.puc.idaho.gov under the "File Room" icon.

Click on "Electric Cases," and then click on the case number shown on the first page of this document.

THE FIVE FEDERAL STANDARDS

Net Metering

> (11) Net Metering. Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term "net metering service" means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

1. Commission Discussion. Net metering generally refers to customers generating their own electricity with any excess being delivered to the utility's distribution system. In essence, the customer's utility meter records the flow of electricity to and from the customer.

In 1997 the Commission approved its first net metering tariff for Idaho Power (Schedule 84). Order No. 26750. In August 2002, the Commission issued Order No. 29094 expanding net metering to all Idaho Power customers and increasing the size of the permissible generating facilities. Avista and Rocky Mountain also have net metering tariffs (Schedules 62 and 135, respectively).[1]

We direct each utility to answer the following questions:

1. Briefly describe your net metering program.

2. Are all customers eligible to participate in your net metering program? If not, why not? Are there limitations on the number of participating customers or the amount of net metering generation? Are there restrictions regarding the type of net metering generation?

3. State the number of net metering customers by customer class.

4. State the amount of net metering generation by customer class.

[1] On June 19, 2006, Avista filed a revised Application seeking authority to amend its net metering provisions and move the net metering provisions to Schedule 63. Case No. AVU-E-06-4. In Order No. 30111 issued August 10, 2006, the Commission approved Avista's Application.

> 5. Does your current or proposed net metering tariff/schedule meet the federal net metering standard set out above? If not, should the Commission adopt this standard or a comparable standard?

2. Utilities' Responses. The utilities responded that they each have a net metering program in place that is available to all customers. The framework of each utility's net metering program is similar in that they: (1) offer net metering to customers using solar, wind, hydropower, biomass or fuel cells; (2) limit the program to .10% of their retail peak generation; (3) limit residential customers to facilities no greater than 25 kW; and (4) restrict any one customer from generating more than 20% of such peak generation. Avista has four residential net metering customers in Idaho producing 16,000 kW during 2005. The Company's net metering Schedule 63 was most recently approved August 1, 2006.

Rocky Mountain currently has one residential net metering customer but has several potential projects pending. The Company's net metering generation ceiling is 714 kW. The Company's net metering Schedule is 135.

Idaho Power has 20 residential customers, 4 small business customers, and 2 large business customers. The 24 smaller customers generated 397,255 kW in 2005. The Company has an application pending to modify its net metering Schedule 84. In Case No. IPC-E-06-17, Idaho Power proposes to change the net credit for net metering generation to 85% of the avoided cost contained in Schedule 84. Comments in that proceeding are due October 13, 2006.

3. Workshop Comments. The utilities and the participants generally agreed that the utilities' net metering programs meet the federal net metering standard. One participant did express a concern that existing net metering customers may be detrimentally affected if they installed generating facilities based upon existing net metering rate structures, and the utility subsequently changes the program.

Fuel Sources

> (12) Fuel Sources. Each electric utility shall develop a plan to minimize dependence on 1 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.

1. Commission Discussion. This standard may have already been implemented in Idaho. In Order No. 22299, we required Avista, Idaho Power, and PacifiCorp (or their predecessors) to bi-annually prepare and file an integrated resource plan (IRP). Each IRP

describes the Company's expectation for load growth and provides an overview of available resource options, including "conservation resources, demand-side resources and other potentially low life-cycle-cost resources." Order No. 22299.

A review of the current IRPs reveals that each utility employs a diverse range of generating resources including renewables. For example, Rocky Mountain's current 2004 IRP reflects the addition of demand-side management (DSM) resources, coal and natural gas thermal generation, combined heat and power generation, wind, geothermal, distributed generation, etc. Notice of Filing, Case No. PAC-E-05-2 (June 30, 2005); *see also* Order Nos. 29614 (Idaho Power) and 29887 (Avista). Thus, it appears that the IRP process minimizes dependence on a single fuel source and our utilities employ a diverse array of fuels and technologies, including renewables. The utilities should comment on whether this standard has already been implemented by the Commission as part of the IRP process.

2. Utilities' Responses. The utilities observed that the Commission's Order No. 30108 asked whether this standard may already have been implemented as part of the IRP process. Each utility indicated that fuel source diversity is part of their respective IRPs. The utilities concluded that this new PURPA standard has already been implemented by the Commission as part of the IRP process.

3. Workshop Comments. The participants agreed that diversifying generating fuel sources was evident by each utility's resource stack in their IRPs. Consequently, the participants agreed that the Commission has already implemented this federal standard.

Fossil Fuel Generation Efficiency

> (13) Fossil Fuel Generation Efficiency. Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

1. Commission Discussion. This standard promotes the efficiency of fossil fuel generating facilities. All three utilities have fossil fuel (coal and natural gas) generation facilities. Increasing the efficiency of existing generating resources may already be a part of the IRP process. The utilities should comment on whether increasing fuel efficiency is already a part of their respective IRPs. If not, should the Commission require that the issue of fossil fuel efficiency be included in the bi-annual IRPs?

2. Utilities' Responses. The three utilities assert that fossil fuel efficiency is a part of their IRPs. For example, Avista noted that examining fossil fuel efficiency is a part of the ongoing review process performed by the Colstrip owners committee. Idaho Power noted that since 1995 it has implemented 18 MW of generation efficiency upgrades. The utilities maintained the Commission need not take further action on this standard because it has already been implemented.

3. Workshop Comments. The participants did not disagree with the utilities' assessment that generation efficiency is part of their respective IRPs. The Industrial Customers of Idaho Power did note that the Commission may want to require future IRPs to explicitly address this issue instead of being subsumed in the IRP.

"Smart Metering"

(14) Time-based metering and communications.

> (A) Not later than 18 months after the date of enactment of this paragraph, 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 electric use and cost through advanced metering and communications technology.
>
> (B) The type of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others –
>
> > (i) time-of-use pricing whereby electricity prices are set for a specific time period on an advanced 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 a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

1. Commission Discussion. As was the case with net metering, this Commission and the utilities have previously addressed Smart Metering (time-based metering and communications). For example, Avista began installing Advanced Meter Reading (AMR) devices on all of its Idaho electric and gas meters in 2005. Order No. 24602 at 51. Rocky Mountain has offered its residential customers time-of-day service (Schedule 36) for many years. For its part, Idaho Power has implemented an AMR pilot program for more than 23,000 residential customers that provides two optional services – time-variant pricing and air conditioner cycling. Order No. 29959. When authorizing these Smart Metering programs, the Commission stated that the implementation of the programs should be prudent and cost-effective.

A recent Federal Energy Regulatory Commission Staff Report indicated that Idaho ranks fifth (at 16.2%) in the percentage of customers with "advanced metering."[2] Given this brief background information, the Commission directed the utilities to address the following questions:

1. Briefly describe your Smart Metering programs previously implemented. For each program indicate the number of customers by class eligible to participate in the program and the number of customers actually

[2] Slide 7 at http://www.ferc.gov/whats-new/headlines/2006/2006-3/07-20-06-demand-response.pdf.

participating in each program. What are the differences between your programs and the federal standard, including costs and benefits?

2. Should the Commission adopt the Smart Metering standard by requiring each utility to offer by February 8, 2007, a time-based rate to each customer class and the necessary time-based metering to individual customers upon request? Why, or why not?

3. Should the Commission adopt the time-based metering and communications standard by applying the same requirements to all utilities?

4. Which, if any, of the four listed types of time-based rate schedules should the Commission require? Should the same types of rate schedules be required of all utilities and for all customer classes?

5. Are there other issues the Commission should consider in reviewing this standard?

2. Utilities' Responses. This standard generated the greatest amount of comments from both the utilities and the participants at the public workshop. All of the utilities indicated that they have started "Smart Metering" programs and have partially implemented the standards. In particular, Avista noted that it is in the second year of a four-year deployment of AMR meters for all of their Idaho customers. In answer to the Commission's second question, Avista indicated that it could not offer time-based rates by either February or August 2007.[3] Avista recommended that the Commission not adopt this standard for several reasons. First, Avista indicated that it would not have all of its meters installed by August 2007. Second, the Company stated that it did not have implementing tariffs, data storage, and necessary billing changes to support time-based rates. The Company estimated that the billing and data storage costs alone would be approximately $22 million. Finally, the Company asserted that it was not cost effective to offer time-based rates to all classes of customers, but that it might be effective for large customers.

Rocky Mountain declared that it currently offers optional time-of-day service to all residential and distribution voltage customers. It maintained that its time-of-day service complies with the spirit of the standard. The Company indicated it was neither achievable nor

[3] The workshop participants recognized that there was confusion in the industry of exactly when Congress required this standard to be reviewed and/or implemented. One portion of the Energy Policy Act indicates a deadline for this standard of February 8, 2007 while another section indicates August 8, 2007. The participants generally concluded that the implementation date for this standard be August 8, 2007.

reasonable to adopt this standard by February 2007. Rocky Mountain did agree with the Commission's statement that all Smart Metering programs should "be prudent and cost effective." Rocky Mountain Comments at 7; Order No. 30108 at 7.

Idaho Power commented that it is steadily deploying smart meters so that the costs of deployment are commensurate with the benefits. The Company reported it has 123 industrial customers (Schedule 19) on time-of-use; 130 large business customers (Schedule 9) on time-of-use; and 117 irrigation customers on time-of-use (but not ARM meters). The Company has approximately 25,500 AMR meters currently installed. It too noted that it would not be able to implement this standard for all customers by February 2007. All three utilities indicated that adoption of Smart Metering policies should be based on a company-by-company basis and implemented in situations where the cost and benefits are reasonable.

3. Workshop Comments. Representatives of Hunt Technology agreed with the utilities that there should be specific Smart Metering policies for each utility based upon their distinct territories and customer base. The participants recognized that Idaho ranks fifth nationally in the percentage of customers with "advanced meters." *See* Order No. 30108 at 7. If the Commission were to consider greater deployments of smart meters, Hunt suggested that the policy should be guided by: (1) what is in the best operational interest of the utility; (2) what is in the best interest of ratepayers; and (3) what functionalities work for each utility.

Interconnection

Section 1254(a) establishes an interconnection standard for customers with on-site generating facilities. This standard states:

> (15) Interconnection. Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term "interconnection service" means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute Of Electrical And Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

1. Commission Discussion. This standard encourages state commissions to adopt "best practices" to promote the interconnection of distributed generation facilities. Distributed generation generally refers to a customer's on-site generating facility that may provide generation (i.e., interconnects) to the local distribution system as opposed to serving the utility's transmission system. *See* Order No. 29260 at 6-7 (comparing net metering and distributed generation); 42 U.S.C. § 16197(g)(3). The federal standard adopts interconnection standards published by the Institute of Electrical and Electronics Engineers (IEEE) and references other model codes adopted by state regulatory agencies.[4]

IEEE Standard No. 1547-2003 (July 2003) is intended to provide uniform standards for interconnecting a customer's on-site "distribution resource" with the local electric power system. It provides requirements for the performance, operation, testing, maintenance and safety considerations of the interconnection. Standard 1547-2003 at ¶ 1.2. The IEEE Standard is further intended to apply to all distributed generation technologies with aggregate capacity of 10 MVA or less at interconnection. The standard does not define the maximum distributed generation capacity for a particular installation. *Id.* at ¶ 1.3.

1. Should the Commission adopt this standard for interconnecting a customer's on-site generating facility to local distribution facilities?

2. Do the utilities currently have tariffs, agreements, procedures or schedules delineating interconnection standards of customer-owned generating facilities? If yes, where are they located (e.g., tariffs, schedules, websites, etc.)? Are there limitations on the per customer capacity or total system capacity of customer-owned generation facilities? What are the limits?

3. Should the Commission adopt or consider separate interconnection standards for smaller and larger generating facilities (e.g., < 25 kW up to 100 kW, < 1MW, > 1MW, or some other limitation)?

4. Should the Commission adopt IEEE Standard 1547?

5. Should the Commission adopt the NARUC Model Interconnection Procedures and Agreement?

---

[4] In 2003 the National Association of Regulatory Utility Commissioners (NARUC) published a model code entitled "Model Interconnection Procedures and Agreement for Small Distribution Generation Resources." The Model Procedures and Agreement are available via NARUC's website at: http://naruc.org/goto.cfm?returnto=displayindustrynews.cfm&industrytopicnbr=380&page=http://www.naruc.org/associations/1773/files/dgiaip_oct03.pdf

6. Are there other issues the Commission should consider regarding this standard?

2. Utilities' Responses. The utilities indicated that for the most part they have already implemented this federal standard. Avista stated that its interconnection requirements are contained in its Schedule 70, Part 28 and on its website. It also indicated that it recently amended its tariff to include the adoption of IEEE Standard 1547. *See* Order No. 30111, Case No. AVU-E-06-4. In response to the question about whether the Commission should adopt the NARUC Model Interconnection Procedures and Agreement (the "Model"), the Company suggested the Commission adopt it as a guideline recognizing that utilities may have particular problems with certain elements of the Model Agreement. In particular, Avista said that it may have difficulty providing notice of interruptions seven days in advance.

Rocky Mountain asserted it did not need to adopt IEEE Standard 1547 because the Company already uses the standard and further noted that it is not applicable to every situation. The Company's interconnection standards are set out in its net metering Schedule 135 and its Open Access Transmission Tariff (OATT) posted on its website. If the Commission wishes to adopt thresholds for interconnection, then a reasonable breaking point would be 100 kW and less for net metering and at 100 kW and larger generators may need additional protections. Rocky Mountain also recommended the Commission consider not adopting the NARUC Model because: its timelines are too restrictive; it may inadvertently limit due diligence for each plant; and Idaho is only one of six states where PacifiCorp operates.

Idaho Power indicated that it is in compliance with the federal interconnection standard except it has not explicitly adopted IEEE Standard 1547. However, it intended to incorporate this standard. Idaho Power's interconnection policies and practices are contained in its Schedules 72 and 84; in its Best Practices (website); and in its OATT. Rather than adopting standards for certain sized facilities, Idaho Power currently divides facilities into small, medium, and large interconnecting facilities. While Idaho Power did not object to adoption of IEEE Standard 1547, it asserted the IEEE standard is not applicable to all situations because it applies to facilities of 10 MVA or less. Turning to the NARUC Model, Idaho Power supported the model in principle but recognizes that "one size does not fit all." It indicated it will file a new Schedule 72 (and Schedule 84 for QF) as part of a proposed uniform interconnection agreement this month in response to FERC's Standards of Conduct.

3. Workshop Comments. The participants did not voice any disagreement with the utilities' comments.

NOTICE OF MODIFIED PROCEDURE

YOU ARE HEREBY NOTIFIED that the Commission has preliminarily determined that the public interest may not require a formal hearing in this matter and will proceed under Modified Procedure pursuant to Rules 201 through 204 of the Idaho Public Utilities Commission's Rules of Procedure, IDAPA 31.01.01.201 through .204. Written comments have proven to be an efficient means for obtaining public input and participation.

YOU ARE FURTHER NOTIFIED that the Commission invites additional public comments from the workshop participants and other interested persons on the five federal standards. In particular, the Commission seeks comments on whether the five federal standards or comparable standards should be adopted or declined and the reasons supporting such comments.

YOU ARE FURTHER NOTIFIED that any person desiring to state a position on this Inquiry may file a written comment in support or opposition with the Commission within 21 days from the service date of this Notice. The comment must contain a statement of reasons supporting the comment. Persons desiring a hearing must specifically request a hearing in their written comments. Written comments concerning this Inquiry shall be mailed to the Commission at the address reflected below:

Commission Secretary
Idaho Public Utilities Commission
PO Box 83720
Boise, ID 83720-0074

Street Address for Express Mail:

472 W. Washington Street
Boise, ID 83702-5983

These comments should contain the case caption and case number shown on the first page of this document. Persons desiring to submit comments via e-mail may do so by accessing the Commission's home page located at www.puc.idaho.gov. Click the "Comments and Questions" icon, and complete the comment form, using the case number as it appears on the front of this document.

YOU ARE FURTHER NOTIFIED that if no written comments or protests are received within the time limit set, the Commission will consider this matter on its merits and enter its Order without a formal hearing. If written comments are received within the time limit set, the Commission will consider them and, in its discretion, may set the same for formal hearing.

YOU ARE FURTHER NOTIFIED that the utilities may file a response to any public comments within 35 days of the date of this Order.

YOU ARE FURTHER NOTIFIED that all proceedings in this case will be held pursuant to the Commission's jurisdiction under the Energy Policy Act of 2005; Title 61 of the Idaho Code; and specifically *Idaho Code* §§ 61-302, 61-307, 61-336, and 61-507. The Commission may enter any final Order consistent with its authority under Title 61.

YOU ARE FURTHER NOTIFIED that all proceedings in this matter will be conducted pursuant to the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq*.

O R D E R

IT IS HEREBY ORDERED that persons interested in submitting written comments regarding the five federal PURPA standards should do so no later than 21 days from the service date of this Order.

IT IS FURTHER ORDERED that the utilities may, if necessary, file a response to written comments no later than 35 days from the service date of this Order.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 5th day of October 2006.

PAUL KJELLANDER, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

bls/GNR-E-06-02_dh2