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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-06-2** **STAFF COMMENTS**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its attorney of record, Donald L. Howell, II, Deputy Attorney General, and submits the following comments in response to Order No. 30146 issued on October 6, 2006.

BACKGROUND

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.[1] The Notice

[1]Atlanta Power is not subject to the PURPA standards. Order No. 30108 at n.2.

required that the utilities serve their comments on a service list of interested persons. Order No. 30108 at 10.

A. The Public Workshop

The Commission's Notice also scheduled a public workshop on September 13, 2006, for the purpose of reviewing the utilities' written comments. Participants at the public workshop included the three utilities, Hunt Technologies, the Industrial Customers of Idaho Power, Distribution Control Systems, the Commission Staff, and customers John Weber and Jay Blackhurst. 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. In Order No. 30146 the participants and other interested persons were invited to comment on the five federal standards. These Staff Comments are submitted pursuant to Order No. 30146.

B. The Commission's Responsibilities on Review

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 <u>it is not appropriate</u> to implement any such standard. . . ." Order No. 30108 at 2 *citing* 16 U.S.C. § 2621(a) (emphasis original). 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).

In reviewing the five standards, the Act requires that the Commission consider the three goals of PURPA. The goals of PURPA are: (1) conservation of energy supplied by electric utilities;

(2) optimal efficiency of electric utility facilities and resources; and (3) equitable rates for electric consumers.

C. Timelines and Deadlines

The timeline for each standard as set by the Act are listed below. If the Commission has not completed its review of each standard by the respective deadline, then the review shall occur in the first applicable proceeding that follows the deadline, but no later than three years after the deadline.

Net Metering

Commission Begins or Schedules Consideration	August 8, 2007
Commission Makes a Determination	August 8, 2008

Fuel Sources (diversity)

Commission Begins or Schedules Consideration	August 8, 2007
Commission Makes a Determination	August 8, 2008

Fossil Fuel Generation (increased efficiency)

Commission Begins or Schedules Consideration	August 8, 2007
Commission Makes a Determination	August 8, 2008

"Smart Metering"

Commission Begins or Schedules Consideration	February 8, 2007
Commission Makes a Determination	August 8, 2007

Interconnection (for customer on-site generation)

Commission Begins or Schedules Consideration	August 8, 2006
Commission Makes a Determination	August 8, 2007

THE FIVE STANDARDS

Net Metering

Section 1251 of the Act states that net metering should be made available to any electric consumer that the utility serves. It also defines "net metering" clearly so that any net offset has to apply "during the applicable billing period" in which the consumer's generation is delivered to the local grid.

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 generating electricity using solar, wind, hydropower, biomass or fuel cells; (2) limit the program to 0.10% of their retail peak generation; and (3) limit residential customers to facilities no greater than 25 kW.

1. Avista. Avista has four residential net metering customers in Idaho that produced 16,000 kWh during 2005. The Company's net metering tariff (Schedule 63) was most recently approved August 1, 2006. Schedule 63 credits excess generation at full retail rates on the customer's next monthly billing.

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

3. Idaho Power. Idaho Power has 20 residential customers, 4 small business customers, and 2 large business customers. The 24 smaller customers generated 397,255 kWh 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.

Staff Recommendation: The parties generally agree that the utilities' net metering programs meet the net metering standard. One concern expressed at the workshop was 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. While this may occur, Staff believes that net metering customers with significant and excess generation have other rate structures available. For example, Idaho Power customers have the option of participating under Schedule 86 (Co-generation and Small Power Production Non-Firm Energy). In addition, firm energy generation customers with qualifying facilities are entitled to published avoided cost rates under PURPA.

It is also important to note that the three utilities all offer net metering programs under tariffs, not contracts. The Commission is well aware that there is no guarantee that tariff rates will remain unchanged. As Staff noted in its comments in Idaho Power's net metering Case No. IPC-E-06-17, net metering customers who desire certain fixed rates and terms may wish to consider a QF contract.

In summary, Staff believes that the Commission has already adopted the federal net metering standard by implementing net metering schedules for the three utilities. The Staff further recognizes that Idaho Power's proposed changes to its net metering Schedule 84 is currently before the Commission.

Diversity of Fuel Sources

This standard requires that each utility prepare a plan to minimize dependence on any single fuel for its generation resources. It also requires that utilities take steps to assure that a diverse range of fuels and technologies are included in the resource mix, including renewable resources.

Staff asserts that this standard is presently the practice for the applicable electric utilities serving customers in Idaho. In Order No. 22299, the Commission required Avista, Idaho Power, and Rocky Mountain Power (or their predecessors) to biennially 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). The IRP process allows the Commission to review the utilities' planned generation every two years and thereby be assured that the companies minimize dependence on any single fuel source and that they employ a diverse array of fuels and technologies, including renewables.

Staff Recommendation: The workshop participants agreed that diversification of generating fuel sources was evident from review of each utility's resource stack as presented in their IRPs. Consequently, the Staff believes that the Commission has already implemented this federal standard. Further action is not necessary.

Fossil Fuel Generation Efficiency

The fossil fuel generation efficiency standard relates almost exclusively to the second PURPA goal of "optimal efficiency." Fossil fuel generated electricity used in Idaho is sourced from either coal or natural gas. All three utilities have fossil fuel (coal and natural gas) generation facilities. Planning for and increasing the efficiency of existing generating resources is most commonly a part of general utility practices and a part of the IRP process.

The three utilities assert that addressing expansion and improvements involving fossil fuel efficiency is already 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 maintain that the Commission need not take further action on this standard because it has already been implemented.

Staff Recommendation: Staff agrees with the utilities' assessment that generation efficiency is part of their respective IRPs. To make generation efficiency more transparent, however, Staff recommends that the Commission direct that future IRPs explicitly address this issue as part of the IRP Process.

"Smart Metering"

This standard requires each utility to make available to each customer class time-based rate schedules and, upon request, offer each customer a time-based rate schedule. The intent is to conserve energy and reduce load by providing the tools for the utilities and customers to manage their energy use and costs through advanced metering, communications technology and sophisticated rate structures. The standard recognizes that a wide variety of rate structures may be used, including:

- Time-of-Use Pricing
- Critical-Peak Pricing
- Real-Time Pricing
- Credits for Load Reduction

As the Commission noted in its Order No. 30146, the utilities have already initiated various Smart Metering (time-based metering and communications) programs. For example, Avista began installing Advanced Meter Reading (AMR) devices on all of its Idaho electric and gas meters in 2005 and expects to complete the change by 2009. 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 (FERC) Staff Report indicated that Idaho ranks fifth (at 16.2%) in the percentage of customers with "advanced metering."

1. Avista. Avista noted that it is in the second year of a four-year deployment of AMR meters for all of their Idaho customers. The equipment being deployed is AMR capable and was selected by Avista so that the Company would have options in implementing time-of-use and demand response practices. The Company has pointed out that, once the AMR installation at the customer's meter is complete, the additions necessary for a "fully" advanced system will all be at the Company's end in the form of software and communications systems. The Company also calculated that adding the necessary data storage and billing system software would cost approximately $22 million. *Id.*

Avista indicated in its comments that time-of-use pricing may not be cost-effective for all customer classes and all customers. In particular, the Company stated that the potential "savings created by customers shifting their day time demand into the night does not outweigh the cost of meter installation, software upgrades, and associated operational costs." Avista Comments at 7. However, Avista did see some advantages by offering time-of-use rate structures to its large industrial customers.

2. Rocky Mountain Power. Rocky Mountain declared that it currently offers optional time-of-day service to all residential and distribution voltage customers. The Company has more than 16,400 residential customers (31%) and 2 general service customers on time-of-use schedules. It maintained that its time-of-day service complies with the spirit of the standard. The Company indicated it was neither achievable nor reasonable to adopt the new standard by February 2007. Rocky Mountain did agree with the Commission's statement that all Smart Metering programs should "be prudent and cost effective."

3. Idaho Power. The Company 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. The Company's next AMR report on its pilot is due May 1, 2007. Order No. 30102.

The Company also offers an Air Conditioner Cycling program (Schedule 81) as an optional service for eligible residential customers in Ada, Canyon and Gem Counties. By controlling the residential air conditioners of 40,000 participants, the Company plans to reduce its summer peak loads by more than 40 MW. The air conditioners are directly controlled by Idaho Power by radio communications. Order No. 29702.

4. Workshop. In the workshops, 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." If the Commission were to consider greater deployments of Smart Meters, Hunt suggested that the policy should be guided by consideration of three issues: (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.

Staff Recommendation: As the Commission noted in Order No. 30146, and as set out above, the utilities are in various stages of AMR deployment. The opportunities to conserve energy, reduce peak demand, and provide customers with the ability to manage their energy use are intrinsic in both Smart Metering and the use of more sophisticated rate structures suggested by this federal standard. While the Commission has authorized various Smart Metering programs, Staff does not believe the Commission should adopt the federal standard at this time for several reasons.

First, Staff agrees with the three utilities that they would be unable to implement AMR within the time period contemplated by the standard. Even though the FERC staff reported that Idaho ranks fifth in the percentage of customers with "advanced metering," this statistic may overstate the reality of the situation. It is unrealistic to assume that the utilities could make time-based metering available to all requesting customers by 2007. Second, AMR technology has not fully developed or reached a state of trouble-free deployment. In the Commission's recent review of Idaho Power's AMR pilot program, it recognized that "AMR technology is relatively new and is evolving." Order No. 30102 at 6. For example, Idaho Power is still attempting to resolve interface issues in its AMR pilot. Idaho Power Comments at 12. Given Idaho Power's difficulties in integrating the AMR metering and communication technologies, the Commission continued the pilot and ordered Idaho Power to submit another report no later than May 1, 2007.

Third, Staff agrees with the comments offered by Hunt Technology that AMR deployment will be different for each utility based upon the characteristics of its loads and customers. As evident above, each of the three utilities has implemented various AMR programs and is at various stages of implementation. What works for one utility may not necessarily work for the other electric utilities. Finally, there is the economy of scale to consider. Staff agrees with Avista that offering every customer in every customer class time-based rates may not be cost-effective. However, Staff continues to believe that AMR can offer cost-effective benefits for both the utilities and consumers alike; the Staff recommends that the Commission continue its measured implementation of AMR.

Staff's comments should not be viewed as opposing AMR deployment. Staff recognizes that "the potential benefits of advanced metering available to ratepayers and the Company are too great to delay AMR implementation indefinitely." Order No. 29362. Rather, Staff believes that the utilities should continue to take measured, pro-active steps to implement cost-effective AMR programs. Therefore, Staff recommends that the Commission should not adopt the federal standard, but instead, continue to work with the utilities in establishing AMR systems and rate structures on a schedule that benefits both utilities and customers.

In the interest of continued progress in pursuit of cost effective AMR, Staff recommends that Avista and Rocky Mountain each address Smart Metering deployment in the context of their next general rate cases.

1) Avista should address the status of its AMR installation program, its cost recovery proposal and its plans for development of the infrastructure necessary to implement time-of-use rates, demand response or other appropriate rate structures for its customers or classes of customers.

2) Rocky Mountain should address the status of its time-of-use programs, justification for existing rate differentials and plans for changes or upgrades to advanced metering including infrastructure necessary to implement time-of-use rates, demand response or other appropriate rate structures for its customers or classes of customers.

Interconnection

The interconnection standard in Section 1254 of the Act adopts the IEEE Standard 1547 for interconnecting electric consumers who self-generate and supply their excess energy to the grid. The standard also proposes to establish standard agreements and procedures for interconnecting to utility systems using best practices with procedures that are just, reasonable and non-discriminatory. The federal standard also urges adoption of other model codes issued by state regulatory agencies such as NARUC's Model Interconnection Procedures and Agreement (the "Model").

In this case, distributed generation refers to a customer's on-site generating facility that may provide a generation resource (i.e., interconnects) to the local distribution system as opposed to connection to the utility transmission system. *See* Order No. 29260 at 6-7 (comparing net metering and distributed generation); 42 U.S.C. § 16197(g)(3).

IEEE Standard 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. The IEEE standard is further intended to apply to all distributed generation technologies with aggregate capacity of 1 MW or less at interconnection. The standard does not define the maximum distributed generation capacity for a particular installation and in fact many systems of less than 1 MW may require interconnection different than that suggested by IEEE 1547 to assure safety of the system and of other customers. The utilities indicated that they generally have already implemented this federal standard.

1. Avista. Avista stated that its interconnection requirements are contained in its Schedule 70, Part 28 and on its website. Avista recently amended its tariff to include the adoption of IEEE Standard 1547. *See* Order No. 30111, Case No. AVU-E-06-4. The Company also suggested the Commission adopt the NARUC Model as a guideline recognizing that utilities may have particular

problems with certain elements of the Model. In particular, Avista may have difficulty providing notice of interruptions seven days in advance.

2. Rocky Mountain Power. 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. Generators of 100 kW and larger 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.

3. Idaho Power. Idaho Power indicated that it is in compliance with the federal interconnection standard except it has not explicitly adopted IEEE Standard 1547. However, it has proposed to incorporate this standard in Case No. IPC-E-06-18. 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. Idaho Power supported the NARUC 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.

Staff Recommendation: Staff believes that the utilities generally meet the spirit and intent of the standard by their inclusion of IEEE 1547 and recommends that the Commission not adopt the standard. Finally, Staff recommends that the NARUC Model Agreement be used as a guideline for interconnection agreements thereby maintaining flexibility in schedule and technical application for the utilities to work with special or unique projects and conditions.

SUMMARY

1. Staff recommends that the Commission require future IRPs to explicitly address the issues of fossil fuel efficiency.

2. Staff recommends that the Commission find that it has already implemented the four standards other than Smart Metering and that further action regarding those four standards is not required.

3. Staff recommends that the Commission find that adoption of the Smart Metering standard is not appropriate at this time, but that the Commission require:

a) Avista to address its AMR installation program and its plans for development of the infrastructure necessary to implement time-of-use rates, demand response or other appropriate rate structures for each of its customer classes in its next general rate case.

b) Rocky Mountain to address the status of its time-of-use programs, justification for existing rate differentials and plans for changes or upgrades to advanced metering.

4. Staff recommends that the NARUC Model Agreement be used as a guideline for interconnection agreements thereby maintaining flexibility in schedule and technical application for the utilities to work with special or unique projects and conditions.

5. Finally, Staff recommends that the Commission find that the utilities' prior submittals, tariffs, prior Orders and this decision have satisfied all requirements of the Act for current action by the utilities.

Respectfully submitted this 27th day of October 2006.

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Deputy Attorney General

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 27TH DAY OF OCTOBER 2006, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. GNR-E-06-02, BY E-MAILING A COPY THEREOF TO THE FOLLOWING:

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