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IDAHO PUBLIC
UTILITIES COMMISSION

25 June 2012

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
P O Box 83720
Boise ID 83720-0074

RE: **Case No.IPC-E-12-15**

Dear Ms. Jewell:

Enclosed please find an original and 7 (seven) copies of the **COMMENTS OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER** in the above case.

I have also enclosed an extra copy to be service-dated and returned to us for our files. Thank you.

Sincerely,

Nina Curtis
Administrative Assistant

encl.

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Attorneys for the Industrial Customers of Idaho Power

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**BEFORE THE**

**IDAHO PUBLIC UTILITIES COMMISSION**

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| IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR A DETERMINATION OF 2011 DEMAND-SIDE MANAGEMENT ("DSM") EXPENDITURES AS PRUDENTLY INCURRED | CASE NO. IPC-E-12-15<br><br>COMMENTS OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER |

## INTRODUCTION

**COMES NOW,** the Industrial Customers of Idaho Power ("ICIP") and pursuant to Order Nos. 32512 and 32569 issued April, 10 and June 7, 2012 in the above captioned docket and hereby respectfully submits the following Comments on Idaho Power Company's ("Idaho Power" or "Company") Application for a Determination of 2011 Demand-Side Management ("DSM") Expenditures as Prudently Incurred. As explained below, the ICIP's comments focus on the need to consistently evaluate cost effectiveness by applying the same test to all resources for both the demand- and the supply-side of the equation.

## 1. MEASURE OF DEMAND-SIDE MANAGEMENT COST EFFECTIVENESS

According to Idaho Power, and consistent with the Commission's directives, its goals regarding DSM and energy conservation are:

> Through DSM programs, Idaho Power seeks to provide customers with programs and information to help them manage their energy usage and to achieve prudent cost effective energy efficiency and demand response resources [collectively, "DSM"] to meet its electrical system's energy and demand needs.[1]

Meeting the "electrical system's energy and demand needs" through DSM has the effect of reducing the need to build new electric generation facilities and/or purchases in the relatively volatile wholesale market. The test of "prudent cost effective energy efficiency and demand response resources" must be whether the cost of a kWh or kW saved is equal to or less than the cost of Company generation and or market purchases of the same amount of energy. According to the Company, the alternative energy costs used to measure the cost effectiveness of DSM programs are defined as follows:

- The *alternative energy costs* are based on both the projected fuel costs of a peaking unit and forward electricity prices as determined by Idaho Power's power supply model, AURORAxmp® Electric Market Model.
- The *avoided capital cost* of capacity is based on a gas fired simple cycle turbine.[2]

In the Company's 2011 IRP, the annual avoided capacity cost is $94.00/kW. When multiplied by the effective load carrying capacity (to reduce the avoided capacity cost), the annual avoided capacity cost is $87.80/kW. In addition, it is noteworthy that the avoided capacity cost of a simple

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[1] Idaho Power Application, p. 2, IPC-E-12-15.
[2] Demand-Side Management 2011 Annual Report, Supplement 1: Cost-Effectiveness, p. 3, IPC-E-12-15. Emphasis provided.

cycle turbine in the DSM calculation in 2009 was $63.00/kW, an increase of 49% over this two year period.[3]

The alternative energy costs used by the Company in determining the cost/benefit ratios for the various DSM programs are divided into five different pricing periods. The five pricing periods are:

- Summer On-Peak (SONP)-Average of variable energy and operating costs of a 170 MW SCCT, which is the marginal resource for peak hour load deficits during summertime heavy load hours;
- Summer Mid-Peak (SMP)-Average of heavy load prices from June-August;
- Summer Off-Peak (SOFP)-Average of light load prices from June-August;
- Non-Summer Mid-Peak (NSMP)-Average of heavy load prices in January-May and September-December; and
- Non-Summer Off-Peak (NSOFP)-Average of light load prices in January-May and September-December.[4]

The values used for these five pricing periods – as shown below in Table 1 – were derived from financial assumptions including Idaho Power's discount rate and cost escalation rate as inputs to the AURORA model. As explained in Idaho Power's current Integrated Resource Plan:

> The prices of avoided energy throughout the 20-year planning period were simulated using the Preferred Portfolio module with the AURORA model. The Preferred Portfolio module considers the energy capacity and resource costs of the current preferred mix of IRP resources along with regional transmission resources in the Western Electricity Coordinating Council (WECC) region to project forward electric market prices. The forward prices are placed into five homogenous pricing categories that follow the pattern of heavy- and light-load pricing [see above] throughout each year of the planning period.[5]

The Company uses three common cost/benefit ratios to determine the cost effectiveness of its DSM programs. These ratios are aimed at equating demand-side programs with supply-side

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[3] Idaho Power's 2009 Integrated Resource Plan, Appendix C, p. 98, IPC-E-09-33.
[4] Idaho Power's 2011 Integrated Resource Plan, Appendix C, p. 67, IPC-E-11-11.
[5] *Id.*

resources. "Specific programs or potential energy measures are screened using a static economic analysis to determine if these programs or measures are potentially more cost-effective than the next best supply-side resource alternative."[6] The ratios are also used to provide information about the costs and benefits of a given program from a variety of perspectives, including that of the Company, all of the Company's customers in its service area (participating and non-participating), and the Company's average participating customers (those participating in the relevant conservation program).[7]

Idaho Power tests the cost effectiveness of its Demand Response Programs (A/C Cool Credits, FlexPeak Management, and Irrigation Peak Rewards) over a 20-year period.

> The goal of demand response programs is to minimize or delay the need to build new supply-side resources. Unlike energy efficiency programs, demand response programs must acquire and retain participants each year to maintain a level of demand reduction capacity for the company. Demand response programs are expensive and generally have a higher initial investment than energy efficiency programs. As such, demand response programs are analyzed over the program life in which historical program demand reduction and expenses are combined with forecasted program activity to better compare the program to a supply-side resource. [8]

Hence, cost-effective DSM measures are not assured over the twenty year planning horizon; they must be recalculated every year to ensure there is sufficient participation.

## 2. AVOIDED COST RATE REDUCTION IN CURRENT CASE GNR-E-11-03

The question of the value of avoiding future construction and/or market purchases is currently being addressed in another docket before this Commission. In the generic avoided cost

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[6] Direct testimony of Idaho Power witness Darlene Nemnich, p. 14, IPC-E-12-15.
[7] *Id.* at pp. 13-14.
[8] Idaho Power's Demand-Side Management 2011 Annual Report, Supplement 1, p. 2, IPC-E-12-15.

docket,[9] all three utilities are proposing that their actual energy and capacity needs be taken into account in determining the costs the utilities will avoid if they purchase power from PURPA qualifying facilities. The reason the utilities are advocating for such a change in calculating their avoided costs is that during a time of energy or capacity surplus QF purchases arguably do not displace or defer new resources. The standard rate offered QFs under PURPA contracts is based on the costs the utility avoids by not having to generate or purchase power itself. Energy efficiency works in the same way, in that it reduces a utility's energy as well as capacity needs. A utility thus avoids generation and purchase costs when it implements energy efficiency.

The Commission is re-examining the calculation of QF avoided cost rates in light of reduced natural gas forecasts, reduced load forecasts and least-cost model forecasts in the Company's IRP.[10] The Company's primary concern in that case is that it will be required under PURPA regulations to enter into contracts for energy it does not need at prices that are too high, unduly inflating customer rates. Assuming this argument is valid in the context of avoided cost rates for QFs, this same argument ought to instruct the validity of the current method for evaluating future energy efficiency and demand-side management expenditures.

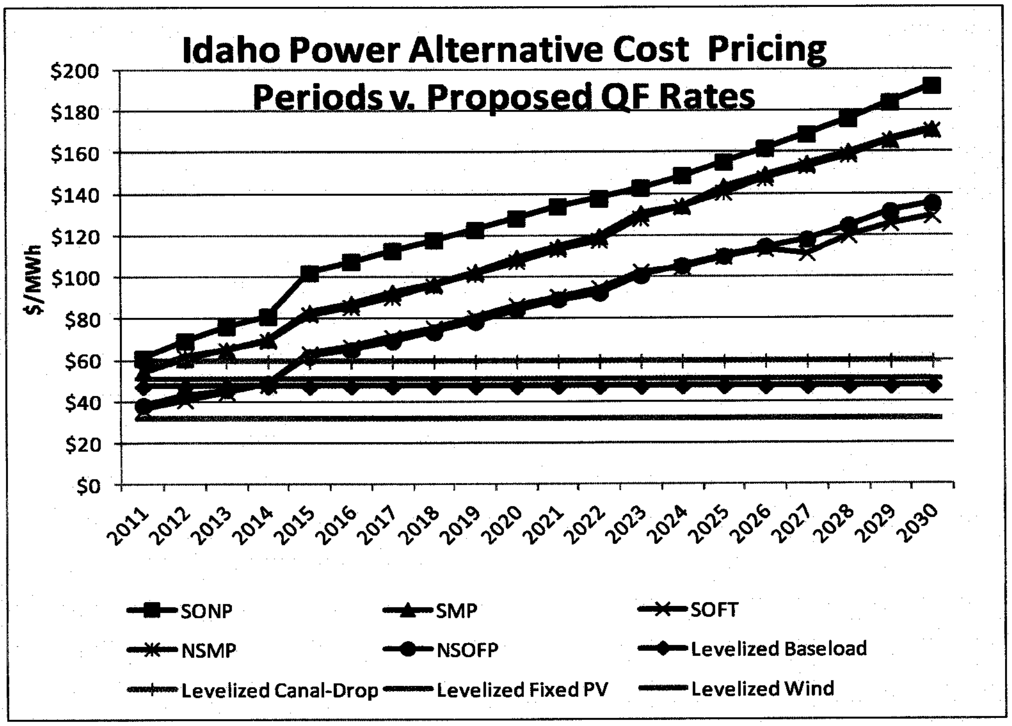
The evaluation of system costs used by the Company for DSM in this docket is significantly different from that used in the determination of QF rates currently and separately being advocated before the Commission in case GNR-E-11-03. Table 1 below demonstrates the vast difference in the alternative costs used in the cost/benefit analysis to determine the cost effectiveness of DSM programs as compared to those avoided costs proposed for QFs. With the decrease in forecasted costs, the difference between the DSM methodologies and, the QF avoided

[9] Case No. GNR-E-11-03.
[10] *Id.*

cost methodologies (that the Company is currently advocating in GNR-E-11-03) will become so disparate as to warrant modifying the measurement of cost effectiveness for energy efficiency and DSM programs.

Table 1, below, is a graphic illustration of the cost effectiveness hurdle for the various DSM programs and energy efficiency as compared to the forecast avoided cost rates.

Table 1




[11]

As Table 1 shows, each of the five pricing period costs used as alternative costs for testing DSM programs is significantly higher than the levelized avoided costs for generic QFs. It might be argued that QF's are not dispatchable and rather are 'must takes' that are therefore not directly comparable. However majority (56%) of expenditures Company's conservation programs are for

[11] Idaho Power 2011 Integrated Resource Plan, Appendix C, p. 69, IPC-E-11-11; *see also* Memorandum in Support of Temporary Stay, p. 15, GNR-E-11-03.

energy efficiency programs that are also 'must take.'[12] There are several reasons for this significant difference. One is the use of a slightly lower gas forecast in each year over the next 20 years. However, by far the two most significant drivers in the low avoided costs in the QF context as compared to the avoided costs in the DSM context are that; (1) Idaho Power is proposing to eliminate QF's capacity payments during periods of declared surplus; and (2) the Company is proposing to define QF avoided costs in very short-run terms. According to Idaho Power this short run approach includes times when the Company states its avoidable incremental costs are either zero or negative. If it costs the Company very little or nothing for its incremental supply, then that factor should be recognized whether the company is looking to purchase energy, reduce demand or promote energy efficiency. Idaho Power is currently taking the position in the generic avoided cost docket that near term avoided cost rates are potentially negative. According to Idaho Power witness Karl Bokencamp:

> Q. Are there times when the avoidable incremental costs calculated with Idaho Power's proposed methodology are zero?
>
> A. Yes, and this is not unrealistic. Considering the minimum load levels established for the thermal generating resources, and the amount of non-dispatchable QF generation on Idaho Power's system, there may be hours during low load periods when Idaho Power's avoidable incremental costs are zero. In fact, there could be times when Idaho Power's avoided incremental costs would be negative (i.e. an increased incremental cost would be imposed). For example, if loads are low and a thermal unit is shutdown in order to accept additional QF generation and then the output of the intermittent QF generation drops off, additional costs could be incurred if the previously shutdown thermal unit is unavailable to replace the QF output. A more expensive unit may have to be started or more expensive market purchases may be required. In either situation, additional costs are incurred.[13]

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[12] Direct Testimony of Idaho Power witness Darlene Nemnich, Exhibit 1, IPC-E-12-15.
[13] Direct Testimony of Idaho Power witness Karl Bokenkamp, pp. 14-15, GNR-E-11-03.

The implications for avoided cost rates, if the Company's position is adopted by the Commission, are nothing short of a dramatic reduction which will surely mothball the QF industry. The implications for the demand-side management must likewise be considered in this docket.

## 3. EFFECT OF A SHORT-RUN, REDUCED AVOIDED COST RATE FOR QFs

The new, short-run avoided cost rates as advocated in GNR-E-11-03 could in fact disallow those energy efficiency expenditures which fail to meet the Company's own test for cost effectiveness as applied to PURPA projects. If an energy or capacity surplus affects the value of QF energy, then it follows that at a time of surplus, many heretofore cost-effective energy efficiency measures will be 'out of the money.' Because the avoided cost rates are only now being questioned, the 2011 DSM expenditures are not therefore *per se* imprudent. However, if the methods advanced in GNR-E-11-03 are meant to reflect a more holistic approach in ascertaining what the Company has avoided by not having to generate or buy power itself, then that same approach should be applied across the board to all aspects of the Company's cost effectiveness evaluations generally. Ultimately, both considerations serve the same purpose for a utility and its customers alike – to provide the means for the utility to meet its service area's energy and demand with resources relatively less expensive than generation or purchases.

## 4. ALTERNATIVE AND AVOIDED COSTS SERVE THE SAME PURPOSE, AND THUS SHOULD BE APPLIED FOR COST EFFECTIVENESS ON THE SAME BASIS

Idaho Power's approach in the QF docket incorrectly assumes avoided costs should be based on a *very* short-run hourly basis.[14] In Dr. Reading's direct testimony filed in GNR-E-11-03 he advocated that the correct avoided costs for an electric system should be based on the long-run costs of the utility. That said, if Commission rejects Dr. Reading's argument that avoided costs are

[14] Direct Testimony of Don Reading, p. 29, GNR-E-11-03.

properly calculated on a long-run basis and if the Commission agrees with Idaho Power that there are public-interest and "just & reasonable" concerns over current QF avoided costs, the result will simply eliminate virtually all of Idaho Power's energy efficiency measures. If the Commission buys Idaho Power's avoided cost arguments and finds that customers are being forced to pay for inflated resources before energy is actually needed by the utility to serve its customers, those concerns do not simply disappear when energy efficiency measures are being evaluated. This means that a short-run application would wipe out almost all energy efficiency and DSM measures.

Without looking in detail at the various cost/benefit ratios employed for each conservation program, the basic approach is to compare the costs of each program with the energy saved (priced at the alternative costs found in each of the above referenced five pricing periods). Therefore, the measuring stick for "prudent cost effective energy" savings equals the costs the Company can avoid by implementing DSM programs rather than building additional generation capacity to meet the system needs. Stated another way, the savings equal the cost of the electric energy which, but for the energy efficiency measures, the Company would have had to produce itself or purchase from another source. This formulation of a "but-for" analysis for alternative costs has its basis in the avoided costs determination in Section 210 of PURPA to offer to purchase Qualifying Facilities. In GNR-E-11-03 Idaho Power witness Hieronymus provided a definition of avoided costs, quoting Section 210 of PURPA:

> "For purposes of this section, the term 'incremental cost of alternative electric energy' means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the

> electric energy which, but for the purchase from such cogenerator or small power producer, such utility would produce or purchase from another source."[15]

As can be seen by the above definitions of alternative and avoided costs that are used by Idaho Power, the cost effectiveness of DSM programs and the avoided cost required in Section 210 of PURPA to be offered to QFs are essentially the same. Whether it is "but-for" the energy efficiency implemented by the Company or "but for" the QF generation supply, the end result is that the Company has avoided having to produce or purchase energy to meet the demand in its electricity service area. Therefore, the measuring stick of determining the cost effectiveness of either alternative or avoided costs should likewise be the same.

If the costs of additional power to the system are, as the Company states, at times zero for the purpose of determining avoided cost rates for independent power producers, then it also means the value of conservation programs the ratepayers are being charged for would at those times also be zero. This cost to the Company serves as a starting point to determine what economically viable alternatives are available to it, be they energy efficiency and demand-side resources, or alternative energy generators offering supply-side resources. The Commission has stated repeatedly that it favors all cost-effective conservation.

> The Commission has consistently stated that cost-effective DSM programs are in the public interest and has admonished electric utilities operating in the State of Idaho to develop and implement DSM programs in order to promote energy efficiency. See Order Nos. 29784, 29952.[16]

The key element in the Commission's directive is the phrase "cost-effective DSM programs." "Cost-effective" is, of course, a function of the cost the utility assigns the estimated power savings

[15] Direct Testimony of Idaho Power witness William Hieronymus, p. 19, GNR-E-11-03.
[16] Idaho Public Commission Order 32113, p. 8, Case No. IPC-E-10-09.

of its DSM programs. If those costs do not reflect realistic costs of the power system, then the cost/benefits of the program will not be accurately calculated.

If the system costs used in the evaluation of DSM programs were equivalent to those proposed for the determination of QFs' avoided cost rates, it would mean the majority – if not all – of those DSM programs would be deemed cost-*in*effective. This result would effectively mean the end of conservation efforts by Idaho Power (just as the proposed avoided costs by Idaho Power will mean an end of PURPA projects for QFs for the foreseeable future). That result will have to be applied to DSM as well as PURPA. While the ICIP is not a party to the avoided cost docket, it does expect consistent application of cost-effective tests. Should the Commission determine that Dr. Reading's testimony in that docket is incorrect and should the Commission adopt Idaho Power's short-run avoided costs test, then in order to avoid discriminatory treatment of similar resources and to avoid massive subsidies of DSM measures, the Commission will have to eliminate most, if not all, DSM programs. This would not be a desirable result or one advocated by the ICIP. We agree with the Commission that when all cost-effective DSM are undertaken by the utilities it is good for the power system and ratepayers. The correct measure is the long-run approach akin to the method offered by Dr. Reading in GNR-E-11-03. This approach, as pointed out in Dr. Reading's testimony in that docket, is a realistic approach in determining alternative costs of a power system.

**CONCLUSION**

If the Commission determines the proper avoided costs for determining cost effectiveness are consistent with those proposed by the Company in GNR-E-11-03, then the ICIP recommends that the Commission find that Idaho Power's expenditures for all DSM programs in the future be assessed in the same manner for determining prudence. The measuring stick for alternative or avoided costs rationally must be equal, and equally applied. Therefore, if avoided costs are measured based on short-run projections, then so too must DSM expenditures be measured against short-run projections. Otherwise, a short-run perspective on QF avoided costs with disparate long-run views on DSM/energy efficiency would result in disparate treatment between the various "resources" the Company will employ to ensure it uses the least-cost alternative to meet the energy and demand needs of its service area. If the reduced natural gas prices affect the Company's avoided cost as to QF purchases, then they must logically also affect (and thus lower) the costs against which DSM/energy efficiency is to be measured.

Using a short-run benchmark for determining the cost effectiveness of DSM will likely mean that all or most of the Company's current DSM programs will be above the avoided cost rates the Company itself is currently advocating (based on its short-term natural gas price projections). Setting the benchmark for all marginal avoided costs over the long term is the only way to ensure not only that the utility values these various resources equally, but that some of the DSM programs will still be economically viable.

Respectfully submitted this 25th day of June, 2012

Peter Richardson
Richardson & O'Leary, PLLC
Attorney for the Industrial Customers
of Idaho Power

**CERTIFICATE OF SERVICE**

I HEREBY CERTIFY that on the 25th day of June, 2012, a true and correct copy of the within and foregoing COMMENTS OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER IN CASE NO.IPC-E-12-15 was served in the manner shown to:

| | |
|---|---|
| **Ms. Jean Jewell**<br>Commission Secretary<br>Idaho Public Utilities Commission<br>P O Box 83720<br>Boise, ID 83720-0074 | X Hand Delivery<br>__ U.S. Mail, postage pre-paid<br>__ Facsimile<br>__ Electronic Mail |
| Lisa D Nordstrom<br>Julia A Hilton<br>Idaho Power Company<br>PO Box 70<br>Boise, Idaho 83707-0070<br>lnordstrom@idahopower.com<br>jhilton@idahopower.com | __ Hand Delivery<br>X U.S. Mail, postage pre-paid<br>__ Facsimile<br>X Electronic Mail |
| Darlene Nemnich<br>Greg Said<br>Idaho Power Company<br>PO Box 70<br>Boise, Idaho 83707-0070<br>dnemnich@idahopower.com<br>gsaid@idahopower.com | __ Hand Delivery<br>X U.S. Mail, postage pre-paid<br>__ Facsimile<br>X Electronic Mail |
| Ken Miller<br>Snake River Alliance<br>PO Box 1731<br>Boise ID 83701<br>kmiller@snakeriveralliance.org | __ Hand Delivery<br>X U.S. Mail, postage pre-paid<br>__ Facsimile<br>X Electronic Mail |
| Benjamin Otto<br>Idaho Conservation League<br>710 N 6th Street<br>Boise ID 83702<br>botto@idahoconservation.org | __ Hand Delivery<br>X U.S. Mail, postage pre-paid<br>__ Facsimile<br>X Electronic Mail |

Nina Curtis