BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION TIME-OF-USE PRICING FOR IDAHO POWER RESIDENTIAL CUSTOMERS.	))))	**CASE NO. IPC-E-02-12**

Comments of the Demand Response and Advanced Metering Coalition (DRAM)

The Demand Response and Advanced Metering Coalition (DRAM) is a policy organization comprised of utilities, public interest groups, metering and communications companies and demand response providers. DRAM's interest is in providing input and information to parties that are examining or implementing advanced metering and demand response programs. DRAM previously filed comments in the subject proceeding on December 6, 2002. We appreciate the opportunity now to provide additional comments to the Commission and other interested parties in Idaho and hope that they will be of assistance relative to this proceeding.

Background

DRAM's comments are submitted pursuant to Commission Order No. 29291. In that order, the Commission sought comment on the "Automated Meter Reading Report, Idaho Power Company, May 2003" filed May 9, 2003, (hereinafter "2003 AMR Report"). The Commission in particular sought comment on five questions:

1. Should the Commission direct the Company to implement AMR on its system?
2. How can advanced metering technology enable Idaho Power Company and ratepayers to make the most of future "smart grid" transmission and distribution technology?
3. As part of a wise investment, what features or technology should the Company employ?
4. Under what timeframe should the Company implement AMR?
5. How should the Company recover the costs associated with AMR?

Overview

DRAM commends the Commission and the other parties to this proceeding for their persistence and dedication to what, as DRAM identified in it previous comments, is a new and challenging undertaking – assessing how to move forward to provide consumers and electricity providers with advanced metering technology that provides each with new, previously unavailable benefits and capabilities.

As DRAM has previously discussed, the challenge in part comes from the fact that a metering decision is no longer simply a question of how to best accomplish the historical metering function, *i.e.* measuring and retrieving simple usage data for billing purposes. Today, advances in metering and communications technology mean that a metering system can become an informational gateway between an electricity provider and its customers as well an a key enabling tool that provides both with new benefits and capabilities that have not historically been associated with the metering function. Add the fact that these benefits accrue in areas that have historically had nothing to do with metering and the challenge becomes apparent – identifying, quantifying and evaluating all of these benefits in a cohesive and comprehensive manner.

In terms of a conceptual approach, a useful analogy may be that of the transition from use of adding machines or calculators to personal computers for performing calculations and other computational functions. An adding machine satisfactorily met the purpose for which it was primarily, perhaps even singularly, designed, *i.e.* number "crunching". But that is all it did. It provided no added value nor new capabilities, either related or unrelated to its primary function. With the introduction of personal computers, a new technology arrived that did the basic function of the adding machine and calculator, but of course was capable of much, much more. In terms of the business world, the additional functions and benefits that computers introduced created a new world of business operations and a new level at which businesses could perform. While it may still be possible for certain small companies to use adding machines in their business operations, it is a rare business today that can be competitive and produce and support its products and services without the added value and additional capability of computers, particularly with respect to the media storage and communication abilities that they provide.

For decades, electricity meters have had a simple job to perform: accurately and reliably measure the amount of electricity used at a particular location such that correct and accurate bills based on total usage can be rendered to the electricity customer by the electricity provider. While electricity costs have always been much higher during peak periods, technology did not exist or was too expensive to record time-based usage. Accordingly, regulators designed rates based on total consumption, and required nor expected any further functionality from the meter.

The cost of a computer is obviously higher than an adding machine. Yet almost every business has replaced its still-functional adding machines with computers, understanding the cost as an investment, where the return on that investment would not be measured simply by the ability of the computer to replicate the computational functions of the adding machine.

Today, new technologies have entered the metering arena. With the advent of new electronic and digital metering technology, as well as the introduction of new data communication media and technologies, the modern electricity metering system is no longer simply an "adding machine". It is a combination of hardware and software that goes far beyond the historical metering requirement and provides new capabilities and new benefits. But it is not only the technology that is different, today. The electricity industry is different. It is an industry that, whether or not it may be moving to wholesale and retail competition in a particular state or region, is changing in terms of the expectations placed upon it by electricity customers and by those who legislate and regulate on behalf of those customers.

Importantly, many of the benefits of advanced metering, if not most, accrue directly to ratepayers in the form of lower peak power costs and higher reliability. Since these benefits typically do not accrue to utility shareholders, the benefits are usually excluded from metering business cases. Since ratepayers are receiving these benefits, ratepayers have an interest in paying for the technology that enables them.

It is in this context that DRAM recommends parties to this proceeding view the questions and the issues at hand. The advanced meters that the Commission believes should be deployed in Idaho provide a number of different types of benefits that accrue to different parties in different ways – benefits that go beyond the core task of “revenue” metering. It is DRAM’s contention that when all of the benefits are considered against correct, appropriate and up-to-date costs, that advanced metering is a prudent and proper investment by Idaho utilities on behalf of their customers.

Question 1: Should the Commission direct the Company to implement AMR on its system?

Before this question can be answered, it is necessary to define what is meant by “AMR”. While sometimes mistakenly interpreted as an acronym for “advanced” meter reading, AMR in actuality is an acronym used within the metering and energy industries for “automated” meter reading. Whereas a Automated Meter Reading system provides only one advantage over basic, historical metering technology, in that it allows the collection of measured data to be done via a mobile, “drive-by” system, a true “advanced metering” AMR, (hereinafter “Advanced Metering System”) provides many additional benefits. DRAM discussed these benefits in its December 6, 2002 filing and it will refer to such in these comments as well.

It is important to note that these benefits are in addition to the automation of meter reading. Remote meter reading is a standard part of either an AMR system or an Advanced Metering System; it is not an either/or factor between the two.

If the Commission is asking Question # 1 in the context of basic Automated Meter Reading, DRAM would submit that the answer is no. To invest in such technology would not provide the additional technological and functional capabilities that Idaho electricity consumers will desire nor provide Idaho providers with additional capabilities with which to modernize and optimize their operations. It may the case that an expenditure on such a system may not be an investment at all, where an investment is defined as an outlay of capital that will provide future returns and benefits.

To the question of whether the Commission should direct the deployment of an Advanced Metering System, the rebuttable presumption should be yes, in the sense that absent such metering being in place, meter reading costs will be higher than necessary, customers will still be receiving only minimal data about their consumption and will not be able to choose to manage their usage according to time-varying prices, and Idaho providers will not have any enhanced data or functionality with which to improve and optimize their operations and performance.

A variation on this question, which is raised by the 2003 AMR Report, is the question of whether the Commission's direction should be to immediately proceed to a full deployment of advanced metering or whether it should proceed in stages. Idaho Power Company (hereinafter "Idaho Power" or "the Company") suggests in the subject report that it may be appropriate for the Company to undertake an implementation in a phased manner. Metering deployments often occur over a period of years and such an approach makes sense in this case.

There is an important caveat that accompanies the answer to this question, however. If the Commission is to direct electricity providers in Idaho to deploy and implement advanced metering, it must also provide a means of recovery by the regulated provider of the cost of such investment. In the case of Advanced Metering System where many of the benefits accrue, either directly or indirectly, to the ratepayer, it is proper for the costs of this investment to be recovered in rates and for the utility to receive regulatory certainty that those costs will be recovered.

Question 2: How can advanced metering technology enable Idaho Power Company and ratepayers to make the most of the future "smart" grid transmission and distribution technology?

The term "smart grid" is not defined in the Order; while this term is frequently being used in the energy industry today, it is subject to broad interpretation. DRAM would offer that, however defined, many of the non-billing and customer services capabilities that an Advanced Metering System provides are functions that help create a "smart grid", *i.e.* that a grid cannot be considered "smart" unless it includes a "smart" metering system. These functions include, but are not limited to:

- Interfacing with an outage management system to respond more efficiently to outages and provide better information to customers on the scope and status of outages, particularly automatic verification of restoration at the individual customer level.

- Collecting meter information and matching this with connectivity information in order to construct system loading models that can be used for both long-term planning and daily operations decision-making.

- Collecting and analyzing circuit and transformer loading and outage data to improve distribution system planning and optimize distribution system investments

- Combining the advanced metering system with load control capability to create a fully functioning demand response program, capable of managing loads as well as validating load reductions and results.

- Collecting and analyzing selected voltage data to ensure proper operation of the distribution system.

The Company benefits from lower meter reading costs and savings on distribution investments. Ratepayers will from higher quality service, reduced personnel cost, more demand response options, and a better managed system that will decrease the need for expensive new generation.

Question 3: As part of a wise investment, what features or technology should the Company employ?

By completing a detailed market analysis in the context of its own specific geographic and other requirements, the Company has correctly determined the appropriate technology for it Advanced Metering System. In addition, the Company has conducted a pilot to ensure that its Idaho ratepayers would have coverage over the great, and varied terrain of its service territory. Company's 2003 Report shows that the results of its analysis has led it to focus on a technology option which is indeed an Advanced Metering System according to the energy industry's generally accepted definitions of Advanced Metering. This analysis also involved a pilot of the technology to ensure that it would serve all of the Company's customers throughout the dispersed area, and varied terrain of its service territory.

Members of the DRAM Coalition agree that an appropriate advanced metering and communications technology should be capable of meeting the following definitions:

Demand Response - Retail
Pricing programs or rate structures, including time-of-use and real-time prices, which provide energy consumers with a price per unit of energy that varies according to the period in which the energy is purchased or consumed.

Time-Based Pricing
Retail prices for energy consumed that offer different prices during different time periods and reflect the fact that power generation costs and wholesale power purchase costs vary during different time periods. Includes Time-of-Use Pricing and Real-Time Pricing.

Time-Of-Use Pricing

Energy prices that are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year (summer and winter season). Prices paid for energy consumed during these periods are 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 consumption overall. The time periods are pre-established, typically include from two to no more than four periods per day, and do not vary in start or stop times.

Real-Time Pricing
Energy prices that are set for a specific time period on an advance or forward basis and that may change as often as hourly. Prices paid for energy consumed during these periods are typically established and known to consumers a day ahead ("day-ahead pricing") or an hour ahead ("hour-ahead pricing") 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 consumption overall.

Advanced Meter
An electric energy or natural gas meter, new or appropriately retrofitted, which measures and records usage data, at a minimum, in hourly (electric) or daily (gas) intervals, and which allows electric energy or natural gas consumers, suppliers and service providers to participate in price-based demand response programs and manage the purchase, sale, and use of electricity or natural gas in response to energy usage data that consumers, suppliers and service providers receive on at least a daily basis.

Advanced Metering Device
Equipment, systems, software, and/or related devices which have as a purpose the measurement and recording of usage data, at a minimum, in hourly (electric) or daily (gas) intervals, and which allows electric energy or natural gas consumers, suppliers and service providers to participate in price-based demand response programs and manage the purchase, sale, and use of electricity or natural gas in response to energy usage signals that consumers, suppliers and service providers receive on at least a daily basis.

Retrofitted Meter
An electric energy or natural gas meter or metering device that has been modified by the addition of equipment, systems, software and/or related devices which have as a purpose the measurement and recording of usage data, at a minimum, in hourly (electric) or daily (gas) intervals, and which allows electric energy or natural gas consumers, suppliers and service providers to participate in price-based demand response programs and manage the purchase, sale, and use of electricity or natural gas in response to energy usage signals that consumers, suppliers and service providers receive on at least a daily basis.

The technology being focused on by the Company is capable of meeting the metering definitions and supporting the pricing structures above. It therefore meets the technology test of being a wise investment.

Question 4: Under what time frame should the Company implement AMR?

DRAM believes the Company's proposed timeline of four years is reasonable. The Company's plan, particularly as it pertains to working out the inevitable hiccups and bugs of a new system before it deploys in the denser urban areas, seems prudent. The one caveat is that the tax benefits of the accelerated depreciation under the Economic Stimulus Bill are scheduled to expire in 2005. Further, if the proposed Federal Energy Bill is passed it provides an accelerated depreciation tax deduction for Advanced Metering deployed from 2004 through 2007. The Company may desire to calculate these tax benefits to analyze the cost/benefit of delayed or accelerated deployment.

Generally, electric utility equipment such as meters and related substation equipment is depreciated, for income tax purposes, over a 20-year recovery period. Software is typically depreciated over a 3-year (36 months) period. Due to recently enacted legislation, there are potentially significant current income tax benefits that accrue to suppliers of electric energy (such as Idaho Power) if such suppliers purchase and place in service equipment, including software, meters and related substation equipment. Current tax law provides for 50% bonus depreciation on certain property that is placed in service prior to January 1, 2005. Thus, 50% of the cost of such property, including software, which is placed in service prior to January 1, 2005, is recovered in the 1st year. The remaining cost is then depreciated over its applicable recovery period. This cost recovery provision can generate substantial tax cash benefits by reducing Federal income taxes in the year such property is placed in service. The greater the amount of software, meters and equipment placed in service prior to January 1, 2005, the greater the current tax benefit accruing to the electricity supplier.

These benefits will be magnified further if pending legislation is enacted. Pending legislation (the Federal Energy Bill) would, in addition to the 50% bonus depreciation, allow a current tax deduction (up to a maximum deduction of $30 per device) for Advanced Metering Systems placed in service during the years 2004 through 2007. Further, additional pending legislation would decrease the recovery period for such systems from 20 years to 3 years. Thus, there could soon be available potential tax deductions of up to $30 per meter in the 1st year placed in service, plus 50% bonus depreciation in the 1st year placed in service, with the remaining cost of each meter being depreciated over a 3-year period (as opposed to a 20 year period). These additional income tax benefits provided by pending legislation would further reduce Federal income taxes in the first year, and would provide increased tax depreciation deductions for the remaining 3 years.

Question 5: How should the Company recover the costs associated with AMR?

DRAM will refrain from making a specific recommendation in terms of how the revenue requirement of the investment should be determined and how that rates relative to such should be specifically designed. The important point is that the costs should be recovered, subject to cost verification, as a prudent and appropriate investment in a provider's core infrastructure which will provide both future and current benefits to the provider and, either directly or indirectly, to its customers.

One issue that should be considered is that the metering systems in question are no longer simply mechanical hardware devices. Advanced metering systems represent state-of-the-art combinations of electronic/digital hardware and software. As such, they need to be considered for treatment of such in terms of depreciation and other cost recovery components. As noted above, pending legislation in the U.S. Congress recognizes this development by providing advanced metering systems with special tax deductions, including accelerated depreciation.

Another issue is the anticipated savings. Since many of the savings will accrue to ratepayers in the form or lower power costs in the long term, it may be appropriate to consider including any incremental cost in per kWh (as opposed to per customer) charges. In any case, Idaho Power is in the best position to make a specific cost recovery recommendation.

Additional Comments

A. Cost Allocation over the Four-Year Deployment Period

The May 9, 2003 AMR Report of Idaho Power raises questions as to how the costs are allocated over the four-year deployment. Based on the number of units expected to be deployed in the first year, and taking into consideration the specific characteristics of that part of the Company's service territory, it appears that the cost indicated in the Report for this first year may be high. This could result in two problems. First, it may inappropriately raise the cost estimates based on different assumptions as to when an outlay must be made, *i.e.* presently or discounted as a future outlay. Second, it may distort the comparison of costs and benefits, when certain benefits, particularly those not related to meter reading savings, occur in later years.

This again brings focus to the need to balance costs and benefits. In that vein, DRAM finds insufficient assessment and quantification of the benefits of the Advanced Metering System in the report. The only benefit that appears to be included is that of savings on the meter reading function. Yet other benefits will accrue.

One of the challenges with advanced metering when it is employed to enable customers for demand response (which was and presumably still is a major driver for the Commission's action in what began as a TOU proceeding) is that is that some of the benefits accrue more directly to the customer than to the provider itself. For example, in a TOU program, customers benefit by shifting their load to lower their bill, and in doing so other non-participating customers also benefit from the downward pressure on peak wholesale prices that such shifting yields. While this customer behavior can also be of benefit to a utility in terms of its ability to optimally and reliably operate its system, it can also lead to lost revenue for the utility, particularly through the conservation effect that normally occurs in addition to that of load shifting.

The important point here is that the benefit to customers is real. It should be recognized as such and included as a benefit of advanced metering to be weighed against the cost. This should be the case even if a demand response pricing program is not immediately implemented since the capability for such will have been implemented via the deployment of advanced metering.

By comparing a cost for an Advanced Metering System that is not "plain vanilla" to the sole benefit that comes with a "plain vanilla", *i.e*. basic Automated Meter Reading system, the 2003 AMR Report may have created an apples to oranges situation. DRAM believes the Commission should review and discuss both the cost and benefit data with the Company to remedy this situation before making a decision.

The example above also ties to the question of cost recovery for the utility. Utilities should be allowed to recover the costs of an Advanced Metering deployment in rates in recognition of the benefits to its customers that are provided and/or enabled as a result of such.

B. Storage of Hourly Interval Data

In addition to further quantification of the benefits, there are questions to be raised regarding the some of the costs alluded to in the 2003 AMR Report. DRAM questions the need to store all hourly data, per Idaho Power's 2003 AMR Report (see p.21). On one hand, Idaho Power included only the benefits of MONTHLY reads, but on the other included the costs of data storage for HOURLY reads. Given the redaction of the Report, DRAM is unable to ascertain:

- The costs associated with "Additional Data Storage to Handle Hourly Meter Readings"
- The methodology IP chose to store the data
- Whether the hourly data stored was to be incorporated/integrated directly into IP's CIS.
- Whether the costs included ALL hourly reads from ALL meters, or only hourly reads from that subset of Customers who would be on a Critical Peak Pricing rate and only those relevant hourly reads

It does not seem logical to include a cost of hourly data storage, unless one also calculates the benefit. Since, the Commission has not yet created a Critical Peak Pricing (or other Demand Response type) rate utilizing hourly data, it does not seem fair to impose upon the Company an obligation to store such data. Once, a Demand Response rate has been created then "an apples to apples" comparison of cost/benefit may be undertaken. For example, the Oregon Public Utilities Commission ordered PacifiCorp and Portland General Electric to "evaluate demand response programs on par with other options for meeting energy and capacity needs." (Order 03-408, In re Demand Response Programs, Oregon Public Utility Commission http://www.puc.state.or.us/orders/2003ords/03-408.pdf).

If this Commission believes nonetheless, that this cost should be included, the questions remain "how and how much of the hourly reads should be stored?" in order to accurately assess the cost impact. The hourly data could be archived on tape drive for a, relatively speaking, nominal amount. If the Company is not required to bill off the hourly data, this may be a completely acceptable solution. The question also arises as to how much of the data must be stored. DRAM cannot ascertain how the Company calculated its storage needs. DRAM is under the assumption that the storage would be of 3 years data. If the Company simply took each meter and multiplied by 24 and then by 365 and then by 3 (24x365x3) that results in storing 26,280 meter readings. However, if the Company's requirement to store data only related to the Hourly readings during a Critical Peak Pricing ("CPP") period it would be substantially less. Usually, CPP rates are only imposed on customers for a limited number of days during the year (generally ten to twenty days) and only for a portion of the day (usually between 4 to 8 hours). If one took 20 days by 8 hours for 3 years (20x8x3) that results in storage of 480 meter readings, substantially less than 26,280.

DRAM does not know exactly how the Company quantified the costs, but in any case believes this cost component if included, should not be constructed in such a way as to impose unreasonable costs on the Company.

C. "Plain Vanilla" AMR

The 2003 AMR Report claims to have evaluated a "plain vanilla" power line carrier technology that is "capable of replacing the functions currently performed by existing meter reading technicians". With this definition, "vanilla" would appear to clearly refer to a basic Automated Meter Reading system, as opposed to an advanced system. Yet, as the 2003 AMR Report goes on to state, the Advanced Metering System referred to does more than the basic automated reading function.

D. Advanced Features Requiring Additional Investment

Several comments are in order in response to this section on page 11 of the Report. Contrary to the Report, the system being contemplated would allow Critical Peak Pricing, although the report is correct that some modifications to the customer billing system (or Customer Information System or "CIS") would be necessary. Finally, the Report also infers that an investment would be necessary to be able to communicate price signals to customers for "advanced pricing". This is not necessarily the case. Various existing communication media can be employed in a time-based pricing program, including conventional Radio and TV and Print for notification of Critical Peak Days and/or TOU price changes. The Internet and email also can be utilized. Also, the bill itself becomes a communication medium as it begins to provide more information about the magnitude and frequency of price signals.

E. Potential Risk of Obsolescence

Technology obsolescence is a valid factor to be cautious about in a decision on any investment in today's world. It is prudent criteria for a provider and regulator to consider. But at the same time, it cannot be the sole threshold criteria for an investment. If so, it could easily lead to a continuous attempt at "technology-timing" whereby an investment is never made for fear of something better or cheaper being on the market the next day.

The key with a metering system is to choose a technology that provides the immediate functionality desired but which also allows additional functionality to be employed or added later. It should be a platform that can accommodate future technology developments and not require complete replacement to meet anticipated and unanticipated future requirements.

In its concluding section with its recommendation, the Company infers that further technological development in metering is necessary. It states that one of the reasons to wait to deploy advanced metering is that the technology will increase in functionality. DRAM cannot discern from the report what this increase in functionality might be. In fact, all of the functionality that is discussed anywhere in the report is available with today's advanced metering technology – and more.

Conclusion

The essential question before the Commission, as it always must be, is that of what is best for ratepayers. DRAM submits, that *prima facie*, the best for ratepayers is to deploy a metering system that will provide them with benefits now, as well as in the near term and on into the future. As with many technology investments, the important issue is that of whether a certain technology will allow the owner or user to reap future benefits, contemplated now or as yet unidentified. The alternative would be to make a technology "expenditure", as opposed to an investment, where the former may address an immediate need but provide no capability for anything else.

Advanced Metering Systems represent a prudent investment made now on behalf of Idaho ratepayers. With its present costs and its technological and functional capabilities, there is no need to risk either a shortsighted expenditure on a less-capable metering system, or the trap of waiting for the next "big breakthrough" on costs and features.

DRAM recognizes a major component of the benefits of an Advanced Metering AMR system is the automation of the meter reading itself. Those benefits usually are greater in the rural areas and represent areas where the benefits can often be more quickly captured.

Those areas may also experience a much higher ROI. For example, Kootenai Electric Cooperative calculates a 5 year Return on Investment by implementing the same PLC technology as piloted by the Company. The 5 year ROI Kootenai hopes to achieve was calculated on the basis of 1) improvement of its meter stock, and 2) the savings on its meter reading expenses. (See, Systems Watch, Summer 2003, Vol.17, and Ed.2, p.5 Schlumberger Electricity, Inc.). If the Commission allows the Company to implement an Advanced Metering System in the remote areas, DRAM is confident that the Company can achieve a much better payback than 21 years.

Accordingly, the Commission's Order No. 29210 staying Order 29126 should be lifted and, as previously directed, the Company should file a four (4) year implementation plan for deployment beginning April 2004. The deployment should be in several phases with the first phase comprised, as proposed, of the Company's rural and operationally isolated residential ratepayers.

Respectfully signed and submitted this 15th day of August, 2003

Dan Delurey

____

Dan Delurey
Executive Director

Dan Delurey
Executive Director
Demand Response and Advanced Metering Coalition (DRAM)
P.O. Box 33957
Washington, DC 20033
Telephone: 202.441.1420
Email: dan.delurey@dramcoalition.org