Demand Responsive Programs - An Emerging Resource for Competitive Electricity Markets?

Dr. Grayson C. Heffner, Lawrence Berkeley National Laboratory, Berkeley, CA
Charles A. Goldman, Lawrence Berkeley National Laboratory, Berkeley, CA

ABSTRACT

The restructuring of regional electricity markets in the US has been accompanied by numerous problems, including generation capacity shortages, transmission congestion, wholesale price volatility, and reduced system reliability. These problems have created significant new opportunities for technologies and business approaches that allow load serving entities and other aggregators, to control and manage the load patterns of their wholesale or retail end-users. These technologies and business approaches for manipulating end-user load shapes are known as Load Management or, more recently, Demand Responsive programs.

Lawrence Berkeley National Laboratory (LBNL) is conducting case studies on innovative demand responsive programs and presents preliminary results for five case studies in this paper. These case studies illustrate the diversity of market participants and range of technologies and business approaches and focus on key program elements such as target markets, market segmentation and participation results; pricing scheme; dispatch and coordination; measurement, verification, and settlement; and operational results where available.

Introduction

Demand Responsive Programs, once called Load Management, have recently re-emerged as an important element in the fine-tuning of newly restructured regional electricity markets. These programs, which can include everything from direct control of small customer end uses to voluntary load shedding by large commercial/industrial customers, have experienced explosive growth in number and participation over the past two years (Hirst 2001). The resurgence of demand responsive programs stems directly from their rediscovered value as a dual hedge against reliability risks such as generation shortfalls and transmission congestion as well as financial risks such as wholesale price spikes. The versatility of these programs has attracted the interest of many market participants in both traditional and newly competitive electricity supply markets.

The research described here is part of a larger LBNL effort, funded through the US DOE Restructuring and Electricity Reliability Program to examine the potential role of customer demand management in an overall program of power system reliability improvement. The objective of this particular project was to increase understanding of how new technology and new business approaches are being combined to create rapid innovation and explosive growth in the load management industry.

For reasons of both cost and time, the authors chose a "case study" approach to this initial survey of demand responsive programs. Three criteria were used to select the cases - innovation in technology or business approach, diversity of market players in traditional and competitive electricity markets, and type of demand response program (see Table 1).

Table 1. Overview of Selected Demand Response Programs

Case Study	Type of Organization	Type of Program
BPA	Federal Power Marketing Agency	• Large Customer "Demand Exchange"
Cinergy	Investor-owned G, T, & D Utility	• Voluntary Interruptible programs for medium & large C/I customers
PJM	Independent system Operator	• Voluntary interruptible programs – Emergency and Economic Options – for large customers
Puget Sound Energy	Investor-owned T&D Utility	• AMR-based Energy Mgmt Advisory Program for all customers • Thermostat control for residential customers
Wabash Valley Power Association	Rural Electric Cooperative	• Interruptible Program for large customers • Residential Load Control

We developed a standard survey protocol and conducted in-person interviews with program managers. Program characteristics of particular interest included:

- Motivation of the LSE or ISO for offering the program
- Exact nature of the pricing scheme
- Program operational details and results
- Customer participation and results, including customer retention
- Program costs, including hardware and communications requirements
- Industry issues and technology development needs

Overview of Selected Programs

Bonneville Power Administration

Utility Motivation: Bonneville Power Administration's (BPA) Power Business Line is transitioning its 1999-2000 Demand Exchange Pilot Program into a full-scale, system-wide offering. The program provides needed flexibility as BPA operators seek to optimize four operating objectives – least-cost, reliability, fish & wildlife management, and energy savings.

Program Design: The Demand Exchange, or DEMX, is an internet-based auction site where participants are alerted to real-time, day ahead, and two-day-ahead pricing and then can post their willingness to voluntarily curtail loads at a given price (Gilbert, 2000). The BPA version of the DEMX offering has two parts – a ***Voluntary Curtailment Option*** and a ***Pre-Purchase Option***. The Voluntary Curtailment Option is a classic "Quote Scheme", while the Pre-Purchase option is very similar to a "Call Scheme[1]" (Hairston, 2001a, 2001b).

[1] Many interruptible and curtailable programs have separate "quote" and "call" options. A "quote" program allows the customer to specify when and at what price they are willing to reduce load. A "call" option requires the customer to reduce load when called upon or face penalties.

Program Operations and Results: Both the ***Voluntary Curtailment Option*** and the ***Pre-Purchase Option*** are operated on a day-ahead basis. BPA seeks out end-users whose electricity costs make up a large portion of operating costs and who have some flexibility to change their pattern of electricity use. Participants include municipal and investor-owned utilities serving as aggregators, direct-serve customers, and several large retail end-use customers of the resellers. Pulp and paper and aluminum/basic metals were the two most represented SIC codes.

As of April 2001, BPA has signed up 14 customers with ~525 MW of potential demand reduction potential. BPA has received over 6500 MWh of load reduction over the life of the program. Over 90% of these load reductions have occurred since December 2000 in response to high wholesale prices. BPA is currently averaging nine MW per hour of load reductions and has a target of ~25 MW per hour in 2001.

Conclusions: The most common use of these programs is as a hedge against energy shortages from the hydro system when wholesale purchase prices are high. When this is the case, usually during the winter peak months, BPA will initiate both day-ahead and two-day-ahead load curtailment requests covering many hours or even entire days. Such extensive use of the curtailment option for days or even weeks may result in customers reducing their overall manufacturing output. BPA is tracking closely any labor or regional GDP impacts that could be traceable to this use of the program.

Cinergy

Cinergy has consolidated its demand management programs into one umbrella offering - the ***PowerShare Pricing Program***. PowerShare provides customers with a menu of choices and is a market-based program of financial incentives that encourages Cinergy customers to reduce summer peak load (Darnell, 2001, 2000).

Utility Motivation: Cinergy has arguably the most aggressive demand management program in the U.S., driven in part because of their experience during the disastrous summer of 1999 when the wholesale electricity market experienced extreme price volatility in the Midwest. High temperatures, low rainfall, extended heat waves, and generation outages all combined to expose Cinergy and its customers to extreme price spikes and severe reliability problems. After Cinergy's well-publicized contract default and subsequent exposure to liquidated damages, the Company made a concerted effort to rapidly grow their demand management programs.

Program Design: To participate in the CallOption, the customer must have a potential load reduction of at least 500 kW. The customer will select a Strike Price (10, 30, 60, or 90 cents per kWh) based upon their own estimate of the costs of complying with curtailments. When the day-ahead market prices are projected to be greater than the Strike Prices, Cinergy can call the option by notifying customers by 4 pm the day ahead. In exchange for participation, customers receive a guaranteed premium plus an additional Energy Credit whenever they are called. The penalty for non-compliance is payment of market prices (assuming energy is available) or a penalty cap of $10 per kWh. Customers can specify a Firm Load Level; identify a generator (2 MW minimum) to operate; pledge a specific end use or process to shut down; or pledge a fixed reduction in their pro forma load. . Customers may also select among three levels of curtailment frequency and duration as specified in **Table 2** below.

Table 2: CallOption Choices Offered by Cinergy's PowerShare Pricing Program

Option	Max Duration	Period (time)	Calls per year	Consecutive days per week
CallOption A	8 hours	12-8 pm	12	3
CallOption B	4 hours	2-6 pm	12	3
CallOption C	8 hours	12-8 pm	4	4

The QuoteOption is much less complex. It is designed to be a no-risk proposition for the same group of customers eligible for the CallOption but who are reluctant to commit to a Firm Load Level or be subject to non-compliance penalties. Customers pre-specify only the type of load block (load reduction from a pro forma load shape or generator of minimum 2 MW size to be switched on) and a Strike Price below which they are not interested in participating. The QuoteOption is a day-of program. Cinergy provides price quotes for the same day and interested customers must respond with an estimate of voluntary load reduction within one hour.

Energy credits are calculated as the product of kW reduction, hours of curtailment, and the selected Strike Price. A single customer with 500 kW of curtailable load choosing CallOption and a $.15/kWh strike price would thus receive $14,000 of annual premium and $600 in energy credits each time they successfully curtailed their load. In the Shared Energy Credits scheme, customers can save up to 50% of the difference between their Strike Price and the projected hourly wholesale price.

Program Operations and Results: The Cinergy PowerShare website is a key vehicle for program operations. The web site for each customer contains their pro forma load shape plus price quotes for both the day-off and day-ahead program options. The customer accesses the web site and for the QuoteOption they can then nominate their loads for that day. The CallOption customers are also given notification by e-mail, cell phone, pager, or fax of an impending curtailment the next day.

Cinergy currently offers the PowerShare program to Cinergy customers with peak demands greater than 500 kW. Beginning in 2001, Cinergy will begin offering two new variants of the basic PowerShare program – *PowerShare Basic* and *PowerShare Lite* – to 750 additional customers with summer peak demands that range from 200 to 500 kW. These new programs target customers that don't yet have hourly interval metering or a dedicated phone line. The strategy is to offer a way for customers to put smaller blocks of load on offer for either the day-ahead Call or day-of Quote options. Readily-identifiable and measurable blocks of load, such as retail lighting or individual motors or drives, are likely to be the most-common load blocks that are targeted.

As of late 2000, over 90% of Cinergy's 312 large customers were participating in one or more of the PowerShare options. These customers together comprise 2500 MW of subscribed load. Cinergy estimates that as much as 600 MW would be available from these customers on a summer peak day with high wholesale prices. The per-customer load reduction expected averages about 10-15%, with some big customers (such as steel producers) able to drop as much as 50% of their pro forma loads.

In Summer 2000 there were over 300 customers participating with an estimated curtailable load of 440 MW. However, the weather was so mild that the program was not operated at all during the year. In 1999, with prices as high as $850/MWh, Cinergy received as much as 200 MW from the pilot program participants.

Conclusions: The Cinergy program illustrates that high market penetration can be achieved among large C/I customers with targeted and customized program offerings. However, the restricted annual number of hours (only 96 for the most-severe CallOption offering) makes them more suitable for emergency as opposed to economic operations. The extension of these offerings to medium-size C/I customers without interval metering is a key development to watch in 2001.

PJM Interconnection, L.L.C.

PJM Interconnection, L.L.C. became the first operational Independent System Operator in the U.S. on January 1, 1998, managing the PJM Open Access Transmission Tariff and facilitating the Mid-Atlantic Spot Market.

ISO Motivation: In response to a May 2000 Federal Energy Regulatory Commission (FERC) order that directed ISOs to expedite procedures for including distributed and demand-side resources in bulk power markets, PJM formed the Distributed Generation User Group (DGUG). The PJM DGUG focused on developing pilot demand response projects that would help identify key issues and requirements for future system-wide programs (Bressler, 2001).

Summer 2000 Pilot: The Summer 2000 temporary pilot provided compensation for end-use customers willing to reduce energy consumption from the PJM system during emergency conditions. Upon declaration of a Maximum Generation Emergency Event, PJM would request participants to reduce load, and all participants that did so would be paid the higher of $500/MWh or their zonal Locational Marginal Price (LMP) for the reduced consumption.

The Summer 2000 Customer Pilot Program was operated on a strictly emergency basis. Since PJM has a $1,000 per MWH price cap on all in-system purchases, the criteria for operation was a Maximum Generation Emergency Event, which immediately precedes going out of system to purchase Emergency Energy at any cost.

Summer 2001 Pilot: Greater efficiency would exist in the PJM marketplace, and indeed the existing $1,000/MWh cap on generator bids might not even be necessary, if the load in PJM could respond to high prices and reduce demand during times of short supply. The main obstacle to tapping the potential of price-responsive load in the PJM system is the fact that most end-use customers are not exposed to real time prices. In addition to end-users not being exposed to real-time price signals, Load Serving Entities (LSEs) may pay more for energy in the wholesale market than they collect from their retail customers during times when the wholesale energy price in the PJM market rises above the applicable retail rate. The Summer 2001 Load Response Pilot Program includes two options (Emergency and Economic) and will test whether the ISO, working directly with both LSEs and customers, can begin to tap these potential savings.

PJM expects that the Emergency Option will attract principally large industrial customers and is similar to the program offered in 2000. The Economic Option is based on the economic decisions of the PJM market participants in response to market conditions. Participants in this Pilot Program are responsible for determining when load reductions will take place and implementing the reductions should pre-determined conditions arise. The prime indicator will be the Locational Marginal Price (LMP) of energy on the PJM system. In order to maintain system control, PJM operators will be know the amounts of load expected to be reduced at different price levels. (These amounts may change on a daily basis.) Each PJM market participant is therefore responsible for informing PJM daily of the amount of load reduction for which they have contracted in each PJM zone, and the price at which that load may be reduced. A web page will be created through which market participants may submit the expected amount of load reduction, together with the LMP values at which the load may be reduced. PJM will then compile daily aggregate load reductions on a zonal basis for use in operations.

Conclusions: The PJM philosophy is that economic programs will lead to a shift away from Active Load Management (ALM)[2] and emergency-type programs and towards real-time pricing and interval metering for all customers. This will lead to power systems and markets that are decentralized and market-driven, with less of a need for highly centralized ISO-style command and control procedures.

Roles and responsibilities among organizations participating in demand response programs offered by newly formed ISOs are not fully resolved. Some Transmission Owners and LSEs have raised concerns that they will lose distribution revenues as a result of these new programs. Distribution companies are uncertain as to whether they want to get involved and, if so, in what role – aggregator? Some LSEs – notably PP&L – are already very active in the area of price-responsive demand management and see the ISO as a competitor.

Puget Sound Energy (PSE)

Puget Sound Energy is a $2 billion investor-owned utility providing electricity, natural gas, and energy related services to 1.2 million homes and businesses in Washington. PSE has been steadily implementing integrated technologies including Automated Meter Reading (AMR) and advanced Customer Information Systems (CIS).

PSE has two distinctive programs now underway:

- Personal Energy Management Program. This is essentially an **information** program. Customers are provided an informational bill showing usage by time of day and are given advice on how to shift usage away from on-peak periods. Customers can then track their progress in shifting their usage from bill to bill.
- Home Comfort Control Program is a cooperative pilot project between Carrier, Silicon Energy, Schlumberger CellNet and PSE. About 110 residences were fitted with controllable thermostats that could be remotely accessed to adjust the set point. Customers agreed to allow the utility to adjust the thermostat by up to 4 ^{o}F. A key feature of the program was a PSE-managed web site from which set point adjustment commands could be sent and thermostat status monitored using the AMR communications medium. Customers were given the option of over-riding the utility control of the set point but were charged a penalty when they did so.

Motivation for PSE: The main drivers for PSE are the ability to offer value-added services to customers, and the flexibility gained with a customer communications system that can provide dynamic pricing.

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[2] Active Load Management programs are defined as those that can be directly dispatched by the ISO or the LSE. The ALM programs are a legacy resource embedded in the operations of PJM's LSE members, and include three types of programs: Direct load control (DLC), where load management is initiated directly by the LSE's control center using a communications signal to control equipment such as air conditioners and water heaters; Firm Service Level (FSL), where load management is achieved by a customer reducing its load to a pre-determined level upon notification for the LSE's control center; and Guaranteed Load Drop (GLD), where load management is achieved by a customer reducing its load by a predetermined amount upon notification from the LSE's control center.

Motivation for Customers: Customers have embraced the concept. PEM was originally contemplated as a four-month pilot, but it has been so successful that it has been continued indefinitely. A business version – "Business Energy Management" – is also available. Once time-of-day rates are introduced, bill savings will become a motivator for customer participation.

The Comfort Home program was also very popular – especially the value-added capability to remotely access and control their thermostat for pre-heating or other purposes. Customers appreciate being able to log on to the internet, see the temperature and temperature setting in their house, make their own adjustments to the set point, and have the power to over-ride the utility if they want to (this happened only a few times).

Current Customer Participation and Results: As of late 2000 there were 400,000 customers with AMR who were eligible for the PEM program. The early load impact results (based on November, December, and January) indicate a 3-4 % shift in usage from the "expensive" to the "economy" and "bargain" periods.

The Home Comfort Control program pilot was conducted between February and April 2000. During this period the 105 voluntary participants experienced 41 two-hour "setback episodes", during which their thermostat control was adjusted either 2° F or 4° F lower than the usual set point. Customers over-rode the utility control on only three instances and in most cases the customers did not even notice that utility control was exercised. A load impact regression model (Puget Sound Energy 2001) was used to analyze the demand impacts of morning, mid-day, and evening "set-back episodes" of both 2° F and 4° F. Although the results varied between these cases, reductions of 1.2 to 1.6 kW were observed for morning and evening setbacks of 4°F. Energy savings were modest – about 1-3 kWh for the 4°F setback and negligible for a 2°F setback.

Conclusions: Both types of programs can work wherever prices are volatile and the regulatory environment is supportive. However, both programs require significant investment in a backbone communications system such as AMR. Since this experiment was for residential space heating only, the potential for summer air conditioning demand reduction was not measured.

Wabash Valley Power Association (WVPA)

WVPA distributes electricity to member co-ops who in turn serve 200,000 residential, commercial and industrial customers located throughout Indiana, southern Michigan, and northwestern Ohio. WVPA operates two load management programs: a commercial-industrial voluntary interruption program (***Customer Payback Plan***); and the ***"It Pays to be COOL"*** residential air conditioner and electric water heater control program (Mizelle 2000, 2001).

Motivation for WVPA: Wabash offers these programs as part of their efforts to keep power costs down by providing a hedge against wholesale price volatility. In 1999, which was a very bad summer in the Midwest, WVPA saved millions of dollars in avoided high-price wholesale purchases as a result of its load control program. They calculate that in just one week during June 1999 the water heater program paid for itself by saving over $500,000 in expensive power purchases.

Motivation for Customers: The customer participates to save money and support the utility's efforts. Participation in the COOL (Conserve Our Overall AC Load) Program earns residential customers an annual payment of $25.00. Customer Payback Plan participants can save $250/MWh for all reduced usage or generated energy when an "energy management period" is declared. Program literature uses the example of a customer with a 250 kW back-up generator that operates for 100 hours at utility request. The customer would make over $6,000 in "payback rewards" ($250*100*250/1000) plus the savings in avoided power purchases.

Program Design and Operation: Both programs are focused on the summer season and are designed specifically as a hedge against wholesale price volatility. Customer Payback Plan participants must be over 50 kW to participate but do not have to have hourly interval meters. Interested customers work with customer reps to conduct a Facility Review and work out ahead of time very specific load curtailment strategies that would yield the pledged load reduction during summer afternoon peak periods. Customers with auxiliary or emergency generators are especially sought-after. The utility notifies the customer by 4 pm the day before and energy management period is expected; frequency is no more than 10 days per summer. Following an energy management episode, utility staff will use a variety of methods to estimate the amount of reduced energy or the output of the generator. These methods might include, depending on the customer, direct metering, analysis of demand and energy components of bills, timers or data loggers on specific end uses, and examination/comparison with baseline or benchmark data collected during the pre-season Facility Review. Obviously, these non-interval-metered methods require a high degree of collaboration and trust between the customer and the utility representative.

Results: The residential appliance control program currently delivers an estimated 30 MW of load relief in summer and 20 MW of load relief in winter. As of 2001, the Customer Payback program included 250 customers capable of delivering as much as 30 MW of load curtailment. The agricultural irrigation pump load control program has 130 participants and about 30 MW of controllable load. There was no need to operate any of these programs during Summer 2000, as it was unusually cool and wholesale prices stayed low.

Conclusions: Co-ops have a unique niche in terms of serving rural loads. Over 31,000 MW of load – especially in the Midwest – is served by member-owned G&T utilities and distribution co-ops. These co-ops enjoy usually close relationships with their customers, where cooperation and trust can be real factors in the design and implementation of demand management programs. Wabash Valley Power substitutes simplicity in program design, a good multi-channel communications program, and what is basically an "honor system" for the large amounts of interval metering and other M&V hardware observed in other programs.

Comparison of Key Program Design Features

Table 3 summarizes key program design features of our selected demand response programs.

- Target Markets: "Mass market" (Violette 2000) programs for small customers vs. large customer demand responsive programs
- Dispatchability: Utility-controlled vs. customer-controlled loads
- Resource Firmness: Call (participation is pre-paid) vs. quote (participation is fully voluntary) programs
- Operational threshold: Emergency vs. Economic programs
- Exposure to & assignment of forecast risk: Day-ahead vs. day-of vs. real-time demand and prices
- Role of aggregators/Third Parties: How many relationships are in play?

- Shared savings scheme: Flat rate or variable according to market conditions.

Based on these cases, there is considerably more emphasis on large customer programs than on small customer or "mass market" programs. However, this may change as new technologies such as dispatchable thermostats and AMR advance in performance and affordability. Customer-controlled demand response programs continue to be much more common than utility-controlled alternatives, at least for the large-customer offerings. This too may change as "hybrid" approaches such as "permission-based control"[3] and dispatchable back-up generators become more popular. The degree of firmness of a curtailable load block is generally thought to be higher with "call" programs, where the customer is provided a reservation payment, then with fully voluntary "quote" programs. Another issue is the relative cost per MWH of call vs. quote programs and the optimal split between "reservation" and "performance" payments.

An important change over previous load management programs is the emergence of Economic vs. Emergency approaches to demand management. Most of the programs reviewed here are primarily economic in nature, as they seek to minimize the amount of expensive energy that must be purchased during periods of wholesale price volatility. In our five cases, only one – PJM Interconnection – was based on Emergency or Reliability needs. For some program administrators, the underlying philosophy is that demand response programs may provide a sufficient hedge of price-driven demand reduction in the long term that will minimize the need to implement demand management for reliability reasons.

Forecast risk is a not-well-understood issue that is revisited in the Research Avenues discussion below. Many of these programs are based on day-ahead or two-day-ahead price projection or strike prices which customers pledge load reductions in response to. Any risk that the spot price will be lower than the projected or strike price currently devolves onto the program sponsor.

Aggregators and "DMSCOS/CURTAILCOS" are new organizations that can potentially play a vital role in realizing the potential of demand response programs. Of these five cases only Cinergy has carved out a specific role for aggregators and other third parties to play. Marketing and recruiting participants for demand response programs may be an important niche for third parties.

We can observe numerous approaches to pricing and shared savings in even the few case studies reviewed here. Across programs, payment levels and the design of the payment schemes are complicated, non-uniform, and seemingly ad hoc.

Promising Research Avenues

Based on this initial review of selected demand response programs, we describe several promising areas where additional analysis and/or research would be useful to policymakers and program designers.

Analysis of Variations in Participant Payment and "Shared Savings" Schemes

Table 3 indicates a remarkable range in potential payment levels for participants in commercial and industrial load curtailment programs. Flat payments range from \$100/MWh for Cinergy's lowest Strike Price up to \$500/MWH for PJM's Emergency Pilot Program. Some programs offer a variable credit based on a share of the difference between a Strike Price or flat rate and the day-ahead forecast, day-of forecast, or actual hourly spot price. A quick calculation reveals that for any of the three days

[3] "Permission Based Control" or "Positive Control" requires that customers provide permission before a end-use load control switch is activated. The exchange of utility request and customer permission typically takes place via the inter-net or pager.

during the summer of 1999, when PJM prices approached the $1000/MWH cap (June 7, July 6, or July 29. See PJM 2000), the payment for the exact same customer participating in the different programs described here could be as low as $600 per MW for a six-hour curtailment to as high as $5000 per MW for the same period. Such an order-of-magnitude variation suggests that the participant payment schemes now in place have yet to be examined in a systematic fashion by either LSEs or end users.

Valuation of Interruptible Load

Several analysts have begun to address the analytic issue of how to value interruptible loads (Marcus 2000, PJM 2000, Hirst 2000). Such a method for valuation of interruptible load in various wholesale markets would provide a basis for designing programs and determining the break-even cost of important (but expensive) program components such as interval metering and two-way communications. It would also provide an objective "check" on the payments now being offered by LSEs and ISOs.

Assignment of Forecast Risk

Most of the programs described here have a participant payment scheme that is based on day-ahead or day-off projections of hourly interval prices. Only the PJM 2001 scheme pays participants strictly based on actual spot prices (LMP), which is inherently a risk-free settlement scheme. In addition, all of the load curtailment programs rely on participant pro forma load shapes that are simply a forecast based on average conditions for that customer. If a customer has a planned or unplanned process shut-down for the day of a curtailment it may not be possible to distinguish this condition from the expected condition where a customer reduces load in response to utility request. Both types of forecast require risk. An interesting analytical question is the relative magnitude of these risks and the implicit assignment of risk inherent in all of the programs except for the PJM program.

Proxy Methods for Estimating Load Reductions of Non-Interval-Metered End Users

Several of the programs involve customers who do not have interval metering. A key issue for regulators and planners is the level of reliability of proxy methods for estimating curtailable load reductions. One hypothesis is that the reliability level may be affected not only by statistical considerations but also by the nature of the relationship between the LSE and the end user.

Technology Development Needs

Most of the respondents cited specific technology needs that would refine or extend current demand responsive program offerings or enable new demand responsive program offerings. Among the enabling and facilitating technologies that are not now fully or cost-effectively available are:

- Web based communications and control – and the gateways to enable it
- Automatic dispatch & direct control over end-uses & customer-owned generation
- Energy management systems capable of optimizing home & small business end-use patterns based on forecast or real-time energy price inputs
- Affordable, easy-to-install interval metering
- Seamless extraction of data from customer meters
- New applications of two-way paging technology

Table 3. Distinctive Characteristics of Case Studies Analyzed

Case Study	Target Markets	Dispatchability	Resource Firmness	Operational Threshold & Frequency	Exposure to & Assignment of Forecast Risk	Aggregator-End User Interaction	Shared Savings Scheme
Bonneville Power Administration	Large Customer	Customer-controlled	Call at present. Quote program new in 2001	Economic	LSE pays based on day-ahead forecast of demand & price	Wholesale utilities can act as aggregators	Voluntary Curtailment Option: Based on day-ahead & variable "expected market price"
Cinergy	Large Customer*	Both	Both Call and Quote, but Quote participants must be Call customers first.	Economic	Day-ahead for CallOption; Day-of for QuoteOption	"DMSCOS" (Demand Mgmt Service Companies) encouraged	CallOption & Quote-Option have 2 energy credit options: Guaranteed Energy Credit- Product of flat "strike price", curtailment length, & load reduced** Shared Energy Credit is 50% of the difference between Strike Price & forecast wholesale price
PJM Interconnection LLC	Large Customer	Customer-controlled	All quote.	Both economic & emergency	Both Emergency or Economic option payments based on Spot LMP	Role of LSEs vs. ISO under discussion	Emergency option pays flat \$500/MWH or the LMP
Puget Sound Energy	Both	Customer-controlled	All quote.	Economic	Averaged costing periods	None	None yet – dispatchable TOD scheme proposed
Wabash Valley Power Assoc.	Both	Mass Market is Utility controlled; Large Customer is Customer Controlled	All call, plus direct load control.	Economic	Day ahead forecast of demand	None other than co-op member staff	For the Voluntary Interruptible Program, flat \$250 per MWH for curtailed energy

*Cinergy's plans to extend availability of *PowerShare* via *PowerShareLite* will change this
**Cinergy's CallOption customers also receive a Guaranteed Premium for their availability to be curtailed.

Conclusions

Based on this initial review of selected demand response programs, we would offer several conclusions:

- There is a rapid proliferation of a new generation of load management program.
- Two tiers of program sophistication are in evidence – simple bulletin-board-style posting and quoting programs vs. more-costly real-time communication & metering programs.
- Voluntary interruptible programs using both call and quote schemes seem to be applicable in most situations where end users can provide a hedge against high prices – regardless of whether the load serving entity is an ISO, an IOU, a rural cooperative, or even a FMA.
- The key discriminator amongst different end-users in terms of their ability to participate is their size and the availability of interval metering.
- Different LSEs have vastly different shared savings schemes. There does not appear to be an analytic basis for determining a reasonable allocation of savings/profits between end-users, LSEs, aggregators, and ISOs.

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