Demand Response:
Design Principles for Creating Customer and Market Value

prepared by

Peak Load Management Alliance

www.PeakLMA.com

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Preface

The Board of Directors of the Peak Load Management Alliance (PLMA) reviewed several drafts of this document with the understanding that its review did not constitute endorsement of all the recommendations either personally by the Board members or by their organizations. However, there is agreement that this version makes a positive contribution to the debate and the Board members in attendance voted unanimously in favor of the PLMA publishing this paper. It is recognized that additional information and learning about the role of demand response in energy markets will occur over time and as additional experiences are gained. The PLMA welcomes comments and encourages organizations and individuals to participate in discussions that will result in subsequent versions of this paper.

Acknowledgments

This policy paper developed under the active leadership of Mr. Ross Malme (Chair of the Peak Load Management Alliance and CEO of RETX) and Mr. Joel Gilbert (PLMA Vice-Chair and CEO of Apogee Interactive). Dr. Daniel Violette (PLMA Board Member and Principal, Summit Blue Consulting) served as the project leader and contributing author. Larry Barrett (President, Barrett Consulting Associates, Inc.) served as lead researcher, facilitator, and writer.

Many significant contributions came from PLMA Board members, as well as from outside contributors. Nathan Adams of E Source shared results of research on success factors for peak load management for large commercial customers. Research conducted by Bernie Neenan of Neenan Associates and Steve Rosenstock of Edison Electric Institute was particularly helpful. Prepublication papers regarding real-time pricing were provided by Ahmad Faruqui and Steve George of Charles River Associates and Melanie Mauldin. Paul Wattles of Good Company Associates assisted with the discussions on advanced meter reading, competitive metering, and mass market price response. Other contributors include Doug Backer of Cannon Technologies, Greg Bullington of KCP&L, Dave Kathan of ICF Consulting, Chris King of eMeter, Jay Morrison of the National Rural Electric Cooperative Association, Pete Scarpelli of RETX, William Smith of EPRI, Miriam Goldberg of Xenergy and Bill Uhr of UHR Technologies.

We particularly appreciate access to proprietary reports. Chartwell provided the *Report on Demand Response Programs*, and the *Report on Direct Load Control for Residential Customers*, both published in March 2002. Energy Info Source provided *Demand Response Programs* published in May 2002.

More information about PLMA can be found at – www.PeakLMA.com.

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Executive Summary

This information paper summarizes design principles for gaining customer participation, and creating customer and market value for demand response resources (DRR). The challenges to recruiting and sustaining DRR are many and varied, especially now with industry restructuring. The paper suggests design principles that help build value propositions for customers and equitably support efficient electric markets. These principles arise from the extensive experience of professionals in demand response and builds on the first policy paper of the Peak Load Management Alliance, "Demand Response: Principles for Regulatory Guidance."[1]

Demand response in electricity markets is defined as load response called for by others and price response managed by end-use customers. Load response includes direct load control such as residential air conditioners, partial or curtailable load reductions, and complete load interruptions. Price response includes real-time pricing, dynamic pricing, coincident peak pricing, time-of-use rates, and demand bidding or buyback programs.

Thus, a fundamental need for demand response resources is to develop value propositions for customers where the benefits or values received by customers exceed the costs or risks of participation. DRR provides many benefits, including:

- System reliability,
- Cost reduction,
- Market efficiency,
- Risk management,
- Environmental,
- Customer service, and
- Market power mitigation.

Even though these many benefits can be achieved reliably, rapidly, and flexibly, it is difficult for DRR to maintain a balanced relationship with supply side resources as

[1] Peak Load Management Alliance, "Demand Response: Principles for Regulatory Guidance," February 2002. Available at www.PeakLMA.com.

wholesale energy markets transition to more competitive structures. One challenge is to develop compelling value propositions to recruit customers that will provide the levels of load that achieve these market benefits. Market studies have shown that substantial benefits may result from having relatively small amounts (e.g., 5 percent of peak demand) of DRR available. Recruiting and maintaining over time this small but critical amount of load into DRR programs is one challenge to be met by DRR programs. These required value propositions need to be better incorporated into program designs to stimulate greater use of DRR. In particular, the following three types of design criteria may be distinguished:

- Participant criteria that determine attractive customer characteristics.
- Operations criteria by which the load resource is called or dispatched.
- Settlement criteria describing the financial arrangements.

The following sixteen design criteria are identified and discussed in the paper:

D-1. Communicate with customers on design and implementation
D-2. Keep program design understandable
D-3. Provide program choices
D-4. Accommodate small participants
D-5. Enable customer decisions
D-6. Leverage customer infrastructure
D-7. Address environmental priorities
D-8. Reduce high costs of customer equipment
D-9. Develop fair and practical baseline estimation procedures
D-10. Use advanced notification procedures
D-11. Compensate for full value
D-12. Reflect location and reliability values
D-13. Balance penalty provisions
D-14. Settle payments in a timely manner
D-15. Deploy multiple marketing strategies
D-16. Develop long-term capabilities and relationships.

These design principles will contribute to the deliberate development and regular utilization of DRR based on customer and market value. With attention to these design principles, demand response resources should become a significant, cost-effective, and long-term part of the energy marketplace.

The need to focus on DRR as a long-run resource in planning and market design is a key message in this paper and is discussed in design principle D-16. DRR may not be available to meet critical needs if it is not incorporated into the day-to-day and year-to-year planning by market participants. In some respects, DRR augments reserves, and even if not called upon substantively in a given year, DRR still can have considerable value.

DRR programs can be ramped up and down over different time periods, but they are hard to create from scratch. As a result, just as there are reserve margins, a target threshold of DRR, possibly as a percent of peak demand, may be a useful design requirement for some regions. If deemed desirable, an appropriate target threshold for DRR would likely vary by region and by overall cost-effectiveness.

It is important to recognize that DRR provides market benefits that are not easily captured such as mitigation of market power; incentives to innovate through price signals that represent the scarce commodity, i.e., on-peak electricity; and enhanced market efficiency that comes from having both demand and supply adjust to market signals. These benefits can be hard to quantify and put into a DRR payment to a participant. However, they exist and should be acknowledged.

In summary, there is significant market value in building long-term demand response capabilities. These capabilities would allow those customers that are able to alter demand in response to market conditions to have the opportunity to make these adjustments, and be able to benefit appropriately. Designing markets that allow for appropriate demand response is one component of an efficient market design. Both demand and supply need to have an opportunity to adjust to market conditions produce efficient market clearing prices for electricity. In addition, market agents such as RTOs/ISOs need to be able to select from an appropriate set of cost-effective resources to meet operating reserve criteria. Demand response can be obtained through pricing or various load response programs, but the appropriate infrastructure and customer relationships are needed to make this a reality.

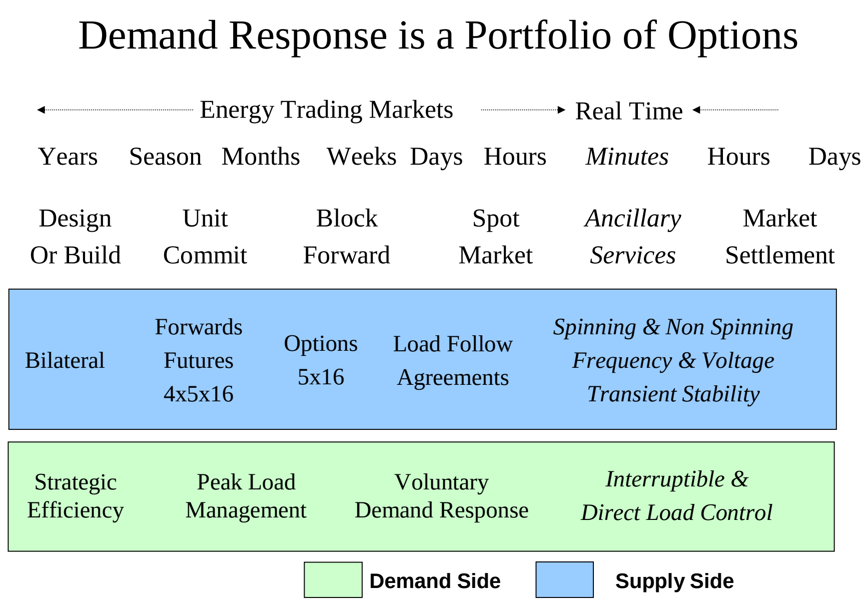
Note: Copies of this and other papers from the Peak Load Management Alliance may be downloaded at no charge from www.PeakLMA.com.

1.0 Introduction and Purpose

This information paper summarizes design principles for gaining customer participation, and creating customer and market value for demand response resources (DRR). The challenges to recruiting and sustaining DRR are many and varied, especially now with industry restructuring. The paper suggests design principles that help build value propositions for customers and support efficient electric markets. These principles arise from the extensive experience of professionals in demand response.

Demand response in electricity markets is defined as load response called for by others and price response managed by end-use customers. Load response includes direct load control, such as residential air conditioners, partial or curtailable load reductions, and complete load interruptions. Price response includes real-time pricing, dynamic pricing, coincident peak pricing, time-of-use rates, and demand bidding or buyback programs. These definitions come from an earlier paper by the Peak Load Management Alliance (PLMA) on "Demand Response: Principles for Regulatory Guidance."[2]

Demand response resources should be seen as a portfolio of options, each with its relative benefits and costs.[3] As shown in the chart, demand response serves the full range of timeliness in resource needs, from months to minutes. In addition, to the portfolio of options complementing generation resources, DRR supports transmission and distribution asset management. Energy efficiency and distributed generation resources further complement DRR through their probable contributions to peak management. While DRR may be viewed as competing with these other options, in practice all are important as the demand for energy continues to grow.



[2] Peak Load Management Alliance, "Demand Response: Principles for Regulatory Guidance," February 2002, p. 1.
[3] Joel Gilbert, "Customer Demand Response: The Four Not So Easy P's," Presented at FERC/DOE Workshop on Demand Response, February 14, 2002.

DRR can play a significant role in the market for ancillary services. "Ancillary services are those functions performed by the equipment and people that generate, control, and transmit electricity in support of the basic services of generating capacity, energy supply, and power delivery."[4] As outlined in Table 1, three types of ancillary services could be accommodated by DRR.

Table 1
Ancillary Services Descriptions

Ancillary Service	**Description**
Spinning reserve	Resources that can increase output immediately in response to a major generator or transmission outage and can reach full output to a specified level within 15 minutes.
Supplemental reserve	Same as spinning reserve, but need not respond immediately, since they may be off-line and still reach full output in 15 minutes.
Replacement reserve	Same as supplemental reserve, but with a 30- to 60-minute response time.

The North American Electric Reliability Council policies "inappropriately favor generation resources over customer loads in the provision of reliability (ancillary) services."[5]

Yet, DRR can meet ancillary services in many ways. For example, municipal water-pumping, which accounts for 2-3% of electricity use in the United States, can be operated in concert with requirements for spinning reserves. For mass-market programs such as direct load control of residential air conditioners, reductions of 200 MW for one utility took place within a few minutes of a request by the grid operator.[6]

One recent study recommends that "ISOs, utilities, other retail service providers, state regulatory commissions, FERC, and others should educate customers on the potential benefits they would derive from participating in the day-ahead markets for energy and ancillary services, especially for contingency reserves."[7]

The fundamental need for demand response resources is to develop value propositions for customers where the benefits or values received exceed the costs or risks of participation. As presented in the initial PLMA policy paper, DRR provides many benefits including:

[4] Eric Hirst: "Price-Responsive Demand as Reliability Resources," April 2002.
[5] Ibid.
[6] Dan Violette and Frank Stern, "Cost-Effective Estimation of the Load Impacts from Mass-Market Programs: Obtaining Capacity and Energy Payments in Restructured Markets for Aggregators of Mass-Market Loads," 2001 International Energy Evaluation Conference, August 21-24, 2001.
[7] Eric Hirst, Op. cit., April 2002.

- System reliability,
- Cost reduction,
- Market efficiency,
- Risk management,
- Environmental,
- Customer service, and
- Market power mitigation.

Even though these many benefits can be achieved reliably, rapidly, and flexibly, it is difficult for DRR to maintain a balanced relationship with supply side resources as the rules for wholesale energy markets have changed creating more open and competitive structures. While actions by the Federal Energy Regulatory Commission (FERC) and state public utility commissions (PUCs) have opened up wholesale energy supply markets to independent power producers (IPPs) with market-based pricing and eased entry, the application of DRR has been declining in absolute and relative terms in some regions.

In Texas for example, about 3,000 MW of load was available through interruptible programs and 1,000 MW in curtailable programs prior to restructuring. Only about 500 MW was expected to be under contract in the summer of 2002, the first year of retail choice in Texas.[8]

One reason for the decline in DRR is related to the changing role of electric distribution companies. Uncertainty about the role of distribution companies limits management willingness to invest in DRR.

Another reason for the decline in DRR stems from policies and practices that shelter retail customers from the price volatility in wholesale markets. As wholesale markets have opened up, price volatility has increased. Yet consumers are protected from premium, as well as discount prices through fixed rates and rate structures that average these prices over broad time intervals.

In other regions, DRR has been increasing, including the Independent System Operator of New England (ISO NE), New York Independent System Operator (NY ISO) and the PJM Interconnection (PJM). In fact, capabilities for ISO NE and NY ISO were expected to be twice as high in the summer of 2002 compared with 2001.[9]

Ironically, it takes only a small percentage of DRR out of total system load to affect a large percentage reduction in wholesale market prices. For example, it has been shown for the ISO NE on a peak day in the summer of 2001, that a 2% reduction in peak

[8] Dr. Jay Zarnikau, Frontier Associates, PLMA Annual Spring Meeting, April 26, 2002.
[9] RETX, *The RETX Dispatcher*, July 15, 2002.

demand (about 500 MW) would have reduced the clearing price from $400 to $175 per MWh or about 56%.[10]

The fact that small amounts of load can provide sizeable benefits is an important point. DRR does not have to gain favor with all customers. For success, only a portion of customers that have the ability to adjust load in response are needed to participate.

The value of DRR may be underestimated by focusing on the "average" customer or certain segments of customers that are not likely to participate. Instead, the focus should be on the target customers or customer segments that are likely to participate. A small percentage of customers or small number of customer segments can make a meaningful contribution to peak load management and to the operation of efficient electricity markets.

The challenge is to develop compelling value propositions for recruiting these customers that have the flexibility and can provide the needed market benefits. Of course, participants in DRR need to have their benefits of participation outweigh their costs. This includes potential providers of DRR programs (e.g., distribution companies), infrastructure, and aggregators. With industry restructuring, there are many uncertainties and the overall value proposition of DRR needs to be fairly assessed and participants provided with payments that represent this value.

These value propositions in turn must be reflected in better program designs to stimulate greater use of DRR. In particular, the following three types of design criteria may be distinguished:

- Participant criteria that determine attractive customer characteristics.
- Operations criteria by which the load resource is called or dispatched.
- Settlement criteria describing the financial arrangements.

This paper develops design principles around these three criteria. The design criteria are presented in the context of several prototypical programs described in Chapter 2. Chapter 3 summarizes selected findings about why customers choose to participate or not participate in DRR efforts. Chapter 4 presents the customer-oriented design principles considered essential to DRR and is then followed by conclusions in Chapter 5.

Several audiences should find this paper of importance. First, developers and operators of DRR need to be sensitive to the key principles affecting customer participation. Second, government policy officials should benefit from greater understanding of their ultimate client, the consumer. Third, suppliers of products and services enabling DRR may be able to better target their efforts in improving and developing platforms for success.

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[10] Bob Burke, Independent System Operator of New England, Remarks at the PLMA Spring Meeting on April 25, 2002. PLMA May Newsletter.

The timing of this report is propitious as there are signs of renewed interest and growth in DRR. A survey conducted recently by Chartwell of 30 utilities with at least 50,000 customers reports that 40% are offering and 10% are planning to offer demand bidding or buyback programs.[11] For residential direct load control, the survey reports 43% operate a program and another 13% are planning to implement programs.[12]

This paper is also timely given the expressed interest in demand response by regulatory authorities. In particular, the Federal Energy Regulatory Commission issued on July 31, 2002 a notice of proposed rulemaking on standard electricity market design. The notice proposes to "…establish procedures to assure, on a long-term regional basis, that there are adequate transmission, generation and demand-side resources."[13]

As with the initial policy paper, PLMA intends this document to be educational and reflect a range of views. The PLMA is a not-for-profit corporation whose mission is to develop, demonstrate, and evaluate methods for reducing peak electric demand. Membership includes leading companies in electric generation, retail energy services, load aggregation, power exchange, and demand response equipment, metering, and information systems.

[11] Chartwell, *Report on Demand Response Programs*, March 2002.
[12] Chartwell, *Report on Direct Load Control for Residential Customers*, March 2002.
[13] Federal Energy Regulatory Commission, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design: Notice of Proposed Rulemaking*, Docket No. RM01-12-000, July 31, 2002, p. 12.

2.0 Prototypical Programs

There are numerous types of programs for DRR with various characteristics. Some have been around for decades with little change, but others are relatively recent and continue to change. To provide context to the design principles, this chapter summarizes key types of programs.

2.1 Load Response

Load response programs operate in response to requests for peak load reductions with little, if any, discretion in compliance on the part of the customer. Load response programs are directed by the buyer or operator, such as a traditional utility, load serving entity, curtailment service provider, or grid operator. In contrast, price response programs are directed by the customer in response to offers from the buyer or operator. While there are many types of load response programs, three generic types of programs are presented here.

2.1.1 Mass Market Direct Load Control Programs

Eligible customers are residential and small commercial facilities with equipment that may be cycled or turned off for limited periods of time. Target equipment includes central air conditioners and heat pumps, water heaters, and swimming pool pumps. Switches are installed to control units directly or through other controls, such as thermostats. Communication to cycle the equipment is through power-line carrier or wireless networks managed at the direction of the party calling for load reductions.

Participating customers agree, under many program designs, to a limited number of events and durations, such as up to fifteen events per season for no more than six hours per event. Another variable is cycling times. Some programs offer one choice such as 15 minutes of cycling off the air conditioner compressor every half hour or a 50% cycling strategy. Other programs offer multiple choices such as cycling strategies of 33%, 50%, and 100%.

In exchange, the customers earn a credit or payment such as $8/month for the peak summer months for each air conditioner in the program. Some programs provide a lower monthly credit which is supplemented by a payment for each time cycling is exercised. Also where the duration of the cycling period is an option, longer periods earn higher credits than shorter periods.

A further option is available to customers in terms of the incentive or price. Customers may be offered real-time prices or credits that can be earned based on system conditions. Thus, if the wholesale market prices are unusually high, the customer may be able to cycle more often or longer with a control system programmed to adopt those behaviors. With this feature of customers responding to different prices, direct load control could be categorized as a price response rather than a load response program.

Settlement from the utility or load serving entity to the customer may come with each monthly bill, or in some programs, at the end of the season in one large payment. Monitoring for compliance is not common, but is becoming more cost-effective using two-way communication systems.

2.1.2 Curtailable Load Programs

Target customers are large commercial and industrial facilities that can reduce at least some of their load with a minimum threshold, such as 100 kW per event. Energy reduction practices encompass lighting, air conditioning, ventilation, process heating and cooling, crushing and compressing operations, scheduling of production, and backup generators. Facility managers or central control operations of the participating customer are responsible for managing each call for curtailment. Notification is from thirty minutes to two hours ahead. Communications with the participant may be by one or more methods, including telephone, fax, email, and pager.

Participating customers agree to attempt to curtail for a maximum number of events and durations within a period defined by season and hours of the day. Participation may be voluntary for each event, but failure to meet target reductions may result in reduced payments or penalty costs to the customer. Some programs require mandatory reductions to the contracted firm service level, subject to penalties or reduced payments. Payments are typically based on amounts of load reduction from baseline consumption to a firm service level and made through billing adjustments.

Baseline consumption is calculated as energy use that would have taken place in the absence of curtailment. Monitoring through interval meters is performed to enable load reduction calculations for the duration of each event.

2.1.3 Interruptible Programs

Target customers tend to be industrial operations that can shed all or major portions of their load. Commercial facilities may also participate, particularly if backup generators can provide large portions of the load. To be eligible, significant amounts of load, such as 1,000 kW minimum, must be available for interruption. Facility managers may be responsible for reducing load or disconnection may be accomplished by the buyer, whether the load serving entity (LSE), utility distribution company (UDC), or the electrical grid's ISO. Multiple methods of communication may be employed, but with short notice of from ten minutes to a few hours.

Participation is mandatory and may be required at any time during the year or within prescribed periods. Incentives take the form of rate discounts throughout the term of the agreement and are reflected on monthly energy bills. Failure to comply with requests often leads to financial penalties. No extra settlement actions need to be imposed except where penalties are involved. Special metering is required to measure performance.

2.2 Price Response

Price response programs operate based on voluntary actions of customers in response to economic signals. Four types of price response programs are presented in this section.

2.2.1 Emergency Programs

Target participants are end-use customers or aggregators such as LSEs or curtailment service providers (CSPs). Participating end-use customers are typically large commercial and industrial facilities that can provide a minimum amount of load reduction, such as 100 kW per event. However, aggregation of residential and small commercial accounts without interval meters may be allowed in limited cases where methods of estimating load reductions are acceptable.

Emergency programs are triggered by grid conditions considered threatening to system reliability. In rules for one ISO state: "The program will be implemented when generation is needed that cannot otherwise be obtained from economic efforts that have been made into the PJM Interchange Energy market."[14]

Emergency price response programs may give the customer the option to not participate on any particular event. However, some installed capacity programs (ICAP) are called only in emergency situations and load reductions are mandatory.

Emergency programs have a variable payment based usually on locational marginal price (LMP) or some high minimum payment, such as $500 per megawatt hour (MWh). Curtailment programs typically have a fixed price for participation.

In other respects, emergency programs are similar to load curtailment programs in terms of load reduction practices, methods of communication, number and duration of events, nature and amount of notification and types of metering and performance measurement. Settlement takes place upon confirmation of performance and when funds are made available from the buyer. Interval meters are required for monitoring.

2.2.2 Economic Programs

Economic programs target similar participants and resources as emergency programs. Participants may be price takers by seeing a proposed price or set of hourly prices for a day ahead and then offering load reductions in certain amounts for certain hours.

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[14] PJM, "PJM Interconnection LLC, Docket No. ER02 (PJM Emergency Load Response Program)," Filed with the Federal Energy Regulatory Commission, March 1, 2002, p.7.

Alternatively, participants may bid loads for certain hours at certain bid prices. Another variation is for participants to offer standing bids or strike prices that the buyer may call when the LMP reaches action levels. For some programs, there is a choice of same day load reductions, as well as day ahead reductions when bid by the participant. The buyer has the option to accept the offer or rely on other resources. If the offer is accepted, the customer must perform or suffer penalties.

Payment is based on the price bid by the participant and accepted by the buyer for day ahead programs. In some programs, if the participant provides additional reduction above the bid they may be paid the LMP. Participants may obtain start-up costs and require a minimum number of hours of operation. Same day participants may be paid a bid price, which could be above the LMP and their bid prices, if the load is dispatched by the ISO. Settlement takes place after the buyer confirms performance and receives payment from the grid operator.

Metering and communication systems are similar to load curtailment and emergency programs. One difference is that the economic program may operate each hour throughout the year.

2.2.3 Real-Time Pricing

Target customers are commercial and industrial facilities with the ability to reduce or shift loads. Operating measures include the normal options available in other commercial/industrial programs. Advanced communication systems allow customers to observe real-time energy usage and forward prices.

In one version, customers are provided hourly prices for the next day. Facility managers are free to maintain operations as planned or adjust operations to take advantage of higher or lower rates. “Two-part” tariffs establish a baseline energy usage for each hour of the year. Baseline usage is agreed to by both parties based on historical use subject to appropriate adjustments, such as changes in operations or weather. Variances in usage from baseline estimates are charged a premium if above and a discount if below the baseline using spot market prices. Special interval meters are required. Settlement takes place in the monthly billing process.

An alternative to the two-part tariff is a “one-part” tariff that links all usage to hourly prices to spot prices and avoids baseline estimation.

Another variation on real-time pricing is super-peak or coincident peak pricing. The customer agrees to be charged premium prices for a limited number of hours per year. Notification is provided a day ahead when the premium hours will be charged allowing the customer to take appropriate action. In exchange for accepting coincident peak pricing, the customer receives a discount on the other hours of the year.

2.2.4 Time-of-Use Rates

Eligible customers may be residential, commercial, and industrial markets depending on the target class or segment. Participation may be mandatory or voluntary depending on the jurisdiction. Special meters are installed to measure consumption during peak, off-peak and sometimes intermediate peak hours. Rates vary with time-of-day; day-of-week, since weekends are considered off-peak normally; and season of year, since winter weekdays may be considered off-peak or intermediate hours. However, rates are fixed for each period so the customer knows well in advance what the prices will be.

Time-of-use meters may contain features allowing the customer to obtain real-time information or historical load profiles. Meter gateways and other devices such as thermostats and pool pumps may be configured to take advantage of time-of-use rates.

There are other types of programs for DRR such as load shifting using thermal energy storage. However, the intent of this chapter is to document the most common types of programs of significant current interest. The next chapter explores customer considerations in participating with DRR.

3.0 Participation Perspectives

This chapter discusses recent research on customer perceptions and behaviors regarding DRR. While extensive research has been conducted on customer perspectives and preferences, much of it is proprietary. The studies in this chapter are publicly available, current, and meaningful in portraying participation perspectives.

In general, participation depends on the value customers perceive in DRR. In practice, this requires a balancing of the benefits received against the costs of participation.

The recent benchmarking survey of the Edison Electric Institute with PLMA documented the most common reasons for joining a DRR program among the 25 responding organizations encompassing 35 programs.[15] The reasons given in priority order were:

- Obtain bill credits and incentive payments
- Help the utility company during peak situations
- Help the community
- Obtain non-financial product or service
- Other.

It is useful to supplement these general participation reasons with more specific considerations for the various types of programs such as direct load control, demand bidding, real-time pricing, and other demand response resources.

3.1 Participation Factors in Mass Market Direct Load Control

Mass market direct load control programs depend on satisfying many customer preferences and behaviors. These include such factors as convenience, comfort, and choices.

One of the programs with an extensive history, high levels of participation, and various customer options is operated by the Sacramento Municipal Utility District (SMUD). For these reasons, and because it has conducted extensive customer research with published findings, this section summarizes some of their findings on customer participation and satisfaction.

SMUD has operated a program since 1989 with over 100,000 participants. As a result of exercising the program heavily in 2000, a study was conducted to evaluate and

[15] Steve Rosenstock, "Preliminary Results of the EEI/PLMA 2001 Demand Response Benchmarking Survey," Edison Electric Institute, March 15, 2002.

redesign the program. Both participants and former participants were recruited as part of the study. Key findings are summarized below.[16]

A telephone survey revealed the results:

- 97% of participants were satisfied in 1994
- 62% were satisfied in 2000
- 40% of the dissatisfied participants in 2000 were considering leaving.

The primary reasons for dissatisfaction were:

- Discomfort during the cycling
- Low incentive
- Not being operated as promised.

In addition to the telephone survey, a conjoint analysis was conducted to evaluate the various program attributes. As shown in Table 2, the maximum cycling level was the most important attribute by far. The respondents were given cycling level choices of 33%, 66%, and 100% cycling.

Table 2
SMUD Peak Corps Program Attributes

Program Attribute	**Importance**
Maximum Cycling Level	48.46
Fixed Seasonal Payment	19.22
Payment per Cycling Day	15.29
Maximum Hours Used per Day	9.75
Maximum Days Used per Month	7.28

The incentive was the second most important attribute. Here the respondents slightly favored fixed payments over payments per event. The number of events was much less important.

In addition to these program operating features, other factors may be considered as influencing program participation. Demographic factors are relevant as the SMUD experience shows. Key participation factors were found to be whether or not the home was owner occupied, single-family versus multi-family, length of time in the home, age of property, and homeowner income. About 71% keep air conditioning temperatures at 78 F and 77% of the homes are occupied during peak hours on summer weekdays.

[16] Vikki Wood, Rajan Sambandam and Ed Kolodzeij, “Residential Peak Corps Market Study: An Application of Choice-Based Conjoint Analysis Using Heirarchical Bayes Estimation,” 2001 International Energy Evaluation Conference, August 21-24, 2001.

3.2 Participation Factors in Demand Bidding

Demand bidding programs are more common among commercial and industrial end-use customers and accordingly can experience different participation factors. A recent survey of the demand response markets claims: "Demand response programs provide a safe place where customers can go to get liquidity for the demand response resources."[17]

Incentives are important in demand bidding with some types of customers more likely to participate than others. A timely study of participation from 2001 shows the importance of size in customer participation.[18] Based on demand response programs for the NYISO for the summer of 2001, the study finds "the large customers with loads of one megawatt or greater exhibit the highest price responsiveness." It suggests that larger customers are more attractive targets because with the high transaction costs in recruiting, they provide more response per dollar spent.

However, the study notes that a number of customers less than one megawatt demonstrate high responsiveness and provide proportionally more response. It suggests, "through education, training and perhaps some financial assistance to purchase necessary meters and other equipment, more of these types of customers would find participation in these PRL (price-responsive load) programs of value…"

The study estimates participation factors based on revealed preferences of customers.

- The most important characteristic is peak usage. When customers' peak usage occurs between noon and 4 p.m., they will be more than 3.6 times as likely to participate as customers that peak at other times.
- If customers participate in or are knowledgeable about other load management programs of the load serving entity, they will be more than 3.4 times as likely to participate as customers without such characteristics.
- Customers with several production shifts are twice as likely to participate as customers with one shift in production.
- Customers who found program information to be useful have a 30% probability of participating.

According to Jim Laird, Director of Energy Programs for Home Depot, the national retail store chain has several needs when participating in load response programs.[19]

- The incentive must be sufficiently high to be worthwhile.
- Guaranteed or assured payments are important.

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[17] Energy Info Source, Demand Response Programs, May 2002.

[18] Bernie Neenan, "NYISO PRL Program Evaluation: Report Summary," Neenan Associates for NYISO, January 15, 2002.

[19] Jim Laird, Comments on behalf of Home Depot at the PLMA Annual Spring Meeting, April 26, 2002.

- Payments must be received within the company fiscal year or store managers can jeopardize their bonuses by going over the energy budget.
- There must be a public relations benefit to participating.
- It must be easy to participate, such as when a load serving entity handles most of the analytical and administrative details.

In 2001, Home Depot chose to participate in programs in California, Illinois, and New York. Even though many other programs were available, they did not meet sufficiently the foregoing priority considerations of Home Depot for participation.

3.3 Non-Participation in Demand Bidding

Another way to explore this subject is to examine why customers choose not to participate. This helps in designing programs to overcome customer objections and perceptions.

Customers choose not to participate for a variety of reasons. In the case of emergency demand response programs (EDRP) in the NYISO, the most common reasons were uncertainty about when the events will be called and about being able to meet the 100 kW minimum load reduction. These and other reasons based on a survey involving 58 responses from 28 respondents are shown in Table 3.

Table 3
Reasons for Not Signing up for EDRP

Reason	Percent
Uncertainty regarding days events will be called	14%
Required minimum 100 kW load reduction	14%
Cost of metering and communication equipment	11%
Uncertainty about customer base load	11%
Aware of program too late	7%
Not enough staff to implement	7%
Length of notice prior to curtailment	7%
Payment level for load reduction too low	5%
Late installation of metering and communication equipment	4%
Timing of the payment for load curtailments	4%
Landlord/tenant lease limitations (submetering)	2%
Other	14%

NYISO also ran a separate day-ahead demand response program (DADRP). Non-participants claimed the most common reason for avoiding the program was the penalty imposed when curtailment obligations were not met. This was the main objection for 21% of the respondents. Other common objections to participation were lack of sufficient curtailable load and insufficient staff to implement.

Pulling these findings together, "A central theme to the results of the customer preference and attitude research is the importance of conveying the value proposition to customers in an understandable and compelling manner."[20]

But not all customers should or need to participate. In a survey of more than 700 respondents, E Source documented commercial energy manager interests in participating in a voluntary load reduction program as shown in Table 4.[21]

Table 4
Commercial Energy Manager Interest in Voluntary Load Reduction

Response	Percent
Very likely	13%
Somewhat likely	40%
Not too likely	22%
Not at all likely	24%
Do not know	2%

For respondents not too likely or not at all likely to participate, the biggest concern was maintaining a "constant flow of power." Other objections were operational deadlines, nature of business, computer usage, and not compatible with "type of service we provide." These are perfectly acceptable objections and concerns, although many may be resolved through customer education.

However, if 13% of commercial customers are able to participate in DRR programs and the class of commercial customers represents 30% to 40% of peak demand that could be sufficient to impact wholesale market prices. Load reductions of a few percent for a system can translate into reductions in wholesale prices that are many times greater as mentioned earlier.

3.4 Participation and Non-Participation in Real-Time Pricing

The findings about participant behaviors in price response programs are further supported by analyses of real-time pricing (RTP). Certain types of customers are more likely join RTP programs than others.[22]

- Customers more likely to shift loads include those with on-site generation, high energy costs as a percentage of total costs, non-continuous production processes, and previous experience with interruptible rates.

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[20] Bernie Neenan, Op. cit.
[21] William LeBlanc and Tia Hensler, "Energy Pricing and Load Management: What Do End Users Want?" E Source, October 2000.
[22] Stephen S. George and Ahmad Faruqui: "The Value of Dynamic Pricing for Small Consumers," Presented by Charles River Associates before the California Energy Commission Workshop on Achieving Greater Demand Response in the California Electric Market, March 15, 2002.

- Customers join RTP programs to save money, and become less satisfied as prices increase.
- Customers dislike price volatility. One of the ways to overcome this challenge is to put on price caps. Another is to limit the number of high-cost days and low-cost days. Two-part RTP rates also add stability not only for the customer but also the utility.
- Customers prefer simpler two-part RTP rates in calculation of baselines.

Even for customers participating in RTP, a major portion of the load shifting under RTP comes from only a few participants. Interviews with several utilities show that customers respond to RTP in different ways:[23]

- A utility found the aggregate response in 2001 from 59 participating customers was about the same as in 2000 from 100 customers.
- A utility reported that only three of its 14 customers did any significant shifting.
- A utility with 25 participants found only one ever really shifted load.
- Customers have varying capabilities over time so that they may be able to shift load in some seasons or at certain times, but not others.
- Price responsiveness among customers increases with experience.

While the number of studies referenced in this chapter is not large, they represent timely and important research on customer participation in demand response.

[23] Ahmad Faruqui and Melanie Mauldin, "The Barriers to Real-Time Pricing," *Public Utilities Fortnightly*, July 15, 2002.

4.0 Design Principles for DRR

This chapter captures key design principles for demand response resources. These design principles reflect the important balances that must be achieved between benefits and costs to develop compelling value propositions for participating customers. In turn, this will also enhance electric market efficiency and reliability.

D-1. Communicate with Customers on Design and Implementation

Customers should be consulted and included in planning program designs and operations for DRR. Communicating and working with customers to address needs and wants is a basic principle for any service offering, including DRR.

Customer research allows better appreciation of their concerns about comfort, convenience, costs, savings, environment, and other factors they consider important to their participation with DRR. In addition, communication should be two-way. Customers need to be informed about program objectives, procedures, incentives, marketing approaches, and operations. A process based on effective communication between the market actors in the design of programs will help create customer and market-oriented programs that will improve the cost-effectiveness and overall market value of DRR.

Numerous types of communication are available from informal and unstructured to formal and structured methods. Obvious formal methods include focus groups, telephone surveys, and direct mail questionnaires. Customer communications can be occasional or regular, involving both likely participants and non-participants. Once programs are underway, evaluations of customer interest and satisfaction may be simple and straightforward, as well as complex and intensive. Part of the program implementation approach may be to confirm customer needs and wants by conducting technical demonstrations and pilot programs.

While it is important to listen to customers, it is also important to recognize that customers may need a better understanding of how energy is produced and used, as well as delivered and managed, both in their own facilities and in the marketplace. Although customers will largely be driven by self interest, an understanding of the relationships between market capacity and prices, in both the short term and the long term, will help them contribute to the development of appropriate value propositions. For many customers, this involves unfamiliar terms, unfamiliar parties, and unfamiliar practices. It is helpful to develop standard terminology that is simple and easy to understand.[24]

[24] William M. Smith, Joel Gilbert and Paul Meagher, "The Ten Commandments of Demand Trading," *Public Utilities Fortnightly*, March 1, 2002.

Customers should be able to grasp the need for and value of demand response. Variable pricing exists in numerous industries such as airlines, hotels, rental cars, telephone usage, and weekend appliance repair. In fact, the large numbers of customers currently participating in demand response attest to their appreciation and acceptance. An appreciation of the fact that electricity costs vary by both season and time-of-day provides an initial rationale for DRR that customers can understand. In general, customers are more comfortable in participating in markets where they understand the price drivers and believe that the DRR offers reflect legitimate market factors.

The willingness to participate in demand response programs can vary dramatically within an organization. It is important to identify and recruit participation from the most willing officials. E Source found significant differences between corporate energy managers and facility energy managers.[25] In particular, facility energy managers were three times higher in their estimate of load reduction capabilities than corporate energy managers. It is likely that the facility energy managers are more familiar with their operations, energy using equipment and demand patterns.

It helps to find a "champion" in a customer organization. To the extent facility managers embrace peak load management opportunities at the local level, they can help sell the program to other decision-makers, whether in the store, plant, or corporate headquarters.

It is important to recognize that multiple decision-makers may be involved within a single organization, each with his own education needs. In large organizations, multiple levels from the chief executive officer to the maintenance supervisor may be critical to success. In homes, the spouse and children may be important to success.

The PLMA recommends considering the following practices:

- Communicate with customers early in the process.
- Employ multiple communication approaches.
- Educate customers about DRR values and programs.
- Cultivate key decision-makers and influencers.
- Use standard terminology that is simple and easy to understand.
- Pilot new designs and refinements in response to customer preferences and behaviors.
- Run "readiness tests" to help customers learn capabilities and procedures.
- Evaluate progress with customers regularly.

[25] Nathan Adams, *Peak Load Management Programs for Large Commercial Customers: Secrets of Success*, E Source, May 2001.

D-2. Keep Program Designs Understandable

Program designs should be understandable to a meaningful number of customers. Too often, programs run the risk of being difficult to join, complicated to operate, and onerous to settle. Certainly some complexity may be warranted for appropriate customer segments. More complexity may be justified as a function of larger customer sizes, greater demand response potential of the participant, and higher values of DRR. The challenge is to strike a proper balance. As a result, a single DRR program may need to offer different types and levels of participation and communication to reflect the special needs of different customer segments.

One way to improve this aspect of program designs is to involve end-use customers and other stakeholders. Evaluations of DRR programs in New York in 2001 have indicated that the levels of participation improved with the involvement of customers in the program design.[26] The Electric Reliability Council of Texas (ERCOT), with encouragement from the Texas Public Utility Commission has organized a Working Group on Demand-Side Resources and Demand Responsiveness.[27] The PJM sponsors the Demand-Side Response Working Group (DSRWG) that participates in planning the emergency and economic programs. It is a successor to the Distributed Generation User Group (DGUG).

The PLMA recommends considering the following practices:

- Involve customers in planning and design.
- Simplify program descriptions.
- Standardize contracts.
- Simplify monitoring requirements.
- Seek a balance between overall complexity and program objectives.

D-3. Provide Program Choices

Program choices and options should be provided for different customer segments and across different types of DRR. Customer classes are composed of multiple segments that justify various program choices. Also load response and price response programs offer opportunities for multiple designs or choices.

One size seldom fits all when it comes to DRR. Yet, there can be a temptation to try to design the perfect or optimal program. The optimal program may not only be difficult to find, as well as expensive and time consuming in conducting research and pilot projects, it may also deny customers the choice of options that may be just as cost-effective given the broader participation that they allow.

[26] Bob Loughney, Remarks on behalf of Couch White, PLMA Annual Spring Meeting, April 26, 2002.
[27] Paul Wattles, Personal communication, Good Company Associates, May 16, 2002.

On the other hand, too many choices may not be cost-effective as well and result in customer confusion. Again, the challenge is to find the proper balance between program simplicity and choice.

Research by E Source of 50 corporate energy managers found a steady increase in their willingness to shed peak load as financial incentives increased, as shown in Table 5.[28]

Table 5
Willingness of Energy Managers to Reduce Load

Incentive in $/kWh	Load Reduction in %
$.15	1%
$.25	2%
$.50	5%
$1.00	7%
$5.00	10%

One approach is to offer multiple incentives. According to E Source, Cinergy has offered four different price thresholds at which customers may choose to participate. Furthermore, for each threshold, customers could choose to participate under a mandatory "call option" or an elective "quote option." And within the call option, customers could elect a "guaranteed" credit or a "shared" credit. The quote option does not have a guaranteed monthly credit, but customers receive a shared credit equal to half the market price. Since the quote option is less risky, about four out of five participants choose it. About half of the participants needed a strike price of at least $.90/kWh under either the call or quote option. The other participants were willing to participate at one of the three lower strike prices ranging from $.10/kWh to $.60/kWh.

The PLMA recommends considering the following practices:

- Offer multiple programs to serve different customer segments and provide different types of DRR (spinning reserves, dispatchable resources, emergency resources, price response, etc.). Multiple programs help spread the risk of relying on one program.
- Offer choices to stimulate greater customer participation. While this might be viewed as inconsistent with the design principle for keeping programs simple, it should be complementary. One way to keep programs simple is to offer choices that help accommodate the different needs of specific customers.
- Allow multiple program participation. Participants should be permitted to join multiple programs as long as the value contribution is clear without double counting of savings and duplicating payments to the customer.

[28] Nathan Adams, Op. cit.

D-4. Accommodate Small Participants

Mass market customers, including residential and small commercial accounts can provide substantial amounts of DRR and should be accommodated. Many load response programs for commercial and industrial accounts require minimum load reductions of 100 kW. At the same time, many chain accounts such as retail stores, restaurants, and schools can provide 20 to 50 kW per location. Collectively one chain account may easily be able to provide well over 100 kW where multiple sites are located in one community or area.

Similar opportunities exist with mass market programs. Large numbers of residential and small commercial accounts can collectively provide significant load reductions that are readily dispatched with high reliability. Integrated utilities, distribution companies and others can aggregate these accounts and provide large load reductions on short notice. This short notice, dispatchable capability can allow these aggregated demand response resources to meet the needs of ancillary service markets, including spinning reserves, supplemental reserves and replacement reserves. The diversity effect which accompanies large numbers of small accounts results in a high probability of achieving performance targets through DRR offers that are reliable and scalable over time.

The PLMA recommends the inclusion of mass-market participants in DRR programs given cost-effectiveness considerations and appropriate valuation of the characteristics of the resource, i.e., availability, dispatchability, and reliability.

- Chain accounts with small individual properties where energy use patterns are similar can be aggregated readily into significant load reductions in some communities and areas.
- Residential and small commercial accounts can collectively provide large load reductions.

D-5. Enable Customer Decisions

Programs should provide support to customers to help them make decisions in as easy and straightforward a manner as practical. Various value-added services can enable and facilitate customer decisions to join and stay in demand response programs.

Peak load reduction opportunities vary among facilities. What may be acceptable for an office building may not be for a retail store. Load reduction opportunities vary not only by facility type, but also equipment configurations, facility ownership, decision making processes, and many other factors. According to energy managers of national accounts in a study for EEI,[29] they need time to:

[29]Steve Rosenstock, "Summary of National Accounts Customer-Member Forums," Edison Electric Institute, April 30, 2002.

- Evaluate programs,
- Sell participation up and down the management chain,
- Approve contracts,
- Reconfigure or install energy information systems and controls,
- Install meters, and
- Prepare for curtailment measures.

These national accounts energy managers in this EEI study also indicated that it was important to release program details by January, if participation is expected in the following summer.

An E Source study[30] suggests that customer planning and decision-making is further enabled by providing value-added services such as:

- Facility specific audits for identifying peak load management opportunities,
- Organization specific operating manuals to implement priority recommendations, and
- Real-time monitoring and coaching by curtailment service providers to ensure success.

While these practices may be seen as more expensive, they enable customers to decide in favor of participating and they help programs to succeed in meeting the peak load management goals.

D-6. Leverage Customer Infrastructure

Program designs should leverage existing customer investments and operations related to energy management. This includes investments by customers in equipment, controls, communications, and information systems. Much investment exists in such systems as energy management controls, backup generators, and advanced telecommunications. These customer resources can be tapped with little or modest enabling investments, particularly if the program includes some flexibility and is not completely prescriptive regarding specific hardware and software for communications and control.

The PLMA recommends leveraging customer infrastructure by such means as:

- Documenting customer investments.
- Analyzing the costs and investments of upgrades to support DRR.
- Developing alternative program designs to complement the customer resources.
- Giving customer choices to take advantage of their resources.

[30] Nathan Adams, Op. cit.

D-7. Address Environmental Priorities

DRR should be sensitive to environmental concerns. Environmental benefits accrue when demand response actions result in energy being used less or not at all for certain periods of time. By such practices as reducing lighting or increasing thermostat setpoints, less electric energy consumption can translate into lower environmental burdens.

However, other demand response resources may complicate environmental compliance. Backup or emergency distributed generators can cause emissions to increase in certain localities where fired by diesel fuel and called upon for peak load management.

On balance, when backup diesel generation is combined with other demand response resources, the result still can be " green." One study calculated that 75% of the aggregate demand response resource is simply turning things off.[31]

Furthermore, mitigation possibilities exist for backup distributed generation. A recent report from Energy Info Source notes:

> "…demand response programs fundamentally change the value proposition for distributed generation. Rather than buying the distributed generation asset solely for backup reliability purposes when power from the grid is lost, the customer can now get a real return on the distributed generation assets. If a customer knows with some certainty that there is a place to sell capacity, more investments in clean, efficient distributed generation will occur."[32]

One challenge for distributed generators is disparate permitting rules between states and within states. Often, they must accommodate different requirements about what constitutes emergency operations, when units may be operated for non-emergency load management operations, the number of hours of operation, the degree of variance allowed on emission limits, abatement or control requirements, and other restrictions. For example, some jurisdictions prohibit operation of backup generators until the power has gone out, others prohibit operation until just prior to a power outage, and still others have no such restrictions.

While respecting the environmental permitting prerogatives of the various local, state, and regional authorities, PLMA encourages consistent permitting rules for distributed generation resources. Where emission reductions are called for, customer solutions include:

[31] Joel Gilbert, Op. cit.
[32] Energy Info Source, Op. cit.

- Installing catalytic converters;
- Burning low sulfur diesel fuel;
- Converting to natural gas fuels;
- Adopting fuel blends like biodiesel, a mixture of diesel and biofuels; and
- Purchasing emission allowances, as was done by New York State Energy Research and Development Administration on behalf of participants.

D-8. Reduce High Costs of Required Customer Equipment

High initial costs borne by customers should be minimized where practical. Large accounts frequently must install metering and monitoring systems to participate in load reduction programs. Utilities often charge to connect meters to customer monitoring systems to obtain pulse counts of electric usage. The costs of thousands of dollars per location add up quickly and may have paybacks of many years.

The PLMA recommends considering the following practices:

- Simplify and standardize hardware requirements.
- Minimize redundant software requirements.
- Communicate with customers using more cost-effective media, e.g., the Internet.
- Underwrite some of the customer equipment and installation costs, e.g., advanced metering.

Various opportunities exist for sharing costs, including:

- Grants from government agencies,
- Research and development projects,
- Allocation of system benefit charges, and
- Tax incentives.

For distributed generation systems, interconnection of customer units to the electric grid can be reduced in cost and time by adopting standard protocols. Common interconnection standards are encouraged through consensus and regulatory efforts such as may be found from the National Rural Electric Cooperative Association available on-line at www.nreca.org and the Texas Public Utility Commission at www.puc.state.tx.us. On July 31, 2002 the National Association of Regulatory Utility Commissioners adopted and recommended to its members the use of a model interconnection agreement and interconnection agreement developed by a working group of commissioners and staff. On August 16, 2002 FERC issued Standardization of Small Generator Interconnection Agreements and Procedures Advance Notice of Proposed Rulemaking.[33]

[33] "FERC Invites NARUC to Participate in Small SG Interconnection ANOPR," *NARUC Bulletin*, September 2, 2002. The NARUC model agreement may be found at www.naruc.org. The FERC NOPR may be found at www. ferc.gov.

D-9. Develop Fair and Practical Baseline Estimation Procedures

Baseline estimates of customer energy usage should be developed fairly and implemented practically. Baseline estimation refers to procedures to document what customer energy usage would have been in the absence of demand response. In the absence of demand response, usage would have been higher, but the question is how much higher. This becomes the basis usually for calculating payment for load reductions.

Baseline estimates can be developed for load response programs using a number of different methods.[34] One common approach is to compare usage during the demand response period with usage on days without demand response. Then the challenge is to find representative days. Some programs average the 10 prior days and others the 5 prior days. These are further selected to be only weekdays and only days without demand response.

Other adjustments are often made for loads that are expected to be weather-sensitive. If the demand response day is particularly hot, for example the baseline may be adjusted for these loads in ways to show a greater reduction. In the case of PJM, the end-use customer or its representative (LSE or CSP), must specify whether it desires to apply a Weather Sensitivity Adjustment (WSA) prior to the season and may only change it once a year to minimize gaming and windfalls.[35]

A complication can occur with gaming the baseline estimate. There can be circumstances where a customer could run equipment or operate a facility to create a higher baseline against which to estimate reductions during demand response periods. Or the customer may have scheduled equipment off before participating in the demand response event, but still claim the reduction as due to the event.

Power generators do not have this complication since their baseline is zero. In the case of backup and other distributed generation resources, estimation is also relatively non-controversial by measuring connected loads and change in usage when called upon. It is more complicated to measure load reductions with facilities that are reducing lighting, air conditioning and production activity.

However, the use of baselines is common to a number of tariff designs. In a two-part rate design, one part is based on historical baseline usage. A second part is based on deviations from the baseline. If the customer usage exceeds the baseline, the real-time electricity price is used to calculate the amount due for that usage. If the usage falls below the baseline, the real-time price is used to produce a bill credit. The baseline usage is calculated at a fixed or contractual rate.

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[34] A review of baseline methods can be found in Xenergy, "Protocol Development for Demand Response Calculation," prepared for the California Energy Commission, Contract 400-28-002, www.energy.ca.gov, August 2002.

[35] PJM, "PJM Load Response Programs – Business Rules," Revision #2, June 24, 2002.

Some types of customers present greater challenges than others in calculating baselines. For example, hotels experience highly variable loads from day to day and hour to hour based on numerous factors. While program designs that simplify baselines are preferred in principle, it is not always possible in practice.

The PLMA recommends considering the following practices:

- Keep customer baseline calculations simple.
- Customize baseline calculations to customer needs.
- Assign baseline calculations to trusted third parties.

In the final analysis, the essence of successful baseline methods is that the buyer and the seller agree on the terms considered fair by both parties.

D-10. Use Advanced Notification Procedures

Advanced notification procedures should be used for most demand response programs. The amount of time customers have to respond to demand response requests has been found to be a critical factor for participation among commercial and industrial customers.[36] Depending on the program, notification can vary from a few minutes to a few hours to a few days. For example, a survey of participants in the NY ISO Emergency Demand Response Program found a relatively low level of satisfaction with the two-hour notice and a general preference for longer notice periods.[37]

A related issue is the method of communication, such as the Internet, telephone, pager, or fax. For commercial and industrial customers, participants often prefer multiple methods of communications, particularly if there are penalty clauses or if the cost savings from load shedding are significant. One participant contacted for this study objected to e-mail only communications, since email may not be checked until late in the day.

In the case of mass market programs for direct load control of central air conditioners and other equipment, there is usually little or no advance notification. When properly educated, customers participate in large numbers. From the perspective of the LSE or ISO, these programs are attractive since load reductions are reliable, rapid, and scaleable.

[36] Nathan Adams, Op. Cit.
[37] Bernie Neenan, Op. Cit.

The PLMA recommends considering the following practices:

- Extend notification periods over longer intervals.
- Employ multiple notification media.
- Offer a choice of notification periods to customers.
- Provide a choice of programs with different notification periods.

D-11. Compensate for Full Value

DRR should receive fair compensation reflecting the value of the services provided to the market. In some cases, this will include both energy and capacity savings, ancillary services where requirements for these services are met by DRR, and congestion alleviation. In some cases, prices for demand response only reflect savings in energy costs. In other programs, prices for DRR incorporate not only energy cost savings, but also savings or benefits in capacity reductions.

Unfortunately, the value chain is fragmented in electricity markets and subject to insufficient transparency that a single buyer of DRR may not be able to capture the full value of DRR and may not be able to pay appropriate compensation for both energy and capacity savings. For example, distribution companies may receive benefits from lowered costs of providing standard offer service and potentially some distribution system efficiencies, while other entities managing control areas receive the benefits of enhanced reliability and ancillary services at a lower cost. Customers and other market participants need help in resolving this situation from proactive regulators and market-makers such as RTOs/ISOs.

Some DRR contracts reflect only short-term energy savings, and therefore do not capture any long-term generation capacity savings. An advantage of long-term contracts between multiple buyers and sellers of DRR is that reliability increases as performance risk is spread over more resources. The development of long-term contracts with standard terms and conditions could better capture the full value of demand response resources. A standard contract may develop for DRR similar to strip contracts for the wholesale market. Regulatory stimulus of such tools as standard long-term contracts may be appropriate initially and until markets become more robust and transparent.[38]

Another challenge arises for small utility systems or control areas which encompass only a few large commercial or industrial accounts capable of participating. Pure price response resources based on short-term agreements may not materialize with sufficient size or reliability to serve system needs because the "pay when called" policy is too uncertain for customers planning their utility budgets. Call options built into long-term agreements where customers are paid, at least in part, in advance for the option to call

[38] David Kathan, Personal Communication, June 13, 2002.

on the DRR capacity contained in the contract can encourage greater participation and investment by buyers and sellers.

Ultimately, markets should be able to reflect the many benefits of demand response in fair prices. But in these times of transition in wholesale and retail energy markets, prices for DRR may not fairly reflect all the cost savings and benefits produced.

The PLMA recommends considering the following practices:

- Develop markets that better compensate DRR for energy and capacity savings.
- Adopt standard contracts, such as for long term call options, to better reward the long term savings in DRR.

D-12. Reflect Location and Reliability Values

As a refinement to the previous design principle in compensating for full value, prices for DRR should also reflect locational and reliability values. Transmission congestion develops in geographic areas or zones where demand exceeds local generation capacity. Zonal congestion can be relieved, partially in some cases and totally in other cases, by demand response. Even though a region or state may have sufficient capacity, local areas may be constrained to meet electric loads. In Texas, for example, the market for demand response is not likely to be significant on a statewide basis, but could be important in areas where zonal congestion is prevalent, such as the Dallas-Fort Worth area.[38]

Congestion costs can be reflected in LMP. A significant benefit is the potential to stimulate greater DRR investments in areas constrained by capacity and this can be a more efficient solution than adding transmission and distribution resources. Several grid operators are taking advantage of these opportunities, including the ISO New England, the NY ISO, and PJM.

DRR has further potential than generally recognized for reliability purposes. In particular, it is suggested demand response resources can participate in day-ahead markets to not only provide energy and congestion management, but also ancillary services, including spinning reserves, supplemental reserves, and replacement reserves.

The PLMA recommends that locational and reliability values should be included in DRR agreements with customer participants.

D-13. Balance Penalty Provisions

Where penalties are present, a balance should be sought between the possibilities of penalties and the opportunities for rewards. Depending on the program, failure to reach a target demand reduction by a participating customer can cause penalties that well exceed the possible payment. Penalties imposed on customers are commonly justified to compensate for the higher costs expected for purchasing capacity on short notice to make up for the targeted demand reduction that was not achieved.

The balance between prospective payments and penalties is a concern to certain customers. This has been highlighted recently in a demand response program sponsored by the California Power Authority where 10 MW of load has been recruited against a goal of 250 MW. The Silicon Valley Manufacturers Group writes: "The number of customers and aggregators willing to accept that mismatch of penalties for non-performance vs. rewards is very limited."[39]

Failure to reduce load upon request at any particular facility may be due to such factors as an equipment malfunction or operator error. However, across multiple facilities for multiple participants, the impacts of malfunctions at one facility are less serious. Furthermore, some participants and facilities may be able to achieve larger than targeted reductions on any particular day due to their unique operations.

In the long run, markets should be sufficiently deep and liquid to handle imbalances between demand and supply. Then penalties, if any, may be more reasonably based on costs imposed by failure to meet curtailment agreements on a collective versus an individual basis.

The PLMA recommends considering the following practices:

- Provide credit for load reductions exceeding the targets.
- Allow aggregation across facilities or customers.
- Guarantee some payout, such as through a call option feature.
- Customize penalty provisions to balance individual customer and program needs.
- Waive penalties during experimental or early curtailments until load reductions are more certain.

D-14. Settle Payments in a Timely Manner

Programs should calculate and settle payments to participants on a timely basis. Participants rightfully expect to receive timely payments for their actions. Delays in payment inhibit program participation, particularly among customers subject to detailed budgeting of utilities and other operation costs.

The PLMA recommends considering the following practices:

- Provide feedback on performance and compensation to sellers the day after the event.

[39] Letter from Silicon Valley Manufacturers Group to California Power Authority, September 5, 2002, reported in "Some Give the California Power Authority's Negawatt Program Low Marks," *California Energy Markets*, September 9, 2002.

- Make payments in the next billing cycle or at the end of the season for load response programs where there are clearly understood credits and rewards.
- Make immediate partial payments for participants with real-time or near real-time monitoring and recording devices.
- Make payments within 60 days for price response programs with complex formulas.
- Minimize and preferably absorb fees for settlement in the near term, based on mutual agreement between the affected parties.

D-15. Deploy Multiple Marketing Strategies

Customers should be approached and sold with multiple marketing strategies. Relying on one or two strategies can risk recruiting too few participants for meaningful results. The sales cycle for DRR can be relatively long as the product is relatively unfamiliar to many prospective participants.

Two recent surveys include an assessment of marketing strategies used by utilities. As shown in Table 6, Commercial/industrial programs rely more on personal sales and less on other strategies such as the mass media. Residential relies more on mass media strategies with virtually no personal sales.

Table 6
Marketing Strategies by Utilities by Classes of Customer

Marketing Strategy	Commercial/Industrial[1]	Residential[2]
In person	77%	None
On Web site	63%	83%
Newsletter	43%	77%
Bill inserts	37%	79%
Direct mail	30%	27%
Print on bill	27%	37%
Newspaper ads	27%	57%
Radio ads	17%	33%
Telemarketing	3%	7%
TV ads	3%	30%

Notes:
1. Chartwell, *Report on Demand Response Programs*, March 2002.
2. Chartwell, *Report on Direct Load Control for Residential Customers*, March 2002.

The PLMA recommends considering the following practices:

- Focus significant personal contact for commercial and industrial programs.
- Build awareness and commitment through e-commerce.
- Leverage monthly billing communications.
- Segment media approaches consistent with customer segments.
- Act opportunistic in promotional practices.

In general, PLMA encourages deploying multiple marketing strategies to build customer awareness, provide participation information and gain commitment. Multiple approaches should increase the chances of adoption and retain customer participation.

D-16. Develop Long-Term Capabilities and Relationships

To ensure demand response resources are there when needed, programs and customer relationships should be built for the long term. While listed last, this is a key design principle. Too often, DRR is needed in a region, but is not available due to a lack of investment. Then there is a rush to develop DRR. However, if DRR is then not needed in the next year or two, providers' and consumers' interest lapses and the resource atrophies. The largest benefits for DRR often stem from its value as a hedge against low probability, infrequent events, but where each event has large consequences or costs, e.g., a system outage. Therefore, a DRR program can have value even if it is not fully utilized for a number of years. Traditional planning tools typically are not able to address the value of hedges against low probability, high consequence events, and this value not appropriately included in DRR assessments.

DRR may not be available to meet critical needs if it is not incorporated into the day-to-day and year-to-year planning by market participants. In some respects, DRR augments reserves, and even if not called upon substantively in a given year, it still can have considerable value.

DRR can be viewed as an insurance policy with the costs of maintaining threshold DRR programs viewed as a normal operating cost. These programs can be ramped up and down over different time periods, but they are hard to create from scratch. As a result, just as there are reserve margins, a target threshold of DRR, possibly as a percent of peak demand, may be an effective design requirement. Such a target threshold for DRR could vary by region and cost-effectiveness.

It is important to recognize that DRR provides market benefits that are not easily captured such as mitigation of market power, incentives to innovate through price signals that represent the scarce commodity, i.e., on-peak electricity, and enhanced market efficiency that comes from having both demand and supply adjust to market signals. These benefits can be hard to quantify and put into a DRR payment to a participant. However, they exist and should be acknowledged. Maintaining a given target level of DRR should be considered on a regional basis as electricity markets continue to develop allowing DRR to become a feasible long-term resource in these markets.

FERC appears to recognize the virtues of building long-term capability for DRR. The recent notice of proposed rulemaking on standard electricity market design requests comments on an appropriate planning horizon for each region of the country using two or three years as possible requirements.[40]

Customers are more likely to participate when program commitments show some stability, when resources are called upon on a regular basis with an accompanying payment, or when some minimum payment is assured. For DRR to be available when needed, customers may receive payments even if load reductions are not required for system reliability purposes or are not economic in terms of system production costs for a season or year. This may happen in a mild summer when reserves are sufficient.

The PLMA recommends considering the following practices at the strategic level to gain the benefits of DRR as an appropriate component of a long-term portfolio of resources:

- Designate DRR as responsible for meeting a target share or goal of system peak load requirements based on regional requirements. For example, a 3% to 5% target share of system peak to be met by DRR might provide a DRR infrastructure that would be scaleable when needs increase.
- Determine that a specific share or goal of reserve margins (e.g. 10% to 25%) will be served by DRR.
- Adjust the goals, annually or as needed, based on regional differences and cost-effectiveness criteria as suggested in the initial policy paper of PLMA.

The PLMA recommends considering the following practices at the operating level for event-based programs such as load response:

- Conduct a minimum number of curtailments each season.
- Operate each curtailment for a minimum time, such as two or four hours.
- Offer a basic payment, like a call option, even if no curtailments are called.
- Build the costs of these practices into program costs.
- Communicate with customers regularly such as before and after each season, about expected needs and actual performance of the system.
- Service customers who need assistance such as before, during, and after curtailment, or for other critical periods, such as when rates change.

In summary, there is significant market value in building long-term program capabilities and customer relationships.

[40] Federal Energy Regulatory Commission, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design: Notice of Proposed Rulemaking,* Docket No. RM01-12-000, July 31, 2002, p. 276.

5.0 Concluding Comments

The initial paper of the PLMA focused on demand response principles for regulatory guidance. This paper focuses on principles for the customer. Lessons learned by the professionals of the Peak Load Management Alliance suggest that subscribing to these design principles for customer participation will foster increased success with demand response resources, subject to many caveats.

All markets should be considered for DRR. While not all market and customer segments are equally able or likely to participate, a portfolio of programs in DRR is desirable. One compelling reason is that DRR can offer a portfolio of alternatives to complement generation, transmission, and distribution resources. For generation resources alone, DRR can help meet needs for ancillary services.

Customer information and education should be a central mission of any program targeting DRR. Customers accustomed to fixed rates and sheltered from rate fluctuations are relatively unsophisticated about energy markets. Since customers appreciate the reasons and opportunities in other markets with price fluctuations, they should be able to understand and take advantage of energy markets as they become more complex.

Many market participants have a role in educating and encouraging customer participation in the use of DRR. An important role should be played by incumbent utilities, regulated distribution companies, unregulated load serving entities, and curtailment service providers.

However, these market participants need a favorable regulatory environment. Accordingly, one of the clearest needs is for greater appreciation by regulatory officials of the value of DRR. This depends in turn on providing convincing evidence to regulatory officials of the willingness and ability of customers to participate. While professionals in the world of DRR may be satisfied that the evidence is clear, the slow pace of adoption suggests many regulatory and market participants are not convinced.

In conclusion, this paper attempts to contribute to the deliberate development and regular utilization of demand response resources by demonstrating the main design principles for creating customer and market value. With attention to these design principles, demand response resources should become a more significant, cost-effective and long-term part of the energy marketplace.

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Appendix: Additional Discussion and Caveats

Consideration of customer perspectives about participation and design principles for better value propositions in DRR should be viewed in the context of caveats regarding other market players and issues. In particular, it is important to recognize the perceptions of DRR buyers such as traditional utilities, distribution companies, and others. It is also important to appreciate the attitudes and policies of regulatory officials.

A.1 State Government Support

A significant challenge has to do with the perceptions of price response programs such as RTP. From one study:

> The overarching barrier to widespread application of RTP is a misperception that a shift to RTP will create new types of risks for utilities and regulators, without creating commensurate benefits for either utilities or customers….The challenge is to convince them that no such failures await them with implementing RTP…Another barrier is a misperception that a pre-requisite for RTP is competition between retail energy service providers. However, as examples of California and Georgia illustrate, retail competition is neither sufficient nor necessary for RTP.[41]

Public utility commissions struggle with concerns about customer choice in demand response programs. In particular, some commissions believe customers cannot adjust usage to price changes and therefore, favor voluntary over mandatory time-of-use rate programs.[42]

Other researchers offer similar observations: "The greatest barriers are legislative and regulatory, deriving from state efforts to protect retail customers from the vagaries of competitive markets."[43]

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[41] Ahmad Faruqui and Melanie Mauldin, "The Barriers to Real-Time Pricing," *Public Utilities Fortnightly,* July 15, 2002.
[42] Frederick Weston and Jim Lazar, "Framing Paper #3: Metering and Retail Pricing," The Regulatory Assistance Project for the New England Demand Response Initiative, April 18, 2002.
[43] Eric Hirst, "Price-Responsive Demand in Wholesale Markets: Why Is So Little Happening?" The Electricity Journal, May 2001.

A.2 Federal Government Jurisdiction

There is a question about state versus federal jurisdiction in DRR. Traditionally, DRR has been a matter of state jurisdiction. More recently, there have been federal initiatives. On July 31, 2002, the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rulemaking on standard electricity market design that contains provisions regarding DRR.[44]

DRR participants are retail customers normally and are subject to state jurisdiction. This was called in question by the FERC in March 2001 when it suggested that it had jurisdiction over all consumers that participate in demand response programs."[45] Following concerns expressed by the National Rural Electric Cooperative Association (NRECA), the Commission backed part way off its jurisdiction statement on rehearing. There the Commission held that:

> We recognize that there is a fine line separating state and federal jurisdiction where a retail customer receives compensation for a load reduction. Where a supplier directly compensates its retail consumer for load reduction, state jurisdiction is indicated. Where there are third parties involved, particularly where the transaction is tied to markets within our jurisdiction, then load reduction transactions where the seller is a public utility would fall within our jurisdiction.[46]

Subsequently, in its Orders accepting PJM's Load Response Programs,[47] the Commission appears to have implicitly moved away from the jurisdictional position in *Removing Obstacles* and thus is again imperiling existing DSM programs. In the PJM Orders the Commission explained that the sale of demand response from an end-user "to another party (whether an LSE or otherwise) for payment or credit," is jurisdictional sale for resale.

NRECA suggests that treating retail consumers that participate in demand response programs as jurisdictional public utilities subject to FERC requirements on tariffs, accounting rules and reporting would discourage utilities from implementing such programs and would discourage consumers from participating. Treating retail consumers as public utilities would also conflict with FERC's conclusion that end-use customer net metering arrangements with retail utilities are not subject to FERC jurisdiction.[48] As a remedy NRECA recommends reaffirming FERC holding in the

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[44] Federal Energy Regulatory Commission, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design: Notice of Proposed Rulemaking,* Docket No. RM01-12-000, July 31, 2002,

[45] FERC, *Removing Obstacles to Increased Energy Supply and Reduced Demand in the Western United States and Dismissing Petition for Rehearing*, March 14, 2001 Order, 94 FERC p. 61,972.

[46] Removing Obstacles, 96 FERC at p. 61,679.

[47] PJM Interconnection. L.L.C., 99 FERC ¶ 61,139 (2002); 99 FERC ¶ 61,227 (2002) (order accepting tariff sheets as modified). ("PJM")

[48] MidAmerican Energy Company, 94 FERC ¶ 61,340 (2001) ("Mid American")

Removing Obstacles case that "where a supplier directly compensates its retail consumer for load reduction, state jurisdiction is indicated."

A.3 Customer Bypass

Customer bypass creates other concerns. Bypass occurs in DRR where participants sell to competitive buyers other than the traditional distribution utility. Utilities have several concerns with bypass:

- Bypass may strand investments that utilities have made in generation capacity to serve its customers.
- Bypass may strand investments that utilities have made to implement their own demand response programs, including control switches, metering, communications, and billing for DRR.
- Bypass may discourage consumers from participating in utilities' own demand response programs, denying those utilities' access to demand response resources on which they may rely to keep costs and market risks down for other consumers on the system.

State may also be concerned with bypass where bypass can undermine state mandated or sponsored demand response programs. They may also be concerned by the effect that bypass may have on local employment and economies.

One solution is to acknowledge differences between those states that have adopted retail competition and those states and service territories that have not. Bypass concerns would be reduced according to NRECA if retail consumers are permitted to participate only if they are:

- Located in states and service territories with established retail competition,
- Served by a competitive supplier that is not a default supplier with a traditional obligation to serve at a regulated rate, and
- Metered or otherwise confirmed in the time and quantity of their actual load reduction.[49]

NRECA explained that limiting those who are eligible to participate directly in wholesale demand response markets to consumers with retail choice would not reduce FERC's ability to encourage and regulate wholesale demand response markets or reduce the amount of demand response. Traditional utilities providing bundled retail service, NRECA argues, are in a better position to aggregate demand response on their systems than any third parties. Cooperatives are already extremely active in demand response. And, as illustrated by Puget Sound Energy and others, state regulators are requiring regulated utilities to provide demand response resources.

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[49] Ibid.

A.4 Revenue Loss

Another issue for buyers and certain market participants is revenue loss. Integrated utilities must deal with the prospect that reductions in peak demand reduce revenues from energy and demand charges. From one perspective, appropriately addressing this revenue loss can represent a reasonable change in rates because the customers that are not contributing to peak demands are now being credited appropriately through the time differentiated rates. However, it is important that the potential for revenue changes to parties be recognized and equitably addressed.

In the unbundled world of utility deregulation, the revenue loss potential becomes more complicated. This can be particularly true for a distribution company whose rates are based on throughput, which is measured on a volumetric rate, such as kilowatthours.

In many instances, the revenue impact of a few hours of load reduction for a distribution company or energy provider is a fraction of the total revenue stream. In fact, since many load reductions amount to less than one percent of the hours in a year and only apply to participating DRR customers, the annual revenue impacts are a small fraction of the revenue stream.

Realistically, revenue loss can be much greater from other variables such as weather and economic activity. Also revenue loss may not be quite as small a fraction if higher prices are charged during peak hours. Nevertheless, one approach is to permit a non-bypassable surcharge on customers regardless of throughput.[50]

The revenue loss situation under voluntary programs for time sensitive pricing is somewhat different. Customers with favorable load profiles will tend to participate in time-of-use and real time pricing programs. Furthermore, unless the participating customers shift loads, there are no peak load benefits. The associated net revenue losses must then be made up in a regulated market by rate increases to other customers. However, it can also be argued that this is a desirable proposition in that those customers that shift to time sensitive pricing programs are now being credited appropriately since they do not contribute to peak demands (i.e., they have favorable load profiles that cost less to serve). These customers may have been subsidizing those customers who are using more electricity on peak and it can be argued that the new rates simply correct a subsidy that has been in place for a long period and represent a move toward pricing based on the costs of serving each customer.[51]

Conceptually, there is nothing wrong when a customer chooses to install an interval meter and opt for time-differentiated pricing even if it changes revenue collections. In fact, this can be quite appropriate as that customer is now being charged their true costs. It has been argued that "this represents good decision making based on rational

[50] EPRI, Ibid., p. 30.
[51] Violette, Dan, and Steve George, "Market Design for Retail Competition -- Load Profiling Method," *Appendix 6 -- Final Retail Technical Panel Report to the Ontario Market Design Committee*, April 29, 1999; p. 3-40.

economic behavior. While such decisions may mean that load profiles and revenues collected must be adjusted periodically to account for customer migration, and that those customers who do not install meters will ultimately pay higher (but more accurate) prices for electricity, this is not a defect in the process. In fact, such changes are desirable because they improve the overall accuracy of the cost allocation process."[52]

Revenue losses can also occur with mandated pricing programs. Customers may alter usage more than expected exposing the LSE to unanticipated generation obligations

Revenue loss can occur to the LSE with real-time pricing. This challenge to real-time pricing is most likely where:

- The rate is a one-part design,
- Customers may participate on a voluntary basis, and
- Voluntary customers with favorable load shapes do not shift usage.

Solutions to these challenges of real-time pricing include:

- Offering a two-part rate design, or
- Mandating participation for sets of customers that is revenue neutral, or
- Offering a true-up mechanism to ensure recovery of forecasted revenues.[53]

A.5 Mass Metering

The adoption of mass metering is likely to encourage greater use of DRR. Some analysts conclude that the rolling blackouts in California in 2000 and 2001 could have been prevented if more customers had been empowered with DRR. Rather, an energy crisis developed despite the fact that California claims the lowest residential electric use per capita.[54]

About the only demand reduction during the crisis came voluntarily, including interruptible loads. In a belated yet aggressive move to shore up DRR, the California legislature appropriated $35 million to help finance installation of advanced meters and communication networks for all commercial facilities over 200 kW in size. In many cases, large industrial customers already have the equipment to monitor and adjust their demand in the face of rising prices, and in fact, do so. Successful restructuring may necessitate that residential and commercial customers acquire many of the same demand-management capabilities.[55]

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[52] Ibid.
[53] EPRI, "New Principles for Demand Response Planning," May 2002.
[54] Congressional Budget Office, "Causes and Lessons of California Energy Crisis," September 2001.
[55] Ibid.

Similarly, a key challenge facing the implementation of time-sensitive pricing in the mass market is the absence of an advanced metering infrastructure. As noted recently by EPRI:

> "The use of advanced metering, to provide measurement capability, affects demand management in two very fundamental ways: first as an enabler and second as an integrator. Advanced metering provides capability that enables demand response options to use price-based control signals to all customers and all load. Removing end-use and customer size restrictions expands the potential for program load impacts."[56]

With the notable exceptions of Puget Sound Energy and PPL, few utilities in recent years have launched large-scale metering initiatives with demand response as a primary objective. Indeed, even as electric, gas and water utilities have gradually deployed AMR to its current level of 11% percent of U.S. meters, only 13% of utilities with AMR report using it for time-of-use pricing.[57] This suggests that for the mass market, utilities have implemented AMR primarily to automate their monthly kWh reads in conjunction with flat-rate billing.

Retail electric providers are in a position to respond to the compelling economics of selling electricity based on price signals. At least one prominent retailer, Green Mountain Energy Company, serving the mass market has indicated it is "very excited" about adding time-sensitive pricing to its line of customer options, assuming a critical mass of advanced meters in the field.[58] Several state commissions are now evaluating public policy options for stimulating advanced meter deployments.

Thanks to technology advances, it is generally accepted that most if not all technical challenges in metering and verification have been overcome in recent years. Now, the real issue is cost.[59]

Unit costs can be prohibitive when meters are installed individually, but can be much more attractive when installed universally. Universal deployment of advanced meters in residential markets can be accomplished from $7 to $25 per meter versus $100 to $200 per meter when installed one by one.[60]

Even when the need for more data exists for demand response programs, there is a question over where the investment should be made. One view is that the choice is between a "smart meter, dumb network or dumb meter, smart network." There are economies of scale with dedicated networks allowing them to be used for widespread

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[56] EPRI, New Principles for Demand Response Planning," May 2002.
[57] Chartwell AMR Report, 2001.
[58] Dennis Kelly, Remarks on behalf of Green Mountain Energy Company, PLMA Annual Spring Meeting, April 26, 2002.
[59] Frederick Weston and Jim Lazar: "Framing Paper #3: Metering and Retail Pricing," The Regulatory Assistance Project for the New England Demand Response Initiative, April 18, 2002.
[60] Chris King, Remarks on behalf of eMeter Corp., PLMA Annual Spring Meeting, April 27, 2002.

deployments. Experience has shown that no single meter and communications configuration will meet all the needs in a service territory in a cost-effective manner. For large-scale applications, hybrid solutions are the norm. One of which can be to upgrade existing meters rather than replace them.

Several states have passed rules or legislation opening the metering to competition, removing the responsibility for meter deployment from the distribution utilities in an effort to stimulate upgrades to advanced metering. While California and Pennsylvania permit competitive metering, market incentives in those states are proving largely insufficient for third party suppliers.[61] In California, there is a petition before the Public Utilities Commission urging that competitive metering be revoked and utility distribution companies be instructed to file plans to deploy advanced metering.[62]

Massachusetts reversed its decision to unbundle metering just prior to the scheduled rollout of competition. Texas is currently scheduled to phase-in metering competition starting in 2004. However, “a key lesson drawn from the early states is that meter deregulation by itself - unaccompanied by additional market development incentives and protections - can lead to stagnation and failure”.[63] The Public Utility Commission of Texas currently re-evaluating metering competition in the context of a report it is scheduled to deliver to the incoming 2003 legislature.

In order to encourage installation of advanced meters in mass markets several solutions could be considered. These include the following options, some of which are mutually exclusive, and in all cases meant to be suggestive:

- Reconsider competitive metering mandates.
- Restore or maintain responsibility for metering services with the distribution utilities, combined with incentive packages or mandates for deployments of advanced meters in mass markets, and cost recovery assurances.
- Allow advanced meter installation for any customer that wants one from the distribution utility with costs socialized.
- Offer rebate programs for advanced meters, financed by such mechanisms as efficiency funds or system benefit charges.
- Encourage or require retail electric providers to offer time sensitive rates, where cost-effective, for all customers in certain categories and couple with advanced meter requirements.
- Allow investments to be depreciated more quickly than the 30 years typically used for meters in recognition of the rapid changes in meter technologies.

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[61] Ed Finamore, personal communication, Valutech Solutions, May 29, 2002.
[62] Chris King, “Petition to Modify D.97-05-039 by the California Consumer Empowerment Alliance (“CCEA”) to Revoke Competitive Metering and Order UDCs to Submit Advanced Metering Deployment Plans.” On behalf of eMeter Corporation, March 21, 2002.
[63] Wattles, Paul: “The Case for Advanced Electrical Metering in Texas,” Good Company Associates Draft Policy Research Report for the Texas Advanced Metering Coalition, April 2002.

- Offer tax and other government incentives for advanced meters as proposed in various state and federal legislative proposals.
- Expand the definition of advanced metering beyond automatic meter reading to include a capability to enable time-sensitive price response (Wattles).

A.6 Energy Information Infrastructure

Similar arguments may be made regarding the energy information infrastructure. If the costs of meters should be spread among all customers whether or not they participate in certain programs, the same argument may be made for energy information systems that are deployed to handle metering data.