Framing Paper #1: Price-Responsive Load (PRL) Programs

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Prepared for

The New England Demand Response Initiative (NEDRI)

Prepared by

C. Goldman
Lawrence Berkeley National Laboratory (LBNL)[1]

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[1] Galen Barbose (LBNL), Fran Cummings (KEMA Consulting), and Eric Hirst contributed draft material for various sections. Bernie Neenan (Neenan Associates) provided draft working papers, technical reports, and published evaluations that were extremely useful in preparation of this Framing Paper.

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Acronyms

BUG	Back-up Generators
CBL	Customer Baseline
CCM	Congestion Cost Multiplier
CSP	Curtailment Service Provider
DAM	Day-Ahead Energy Market
DRR	Demand Response Resources
FERC	Federal Energy Regulatory Commission
ICAP	Installed Capability
ISO-NE	Independent System Operation – New England
LBMP	Locationally-based Marginal Price
LSE	Load serving Entity
MCP	Energy market clearing price
NEDRI	New England Demand Response Initiative
NYISO DADRP	New York ISO Day-Ahead Demand Response Program
NYISO EDRP	New York ISO Emergency Demand Response Program
NYSERDA	New York State Energy Research & Development Authority
PCLB	Day-ahead Price-capped Load Bidding
PJM ISO	Pennyslvania, New Jersey, Maryland ISO
PRL	Price-Responsive Load
RES	Competitive Retail Energy Supplier (or Energy Service Provider)
SMD	FERC Standardized Transmission Service and Wholesale Electric Market Design

New England Demand Response Initiative

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C. Goldman, LBNL

I. Introduction

The FERC staff recently issued its "Working Paper on Standardized Transmission Service and Wholesale Electric Market Design." In this report, FERC staff articulates its vision of the role of demand resources in wholesale electricity markets (see excerpts in italics below):

"B. General Principles for Standard Market Design

7. *Market rules must be technology- and fuel-neutral. Demand resources and intermittent supply resources should be able to participate fully in energy, ancillary services, and capacity markets.*
8. *Demand response is essential in competitive markets to assure the efficient interaction of supply and demand, as a check on supplier and locational market power, and as an opportunity for choice by wholesale and end-use customers.*

D. Energy Market Design

Day Ahead Energy Market

5. Demand can best respond by participating in the day-ahead market. Demand response options should be available so that end users can respond to price signals and reduce loads as they feel the price exceeds their individual willingness to pay for delivered electricity.

Scheduling and Bidding Rules

6. The demand side must be able to participate in the energy market. The demand side can participate as buyers or sellers (e.g., offering to sell operating reserves). As a buyer, an entity must be able to submit bids that indicate it is willing to vary the quantities it purchases based on the prices that it may be charged."

7. Sellers (including demand side) must have the option of submitting multi-part bids, e.g., submitting separate but related bids for start-up costs, no load costs, and energy."

Translating FERC's broad principles on the role of demand resources in competitive wholesale markets into a set of programs, initiatives, and activities that facilitate development of demand response resources in the New England electricity market is a major challenge for participants in the NEDRI process. The ultimate goal/objective of such efforts is to create sufficient "price-responsive" load so as to improve the performance, efficiency and reliability of wholesale electricity markets. Several conceptual studies have demonstrated that a relatively small amount of price-responsive load can substantially reduce market clearing prices during "tight" market conditions, producing significant benefits to consumers.

In Framing Paper #1, we explore and examine various options for demand response resources to provide load curtailments or decrements in response to market (price) signals in the day-ahead energy market as well as key policy and program design issues.[2] In order to provide appropriate context for consideration of these issues, in Section 2, we describe various wholesale electricity markets, identify various barriers that currently limit participation in these markets by demand response resources, and summarize recent experiences and lessons learned from ISOs and utilities that have offered similar and related demand-response programs.

For discussion purposes, we assume that New England ISO will be developing a day-ahead market as part of its Standard Market Design and that FERC will require ISO/RTOs to implement a set of demand response initiatives and programs that are consistent with Standard Market Design which will be included in a revised transmission tariff. We assume some form of integration or coordination will occur with NYISO in the area of demand response programs, based on the current NERTO negotiations or through some other process. We also assume that ISO-NE will consider various types of wholesale market programs designed to elicit demand response resources as part of its effort to implement the FERC Standard Market Design and a reformed open access transmission tariff.

The fundamental policy issues that should be considered and resolved by NEDRI participants as they assess various types of program approaches include the following:

- *What market mechanisms are needed or desired by end users and other market players in the price-responsive load area?*

- *Are PRL-type programs activities that should be undertaken and supported by ISOs or should they be considered solely at the state/retail jurisdictional level?*

- *Under what conditions or circumstances are wholesale market PRL programs appropriate (e.g., are economic demand bidding programs necessary if RTP was widespread)?*

- *What is the relative magnitude of demand response resources (DRR) needed to ensure efficient and well-performing wholesale electricity markets? Is Price-Capped Load Bidding (PCLB) likely to provide sufficient DRR or will other types of load reduction programs be necessary?*

- *How do you pay for the enabling demand response technology infrastructure necessary to capture consumer market benefits of PRL?*

- *Is the provision of demand response resources an attractive business opportunity for potential load aggregators? Is it a viable "stand-alone" business"? Are there disincentives that limit the interest of potential load aggregators (e.g., utilities)?*

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[2] In principle, these programs could also encompass customer load curtailments offered **in** short-term forward markets – e.g. several days to weeks.

- *What types of demand-side resources should be eligible to participate in price-responsive load programs (e.g., the role of and or limits on the use of diesel-fired back-up generators)?*

II. Price-Responsive Load (PRL) Programs in Wholesale Markets

A. Overview

In this section, we describe various wholesale energy markets and how demand response resources can participate and be integrated into these markets, summarize recent experience of ISOs and utilities that have offered price-responsive load (PRL) programs, and discuss barriers to participation by customers and load aggregators.

B. Wholesale Electricity Markets

Wholesale electricity markets typically include long-term markets for transmission rights (either financial or physical) and installed generation capability as well as short-term markets for energy, ancillary services, and congestion. Material in this section is drawn primarily from Neenan Associates (2001) and Hirst (2002).[3] Table 1 lists and describes various wholesale markets and ways in which price-responsive loads can participate (see Framing Paper #2 for a more in-depth discussion of wholesale electricity markets).

[3] Neenan Associates 2001. *Valuing Investments in Developing Customer Price Responsiveness*. Working Paper, Dec. 21.; Hirst, E. 2002 *Reliability Benefits of Price-Responsive Demand*. March 8.

Table 1. Wholesale Electricity Markets and Demand Response Resources

Market	Description	Demand Response Resources
Day-ahead Energy	LSEs submit orders for day-ahead contracts; Suppliers submit bids to make unobligated capacity available to LSEs; ISO schedules generation to meet loads in economic merit order subject to security-constrained unit commitment constraints	Scheduled Price-Responsive Load
Real-time Energy	Suppliers submit bids to provide balancing energy that are dispatched to meet residual LSE requirements; ISO dispatches according to economic merit order (i.e., minimize cost of meeting electricity demand with resources then online or which can be started quickly)	Dispatchable Price Responsive Load
Day-ahead Ancillary Services	Potential suppliers submit capacity, energy bids to supply various ancillary services (e.g., supplemental reserve, replacement reserve, spinning reserve, regulation, frequency response)	Dispatchable PRL that meets dispatch/curtailment requirements for ISO ancillary Services
"Emergency Resources"	Resources dispatched only when system emergency exists, when reserve shortfalls are forecast or imminent; customers paid either market clearing price or price floor (e.g., $500/MWh)	Dispatchable PRL that agree to curtail load for specified number of hours (e.g., 4-6 hours) when called with 1-2 hours notice
Installed Capability (ICAP)	LSE required to procure capacity call options equal to their load serving obligations; generators selling ICAP to LSE are typically obliged to bid that resource amount into ISO market each day and be available under emergency conditions; note problems in defining product and ensuring performance	Option-Contracted Price-Responsive Load

Sources: Neenan Associates 2002. *Valuing Investments in Developing Customer Price Responsiveness.* Hirst, E. 2002 *Reliability Benefits of Price-Responsive Demand*. March 8.

For example, in the day-ahead energy market, it is quite logical to allow demand response resources to bid against generation to serve load requirements. Typically, loads follow similar procedures as generators as to the timing for submitting bids (e.g., 11 AM or 2 PM of the day-ahead), and the structure of bids. Some programs, such as the NYISO, impose damages on participants that fail to curtail, which are established at amounts comparable to the cost of purchasing coverage in the real-time market.

Similarly, in the Installed Capability market, long-term contracts for load interruptions generally qualify as installed capability. PJM's Active Load Management program, operated primarily by the distribution utilities, includes direct control of residential equipment, customer load reduction to a firm level (interruptible contracts), and guaranteed load drops implemented through the use of onsite generation. In this program, PJM provides no monetary payment. Instead, participating load-serving entities receive installed-capability credits for the load reductions, which reduce their costs of installed generating capacity. Participating loads must be available for up to ten PJM-initiated interruptions during the planning period (October through May and June through

September), for interruptions lasting up to six hours between noon and 8 pm on weekdays, and within two hours of notification to the load-serving entity by PJM. Failure to perform can lead to penalty charges related to PJM's capacity deficiency charge.

Finally, in the ancillary services markets, PRL resources could be integrated into the market directly or indirectly and could bid against generators to provide load balancing, reserves, and/or regulation services (see Framing Paper #2 for more in-depth discussion of this issue). Thus far, there are relatively few customers that can meet the dispatch/curtailment requirements set by ISOs for ancillary services.

Some ISOs have established programs that allow loads to provide emergency resources when called upon with relatively short notice (i.e., 1-2 hours) in part due to the desire to incorporate various "legacy" load management programs. These resources are dispatched only when a system emergency exists, when reserve shortfalls are likely or imminent, and thus don't directly compete with generators. Some ISOs have included program design features that make these programs more attractive to customers: incentives payments that include guaranteed price floors or market-clearing price, whichever is higher; limitations on frequency and duration of curtailments (e.g., 100 hours per year; 6 hours per day); and minimal or no penalties. Based on discussions with ISO and utility program managers and customer market research, one of the more compelling benefits of emergency programs (from a marketing perspective) is that they provide a means to introduce and allow customers to the concept of direct participation in the new wholesale electricity markets, that customers learn about price volatility and risks involved in these markets, and install enabling technology (e.g., metering, communication, notification equipment). This provides a very useful platform for customers to then decide whether they want to curtail loads in response to market prices and develop some actual experience with how much price risk and exposure they can handle in PRL programs (Neenan 2001).

C. Potential Benefits of Price-Responsive Load Programs[4]

PRL program participants that curtail their loads are typically paid either the energy market clearing price (MCP), or a floor price which reflects what that price would have been but for the availability of these resources. Some fraction or all of these gross benefits may be passed through to customers. From the customer's perspective, their net benefits depends on the level of costs that they incur in undertaking curtailments (e.g., costs associated with rescheduling business activities, investments made in equipment and monitoring and control technology). PRL programs are of particular interest because they also have the potential of producing three types of benefits for all customers (i.e.,participants and non-participants alike). See Neenan Associates (2002) evaluation of the New York ISO PRL 2001 programs for an illustration of how these benefits can be determined and estimated for specific ISO PRL programs, both Emergency Demand Response Program (EDRP) and Day-Ahead Demand Response Programs (DADRP).

[4] This section draws heavily from Neenan Associates 2002. *Expected Benefits from Participation in the ISO-NE's Price Responsive Load Programs*. Prepared for Connecticut Light & Power. January 31.

- **Reliability benefits**. When PRL resources are dispatched in response to reserve shortfalls, all end-use consumers benefit directly from the improvement in system reliability
- **Collateral benefits: downward pressure on market clearing price** - The PRL resources can place downward pressure on market clearing prices by displacing the highest priced units in the bid curve. The extent to which load curtailments dampen market prices depends on the steepness of the supply curve at the time: the steeper the curve, the greater the impact[5]
- **Collateral benefits: hedging price impacts** – Over the long-term, significant amounts of PRL resources may also be expected to impact price volatility and average market price.[6]

Table 2 summarizes how the market benefits of PRL resources can impact various wholesale electricity markets (Neenan 2001). In quantifying the magnitude of benefits of demand reduction, the relativeness steepness and shape of the supply curve (e.g., hockey stick) have a significant impact (e.g., load curtailment will have greater impacts on dampening market prices, the steeper the supply curve).

Table 2: Value to Consumers of Price-Responsive Load Resources in Wholesale Electricity Markets.

Potential Impacts of PRL	**Scheduled PRL ("Market" DR programs)**	**PRL dispatched in response to System Emergencies**	**ICAP-certified Loads**
Reliability	Indirect benefits (ISO has more generation available to meet contingencies; spillover effect felt in Real Time Market)	Direct benefits (restore system security to design levels and help avoid forced outages)	
Short-run Market Clearing Price	Collateral benefits (e.g., effect on price spikes)	Collateral benefits	
Long-run Energy Price	Reduced hedge costs	Reduced hedge costs	
Capacity Market Price			Reduced ICAP costs

Source: Adapted from Neenan Associates 2001 *Valuing Investments in Developing Customer Price Responsiveness,* Working Draft, December 21.

End-use consumers enjoy the reliability benefits directly. Collateral benefits flow to consumers through LSEs. As the costs and risks of serving retail loads is reduced, because of lower hedging costs, these benefits will be passed on to consumers served by default providers through lower tariff rates, and to those purchasing electricity from a competitive retail supplier as a result of competitive pressures. Thus, all end users benefit

[5] These benefits include *settlement benefits,* which are the product of the price decrease resulting from the PRL curtailments and the amount of load settled at real-time prices; and the *full market impact benefits*, which includes reduction in price volatility (which reduces the risks associated with load settled in the real-time market). The full market impact is a measure of this effect on bilateral prices as it reflects equilibrium market prices under more robust competitive conditions. These benefits are measured by the product of the price decrease caused by the PRL curtailments and the total load served at the time.

[6] Reduction in average market price multiplied by amount of load traded under bilateral contracts provides estimate of these benefits

from the load curtailment and management actions of a relatively few customers participating directly in a competitive wholesale electricity market.

Note however, that the participants that actually curtail load cannot capture these reliability and collateral benefits, because they only receive payments from their ISO or LSE. Moreover, from the participant's perspective, this stream of potential benefits appears speculative and risky (e.g., infrequent curtailment calls, uncertainty about performance, payment lags and delays). Given this reality, we should not be surprised if there is under-investment by customers in aggregate in price-responsive technologies, information systems, and operational strategies.

D. Experience with PRL Programs offered by ISOs

The ISO-NE, NYISO, and PJM each offered PRL Programs for 2001. The programs were designed through collaborative multi-stakeholder processes and rolled out under fairly restrictive timelines in order to be in place by summer. The programs represented pilot efforts at creating price responsive load in most cases. Table 3 highlights key program design features of each program while Table 4 summarizes 2001 results.

Program Design

The ISO-NE offered the Price Response Program (Load Response Pilot Program – Class 2), which allowed customers to voluntarily reduce energy consumption during periods for which the day-ahead forecast Energy Clearing Price (ECP) exceeded $100/MWh. Payments were made, and thus also the customer's decision to follow through with curtailments, based on the real-time ECP. Customers could enroll in the program through any NEPOOL Participant. All customers were required to purchase and install the RETX Load Management Dispatch software, which allowed them to make bids and monitor their performance during curtailment events, and which automated the submission of data to the ISO for settlement. This was the only PRL program among those offered by the three ISOs that directly incorporated any real-time monitoring capability for the participating customers.

The NYISO Day Ahead Demand Response Program (DADRP) provided an opportunity for participants to bid load reductions into the day-ahead energy market. Customers participated in the program through their LSE, who submitted bids on their behalf to the ISO. (Starting in 2002, customers can participate through third-party Curtailment Service Providers.) Among the three ISOs programs, this was the only program in which load reduction bids were fully integrated into the ISO scheduling processes, with load reduction and generation bids considered equivalently (see Section III, Program Type 2). Load reduction bids were submitted in minimum increments of 1 MW per bus in contiguous strips of one or more hours. If a load reduction bid was the highest cost bid accepted, it was able to set the Locationally Based Marginal Price (LBMP) just as a comparably bid generator. Also like comparable generators, participants who failed to deliver any portion of an accepted load reduction bid were penalized.

PJM developed the Economic Load Response Program for 2001. The program was an expansion of the 2000 Customer Load Response Program, which was directed at facilitating demand response to emergency conditions. The Economic Load Response Program was designed to provide a mechanism by which a PJM member could be compensated for contracting with end-use customers to reduce load during high price periods. Curtailments were initiated by participants, who were able to reduce load whenever their zonal Locational Marginal Price (LMP) dictated that it was economically beneficial to do so. Unlike the earlier program, customers could participate in the 2001 Economic program through any PJM member, not solely their LSE.

Table 3: 2001 ISO PRL Program Design Features

Program Design	ISO-NE Price Response Program	NYISO Day Ahead Demand Response Program	PJM Load Response Pilot Program – Economic Response
Participation Requirements	Customers can participate through any NEPOOL member	Customers can participate through their host LSE (2001 only)	Customers or third-parties can participate through any PJM member
Minimum Load Reduction	100 kW (aggregated)	100 kW (per customer), 1 MW (aggregated)	100 kW (per customer)
Operational Trigger	Customers may offer load reductions when day-ahead forecast ECP > $100/MWh	Participant may offer bids on any occasion; bids scheduled by ISO based on cost	Participant may offer bids on any occasion
Technical Requirements	Interval Metering and RETX ICBS program	Interval Metering	Interval Metering
Verification and Settlement	Interval data submitted in real time via RETX	Metering data submitted by MDSP following curtailment	Metering data submitted within 45 days
Incentives	Real Time ECP	Greater of day-ahead LBMP or bid price, including curtailment initiation costs	Real Time LMP less retail G&T rate
Penalties	None	110% of the greater of real-time or day-ahead LBMP	None
CBL	Adjusted 10-day rolling hourly average	Based on 5 highest days out of last 10 days	Negotiated between Participant, PJM, and EDC

2001 Results

Overall, as shown in Table 3, the programs achieved relatively modest levels of participation, in terms of potential curtailable load (57 – 300 MW). This was certainly due, not in small part, to the fact that the programs were new and that they were not finalized until late spring. Moreover, on those days, when the ISOs accepted customer offers to curtail load, the actual load curtailed typically represented a small fraction of the potential curtailable load of all participants (i.e., 3-30%).

The ISO-NE's program was utilized on six occasions in 2001, when prices frequently reached $1000/MWh, providing an average load reduction of 17 MW. The program enrolled 57 MW of potential load reduction, which was significantly below the original target of 600 MW (ISO-NE 2001). Anecdotal evidence suggests that participation rates may have been adversely affected by the fact that customers incurred significant upfront costs (i.e., purchase and installation of the RETX system), but were not assured with a guaranteed benefit stream of payments.

The NYISO's program was able to enroll a substantial amount of load reduction (300 MW); however, the maximum scheduled peak period load was 25 MW and average load curtailment were 8 MW when bids were accepted. Average customer satisfaction ratings for the DADRP program were relatively low (2.5 on scale of 6). A number of program design and implementation idiosyncracies adversely affected participation rates and customer satisfaction: high minimum bid thresholds, limitations in the NYISO software, concerns about penalties, low benefit expectations, and the length of time that elapsed between curtailments and payments for those reductions.[7]

PJM enrolled 65 MW of potential load reduction in its Economic program. The program operated five times over the summer, providing just 2 MW of load curtailments on average. Throughout most of the program's operating hours, load reductions under PJM's Active Load Management (ALM) took place concurrently. Since a large fraction of customers in the Economic program were also ALM participants, and ALM commitments take precedence, this was one factor contributing to the low performance of the Economic program (PJM 2001).

Table 4: 2001 ISO PRL Program Results[8]

Program	Potential Curtailable Load (MW)	Average Actual Curtailed Load (MW)	Days of Operation
ISO-NE Price Response Program	57	17	6
NYISO Day Ahead Demand Response Program (DADRP)	300	8	24
PJM Economic Load Response Pilot Program	65	2	5

[7] Neenan Associates 2002. *NYISO PRL Evaluation*.
[8] In the NYISO DADRP program, participants could submit bids on a daily basis; NYISO accepted participant bids on 24 occasions.

Program Changes for 2002

Both the ISO-NE and PJM filed proposed revisions to FERC for their 2002 PRL programs, with the objective of expanding participation (NEPOOL 2001), (PJM 2002). The ISO-NE made the following modifications to their program:

- Provide customers with the option of a low-tech communication protocol. The cost of the RETX system was viewed as barrier to participation. A low-tech alternative will involve (a) an alternate notification scheme (e.g., email, website, fax, etc.) and (b) submission of interval meter data within several days of curtailment event. Furthermore, customers will not be required to notify ISO-NE of their intent to reduce load ahead of time, but can provide notification after the fact simply by submitting meter data within 36 hours after the event

- Provide locational value to load response. This will be achieved through incorporating zonal Congestion Cost Multiplier (CCM) based on the zonal Transmission Congestion Costs. The effect of the CCM will be limited by a maximum incentive payment capped at ECM + $100/MWh – i.e., the incremental effect of the CCM is capped at $100/MWh.

- The program is set to expire on May 31, 2003 or upon implementation of an alternative design, whichever occurs first.

PJM proposed fairly substantial modifications to their PRL program for 2002.[9]

- Extend the program until December 2004. PJM expects that this level of commitment (spanning three summer periods) will stimulate participation through providing more certainty to participants.

- Provide a subsidy to participants by paying the full LMP when it is $75/MWh or greater. Previously, customers were paid the LMP less the retail generation and transmission (G&T) charges.

- Provide options for load reductions in both the day-ahead and real-time energy markets.

- Offer an experimental program, limited to 25 MW, for non-hourly metered residential, commercial, and small industrial customers. Verification of load reductions will be based on customized methodologies approved by PJM for each participant.

[9] The modifications were not approved by the PJM Members Committee although the PJM Board proposed the following modification to FERC.

E. Experience with PRL Programs offered by Utilities[10]

Utilities have offered various types of load management programs for many years, which typically focus on reducing or shifting peak demand in response to system contingency events. With the emergence of competitive wholesale electricity markets, utilities have increasingly offered PRL programs as a means to establishing a physical and financial hedge against volatile and/or high wholesale electricity market prices. In some instances, PRL programs have provided profit opportunities by enabling utilities to purchase load reductions from their customers and sell into high priced markets the generation capacity that would otherwise be designated for those loads (e.g., Pacific Northwest utilities selling into the California market in late 2000 and spring 2001). These programs provide a more comprehensive experience base upon which to draw insights on factors that affect program success, customer participation rates and highlight "best practices." In particular, the most successful or innovative LSE PRL programs are characterized by:

- A much greater degree of hand-holding (e.g., technical audits, energy and demand reduction information management tools) and customer education
- A variety of forward-contracting options (e.g., day-ahead, term events)
- Substantial customer response at high offer prices
- Implicit sharing of savings with customers by the utility
- Multiple participation options with different features offered under a single program "brand"
- Use of customer-specific baselines for verification/settlement of load curtailments

Programs offered by Portland General Electric and Cinergy are particularly innovative and provide good examples of "best practices" among utilities (Goldman et al 2002a).

Portland General Electric's (PGE) Demand Buy Back Program is a voluntary, "quote-type" demand bidding program. In 2001, PGE offered the Demand Buy Back Program with three types of load reduction bidding variants: day-ahead, pre-scheduled (up to one week in advance), and term events (lasting weeks to months). As of September 2001, the program had 26 participants with 230 MW of potential curtailable load. Customers as small as 250 kW could participate, although over two thirds of the participants were over 500 kW.

PGE has had significant success in eliciting a substantial demand response from participants. From July 2000 to May 24, 2001, there were 122 daily events, resulting in average load reductions of 162 MW. In December 2000, when offers to participants reached $300/MWh, the full potential load reduction was curtailed, representing 50% of the participants' collective summer peak demand. A significant basis for their success has been that PGE worked with each participant individually to identify specific load curtailment strategies and quantify the associated load reduction. A further factor (not at all incidental) was that the program was launched in time to capitalize on the skyrocketing wholesale electricity prices in the West. By purchasing these load

[10] This section is based mainly on LBNL research and work reported in Goldman et al, 2002a and 2002b.

reductions, PGE was able to avoid more expensive purchases in the wholesale market to cover net short load and/or sell any excess generating capacity into the market.

Cinergy has had arguably the most aggressive demand response program in the country because of their experience during the summer of 1999, when the combination of generation outages and an explosion in wholesale price volatility exposed the company and its customers to extreme price spikes and system reliability problems. After Cinergy's well-publicized contract default and subsequent exposure to liquidated damages, the company made a concerted effort to rapidly grow their demand response programs.

Cinergy has consolidated all of its load management programs into one umbrella offering, the PowerShare Program. Cinergy's program is one of the largest programs in the U.S. and has achieved very high participation rates – over 90% of Cinergy's 312 large C/I customers were participating in one or more of the PowerShare options in 2000. Cinergy estimates of curtailable load range from 440-600 MW, although the program was not operated during 2000 and 2001. The program draws from industrial and commercial customers and attracts a variety of customer sizes – from 100 kW to over 1 MW. In 2001, the program drew 40% of its participation from its base of customers with peak demand below 500 kW.

Table 5: PowerShare CallOption Choices

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

Cinergy's program demonstrates the level of participation that can be achieved by offering a wide variety of "product lines" under a single program "brand name." The two major program variants are the CallOption and the QuoteOption. Participants in the CallOption choose from among three options for curtailment frequency and duration (see Table 5) and select a Strike Price from among a pre-specified set of choices ($0.15, 0.50, or 1.00/kWh). When the day-ahead market prices are projected to be greater than the Strike Prices, Cinergy can "call" the option. Customers have several choices in how they identify their curtailable load block: they can specify a Firm Load Level, identify a generator to operate, pledge a specific end use or process to shut down, or pledge a fixed reduction in their pro forma load. Customers may also select from among several levels of curtailment frequency and duration. These various options are packaged into discrete product offerings: the Core Offering, PowerShare Basic, PowerShare Lite, and PowerShare DG. The Quote Option is less complex and offers customers a no-risk proposition. Participants pre-specify only the type of load block (load reduction from a pro forma load shape or generator to be switched on) and a Strike Price below which they are not interested in participating. Cinergy provides price quotes for the same day via the program web site, and interested customers must respond with an estimate of voluntary load reduction within one hour.

F. Summary of Current Experience/Lessons Learned

This section draws heavily from an ongoing research project conducted by Lawrence Berkeley National Laboratory, in which LBNL conducted case studies of 32 demand response programs targeted to commercial/industrial customers (Goldman et al 2002b).[11] The programs surveyed include a number of "legacy" interruptible rate programs and price-responsive load programs. Eighteen of the programs were PRL programs, while the remaining 14 programs operated in response to system emergencies (i.e., "reliability-based"). The case studies were developed based on phone interviews with program managers, program information materials, and evaluation studies. The interviews covered key program elements such as target markets, market segmentation, and participation results; pricing schemes; dispatch and coordination; measurement, verification, and settlement; enabling technologies; and operational results, where available.

(1) Current Level of PRL Market Activity is relatively low and most programs are relatively new

Of the PRL programs surveyed, only four operated more than ten times, and half operated just once or not at all (see Figure 1). The proximate cause for the generally low level of activity was the relatively low wholesale electricity market prices throughout many parts of the country, which prevented program administrators from being able to offer attractive incentives for load reduction.

[11] LBNL work is funded by the DOE Office of Power Technologies, Electricity Restructuring Program. Initial work on demand response programs is summarized in Heffner, G. and C Goldman. *Demand Response Programs – An Emerging Resource for Competitive Electricity Markets*, 2001 International Energy Program Evaluation Conference, August 21-24, 2001, Salt Lake City, Utah.

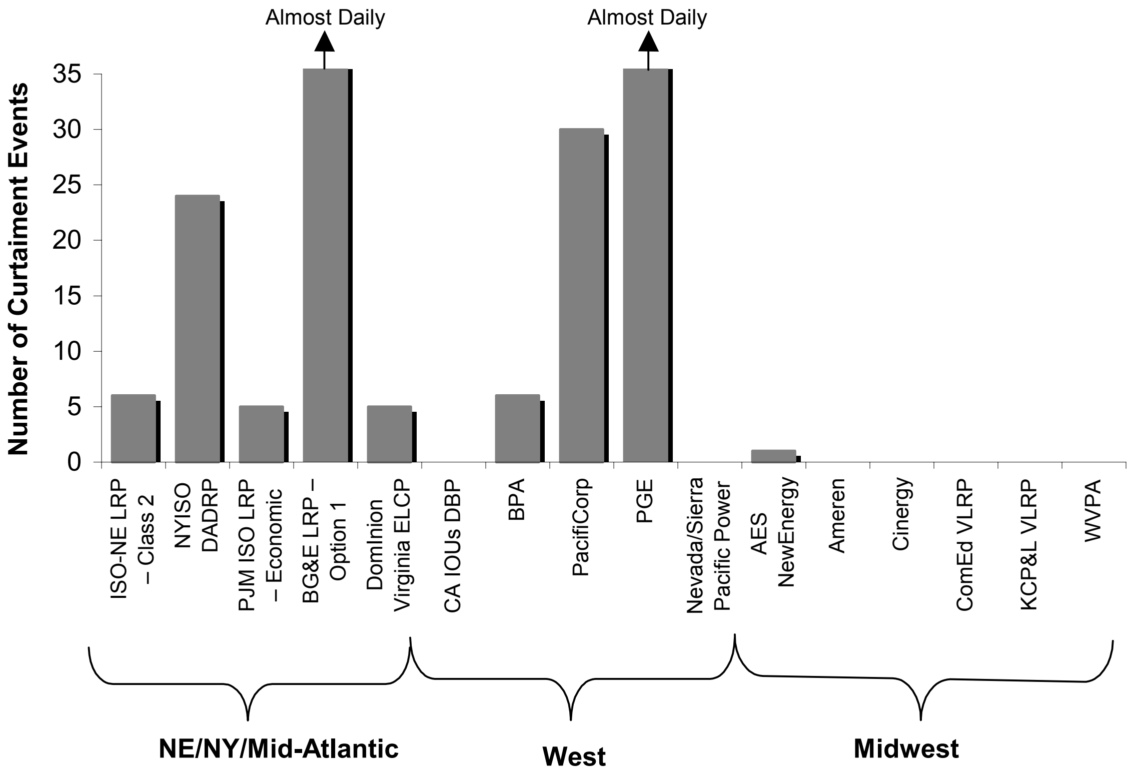

Figure 1: Activity of PRL Programs in Summer 2001

(2) When PRL programs operated, they often achieved relatively modest actual load reductions, with a few noticeable exceptions.

On average, PRL programs provided *actual* load reductions of 19 MW, with a maximum of 75 MW provided by PGE's program (see Fig. 2). This represents just one fifth of the average load reduction from Emergency DR programs in the LBNL sample of programs (see Table 6). For example, the NYISO's DADRP was able to garner a maximum of ~25 MW load reduction compared to 425 MW from its sister program, the EDRP. These low levels of demand response from Economic DR programs occurred despite a fairly large base of potential load reduction enrolled in many of the programs (i.e., 200-400 MW in the largest programs). Across the programs surveyed by LBNL, just 17% of the potential load reduction was achieved on average, compared to 68% for the Emergency DR programs.

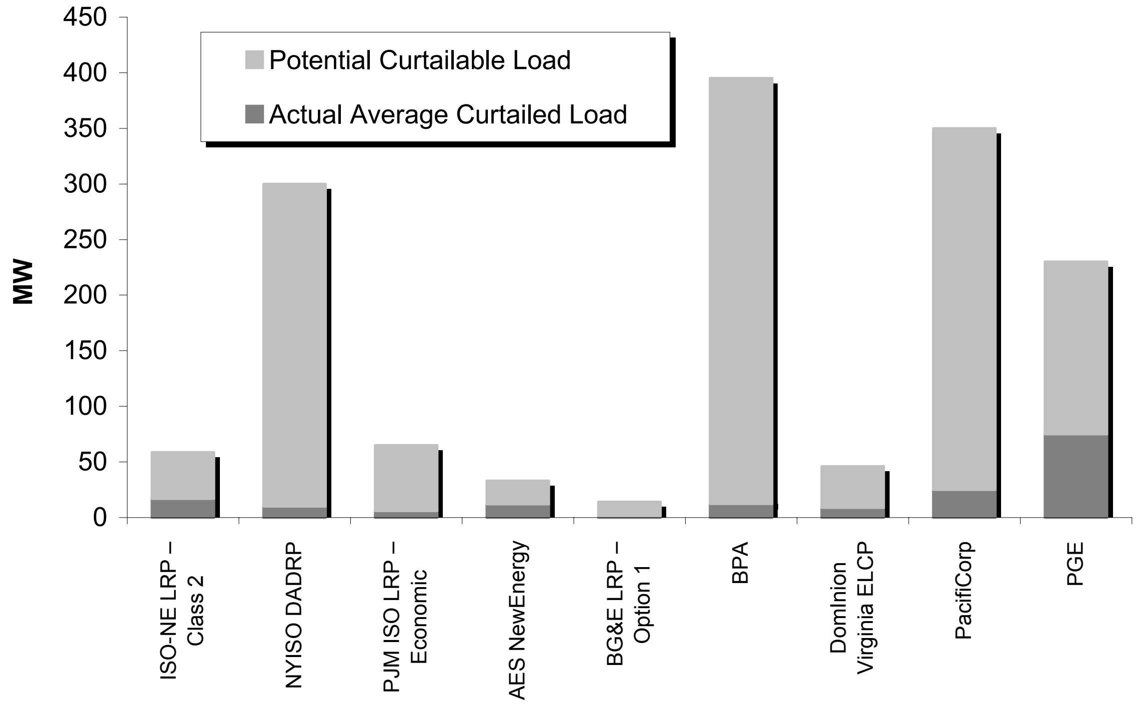

Figure 2: Performance of Economic DR Programs in Summer 2001

Table 6: Comparison of Emergency and Economic DR Program Performance

Program Type	Number of Programs in Sample	Average Curtailed Load (MW)	Average Performance*
Emergency	8	94	68%
Economic	9	19	17%

* Performance = Actual Curtailed Load/Potential Curtailable Load

However, care should be taken in interpreting these results. First, for many of the programs, the low performance was inseparable from the prevailing wholesale electricity prices. With low electricity prices, any incentive offered to participants was correspondingly low, and thus relatively few participants were induced to bid. At times prior to Summer 2001 when wholesale electricity prices were higher, a more substantial response was often stimulated. For example, in PGE's Demand Buy Back Program, 175 MW were reduced on average during the winter and spring of 2001, when incentives averaged \$150/MWh. During December 2000, when incentives reached \$300/MWh, a load reduction of 230 MW occurred, representing 100% of the potential load reduction for the program and ~50% of the participants' summer peak demand.

Moreover, most PRL programs are essentially "voluntary" – i.e. participants decide to bid on a case-by-case basis, with no standing commitment.[12] This contrasts with many of the

[12] Exceptions among our set of case studies include Cinergy's PowerShare Call Option, ComEd's Voluntary Load Reduction Program, and Wabash Valley Power Authority's Customer Payback Plan.

Emergency DR programs, which operate as "Call" type programs, and customers may be assessed significant non-compliance penalties. The impact of this difference was clearly illustrated in the instance of KCP&L's PLCC program, in which participants performed at 30% *above* their committed level, reportedly in order to avoid the non-compliance penalty of $1,250/MWh.

There are also definitional problems in establishing the "potential load reduction" in a PRL program.[13] Thus, to an extent, a direct comparison between the two program types, in terms of % of potential load reduction that is achieved, is like "apples to oranges."

(3) PRL programs offered by utilities in the Pacific Northwest achieved significant market response in Winter and Spring 2001, until prices in wholesale markets dropped significantly, FERC rate mitigation measures were enacted, and longer-term demand buy-back contracts were put in place by utilities/customers.

Day-of and day-ahead bidding programs operated by PGE and PacifiCorp had high levels of activity during winter and spring 2001 driven by high wholesale electricity prices. However, with Summer 2001 came a dramatic drop-off in demand-response program activity, apparently driven by the impacts of the FERC price mitigation measures implemented in the Western United States. These programs base the incentives for load reductions bids on an approximate 50/50 sharing of the avoided wholesale purchase cost. With the soft price cap of ~$92/MWh, the incentive available for participants dropped down into the $40-50/MWh range, which is well below the level at which end-users would generally be willing to bid in load.[14]

(4) Industrial customers form the backbone of most PRL programs, although participation is increasing from commercial and institutional customers.

In the LBNL program sample, about 50% of the participants were industrial customers (e.g., steel mills, pulp and paper mills, cement plants), ~25% are commercial customers (e.g., office and retail), with the remainder consisting primarily of institutional and manufacturing customers (see Figure 3). Many industrial customers have the ability to shift or curtail load for a period of time, and still maintain their basic operations. Moreover, industrial customers have been active participants in "legacy" load management programs such as interruptible rates and are therefore already acquainted with load curtailment protocols, requirements, and settlement. Attracting greater participation from commercial and institutional customers will be critical if DR programs are to achieve their full potential.

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[13] For many of the Emergency DR programs, participants pledge a committed level of load reduction. However, in most PRL programs, participants identify some "nominal" amount of load reduction when they enroll, with no element of commitment.

[14] The PGE program did continue to provide load curtailments throughout the summer through "term" events (i.e., demand buy-back) procured prior to the imposition of the price caps

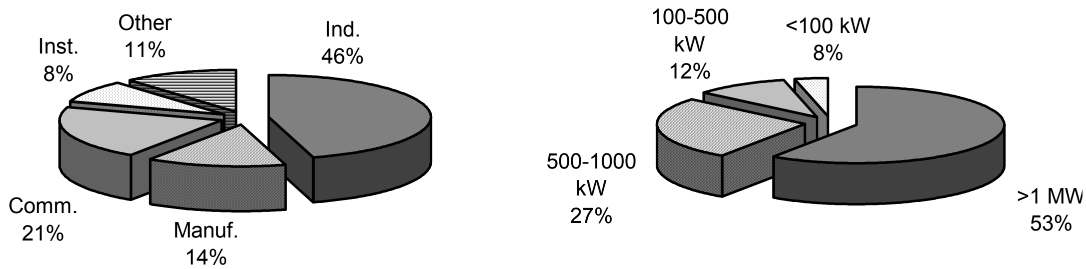

Figure 3: Market Segmentation and Customer Size among Case Study Programs

Approximately 80% of program participants are large or very large customers. In many cases, this is the direct result of program design decisions to limit participation to customers above some minimum size or who can curtail above some minimum level of demand. Some programs require load curtailments on the scale of 500 kW or even 1 MW. Most PRL programs in our sample required curtailments of at least 100 kW. These requirements severely limit participation by small and medium-sized C/I customers without a large percentage of discretionary load. These customers represent a significant fraction of the remaining market potential; policymakers and program administrators will have to consider aggregation schemes or lower load curtailment thresholds if they hope to tap these customer market segments.

(5) Significant financial incentives are required in order to obtain a sizeable customer market response, even with good program design and implementation

Various studies and program experience confirm that customers typically require high incentives or compensation that well exceeds their electricity bill savings from curtailing electricity usage in order to participate in PRL programs. Based on interviews with PRL program managers at utilities, LBNL found that financial incentives of $150-200/MWh were the minimum threshold for noticeable customer response. Significantly higher incentive payments have been provided in "emergency" DR programs such as the New York EDRP (i.e., $500/MWh) with substantial market response (~425 MW) or incentive payments for curtailment events have been coupled with various types of upfront, reservation or capacity payments.

(6) The most successful programs offered by LSEs feature a broad array of DR programs – including both emergency and PRL-type programs.

Based on interviews with utility program managers, they emphasize that demand response programs triggered by system emergency conditions are an effective way to get customers participating in wholesale markets; and that these "emergency" DR programs often provide the pathway for customers to consider participating in "economic" DR programs. See discussion of Cinergy program in Section IIE as an example of utility that has a broad portfolio of DR service offerings.

(7) Emergency-backup generation is an important resource in some PRL programs; in other cases, use of "dirty" generating resources is prohibited or strictly limited (e.g., NY, CA)

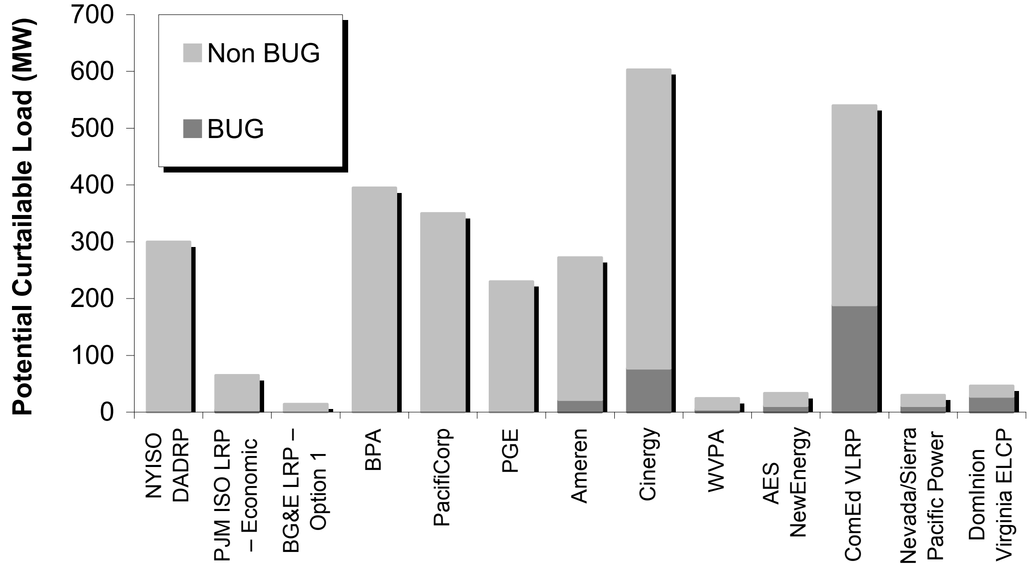

Figure 4: Use of Backup Generation (BUG) in Economic DR Programs

Emergency Backup Generators (BUGs) were a strategy used by some customers in PRL programs. From the customer's perspective, BUGs provide a predictable level of load reduction; their operation can be initiated quickly and with minimal disruption to the end-user's normal operations. However, BUGs are typically diesel-powered and pollute at a significantly higher level than typical central station power plants and their use is typically restricted to a relatively few number of hours per year (e.g., 100-500 hours) under certain prescribed conditions by the local air quality control district .

Among the PRL programs in our sample, BUGs represent approximately 17% of the total potential curtailable load.[15] They tended to be more heavily used in Emergency programs, representing 31% of potential load reduction compared to 12% in Economic programs (see Figure 4. A number of states have precluded or limited their use in PRL programs. For example, NYISO's DADRP limited participation to non-diesel BUGs, and none of the three programs surveyed from the Pacific Northwest (BPA, PacifiCorp, and PGE) permitted BUGs to be used.

Novel approaches can potentially be taken to offset the environmental impact of BUGs that are eligible for "emergency" DR programs. For example, the New York State

[15] Several programs in our sample did not provide an estimate for the percent contribution from BUGs, although they did indicate that a significant portion of their potential curtailable load was associated with BUGs. Since these programs were not included in the calculation, it is likely that the overall contribution of BUGs among our sample was in the 20-25% range.

Research and Development Agency (NYSERDA) provided funding for enabling technology, including BUGs, in order to facilitate participation in the NYISO's demand response programs. To mitigate the environmental impact, NYSERDA purchased and retired NO_x allowances equal to twice the total calculated NO_x emissions associated with use of these BUGs in the NYISO program.

G. Barriers to End User Participation

Existing PRL programs have achieved only modest results to date, in part because they are so new and in part because of the many barriers to end user participation, including those related to retail customers, government regulations, and technologies.

(1) Customer Barriers

Consumers generally do not recognize that the high prices during a few hours a year are more than offset by low prices during much of the year, resulting in a lower electricity bill for the year as a whole. In addition, consumers may not recognize the opportunities they have to shift consumption from high-priced to low-priced periods, further reducing their electricity bill. Thus, even if customers had the opportunity to face dynamic prices and had interval meters and the necessary communications systems, they still might choose not to participate in such programs. These consumer perceptions highlight the critical need for customer education. Customers need information on how dynamic-pricing options work and how they might benefit from such programs before they will be willing to participate in such programs.

(2) Regulatory Barriers

Standard Offer Service

Most customer loads continue to buy generation from their local utility under "default" or standard offer tariffs with rate designs that provide the customer and the utility with inadequate incentives to reduce loads in high-priced hours. Standard-offer services can hinder the development of forward markets that would otherwise be used for customer hedging and discourage new retail providers from offering risk management services as value added products (Graves and Wharton 2001).

Key to resolving these problems is explicit PUC recognition that the provision of fixed-price electricity includes an insurance policy as well as the electricity commodity (Hirst 2002a). These risk-management costs should be included in the rates customers face, and such costs must be reflected in the earnings that the provider of the standard-offer service receives for this service.

If PUCs impose rate caps on the local utilities, the utilities lose money if they run innovative load-reduction programs and pay for the associated metering and communication infrastructure. To the extent the utility recovers fixed transmission, distribution, and customer-service costs through a volumetric charge (i.e., on a ¢/kWh basis), its revenues and earnings will decline if customers reduce their electricity use.

Metering and Billing Infrastructure

PUC decisions on metering and related services (billing and access to meter data) are also critical to expanding price-responsive demand. Based on the regulatory uncertainty about who eventually will own the meters and related equipment and the data generated from meter reading, utilities are justifiably ambivalent about making an investment today that might become a stranded asset tomorrow (Causey 1999). Retail providers are unsure whether they are permitted to install such systems. If they do install these systems, how will they recover costs if customers switch to a different energy supplier? In the meantime, what entities have access to customer-meter data? Similar issues may apply to the computer systems required for billing and settlements. Advanced metering can occur with either a regulated monopoly or a competitive market, but it will likely not occur until regulators decide on the framework for such metering and infrastructure issues.

Load Profiles

The use of predetermined load profiles, rather than hourly metering, to bill customers further inhibits adoption of price-responsive demand. If customer meters are read only monthly, retail providers have no knowledge of the dynamics of electricity use and, therefore, no ability to either charge customers appropriately for their electricity use or mechanisms to reward them for changing the timing of their electricity use. In a similar fashion, customers have no incentive to respond to time-varying wholesale prices. State regulators may want to consider making interval meters a requirement for retail electric service, at least for larger users (e.g., greater than 20 kW) – see Framing .

FERC

A fundamental regulatory obstacle to greater use of demand-side resources is uncertainty on the part of market participants (both suppliers and consumers) about future government regulations and market design. Until the rules concerning definition, participation, and pricing for wholesale markets for energy, transmission congestion, and ancillary services are stable, suppliers and consumers will be unwilling to invest time and money to manage demand. Similarly, the rules concerning price caps and other forms of market-power mitigation must be stable before such programs can flourish. FERC's acceptance and imposition of low price caps in the ISO markets it regulates will suppress customer participation in voluntary load-reduction programs.

State/Federal Jurisdiction

A critical issue is the potential conflict between state and federal regulation of price-responsive demand programs. Although FERC regulates wholesale markets and the ISOs that operate these markets, it has no jurisdiction over retail activities. The state PUCs, on the other hand, have authority over sales and service to retail customers but limited jurisdiction over wholesale markets. Thus, utilities may be required by FERC to implement programs that increase their costs and reduce their revenue. These costs, however, can only be recovered with approval from the state regulator.

Independent System Operators

System operators (today's vertically integrated utilities and ISOs and tomorrow's RTOs) have traditionally focused on the supply side and ignored the demand side of the equation (by assuming, in essence, that demand is completely price inelastic). System operators need to broaden their thinking to accommodate the unique characteristics of customer loads, just as they have done for the unique characteristics of individual generating units.

(3) Technology Barriers

All the technical components necessary for dynamic-pricing and voluntary load-reduction programs exist and have been applied in various settings. However, the industry has not evolved to the point that standardized (off-the-shelf) equipment and communication packages are readily available. The industry may need to develop standards to ensure that the various components can work well with each other, regardless of who manufactures what. If the requirements for these services can be standardized, mass-produced electronics can likely dramatically reduce the cost and increase the performance of advanced metering. This would facilitate real-time market response for even the smallest load.

III. Types of Wholesale Market Demand Response Programs

This section focuses on types of wholesale market programs and draws heavily from a KEMA Consulting, Inc. (2001) study that was sponsored by ISO-NE. The KEMA study focused on issues involved in transitioning load response program given the movement toward a Standard Market Design (SMD). As part of this work, KEMA identified four types of wholesale market programs that might facilitate the development of price responsive loads:

- Program Type 1: Day Ahead Price-Capped Load Bidding,
- Program Type 2: Load Reduction Bidding as Generation,
- Program Type 3: Transitional Load Reduction Pricing, and
- Program Type 4: Voluntary Response to Market Price.

Note that these program types are not mutually exclusive. In fact, these program types may well be complementary, depending on your assessment of the type and extent of explicit load reduction products that should be developed by ISO-NE. We assume that some variant of Price-Capped Load Bidding is likely to be included as part of the SMD. A threshold question for NEDRI Participants is whether Program Type 1 is sufficient to induce the desired magnitudes of demand response resources or whether or types of program interventions are necessary for some period of time. We describe the four approaches and discuss their relative merits (e.g., pros/cons) with respect to specific criteria (see Table 7).

Market Development and Functioning

- Potential to attract a meaningful level of customer participation and demand responsiveness
- Potential to provide the full benefits of demand response
- Degree of integration of load reduction transactions into the ISO scheduling and settlement processes
- Consistency with retail restructuring and competition policy objectives (e.g., accommodate changing utility roles and range of retail market conditions), including opportunities and options for new entrants, such as Retail Energy Suppliers or Curtailment Service Providers (CSP), to participate in PRL programs

Program costs, risks, and implementation issues

- Adequate of financial benefits for participants and associated implications for cost recovery and uplift charges
- Risk to ISO associated with the reliance on an estimated Customer Baseline Load (CBL)
- Program complexity, both for participants and for administrators

Table 7. Comparison of Wholesale Market Demand Response Program Types

	1 D-A PCLB (No LR Bidding Program)	2 Load Reduction Bidding as Generation	3 Transitional Load Response Pricing	4 Voluntary Response to Market Price
	Rating of Program Options by Criteria			
Quantity: Potential to attract a meaningful level of customer participation and demand responsiveness; Potential to provide the full benefits of demand response	No option to bid DR as separate product (comparable to generation). Only get LR offered by LSEs; may be used as financial hedge instead of actual reduction	Provides direct role for customers or LRPs to offer prices & quantities of LR. Theorectically, all can participate. Limited in short term to customers with sophisticated systems &/or assistance.	May be highest in short term by attracting more risk-averse users & maintaining Type 4 Disp. Load. Strong assurance of LR when called.	Available for some customers with quick-response capability that would not bid in advance.Oriented primarily to customers that can function with limited notice in real-time market. Best monitoring of real-time response, but least assurance of response before the hour.
Opportunities and options for new entrants, such as Retail Energy Suppliers or Curtailment Service Providers (CSP), to participate in PRL programs	No role for CSPs if not LSEs.	CSPs can have role	CSPs can not have direct role	CSPs can have role. Provides option for demand response without bidding.
Consistency with retail restructuring and competition policy objectives (e.g., accommodate changing utility roles and range of retail market conditions)	Not likely to be sufficient in short term to instill confidence needed to eliminate retail or w/s price caps. Least market intervention.	If successful, most integrated demand response for all customers, so may convince PUCs that mkt is mature. May support retailer provision of value added hedging products.	Substantial demand response from big loads may convince PUCs that LR will work	Quick reporting of impact may reassure observers
SMD: Degree of integration of load reduction transactions into the ISO scheduling and settlement processes	Will be part of SMD	Not part of SMD but likely to be a best practice in NERTO	Can be implemented outside SMD. Does not set clearing price. Load treated differently from generation.	Can not 'set' clearing price
Adequate of financial benefits for participants and associated implications for cost recovery and uplift charges	No incentive payments from ISO			R-T feedback, but late baseline adjustment creates risk
Risk to ISO associated with the reliance on an estimated Customer Baseline Load (CBL)	Advantage that not dependent on baseline procedures. (Disadvantage that actual load reduction may not be known by ISO.)	Baseline clouds some transparency and could lead to uncertainity in a load response bid.	High	Varies. ISO-NE program not predictible, but impact results knowable soon after program call
Feasibility and cost of Implementation for 2002 & 2003	No incremental costs over SMD.	This program approach is the most expensive to develop and has an uncertain response.	Already in Place. Unknown modifications for SMD.	High cost for particip's if 2-way R-T communicat. req'd.
Program complexity, both for participants and for administrators; Program costs, risks, and implementation issues	No additional investements needed to partcipate	Metering and reporting will add small costs	Mechanisms already in place. Must provide strike price or demand curve for LR farther ahead of time. Plan to retain dispatchable load options clarifies future for existing participants.	Specilaized software / hardware may be H64needed to be eligible for ancillary service payments

Program Type 1: Day Ahead Price-Capped Load Bidding

Price-Capped Load Bidding (PCLB) is a basic structural feature that is likely to be included in the SMD for the day-ahead energy market (DAM). In this approach, the LSE places a price-contingent offer in the DAM. Rather than simply bidding the entire quantity of load it expects to serve before the price is known, a LSE would be able to bid the price points at which it will reduce that load by specified MW levels. In effect, the LSE bids a demand curve, rather than single load.[16] In this program type, the ISO does not offer an explicit PRL program at the wholesale level (although LSEs might develop PRL programs at the retail level, such as interruptible, curtailable rates).

In terms of relative merits, under this approach, the ISO does not provide additional incentive payments to participants, thus it minimizes additional ISO uplift costs. The ISO also does not have to establish procedures to determine customer baselines for the purpose of determining "load reductions. " Because settlement process does not rely upon the use of estimated baseline loads; revenues and penalties are simply based on the total metered load. Consequently, PCLB is relatively easy for the ISO to administer and can be readily integrated into the SMD scheduling and settlement systems. Price responsiveness is fully integrated into the wholesale market, and is able to impact the market-clearing price.

A major limitation of this approach is that it is unlikely that PCLB provides LSEs with sufficient means to induce significant quantities of price-responsive load. It is likely that the potential benefits to customers are insufficient, given level of risks and lack of financial incentives.[17] Customers will require that they be paid the marginal value of their foregone electricity consumption, which will be well above their retail rate; and thus bill savings alone is unlikely to induce much retail load participation. Moreover, customers that are on fixed tariffs, have no incentive to bid PCLB strike prices above that rate. This approach also limits direct participation in the wholesale market by entities that are NOT LSEs. Thus, if one of the goals of retail competition is to encourage new entrants and services, then PCLB may by itself not be sufficient to develop price responsive load.

Program Type 2: Load Reduction Bidding as Generation (LRB)

In essence, in this approach, ISO-NE would create a separate "load reduction" product that can compete head-to-head with generator's bids in the DAM.. The NYISO's DADRP is an example of this option. In the NYISO DADRP program, participants submit demand reduction bids and receive zonal market clearing prices for load reductions that are scheduled for the next day. Participants were paid for their load

[16] It is important to note that under the two-settlement system, load that is not contracted in the DAM is settled at the real-time market clearing price.

[17] See Neenan Associates, 2001. *Using Price Cap Load Bidding to Capture the Benefits of Customer's Load Management Capabilities,* prepared for ISO-NE, July 26.

reduction based upon the difference between an estimated baseline and their metered load; participants also paid liquidated damages for non-compliance. NEDRI participants should explore the issue of penalties in more detail because it was cited as one of the barriers to customer participation in New York (Neenan Associates 2002). Customers control when they are expected to curtail, are paid their bid price or more for curtailing, and get advanced notice of their curtailment obligation. As a practical matter, individual end users are typically aggregated through LSEs and/or CSPs into large blocks (e.g., 1 MW) in order to accommodate ISO scheduling and settlement software.

Compared to PCLB, Program Type 2 is likely to stimulate more demand response resources participating in the DAM. This type of program is also conducive to participation by various types of entities, thus broadening the set of service providers. In New York, utilities, retail suppliers and Curtailment Service Providers are eligible to participate. This option, as implemented in New York, is integrated into the scheduling process and is therefore able to impact the market-clearing price.[18]

However, this type of program does increase overall ISO "uplift" costs (because of incentives paid to participants) and would require the ISO to devote additional staff resources to develop and administer the program. This program type also requires the ISO to develop protocols that establish and then verify load reductions relative to a specified customer baseline (i.e., what customer usage would have been in the absence of the curtailment event).

Program Type 3:Transitional Load Reduction Pricing

The distinguishing feature of Program Type 3, Transitional Load Reduction Pricing, is that it provides participants with a simpler and more predictable business proposition, by allowing them to submit a certain load curtailment bid price in advance and decoupling the incentive payments from the wholesale DAM clearing price. This could be achieved through any number of specific program design concepts. For example, participants could be allowed to bid a load reduction price in advance, which would then serve as a guaranteed price floor for duration of load reduction request by ISO. Alternatively, customers could submit bids (as standing offers, daily bids, or in some other form) to curtail whenever the wholesale DAM price was forecast to reach some specified level. Participants could be offered reservation payments in return for agreeing to curtail for a limited number of hours or events per year which might be augmented by payments for actual curtailments. Other program design concepts are also possible. A number of LSEs (e.g., Cinergy and PGE, discussed above) have experience implementing retail-level versions of these types of PRL programs. The ISO-NE's existing Type 3 and Type 4 dispatchable load programs could potentially be adapted into this type of program (e.g., LSE could bid in direct load control resources at price floor).

The underlying premise of Program Type 3 is that significant demand response resources are more likely to develop if a variety of pricing and program design arrangements are

[18] The KEMA report notes that load reduction bids could be processed in a separate scheduling algorithm or process and then combined iteratively into schedule with generation resources (p. 23).

offered to potential participants. Initially, pricing terms would be less tightly tied to actual ISO DAM clearing prices. The policy drivers for this option are: 1) priority given to making ISO PRL programs easier for customers/participants to enroll with more certainty about the benefits stream, and 2) encouraging development of demand response product supported by the ISO that could be used by a relatively immature retail services industry to promote value-added services among customers.

In terms of relative merits, this type of program has the potential to be particularly "customer friendly" and may be well suited to capturing small and medium sized customer loads. This option can be introduced prior to Standard Market Design being implemented, as a means to build up the demand response infrastructure and establish a resource pool of loads. This type of program also requires less ISO attention to system integration needs because load reduction bids would not participate in setting the Energy Clearing Price.

However, in this type of programs, it is likely that the ISO would have to incur substantial program development, administration, and possibly IT costs (unless this option was explicitly part of the SMD). This type of program has issues of customer baseline and increased uplift costs, similar to Program Type 2.

Program Type 4:Voluntary Response to Market Price

This type of program is a generalization of the ISO-NE's Price Response Program, discussed above. In essence, Program Type 4 pays the real-time market-clearing price to customers who are able to respond in real-time before knowing where the price will settle. In the case of ISO-NE's program, the available hours are restricted. This type of program is inherently voluntary, in that no penalties are assessed. For the 2001 ISO-NE program, customers were required to submit their planned level of load reduction to the ISO, a day ahead. However, these did not represent firm commitments, since customers were free to provide less load reduction based on their assessment of where the real time price would settle. For the 2002 program, there will be an even greater degree of flexibility in that customers will not even be required to provide any advance notice, and can simply provide notice after the fact.

In terms of relative merits, Program Type 4 poses few risks to customers because there are no penalties and participants can see results of their load curtailments quickly. This type of program can be leveraged by retail providers or LSEs that want to offer a load reduction product to customers.

However, Program Type 4 is not integrated into the scheduling/settlement process and thus does not directly affect energy market clearing price. Market response was relatively low to the 2001 program for various reasons; it will be important to monitor the impact of the program design changes approved for 2002 on market participation rates. This type of DR program is of primary interest to customers who can respond in real time, even if they don't know where the real-time price will ultimately settle and thus it probably will not be able to garner significant demand response resources over the entire market.

IV. Key Policy & Program Design Issues

A. Policy Issues[19]

1) Are PRL-type programs efforts that should be undertaken/supported by ISOs or should they be considered solely at the state/retail jurisdictional level?

The FERC staff report on Standard Market Design makes it clear that competitive wholesale electricity markets require demand response resources. The question is which institutions and entities are best suited to facilitate the development and deployment of demand response resources. Initially, the primary mission and responsibilities of ISOs has focused on grid management, system reliability, and establishment of wholesale energy markets. By definition, PRL programs require either the direct or indirect participation of retail customer loads, potentially involving thousands of participants. NEDRI participants should consider the appropriate roles for ISOs, LSEs/PUCs in establishing and administering demand response programs. Options include:
A) PRL programs offered by ISOs
B) State PUCs authorize price-responsive load programs to be offered by LSEs
C) Coordinated ISO and LSE PRL programs

2) Under what conditions are PRL programs appropriate, e.g., are economic demand-bidding programs necessary if RTP was widespread?

Price-responsive load programs offered by ISOs are one approach to encourage demand responsiveness in wholesale markets. Mandatory dynamic pricing programs for large customers at the retail level are another approach often favored by economists as a "first-best" solution (Borenstein 2001), while a number of utilities have offered "voluntary" RTP programs (see Framing Paper #3). NEDRI participants should consider the relative merits of real-time pricing and PRL programs, including the likelihood that state regulators (and customer groups) will support and large customers will accept RTP programs.[20] Issues related to dynamic pricing and metering will be discussed in Framing Paper #3. PRL and dynamic pricing programs are not mutually exclusive alternatives and thus, the relationship and interactions between PRL and RTP programs should also be examined.[21]

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[19] The forthcoming KEMA Consulting report, "Load Response Program Design Issues," December 7, 2001 also explores many of these program design issues in more technical detail and depth.

[20] Some large customers want price stability in their energy costs and find RTP tariffs problematic because they can't budget their energy costs. They will either oppose RTP tariffs or seek financial hedges to mitigate these risks. These customers still might be willing to provide short-term load reductions for a price in a PRL program.

[21] About 250 large customers with peak demands greater than 2 MW served by Niagara Mohawk are currently on tariffs that expose them to day-ahead market energy prices; these customers are also eligible to participate in NYISO PRL programs.

3) An overarching policy issue is whether PCLB is likely to provide sufficient demand response resources or whether other types of PRL program interventions will be necessary?

Based on recent experiences of ISOs and utilities that have offered similar programs and an assessment of market, technical, and regulatory/institutional barriers faced by demand response resources, what types of programs are most likely to elicit sufficient participation by customer loads and LSEs to meet DRR targets or goals that are established? NEDRI participants should review the discussion of the relative merits of various types of programs, customer market barriers, etc in order to resolve this issue in the context of alternative types of programs

4) How do you pay for the enabling demand response technology infrastructure necessary to capture the substantial consumer market benefits?

NEDRI participants may conclude that demand response resources have the potential of providing substantial consumer market benefits which may not be realized given various types of barriers. If so, then NEDRI participants could consider other strategies and approaches for increasing demand responsiveness (e.g., through deployment of various DR enabling technologies, such as interval metering, communications/notification platforms) through various types of public, private or ratepayer investment. This could include one or more of the following options:
(A): using ratepayer funds to pay for interval metering,
(B): having customers pay the cost of advanced meters at their facilities,
(C): using public benefit funds to facilitate customer's ability to participate in DR programs (e.g., NYSERDA's programs that are designed to increase customer adoption of enabling demand response technologies).

5) Is the provision of demand response resources an attractive business opportunity for potential load aggregators? Is it a viable "stand-alone" business"? Are there disincentives that limit the interest of potential load aggregators (e.g., utilities)?

Recognizing that most customers don't want to be "day-traders" suggests that load aggregators (e.g., LSE, retail suppliers, curtailment service providers) will play a key role in the development of PRL programs. As NEDRI participants discuss various wholesale market program options, they need to consider the "business case" for both potential load aggregators and end users in the demand response resource area. This discussion will provide insights on potential synergies between various types of demand response programs (e.g., are emergency programs an attractive way to market DR? do ICAP payments provide an important potential revenue stream for load aggregators or customers?) This dialogue will provide a useful context for discussing incentive payment levels required to attract customers, or program designs that accommodate unique circumstances of loads (vs. generators), or discuss potential rationales for public benefit funds support.

6) What types of demand-side "resources" should be eligible to participate in "economic" load response programs – specifically role of and/or limits on use of diesel-fired back-up generators?

As PRL programs increase in importance, NEDRI participants should consider the types of demand-side resources that should be eligible to participate in these programs. Load curtailment from loads is uncontroversial. However, participation by diesel-fired back-up generation equipment has been particularly controversial. A number of PRL programs in the Midwest allow BUGs to participate; however, NYISO limited participation in their DADRP to non-diesel fired BUGs plus loads. Options include:
(A) load curtailments from load reductions only
(B) load curtailments from load reductions plus all types of local generation equipment (e.g., primary, back-up, emergency, all fuel sources, subject to complying with all permits), and
(C) load curtailments from load reductions plus certain types of local generation equipment (e.g., no diesel-fired equipment).

7) To what extent, should Price-Responsive Load services be unbundled from the services provided by the Electric Distribution Company (EDC)?

Those states that have restructured have had to grapple with issues related to services to be provided by EDC under an environment of retail competition. Some ESPs have argued that the scope of services provided by EDCs should be limited or confined to "monopoly" services, in order to encourage the development of vibrant retail energy services markets. Those services that are demonstrably "competitive" should be provided by retailers. However, given the current level of development of retail market, where over 90% of customers are typically served under default or standard offer service by the EDC, such policies would limit the magnitude of demand response resources. NEDRI participants should consider policies that encourage participation by new entrants in PRL programs.

B. Program Design Issues

There are myriad program design issues – this section focuses on major design issues assumed to be important to stakeholders and which involve coordination/institutional issues between ISO/state entities or energy/environment regulators

1) ISO/End User relationship and eligible entities

NEDRI participants may want to consider the relationships between ISOs and other entities in PRL programs. This issue has been controversial in other jurisdictions (e.g., CA, NY, PJM). In implementing a PRL-Program, does the ISO deal only with Load

Serving Entities (LSE), or with LSEs and other entities that can deliver Load Reductions (e.g., competitive retail energy suppliers, Curtailment Service Providers), or with LSE, CSP, and end users directly?

2) Financial incentives for PRL programs --

Options 2, 3, and 4 all involve the ISO providing financial incentive payments to participants for load reductions. Major design issues that arise in these options include: (a) potential funding sources that should be used to provide ISO incentive payments (e.g., uplift charges), and (b) determining appropriate incentive payment levels, particularly for options that do not rely on energy clearing price for payments to participants (e.g. Option 3).

The KEMA study also considered re-allocating load responsibility among ISO market participants as another mechanism for funding PRL programs.[22] This approach appears complex and potentially raises policy questions related to retail market development, so NEDRI participants must decide whether they want to wrestle with alternative mechanisms for funding incentive payments from PRL programs rather than uplift charges.

In discussing appropriate incentive payment levels, it is important to consider the existing rate structures for most end users. In New England, most consumers are on fixed rate tariffs of relatively long duration (e.g., 6 cents/kWh). Thus, end users that reduce loads during hours that have high electricity prices (e.g., 30-40 cents/kWh) do not receive the full benefit of reducing their loads during these hours; rather their savings are derived from reduced usage based on the existing fixed rates. Financial incentives from the ISO, particularly if they are market-based, may provide an improved price signal to customers to reduce loads. The incentive payments offered by the ISO also serve to enlist the interest of potential load aggregators in facilitating and enabling participation by end users.

3) Baseline methods used to compute quantity of load reductions for which customers get paid

Method used to determine the quantity of load reduction for which customers get paid is a key program design feature. Underlying the discussion of baseline methods are some important public policy objectives – equivalent treatment for loads and generators providing comparable services, relative “certainty” of load reductions vs. output from generators, recognition that loads are not generators, and opportunities to participate by all customer loads (which involves development of load reduction protocols for customers without interval meters).

In the area of baseline methods, ISOs also confront issues and trade-offs between procedures that are administratively tractable and workable (e.g., standardized protocol

[22] KEMA study, pg. 51-52.

for all load reductions) vs. those that may be customized for individual customers (e.g., pro forma load shapes for each customer).

4) Relationship between "emergency" demand response and "economic" demand response programs

As discussed previously, the most successful demand response programs offered by utilities typically involve a portfolio of service offerings. In terms of customer marketing and acceptance, some utilities (e.g., Cinergy) have found that there is a natural progression from participation in "Emergency" demand response programs to participation in "economic" PRL programs. If ISOs offer demand response programs targeted at different wholesale electricity markets, then, of necessity, program design must address customer participation in both types of programs, potential "double-counting" of payment issues, priority of responding, etc.

Over the long term, greater customer participation in PRL programs may lessen the need or relative value of "emergency" demand response programs. NEDRI participants may want to discuss both the near-term and long-term relationships between different types of demand response programs.

Glossary

Available for Interruption (AFI) – The Megawatts (MW) available for interruption.

Available MW – The MW amount that can actually be curtailed *(which may be different from the contracted amount)*

Billing Period - The period of relevant charges and payments either owed or due a Participant for its participation in the NEPOOL markets during the previous month.

Class I Customer – (Demand Response Program end user) – receives compensation for reducing demand at ISO-NE's direction.

Class 2 Customer – (Price Response Program end user) – receives compensation for monitoring and controlling demand in response to real-time market prices.

Compliance Period – Period including every hour in the Load Response event in which performance is greater than zero.

Contracted MW - The MW amount that is expected to be curtailed and is listed on the *most recent* administrative enrollment form (NX-11C).

Customers – End-users who are owners of Type 6 Interruptible Loads in the Load Response Program (LRP) and are compensated by the Enrolling Participant for being contractually enrolled in the LRP.

Customer Baseline (CB) – Average aggregate hourly kWh load for each of the 24 hours in a day for each individual customer.

Distributed Generation – see On-site Generation.

Eligible Type 6 Interruptible Loads - Individual or aggregated loads of end-use customers or individual or aggregated local generation of end-use customers. A Type 6 Interruptible Load cannot presently be modeled in the EMS and a Type 6 Interruptible Load must be less than 5 MW and not less than 100kW or as approved by the ISO on a case-by-case basis.

Energy Clearing Price (ECP) – The wholesale price of energy in $/MWh determined as an hourly value, and calculated using real-time data from ISO-NE's Energy Management System (EMS).

Energy Payment – The amount paid by NEPOOL for the reduction in energy consumed by the Customer.

Enrolling Participant – The NEPOOL Participant that registers customers for the LRP.

Form NX 11C – Administrative form that must be completed to the satisfaction of ISO-NE before a Customer or Participant can enroll in the LRP.

Independent System Operator – New England (ISO-NE) – ISO New England Inc. was established as a not-for-profit, private corporation following its approval by the Federal Energy Regulatory Commission (FERC). The organization immediately assumed responsibility for the management of the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff.

Internet-Based Communication System (IBCS) – Communication through the "World Wide Web" sent in the form of electronic messages on the Retx web site.

Interruption Event – A Class I or Class 2 event signaled by ISO-NE sending a notification via the IBCS.

Interruption Period – the time established by ISO-NE as the beginning and end of a Class I or Class 2 interruption event.

Interval Metering – A metering device that records electricity usage for each five-minute period during a billing period.

Load Curtailment (or Reduction) – A reduction in energy usage at a retail end user's facility that is the result of the retail end user either reducing the energy consumed or operating an on-site generator.

Load Response Program (LRP) – A program established by ISO-NE to promote greater reliability of the New England bulk power system. Reliability is increased through reduction of electric load during capacity deficient periods.

Metered Load – Electricity demand as measured by the Retx metering device.

New England Power Pool (NEPOOL) – An organization formed in 1971 as a voluntary association of electric utilities in New England who established a single regional network to direct the operations of the major generating and transmission (bulk power system) facilities in the region. NEPOOL represents traditional electric utilities and companies that are participating in the emerging competitive wholesale electricity marketplace. ISO-NE has a services contract with NEPOOL to operate the bulk power system and to administer the wholesale marketplace.

On-Site Generation – Electricity generation from facilities located on the premises of a Customer. This generation is typically a replacement for electricity supplied by the New England grid.

Participant – Any member of NEPOOL. Membership is divided into five major sectors: generation, transmission, marketers, municipals, and end-users, with each sector having its own criteria for membership.

Respond By Time – The deadline for a Class 2 Customer to notify ISO-NE via the IBCS of its intent to participate in the Class 2 Interruption Event. A Customer that fails to notify ISO-NE via the ICBS within the Respond By Time of their intent to participate will not receive payments for the interruption event.

Retx – The service bureau for the Load Response Program. Retx supplies customers with the IBCS and metering system needed to participate in the LRP.

Thirty Minute Operating Reserve (TMOR) – Reserve capacity that is available for dispatch within thirty minutes. In the NEPOOL markets, TMOR bids are hourly bids and are submitted day-ahead. Settlement is a single hourly clearing price, and costs for TMOR are shared proportionally by load.

TMOR CP Payment – The amount paid by NEPOOL to a Class I customer for being available and ready to interrupt. The TMOR CP payment is separate from any energy payments made for actual interruptions.

Type 6 Interruptible Load – The classification for all loads in the Load Response Program (LRP). Loads can be sub-classified as Class I or Class 2.

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