Load Response Program Design Issues

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1. EXECUTIVE SUMMARY

KEMA Consulting was engaged by ISO-NE in mid-2001 to specify and characterize the major approaches to transition its load response programs into the context of the Standard Market Design (SMD).[1] ISO-NE established the goal at the outset of this project that the SMD load response programs should be:

- an integral feature of New England wholesale and retail markets over the long term (for periods with high or low reserve margins), not just for potential near-term emergency or capacity shortage conditions, and
- consistent with the development of retail power markets as well as with distribution company systems for procurement of default service.[2]

As part of this assignment, KEMA was also asked to identify potential changes for 2002 from the structure and implementation platform of its existing (2001) load response programs, that would constitute steps in the direction of SMD and that would avoid moving in directions that would be counter-productive for the transition to SMD.

1.1 Program Criteria

Working with ISO-NE representatives, KEMA developed the following nine criteria for assessing load response programs. These criteria are described in the body of this report.

- Quantity (achievement of the level of load relief that is needed under various conditions to meet reliability and economic objectives)
- Quality (usefulness for control room operations, including measurability, diversity and dispersion and equivalence to generation resources)
- Compatibility with SMD
- Integration with settlement systems
- Short-term implementation feasibility
- Flexibility
- Market orientation
- Consistency with needs of end users and market participants
- Consistency with retail restructuring.

These criteria were based on the two main objectives: system reliability and market development, which in turn includes avoiding extreme price spikes, facilitating an elastic demand curve, alleviating pressure on reserve markets and expanding liquidity.

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[1] KEMA Consulting ("KEMA") assigned the management of this project to its affiliate XENERGY Inc. of Burlington, Massachusetts. Neenan Associates also prepared a document entitled "The Role of Day-Ahead Price-Capped Load Bidding" under a subcontract to KEMA Consulting.

[2] For purposes of this report, the term 'default service' is used to include Standard Offer service and other types of generation service procured by utility distribution companies from generating companies or other wholesale suppliers and passed through to distribution customers at retail rates which are not time-varied and do not provide the utilities with significant profit or price risk.

1.2 Program Options

- When the day-ahead power market is introduced as part of the Standard Market Design, it can be expected to facilitate the development of a day-ahead market for quantities of load reduction. This would be an improvement over today's market in which, because the quantities of load reduction are not known in advance of the real time, it is difficult to trade load reductions between market players. However, even with a day-ahead market, such trading would be limited without a mechanism to determine (and agree on) load reduction quantities. In other words, a significant increase in demand response may not be achievable simply by introducing a day-ahead market, so additional economic demand response programs may be required. KEMA identified the following major categories of such programs for integration with the SMD:

  Economic Program Options

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

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- Option #1, Price-Capped Load Bidding (PCLB) represents the base case for this assessment. However, it is inherently a tool for Load-Serving Entities (LSEs) to bid large blocks of load reduction, and does not itself offer an opportunity for end-users to experience the desired hourly price signal directly or through a company other than its commodity supplier. This limitation would be a particularly serious obstacle to achieving the needed load response under the limited development of the retail market,[3] because it would limit end users to the offerings of their local distribution companies. Since most utilities in New England, having divested generating assets, now buy and re-sell power at prices that do not reflect hourly market conditions, they do not have the means to capture the economic savings for themselves or their customers.

- Option #2, Load Reduction Bidding as Generation, is the key element of an economic demand response program, because it best meets the need of most end-use participants to specify the price at which they are willing to reduce load by a specified amount, and it allows the end-users sufficient time to reduce load after learning that they will receive the price they need (or a higher one). One example of such a bidding program for the day-ahead market is NYISO's "Day-Ahead Demand Response Program" (DADRP), and it is likely that such a program will eventually emerge as part of the market design for the NERTO. ISO-NE could consider waiting to implement this approach until the necessary systems are implemented at the level of the NERTO. This would also allow time for existing program issues to be resolved in NY and time to assess the extent of customer willingness to learn program mechanics and accept risk of penalties in return for spot-market-based returns.

Options #1 and #2 together represent in general terms the likely base on which future regional (e.g., NERTO) or national demand response programs will be built. However, questions remain about the extent to which different end-use customer market segments will become engaged in day-ahead bidding behavior based on hourly prices, and the likely extent to which these day-ahead approaches will capture the reliability and market benefits specified above.[4] The following Option #3 could increase participation in demand response programs, without waiting for the retail market to develop, by adding additional features of price certainty and stability to the programs discussed above.

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[3] The retail market will become more active by the time of the SMD introduction, assumed to be mid-2003 for purposes of this project. However, XENERGY expects that most of New England's load will likely remain on the utilities' default service at least through the 2003 - 2004 period.

[4] The reliability and market objectives were discussed in Section 3 above. The nature and extent of potential economic benefits are further discussed in Section 5 below.

- Option #3, Transitional Load Reduction Pricing, has been developed as a transition approach to increase the quantity of load response in the short term.[5] One feature of this program option is consistent with Option #2 -- end-use customer bidding of prices and quantities of load reduction – and would therefore help the market prepare for the implementation of SMD. However, such LR bids would not be integrated into resource scheduling and would not set the ECP or LBMP. After the initial unit commitment, the ISO would select bids that are below the expected ECP – perhaps below it by a specified percentage (risk factor) to limit financial risk to the ISO. The ISO would then (a) notify such customers that they must reduce load the next day and (b) guarantee that each customer will be paid its bid price for its reduction.
- This bid price would be expected to be below the ECP, so this transitional approach diverges from the principle of sending accurate hourly price signals. Nevertheless, it would give customers the needed certainty in advance for a pre-specified number of hours (e.g., 4 hours). Option #3 could incorporate, or could be developed from, the existing ISO-NE energy-price-based Type 4 Dispatchable Load.[6] The systems integration needs are much lower for this Option #3 because load reduction bids would not participate in setting the ECP.

None of the first three Options provide the opportunity to receive credit for deciding to reduce load on a very short-term basis. This capability is provided by the following Option #4, Voluntary Response to Market Price, which is based on the real-time system that has been demonstrated by ISO-NE with RETX information technology, and which also offers current information on load response to control room operators.

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- Option #4, Voluntary Response to Market Price, is of interest primarily to customers who can respond in real time and can decide to respond before knowing where the price will settle. This may include large industrial facilities with processes that can be rescheduled without cutting into production, and those in sectors that have traditionally taken advantage of real-time pricing in areas where it has been offered. Its advantage is the quantity of demand response resource that it can attract as an increment above that which will respond to other programs. It would therefore be appropriate to add this capability to the existing features of the demand response programs in NYISO and PJM, or to treat it as a "best practice" for the NERTO. Since this real-time approach will likely have a future in the region, it could be maintained by ISO-NE and folded into SMD, pending NERTO implementation.
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Each of these four options has unique potential advantages. Each option can constitute a valuable part of a demand response program, and it may therefore be possible to capture the greatest benefits by combining the options over time. The challenge will be to craft a transition strategy that achieves sufficient customer participation and actual load response without incurring an unjustified incremental cost in system development.

1.3 Program Incentive Issues

A key feature of ISO-NE and NYISO load response programs to date has been the use of payments from the ISO to the provider of the load reductions to convey some elements of the economic value that those reductions provide to the system. One reason for including such a payment, generally called an "incentive," in the design of load reduction programs has been the existence of retail market structures in the ISO territory that impair the ability of most end users to obtain that economic value from the market.

This market barrier or market imperfection applies primarily to the retail market configuration, described in the body of this report, in which some or all end-users are supplied a form of "default service" by an electric distribution company (EDC) which passes through to its retail customers the fixed, non-time-differentiated price that it pays to its wholesale generation suppliers. In this configuration, neither the EDC nor the end use customer has a clear

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[5] It could be implemented prior to the SMD, and could then co-exist with the SMD or be phased out when no longer needed.

[6] See below for one way to introduce such an approach in 2002 as a "Class 3."

position in the power supply market from which it could receive a stream of revenue or savings based on the market value that its load reductions create during periods of high hourly prices.

In particular, the end-use customer of default service has no risk of paying the high hourly prices in the wholesale market, and would therefore need to be offered a business proposition with an attractive reward in order to incur the costs of reducing load. It is difficult for a supplier to offer such a reward when the market benefits are uncertain and limited to relatively few hours per year. The wholesale supplier of the fixed-price default service might theoretically be interested in buying load reduction in hours when that would be cheaper than the market value of generation supply, but a supplier of "Standard Offer" or other such default service generally has no financial or other contact with the end users who have the load reduction opportunities, and most such suppliers are not in the business of load management business. More important, a seller of power generally has a financial interest in higher market prices, not lower ones. Due to these market imperfections, some incentive payments are essentially required under present market conditions in order for a program to achieve a significant load response.

When such incentives are offered, they are generally expected to be more than offset by the consumer benefit[7] that they create when clearing prices in the ISO-administered market(s) are reduced from price levels that would have existed without the load reduction induced by the incentives. These benefits are higher at times when generating capacity is tight or in locations where congestion costs are high, and lower when a region is experiencing high reserve margins. In the latter case, benefits are obtained through the option value of reserves in the form of insurance against high cost disruptions.

One of the disadvantages of the use of such incentives in a program design is the need for a source of funds for the incentive payments. Uplift can be one source,[8] but the ISO has a strong objective to minimize uplift charges. However, a load response program can be expected to provide offsetting reductions in other charges, including reductions in the energy clearing prices, reserve costs and congestion costs. Other approaches to provide funds for program incentives include the reallocation of load responsibilities through the settlement process.

1.4 Organization of the Report

After an Introduction, the body of this report is presented in the following three main sections:

3. Objectives and Criteria

4. Program Features and Alternatives

5. Load Reduction Program Incentives.

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[7] This benefit for consumers is sometimes referred to as consumer surplus, although it is not technically a surplus, but a transfer of economic rent to consumers that would otherwise have accrued to suppliers as a result of market imperfections associated with distorted price signals in the market.

[8] An ISO is in a unique position of being able to assess the costs and benefits of the use of uplift to achieve load reduction objectives.

2. INTRODUCTION

2.1 Context

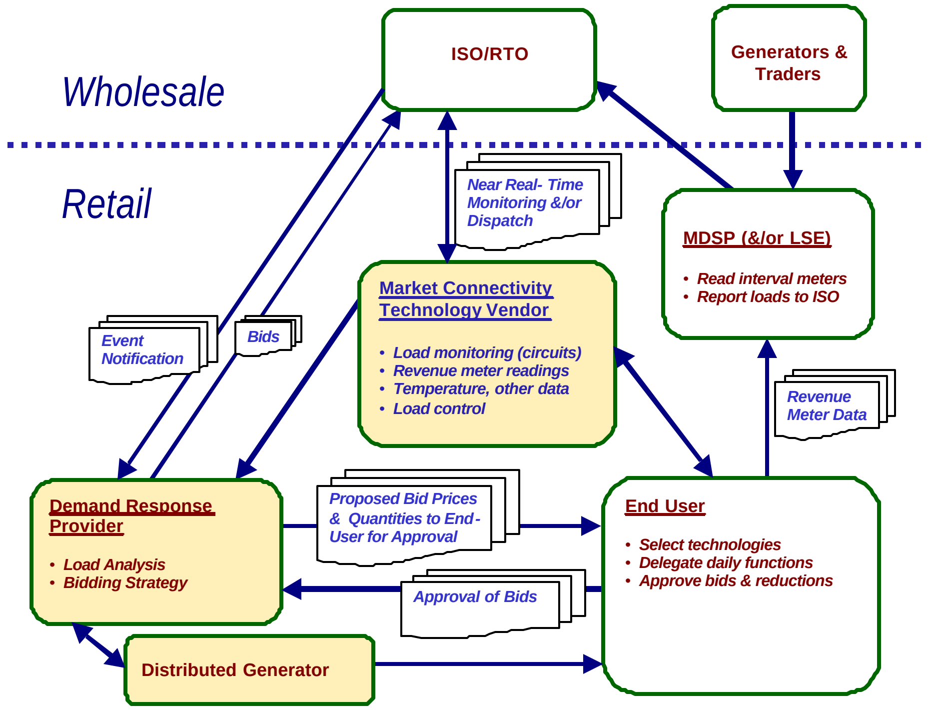
Electric utilities have long offered a range of dispatchable load control options and time-varying rates under traditional regulation. Now that retail electricity markets are being introduced and most New England utilities have divested themselves of generating assets, many such load management options are no longer being provided to distribution customers. Competitive retail suppliers have begun to offer their customers equivalent load management services, but retail markets are not fully developed, so those services are not yet being provided to most end-use customers.

Against this retail background, wholesale prices have been volatile in New England and in other markets, and FERC has emphasized that price-responsive demand is a major requirement for the competitiveness of wholesale electricity markets. All the U.S. Independent System Operators (ISOs) developed new emergency load reduction and economic demand response programs for the summer of 2001. These new regional load management programs:

- use market mechanisms to provide price signals to end-use customers, and
- use new communications and control technologies to communicate price and response information between participants and the ISO.

The ISO programs in the Northeast have achieved some market penetration and load response to date, but they have a range of different features. Development of these programs and the associated communication technologies is generally recognized to be at a relatively early stage. It is inherently difficult to create the conditions for a fully competitive market in which demand and supply resources can compete fairly. It would be hard enough if this were a problem confined to the wholesale market and the regional transmission system. But the root of the challenge is the difficulty of creating new connections and links between the end-use customer and other retail market players and the wholesale and transmission worlds. The following chart illustrates the complexity of this challenge.

New Connections between retail and wholesale markets



The design of load response programs involves activating these complex new linkages between the wholesale market functions of the ISO and the retail functions of distribution companies and competitive suppliers. A major impediment to the ability of new load response programs to make these connections is the limited development of the retail market to date, as discussed below. A healthy retail market may be a prerequisite to achieving price elasticity of demand and is certainly a critical step toward achieving competitive market conditions in which incentive payments may no longer be needed. However, demand response itself appears to be an essential requirement for a competitive market. The key question for program planning is what features are needed to break this catch-22 stalemate. The data and program requirements to meet this challenge are addressed in the body of this report.

2.2 Scope

This report was developed during the period from mid-July through mid-October 2001. It is based on the following scope as developed in proposals and negotiations with ISO-NE:

- Provide a characterization of LR program options.
- Document the basis for decisions made for the 2001 programs.
- Determine if any changes are needed for the 2002 program to avoid major inconsistency with the needs and direction of the 2003 programs.
- Develop high-level recommendations for the structure of the 2003 programs.
- Provide recommendations on additional information gathering to support more detailed decision making for 2003.

This scope includes both emergency and economic load reduction programs, with an emphasis on economic programs which will be most affected by the introduction of the SMD day-ahead market.

We have made a number of assumptions about the wholesale and retail market environment, which are addressed in the next three sections:

2.3 Adoption of Standard Market Design

We have made the following assumptions about the multi-settlement system ("MSS") / Standard Market Design:

- It is assumed that a multi-settlement system ("MSS") will be introduced in New England with a day-ahead market ("DAM") for energy and ancillary services as well as a Real Time Market.
- It is assumed for purposes of this report that such a MSS will be implemented in New England before June of 2003, either through the Standard Market Design ("SMD") process or through other regional developments. Note: in this report, the terms SMD and MSS are used interchangeably and are understood to include whatever day-ahead market structure and other features may result from current discussions of a northeast RTO.
- A longer or shorter lead-time to the adoption of the SMD would lead to minor to moderate modifications of recommendations.

3. OBJECTIVES AND CRITERIA

The design and selection of program options and features for new or improved load response programs must be based on a set of criteria. These should in turn be based on the objectives that the programs are to meet. In order to make these important elements of the program design process explicit, the following set of goals was developed during this project, based on discussions between project participants from ISO-NE and KEMA.

3.1 Broad Objectives[9]

The objectives of LR programs can be most generally broken down into reliability (emergency) and economic concerns – which in turn drive the distinct characteristics of the emergency and economic programs.

The goals and objectives in this section are expressed in terms of the needs of ISO-NE. In addition, any program must also meet the objectives and needs of end use customers and the market participants in the wholesale and retail value chain. These are summarized in very simple terms as Criteria 8 below and described in the subsequent section.

3.1.1 Reliability Objective

The need to ensure reliability of supply in emergencies is paramount. A specific objective is to provide an operational resource under OP4 conditions.

3.1.2 Economic/Market Objectives

- Price Objective: avoid or reduce extreme price spikes.
- Elasticity Objective: facilitate an elastic demand curve and send appropriate price signals to develop liquid wholesale markets with full demand side participation.
- Efficiency Objective: reduce all-in level of ISO clearing prices by alleviating pressure on reserves markets and expand liquidity in energy market.

The key rationale for developing these objectives, and taking action to achieve them, has been that, despite the introduction of markets for energy and capacity, barriers have remained in place from the regulated era that have, in effect, discouraged most customers from managing their demand for power in response to hourly price signals. The primary such barrier is that most of the load continues to buy generation through utility procurement of “default” power, under which arrangement neither the utility nor the customer has an adequate incentive to reduce load in high-priced hours. The primary strategy through which the ISO can achieve the objectives stated above is to target its load response programs at removing this barrier and the other barriers to price elasticity that are discussed below. The following criteria can be used to compare program alternatives and design the best combination of program options.

3.2 Specific Criteria[10]

We present these criteria in the three categories: outcome criteria, system goals and market goals/constraints.

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[9] Objectives have been generalized from the various lists and discussions to date.

[10] Criteria are based on the 7/10 meeting. Text quoted in this section and through out the working drafts is taken from the 7/21 Work Plan, unless another source is cited.

lti-settlement system."

[14] All the accounting components and the security constrained unit commitment dispatch could be handled via a less elegant "iterative" process, similar to how import loads are handled currently.

5 – Short-Term Implementation Feasibility

Short-term implementation feasibility for 2002, including schedule risk and migration path to SMD. This includes consideration of the extent to which costs of new development for 2002 are expected to be useful once the day-ahead market and other SMD features are implemented.

6 – Flexibility

- Appropriate transition of older interruptible load programs.
- Diversity of options available to the market.
- Openness and adaptability of architecture.
- Simplicity.

3.2.3 Market Goals

These criteria generally represent the goals and needs of market participants, which in some case present the ISO with constraints on program design decisions. They are consistent with the approach of creating programs that are market-based to the extent possible rather than "ISO-centric." These criteria can also be thought of as fundamental requirements for success at the retail level.

7 – Market-Based Programs (limited intervention in power markets)

- Minimum increase in uplift charges by ISO to non-participants.
- Maintaining fairness to load and generation sides of the market.
- Minimum reliance on above-market or non-market incentive payments (by ISO).
- Minimize cost and time to implement the system

8 – Needs of End Users and Market Participants

- Adequacy of financial benefits for Participant and end-user participation (discussed more fully in the next two sections below).
- Efficiency, simplicity, economy, and logistical feasibility at the retail level.
- Consistency with structures of wholesale market transactions.

9 – Consistency with Retail Restructuring

- Adaptability: capability to function effectively under most likely range of retail market conditions as state regulations evolve, utility roles potentially change and new entities enter the market over the next few years, including allowing non-LSEs to participate with PRL programs.
- Support: minimizing impediments to customer migration to competitive generation supplier and barriers to participation by those suppliers in the ISO Load Reduction programs.
- Confidence: creating the market conditions, including avoidance of extreme price spikes, that can provide state PUCs the confidence to relax the use of fixed prices for default (or Standard Offer) service.

3.3 Needs of Market Participants

As stated in the Criteria above, any program must also reflect the interests of the market participants and players in the wholesale and retail value chain, including:

- Load Serving Entities (LSEs) as defined in ISO-NE market rules, which may include regulated utilities and competitive, non-utility companies when acting as LSEs,
- competitive suppliers of retail electricity,
- providers of last resort ("POLR"), including electric distribution companies, municipal utilities or others that provide any form of regulated default generation service to retail customers who essentially haven't switched from their utility service (including the "standard offer"),
- distribution "wires" companies or others who provide electricity usage data to the ISO on a daily and monthly basis, including competitive providers of meter data services, if authorized,
- regulated energy efficiency and other demand-side management programs operated by electric (and gas) distribution utilities or other entities,
- Curtailment Service Providers ("CSPs") - also called Load Reduction Providers ("LRPs") - and other new and existing players that aggregate small demand-side resources to a scale at which they can participate in ISO markets and programs,
- energy service companies and others specializing in load management, distributed generation and other demand-side resources,
- vendors of load response software and Internet platforms,
- wholesale traders and marketers,
- generating companies, and
- lenders and other entities that finance the companies and transactions in the market.

While some of these market participants may not participate directly in load reduction programs, their needs are important to the extent that the programs affect them. In addition of course, the goals and requirements of state and federal regulators must be met if any program is to be implemented.

LSEs are the primary interface between the ISO administered markets and the loads. Many features of potential load reduction programs are delivered or administered through bilateral contracts between LSEs and other participants at both the wholesale and retail levels which may not interact directly with the ISO.

3.4 Needs of End-Use Customers

The economic needs of end-use customers can be summarized as the price for which they are willing to implement any given level of load reduction. The implications of these economic needs are addressed theoretically in the Appendix “The Role of Day-Ahead Price-Capped Load Bidding.” In addition, customers have a complex array of non-economic and other needs, which are addressed below.

Given the traditional model of fixed non time of use tariff rates and continued fixed default and standard offer rates, command and control metering options provided by utilities, and lack of retail choice, it is no surprise that PRL program infrastructure is not robust and customers have not been immediately embraced by end-use customers. There are several other substantial barriers or hurdles to the widespread adoption of these PRLM products and services, including the marketing challenge of how best to structure PRLM deals and installations so that the function becomes automated or transparent to the end users; the need for customer education about the technologies and the wholesale market itself; the lack of interval metering among small and medium customers; standby charges and other features of existing utility tariffs; permit limits in environmental and building and other permits; and the unresolved regulatory debate between new market entrants and ISOs over control of PRLM and its status as a competitive function like generation, or as a regulated function like T&D. These hurdles are discussed in turn below.

Major customer education needed-- A major paradigm shift is needed to get end-users and retail supplier to understand how they can leverage PRLM opportunities. As noted, until now, customers have not had the ability or tools to be able to react to price signals. Platform vendors and retail suppliers will need to learn how to effectively communicate the benefits and provide the necessary feedback tools and processes. See "Information or Search Costs" below for additional background on this barrier.

Interval metering and small customers – Many small customers do not have interval metering. In Pennsylvania, for example, monthly metered customers account for 70-75% of the PJM peak load. In the absence of interval metering, competitive suppliers cannot pass through actual prices to retail customers and the costs associated with installing the required metering can be prohibitive.[15] Therefore, subsidies as incentives for investment in the necessary metering may be required, or profiling and other methods should be developed to minimize the requirements for new metering at customer facilities.

Control of PRLM – The application of these new communication and control technologies to the distributed power business has raised new issues for regulators and strategic planners alike. Arguments have been made for treating PRLM as a competitive function like generation, or as a regulated function like T&D. Retailers would like to be the sole providers of PRLM services, and prefer that PRLM be fully unbundled from the transmission and distribution business. They are worried that ISO and utility programs rushed into place to address immediate capacity crises may become permanent or may make it difficult for them to use PRLM services to differentiate competitive retail products from utility or default service. On the other hand, there are system reliability and economies of scale arguments for vesting some control over PRLM programs with distribution utilities and ISOs.

Institutional barriers –Existing utility tariffs and equipment permits may prohibit and/or deter customers from participating in PRLM programs and responding to appropriate price signals. For instance, Niagara Mohawk's residential tariff does not allow for wholesale market price pass-through to customers. Also, language in various utility tariffs limits the circumstances under which back-up generators can run. These tariffs can subject customers to substantial standby charges eliminating any economic incentive to participate. In New York, efforts are underway to give tariff exemptions to back-up generators so they can run in emergency situations. However, ratemaking issues are more complex in the case of back-up generation to be run in conjunction with programs based on an economic or price responsive model.

Environmental permitting issues – In New England the eligibility of some load response as reserves, together with the unique reserve market conditions in the region, has provided the potential for emission reductions. ISO-NE is now studying the environmental impacts of the summer 2001 programs. Nevertheless, environmental regulators are concerned about the proliferation of fossil-fueled distributed generation because of the potential impacts on air quality and public health. This issue is growing in importance as price signals encourage the use of the growing number of generators installed by customers, and has been addressed in detail by the New York ISO's Price Responsive Load Working Group. Emission rates of distributed generation units can be higher than those of large central station generation units and their emissions are typically released at or near ground level resulting in greater local impacts. Also, distributed generation can be most economical during periods of summer peak electric demand when local air quality issues are the worst. The use of emergency diesel generators is especially problematic because they emit high levels of NOx and other pollutants.

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[15] While only a small percent of load need to respond to real-time or day-ahead price signals to (see Hirst & Kirby *Retail-Load Participation in Competitive Wholesale Electricity Markets*, January 2001, the more customers with participating in PRL programs, the more price elastic the demand curve.

3.5 General Market Barriers To Participation In Demand-Side Activities

In addition, end-use customers have a range of general needs that must be met in order for them to effectively participate in this market, including adequate information and the existence of market conditions that make load reduction services attractive. However, in the years since energy conservation became an issue in the 1970s, several “market barriers” have kept many customers from buying energy cost reduction services and from participating in demand-side programs. As a practical matter, these barriers must be addressed by LR programs if they are to be successful. Many of these barriers affect the customer’s decision to invest in the building automation and other monitoring, communication and control systems that make it possible to effectively participate in load response programs. The following table summarizes these “General Market Barriers to Participation in Demand-Side Activities.”

Table 1 – General Market Barriers to Participation in Demand-Side Activities

Barrier	Importance	Summary of Barrier for LR Program Participation
Performance Uncertainties	High	Programmatic uncertainties (economics) are greater than technological uncertainties. Participants are not willing to make the investment required to install LR capability when high levels of uncertainty exist regarding the economics of the investment. LR systems are newer technologies and thus lack the track record and testimonials necessary for high market penetration.
Hassle or Transactions Costs	High	Designing, installing, and operating LR systems requires a great deal of time. Building owners and operators face a large number of non-energy business issues every day that require their attention. Only concern over the reliability of energy supply and the potential for significant increases in energy/peak demand costs are likely to be sufficient to raise consideration of a LR system to a high-priority issue.
Information or Search Costs	High	Information and search costs are very high due to the emerging nature of LR systems and to the complexity of most solutions. At a minimum, potential participants must explore which technologies/end-uses provide potential, how building tenants will be affected, and what program has the appropriate level of commitment and benefits.
Externalities	High	Uncertainty regarding the effect on comfort and thus the effect on productivity or sales is a critical issue. The effect on reliability of energy supply is generally of very high importance to each potential participant.
Misplaced or Split Incentives	Medium	Classic owner-tenant dichotomy is present. In general, incentives are paid to the owner or operator while building occupants must contend with negative aspects of decreased service levels.
Organizational Practices or Customs	Medium	This barrier is most relevant for revenue-focused organizations. Large organizations often have criteria for energy-cost reduction investments that appear inconsistent with other investment criteria used by the organization or otherwise informal or “irrational” to outside observers.
Asymmetric Information & Opportunism	Medium	Contractor credibility is uncertain where pre-existing, trust-based business relationships do not exist. End-users are not certain that contractors provide complete and accurate information.
Hidden Costs	Medium	The newness and complexity of LR systems and programs create considerable uncertainty regarding hidden costs (e.g., non-performance penalties, unanticipated decreases in productivity).
Product or Service Unavailability	Low	Shortage of interval utility meters could become an issue. LR system product and service availability appears to be high compared to relatively low market demand. A sufficient number of competitive options seem to be available to avoid bottlenecks and high prices. However, whether plethora of products can all perform as advertised remains to be proven.
Access to Financing	Low	Uncertainty of benefits may lead to financing issues. Capital investment requirements are always an issue for institutional customers. However, given programmatic and rate increase uncertainties over time, most customers are likely to demand such short payback periods that access to financing may be relatively moot.
Non-Externality Pricing	Low to High	Program designs being constructed in a largely political environment may lead to incentives and LR system prices that do not reflect marginal plus externality costs. Non-participants benefit from the actions of the participants (i.e., higher reliability, lower energy prices for all). Market clearing price mechanism creates multiplier benefits to all consumers.

4. PROGRAM FEATURES AND ALTERNATIVES

In this section we specify and characterize major program options. This section also describes advantages and disadvantages of these options in terms of the criteria identified in the previous section. While both emergency and economic programs are considered, the primary focus is on the economic programs.

4.1 Load Reduction Program Features

4.1.1 Technical Features Checklist

The ISOs in the United States have put in place or proposed price responsive load reduction programs, with a range of features. Some of the potential program features are listed below:

Type	▪ ISO Dispatch ▪ Price Responsive
Products	▪ Energy ▪ Operating reserves (e.g. TMOR, TMSR, TMNSR) ▪ Other ancillary services ▪ Installed capacity
Payments for Load Reduction	▪ ISO pays for LR at market price ▪ ISO pays for LR at above-market price ▪ Minimum payment for startup costs ▪ Price bid, set or agreed in advance
Scheduling[16]	▪ Fully integrated. Participants bid LR price & quantity, and can set market clearing price (MCP) ▪ Iterative. Equivalent to scheduling imports. Participants bid LR price & quantity, and can get market clearing price (MCP) ▪ Not formally scheduled. LR bids get but do not set MCP, and do not displace other scheduled resources[17]
Settlement[18]	▪ From normal process as fully integrated or iterative settlement ▪ From normal process as fully integrated or iterative settlement, but side process for "incentive" ▪ Side process for both avoided cost and incentive benefit streams
ISO-End User Relationship	▪ ISO deals with LSEs ▪ ISO also deals with LR-only aggregators. ▪ ISO also deals with registered end-users ▪ ISO offers distinct programs to end users

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[16] "Scheduling - is the process of developing the Forecast Schedule showing the projected dispatch levels for the next Scheduled Dispatch Period." (see Glossary)

[17] PJM notes in relation to its economic program "PJM will utilize the data that has been submitted via this site to compile daily aggregate load reductions on a zonal basis for use in operations" . *PJM 2001-2002 Load Response Pilot Program, p. 12.* This is not a very strong statement of integration.

[18] "Settlement - is the process of determining the payments to be made to Participants and charges to be collected from Participants." (see Glossary)

	▪ ISO acts as program facilitator for LSE programs
Eligibility	▪ Load or uncontracted generation > 1MW ▪ Load (> 1MW) ▪ > 100 kW, curtailable for at least four hours
Metering	▪ Scan rate (5-60sec.) ▪ Hourly Interval
Telemetry	▪ Yes ▪ None
Trigger	▪ Declaration of Emergency condition (of various severity, depending on the ISO) ▪ Price Floor ▪ Economic program with no price floor (trigger set if economic bid is accepted)
Notification mechanism	▪ Fax ▪ Pager ▪ Web ▪ E-mail ▪ Telecontrol signal
Notice lead time	▪ 10 min ▪ 30 min ▪ 60 min
Load reduction duration per call	▪ > 1h ▪ > 2h ▪ 2 – 8 h
Expose limit	▪ < 30 h per month ▪ No limit
Capacity commitment	▪ None ▪ As bid
Payment for capacity	▪ Bid $/MW deficiency charge ▪ MW available for sale into bi-lateral or auction market ▪ None
Energy payment	▪ Prevailing market imbalance price (CA) ▪ Post event price ($500, $750, $1,000/MWh) ▪ Greater of LMP or $500/MWh
Basis for determining load reduction	▪ Facility under ISO control ▪ ISO profile of the load less metered hourly usage ▪ Typical load less metered hourly usage ▪ Purchased baseline level ▪ Reasonable proposal from CSP
Compliance	▪ Mandatory (there is a penalty for non-compliance) ▪ Subscriber’s discretion (there is no penalty for non-compliance)

An unlimited number of program options could be developed with various combinations of the features listed above. For this project, a limited number of general program options were developed in response to the objectives presented above and are defined in the section below entitled “Economic Load Reduction Pr
are based on KEMA’s experience with load management programs and on the characteristics of programs implemented by other ISOs to date.

4.1.2 Baseline Methodologies

One of the critical program features is the baseline methodology that is used to compute the quantity of LR for which the customer will actually get paid. To be economically efficient from a public policy perspective, payments for energy, operating reserve and ancillary services that are available to generation should be available to load response that provides equivalent services (e.g., dispatchable demand response may be equivalent to spinning reserve). However, it is difficult to put genuine load reduction response (as opposed to response from distributed / back-up generation) on an equivalent footing with generation in economic LR programs because of the need for baseline methodology. (This does not apply to load response through PCLB, and may not apply in the future to properly sub-metered applications.) The payment of an incentive for load reduction needs to be calculated as the difference between the baseline consumption (what would have happened without the load response) and the actual demand consumption.

Baselines that are not fully determined until after the load response kicks in cannot be known with certainty the day before or even the hour before the load response. Baselines that are known the day prior (or season prior) to the load reduction are second best projections of what the appropriate baseline should be (particularly for weather sensitive loads) for the following day, and are subject to gaming. Thus, for a day-ahead bidding market, there is no baseline that can provide the same certainty as to quantity of power that is provided by a generation asset. In other words, load response is handicapped as compared to generation by facing this added risk.

4.1.3 Integration with Scheduling and Settlement

The degree of integration of load reduction transactions into the scheduling and settlement functions is closely related to other program features and has substantial impacts on system development requirements. In general, if load reduction is treated as an equivalent resource to generation, then the financial streams can be designed to flow through the settlement process like any generation source. However, design of programs and the systems to implement them may need to address the following potential situations:

- LR provider and LSE may not be the same -- the revenue and obligation may flow on two different paths, even if the load reduction bid is integrated into the settlement system.
- The LR provider may be a non-LSE entity -- settlement systems may not be structured to account for an entity without traditional generation or load obligation.
- Incentives may be available to load reduction, above and beyond the scheduled load reduction -- this may necessitate a separate accounting of financial flows that may result in additional uplift.
- Load reduction may not be scheduled and dispatched like generation resources -- some “side” accounting process may be needed to track incentive revenue stream(s).
- The load reduction may be provided at a single customer meter that is supplied by multiple commodity providers -- this results in a conundrum as to the accounting and allocation of savings, incentives or other revenue streams among the multiple providers of generation and load management products.

In the case of a competitive supplier that elects to offer load response services to its customers, such suppliers are in a position to receive the avoided-cost benefit resulting from the load reduction and share that savings with their customers. In the case where a different entity – a Load Reduction Provider that is not the customer’s LSE facilitates a customer’s participation in a LR program, that provider will look to its customer to be paid a share of the savings, but if the customer is paying its LSE a fixed price for its supply, there would be no savings to share. Ways to address these financial/market barriers, potentially through incentives are addressed in Section 5 “Load Reduction Program Incentives”.

4.2 Economic Load Reduction Program Options

The following four major economic program options are described below:

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

The first Table below compares some key features of these options.

Option 1: Day Ahead Price-Capped Load Bidding

This is essentially the “base case” or “no program” option. It is a feature of the day-ahead market in which a LSE can bid not only the quantity of load it expects to serve but also the price points at which it will reduce that load by specified MW levels.

The PCLB option is complex in terms of the development of bids by LSEs, but it is the most straight-forward from a system development point of view because it is already part of the SMD design. Also, no baselines are required because, if no load reductions are scheduled, the LSE is committing to be responsible for its full load in the real-time market. However, PCLB must be implemented through the LSE that supplies each participating customer’s generation, and therefore does not provide an opportunity for firms to enter the “demand response” market to serve end-users unless they also provide them their generation service.

While this provides some demand response capability that does not now exist in New England, an important question is the extent to which this functionality of the DAM obviates the need for separate economic load reduction programs. This issue is discussed further below and in the Appendix “The Role of Day-Ahead Price-Capped Load Bidding.”

Option 2: Load Reduction Bidding as Generation

This section first describes this program option in the context of the SMD, and then discusses the possibility of implementing a form of day-ahead bidding prior to SMD as a transitional mechanism.

Load Reduction Bidding into SMD Day-Ahead Market. In this option, it becomes possible to unbundled “load reduction” from generation service. Quantities of this new LR “product” can be bid into the market, and incorporated directly into the D-A scheduling process, potentially displacing other resources. Based on each day’s clearing of the day-ahead market, the D-A and R-T market transactions of each market participant are therefore fully integrated into the standard settlement accounts for billing purposes.

This is the approach implemented during summer 2001 by NYISO. It has generally functioned correctly but only after aggregating load reduction bids into large blocks, due to the inability of the scheduling software to accept the large number of inputs that would have been required to process each end-user’s bids separately[19]. Until the necessary software systems are in place to do this, there will necessarily be significant limits on the flexibility of users and market participants to formulate independent LR bids with their own unique price, start-up costs, hours of

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[19] That is each LR bid was considered a new generator by the system software. During summer 2001 approximately only 50 extra generator slots could be accommodated.

operation, and quantity levels. In addition, the aggregation process can introduce significant administrative burdens or transactional complexities.

Options #1 and #2, PCLB and Load Reduction Bidding, are similar but vary in the following ways:

- Revenues and penalties under PCLB are based on total metered load, while under the load reduction bidding option, the quantity of the load reduction "product" is based on the difference between each customer's total metered load and a computed baseline.
- Load reduction bidding can include incentive payments to end-users or their providers, as is currently done in the NYISO Day-Ahead Demand Response Program ("DADRP"), while it does not appear that PCLB would provide a means to do this.
- Non-LSEs would be able to bid load reductions into the day-ahead market (which NYISO is planning to allow in 2002).
- Load reduction bidding allows end-use customers to bid in their load reductions directly, unlike the PCLB-only option.

A critical issue for design of this type of load reduction program under the SMD is whether (a) each LR bid price and quantity is included into the schedule via full **integration** into a single unit commitment scheduling algorithm in the same manner as a generator, or (b) LR bids are processed in a separate scheduling algorithm or process for LR resources and are then combined through one or more **iterations** into a schedule with the generation resources (that have been separately optimized in their own schedule). This iterative process could be structured in a way similar to how imports into ISO-NE have been handled. The sooner this decision is made in the SMD development process, the more flexibility there will be to consider the integrated approach and the lower cost will be required to implement it.

Transitional Day-Ahead Bidding Prior to SMD. Load reduction bidding could potentially be implemented either before SMD is implemented or after SMD is implemented. Even before a D-A market is operating in New England under the SMD, it would be possible for load reduction bids to be submitted in the same manner as generators now submit their price and quantity bids to ISO-NE, and to be integrated into:

- the unit commitment process where load reduction could displace other resources, have an obligation to respond, and set the market clearing price; and/or
- the bilateral unit or system contracts which market participants submit to the ISO to determine the extent to which any participant is short, and is therefore billed for that shortfall at the clearing price.

If participants gain market experience under this simplified bidding process, it would then be an easier transition for them to bid into the new D-A market when it is subsequently introduced. However, in the short-term, participants in this program would not know their revenue until the R-T ECP price is determined, after each load reduction is implemented. Also, it would not be cost-justified to develop substantial new IT features for this Option unless they are under development concurrently for SMD. Another approach to capture some of the transitional benefits is presented in Option #3.

	Key Load Reduction Options: 'Economic' Programs			
Title:	**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**
	Summary of Features			
Most Similar Program	Base Case SMD	NYISO 2001	Types 3 & 4 Dispatchable Load	ISO-NE 2001
Timeframe for ISO-NE	When SMD is implemented	With SMD or when NERTO systems are implemented	Can be used before SMD and phased out at any time	In place as of summer 2001; can be retained after SMD is in place
Payments for LR by ISO	LSE responsibility	D-A Clearing Price	Known in advance; other options available	Real-Time Price
Products (in addition to energy)	Implicit in D-A market	Capacity & reserves	Capacity & reserves	None
Penalties	Implicit in R-T market	Penalties if scheduled but don't reduce	Penalties if signed up for ICAP or TMOR; other options available	None
Interval Metering	Not required	Required unless load profiling procedures are introduced		
Real Time Metering (via RETX)	Not required	Not required, but could be used to add value	Options available (see Class 3a Bidding Program for 2002)	As in 2001 Price Response Program (Class 2)
End of Day Polling (via interval telemeter)	Not required	Not required, but could be used to add value	See Class 3b ("Customized LR Bidding Program without Reserve")	See Class 2b ("Voluntary Price Bidding Program")
Scheduling Structure	LR can set MCP if part of LSE load bid	LR can set MCP	LR cannot set MCP	
ISO-End User Relationship	None	Only if end-user becomes a Participant	ISO may negotiate with end users & take price risk	ISO receives R-T LR data
Role for LR Providers (not LSE)	None	LRP may bid if a Participant	Options available	LRP signs up end user for ISO programs

Option 3: Transitional Load Response Pricing

Option 1 is essentially a "no program" base case, and Options 2 and 4 are modeled after existing ISO programs Option 2 is generally based on the NY DADRP – widely regarded as the most fully evolved ISO LR program to date for the day-ahead market; Option 4, discussed below, is based on this summer's ISO-NE Price Response Program. In contrast, Option 3 represents an opportunity to develop a middle-ground or transitional LR program designed to achieve additional demand response benefits by being more customer-friendly in the period while the retail power market remains immature.

This "Transitional Load Response Pricing" option is based on the premise that the objectives of LR programs will be best served by a variety of pricing arrangements, including those that are customized to be as simple and predictable for load response customers as possible. Option 3 would respond to this need by offering a standard set of pricing terms that are less tightly tied to actual ISO market prices, whether real-time or day-ahead, than the other program options. In addition, for each individual customer that can provide a sufficiently large quantity of load reduction, pricing terms could be further customized or negotiated to meet their individual requirements.

A Transitional Load Response Pricing program could offer the opportunity for customers to bid a load reduction price in advance, which would then serve as a guaranteed floor price for the duration of any load reduction requested by the ISO. This would be more predictable than making a decision to reduce load based on estimated prices issued at 6:00 pm the day before, but then getting paid the ECP, at whatever level it clears in real time. [20]

This kind of pricing may attract greater program participation that programs based exclusively on market prices, and can be introduced without waiting for SMD implementation. It can be seen as a transition step toward the day-ahead market. In the SMD day-ahead market, the load reduction wouldn't be scheduled unless the clearing price to be paid is at least as high as the price bid. This characteristic is made available in Option 3 approach by setting the bid price as the floor. In this program, price bids could be submitted by customers or their representatives on a day-ahead basis, through the RETX system or otherwise. It may be appropriate to work with a single floor price bid for all hours of the day.

Alternatively, a customer could submit a standing floor price "bid" and leave it unchanged until further notice. Or additional flexibility could be provided for participants to submit a pre-set schedule of prices to which they will respond, and then, as the summer progresses, be able to modify their floor price within an appropriate period of time if they need to (e.g. up to day-ahead). Thus, if a load has certain constraints (i.e. can't shut down first week in August, but very willing to shut-down other weeks), they can give price signals accordingly.

The key element of this Option 3 is bidding a price in advance, rather than seeing estimated ECPs starting at 1800 the day before but getting paid at the ECP, wherever it clears in real time. This can be seen as a transition step toward the day-ahead market. In the SMD day-ahead market, the load reduction wouldn't be scheduled unless the clearing price to be paid is at least as good as the price bid. This characteristic is made available in this Option by setting the bid price as the floor. However, in this program approach, the bids don't need to be submitted on a day-ahead basis.[21]

In order to receive prices based on the value of reserves or capacity, each such price bid would be coupled with the quantity of load reduction. Once a quantity is bid, whether day-ahead or month-ahead or at another frequency, it becomes mandatory to achieve that level of load reduction, or a penalty is incurred. Given the complexity of reserve and capacity markets, one approach to paying for these values would be to determine in advance a "reservation" payment for the ability and willingness of a load to be interrupted. Instead, while pricing can vary widely, such compensation can generally be paid on a regular monthly basis to all eligible program participants.[22]

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[20] The current Type 6, Class 2 program provides a RTP payment, and is only called at $100 MWh expected price. That $100 MWh could be set as a floor price. Under Option #3, the floor could be set at the bid price for the load reduction.

[21] The floor price could be bid on a day-ahead or other basis through the RETX system.

[22] In some cases, customers can choose the level of credit at which they would be willing to curtail if called.

The existing Type 3 and 4 dispatchable load programs could also be adapted, integrated or streamlined into an Option 3 LR program. LR quantities could be bid into the appropriate ISO market by Load Serving Entities generally on behalf of end users with very large loads that have been telemetered on much the same basis as generators. In other words, the communication would be direct between with the control room and the load, rather than aggregated through the RETx system as in the Type 6 programs introduced this summer. Once bids have been submitted and accepted, the dispatch of these loads would be more under the control of the ISO in real time than is the case with the previous economic programs (which rely more heavily on market-based penalties as incentives to actually reduce loads according to day-ahead bids). ISO-NE's Type 3 and 4 Dispatchable Loads[23] are presently structured as follows:

- **Type 3**. "These dispatchable loads are bid into the Operating Reserve market. They are interrupted by the ISO when operating reserve is needed, and must be interruptible an unlimited number of times per year. Type 3 Dispatchable Loads are interrupted by the ISO on an as-needed basis when operating reserve needs to be activated. In order to qualify as Ten- or Thirty-Minute Operating Reserve in accordance with OP 8, Type 3 Dispatchable Loads must be interruptible within ten or thirty minutes, respectively. The loads are selected in the respective Operating Reserve market(s) based on their bid(s) as submitted in accordance with MRP 3, Appendix 3-B, Markets Data for Type 3 & 4 Dispatchable Loads. The loads that qualify for this classification must be interruptible an unlimited number of times per year. These loads may be interrupted at any time in response to a system contingency."

- **Type 4.** "These dispatchable loads are bid into the Energy market. Type 4 Dispatchable Loads are interrupted by the ISO based on $/MW bids submitted in the Energy market. The Participant submits the set of information necessary to form a bid (dispatch lead time, load available for dispatch, price and quantity information, etc.) in accordance with MRP 3, Appendix 3-B, Markets Data for Type 3 & 4 Dispatchable Loads. These loads are interruptible in accordance with minimum interruption duration characteristics established by the Participants. The loads must be available for interruption for an unlimited number of hours per year, and must be available for curtailment on one (1) hour or less notice. These loads may be interrupted at any time based on economics. During hours where the associated load is not interrupted, Type 4 Dispatchable Loads may participate in the NEPOOL Ten- or Thirty-Minute Operating Reserve markets, provided the loads are interruptible within ten or thirty minutes, respectively."

Option 4: Voluntary Response to Market Price

This program option corresponds most closely to the ISO-NE 2001 economic program. As can be seen this program can be used in conjunction with the SMD, since PJM is implementing such a program currently.

The price-responsive voluntary transactions are not an integral part of scheduling and dispatch, and do not set a MCP. They can be viewed as middle ground between emergency load reduction programs that provide reliability, and full-fledged economic programs that provide price elasticity to the demand curve. These programs can be seen as useful primarily during the transition to other economic program options under the SMD, or they could be maintained after the day-ahead market is introduced in order to provide customers with an option to implement additional reductions beyond those reflected in the day-ahead schedule.

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[23] OP14.

4.3 Summary Comparison of Economic Program Alternatives

4.3.1 Summary Matrix of Program Options Against Criteria

	Key Load Reduction Options: 'Economic' Programs			
	1	**2**	**3**	**4**
Title:	**D-A PCLB (No LR Bidding Program)**	**Load Reduction Bidding as Generation**	**Transitional Load Response Pricing**	**Voluntary Response to Market Price**
	Rating of Program Options by Criteria			
Reliability Objective	*Implicit penalties should provide good assurance of response*		*Strong assurance of LR when called*	Least assurance of response
Economic Objective				
Price	Potential to set clearing price.	*Potential to set clearing price as well as to reduce level of demand*	Does not set clearing price	Can not set clearing price
Elasticity	*Strong potential but indirect: mechanism for LSEs to aggregate LR*	*Provides direct role for customers or LRPs to offer prices & quantities of LR*	*Provides additional opportunities for certain customer segments to respond*	
1 **Quantity**	Only get LR offered by LSEs; may be used as financial hedge instead of actual reduction	Limited in S-T to customers with sophisticated systems &/or assistance	*Highest in S-T by attracting more risk-averse users & maintaining Type 4 Disp. Load*	Oriented primarily to customers that can function with limited notice in real-time market
2 **Quality**				
Measurability & Predictibility	Advantage that not dependent on baseline procedures. (Disadvantage that actual load reduction may not be known.)	High	High	Varies. ISO-NE program not predictible, but impact results knowable soon after program call
Diversification	Depends on LSE recruitment for its own arrangements	Limited by constraints on end user participation		
Equivalence to generation	No option to bid LR as separate product (in form of generation).	*Most equivalent*	Treated differently from generation	Treated similrly to generation but only in RT market
3 **SMD**	*Will be part of SMD*	Not part of SMD but likely to be a best practice in NERTO	Can be implemented outside SMD	Should be retained when SMD is implemented

	Key Load Reduction Options: 'Economic' Programs			
	1	**2**	**3**	**4**
Title:	**D-A PCLB (No LR Bidding Program)**	**Load Reduction Bidding as Generation**	**Transitional Load Response Pricing**	**Voluntary Response to Market Price**
	Rating of Program Options by Criteria			
4 **Settlement**				
Integration	*Highly integrated*	Integrated or Interative	Not integrated	Not yet integrated
Timeliness	Normal	Normal	Possibly slower	*High*
Transparency	High	Baseline clouds some transparency	High	High
5 **Feasibility and cost of Implementation for 2002 / 2003**	*No incremental costs over SMD.*	Highest cost option for ISO to develop. SMD in place is a pre-requisite	Already in Place. Unknown modifications for SMD.	High cost for particip's if 2-way R-T communicat. req'd.
6 **Flexibility**				
Transition	*Will be part of SMD*	This program approach is the most expensive to develop and has an uncertain response	*Plan to retain dispatchable load options clarifies future for participants.*	*Retention for SMD has advantage of continuity*
Diversity	No role for CSPs if not LSEs.	*Theorectically, all can participate*	Must be a load or pump storage	
Openness & adaptability of architecture	No role for CSPs if not LSEs.	TBD	N/A - use temporary side system, not integrated	*RETX system is opening up for connection of 3rd party systems to ISO link*
Simplicity	*Straight-forward*	Straight-forward, though CBL could lead to uncertainity in a load response bid	*Must provide demand curve for LR (far??) ahead of time*	*Provides option for demand response without bidding*

	Key Load Reduction Options: 'Economic' Programs			
	1	**2**	**3**	**4**
Title:	**D-A PCLB (No LR Bidding Program)**	**Load Reduction Bidding as Generation**	**Transitional Load Response Pricing**	**Voluntary Response to Market Price**
7 **Market-Based (from ISO perspective)**				
Minimize Uplift	*Low*	Given retail market environment need incentives to get substantial participation	Low	Given retail market environment need incentives to get substantial participation
Maintain Fairness	Yes	Yes, if incentive not used	Yes	No. Incentives and no significant penalty for failure to respond.
Cost & Time	*No additional investements needed to partcipate*	Metering and reporting will add small costs	*Mechanisms already in place*	Specilaized software / hardware may be needed
Incentives	*No incentive payments by ISO*	*Depends on estimates of incentive/penalty/risk levels*		Depends on options
8 **Participant Needs**				
Incentives	No incentive payments from ISO			R-T feedback, but late baseline adjustment creates risk
Efficiency	*No additional investements needed to partcipate*	Metering and reporting will add small costs	*Mechanisms already in place*	Specilaized software / hardware may be needed
Consistency	*Even-handed*	Weather senstivie loads may be biased by CBL	*Even-handed*	Weather senstivie loads may be biased by CBL
9 **Restructuring**				
Adaptability to retail conditions	No role for CSPs if not LSEs.	*CSPs can have role*	CSPs can not have direct role	*CSPs can have role*
Support to retail customer migration	*Could provide an indirect hedge to implement LR*	*Could be value added product / hedge for retailer*	*No additional support, as program is directly with load*	*Potential value added product / hedge for retailer*
Confidence in healthy market	Though could have added some elasticity to demand curve has not been sufficient to instill confidence	*If successful ,most integrated demand response for all customers may convince PUCs that mkt is mature*	*Substantial demand response from big loads may convince PUCs that LR will work*	*Quick reporting of impact may reassure observers*

4.3.2 Conclusions

In the assessment of the advantages and disadvantages of these options, two program types -- #1 and #4 -- were identified as valuable *parts* of a demand response program but unlikely to achieve sufficient participation without additional program options. The first option -- Price-Capped Load Bidding (PCLB) -- will be part of the day-ahead market under the SMD in any event, so it represents the base case for this assessment. Option #4, Voluntary Response to Market Price -- the real-time system that has been demonstrated by ISO-NE with RETX information technology -- would be appropriate to add to the demand response programs in NYISO and PJM as a "best practice" for the new Northeast RTO ("NERTO") and should probably be maintained by ISO-NE and folded into SMD. However, these program options #1 and #4 have disadvantages against the "Quantity" criterion. For this comparison, we address these two Options first:

- Option #1, Price-Capped Load Bidding (PCLB), will be part of the day-ahead market under the SMD in any event, so it represents the base case for this assessment. However, it is inherently a tool for Load-Serving Entities (LSEs) to bid large blocks of load reduction, and does not offer an opportunity for end-users to experience the desired hourly price signal directly or through another company than its commodity supplier. This limitation would be a particularly serious obstacle to achieving the needed load response under the limited development of the retail market,[24] because it would limit end users to the offerings of their local distribution companies. Since these utilities in most cases now buy and re-sell power at prices that do not reflect hourly market conditions, they do not have the means to capture the economic savings for themselves or their customers.

- Option #4, Voluntary Response to Market Price, while an important part of the ISO's load response "portfolio," is of interest primarily to customers who can respond in real time and can decide to respond before knowing where the price will settle. Even combined with PCLB, the first option, this real-time approach does not meet the need of most end-use customers for price certainty several hours in advance of the time the load reduction is to take place.

- Option #2, Load Reduction Bidding as Generation, is the key element of an economic demand response program, because it best meets the need of most end-use participants to specify the price at which they are willing to reduce load by a specified amount, and it allows the end-users sufficient time to reduce load after learning that they will receive the price they need (or a higher one). The best current example of such a bidding program for the day-ahead market is New York's "Day-Ahead Demand Response Program" (DADRP), and it is likely that such a program will eventually emerge as part of the market design for the NERTO. However, for customers without experience of real-time pricing and day-ahead bidding, it is difficult to learn the mechanics of such programs. Also, if there is a risk that penalties could more than wipe out each day's benefits, many customers will not participate unless they have a load reduction provider that can limit that risk.[25] This is particularly important in load response programs that utilize a baseline to determine the quantity of load reduction for which the customer is paid, as this "credited" load reduction may vary substantially from the actual load reduction and dampen or eliminate the customer's incentive to respond to price signals.[26] These program design challenges will require time to sort out, and time may also be required for customer education and training. In view of the very limited customer participation in NYISO's day-ahead bidding demand reduction bidding program during the summer of

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[24] The retail market will become more active by the time of the SMD introduction, assumed to be mid-2003 for purposes of this project. However, XENERGY expects that most of New England's load will likely remain on the utility's default service through the 2003 - 2004 period

[25] The customer's perception of this risk may also depend upon the contractual allocation of responsibility for the steps in the load reduction process -- notification, load forecasting, computation of baseline effects, monitoring and control of loads, etc. – between the end user and the Load Reduction Provider.

[26] Baseline methodologies vary, based on perceived tradeoffs between accuracy and fairness and other factors. The ISO-NE baseline approach, with an adjustment for weather-sensitive loads based on the most recent 2 hours, is currently under consideration by NYISO as an improvement over their 2001 baseline methodology.

2001, it would seem that ISO-NE could consider focusing the available system development resources for SMD on incorporating its existing "Option 4" program into the SMD real-time market, and evaluating the impact of the combination of Options 1 and 4. Then, the day-ahead Option 2 could be introduced into New England along with the rest of the features and systems of the NERTO.

Therefore, a combination of Options 1, 2 and 4 may eventually be developed to cover different market needs. However, it is not clear how long it will take before this combination will achieve an acceptable level of demand responsiveness. Critical questions remain unanswered to date about ways in which different end-use customer market segments can be engaged in dealing with hourly price signals. Most end users are not interested in "playing the spot market" for electricity or any other commodity. Until retail markets are more fully developed, no one will know from experience what arrangements will be successfully introduced between competitive suppliers and their retail customers to share and allocate the benefits, costs and risks associated with hourly prices in load management programs. Therefore, if it is an objective to achieve participation in demand response programs without waiting for the retail market to develop, then it would be appropriate to consider adding additional features of price certainty and stability to the SMD's demand response programs on a transitional basis.

- Option #3, Transitional Load Reduction Pricing, has been developed as a transition approach to respond to this concern. It could be implemented prior to the SMD, and could co-exist with the SMD until no longer needed, at which time it could be phased out. One main feature of such a program option would be the provision for end-use customer bidding of prices and quantities of load reduction. However, such LR bids would not be integrated into resource scheduling and would not set the ECP or LBMP. After the initial unit commitment, the ISO would select bids that are below the expected ECP – perhaps below it by a specified percentage factor to limit financial risk to the ISO. The ISO would then (a) notify such customers that they must reduce load the next day and (b) guarantee that each customer will be paid its bid price if it does so. This bid price would be expected to be below the ECP, so this approach diverges from the principle of sending accurate hourly price signals. Nevertheless, this would give customers the needed certainty in advance as to its price and as to a pre-specified reduction period (e.g., 4 hours). This Option #3 could incorporate, or could be developed from, the existing ISO-NE energy-price-based Type 4 Dispatchable Load.[27] The systems integration needs are much lower for this Option #3 because load reduction bids would not participate in setting the ECP.

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[27] See below for one way to introduce such an approach in 2002 as a "Class 3."

4.4 Emergency Load Reduction Program Options

Emergency programs range from traditional interruptible rates to the 2001 Class 1 Demand Response Program, which compensates users for reducing consumption at ISO-NE's direction. While ISO emergency load response programs increasingly utilize actual hourly market prices to compensate customers, they are all based on "calls" to customers by the ISO at particular times when capacity is dangerously tight.

Emergency and economic LR programs are interrelated. Customers should generally be able to be able to participate in both types of programs on different days, or for different periods of the same day. If a customer has signed up for both programs, and they are called or available for the same time period, then the emergency program should take precedence for both compensation and penalties.

These "Emergency" load response program options not only help ensure system reliability but have the secondary effect of affecting market prices. The emergency programs will have a direct impact on the spot prices, and may cause alternation in bid strategies that could affect multi-settlement (e.g. day-ahead) bidding.

A. Voluntary Price-Responsive Emergency Programs

This type of program is based on ISO dispatch in emergency conditions, but is distinguished by the lack of penalties for failure to respond. A prominent example is the 2001 NYISO EDRP program.

Also, in NE, curtailment is voluntary for Type 5 Interruptible Loads even when OP 4 Actions are implemented. The Type 5 "program" is described as follows: "The ISO requests curtailment of these loads when OP 4 Actions are implemented, after all Type 2 Interruptible Loads have been interrupted. Compliance with the request to curtail is voluntary. For administrative reasons, Type 5 Interruptible Loads must be available for utilization a minimum of four (4) hours a day and can have a maximum notification time of four (4) hours."

B. Mandatory ISO Curtailment with Market Pricing

The existing ISO-NE "Class I" Demand Response Program (for Type 6 ISO-NE Interruptible Loads) falls into this category because the load reductions are mandatory whenever the customer receives "dispatch" instructions (30-minute notice from ISO-NE), and because failure to curtail load when notified by ISO-NE subjects the customer to penalties.[28] The payments that customers receive are based on market clearing prices for (a) the actual energy they save during events and (b) the value of Thirty Minute Operating Reserve (TMOR) for their ongoing participation in the program.

C. Mandatory Curtailment with Reservation Pricing

This category applies to programs that pay loads for interruptions or for their willingness to interrupt, but not based directly on market prices. Instead, while pricing can vary widely, compensation is often administratively determined in advance, much of which is generally paid on a regular monthly basis to all eligible program participants.[29]

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[28] "A Class I Customer that does not reduce demand during a Load Response event will lose its TMOR payment beginning with the start of the month during which the event was called or to the last actual interruption. In addition, on a moving forward basis, that Customer will no longer receive TMOR payments. However, if that Customer is able to fully comply with a subsequent call by ISO-NE for demand reduction, TMOR payments will be reinstated from that point forward. … A Class I Customer that is able to partly reduce demand during a Load Response event, but is unable to reduce the full amount of its agreed-upon exception with the ISO, will be paid a reduced TMOR amount, on a going forward basis only…." -- Load Response Program Manual, page 20.

[29] In some cases, customers can choose the level of credit at which they would be willing to curtail if called.

Examples include ISO-NE's Type 2 Interruptible Load program:[30] "These loads are interrupted by the ISO during capacity deficiencies when OP 4 Actions are implemented. Type 2 Interruptible Loads are divided into three categories based on their notification time prior to interruption ("one (1) hour or less," 1 through 4 hours, and twelve (12) hours or less). These categories impact the number of times the loads must be available for interruption per month or year. "

4.5 Load Reduction Program Options for 2002, Prior to SMD

Before the SMD is implemented, program option 1 (PCLB) will not be feasible, nor will be any of the features of the other programs that depend on the formal day-ahead market. The following table presents the key short-term options by drawing on elements from two of the economic load reduction program options discussed above (#3 Transitional Load Reduction Pricing and #4 Voluntary Response to Market Price). These options for the 2002 time frame are defined here in terms of:

- mandatory or voluntary response,
- frequency of metering of actual LR quantities,
- incorporation of bidding features (in the pre-SMD context), and
- pricing terms.

The Class 1 and 2 categories are maintained from 2001, and a Class 3 is added which is an interim form of program option 3 above, "Transitional Load Reduction Pricing."

The 2002 programs in the second column "b" would be based on polling each customer's meter at the end of each day rather than in near-real-time through the RETX system. As a result, such load reductions would get no TMOR, since operators cannot use it for that purpose.

The new Class 3 category is based roughly on the "Transitional Load Reduction Pricing" program option 3 as described above. Class 2b, the "Voluntary Price Bidding Program," uses a similar "floor price" concept.

These 2002 options are structured here to provide payments for capacity as well as reserves when appropriate for load reductions. Measuring and verifying the quantity of load reduced on a daily basis is still more than a month faster than under the NYISO programs this summer. In addition, the data could be polled in near-real-time if needed, which could be feasible for a small number of large loads. In addition, such loads could be contacted directly to request additional load reduction in an emergency. As a result, there may be a basis for paying ICAP. While ICAP is handled primarily through a bilateral market LR should probably be paid the standard deficiency penalty.

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[30] OP14.

Short-Term Load Reduction Program Options

Program Type	**Real Time Metering** (via RETX)	**End of Day Polling** (via interval telemetering)
Emergency (mandatory response in events called by ISO)	**Class 1a** (“Emergency Demand Response Program”) **Current Class 1 plus ICAP, penalty & floor** • TMOR • ICAP • No Energy Payment • Penalty (pro-rata up to TMOR and ICAP benefits to date)	**Class 1b** (“Emergency Demand Program without **Class 1a minus TMOR** • No TMOR • ICAP • Energy Max of ($500 MWh, ZLMP) • Penalty (pro-rata up to ICAP benefits to date)
Voluntary Response to Market Price	**Class 2a** (“Voluntary Price Response Program”) **Current Class 2 plus floor of trigger price ($100)** • No TMOR • No ICAP • Energy: Respond as current Class 2 and get max (trigger price, ZLMP)	**Class 2b** (“Voluntary Price Bidding Program”) **Current Class 2 plus floor of standing bid price** • No TMOR • No ICAP • Energy: Respond whenever estimated ZLMP > Floor Price and get max of (Floor Price, ZLMP) on measured LR)
Transitional Load Reduction Pricing (bidding of LR price and quantity)	**Class 3a** (“Transitional LR Bidding Program”) **Class 3b plus reserve** payment for mandatory response to RETX notification • ICAP for availability of LR in standing bid Choice between: o TMOR, or o Energy: respond when notified that estimated ZLMP > Floor Price and get max (Floor Price, ZLMP), or a “day-ahead floor” could be bid • Penalty same as Class 1a	**Class 3b** (“Transitional LR Bidding Program without Reserve”) **Class 2b plus ICAP** • ICAP for availability of LR in standing bid • No TMOR • Energy: respond when notified that estimated ZLMP > Floor Price and get max (Floor Price, ZLMP) on bid (committed) LR quantity (just ZLMP on any additional LR) • Penalty same as Class 1b

5. LOAD REDUCTION PROGRAM INCENTIVES

LR programs have in recent year(s) incorporated incentives to encourage program participation in various ways and for various reasons. Generally these incentives have been based on market prices at the time of each load reduction. A critical defining characteristic of any program is the extent to which it includes above-market pricing or other incentive payments provided by the ISO.[31] In this section, we assess the options for the incentive components of LR programs.

This section begins by reviewing the economic benefits that may justify the type and scale of a LR program. We then review the conditions in the region's retail power markets, since they affect the behavior of customers in the target markets for demand response programs and determine in part the types and levels of incentives that may be required to change that behavior. We then distinguish between the different business arrangements through which end-use customers can be offered price responsive load management services, together with or independent from electricity supply. Finally, we assess the implications of these market conditions for pricing strategies to meet the objectives of Load Reduction Programs.

5.1 Economic Characterization of Load Response benefits

This section reviews the potential benefits of demand elasticity in the market and the potential benefits of programs to encourage load response. LR programs and incentives have been justified by the "consumer surplus" benefit that they create when clearing prices in the ISO-administered market(s) are reduced from the levels they would have reached without the load reduction induced by the incentives in the ISO program. While no estimates of these benefits have been prepared for this report, ISO data and previous studies indicate the potential for substantial benefits. These benefits would be much lower when a region is experiencing high reserve margins, but then they would also provide the value of reserves or insurance against the unlikely disruption that could carry a high cost.

<u>Effect on Price Spikes</u>

1. In the short-term, economic load response programs provide insurance (probabilistic consumer benefits) against the occurrence of price spikes.
2. Related, economic load response may not decrease wholesale prices in conditions so tight that prices have already hit a price cap. If wholesale prices are at their capped rate (or at any shelf in the supply curve), the demand curve may not move far enough to the left to move the intersection of demand and supply out of the influence of the price cap.

   Figure 1 shows just such a situation. The supply curve is made up of discrete step bids. For this example we assume a large step at the $1000/MWh price cap[32], though this large plateau may happen at any price point. The initial supply-demand equilibrium without price responsive load is at point ① with the vertical demand curve assumed for simplicity[33]. When load is allowed to respond to prices, a different demand

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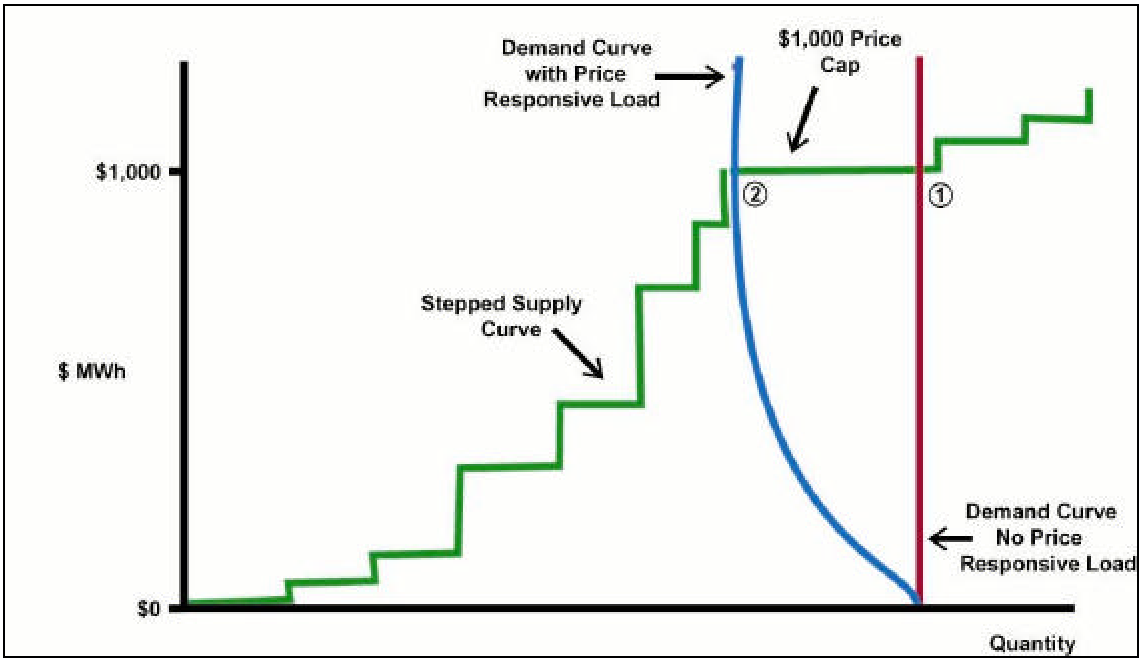
[31] It is understood that pricing between market participants, end-use customers and other market players may vary widely and is to a great extent free to take various different forms outside of the particular rules of the ISO markets and programs

[32] Because of the cost of, logistical constraints, or physical limitations of transferring power out of one market into another, many bids are likely to be pent-up at the price cap.

[33] The demand curve is not actually vertical, but its depiction is reasonable, as consumers will act as though they have a vertical demand curve because of the lack of retail price signals. The lack of variation of retail price signals are caused by retail market policies that present consumers with an invariant retail price (e.g. a fixed rate of 10 ¢/kWh - this is very common for residential customers and becomes less common for the larger non-residential rate classes), and lack of retail ability to take advantage of high wholesale prices (e.g. lack of Price Responsive Load programs). Thus consumers will purchase energy consistent with the invariant retail price signal and therefore without regard to the wholesale prices. See Point 7 for further discussion.

curve is applicable. The new demand curve slopes to the left (i.e. has some elasticity) for the fraction of the market that is willing and able to respond to market price signals. This new demand curve intersects the supply curve at point ②. Nevertheless in this example the decrease in demand is not enough to push the equilibrium off the $1000 / MWh price cap shelf, and the demand response does not decrease the market-clearing price.

Figure 1
Possibility of No Price Change with Demand Response



Note that in practice a supply shelf can occur at any price point. One example is a peaker plant of 300 MW that bids in a price of $150/ MWh. If the original supply-demand equilibrium intersected the very right edge of the shelf, then more than 300 MW of demand reduction would be needed to reduce the market-clearing price. Conversely, if the original supply-demand equilibrium intersected the very left edge of the shelf, only a very slight demand reduction would be needed to reduce the market-clearing price to the next most expensive source.

3. The large likelihood of extreme prices is a natural outgrowth of the hockey-stick shape of the supply curve. If the demand is high enough relative to supply (the demand curve is far enough to the right), then high prices will generally occur. Price caps may moderate extreme price spikes. Load response can make price spikes less frequent or less likely in the short-run (see next point for long-run perspective).

4. In a dynamic long-term world, one effect of load response programs is to send lower price signals to the market, leading to lower levels of new plant construction, thus letting the supply match the lower level of demand. Assuming the supply curve retains its hockey-stick shape, the market will once again be prone to price extremes and spikes. The direct long-term effects on price spikes of added elasticity of demand curve is therefore difficult to anticipate.[34].

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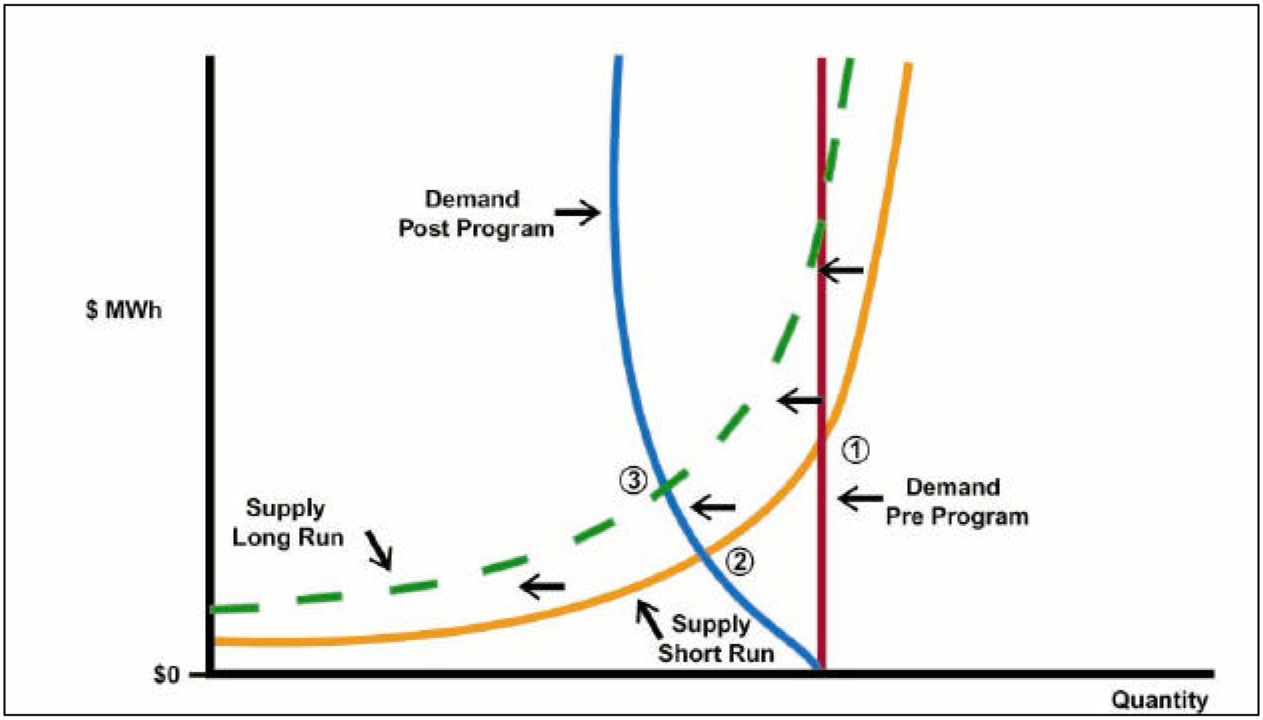
[34] This is not to say that load response programs do not have other long-term benefits, including the reduction in generator market power.

Figure 2 shows an example of the dynamic environment. The demand-supply equilibrium pre price responsive load opportunity is shown at point ①. The introduction of opportunity for price responsive load results in a new demand curve and in a demand-supply equilibrium at point ②. In the long run generators will be less willing to invest and/or maintain plants in this market as they are now getting a lower price because of the demand response. This will result in a relative decrease in supply, shifting the supply curve to the left, and the demand-supply equilibrium will move to point ③, a higher price than point ②. Thus the long-run market-clearing price reduction likely will be a fraction of the initial price reduction caused by the introduction of market price load response.

Figure 2
Price and Quantity Response, First in Short Run with Potential for Price Responsive Load Just Initiated, and Then in Long Run



5. The "appropriate" level of system reliability and amount of insurance to avoid price extremes is, of course, a public policy issue. If public policy choices are made to avoid or mitigate price spikes / extremes, especially if the price caps[35] are kept in place explicitly or implicitly,[36] then market reserve payments (e.g. operating reserve payments, or some variant of ICAP payment) to generators / load response participants are needed to signal the "appropriate" investment in both generation and load response.[37]

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[35] Wholesale price caps dampen investment in both generation and load response, as potential investors cannot garner the full economic rent available to them.

[36] For example, an implicit price cap would be the effect of subjecting very high bids to intense scrutiny with likely rejection / revision.

[37] *Installed Capacity Requirements and Price Caps: Oil on the Water, or Fuel on the Fire?* Benjamin F. Hobbs, Javier Inon, and Steven E. Stoft. The Electricity Journal, July 2001, p 23.

6. It is likely from a public policy perspective that before wholesale price and offer caps can be removed, a market will need to have acceptable level of reserves from a policy (not an economic) viewpoint, appropriate reserve payment mechanisms, and elasticity in the demand curve[38]. In other words if these prerequisites must be met from a policy makers perspective then price caps will be removed only when they are very unlikely to be employed.

Transfer of Wealth

7. The decrease in prices caused by economic load response is partially a transfer of resources -- a consumer benefit, and partially a societal benefit. Figure 3 provides an alternative viewpoint of the interaction between retail markets, wholesale markets and price response programs. Because of regulatory or legislative decisions most retail markets provide most consumers with hourly invariant prices (e.g. prices that do not vary by the time of day, though they may vary by season, or by load factor via demand charges). In Figure 3 we assume that the retail price that confronts consumers ($P_{RETAIL0}$) is lower than the wholesale prices ($P_{WHOLESALE0}$). Given this retail price signal, consumers will demand Q_0. This quantity demanded will result in a wholesale price of $P_{WHOLESALE0}$. In many cases the same policy that dictates fixed retail prices also dictates that the difference between wholesale prices and retail prices is assessed as deferred costs[39], costs that consumers will have to pay for in future years, and is defined by the area ①③$P_{RETAIL0}P_{WHOLESALE0}$.

   The economic inefficiency is caused by the divergence in prices between wholesale and retail, which leads to more quantity being demanded, Q_0 than is economically efficient, Q_1. The size of Dead Weight Loss (DWL) is a function of the difference between Q_0 and Q_1.

   The divergence in wholesale and retail prices can be closed in various ways, the two most relevant here are: A) The pass-through of real-time prices (RTP), and B) The implementation of a price responsive load program (PRLP). Theoretically, in both cases quantity demand will decrease from Q_0 to Q_1 and wholesale prices will drop from $P_{WHOLESALE0}$ to P_1. The area ①②③, the deadweight loss associated with a less than optimum market structure prior to RTP/PRLP, defines the societal benefit from this change in price signals.

   If RTP or PRLP is used to convey retail price signals then another welfare effect will be a transfer of wealth of the area ①②$P_1P_{WHOLESALE0}$. Note this may be viewed as transfer of wealth back to consumer from suppliers, as suppliers were reaping "extra" benefits from the non-optimum price signals that caused excessive consumption over the most economically efficient state. If an RTP program is used then wholesale and retail prices will converge at P_1, and the deferred costs will drop to zero. If a PRLP is used to convey retail price signals then the wholesale price will still drop to P_1, but the retail price will remain at $P_{RETAIL0}$. Therefore, deferred costs will not disappear but decrease to the area ②④ $P_{RETAIL0}$ P_1.

   Implementing a PRLP to provide price signals (instead of RTP) causes at least one more effect. Because of the fixed retail price hedge still remains, consumers must be incented to participate in the PRLP. This incentive, that may be split with a facilitator (e.g. the consumers' load serving entity, or a curtailment service provider) of the PRLP program, is defined in some RTO programs by the area ②⑤Q_0Q_1, the market clearing price in the wholesale market multiplied by the load that responded in the program. This payment has to come from somewhere, and if a RTO with a power exchange is running the program it is likely the cost of this incentive is assessed as "uplift" - higher prices charged on energy cleared through the market.

   If retail prices are above wholesale prices, then Q_0 will be below Q_1. A PRLP will not provide the appropriate price signals for consumers to consume more, which is what is needed to get to the

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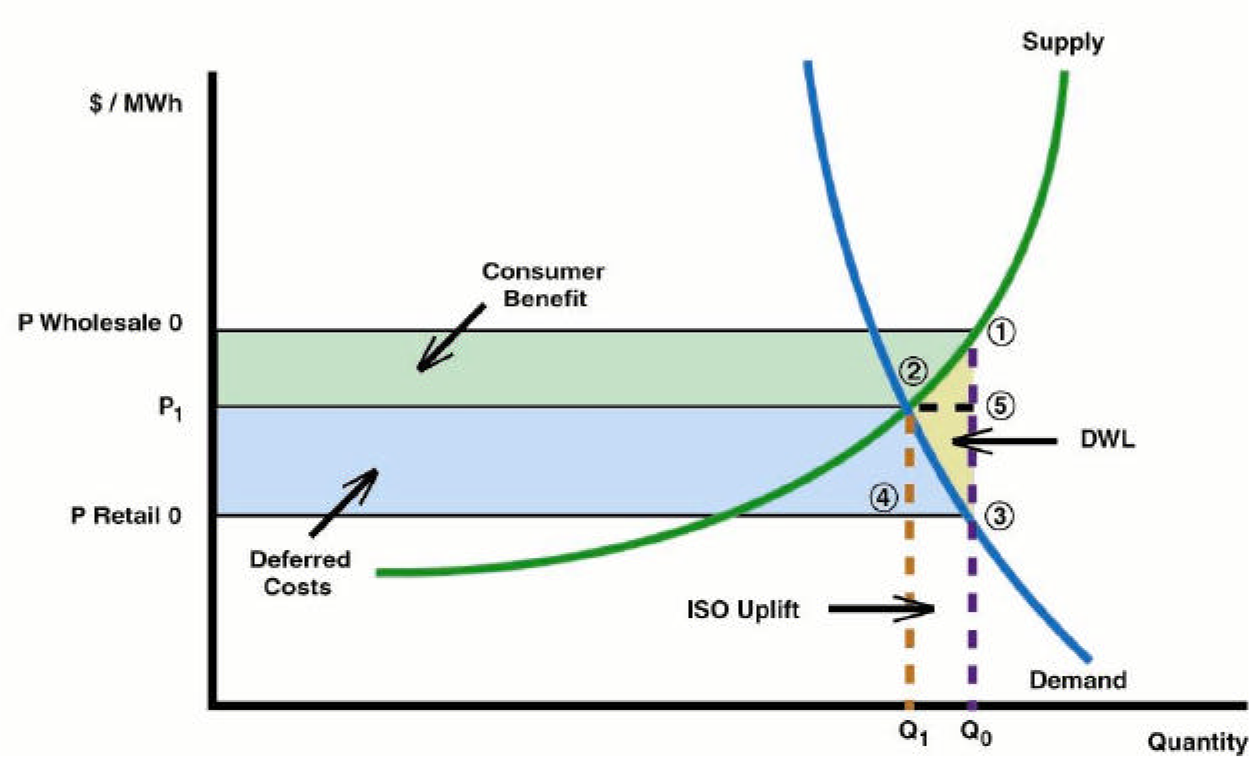
[38] Of course, price caps aren't designed to keep reserve margins up, but in fact are known to have the opposite effect.

[39] It is usually the distribution utility that will be the money middleman for this deferment. If the utility has sold off generation, the wholesale suppliers still get paid immediately in full, and the utility gets the paid the retail price, and the deferred costs.

economically efficient state. Thus, the PRLP will not be effective when retail prices are above wholesale prices. This inefficiency may be mitigated when retail choice is available. In this case a competitive retailer may offer the consumer lower prices to which the consumer would respond with increased consumption.

Figure 3
Welfare Effect of Price Responsive Load



- The immediate benefits associated with this transfer of wealth accrue directly to the portion of the market that is procuring energy through the ISO day-ahead or real-time markets. Benefits may accrue indirectly after a lag to those with bilateral contracts.

8. Price spikes in the ISO clearing markets will become less important to market participants, as more power products and services are tradeable and hedgeable. Electric futures markets are for the most part in their infancy, and hedging opportunities are expensive. Thus, as hedging instruments mature, so will confidence in the wholesale market.

Societal Benefits

9. The primary long-term societal benefit of load response is not necessarily price spike mitigation, but is rather the lowering of average costs; because load reduction competes against additional generation, and only wins if curtailment is cheaper than generation as a long-term investment.
10. Nevertheless, both short and long term load response programs will provide societal benefits by dampening market power. Generators that are otherwise very familiar with their bidding environment, their competitors and the regional "bid stack" will have more difficulty gaming the market if they also have to deal with an elastic demand curve.
11. As noted, the introduction of price responsive load may have various effects: It will increase the elasticity of the demand curve, and may also increase the elasticity of the supply curve by mitigating supplier market power. These curve-shape changes may have another impact: it may provide more gradual warnings of

impending high prices rather than the relatively abrupt price jumps which are a function of the inelastic demand and hockey-stick supply shaped curves. Given the lumpiness in building new generation and investing in new load response capability, these curve-shape changes may give some time for investment to respond to the instantaneous changes in prices without being as socially disruptive.

12. Benefits may accrue from load response programs through the opportunity to decrease investment in distribution and transmission infrastructure as demand peaks are dampened.

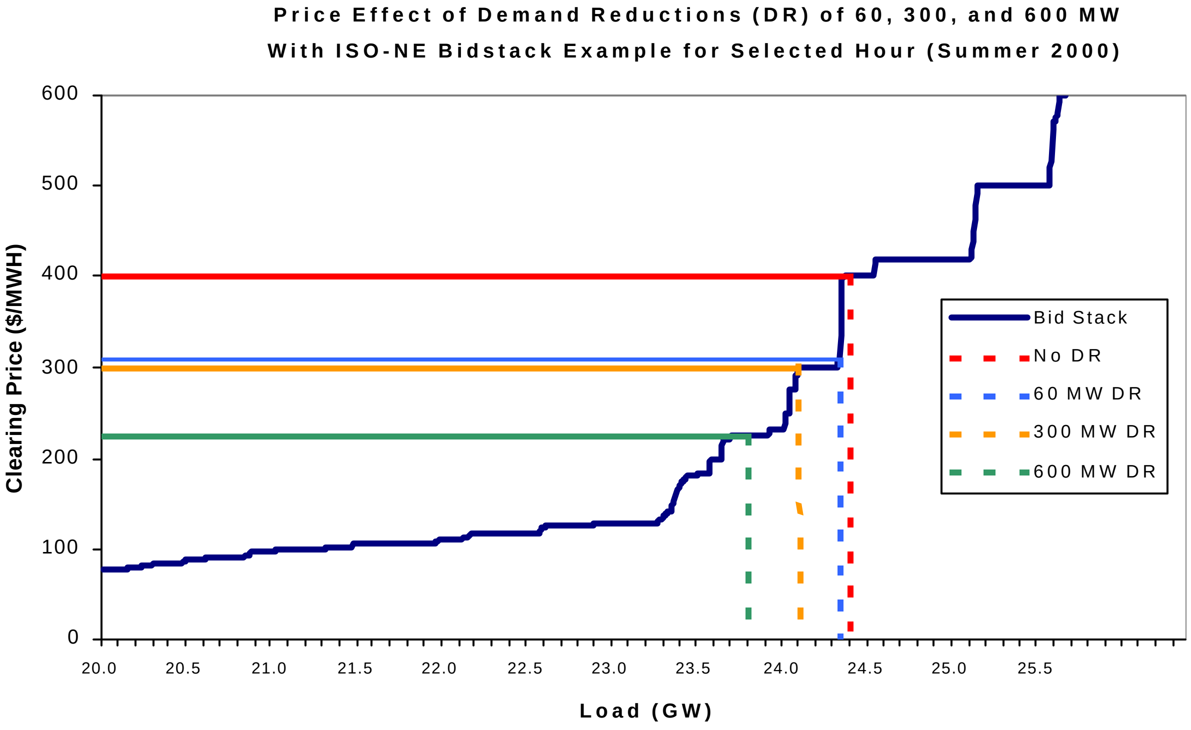
Secondary Effects

13. "Emergency" (or reliability-oriented) load response programs not only help ensure system reliability but also have the secondary effect of affecting market prices. The emergency programs will have a direct impact on the spot prices, and may cause alteration in bid strategies that could affect day-ahead bidding in the SMD multi-settlement system.
14. Similarly, economic load response programs have the secondary effect of improving system reliability.

This discussion underscores the complexity of the impact of LR programs in the marketplace. Substantial economic analysis would be required to estimate the magnitude of these benefits for future market scenarios, or to attribute these overall benefits to the particular type and level of a program incentive. However, it is possible to further illustrate the potential magnitude of some of these potential benefits. The remainder of this section uses data that is publicly available to show in very rough terms the way in which the clearing price may be affected by a given quantity of load reduction.

The most essential piece of information for quantifying the benefits of demand reduction is the supply curve, how much load is available to the market at what price. Day-ahead bid stacks from July and August 2000 provide a reasonable facsimile for purposes of this illustration of the market faced in late July and early August, 2001. While there will be differences in the shapes of the supply curves, this representative 2000 bidstack is sufficient for the present purpose of characterizing the benefits of demand reduction.

The Figure below provides an example bidstack scaled to approximate market load for summer 2001. Price is directly determined by load as with the "No DR" line at 24.5 GW which indicates a clearing price of 400$/MW. Demand reduction is understood in graphical terms by shifting the demand curve to the left consistent with the amount of load reduced. The chart includes lines indicating demand reduction of 60, 300 and 600 MW. The value of demand reduction is completely dependent on the shape of the supply curve in the immediate vicinity to the left of actual load.



This Figure provides an example of how a smaller reduction can have a far greater marginal effect on prices. The first 60 MW of reduction, essentially the size of ISO-NE DR programs in summer 2001, lowers the clearing price by $90 to $310 while increasing that reduction to 300 MW only reduces the price an addition $12 to $298. On the other hand, with a stepped supply curve such as this, there are also loads for which a 60 MW reduction in demand will provide no price relief at all. In some cases even the larger reductions would provide no price relief though as load reduction increases, the chance of remaining on a price plateau diminishes to zero.

Consumer benefit can be roughly measured by calculating the savings, as a result of price reductions, on the remaining load. This value can be measured two different ways. At present clearing prices only affect the energy spot market, so price reductions should only be applied to energy purchased on the spot market. Alternatively, since the concept of demand reduction is based on the idea of a fully competitive market, it is interesting to calculate the value of demand reductions as if the full market faced the clearing price. For this analysis, the energy traded on the spot market is considered just over 20% of the full market. This is the average percentage for peak hours during the months of July and August, 2001.

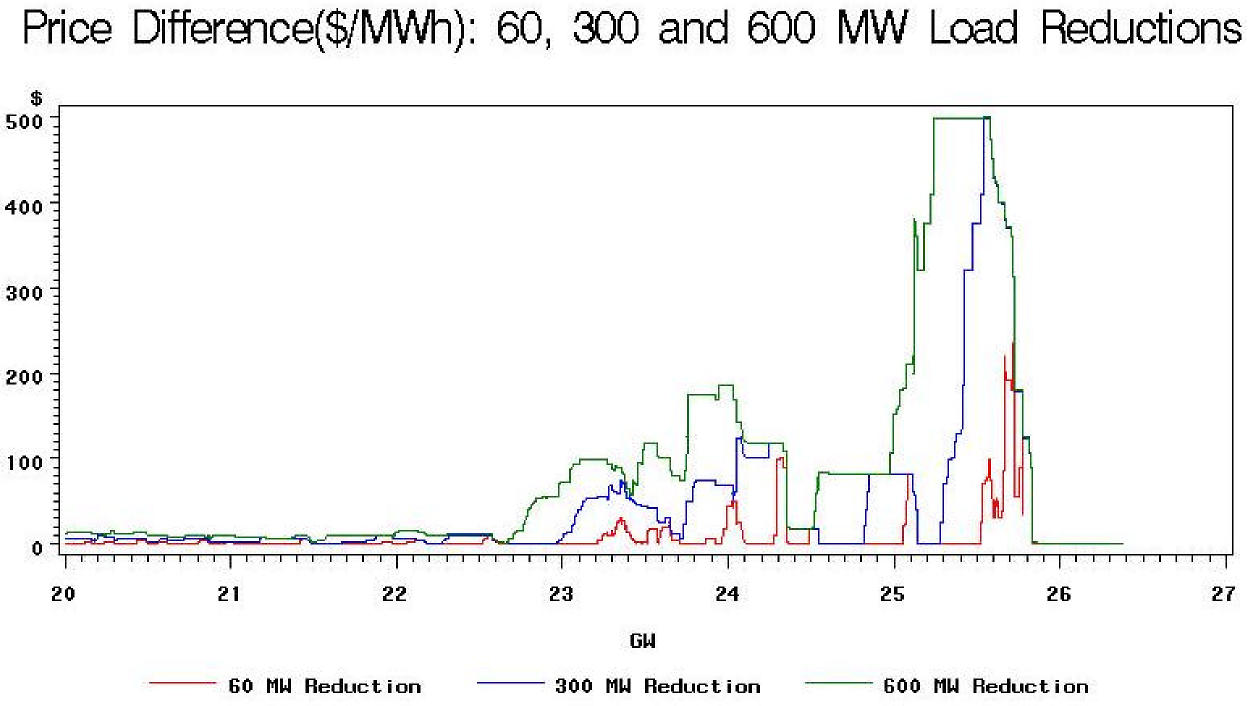
The value of demand reduction is represented in the Figure above by the area between the price line representing no demand reduction and the price line after reduction. Assuming a vertical demand curve, a rectangle is formed with the right end at the reduced load level and the left end determined by how much load is affected by market prices.

Clearly, position on the supply curve is essential to quantifying the benefits of demand reduction. One simple way to quantify the value of various levels of demand reduction is to give an equal probability to each starting load level and determine the average value of each level of demand reduction. Referring again to the Figure above, this is achieved by shifting the four price/load lines from left to right at 1 MW intervals while noting the changing relative prices.

The following Table illustrates the results in terms of the average price change and consumer benefit values using the actual hourly loads for the eight peak hours of the five days on which ISO-NE actually implemented demand reduction programs. This table assumes that the 60, 300 and 600 MW reductions brought the loads down to these levels. These actual load levels should, in fact, reflect the actual reduction of approximately 60 MW.

Average Price Difference and Value of Consumer Benefit: Actual Peak Hour Load, 5 ISO-NE 2001 DR Days				
Amount of Demand Reduction(MW)	Average Decrease in Price Due to DR($)	Average Value of DR($): Spot Market Price Reduced	Average Value of DR(4): Full Load Price Reduced	n
60	$16.80	$84,109	$404,832	40
300	$48.05	$237,357	$1,142,448	40
600	$79.73	$389,929	$1,876,807	40

These price differences and benefit values are only estimates, since the bidstack used here is only an approximation. The following Figure plots the price reduction for each hypothetical demand reduction.



The data used for analysis was obtained from ISO-NE at:

http://www.iso-ne.com/historical_bid_data/,
http://www.iso-ne.com/forecasted_vs_actual/,
http://www.iso-ne.com/historical_market_data/energy_spot_market/

This review of potential economic benefits of load response is one starting point for the assessment of the proper role of incentive payments in program design. It is nevertheless important to consider that LR programs such as those discussed in Section 4 above represent just one category of program approaches that can achieve some of these economic benefits. Others types of approaches include traditional interruptible programs, regulated TOU or RTP rates, and a variety of DSM programs.[40] The ISO need not solve all load response problems. Consumers will be best served by a variety of programs and services in the marketplace.

5.2 Retail Market Context

The development of retail energy markets has been slow and uneven, and there is little consensus among market players and observers in their expectations for future development. This section address the retail market context, which affects the behavior of customers in the target markets for demand response programs and determines in part the types and levels of incentives that may be required to change that behavior.

Retail market conditions are among the most important considerations for the design and functioning of ISO LR programs, partly because the existence of fixed-price S.O./default service “generation credits” dampens the incentive of most customers to incur significant startup and transaction costs and/or accept price risk in order to capture the benefits of shifting loads in response to hourly price patterns. The lack of appropriate price signals is particularly strong when generation credits are below wholesale prices, as customers have little or no reason to give up this cheap fixed price option. When generation credits are above or nearly equivalent wholesale prices, competitive suppliers may be able bundle LR to enhance the economics of an expanded package of services. For example, such a supplier could offer an end-use customer lower fixed rates in order to have rights to call for a certain number of load reductions under pre-specified parameters.[41]

This retail generation credit rate structure will continue for a number of years throughout New England. What default rate structure, if any, will be instituted after the various retail competitive restructuring transitions periods come to an end is uncertain.[42] Concurrently with a retail environment that is not optimum for instilling demand price elasticity there is the urgency of developing liquid wholesale markets with appropriate price signals and adequate demand price elasticity.

A classic chicken-and-egg problem confronts market regulators. While moving to a retail market where wholesale market prices are passed through to end users would increase price elasticity of demand, this is not likely to happen soon. In the current environment state regulators are reluctant to phase out fixed-price S.O./default service (the actions that would improve demand price elasticity) until they see an effective wholesale market that includes load response functionality to prevent price spikes and extreme volatility.

Given these market realities the next sub-section describes five prototype configurations through which load reduction services and commodity generation supply can be provided to end-use customers. These configurations determine the role and impacts of financial incentives that may be used to encourage demand response by end use customers.

In order to clearly describe the different relationships between market players, we make reference to the following diagram. It illustrates the potential flows of price and quantity information from generators (1) to a competitive retail supplier (2), which also receives data on load levels from the customer’s Electric Distribution Company (EDC)

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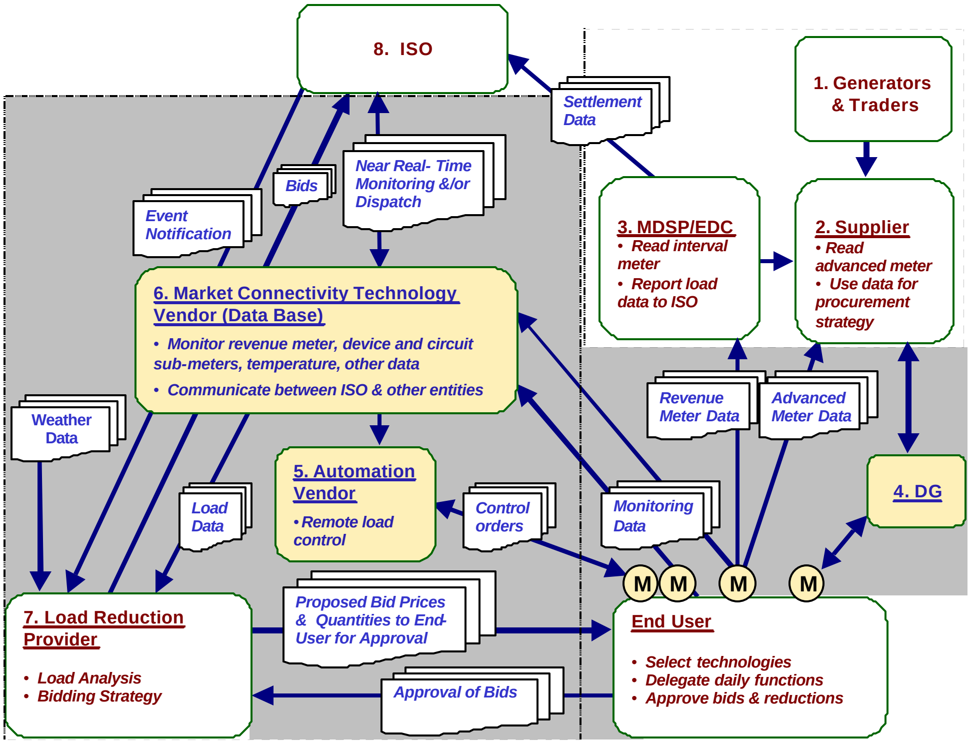
[40] A matrix summarizing examples of the main types of programs that are in place inside and outside New England is provided by KEMA Consulting as an accompanying deliverable.

[41] Such a contractual implementation of a load response service would follow a successful model set by traditional utility interruptible rate programs.

[42] The successful implementation of economic demand response programs by ISO-NE may be a critical factor in laying the groundwork for state regulators to remove artificial mechanisms to protect customers from market prices.

or competitive Meter Data Service Provider (3 – "MDSP"),[43] which in turn sends load data daily to the ISO for settlement. Additional load data may be available directly from advanced metering at end user facilities (each meter or sub-meter is designated by a circle with an M in it). Distributed generation (4) may also be used by the supplier and the customer to provide load response or other generating capabilities.



Meanwhile, the end user may have acquired equipment for remote monitoring -- and perhaps also remote control -- of loads and load reductions from a vendor of end-use EMS systems, building automation systems, sub-metering or related hardware and software (5). This equipment may have been installed without consideration of ways to use it for demand response, so the end user or one of its service providers may have subsequently contracted with a Demand Response Technology Vendor (6), to collect load and other data from the monitoring equipment into a database, together with price data, event notification and other information from the ISO (8) and the wholesale market. This technology may also be capable of transmitting price and quantity bids from the end user or its Load Reduction Provider (7) to the ISO (8).[44]

The section below discusses some of the ways in which these various relationships may change depending on the player(s) that are providing commodity electricity, on the one hand, and those on the other hand that are providing services for price responsive load management and demand response.[45]

Implementing load reduction is not an easy process for end-users, as the complexity of this chart may suggest. As noted above, end users may have to make investments in hardware, software, and training to be prepared to implement load reduction. Even for companies or consumers that have already made these some of these investments for other purposes – such as to automate processes for quality or convenience –some incremental costs

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[43] The dotted lines around these three players indicate that these functions may be combined in one vendor.

[44] Most retail customers will not interact directly with the ISO but go through an intermediary, a market participant.

[45] Not all of the entities are shown in the subsequent illustrations, but the same numbering is used throughout for each type of entity.

will be required to participate in load response programs, so the customers will look for incremental revenue or savings to cover administrative and operating costs or to help amortize the investments.

Currently there are two major potential revenue sources for the energy value[46] of load reduction:

- **Avoided power supply costs**. For every kWh not consumed, there is a kWh not charged under most power supply arrangements, even though most end-use customers are not directly charged rates that are time differentiated or otherwise correlated with their load curve.
- **Incentives**.[47] Payments provided by a load reduction program, above and beyond the first two revenue streams, to end-users or their Load Reduction Providers for reducing load during specified periods or whenever their price bids are accepted. For economic LR programs, these payments are generally set at or based on market clearing prices (MCP), but they may be higher for some emergency or reliability programs (e.g., when a floor price turns out to be above-market).[48]

There has been much discussion in the industry about the extent to which the payment of the second of these benefits constitutes an “incentive” or “double” benefit. We address this question below in terms of the impacts of load reductions on multiple market participants.

Load reductions may create <u>additional</u> market benefits and revenues associated with ancillary services (e.g. TMSR, TMOR) or reserve (e.g. ICAP payments). These should not be described as “incentives” or “double” payments, because these are separate services from the “energy” value of load reduction.

5.3 Role Of Load Reduction Incentives In Retail Market Configurations

In order to analyze incentives and other program design alternatives, it is important to distinguish the competitive portion of the retail generation market from the part of the market served by distribution companies as default suppliers. For this report, we have distinguished five retail supply configurations that represent most of the relevant market arrangements:

Retail Provider Configuration
1) Competitive Supplier Providing Both Generation and Load Reduction
2) Separate Load Reduction Provider Serves “Switched” Customer
3) Distribution Company Providing Both Generation and Load Reduction to Default Customer
4) Single Default Service / Standard Offer Supplier and Separate Load Reduction Provider
5) Multiple Standard Offer Suppliers

Configuration 1) Competitive Supplier Providing Both Generation and Load Reduction

The simplest configuration of these market players is that which may be typical of the mature retail power market, in which a retail customer has switched from its utility default service to a new competitive supplier that provides the commodity supply and bundles with it a set of services to facilitate participation in the ISO load reduction programs

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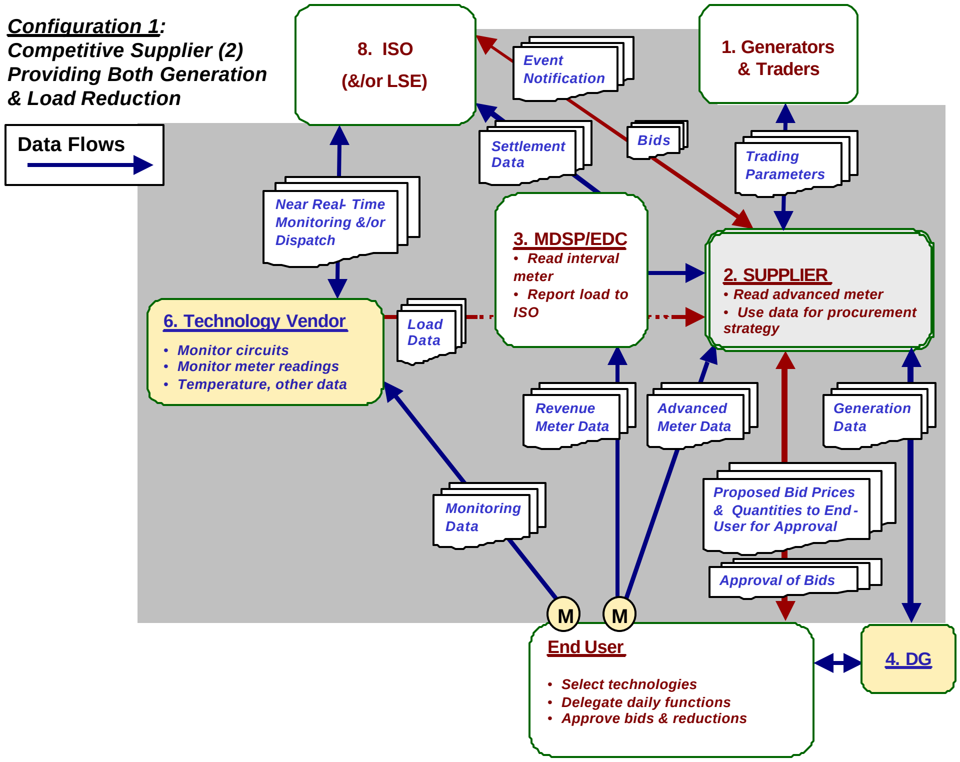
[46] Load reductions may create additional market benefits and revenues associated with ancillary services (e.g. TMSR, TMOR) or reserve (e.g. ICAP payments). These should not be described as incentives or “double” payments, because these are separate services from the energy value of load reduction.

[47] The term “incentives” is subject to a great deal of uncertainty and, often, confusion in the context of load response programs, and must be carefully defined.

[48] The payments for emergency programs could be characterized as an ancillary service and part of the second revenue stream.

(or in a future load reduction market). We refer to this as Configuration 1 "Competitive Supplier Providing Both Generation & Load Reduction." The basic data flows for this configuration are illustrated in the chart below:[49]



The following is a brief summary of the treatment of the two streams of savings (avoided power supply costs and incentives) in this configuration. For a customer that has switched to a competitive supplier for its electric generation service, and in the event that this same supplier is the Participant that signs up the load for the LR Program, then the same supplier receives both of the revenue sources listed at the end of the previous subsection: it avoids power supply costs that would otherwise be incurred to meet whatever portion of its load is actually reduced and also receives the LR incentive. If the supplier is able to in effect resell the load reduction back into the market for its full value, this may constitute a "double" benefit. However, in many cases it is difficult for a retail supplier to structure its procurement arrangements and to plan ahead sufficiently to fully capture the market value of the reduction in its load, so the incentive helps overcome that market barrier.

This treatment is also illustrated in the next flow chart, using purely illustrative prices:

- The solid lines (green) on the far right-hand side of each diagram represent the payments for power supply from the customer to its distribution company and from there to the generators or other entities that provide that supply. These solid lines are designated "payments for power purchase (savings)" -- these savings from avoiding energy procurement at the time of the load reduction would represent a change in the payments traveling along those solid lines. In response to the reduced purchase in the hours of the load reduction, the Supplier may experience savings in its payments for Bilateral Supply (or its costs of generation at its own facilities).[50] If the supplier is short on power in a given hour, it will also experience

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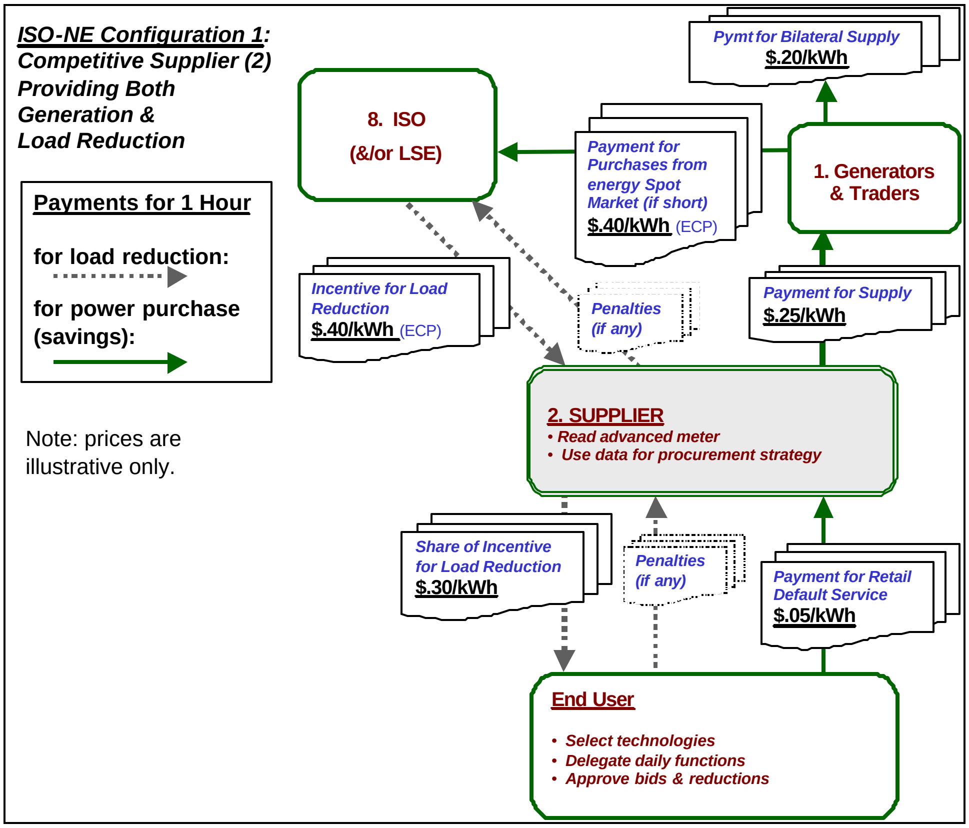
[49] The red lines indicate data flows associated with the ISO LR Programs that are particularly subject to change from one configuration to the next.

[50] The extent to which a supplier will actually achieve savings as a result of load reduction may depend on the extent to which it has timely information with which to forecast this changing load and re-sell that amount of power at the best possible price (or

savings in the "payments for purchases from the ISO energy spot market" that it would have been required to make if not for the load reduction.[51]

- The dotted lines (gray) on the bottom and left of the diagram represent load reduction incentive payments at some pre-determined or market clearing price (or fraction thereof) to an end-user that reduces its load, and/or to the load reduction provider which arranges for that LR. This is illustrated by the dotted gray lines representing payments from the ISO to the Load Reduction Provider (#7) and then to the End User; as noted, these cash flows are generally called incentives.



Configuration 2) Separate Load Reduction Provider Serves "Switched" Customer

For a customer that has switched to a competitive supplier for its electric generation service, but in the event that a different Participant (the LR Provider) signs up the load for the LR Program, then the competitive supplier avoids the cost of buying generation to meet the load that is actually reduced and the LR Provider receives the LR incentive. Part of the rationale for introducing the incentive in addition to the opportunity to avoid generation cost was to permit such entrepreneurs with load reduction expertise to serve end users without needing to enter the commodity market or share the market-price benefits with a commodity supplier.

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change generation schedules at its plants). This suggest the possible need to connect commodity suppliers or their generators to the near-real-time load data from the RETX system.

[51] Depending on the predominant enduses at each customer location, these savings can result from a reduced level of net load (e.g., lighting reductions) or a shift of usage to a lower cost period (e.g., deferral of a process that will be undertaken at a later time). The economic and environmental consequences and impacts may differ significantly.

However, the challenges for the independent LR provider are similar to those under Configuration 1 – end-use customers may have little risk to motivate them to seek the hedge value of load reduction. For example, even in a vibrant retail market, many suppliers will offer fixed pricing that is not time-varying if that's what they hear their customers demanding. As migration takes place away from default services, retail suppliers may also use fixed pricing, at least for those customers that are shopping for such simple or low-risk pricing and are willing to pay the premium for this risk mitigation.

Configuration 3) Distribution Company Providing Both Generation and LR to Default Customer

For a customer that has not yet switched from its default (or "Standard Offer") utility supplier (which passes through the cost of the generation it procures), and in the event that the customer signs up for the LR Program through the same utility, then the utility receives the LR incentive. This configuration is illustrated in the first diagram below. The utility generally shares a large portion of this incentive with the customer. This provides the end user the rationale for participating, since its retail default rate is presumably fixed at a level that does not reflect the actual high hourly avoided cost. However, the utility's share of the incentive may not compensate it for the loss of distribution revenues (energy charges and potentially demand charges).

Meanwhile, the generation company that supplies the utility with default service may avoid the high cost of buying generation to meet the load that is actually reduced, depending on the extent to which it has information that enables it to redeploy the resources no longer needed to serve that load. The RETX system provides one type of such information. When a day-ahead market is introduced in New England, it will provide another type of information that will enable retail and wholesale players to redeploy their resources where the market value is highest. After adjusting for the generation company's lost revenue at its low average generation price, such avoided cost may represent a windfall, to the extent that its contracts do not require it to pass on the benefits to the utility or its end use customers.

Configuration 4) Single Default Service / Standard Offer Supplier and Separate LR Provider

This is the configuration in which most end users find themselves today, and in which most of them will likely remain for a few years. It is illustrated in the second diagram below. For a customer that has not switched from its "default" utility (3), but in the event that a different Participant (the LR Provider designated as #7) signs up the load for the LR Program, then the generation company (1) that supplies the utility with default service avoids the cost of buying generation to meet the load that is actually reduced (less its lost revenue at the low average generation price), and the LR Provider (7) receives the LR incentive. In other words, the two benefits are received by two different entities.

This situation provides part of the rationale for introducing the incentive in addition to the opportunity to avoid cost. Meanwhile, the utility still loses distribution revenues, with no immediate offsetting pecuniary benefit, except perhaps some decrease in the loss of load probability. Incentive payments for load reductions have been calculated outside of the settlement accounting systems to date partly because a program decision had been made in mid-2000 to permit any market participant to implement a load reduction arrangement with an end-user, even if that end-user was still on "Default" service or was taking generation service from another LSE.

Load response is inevitably hampered by lack of time-varied price signals in the retail power market. These price signals can be muffled by fixed transition backstop prices (i.e. default service, standard offer, fixed generation credits) that provide "free" call options for generation at a fixed price. Currently, consumers now have most of the property rights. Most consumers have unlimited calls on the amount of energy they consume instantaneously. For those that are on standard offer or default service (the vast majority of load in New England), they have the right to consume an infinite amount of energy at fixed rates regardless of what the wholesale prices are. It is no surprise that these customers have little price elasticity and must be induced to participate in load response by incentives in addition to the savings available at the retail rate. Nevertheless, once the property rights have been assigned, it may be most efficient to give incentives to customers to load respond.

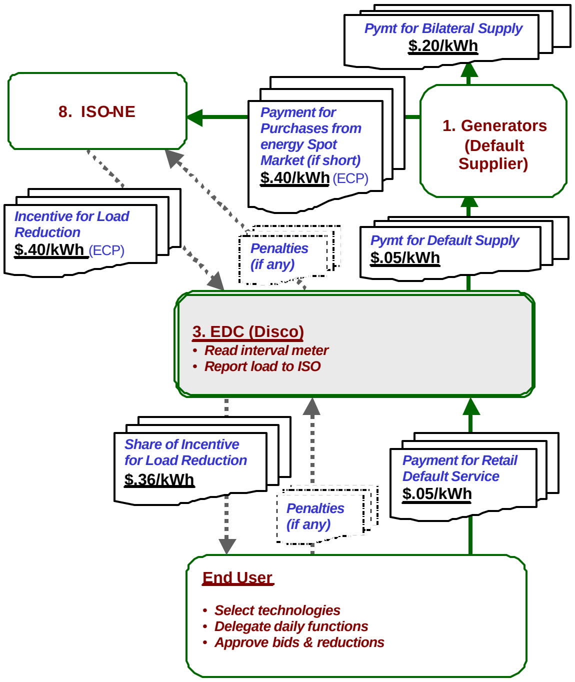
***Configuration 3*: Distribution Company (3) Providing Both Generation & LR to Default Customer**

Payments (ISO-NE)

for load reduction: ⇢

for power purchase (savings): →

Note: prices are illustrative only.



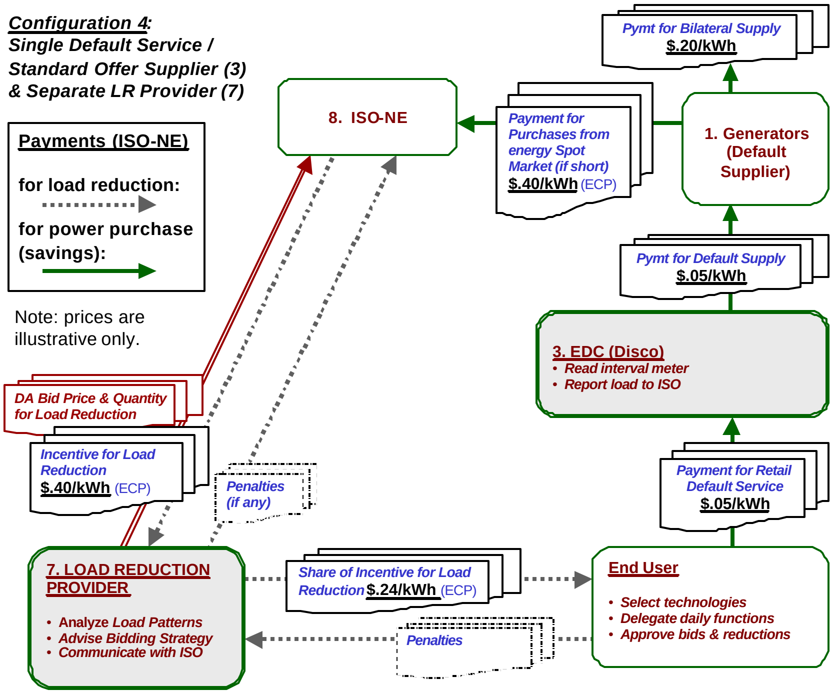
***Configuration 4*: Single Default Service / Standard Offer Supplier (3) & Separate LR Provider (7)**

Payments (ISO-NE)

for load reduction: ⇢

for power purchase (savings): →

Note: prices are illustrative only.



Configuration 5) Multiple Standard Offer Suppliers

The above examples assume that a single generation company provides all the generation to meet the "default" load of a distribution utility. A further complication arises when the utility has procured its generation from multiple generation company, each of which is responsible for a specified percentage of that total default load. In this case, under the existing "outside-the-settlement-system" approach, each generation company receives its specified percentage of the avoided-cost benefit from the load reduction and a related loss in revenue. Problems may arise in the event that one of the generating company suppliers were to take the initiative to sign up some of the end-use customers for the LR program. In this situation the generation company supplier who would still receive the same share of the load reduction, while the remainder of the benefits would accrue to the other suppliers who did nothing to induce the load reduction.[52] While in this scenario only a fraction of the benefits from load reduction will accrue to the appropriate generating company, this scenario does not preclude the generating company who facilitates the LR for an end-use customer from receiving all the incentive payments.

5.4 Potential Re-Allocation of Load Assets

For a program design that includes financial incentives, a number of program design issues arise. One of these issues is what source should be used to provide the funds for the ISO incentive payments. Uplift can be one source. While one ISO objective is to minimize uplift, the load response program can be expected to provide offsetting reductions in other charges, including reduction in the energy clearing price, or reduction in reserve costs and reduction in congestion.

The funds for incentive payments could also be obtained by reallocating load responsibility among ISO market participants such that the load responsibility of the participating end user's commodity supplier or LSE is maintained for purposes of the ISO settlement and billing system at the same level it would have reached if not for the load reduction. In other words, while the revenue meter served by such a supplier would show a reduced load, an adjustment would be made to increase that load for billing the supplier. This would be the same MW level as the MW of load reduction for which a payment is to be made to the LRP. This approach would require additional system development by ISO-NE, which is currently expected to be undertaken as part of the introduction of SMD.

As an example of load reallocation, consider the case of a single generation company that is responsible for generation service to follow the load of a utility's default customers (see configurations 3 and 4). A new LR asset could be created, separated from the generation company's main load asset, and added back into the load for which the generation company is responsible at the ISO.

As another example, in configuration 2, consider a LR Provider serving a "switched" retail customer that is, an end user buying electric commodity service from a competitive generation supplier. Should the customer's competitive supplier be responsible for – and pay for – generation that it did not actually supply to the end-user's revenue meter, in order to provide the payment to the LR Provider? If the supplier is to have its load responsibility "reallocated" in this way, it may be important to provide the supplier with information from the RETX system that would put it in a position to anticipate the load reduction and to manage its supply portfolio accordingly to capture the resulting benefits.

If lost revenue is to be made up, then most complicated computation will be benefits in the case of "Multiple Standard Offer Suppliers", configuration #5. One way to correct the allocation of load reduction benefits in the case

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[52] It is therefore unlikely that any generation company supplying a percentage of a load would have sufficient incentive to offer any LR services to default customers. However, this does not in itself provide a strong rationale to remedy this problem, since default generation is most often supplied by wholesale market players that are unlikely in any event to offer LR services to retail customers, and are likely to have disincentives to provide services that would decrease wholesale prices, and thus decrease the value of their other generation assets.

of "Multiple Standard Offer Suppliers" would be to develop a new capability between now and the summer of 2002 to separate and re-allocate LSE load assets and to correctly reallocate the load responsibilities from one LSE to another. Integrating this capability into the ISO-NE settlement software was rejected as too expensive when it was considered in early 2001. When this decision was made, it was estimated that it would take at least one person-year of programming effort to implement this methodology, which would have entailed splitting a participating end-user's load into 2 or more load assets, some of which would then be treated as new interruptible loads and transferred to another LSE through a new set of adjusting entries in the settlement system.

As a practical matter, there may be significant policy and stakeholder questions to work through before deciding whether, to what extent, and how load serving responsibilities should be "reallocated" in such a way that the benefit would shift to the "right" parties or that the incentives could be eliminated. Before committing to a reallocation approach, two potential concerns should be considered:

- Market Power. Reallocation may increase concentration in the control of the "supply" of load reduction. If a Standard Offer supplier is a generator (the likely case), and is selling a portion of its generation into the real time market (or day-ahead market when SMD is implemented), then it would have an incentive not to provide load reduction for a small load. By providing load reduction for a small load, they would potentially lower revenue for the rest of generation for they are selling into the short-term markets.

- Retail Market Development. Reallocation could create an impediment to the development of the retail power market. Standard Offer suppliers might have an incentive to offer retail load reduction services to end-use customers, but without having to win them in the retail market. To address this concern, in the configurations described above where the procurement cost savings accrue to a different party than the one in a position to create the load reduction (Configurations 2 and 4), there may be opportunities for some entities to capture both benefit streams by shifting positions in the value chain. For example, if a fractional standard offer supplier wants to capture all the benefits form the current load reduction it could register as a competitive retailer. It could then sign the customer up for competitive supply as well as load response. This approach would likely not suit a generator or supplier that would lose more money on its power sales when the market price falls than it would gain from the load reduction benefits.

Reallocation would require some increase in system development time and costs. These investments should be based in part on the assessment of the future evolution of LR programs, since at some point the reallocation might no longer be needed. Generally, the shorter the potential period during which benefits are expected to be derived, the lower the return on the system development investment.

5.5 Summary of Role of Incentives for Default Service Customers

We have seen that the retail market configuration is a primary driver of the type of incentive designed into a LR program. In New England the prevalent retail model is one where end-users pay a fixed rate kWh for a relatively long time period (six months, one year, or in some cases, a multi-year period). Because the real-time price of energy is not passed through, the end user who reduces load on a hot afternoon would only experience an "avoided cost" savings based on the fixed-rate kWh charge, which might be, say, 5¢/kWh. In other words, this end user would not be in a position to receive the full benefit of reducing load based on the real-time price for a particularly high-priced hour, which might be, say, 40¢/kWh. This is illustrated in the previous two flow charts.

In such retail market situations, where the configuration of transactions would otherwise leave the end user receiving only a part of the savings, a market-price-based incentive may be able to provide the desired price signal to the end-use customers. The value proposition for load reduction is poor when the majority of the avoided-cost benefits accrue to different parties than the ones that arrange the load reductions or invest in the load reduction capabilities (i.e. the end-user or their LR provider). As noted above, the incentives paid by the LR programs may offset this split incentive problem, but they represent an intervention in the market that policy makers and ISO managers are naturally reluctant to make if it is not necessary.

A related rationale for incentives is the important role that can be played by independent Load Reduction Providers ("LRP"s) in helping end users identify and implement load management solutions and packaging the financial, metering, communication and software arrangements that are needed with respect to the ISO and/or the EDC and/or the supplier of commodity to the end user in order to complete the value proposition. The problem is that, due to the market failure noted above, the only practical revenue stream to attract these players to this market is an incentive from the ISO that constitutes the market value of the demand resource.

Load response is now an infant industry, both in terms of the technology platforms and in terms of the business case and contractual arrangements through which the LR product can be priced and the responsibilities, risks, rewards can be allocated between buyers and sellers in the market. The need for incentives is partly based on the development status of the market for load response, and partly on the conditions in the market for the accompanying product – retail electricity. Incentives for load response will become less important when the LR industry matures and when the following market conditions are realized or approached:

- no retail price cap (e.g., Standard Offer),
- no wholesale price cap,
- robust hedging instruments available,
- minimum abuse of market power (wholesale & retail).