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NARUC

Policy and Technical Issues Associated with ISO Demand Response Programs

The National Association of Regulatory Utility Commissioners

Prepared for NARUC by
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Final Report

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FOREWORD

Who can forget Economics 101? Supply and demand. Market clearing prices. Economic efficiency. Elasticity.

For too long, the demand side of the electricity equation has been neglected, dismissed, discounted, or ignored. Too often, the proposed solution to any problem has been more supply. Now, after the price and reliability problems of the last couple of years in many regions of the country, demand is having its due. It saved the bacon for more than one region in 2000 and 2001.

The benefits of demand response are many:

system reliability,
cost reduction,
market efficiency,
risk management,
environmental,
market power mitigation,
system efficiency, and
energy efficiency.

It's timely to reflect on the role of demand response. We need to understand demand response programs better so we can have improved programs in place for the next crisis as well as to reap the benefits during more "normal" times.

The National Association of Regulatory Utility Commissioners (NARUC) took up that challenge. Its Committee on Energy Resources and Environment, funded by the Department of Energy, engaged ICF Consulting to conduct a comprehensive study of the policy and technical aspects of regional demand bidding programs. Specifically, ICF was asked to:

a) provide an overview and critique of current and impending ISO-based demand response programs, identifying program refinements being considered by ISOs and state utility commissions based on year 2001 results,
b) identify how demand response programs can best be implemented within the constraints of existing ISO market structures and procedures, while proposing improvements to current ISO structures and procedures to improve demand bidding program effectiveness,
c) identify methods to achieve optimal participation by load-serving entities and their customers (industrial, commercial, and residential) in ISO-based demand response programs, and
d) identify relevant state regulatory issues associated with ISO-based demand response programs.

The work was done for ICF by David Kathan. The report illustrates Dr. Kathan's depth of understanding of the subject as well as his skill of analysis and communication. Kathan was especially effective at working with the steering committee.

The project was guided by a NARUC steering committee:

Bob Anderson, Commissioner, Montana Public Service Commission; Chair, NARUC Committee on Energy Resources and Environment
Roy Hemmingway, Commissioner, Oregon Public Utility Commission
Terry Fitzpatrick, Commissioner, Pennsylvania Public Utility Commission
Jim Gallagher, Staff, New York Public Service Commission; Co-Chair, ERE Staff Subcommittee
Denis Bergeron, Staff, Maine Public Utilities Commission
Grace Hu, Staff, District of Columbia Public Service Commission
Jorge Valladares, Staff, Maryland Public Service Commission.
Andrew Spahn, Staff, NARUC.

In the course of the work, drafts were circulated for comment to all state commissions and to a many demand response professionals. All those comments were constructive and greatly enhanced the final product.

Special thanks go to the U.S. Department of Energy, which funded the project. DOE has the big picture in mind and pursues it, in part, through its partnership with NARUC. We especially thank David Garman, Assistant Secretary for DOE's Office of Energy Efficiency and Renewable Energy and Joe Malinovsky our DOE Project Officer.

The proof will be in the pudding. If this report and the concepts it describes are successful, we'll find ourselves at P_2 and Q_2 in Figure 3 on page 6.

Bob Anderson
Chair, NARUC Committee on Energy Resources and Environment
Montana Public Service Commission

ACRONYMS

BIP	Base Interruptible Program implemented at California utilities
BUL	Balancing-Up Load (ERCOT)
BUG	Back-up Generators
CAISO	California Independent System Operator
CBL	Customer Baseline
CDWR	California Department of Water Resources
CPUC	California Public Utilities Commission
CSP	Curtailment Service Provider
DADRP	Day-Ahead Demand Response Program (NYISO)
DBP	Demand Bidding Program implemented at California utilities
DCU	Digital Control Units
DG	Distributed Generation
DLCP	Discretionary Load Curtailment Program (CAISO)
DR	Demand Response
DRP	Demand Relief Program (CAISO)
DSM	Demand-Side Management
ECP	Energy Clearing Price (ISO-NE)
EDRP	Emergency Demand Response Program (NYISO)
EMS	Energy Management System
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
IBCS	Internet-Based Communication System
ICAP	Installed Capability
IOU	Investor Owned Utility
IDR	Interval Data Recorder
ISO-NE	Independent System Operation – New England
LaaRS	Load Acting as a Resource (ERCOT)
LMP	Locational Marginal Price
LSE	Load Serving Entity
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NOPR	Notice of Proposed Rulemaking
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
NYSERDA	New York State Energy Research & Development Authority
OBMC	Optional Binding Mandatory Curtailment program implemented at California utilities
PJM	Pennsylvania, New Jersey, Maryland Interconnection
PLP	Participating Load Program (CAISO)
PRL	Price-Responsive Load
PRLWG	Price-Responsive Load Working Group (NYISO)
PUCT	Public Utilities Commission of Texas
RTO	Regional Transmission Organization
SC	Scheduling Coordinator (CAISO)
SMD	FERC Standardized Transmission Service and Wholesale Electric Market Design
T&D	Transmission and Distribution
UDC	Utility Distribution Companies
VDRP	Voluntary Demand Response Program implemented at California utilities

1. INTRODUCTION AND SUMMARY

One of the fundamental lessons that has been learned from the ongoing California electric crisis is the importance of providing correct price signals to customers. Inelastic demand combined with a tight electric supply demand created a "sellers market" for electricity. Even modest drops in electric demand in this period could have produced significant impacts on market clearing prices. It has been estimated that a 5 percent reduction in demand in California could produce over a 50 percent drop in wholesale prices.[1] Similarly, approximately 400 MW of emergency demand response that was used by the New York Independent System Operator (NYISO) during a few hot days in July and Augusts 2001 reduced market clearing prices as much as 28 percent in the upstate Capital NYISO zones.[2]

Demand response can be introduced into wholesale markets in two fundamental manners. First, customers can be exposed to wholesale market prices through a direct passthrough in the form of dynamic pricing, such as real-time pricing. Experience has shown that exposure to dynamic pricing induces significant shifts in customer demand. Second, customers can be induced to reduce their demand at the time of peak demand or system emergencies through either price signals or through payments/incentives based on market clearing prices. While the former approach will likely be implemented over the long-term, the second approach can provide benefits in the near-term as technology is deployed and regulatory transition periods that fix retail rates are still in existence.

In order to address reliability and price spike concerns, all of the four existing Independent System Operators (ISOs) that were fully operational in 2001 (i.e., the California ISO (CAISO), the ISO New England (ISO-NE), the NYISO, and the Pennsylvania-New Jersey-Maryland Interconnection (PJM)) operated demand response programs in the last several years. These ISO programs were operated in addition to existing electric utility load management programs. The development of a demand response has also taken on a larger policy dimension, and has received national attention. The National Association of Regulatory Utility Commissioners (NARUC) approved a resolution in 2000 calling for regulatory commissions to accommodate demand-side resources and "remove any unnecessary barriers to customer responses to such wholesale market price signals."[3] In addition, the Federal Energy Regulatory Commission (FERC) has begun to express significant interest in demand response,[4] and it is likely that the upcoming Notice of Proposed Rulemaking (NOPR) from FERC concerning Regional Transmission Organization (RTO) standard market design will include a demand response component.

In the face of these recent policy initiatives and developments, the Energy Resources and Environment Committee of the National Association of Regulatory Utility Commissioners

[1] Eric Hirst and Brendan Kirby, *Retail Load Participation in Competitive Wholesale Electricity Markets*, January 2001.
[2] Neenan Associates, *NYISO PRL Program Evaluation: Executive Summary*, January 2002. Other regions were less – Western NY had a 22% reduction, and New York and Long Island had a 4% reduction.
[3] NARUC, *Resolution Regarding Equal Consideration of Demand and Supply Responses in Electricity Markets*, July 2000.
[4] FERC recently co-sponsored a conference on Demand Response on February 14, 2002 in Washington, DC, and has included demand response in their Standard Market Design Working Paper released in March 2002.

commissioned this paper under a U.S. Department of Energy grant to explore the technical and policy issues associated with ISO demand response programs, with particular attention to the interaction between these ISO programs and state regulation. While many of the experiences and issues faced by the four existing ISOs are transferable, the unique structure of these ISOs (all except the CAISO grew out of tight power pools) and the advanced status of electricity deregulation in their regions may limit this transfer. One of the key concerns is whether existing load response capability incorporated in electric utility load management programs could be at risk as the focus of demand response shifts to regional wholesale electric market entities.

To support development of this white paper, a survey was conducted of ISO representatives and state regulators and staff during January and February 2002. These representatives were asked during phone conversations about the key issues and lessons learned from ISO demand response programs.

1.1 Definition of Demand Response

The use of the term "demand response" to refer to demand-side participation in wholesale markets is relatively new. Historically, the term "load management" was used to describe customer load curtailments. The term "price responsive load" or "dynamic pricing" has also been used to describe programs that either passed-through wholesale prices to retail customers or to describe tariffs that incorporated time-varying prices. The term "demand response" is used in this paper as the generic term for all customer changes in actions or behaviors that introduce price elasticity into the wholesale market or that can be used to increase system reliability. This definition is in concert with the definition provided in a recent Peak Load Management Alliance position paper, i.e.,

> Demand response in electricity is defined as load response called for by others and price response managed by end-use customers. Load response includes: direct load control, such as of residential air conditioners; partial or curtailable load reductions; and complete load interruptions. Those calling for load response include: independent system operators (ISOs), load serving entities (LSEs), and utility distribution companies (UDCs). Price response includes real-time pricing, dynamic pricing, coincident peak pricing, time-of-use rates and demand bidding or buyback programs.[5]

As this definition indicates, demand response includes both load reduction and price responsive load. In addition, this definition of demand response also allows for the use of distributed generation to achieve reductions in demand.

Historically, utility distribution companies operated demand response programs. Electric utilities developed and operated these programs in response to their resource planning needs. Objectives of providing additional services to individual consumers were not considered. The new form of demand response programs can be operated by a variety of entities, including ISOs, LSEs, UDCs,[6] and curtailment service providers (CSPs). CSPs are new market entities who aggregate customer load curtailment within ISO programs.

[5] PLMA, *Demand Response: Principles for Regulatory Guidance*, February 2002.
[6] Note that UDCs refer to the regulated distribution portion of electric utilities.

1.2 ISO Demand Response Programs

Table 1 lists the key ISO demand response programs that were in place prior to summer 2001.[7]

Table 1
2001 ISO Demand Response Programs

California	
	Participating Load Program
	Demand Relief Program
	Discretionary Load Control Program
NY ISO	
	Emergency Demand Response Program
	Day Ahead Demand Response Program
	ICAP Special Case Resources
ISO NE	
	Demand Response Program (Class 1)
	Price Response Program (Class 2)
PJM	
	Emergency Load Response Program
	Economic Load Response Program

These ISO demand response programs can be categorized into reliability-based programs and market-based programs. Reliability-based programs operate in response to system contingencies or emergencies. Market-based programs are triggered by wholesale market prices.

These two categories should be further subcategorized. Reliability-based programs include both contractual (also known as call options) and voluntary programs. In the contractual program, program participants[8] are paid a guaranteed payment per month or per kW in exchange for curtailing their consumption during system emergencies. An example of an ISO contractual program is the ICAP Special Resources Program.[9] Program participants can be penalized if they do not reduce their consumption when directed. Voluntary programs do not include a guaranteed payment – participants are asked to reduce their consumption when directed. However, they are not obligated to perform the curtailment. Participating customers are typically paid only the market clearing energy price as incentive to participate, although several ISO programs specify a minimum incentive level, e.g., $500/MWh in NYISO's Emergency Demand Response Program (EDRP).

Market-based programs can also be subcategorized into bid-based programs and into programs where the customer is a price-taker. In the bid-based programs, also known as demand bidding, the program participant submits a bid identifying the minimum price that would be required to reduce their demand and the demand reduction amount.[10] This bid is chosen when it is economic for the system operator to dispatch the demand reduction instead of an alternative demand bid or a generator bid. In the price-taker programs, the participating customer only indicates the level of load available to be curtailed. In these price-taker programs, either the ISO specifies the minimum price or the participant receives the prevailing market-clearing price during their curtailments.

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[7] Note that the suite of California demand response programs changed during the summer of 2001 (See Section 2.1).
[8] Program participation is typically limited to ISO members, load-serving entities, or approved aggregators. Except for the largest customers, end-use customers cannot directly participate in the programs. These entities aggregate the customer load reductions, and pass on the payments to customers.
[9] ICAP is short for Installed Capability. ICAP markets exist in markets such as New York that have an installed capability requirement for LSEs.
[10] The California Demand Bidding Program provides a good example of the components of a demand bid: (a) the time block during which the customer offers to reduce their demand; (b) a bid price ($/kWh); and (c) the amount of kW per hour the customer commits to reduce.

Table 2 places each of the existing ISO programs that were designed before the summer of 2001 into one of these four categories.

Table 2
Classification of 2001 ISO Demand Response Programs

ISO	Reliability-Based		Market-Based	
	Contractual	Voluntary	Bid-Based	Price-Taker
CA ISO	• Participating Load Program • Demand Relief Program	Discretionary Load Curtailment Program		
ISO NE	Demand Response Program			Price Response Program
NYISO	ICAP Special Case Resources	Emergency Demand Response Program	Day-Ahead Demand Response Program	
PJM		Emergency Load Response Program		Economic Load Response Program

The ISO-operated demand response programs were active during 2001. Table 3 presents the reductions achieved in all of the ISO demand response programs and from interruptible program active in the ISO region.[11] While the total reductions were not large (NYISO's programs represent the largest percentage of the ISO peak load – about 2 percent), the size of the reductions are significant because the programs were new and were only in existence for several months prior to the summer of 2001.

Table 3
Load Reductions Achieved in 2001 Demand Response Programs

ISO	ISO Demand Response Program Reductions (MW)	Electric Utility Interruptible Program Reductions (MW)
CA ISO		760
Demand Relief Program	162	
Discretionary Load Curtailment Program	22	
ISO-NE		
Demand Response	1	
Price Response	20	
NYISO*		
Emergency Demand Response Program	455	
Day Ahead Demand Response Program	25	
ICAP Special Case Resources	360	
PJM		1,796
Emergency Option	62	
Economic Option	1	

* Load reductions in the NYISO programs are not additive because participants can participate in both the Emergency Demand Response Programs and the ICAP Special Case Resources programs.

[11] Interruptible program reductions were included in Table 3 because (a) these programs interact with the ISO programs, and (b) the existing program reductions provide context for the ISO programs. For instance, participation in interruptible programs within PJM takes precedence over demand reductions in the PJM demand response programs.

1.3 Benefits of Demand Response

The incorporation of demand response into electric markets can produce important and significant benefits. These benefits include:[12]

- *System Reliability*. Customer demand management can enhance reliability of the electric system by providing system operators another potentially cost-competitive option to address local reliability, transmission congestion, and system reserve shortages.
- *Cost Reduction*. A key driver for demand management is overall cost reduction. Customers – both participants and non-participants – can benefit through reduced electric rates and bills. System operators, LSEs and UDCs benefit through (a) direct cost savings from avoided generation as well as avoided transmission and distribution costs (such as capacity costs, line losses, and congestion charges), and (b) direct or indirect reductions in wholesale market prices.
- *Market Efficiency*. When customers receive price signals and incentives, usage becomes more aligned with costs. To the extent customers alter behavior and reduce or shift on-peak usage and costs to off-peak periods, the result is more efficient use of the electric system. As the California experience has demonstrated, it is important to not shield consumers from actual energy prices. Note, however, that transitioning fixed rate customers who are currently under rate caps on to dynamic pricing which may vary daily or monthly can be difficult. When San Diego Gas & Electric completed its transition period in California and began to pass wholesale prices on to its customers, negative response from customers led the California legislature pass a law that returned small residential and commercial customers to fixed rates.

  The introduction of demand elasticity allows the market to equilibrate at lower prices. When customer demand reaches the steep section of a supply curve, small changes in demand can produce significant reductions in short-run market clearing prices. Figure 2 provides an example of the short-run benefits to both participant (the area **a b Q_0 Q_1**) and non-participant (the area **P_0 a c P_1**) buyers of electricity when demand elasticity is introduced into tight supply situations. These benefits to participants and non-participants also represent a transfer from sellers of electricity to buyers since the sellers receive lower prices for their provided electricity.

  Figure 3 shows how markets will equilibriate over the long-term. Lower market-clearing prices and sales revenues may induce lower amounts of capacity to be built or operated, and the supply curve could shift upwards. In the example shown in Figure 3, market clearing prices will likely equilibrate at P_2 in the long-run, which is higher than the short-run price P_1, but lower than the inelastic demand price P_0. Society as a whole benefits if long-run average costs are lower after the market equilibrates.

[12] This list of benefits is partially based on the PMLA *Principles for Regulatory Guidance*, February 2002

Figure 2
Benefits of Demand Response

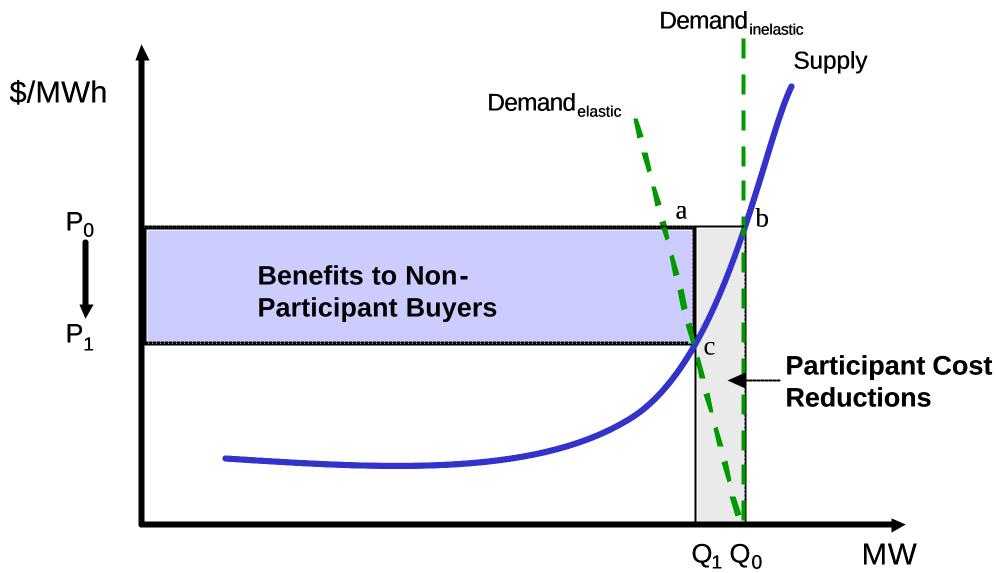
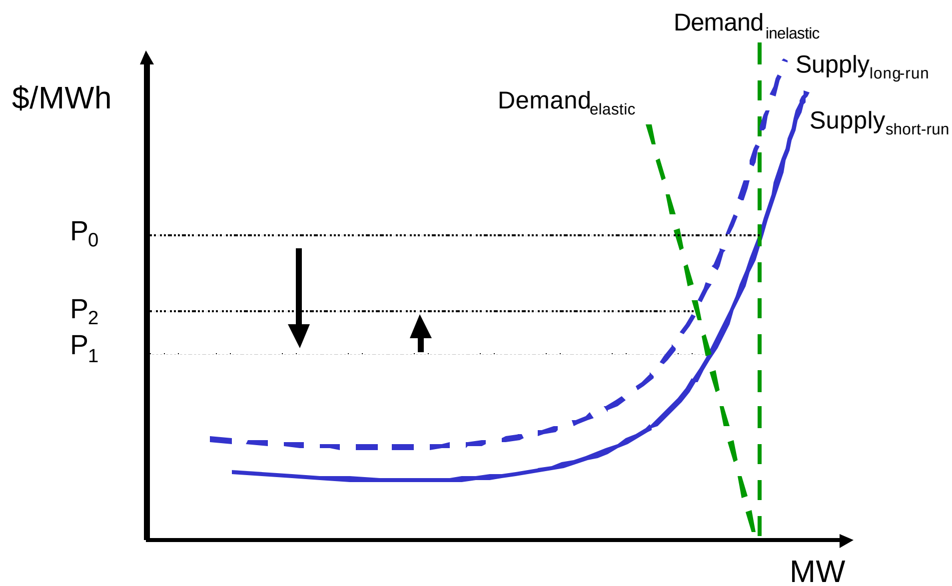


Figure 3
Long-Run Market Equilibrium with Demand Response



Multiple studies have attempted to quantify these potential market clearing price reductions and system cost benefits. An EPRI study concluded that "… a 2.5% reduction in electricity demand statewide could reduce wholesale spot prices in California by as much as 24%; a 10% reduction in demand might slash wholesale price spikes by half."[13] McKinsey estimated national benefits of time-sensitive pricing to be $15 billion.[14] A recent study by ICF Consulting provides additional support for the value of demand response. ICF estimates that approximately $4 billion savings in electric system operation costs could be achieved annually if customers across the continental U.S. were exposed to market-based prices during peak periods.[15]

- *Risk Management*. Demand response allows customers, retailers, and utilities to hedge their risk exposure to system emergencies and price volatility. Retailers can hedge price risks by creating callable quantity options (i.e., contracts for demand response) and by creating dynamic pricing offers for those customers who are willing to face varying prices. Customers can explicitly incorporate demand response into their operations and electricity purchases on an individual facility or enterprise basis. Utilities can use demand response programs to hedge their portfolios. Use of this form of hedging is particularly important when utilities have default service obligations under rate freezes or caps.
- *Environmental*. Demand response has the potential to help reduce environmental burdens placed on the air, land, and water by lowering demand during peak periods. The time periods when electricity demand peaks highly correlates with high ozone episodes. Reductions in electric consumption during these peaks will help partially ameliorate these local environmental problems. Peaking plants are the most inefficient facilities in operation. Reduction in their operation can create important carbon and climate change benefits. Demand response can also reduce or defer new plant development, and may also lead to greater optimization of transmission and distribution capacity.[16] However, if fossil-fired distributed generation is used as the source for the demand reductions, there may be localized negative environmental impacts.
- *Market Power Mitigation.* The use of demand response programs to introduce demand elasticity to the wholesale market can also produce important market power mitigation benefits. The use of reliability-based or market-based demand response during peak periods provides an important safety valve for the market. During these peak periods, power suppliers will need to consider the potential use of load curtailment when they submit high above-market bids. Similarly, if demand elasticity reduces peak severity, strategies that involve capacity withholding may be non-optimal for suppliers. Withheld capacity in this scenario may never be called.

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[13] Taylor Moore, "Energizing Customer Demand Response in California," *EPRI Journal*, Summer 2001, p. 8.
[14] McKinsey and Company, "The Benefits of Demand-Side Management and Dynamic Pricing Programs," May 1, 2001, p. 2.
[15] ICF Consulting. 2002. *Economic Assessment of RTO Policy*, Prepared for FERC, February 2002. The key assumptions in the ICF study were that 50% of the customers would be exposed to dynamic pricing only in the peak period, and that their demand elasticity would be 0.1. These assumptions resulted in an assumed 3.5% reduction nationwide.
[16] These net benefits may dissipate if customer load reductions lack permanence. Without newer, more efficient generation, older generation may need to be reactivated, with potentially higher total emissions.

- *System Efficiency.* Demand response introduces not only market efficiencies as previously noted but operational and planning efficiencies as well. From an operational standpoint, demand response provides an option to use to address transmission and distribution bottlenecks. Planners can also select it as an alternative for relieving transmission and distribution constraints, particularly from a standpoint of targeting specific locations within the system. Nevertheless, full exploitation of these operational and planning efficiencies is dependent on the demonstration that demand response provides firm and long-lasting reductions.
- *Energy Efficiency*. Demand response, particularly dynamic pricing programs made possible by advanced meters, new communications technologies, load control hardware/software, and building control and management systems, can also serve as the stimulus and platform for participating customers to undertake expanded and enhanced energy efficiency programs. By gaining access to information about their usage that was previously unavailable to them, and by gaining the means to act upon it, users can undertake energy management and efficiency practices that can provide embedded, more permanent benefits to the system as a whole.

Both FERC and state regulators recognize the benefits of demand response. In multiple orders, FERC has acknowledged the benefits associated with demand response and has directed the establishment of programs in each of the ISOs. For example, in its order accepting PJM's 2001 Load Response Program, FERC stated that "price-responsive demand is a key part of a well-functioning market that would mitigate price volatility and enhance reliability in the face of supply shortages."[17] In 2002, FERC has taken an even more proactive role in the promoting demand response. During congressional testimony, Chairman Pat Wood stated that:

> Effective markets balance supply with customer response, allowing for lower usage as prices rise. But in regulated retail electric markets, with their uniform rates, utilities have no choice but to buy or produce power, whatever the cost, and customers do not receive price signals about the true value of the energy they are using. The Commission will be working with the Department of Energy, RTOs and others to establish price-responsive demand mechanisms that reach a variety of customer groups and allow them to reduce their energy demand when prices are too high. This will reduce overall peak load levels, peak energy prices and supplier market power.[18]

FERC has also indicated in two Working Papers that it strongly believes that demand response has an important role in all of the markets included in the Standard Market Design that it will be attempting to implement over the next several years.[19] FERC's support of demand response in these papers is stronger than its earlier statements, i.e., "Demand response is essential in competitive markets to assure the efficient interaction of supply and demand, as a check on

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[17] Order Accepting Tariff Sheets As Modified, 95 FERC ¶ 61,306, Docket ER01-1671-000.
[18] Pat Wood, Chairman, FERC; testimony before the U.S. House Subcommittee on Energy & Air Quality, September 20, 2001.
[19] See *Standardized Transmission Service and Wholesale Electric Market Design*, FERC Working Paper FERC Working Paper, March 2002, *Options for Resolving Rate and Transition Issues in Standardized Transmission Service and Wholesale Electric Market Design*, FERC Working Paper, April 2002.

supplier and locational market power, and as an opportunity for choice by wholesale and end-use customers."[20]

State public utility commission's (PUCs) have also supported the development of demand response. The New York Public Service Commission (NYPSC) stated in its order requiring all UDCs in New York to implement the NYISO Day-Ahead Demand Response Program (DADRP) program that "peak demand reduction will reduce the risk of brownouts or blackouts. Furthermore, a tight energy market can lead to price spikes when supply conditions become especially constrained. Under these circumstances, even relatively small reductions in load can affect wholesale market prices."[21] In addition, the New York State energy plan for 2002, identifies demand reduction and distributed generation as primary components of a competitive market that interfaces with the ISO/RTO.

1.4 Key Demand Response Issues

Key issues associated with ISO demand response and how the implementation of these programs interacts with state regulation include:

- **Cost recovery**. A key impediment to UDC involvement and aggregation of customers is the issue of recovery of program costs, incentive payments to customers, and lost revenue.
- **Socialization of Program Participant Payments/Incentives**. An important and contentious issue in ISO demand response programs is whether the recovery of program participant payments should be socialized across multiple LSEs or system-wide.
- **Aggregation**. The ability to aggregate curtailments loads by third-parties (i.e., CSPs) who do not have a retail load obligation is a key issue in the four ISOs.
- **Improvements in calculation of usage baseline**. One of the key issues that arose during summer 2001 at the ISOs was the calculation of customer baselines (CBL). The calculation of CBL is essential for the determination of load reduction payments in the ISO demand response programs.
- **Jurisdiction/access to customers**. Concerns have been raised that FERC does not have any jurisdiction in the creation of markets for load curtailment, and have argued that ISOs do not have a role in demand response because they are wholesale entities.
- **Environmental concerns related to distributed generation**. The ability of distributed generation, particularly diesels, to participate in ISO demand response programs is a hotly contested issue because of their potential local environmental impact.
- **Lack of recognition of the uniqueness of demand-side resources**. ISOs, particularly the ISOs that were based on existing power pools (ISO-NE, NYISO, and PJM), were designed to

[20] March Working Paper, p. 6.
[21] CASE 00–E-2054, In the Matter of a Status Report on the Demand/Supply Component of the Department's Electric Price and Reliability Task Force Including Recommendations for Specific Utility Actions on the Demand-Side, ORDER DIRECTING THE MAJOR ELECTRIC UTILITIES TO IMPLEMENT THE NEW YORK ISO'S INCENTIVIZED DAY-AHEAD ECONOMIC LOAD-CURTAILMENT PROGRAM, (Issued and Effective March 20, 2001).

manage physical assets, such as transmission networks and generation resources. The process of designing demand response programs that work within the supply-based ISO structures has been a challenge.

- **Timing of payments/Settlement**. An important issue for many customers last was the speed and timing of payments. Many customers had not received their payments until well after the summer, and in some cases several months later. The slow payment cycle is based on ISO settlement timetables.

These issues are discussed in greater detail in Section 2.5 below.

The key issues identified by state PUCs include:

- **Involvement of smaller customers**. Many of the commissions interviewed raised the need to include smaller customers in ISO programs.
- **Overlap between retail programs and ISO demand response programs**. The proper role of state regulators is to ensure that state policies and UDC tariffs are consistent with ISO market design and demand response programs.
- **Cost Recovery**. California, New York, and Pennsylvania all indicated that cost recovery issues have been raised and explored in their states. The importance of cost recovery was especially important in states with default service obligations coupled with rate caps.
- **Aggregation**. Third-party aggregation of customer load curtailments was not a big issue for the states interviewed.

These PUC-identified issues are discussed in greater detail in Section 4.1 below.

1.5 Recommendations

Key recommendations for state action include:

- **Examine the relationship between flat retail rates during transition periods and the need to send wholesale price signals to retail customers.** A major impediment to the development of price-responsive demand is the existence of rate caps and fixed default service rates.
- **State PUCs should explore how all or only targeted customers can be transitioned onto dynamic pricing.** As long as dynamic pricing is voluntary, the full benefits and/or impact of its application will not be achieved.
- **Support the development of standard market design for demand response**. Greater customer participation would likely occur, particularly from large national chains and corporations, if these customers did not have to track and understand multiple program offerings.
- **Explore state funding or rate-based funding of enabling technology**. State PUCs and legislative bodies should explore funding these programs through state general funds, through rate surcharges like societal benefits charges, or through explicit recovery in rates.

- **Re-examine the introduction of competition into metering**. The introduction of competition into metering has not been successful to date. Along with rate caps, concerns about recovery of meter costs and potential stranded assets have muted UDC interest in providing interval meters to customers. Competition in the provision of metering services, such as meter data management, may still be desirable.
- **Ensure that UDC and ISO demand response programs are coordinated and can co-exist**. ISO programs are important new options for incorporating a demand response into electric markets. Nevertheless, the implementation of these programs needs to be conducted in a fashion that does not negatively impact existing utility load management programs.
- **Address the role of third-party aggregation**. While third-party aggregation of load curtailment will be key source of new demand response and innovation, particularly for smaller customers, there are fundamental issues associated with bypass, revenue impact, and cost recovery that will need to be explored and evaluated.
- **Design programs with guaranteed payments for capability.** A clear outcome from market research on customer interest in demand response programs is the need for programs that provide guaranteed payments for participation.

These recommendations are discussed in greater detail in Section 4.3 below.

2. *OVERVIEW AND CRITIQUE OF ISO DEMAND RESPONSE PROGRAMS*

All four of the ISOs, that were fully operational during 2001, designed and implemented demand response programs. This section reviews these programs, identifies key technical and policy issues associated with their operation, and evaluates their implementation.

2.1 Existing ISO programs

The experience and design of each of the four ISO demand response programs is discussed below. A key emphasis in this review is on the interaction between ISOs and states in the development and operation of the programs.

California

California's experience with the design of demand response programs should serve as a cautionary tale on the potential pitfalls associated with ISO demand response programs. As of the end of 2001, the CAISO has suspended all but one of its demand response programs.

In preparation for potentially tight power supply situations in 2000 and 2001, California developed three separate demand response programs with the cooperation of load participants and aggregators. The three programs that were implemented by the CAISO were:

- **Participating Load Program (PLP)**. The PLP allowed loads to bid directly into the ISO non-spin and replacement reserve and supplemental energy markets. This program was geared towards large loads. Large water pumps are the primary participants in this program.
- **Demand Relief Program (DRP)**. The DRP functioned as a last-resort emergency tool to prevent blackouts. Participants in the DRP received a reservation payment, based on individual aggregator bids, plus an energy payment. Because of their system-wide benefit, costs for the DRP were allocated to all Scheduling Coordinators (SCs) based on metered demand and exports.
- **Discretionary Load Curtailment Program (DLCP).** The DLCP was designed to attract smaller customers, such as commercial lighting and air conditioner loads. This program operated through aggregators and gave smaller customers the ability to offer a firm load curtailment commitment.

Each of these programs was designed to induce participation form different types of load resources.

While these programs attracted offers of more than 1,100 MW of load reduction, the events of the past year in California created significant chaos in the electric market. Fundamental changes in the electric market, the demise of the California Power Exchange, and the introduction of the California Department of Water Resources (CDWR) as the purchaser of power significantly impacted how the programs were ultimately operated. Confusion was further created through orders from the California PUC (CPUC) that created demand response programs at the electric utilities after the ISO programs had been developed and approved.

In an April 3, 2001 decision,[22] the CPUC directed the development of several new demand response programs: the Base Interruptible Program (BIP), the Voluntary Demand Response Program (VDRP), and the Optional Binding Mandatory Curtailment (OBMC) Program, along with expansions of the direct load control programs and a San Diego-specific demand response pilot. The creation of these programs created significant overlap with the ISO programs – particularly between the BIP and the CAISO's DRP, and between the VDRP and the CAISO's DLCP. In addition, the CPUC concluded that existing interruptible customers should not also be able to participate in the CAISO's PLP program because of concerns about "double-dipping". The CPUC also decided not to allow UDCs to serve in the role of aggregators for the ISO's demand response programs. In June and July 2001, the CDWR, CAISO, and the governor's office created yet another program called the Demand Bidding Program (DBP). This program was a bid-based program and allowed loads to bid into multiple price levels, i.e. there might be four price levels available at $200 increments between $100/MWh and $700/MWh. Once the DBP was implemented, the CPUC cancelled the VDRP.

Another source of confusion was the source of funding for the CAISO programs. Along with their new role as the purchaser of power in California, the CDWR also became responsible for the financing of the CAISO programs. The CDWR requested major redesigns of the Demand Relief Program in late Spring 2001, and requested that payment for the programs could only be made through a credit to normal bills of the bundled customers of the IOUs. In addition, the CDWR expressed a preference for the use of the VDRP programs instead of the DLCP programs and chose not to fund full use of the DLCP program. Nevertheless, the ISO decided to maintain the DLCP during summer 2001 to provide a vehicle for unbundled or direct access loads, or loads that could not easily meet the VDRP interval metering requirements. A draft decision in late August reversed earlier state positions and prohibited cost recovery by CDWR for any funding provided for the ISO's DRP and DLCP programs.

Even with this level of confusion, the CAISO programs were used during summer 2001. On July 3, 2001, a Stage 2 System Emergency was called. During this emergency, the level of reductions from each of the ISO programs were:[23]

DRP:	162 MW
DLCP:	22 MW

In addition to these ISO program curtailments, utility-operated interruptible IOU programs contributed 760 MW statewide. The Demand Bidding Program was not operational during this emergency, and went into operation on July 31, 2001. While there were participants who actively bid into this program (albeit small in total MW) in August and September, these bids were never dispatched by the CDWR.

[22] CPUC, Decision 01-04-006, April 3, 2001.
[23] Second Quarterly Report Of The California Independent System Operator Corporation, Docket EL00-95-000, Filed December 14, 2001.

At the end of 2001, the future of demand response programs in California was placed on hold. The CAISO deemed it "prudent to scale back its efforts and defer to the CPUC, the CPA (California Power Authority), and the IOUs to develop programs and provide program funding."[24] In addition, the CDWR informed market participants in December 2001 that it would not be funding or operating the DBP program.[25] As was stated by the CAISO, the end result of the California experience is that

> …many Loads in California have been discouraged from participating in Demand response programs because of payment concerns, extensive curtailment of loads on the interruptible rate tariff, regulatory uncertainty, a large number of different, competing programs, and ongoing revisions to those programs. Demand response programs cannot succeed without better coordination among the various state entities, including the CEC, the CPUC, and the CPA[26]

Recent proposals to develop a new Demand Reserve Program by the California Power Authority[27] suggest that a state or ISO demand response programs may exist in the future. The Demand Reserve Program would be a contractual reliability-based program that will pay fixed payments for the provision of reserves and ancillary services when scheduled by the ISO. In addition, just prior to the issuance of this Report, in June 2002, the CPUC initiated a significant rulemaking proceeding (R.02.06.01) aimed at providing customers with the enabling technologies, tariffs and program options to increase demand response. The California Energy Commission has also initiated a complementary proceeding (OII-02-07-03).

New York ISO

As a counterpoint to the chaos of California, the experience in New York has been significantly more positive. The New York Public Service Commission (NYPSC), the New York ISO (NYISO), and the state's electric utilities have worked together to implement a coordinated set of demand response programs at the NYISO and at the LSE level. The electric utilities, marketers, generators, and the NYPSC were involved in the design and development of the ISO programs, and the NYPSC directed the electric utilities to implement the NYISO programs at the retail level.

In a similar fashion to California, New York developed demand response programs during 2000 and 2001. The NYPSC has historically promoted the development of load curtailment programs. It directed Con Edison to develop a load curtailment program in March 2000 as a partial solution to local reliability problems in New York City.[28] In addition, NYISO allowed participants with the capability to curtail their loads to be deemed curtailable ICAP Special Case Resources (SCR). LSE's were allowed to designate these load-based SCR to fulfill their installed capacity (ICAP) requirements, and purchase this capacity from customers. Qualifying participants

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[24] ibid
[25] Letter from Peter Garris, CDWR, to Terry Winter, CAISO, December 13, 2001.
[26] Second Quarterly Report Of The California Independent System Operator Corporation, page 20.
[27] California Power and Conservation Financing Authority, Demand Reserves Back-Up Materials for April 12, 2002, April 9, 2002.
[28] Case 99-E-0930, Proceeding on Motion of the Commission to Investigate the July 6, 1999 Power Outage of Con Edison's Washington Heights Network, Order Concerning Staff Report and Directing Company to Show Cause (issued March 15, 2000).

received guaranteed payments during the summer period for being on call for the NYISO as ICAP during periods of reserve shortfalls.

Heightened concern about the potential for blackouts and supply shortfalls in New York led the NYISO to establish an ongoing Price-Responsive Load Working Group ("PRLWG") in August 2000. This working group was comprised of representatives of LSEs, NYPSC, NYISO, energy service companies, and other interested market participants. The PRLWG reports directly to the Business Issues Committee. The NYPSC also established a Pricing and Reliability Task Force within the Department of Public Service in the fall of 2000 to ensure New York State would have reliable supplies of electricity at reasonable prices. A major focus of this task force was the development of a demand response in New York.

After months of discussion and development effort, the PRLWG created two demand response programs:

- **Day-Ahead Demand Response Program (DADRP).** Participants in the DADRP submit their demand bids into the day-ahead market. Participants receive the higher of their bid or the market-clearing price if selected.
- **Emergency Demand Response Program (EDRP).** The EDRP is called during system emergency conditions. Participants receive $500/MWh or the market clearing price, whichever is higher.

The EDRP program was submitted to FERC for approval in March 2001 and received final FERC approval in April 2001. The DADRP took longer to design and was submitted for initial approval in April 2001, and received approval in May 2001.

At the same time that the NYISO was developing the demand response programs, the NYPSC in December 2000 ordered electric utilities in New York to "develop program proposals in support of or apart from those being undertaken by other entities, to ensure that all potentially economic demand response programs are available to customers."[29] The intent of this order was to solicit innovative programs from electric utilities. The NYPSC's other goal from this order was to ensure that there were programs in place in New York for the summer if the NYISO programs were delayed. The NYPSC specifically requested utilities to file programs on dynamic pricing and direct load control. New York utilities filed program proposals and concepts in late January 2001. Many of the programs filed included retail versions of the programs being considered by the NYISO, as well as real-time pricing programs, while others such as Con Edison's and Orange & Rockland Company's demand bidding proposals used different program structure. Once the NYISO programs were approved by FERC, the NYPSC ordered the New York utilities to conform their proposed programs to the design of the two NYISO programs. As a result of these actions, New York electric utilities conduct a combination of programs that are operated by the electric utility and by the ISO.

[29] Case 00-E-2054, In the Matter of a Status Report on the Demand/Supply Component of the Department's Electric Price and Reliability Task Force Including Recommendations for Specific Utility Actions on the Demand-Side, Order Requiring Filings And Reports On Utility Demand Response Programs (issued December 20, 2000).

Besides the level of coordination between parties in New York, the NYISO demand response programs are also notable for how they dealt with two key issues: third-party aggregation and the role of distributed generation. New York is one of the few ISOs that allowed third-party entities to aggregate customer load curtailments and submit these aggregated totals in the NYISO programs. According to the NYISO rules, third-party aggregators (known as Curtailment Service Providers (CSPs) or Demand Reduction Providers) are not required to be licensed as a retailer or provide retail electricity to customers. Nearly a quarter of participants in the EDRP program in 2001 were CSPs.[30]

The use of distributed generation, particularly diesel-fired emergency generators, as the source of load curtailments was a significant issue in New York prior to summer 2001. After much debate and negotiations with state and local environmental regulators, participants were allowed to use diesel generators in the EDRP reliability-based program as long as the use of the diesels complied with local permitting and the total amount of diesels did not exceed 150 MW statewide. The rational for this decision was the acknowledgement that if system outages occurred, diesels would be operated far in excess of the 150 MW, with consequent greater localized emissions. In New York City alone, it is estimated that between 950 MW to 1,200 MW of emergency generators are installed at customer sites. Diesels were not allowed in the market-based DADRP.

Load curtailments were executed during early August 2001 within the NYISO. The NYISO has reported the following estimates of maximum reductions associated with each of the ISO programs:[31]

EDRP:	455 MW
DADRP:	25 MW

Key reasons for the difference in impact between these programs were the voluntary nature of the EDRP, customer concerns about the penalty provisions in the DADRP, and the relatively late finalization of the DADRP program.

In addition, during the summer of 2001, approximately 360 MW of ICAP was procured as NYISO ICAP Special Case Resources. Load curtailments comprised 312 MW of this total, the remaining 48 MW was from customer generators. An even higher amount, 446 MW, was selected for the 2001-2002 winter capability period.

Implementation of demand response continues in 2002. As of June 28, 2002, over 1,200 MW of load curtailment is participating in the NYISO programs. Distributed generation comprises about 200 MW of this total.[32] In addition, during an unexpectedly hot mid-April day, the NYISO demand response programs were called.

[30] Neenan Associates, *NYISO PRL Program Evaluation: Executive Summary*, January 2002, p. E-4.
[31] NYISO, *Compliance Report in Docket No. ER01-3001-000*, December 4, 2001.
[32] Personal communication with James Gallagher, NYPSC, July 1, 2002.

PJM

PJM has taken an active role in the development of demand response for the last several years. However, since PJM operates in a multi-state region, the direct linkage between state policy and ISO demand response programs in PJM was not as clear as was the case in California and New York. The development of the demand response programs in PJM was also subject to disagreements between parties that highlight several key issues that will need to be addressed as demand response programs are implemented more widely.

In response to a FERC request for the introduction of a demand response, PJM formed the Distributed Generation User Group in 2000. One of the key tasks of the user group was the implementation of the Customer Load Response Pilot Program in 2000. The 2000 pilot program compensated end-use customers for measurable load reductions made at the request of PJM. Due to moderate temperatures during summer 2000, PJM did not experience sufficiently high demand conditions, and participants were never requested to reduce load. After summer 2000, PJM worked on developing a more expansive set of programs. The User Group developed the Load Response Program, which consists of the Emergency Option and Economic Option, for 2001 and 2002.

The Emergency Option was essentially the same as the reliability-based program included in the 2000 Pilot, except customers participating in the PJM Active Load Management program (ALM) also were allowed to participate in the Pilot Program when such participation did not impact the fulfillment of their ALM commitment. However, when ALM and the Emergency Option are activated simultaneously, participants cannot "double-dip", and the ALM take prcedence. Participants received $500/MWh or the locational marginal price (LMP), whichever was higher. Total payments paid out to participants were allocated across all energy.

The ALM program in PJM includes the various electric utility-operated load management programs. ALM resources are used as an alternative to capacity or capacity purchases to meet load obligations by LSEs, and generally receive a fixed guaranteed payment from LSEs for their participation.

The Economic Option was designed to provide a mechanism by which qualified market participants were compensated when they contracted with end-use customers to voluntarily reduce load during times of high prices. Participants indicated their interest in participating to PJM and then received the LMP that existed during the curtailment minus the retail generation and transmission charge of the customer's LSE. Total payments paid out to participants were allocated to the LSE's that had the obligation to provide energy to the participant.

The implementation of the Economic Option was the subject of controversy and disagreement within PJM. Many generators and electric utility members were not in favor of the program. Two key categories of complaints were expressed about the Economic Option. First, unlike market-based programs at the other ISOs, the Economic Option required LSEs to pay the market-clearing LMP to the participating customer, not the actual avoided generation costs (or other costs associated with purchasing energy and capacity) of serving customers. LSEs raised concern that these payments could result in higher costs for LSEs if LMP is higher than their avoided generation costs.[33] Second, utility distribution companies were concerned about the interaction and potential competition between their existing ALM programs and the Economic Option. The incentives for participation in the 2001 Economic Option and the more lenient participation requirements were perceived as more attractive than the UDC's programs.

Unlike the Emergency Option, which was approved by the full PJM membership, the Economic Option did not receive sufficient votes from the full PJM membership. The PJM Board of Managers chose to exercise its rights and file the Economic Option with FERC. FERC adopted the Load Response Program in May 2001.[34]

As was the case with the other Northeastern ISOs, load curtailments were executed during late July/early August 2001. A mix of reductions from the new ISO demand response programs and pre-existing load management programs were utilized. The PJM has reported the following estimates of maximum participation in each of the ISO programs (which occurred on August 9, 2001):[35]

Emergency Option:	61.7 MW
Economic Option:	0.7 MW

In addition to these reductions, maximum reductions from participants in the ALM program were 1,796 MW. A large contributing factor for these relatively low reductions was that significant quantities of curtailable load that were already participating in the ALM, and the precedence of ALM when ALM resources and the PJM Load Response program are activated at the same time.

ISO New England

The ISO New England (ISO-NE) has probably taken the most active role in developing ISO-based DR. ISO-NE and its predecessor have implemented demand response programs in their region for several years. Prior to the implementation of restructured markets in New England in May 1999, the New England Power Pool (NEPOOL) had implemented a load response program in 1997 that featured a fixed payment ($8,000/MW/per event) for voluntary reductions by customers during available capacity shortages in New England. In preparation for summer 2000, ISO-NE created a voluntary curtailment program similar to the earlier NEPOOL program. The new program allowed the customer to choose curtailment "blocks" of $500 per MWh, $750 per MWh, or $1000 MWh. During an emergency, if ISO-NE anticipated that in the next hour the energy clearing price (ECP) would exceed the block price, then those customers in each block would be notified to reduce their load.

ISO-NE further modified and expanded its Load Response in 2001 to include both a reliability-based program and a market-based program. The two programs were:

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33 This can happen since the LMP is the spot price. Typically, LSEs in PJM purchase only a fraction of their energy from the PJM spot market.
34 See PJM Interconnection, L.L.C., 95 FERC ¶ 61,306, May 30, 2001, order accepting tariff sheets as modified.
35 PJM's Report on the 2001-2002 PJM Customer Load Reduction Pilot Program, filed December 28, 2001 (December 2001 Report) at 5.

- The **Demand Response Program (known as Class I)** required participating customers to commit to mandatory energy reductions (100 kW to ~5 MW) on 30-minute notice from ISO-NE. Customers in the Demand Response Program received payments for their ongoing participation in the program (based on the clearing price for 30-minute operating reserves), and additional payments for the actual energy they saved at the energy clearing price.
- The **Price Response Program (known as Class 2)** allowed participating customers to voluntarily reduce energy consumption during periods when the projected energy clearing price was greater than $100/MWh. Customers in the Price Response Program were price-takers and only receive payments for the actual energy they curtailed. Payments were based on the energy clearing price. The voluntary energy reduction had to between 100 kW and ~5 MW.

The most unique aspect of the 2001 ISO-NE program was the use of a common Internet-Based Communication System (IBCS). During a Load Response event, participants were contacted via an IBCS supplied by RETX. The IBCS also provided customers with price information every five minutes, and collected interval demand information. All participants were required to use the IBCS. In addition, the first 1,000 customers to sign up for each program were reimbursed by NEPOOL for installation of the RETX Internet data collection equipment. Class 1 participants received 100 percent of the hardware costs of the system, while Class 2 participants received 50 percent.

The development of the ISO-NE programs occurred without significant controversy. All market participants were in favor of the 2001 programs and the programs were approved easily by NEPOOL committees. New England regulators were uniform in their approval.[36] The only issue that has created some debate was how to allocate the costs of the IBCS subsidized by ISO-NE. The final resolution was that the half of the cost of acquiring and installing the IBCS would be allocated to participants based on their prorated share of total electrical load for the month. The other half would be allocated based on net hourly load obligation (NHLO), as calculated for each participant for the month, divided by the total of participants' NHLO for that month. The aggregate ECP-based payments made to both Class 1 and Class 2 customers would be allocated to participants based on electrical load as a form of uplift.

Load curtailments were executed during late July/early August 2001 within the ISO-NE. The ISO-NE has reported the following estimates of maximum participation in each of the ISO programs (which occurred on August 10, 2001):[37]

Class 1 – Demand Response:	1 MW
Class 2 – Price Response:	20 MW

[36] See February 14, 2001 letter to Daniel Allegretti, Chairman of NEPOOL Participants Committee, from Donald Downes, Chairperson of the Connecticut Department of Public Utility Control, on behalf of the New England Conference of Public Utility Commissioners.
[37] Paul McCurley, NEPOOL Markets Committee Meeting, October 30, 2001, *New England's Load Response Program: Proposed Enhancements For 2002*. See. http://www.isone.com/committees/Meeting_Material/Market_Committee/2001_10_30/.

2.2 ISO Programs Under Development

In addition to the demand response programs implemented at the four older ISOs discussed earlier, the ERCOT ISO has also been working on the introduction of demand-response into the newly restructured Texas electricity market. This effort was driven by an order from the Public Utilities Commission of Texas (PUCT) that approved ERCOT's proposed protocols implementing the Texas restructuring legislation (SB7).[38] PUCT was concerned that the new electric market did not provide sufficient opportunity for load resources to participate.

A Demand-Side Task Force was created within ERCOT in August 2001 to satisfy this directive. This task force brought together stakeholders with interest and expertise in load management, interruptible rates, ERCOT market operations, energy efficiency, metering, load profiling, and public policy.

The ERCOT market's key distinguishing feature that sets it apart from the other ISOs is that it is primarily a bilateral market, with supporting imbalance and ancillary services markets operated by ERCOT. As a result, many of the demand response programs that depend on reservation payments or day-ahead or hours-ahead energy markets are not transferable to ERCOT. Instead, load resources can participate in the ERCOT as three different resource types: as a responsive load that passively adjusts their usage without ERCOT direction (which results in an over-delivery of resources and a net payment to the participant for the load reduction), as a Balancing-Up Load (BUL)[39] participant, and as a Load Acting as a Resource (LaaRS) provider (essentially acting as if the load were a generator). Table 4 summarizes the fundamentals of these three types of demand-side resources.[40]

Table 4
Demand-Side Resources in ERCOT

Resource Type	Markets in Which it Can Participate	Requirements
Responsive Load (Passive)	Passive participation in balancing energy market	• Interval Data Recorder (IDR) meter
Certified BUL	Balancing energy market	• IDR meter • Certification
Load acting as a resource	• Responsive reserves • Non-spinning reserves • Replacement reserves • Balancing energy	• Telemetry • Certification

The actual development of markets for these demand-side resources has been the focus of the Demand-Side Task Force since August 2001. While there are multiple issues to be resolved

[38] PUCT, *Final Order in Docket No. 23220: Petition of the Electric Reliability Council of Texas for Approval of the ERCOT Protocols*.
[39] "Loads that contract with a qualifying scheduling entity to formally submit offers to ERCOT to provide balancing energy by reducing their electricity use are referred to as Balancing Up Loads (BULs), *Financial Opportunities for Reducing Electricity Load*, ERCOT, June 2002.
[40] From *Task Force On Demand-Side Resources And Demand Responsiveness: Status Report*, First Draft, January 2002.

(including metering, existing small customer direct load control program participation, and caps on the participation of LaaRS in Responsive Reserves markets), additional work will be required. The key recommendations that have been presented and/or approved by ERCOT include:

- *Provisional Qualification of BULs and LaaRs*. Designed to provisionally qualify and certify existing demand-side resources to facilitate their transition to the new market structure and rules.
- *BUL Baseline*. Designed to change the baseline used to quantify the capacity payment to which a BUL would be entitled. New baseline calculations are based on historical usage adjusted to reflect usage immediately prior to curtailment.
- *Controllable Resources*. Designed to permit certain controllable demand-side resources an opportunity to participate as a regulation service resource.
- *Direct Load Control Programs*. To transition residential and commercial direct load control programs into BULs.

2.3 Programs at New ISOs

The development of demand response programs at new ISOs is still in its infancy. The Midwest ISO (MISO) officially began operations on February 1, 2002. At the present time, the MISO is focused on serving as a scheduling agent, and region-wide markets are not currently in place. The involvement of demand in markets will likely need to wait until at least a MISO imbalance market is implemented. MISO is also actively working with the SPP and PJM on a single market design, likely based on the PJM market structure.

The recent actions by FERC on Standard Market Design[41] suggest that demand response will occupy an important role in future wholesale markets, and that FERC is interested in RTO market designs that incorporate demand response in the following markets:

- transmission rights and access
- day-ahead markets
- real-time market
- markets for operating reserves
- capacity adequacy

Furthermore, the March FERC Staff Working Paper recommends that "proactive long-term planning and expansion must be done regionally," with full examination of transmission, generation or demand side options. It is expected that these concepts will be incorporated in a draft rule that will be released in summer 2002. As a result, future RTO proposals will likely need to incorporate demand response in their market design from their inception.

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[41] See *Standardized Transmission Service and Wholesale Electric Market Design*, FERC Working Paper FERC Working Paper, March 2002, *Options for Resolving Rate and Transition Issues in Standardized Transmission Service and Wholesale Electric Market Design*, FERC Working Paper, April 2002.

2.4 Program Refinements Under Consideration

The 2001 ISO demand response programs were "works in progress." Many still retained their status as pilot programs. In response to requests by members and market participants, ISO-NE, NYISO, and PJM have been actively considering modifications to their programs. The CAISO has chosen not to continue implementation of most of their programs in 2002.

Through these refinements, the three Northeastern ISOs are moving toward greater standardization of their programs. The key areas being addressed in the refinements are:

- Baseline calculations
- Aggregation
- Payment refinements
- Inclusion of congestion charges
- Floors on energy payments

This section presents and summarizes the status of the refinements by ISO.

ISO-NE

The ISO-NE has approved the following refinements to their Load Response programs in order to induce greater customer participation:

- *Greater Price Certainty.* Provide Load Response Customers with greater price certainty by providing a minimum payment amount and a minimum payment period to induce participation. A two-hour minimum payment period will be implemented in order to provide greater price certainty for participants, and a guaranteed minimum payment of $100/MWh for Class 1 customers will also be used.
- *Reduction in Response Period.* Revise the Response Period End Time for Class 1 by reducing the period that Class 1 customers be available to curtail from 7 a.m. until 11 p.m., to 7 a.m. until 6 p.m., to increase participation.
- *Provide Locational Value.* Provide Locational Value to Load Response by incorporating the concept of a "zonal congestion multiplier" into the program. The multiplier is based on the historical cost of congestion and represents a first step toward reflecting the locational value of load response (and energy) that will be an integral part of the market under Standard Market Design ("SMD") with locational pricing. A static multiplier would automatically increase the ECP payments to load response in the three most congested zones in New England.
- *Low-Tech Communications.* Provide customers in the Class 2 program the option of a low-tech communications protocol that would enable entities with less sophisticated communications capabilities to participate. These communications could include notification by pager or email.
- *ICAP Credit.* Provide ICAP credit for Class 1 customers on an equivalent basis to "Settlement Only" generators. This credit could be valued and sold through the bilateral ICAP market.

FERC approved these changes in March 2002.[42]

NYISO

The NYISO has approved the following refinements to their demand response programs in order to induce greater customer participation and to fix technical issues:

- *Customer Baseline Load Calculation*. Customer baseline estimates to determine customer curtailment levels in the 2001 demand response programs were based on average historical usage. An optional baseline calculation is now available to adjust the baseline to the level of load observed during the day of curtailment. This change addresses weather sensitivity and should be advantageous for temperature sensitive load.
- *DADRP Payment Calculations*. The 2001 DADRP program payments exposed LSEs to risks associated with their default service obligation when CSPs aggregated customer load curtailments. The Price-Responsive Load Working Group of the NYISO has approved changes that holds LSEs harmless for the payments up to the level of the bid.
- *Small Customer Aggregation*. The NYISO has approved a small customer aggregation pilot. This pilot is limited to 25 MW maximum and is focused on procedures to measure customer curtailment without the use of interval meters on each customer. Large cooperative apartment buildings in New York City have expressed interest in this program.

PJM

The PJM has proposed several refinements to their demand response programs in order to induce greater customer participation and to fix technical issues. PJM made generally minor changes to the Emergency Load Response pilot program, and proposed to make the Emergency program permanent. PJM also added a day-ahead option to the Economic program. Specific changes associated with each PJM program include:

Emergency Load Response Program

- *Reduced participation period.* Removed the requirement that a party must participate for a period of 10 hours. Minimum duration of a load reduction request will be two hours and the magnitude of relief provided could be less than, equal to, or greater than the kW declared on the Emergency Load Response Program registration form.
- *Trial non-hourly metered program.* Trial program for the next two years to allow non-hourly metered customers to participate in the Emergency Load Response Program. Participation by non-hourly metered customers will be limited to a total of 25 MW of aggregate load reduction over the PJM region.
- *Extended period.* Proposed to extend the program through December 1, 2004.

[42] See New England Power Pool, 98 FERC 61, 229, Order Accepting For Filing Proposed Market Rule Changes, March 1, 2002.

The Emergency program was approved by FERC on April 30, 2002.[43] The program will be effective June 1, 2002 through December 1, 2004. FERC chose not to make the Emergency program permanent as PJM had proposed.

Economic Load Response Program

- *Subsidies.* Provides an incentive to participate by providing a subsidy to participants by paying the full LMP when the LMP is $75/MWh or greater. When LMP is lower than $75/MWh, the payment to participants is reduced by the applicable generation and transmission charges paid by the customer to its LSE. Subsidies are limited to $17.5 million annually, which will be funded by the LSEs in the zone in which the reduction took place.
- *Extended Period.* Proposed effective period between June 1, 2002 and December 1, 2004.
- *Baseline Calculations.* Introduced alternative customer baseline calculation methods based on historical use, including optional weather-sensitive adjustment.
- *Day-Ahead Bidding Capability.* Introduces day-ahead bidding capability. In the day-ahead operations of the Economic Load Response Program, participants may submit offers to PJM by noon of the day that the day-ahead market is run. The offers shall include (1) the specific MW amount in minimum increments of 0.1 MW that the participant is willing to reduce; and (2) the day-ahead LMP level above which the load would reduce. The offer also could include a start-up and/or a minimum number of contiguous hours for which the load reduction must be committed.
- *Trial non-hourly metered program.* Extends the trial non-hourly metered program to participants in the Economic Load Response Program.

The Economic program was approved by FERC on May 31, 2002.[44]

2.5 Issues Associated with ISO Programs

Key issues associated with ISO demand response and how the implementation of these programs interacts with state regulation include:

- UDC Cost recovery
- Socialization of program participant payments/incentives
- Use of load profiles
- Aggregation
- Improvements in calculation of usage baseline
- Jurisdiction/access to customers
- Environmental Concerns Associated with Distributed Generation
- Lack of Recognition of the Uniqueness of Demand-Side Resources
- Timing of Payments

[43] See PJM Interconnection, L.L.C., 99 FERC ¶ 61,139 (2002), April 30, 2002, order accepting tariff sheets as modified.
[44] See PJM Interconnection, L.L.C., 99 FERC 61 ,227 (2002), May 31, 2002, order accepting tariff sheets as modified.

Each of these issues is discussed in greater detail below.

UDC Cost recovery

A key impediment to UDC involvement and aggregation of customers is the issue of recovery of program costs and lost revenue. UDC implementation of ISO programs or aggregation of load requires systems and processes for curtailing load, collecting interval meter data, and presenting interval demand to customers (typically done through a web-based energy information system). In addition, several utility demand response programs provide an interval meter at no cost for participants (e.g., the VDRP, BIP, and DBP programs in California). Utility personnel is also required to administer these programs.

UDCs will also suffer lost revenue from program operation. This revenue loss affects UDCs in both regulated and deregulated states. Of particular concern to UDCs is the loss of transmission and distribution (T&D) revenue. Since T&D charges typically contain significant volumetric components, reduced electricity consumption during the curtailment period can reduce UDC revenue. Revenue from demand charges may also be reduced if load curtailments occur at the same time that a new demand would have been reached under large customer demand ratchets. On the other hand, LSEs could lose significantly more revenue if full or rolling blackouts occur due to lack of available resources.

Fundamentally, if UDCs can be made whole for their costs and lost revenue, then UDCs should be indifferent about customer participation in ISO programs. However, recent experience suggests that cost recovery is not complete and eventually may be uncertain. Many of the PJM utility distribution companies have protested the forced "subsidization" of program participants that are features of the current ISO programs. State commissions have either not provided full recovery of program costs, made recovery subject to uncertainty, or have deferred recovery until a later point.

The NYPSC has acknowledged that cost recovery was an issue and is supportive of UDC recovery of their costs. In its order requiring UDCs to implement the NYISO's programs, the Commission directed that utilities are allowed to keep up to 10 percent of the payments for load curtailment they receive from the ISO programs to cover their program costs. However, in years when the wholesale prices are low and system emergencies are rare, utilities will receive little compensation for maintaining the capability for customers to access the NYISO market.[45] UDCs in California were instructed to place all their implementation costs in a memorandum account that will be examined for recovery at the end of UDC transitions.

UDCs can also benefit from demand response. UDCs with provider of last resort or default service obligations, particularly under rate caps, can benefit from lower market clearing prices if they purchase a portion of their requirements in either the day-ahead or real-time markets. This benefit needs to be balanced against program costs.

[45] The UDCs were also invited to submit petitions for alternative means of recovery. No UDC has made such a petition yet.

Socialization of Program Participant Payments/Incentives

An important and contentious issue in ISO demand response programs is whether the recovery of program participant payments should be socialized across multiple LSEs or system-wide. The primary justification for socialization are the benefits such as market clearing price reduction (see Figures 2 and 3) and improved system reliability that are created by demand response programs. FERC has supported these payments as a means to kick-start demand response programs. Recent studies have demonstrated that these benefits can exceed program payments or incentives.[46] Nevertheless, many utility distribution companies, particularly within PJM, view socialization as subsidization and are against this practice.[47]

The issue is primarily focused on demand-bidding programs, and is due to the lack of dynamic pricing. Theoretically, in the current environment of fixed retail prices, LSEs will be willing to pay no more than the difference between the wholesale cost and the fixed retail price for load reductions to program participants. If they don't pay for demand reductions and wholesale prices are above the fixed retail price, then they have a loss equal to that difference. They can avoid this loss by paying upwards of the full difference in the wholesale price and the fixed retail price. However, the demand reductions achieved may also reduce the costs of serving customers for other LSEs, particularly when the supply curve is steep. For example, Neenan (2002) found that market-clearing prices were reduced by more than program payments in 2001. These additional benefits have led industry observers to call for subsidies[48] and for PJM to incorporate subsidies in the 2002 Economic program. Other experts, such as Richart Cowart have suggested that socialization of demand response payments is no different than the recovery of transmission and congestion management costs in ISOs.[49]

Since the reliability benefits of emergency programs are significant and can be system-wide, recovery of program payments from affected zones or across the ISO is less contentious.[50] For reliability-based programs, the only key issue is the level of the payment, which has generally been between $250 to $500/MWh.

Depending on the ISO, the source of program participant payments for load curtailment can either be provided by (a) all energy consumers in the ISO, (b) all LSEs within a zone in which the reduction is required,[51] or (c) directly from the LSEs that serve participating customers. The ISO-NE and the PJM Emergency program are examples of the first payment recovery approach,

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[46] Neenan Associates (2002) demonstrated that reductions in market clearing prices paid by LSEs and customers exceeded program payments for the NYISO demand response programs in 2001, and that reliability benefits exceeded program payments by a factor of more than 4:1.

[47] See comments and protests filed on the PJM Economic Load Response Program proposal at FERC in Docket ER02-1326.

[48] See the comments in FERC Docket ER02-1326.

[49] Richart Cowart, *Demand-Side Resources and Regional Power Markets: A Roadmap for FERC*, draft, January 2002.

[50] A new issue about emergency programs has arisen in New York. Since the NYISO schedules all EDRP curtailments when system emergencies are imminent, generators have raised the concern that the level of EDRP reductions could go beyond restoring market equilibrium and reserves, and may reduce market clearing prices.

[51] Note that in Emergency programs, when there is no congestion, and reductions are needed system-wide, then all LSEs will be charged for participant payments.

and the subsidized amount of the 2002 PJM Economic Program, the NYISO EDRP and DADRP are examples of the second recovery approach. For instance, the 2002 PJM Economic Load Response Program allocates up to $17.5 million of payments every year for this socialization, and collects these payments from all LSEs in the zone in which the reduction took place.

The third payment approach recovers payments directly from retailers and LSEs who have the obligation to serve program participants. The PJM pilot economic programs in 2001 recovered payments to participating customers from the customer's LSE. The rationale behind this approach was that the participant's LSE benefits directly from the reduced need to purchase power during system emergencies or periods of high wholesale prices, and thereby should shoulder the cost of the program.

Aggregation

Aggregation of customer load curtailments is a key aspect of all ISO demand response programs. ISOs are wholesale entities and do not have the interest or the capability to directly interface with retail customers.[52] The ability to aggregate curtailments loads by third-parties (i.e., CSPs) who do not have a retail load obligation is a key issue in the four ISOs. In 2001, only New York and California allowed third-party aggregation, and non-LSEs were not allowed to participate in the DADRP program. These aggregators were required to file applications with the ISOs. PJM allowed entities to aggregate load as long as they became special PJM members. In 2002, non-utility aggregators (known as Demand Reduction Providers in NYISO's DADRP program) CSPs will be allowed to operate in the DADRP program. As defined by the NYISO, a CSP is a

> qualified provider that can produce real-time, verified reductions in NYCA *(New York Control Area)* Load of at least 100 kW, pursuant to the Emergency Demand Response Program ("EDRP") and related ISO procedures. CSPs can be either an LSE, a Direct Customer, a Curtailment Customer Aggregator, or a Curtailment Program End Use Customer.[53]

Demand response programs operated by utilities generally do not allow any third-party aggregation.

As will be discussed in a later section, allowing third-party aggregation has positive benefits. Aggregators can be important sources of innovation for introducing demand response into wholesale markets. In particular, aggregators provide an important role in bringing smaller customers, who may not want to purchase from a non-utility LSE for their commodity electricity, into the market. All three of the northeastern ISOs have recognized the potential for aggregation in preparation for summer 2001, and have implemented smaller customer aggregation pilots.

Nevertheless, aggregation introduces complexity into the ISO demand response markets, particularly with regards to payment and measurement of curtailments. Introducing another party into the payment stream requires additional transfer flows and must be designed to not place the LSE at risk. Table 5 presents an example of changes to payments in the NYISO

[52] Note that some ISOs such as NYISO do interact with large multi-MW Direct Customers.
[53] NYISO FERC tariff.

DADRP program to accommodate Competitive Service Providers or Demand Reduction Providers (DRP).[54] In order to make the LSE whole for their commodity costs (but not their lost distribution revenue) under most scenarios, the following credits and debits are made: (a) the LSE is charged for the whole load of their customers at day-ahead prices, explicitly ignoring customer curtailments (100 MW in the example), (b) the LSE is also paid the incentive associated with the curtailing at the day-ahead price, (c) the LSE pays the CSP for the actual load reduction at the day-ahead price, and (d) adjustments are made to reflect deviations from the schedule at real-time prices. As can be seen in the Table, the total paid out by the LSE is the same ($25,000 – a lower net amount owed to the ISO plus payments to the CSP), with and without any load reduction. Under this structure, if the DRP oversupplies and real-time prices are lower than day-ahead prices, LSEs are liable.

Table 5
Example Payment for Demand Reduction Provider Participation in the NYISO DADRP Program

Actual load reduction equals scheduled load reduction

	Day Ahead	Real Time	
$LBMP_{bus}$	**$250**	**$300**	assumed
$LBMP_{zonal}$	**$250**	**$300**	assumed
Fixed Load (MW)only	**100**	**100**	Real time fixed load is metered load plus measured DRP reduction
Load Reduction (MW)	**10**	**10**	Measured performance by DRP
Total DAM Load (MW)	**90**	**90**	Real time net load appearing on meters.
Shutdown duration (hrs)	**1**	**1**	assumed

Day-Ahead Settlement	**DRP**	**LSE**
Day-Ahead Energy Purchase		-$25,000
Payment for Day-Ahead Schedule		$2,500
Real-Time Settlement		
Payment for Performance	$2,500	
Nonperformance Penalty	$0	$0
LSE Normal Load Balance Credit		$3,000
Debit		-$3,000
Total Received (Paid)	$2,500	-$22,500

[54] Agenda Item 4: DADRP payment breakdown from December 10, 2001 meeting of the Price Responsive Working Group of the NYISO

Many UDCs have raised issues associated with allowing third-party curtailment aggregators into wholesale markets. The concern is that third-party aggregation is a form of bypass. If UDC customers, particularly customers who are currently served under default service, choose to be aggregated by a DRP or CSP and are selected to curtail, then UDCs may be liable for imbalance payments for oversupplying. In addition, UDCs may have invested in peaking capacity or purchased peak power to serve these customers. These investments could become stranded. Similarly, UDCs are also concerned that investments in load management could also become stranded if customers if aggregators are able to serve participants in these programs.

Improvements in Customer Baseline

One of the key issues that arose during summer 2001 at the ISOs was the calculation of customer baselines (CBL). The calculation of CBL is essential for the determination of load reduction payments in the ISO demand response programs. A CBL represents the level of usage that a customer would have consumed if it didn't curtail load. Load reductions are calculated as the difference between the CBL and the actual metered load. However, all CBL methods are susceptible to gaming to one degree or another, and most of the effort in designing CBL approaches is focused on limiting the ability to game or limiting the gains associated with gaming.

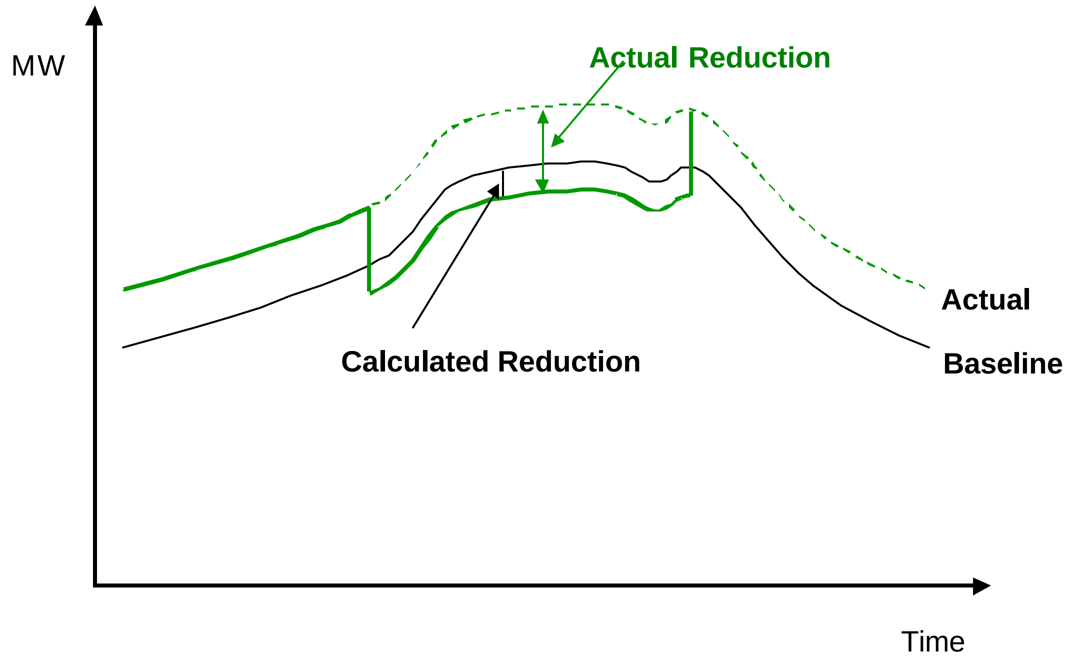
The most prevalent approach for calculating CBL in 2001 was a straight average of customer load over the previous 5 to 10 days.[55] However, this approach can disadvantage weather sensitive load and can be easily gamed. Customers with varying load (e.g., temperature sensitive loads) may find it difficult to reduce their loads sufficiently to meet minimum load curtailment levels or meet their demand bid levels. This can occur if temperature during the day in which the curtailment occurs is higher than the average temperature for the last 10 days. Figure 4 demonstrates the dynamics of this situation. The customer in this scenario takes action to reduce its load by a specific amount associated with their bid. However, since the remainder of their load is higher due to higher temperature, the reduction calculated with the 10-day average baseline will be less, and they may be subject to penalty for nonperformance. The NYISO found that many customers were unable to participate during a heat wave that followed a cooler than usual weather.

In addition, the use of a baseline based on a simple average may allow customers to easily game the system. In particular, a customer could bid into the day-ahead market when their facility will not be operating the next day. Since their actual load will be less than the baseline, they will be paid their bid, even though they did not actually produce any actual reductions. The NYISO market monitor uncovered this form of gaming in 2001.

In order to correct these problems, an alternative and effective baseline approach that adjusts the baseline to the actual load prior to notice is gaining favor. Instead of using the simple average baseline directly, the baseline is adjusted to reflect the actual load prior to the curtailment. This adjustment would have the affect of shifting the baseline upwards in Figure 4 to match the load prior to the curtailment. This is the approach used by the ISO-NE in 2001. Similar approaches

[55] The exception was the 2001 PJM Emergency Load Response Program. The PJM Emergency Load Response Program calculates CBL as the usage in the hour immediately prior to curtailment.

Figure 4
Problems with Non-Adjusted Baseline Calculations



are being implemented and/or proposed at NYISO, PJM, and ERCOT. This approach is not entirely without problems. Gaming can still occur by a customer who increases his production immediately prior to curtailment. This approach can also overpay for reductions associated with one of the primary methods of coping and planning for a load reduction, i.e., pre-chilling refrigeration systems or pre-cooling buildings in anticipation of an event would increase a customer's baseline.

Some observers and market participants question the need for baselines in markets that operate both day-ahead and real-time markets. In their comments on PJM's proposed 2002 Economic Load Response Program, Public Service Electric and Gas and its affiliates made the following argument:

> PJM already has a two-settlement system, where participants can "order" power in the day-ahead market, which is settled at the day-ahead clearing prices. This settlement is purely financial and allows parties to set their anticipated level of consumption. These same parties can then "sell back" any power that was not used at the real-time prices (or buy more at the real-time price if more was used). Thus, the day-ahead quantities serve as the CBL, and the demand response is simply any deviation from the day-ahead CBL, which is set by the CSPs themselves.[56]

[56] Joint Motion to Intervene and Protest of the PSEG Companies, FERC Docket ER02-1326, filed April 5, 2002.

Jurisdiction/Access to Customers

ISOs are wholesale entities and directly deal with only the largest customers. Since demand response is focused on eliciting customer participation and load reduction, key issues have arisen on how to best market programs and gain access to customers. In particular, concerns have been raised that FERC does not have any jurisdiction in the creation of markets for load curtailment.

These concerns have been raised primarily by UDCs. For example, PECO Energy filed a protest before FERC over PJM's design of its Load Response programs, particularly the PJM Economic Program. According to PECO,

> In a nutshell, PJM is proposing to pay retail customers, or their load reduction service agents, to reduce demand for electricity supplied by state regulated public utilities or state licensed competitive retail suppliers. The Load Response Program is in reality a retail demand-side management (DSM) program. DSM with respect to retail end-users can not be divorced from the retail demand from which it derives. DSM is thus the exclusive responsibility of state regulators. The FPA *(Federal Power Act)* does not authorize the Commission to bypass state regulation to establish DSM payments anymore than it empowers the Commission to set retail rates.[57]

FERC's answer to this protest and other similar protests in other ISOs is that these transactions "are considered wholesale when they involve the sale for resale of energy that would ordinarily be consumed by the retail customer." In that same order, FERC stressed that they "were not encouraging actions that violated state laws or regulations, stating that in our earlier order we had 'allowed retail customers, as permitted by state laws and regulations, and wholesale customers to reduce consumption for the purpose of reselling their load reduction at wholesale' and that nothing in our order 'authorized a retail customer to violate existing laws or regulations, or contract rights.'"[58]

Other comments have noted that FERC overreached in its applying this principle to load reductions. In its petition for a rehearing in California, the National Rural Electric Cooperative Association raised the question whether customers can take ownership of electric power provided to them under default service where the UDC has an obligation to serve.[59]

The issue of jurisdiction was raised with regulators in states where an ISO was in existence this past year. The consensus response of the states contacted was that these jurisdictional issues were not a major issue for their commissions. However, comments to FERC by NYPSC staff suggested that NYISO may need to file retail tariffs for the services and sales that they make to direct customers.

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[57] PECO Energy Company's Motion To Intervene And Protest and Request For Proper Docket Designation, Docket ER01-1671, April 20, 2001.

[58] Order Accepting Tariff Sheets As Modified, 95 FERC ¶ 61,306, Docket ER01-1671-000.

[59] Petition For Rehearing Of The National Rural Electric Cooperative Association, Docket EL01-47-001, June 15, 2001.

Environmental Concerns Related to Distributed Generation

The ability of distributed generation, particularly diesels, to participate in ISO demand response programs is a hotly contested issue. The source of this concern is environmental. Environmentalists and environmental regulators are concerned that local air quality will be negatively affected by the operation of distributed generation units that are participating in the demand response programs.

In response to these concerns, several states have placed restrictions on the use of diesel-based distributed generation. California did not allow diesels to participate in the CAISO programs. California State officials became increasingly concerned that the inclusion of back-up generators in the CAISO DRP program would encourage more diesel generator installations, and a request for bids for curtailments based on back-up generators for the DRP program was never reissued.

After significant debate and deliberation, the New York Department of Environmental Conservation allowed diesels to participate in the NYISO EDRP program, but not in NYISO's DADRP program. As was mentioned earlier, the limited use of diesels in the EDRP was driven by recognition that a small amount of diesel use could forestall blackouts, which would result in significantly higher diesel emissions. Diesel generator participation in the EDRP was limited to 150 MW statewide and all generators were required to meet local and state permitting requirements. Diesels were not allowed to participate in the DADRP because environmental regulators did not want to support profit-making actions of customers that would negatively impact local environmental quality. Funding was provided under the State's System Benefits Charge to clean up participating diesels.

For 2002, New York removed the 150 MW cap, put into place new permitting requirements for emergency generators, and provided assistance to assist in the permitting process. Of the 1,200 MW of demand reduction potential as of June 28, 2002 in New York, approximately 200 MW are associated with generation.

Lack of Recognition of the Uniqueness of Demand-Side Resources

The incorporation of demand-side resources into ISO markets has not been easy. ISOs, particularly the ISOs that were based on existing power pools (ISO-NE, NYISO, and PJM), were designed to manage physical assets, such as transmission networks and generation resources. The process of designing demand response programs that work within the supply-based ISO structures has been a challenge.

For example, the scheduling coordination software in use in the NYISO only has 50 bid slots available for demand-side resources statewide. Demand-side resources and demand response options are not negative supply resources and have fundamentally different characteristics. While a small number of available bid slots are acceptable for supply resources, it is not adequate for multiple bids by each LSE. A better approach for incorporating demand response into a wholesale market should be as a load-modifier or as multi-part, demand curve. Alternatively, the multi-settlement nature of many ISOs could be exploited to allow participants to purchase power in the day-ahead market and sell the power back to the ISO through demand reductions in the real-time market. The choice to view demand response as a generator added to the complexity of the DADRP program.

Another bias that has impacted demand-side resources is the view that if demand-side resources want to be paid as if they were a supply-side resource in the ISO markets, then they should be held to the same standards. These views are generally expounded by ISO system planners and other non-demand-side market participants. Application of these supply-side principles to demand-side resources has led to requirements for advanced telemetry or detailed verification procedures on customer load and meter locations.

The use of existing systems and procedures at ISOs is also seen in minimum bid sizes. ISOs typically work with generation resources in multi-MW sizes. As a result, most ISOs have minimum bid or load reduction resource sizes of 1 MW. These minimum size requirements create a bias towards large participants, and make it more difficult to aggregate smaller load reductions.

Timing of Payments/Settlement

An important issue for many customers who curtailed load in 2001 has been the speed and timing of payments. Many customers did not received their payments until well after the summer, and in some cases several months later. Customers were displeased and frustrated with this lengthy turnaround.

The slow payment cycle was based on ISO settlement timetables. LSEs were waiting until final settlement occurred before they paid participating customers. In the wholesale market, final settlement cannot occur until consumption meters are read for all customers, typically within a month. These settlements are then typically subject to review and editing prior to finalization. This process can take another 15 to 60 days. LSEs are always in the market and can have positive and negative settlement positions that change daily over the course of the year. As a result, these long settlement and payment periods are not problematic. However, end-use participants disliked the delays and slow payment may influence future participation.

Although settlement procedures and timetables are important and should be followed, alternative settlement provisions and/or accelerated payment schedules from LSEs should be examined. For example, if a customer has software and interval metering equipment either installed or supported by an LSE that can calculate and transmit load reductions from customer baselines in near real-time, then LSEs should have confidence in resultant demand reduction levels. It should not be necessary in this circumstance to wait 45 to 90 days to pay customers.

2.6 Lessons Learned and Critique of Existing ISO Programs

The experience with ISO demand response programs over the last several years has been generally positive. Reductions have been achieved during periods of high demand and high prices, and participating customers are satisfied with their interaction with LSEs, aggregators and the ISOs. Nevertheless, there are several important lessons that have been learned, and areas where the ISO programs could be improved. The focus of this section is on program design.

Issues and lessons associated with customer participation are discussed in Section 3. These lessons and areas for improvement include:

- Lack of complete cost recovery
- ISO program complexity
- Whether benefits should be socialized is still unanswered
- Third-party aggregation works
- ISO demand response programs need to be fully coordinated with LSE demand response and load management programs
- Design programs early and conduct customer education
- Reduce the payment delay
- If limited calls for curtailment occur this summer, it may be difficult to retain participants, unless the customer is paid for the capability to reduce.

A discussion of each of these lessons and critiques follows.

Lack of Complete UDC Cost Recovery

Cost-recovery of the costs associated with ISO demand response programs has not been addressed in a satisfactory manner in any region served by an ISO. As the natural aggregators of customer demand reductions as part of ISO demand response programs, UDCs will expend funds to administer, collect, and process customer demand reductions. While the UDC will clearly benefit from improved reliability and reduced wholesale market clearing price when a program is operated, program operation and the extent of the benefits are uncertain. In addition, under the current volumetric-based distribution rate structure, UDCs are at risk of losing distribution revenue when customers actively participate in the ISO programs.

Except for New York, no jurisdiction has directly addressed the cost recovery issue. The remaining states have either not directly addressed the issue or have directed their utilities to track their costs for recovery in a later rate case. This latter recovery policy only defers the decision and still subjects the UDC to potential disallowance. In New York, UDCs are able to retain 10% of the incentive payments to program participants. However, in a cool summer with low prices and limited use of demand response, the UDCs may not cover their costs. Utilities were invited to file alternative cost recovery petitions, but no utility has filed. In PJM, how utilities will or should recover their share of the $17.5 million subsidy is also undetermined.

Ultimately, cost recovery will need to be resolved in a manner that benefits or does not hurt all parties. UDCs, particularly utilities who are distribution-only companies, should not be disadvantaged through actions taken by their customers and by ISOs to improve the efficiency of wholesale markets.

ISO Program Complexity

Many of the currently implemented ISO programs were complex. Due to their pilot status and the need to work with existing systems built for large generators, the design of demand response programs was not user-friendly in 2001. For example, the DADRP at the NYISO limited both the number of possible price points at which the customer could bid and the number of total aggregated bids that could be entered in the ISO's unit commitment software. The payment streams that have been devised in the DADRP program to allow CSP involvement and make UDCs whole are very complex. In order to obtain payment for demand reduction in ERCOT, participants may need to sign multiple agreements with retail electric providers and scheduling entities, and may be required to install extensive telemetry. Customer baseline calculations are also complex and can create customer frustration and confusion.

Nevertheless, power markets and ISO markets are complex. If customers want to participate in these markets, they will need to be cognizant of this complexity. Moreover, payments for reductions must be made on verifiable measurements of load reductions. LSEs and aggregators are the logical entities to translate ISO programs into offerings that are understandable and attractive to customers.

Whether Benefits Should be Socialized is Still Unanswered

As was discussed in the Introduction, the introduction of demand response can produce significant benefits. Reliability-based programs can create significant reliability benefits to purchasers of electricity in ISOs. While the direct impact of market-based programs is on spot prices (either in the day-ahead or real-time markets), these programs can also lessen the severity in price spikes, produce additional reliability benefits (which can be quantified), and may affect forward prices in the longer-term through reducing the need for maintaining high-cost peaking capacity.

At the same time, customers and aggregators (either LSEs or CSPs) must make economic decisions based on their own cost-benefit. The result of this disparity of cost and total benefit may result in less than optimal investment in demand response capability. While a full transfer of benefits is not being advocated, some recognition of this disparity should guide the design of incentives. Nevertheless, many parties (most notably, UDCs within the PJM) are against any socialization because it represents a direct subsidy and distorts markets. The limited extent and duration of the incentive in the PJM Economic program reflects a compromise on the part of PJM and FERC to jump-start a new market, but not significantly impact markets. Further examination of this issue is required.

Third-Party Aggregation Works

Albeit limited in scope, the experience in the NYISO demonstrates that CSPs can produce meaningful demand response when given the chance. Note, however, that much of this participation was in the combination of the ICAP SCR and the EDRP programs, where at least a portion of the payments that they received was fixed based on the provision of interruptible capacity. Given the greater uncertainty in market-based programs on whether bids will be called, it is unclear whether aggregators will be interested in participating in the DADRP program summer 2002.

Coordination of LSE and ISO Programs is Advantageous

The experience of this last summer in New York and PJM demonstrates the benefits of coordinated LSE and ISO demand response programs. In New York, the NYPSC required all UDCs to file tariffs that implemented the NYISO programs. This coordination helped reduce confusion and provided a straightforward means for the aggregation of UDC customer load. Although the states in the PJM did not require the same coordinated programs as in New York, the requirement that customers must first meet their ALM obligations provided clear direction on which program had precedence. Contrast these two ISOs with the experience in California. Limited coordination resulted in customer confusion. States should encourage greater coordination as these programs are further deployed.

Design and Finalize Demand Response Programs Early

The experience of the past several years suggests that when programs are designed and approved well before the summer, the degree of customer confusion is less. Sufficient lead-time also allows customers to be trained on program rules and invest in technologies or engage software or notification services. In addition, although the number of programs are too small to draw general conclusions, the programs that were completed and approved in 2001 during the late spring or during the summer (such as the DADRP in NYISO and the DBP in California) had smaller participation.

Although most of the proposed changes to ISO programs have been approved by FERC in advance of the summer, the revised PJM Economic program was finally approved May 31, 2002 – one day before the old Economic program was slated for completion. This late approval may result in similar problems that were experienced in California and New York.

Reduce the Payment Delay

One of the key complaints that have been lodged by customers is the delay in the receipt of incentive payments by program participants. The length of time should be shortened to a more reasonable length. One possibility is to pay customers after the end of the next metering cycle subject to adjustment, especially if the customer's usage is interval metered.

Payments for Providing Capability Encourages Customers to Participate

One of the key reasons for the success of the NYISO programs is the existence of the ICAP SCR program. Customers were able to participate in both the SCR program and other programs. Since customers were paid for their capability to reduce load through participation in the ICAP market, they had a greater level of certainty over the return from their participation. This certainty assists the efforts of aggregators to gain participation. Similarly, before it was shut down, the DRP program in the CAISO had attracted a significant number of potential participants because it included a fixed capability payment along with energy payments.

3. *METHODS TO ACHIEVE OPTIMAL PARTICIPATION BY LSEs AND THEIR CUSTOMERS*

The success of demand response programs is dependent on the participation of customers directly or through aggregators in the programs. This discussion explores the various possible methods to encourage participation by LSEs and their customers in demand response programs operated by ISOs, or actively respond to dynamic pricing.

3.1 Barriers to Broad-Based Customer Participation

This section reviews the drivers for customer participation in demand response programs and reviews the key barriers that deterred customers from participating in the ISO programs that have been implemented thus far. The information presented in this section is drawn from market research and demand response program evaluations that were conducted during 2001.[60]

Drivers for Customer Participation

Recent experience suggests that customers, especially large commercial and industrial customers, are interested in demand response programs. Market research has determined that the key factors driving customer interest and participation in demand response are the following:

- *Corporate Citizenship*. Corporate responsibility and citizenship is an important motivator in demand response programs, particularly the programs that are voluntary in nature. Many commercial and industrial customers are sensitive to being seen as doing their part to alleviate energy shortages or emergencies in their communities. They are also sensitive to environmental messages that are focused on helping the environment and mitigating energy shortages. A good example of this type of customer response was the overwhelming response to California's 20/20 rebate program.[61] These motivations suggest that a large number of customers will do what is required to keep the system operating through voluntary curtailments or through participation in voluntary load reductions. Nevertheless, it is important to not violate or overuse this corporate altruism. In addition, the persistence of this driver may diminish over time as other issues take precedence, their offers to participate are not utilized, or if customers perceive that blackouts are less likely. Early indications from California in 2002 are that customer consumption is increasing and that the conservation ethic from 2001 has not persisted.
- *Cost reduction*. A key issue for customers is whether the bill reductions plus any payments for load reduction are sufficient to cover the costs of participating in programs. Costs to participate include direct costs, such as curtailed or reduced production at a facility, operating costs of distributed generation if used to reduce facility demand (including fuel, wear and

[60] See David Kathan and Philip Mihlmester. 2001. "Customer Interest in Demand Response Programs", presented at AESP's 12th National Energy Services Conference, December 2001, Xenergy's market research in CEC's comments on CPUC's Phase II scoping memo as part of R.00-10-002, and Neenan Associates' NYISO evaluation.
[61] The 20/20 rebate program rewards customers with a 20 percent reduction in their bills if they reduce their electric consumption by at least 20 percent with respect to last year's consumption. All three large distribution companies have reported that that over 30 percent of their customers have qualified for this rebate.

tear on generators, and labor costs), any metering or information systems required for accessing load data, and the administrative costs (e.g., operation and maintenance, fuel costs, data analysis and tracking, manpower, etc) of monitoring and participating in programs. If customers do not believe that the bill reductions that they achieve from participation are greater than these infrastructure and administrative costs, they will be less inclined to participate.

- *Predictable Returns*. Customers are interested in a predictable return on their investment in demand response systems. To justify these investments, customers want some assurance that they would get enough financial benefits (i.e., financial payback) from the program to justify the investment and effort.[62] Participation in voluntary emergency programs that may never be called or market-based programs which may never reach customer price thresholds do not provide this justification. In addition, forecasted lower electricity prices in many regions and the lack of significant use of the programs has also raised doubts on whether the programs will be used and customers will receive payments in the future. It is possible that this issue can be mitigated by increased educational efforts aimed at demonstrating how the technologies can produce other benefits to the user, including increased energy efficiency and optimization of building systems.
- *Access to low-cost or subsidized hardware and software*. Customers are very receptive to receiving low-cost or subsidized hardware and software. While some customers stated that they already had interval meters in place, companies generally felt a program that included software to access their usage data would be of significant benefit to their organization. Customers feel interval meters could help them get more control of the energy consumption in their locations.
- *Access to distributed generation.* The access to and ability to use distributed generation, particularly the operation of emergency generators, is an important factor in customer participation. Operating a generator in response to notification can involve less inconvenience to facility operators. Depending on fuel costs and electric market clearing prices, operating a generator can also produce positive returns to the customer. New York has responded to this interest by implementing streamlined permitting procedures for emergency generators.
- *Availability of Incentives*. The use of incentives, e.g., bill reductions or payments for curtailed load, motivates customers to program participation. However, while incentives create interest in the programs, they may not be large enough to offset customer risk and volatility concerns.
- *Familiarity with demand response*. The customers with the highest probability of participating in demand response programs are those familiar and conversant with demand response concepts. Neenan Associates found that customers who have participated in utility DSM and load management programs were more than three times more likely to participate in the NYISO demand response programs.[63]

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[62] Jim Laird, Energy Manager for Home Depot, spoke at the Spring 2002 PLMA conference and stated that Home Depot is only interested in contractual programs that provide guaranteed payments. He stated that he cannot get facility managers interested in voluntary programs without predictable returns from their load reductions.
[63] Neenan Associates, NYISO PRL Program Evaluation, January 2002.

- *Educated and trained utility account representatives and field personnel.* A concern raised by customers and regulators was the lack of trained utility staff to respond to customer inquiries. Even if the utility distribution company does not have a financial stake in a particular program, utility account representatives and field personnel should be trained on the ISO programs and where to direct customer inquiries.

Barriers to Broad-based Customer Participation

As presented above, there are several drivers for customer participation in DR. Nevertheless, the amount of participation in ISO demand response programs has not been significant in most of the ISOs, other than New York. Evaluations and market research of participating and non-participating customers both before and after the 2001 summer has identified a number of key barriers to broader customer participation. These include:

- *Perception of risk*. Customers are generally wary of risk in all forms from participation in demand response programs. Customers currently perceive demand response programs as risky. These risks include potential for lost business during curtailment, risk of critical system loss, unavailability of backup generation, unknown costs of participation, or risks of incurring financial penalties. In particular, customers are risk-averse and concerned about exposing themselves to price volatility.
- *Penalties for non-compliance*. There is a notable shift in customer interest between voluntary programs and programs that contain penalty provisions. Customers are notably less interested in the price responsive programs that contain credible penalties. When the word "penalty" is attached to possible participation, upper management will closely scrutinize participation and participation will likely be limited.
- *Need for interval meters.* One of the primary costs of participating in demand response programs is the need to install interval meters, communications, and software to monitor and access customer loads on a near real-time basis. While costs for this equipment are declining, interval meters and associated support can be expensive when not undertaken via a mass deployment effort. Customers are reluctant to expend funds and effort to install this equipment unless they believe that they can recover their costs. Nevertheless, many large customers already have advanced meters installed that can be used to participate in these programs.
- *Time required to monitor prices and system conditions*. Monitoring prices and actively participating in demand response programs, particularly market-based programs, takes time and effort, in addition to corporate commitment and oversight. For some organizations, this type of participation is quite daunting and there can be a strong reluctance to move into unknown or uncertain business areas. Customers have indicated concerns about the administrative cost of participating in demand response programs, particularly dynamic pricing programs, such as real-time pricing. Unless the company is of sufficient scale to hire staff or procure services to monitor wholesale market price fluctuations and to participate actively in real-time markets or demand response programs, many companies indicate that the time and effort exceeds their perceived benefits of participation. Consultants and other advisors may be needed to help him manage the process. The costs of this assistance may make participation cost prohibitive.

- *Removal of control of their systems.* Commercial and industrial customers are reluctant to give up any control of the operation of their facilities. This reluctance suggests that broader customer participation in programs or aggregations of customers that rely upon third-party remote operation and curtailment, such as direct load control, will be difficult. One possible way to address this will be via programs whereby control by a third party is limited to certain triggering parameters and then, once implemented, subject to certain performance constraints. Consolidated Edison's recently announced "smart thermostat" program is an example of this.
- *Environmental rules associated with DG.* Given that a driver for customer participation is the use of DG, particularly high-emitting diesel generators, as the source of load curtailments, environmental rules that limit the use of DG may limit customer participation. Environmental rules that limit DG participation include local permitting restrictions, limits on maximum number of hours, and limits on participation in ISO demand response programs. The natural sources of DG are customers with backup, emergency generators on-site. These additional limits on the use of DG may limit customer interest in transforming these generators into demand-side resources. Environmental restrictions were in place for the CAISO DRP and the NYISO EDRP such as limited run hours or requirements to use ultra low-sulfur fuels.
- *Fixed default service rates*. A fundamental barrier to customer participation is that most customers in the ISO markets currently receive service under fixed default service rates. Indeed, a common structure in almost all the currently restructured states is the existence of rate-caps during transition periods. Fixed default service rates remove customer incentives to actively control the pattern of their usage. Even with the provision of interval meters that provide customers with information on their usage pattern, the lack of incentive for shifting usage still remains a barrier. The implication of this barrier is that in order to actively respond to high wholesale markets, customers must take action to participate in ISO programs or in customer aggregation efforts. Another implication is that LSEs need to provide a means to pass-through high market-clearing price above these fixed prices if the customer chooses to participate in demand response programs.
- *Load profiling*. In a similar fashion to the barriers associated with fixed default service rates, the use of load profiling to represent customer load in restructured markets limits the ability of the customer and/or his aggregation agent to extract value from customer curtailments. Unless a specific load profile is developed to reflect customer load during a curtailment, LSEs are obligated to schedule and settle their supply of electric power at standard, non-curtailment, load profiles. This removes an important incentive for customer participation, particularly for small- and medium-sized customers. Creation of specific load profiles may require load research samples with the installation of interval meters, potentially with telemetry, at small customer locations.

  If reasonable load profiles for air conditioner or water heater cycling are available or can be developed and approved by state regulators, the ability of aggregating these small customers to participate in ISO programs is enhanced. In addition, this form of load profiling would improve the allocation of Unaccounted for Energy (i.e., the difference between metered usage and the sum of interval metered usage and load-profiled consumption). Nevertheless, using samples can mean getting away from the basic principle of pay for performance. With samples/profiles/groups, individual incentives and responses that are different than the group as a whole can be diluted or eliminated.

Steps to Reduce Barriers

In order to increase the level of demand response in electric markets, ISOs and state commissions should take the following actions to fix these barriers. Several key steps that should be undertaken include:

- *Implement dynamic pricing.* Perhaps the most important barrier to demand response in wholesale markets is the lack of dynamic pricing. Implementation of dynamic pricing is the most efficient means to introduce elasticity into markets. Dynamic pricing also avoids the complexity and potential for subsidization that occurs with the reliability and market-based ISO demand response programs. State commissions should work with their UDCs to implement pricing programs that pass-through the wholesale prices to customers. These programs can include straight passthrough of wholesale prices, the use of two-part real-time pricing programs similar to Georgia Power's pricing program, or the use of time-of-use rates that include critical pricing periods that are activated when wholesale prices spike.[64]
- *Install interval meters.* Equally important is access to interval meters. Interval meters and associated communication systems are required in almost all ISO and UDC program. While many larger customers already have interval meters installed and are thereby capable of participating in programs, large amounts of smaller customers do not have these meters installed. New York subsidized 100 percent of the costs for installation of interval meters through its Systems Benefit Charge. California appropriated $35 million to install interval meters for large customers who did not already have interval meters installed.
- *Simplify the design of the programs.* If it takes more than a few minutes to describe how a program works, encouragement of customer participation will be difficult. Many of the ISO programs were very complex, particularly NYISO's DADRP program. Simplification will be a problem because there are complex payment and system operation issues associated with these programs. Redesign of ISO market designs to allow multi-part demand curves, or to allow easy access to the multi-settlement systems are possible solutions to reducing some of the required complexity.
- *Engage in customer education efforts.* Given the difficulty with reducing program complexity, customer education and training in the ISO programs will be crucial. Utility personnel and account representatives should be trained and directed to provide support to customers – at the minimum to direct them impartially to ISO websites or lists of retailers or aggregators providing aggregation services. Market research[65] supports this belief – customers want to see manuals, case studies, and have access to analysis tools. Customers have expressed interest in training on how to participate in demand response programs or in opportunities for shifting load. Key topics of interest to customers include sensor and control

[64] A good summary of dynamic pricing options is contained in Braithwait and Eakin, Christensen Associates, *The Role of Demand Response in Electric Power Market Design*, Draft Final Report, prepared for the Edison Electric Institute, June 2002.
[65] Kathan and Mihlmester, 2001 AESP paper.

assistance, technology assessment assistance, how to recognize opportunities to reduce their load, and how to present technical information to financial decision makers. The key question is who will fund this education. At the minimum, PUCs should allow the costs of this education to be recoverable.

- *Reduce the confusion*. The chaotic events of 2001 along with the rushed implementation of the ISO demand response programs created significant customer confusion, particularly in California. Many programs in California and New York were still being designed and implemented during the summer 2001, or were radically changed in mid-summer.[66] In addition, the profusion of competing programs offered by ISOs, utilities, and those sponsored by state agencies such as the California Energy Commission or the New York State Energy Research and Development Authority (NYSERDA) were confusing to customers.[67] If at all possible, the rollout of revised and new ISO programs should be conducted in a logical and staged process long before the summer peak demand period.
- *Broadcast the nature of emergency*. More than one customer in focus groups conducted by ICF Consulting suggested they would be further motivated to participate if the nature of the emergency was made known. The ability to inform tenants why lights are lower or elevator banks are not in operation would help customers, such as property managers and hotel managers, participate in the programs.
- *Incorporate strong recognition/award components*. Market research suggests that many companies participate due to a feeling of corporate citizenship. This feeling of doing good should be rewarded with public recognition. A good example of a program with a strong recognition component is the U.S. Environmental Protection Agency Energy Star programs. Every year, particularly active companies and program allies are recognized in the press and at an awards dinner for their commitment to the program. State versions of these awards could be created.
- *Assist in the installation of enabling technologies*. Market research conducted on the existing programs also suggests that programs that decrease the hassle costs of operating their buildings through the use of "smart" communications and control technologies/software will have higher participation – particularly access to information, near real time, on their load and prices. Access to better information on market prices and system conditions would also be desirable.
- *Offer a range of programs*. The availability of a range of program options by ISOs and UDCs allows customers to make a good investment choice for their business. One of the issues identified by participants in the survey conducted for this study is that most customers are not in favor of a "one demand responsiveness program fits all" philosophy. ISOs and Commissions should also examine how long they will need to implement programs. By their nature, reliability programs may be temporary since they are designed to address short-term reliability issues. On the other hand, economic programs should be considered for long-term implementation until a large portion of customers is served by dynamic pricing.

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[66] California refocused CAISO's demand response programs and raised questions about funding after the beginning of the summer.
[67] New York has recognized this problem and has implemented in 2002 a coordinated demand response effort that includes the NYPSC, the Governor's office, state agencies, power authorities, and the NYISO.

- *Reduce the potential volatility in payments and costs of participating.* The success of the Georgia Power two-part real-time pricing program and feedback from market research in other markets suggests that programs that effectively cap customer exposure to high market prices or include limits on price volatility significantly increase customer interest in real time pricing and other forms of DR.

3.2 Role of Technology

The availability of enabling technologies is essential to the operation of ISO demand response programs. If ISOs have implemented reliability-based programs, they (or UDCs implementing coordinated programs) need the capability to notify customers/aggregators to curtail and/or actively curtail customer load during system emergencies. Customers need the capability to quickly reduce load, technology and/or software to measure and observe their load, and access to communications with the ISO. LSEs or aggregators need the capability to contact and notify customers to curtail.

There is a variety of technology and software solutions to this need. These include: metering, communications hardware, control equipment, energy management systems, and software to monitor and control customer demand (also known as energy information systems). Many of these technological capabilities exist at the present time. In addition, new technology solutions or packages are being developed and brought to market. However, there are many competing technology platforms in operation, and common protocols and/or standards have not been established.[68] In addition, the California electricity crisis, recent generally mild summers, high reserve margins in several regions, and low wholesale prices have not created large markets for technologies that allow customers to directly participate in ISO demand response programs.

The remainder of this section reviews the key enabling technologies, their status, and their current and potential role in demand response programs.

Role of Interval Metering

The most important enabling technology for demand response programs is the use of interval metering. Interval meters are advanced, typically electronic, meters capable of measuring and storing customer electric usage in 15-minute intervals or less. Interval meters typically have some form of automated meter reading capability, typically a telephone modem, for remote acquisition of customer data. Key interval meter manufacturers include Schlumberger, GE, Siemens, ABB, and Itron.

The operation of demand response programs is based on the ability of directing and measuring load curtailments. Payments for actual load curtailments also require accurate measurement of customer load during curtailments. Interval meters are currently the primary means to provide these services. However, in order to allow smaller customers the capability to participate in

[68] Note that many in the emerging demand response industry do not see a need for new standards for meters and associated technologies, since all participants currently agree to existing ANSI standards.

these markets through aggregators, other means and procedures, such as load research sampling or the use of deemed reductions, are being examined and explored.

The reason that interval metering is important for demand response programs is that the timing of load curtailments drives the value of these reductions for both the customer and the ISO. This linkage between usage and notification of customer curtailments and the time that the curtailment is required is especially crucial in ancillary service markets. The closer demand-side resources get to providing reliability services, such as ancillary services and real-time capacity, the greater the importance put on verifiable and observable demand on a near real-time basis.

The importance of interval metering in demand response programs is well understood. Almost all of the ISO demand response programs require an interval meter in order to participate. As mentioned earlier, state-funded programs in California and New York have installed interval meters at medium and large customers locations. On the residential and small commercial side, Puget Sound Energy has taken a bold initiative to install advanced meters at 320,000 customers that measure usage by time of day and which provide usage and price information to those customers on a daily basis.[69]

Interviews with state commissioners and ISO representatives conducted to support this white paper echoed the importance of the interval metering issue to the future of demand response programs. Without a large penetration of interval meters, the proportion of customers who can effectively participate in demand response programs will be limited.

Key issues associated with metering include:

- *Who pays for the meters?* In general, a necessary requirement of all demand response programs is the possession of an interval meter. Market research suggests that this requirement and the high initial cost of meters have been a deterrent to broader customer participation. Depending on the features and accuracy needed by the customer or program and whether revenue-class meters are required, large-scale installations of interval meters can cost between $50 for small customers and up to $3000 for advanced meters for large customers, plus the cost of installation and means to communicate with the meter. The low end of this range are single phase meters for smaller customers, while the higher end of the range are multi-featured polyphase meters for large commercial or industrial loads. In addition, if only time of use information is required for participation, the universal deployment of upgrades to existing meters at Puget Energy for about $30 per meter may be possible.[70]

  There are two possible solutions to this problem. First, states or ISOs could subsidize interval meters. For example, in order to correct this problem and allow customers access to their usage information, California and New York made explicit policy decisions at the state level to subsidize interval meter installations. Funds for these interval meter programs were

[69] Presentation by Gary Swofford, Puget Sound Energy, at the FERC-DOE, *Demand Response Conference*, February 14, 2002.
[70] Note that the Puget Sound Energy meter cost does not include the cost of the fixed-network communications infrastructure required to read the meters.

derived from general funds or from societal benefit funds that are collected through small electric rate surcharges. ISOs could make a similar investment and spread the cost as an uplift charge.

Second, UDCs could provide the interval meters and recover costs through rates. Participants in California utility demand response programs are provided with an interval meter by their electric utility if one isn't already installed. The costs of these meters are included in a memorandum account that may be included in rate base at a later date. One barrier to extensive UDC installation has been the move toward competitive metering in several states. UDCs in these states have been reluctant to invest in meters if their expenditure could potentially be stranded.

It is also important to acknowledge that deployment of advanced meters creates additional benefits beyond those directly associated with demand response. Distribution utilities realize significant operating savings from the implementation of advanced metering. Several utilities, including PECO and Pennsylvania Power & Light, are deploying advanced metering to all of their customers solely on the basis of operating savings. These savings are clearly substantial and should be incorporated in any economic analysis of advanced metering.

- *How often is it read?* A significant portion of the costs associated with interval meters is communication costs. Historically, interval meters were read by some form of automated meter reading technology – typically modems – once a month. While once a month reading may also be the minimum requirement for demand response programs, more frequent reads will likely be the norm. In particular, customers and aggregators will need more frequent meter reads to estimate customer baselines and to prepare demand bids. The more frequent meters are read the higher the cost. Technologies are under development to reduce these costs, such as powerline carrier, fixed wireless, and internet protocol meters. Encouraging developments in Pennsylvania associated with the implementation of automated meter reading systems at PECO Energy and Pennsylvania Power & Light may provide systems that can be used for demand response in future years.

- *Do you need it for all customers or curtailment schemes?* The use of interval meters can be cost-justified for large customers, but may not be cost-effective for aggregations of smaller customers. For example, the installation of advanced meters at every customer in an aggregation that involved residential direct load control would be cost prohibitive. Instead, load research sampling techniques can be used instead. The Protocol Revision Subcommittee of ERCOT has recognized this barrier and has recommended the use of sampling for small customer load control.[71] A stated objective of the new pilot being implemented at the New York ISO's is to explore means of measuring and verifying curtailments without interval meters.

Load Curtailment Hardware and Software

Over the last several decades, technology (both hardware and software) has been developed and implemented that can automate load curtailment. Fully automated load curtailment frees

[71] Communication with Jay Zarnikau, Frontier Associates, February 25, 2002.

customers from the physical process of turning off lights, adjusting temperature settings, turning on generators, or turning-off particular equipment. These curtailment schemes combine remotely operated devices, such as Digital Control Units (DCUs) with newer energy information systems. Other companies have developed backbone systems that facilitate two-way interaction.

The use of "gateway boxes" is a good example of this equipment. Gateway boxes contain switches and connections that allow multiple services such as cable television, internet connectivity, and telephone systems to be accessed from one location, and are typically installed at the service drop for these services. Gateway boxes can configured to provide the means of connecting disparate equipment such as energy management systems (EMS), internet connections, and remote load control switches.

Less automated curtailment systems do not control actual equipment, but provide notification to customers when they are required to curtail or should curtail based on predetermined economic or other criteria. Several companies have developed proprietary and highly customizable notification systems. For example, one vendor has developed a process they refer to as "permission-based" curtailment. Curtailments are automated in these systems, but customers are notified and given the option to not curtail when system conditions call for curtailments. The vendor's market research suggests that customers want the feeling of control that this permission provides.

A good example of the range of companies offering these systems is the participating vendor list from the California Energy Commission's Small Commercial and Industrial Lighting and HVAC Demand Response program.[72] In this program, the CEC is funding the installation of load curtailment capability at customer facilities. Over 20 vendors are participating in this program.

Customers generally pay the costs of these curtailment systems, as up front investments in hardware and/or ongoing service contracts with vendors. Some states, such as California and New York have allocated monies for grants to install curtailment equipment on small, medium, and large commercial and industrial customers, but these efforts are not the norm.

Building Control and Energy Management Systems

Building control and energy management systems have been available and installed at customer facilities for years. Typical systems include those sold by Trane, Novar, and other companies. These systems monitor and operate building systems according to prespecified temperature settings, usage schedules, and other user-specified parameters.

While EMS systems have the capability of shutting down systems, they typically have been used more for optimizing building operation and tracking consumption, and less for load management. In addition, older versions of EMS systems did not collect information on electric consumption.

EMS systems can be used to curtail load through control of key building functions, such as lighting, elevators, or other specific equipment under its control. The use of these systems for

[72] See www.peakreduction.com.

load curtailment is typically through manual overrides. More recent upgrades of these systems incorporate more advanced building control, such as light dimming and additional input sources. New input sources can come from pulse output from interval meters or from external directions obtained remotely or through internet gateway boxes. These advanced features can be exploited for load curtailment. The advanced curtailment systems and energy information systems discussed above have been designed to interface with these EMS systems.

Due to their extensive use and the large potential for reduction, upgrading these systems, or installing these systems at facilities without EMS, to take advantage of energy information systems or remote control should be a major goal for future demand response initiatives. Indeed, many of the demand response grants funded by the California Energy Commission in 2001 were directed towards this form of upgrades to existing EMS systems at large customers or corporate/university campuses. In addition to the funding of interval meter installations, states should consider funding grants to implement these systems.

3.3 Role of aggregators and other innovative programs

ISOs are wholesale entities that do not generally interact directly with retail customers. In addition, the existing ISOs were designed to operate large transmission grids and dispatch large generation resources. Routinely, ISOs only interact with scheduling coordinators, large generators, and/or LSEs. As a result, ISO demand response programs are geared to large aggregations of customer load response. Indeed, most ISOs have a 1 MW minimum size for aggregated load curtailments, and a minimum 100 kW reduction per participant.

Aggregation is a key feature of ISO demand response programs. Electric utilities, by their very nature, are natural aggregators for ISO demand response programs. They have the direct customer relationship and already have the systems and procedures for interacting and settling with the ISO in place. For most customers, particularly current participants in ongoing load management demand response programs offered by electric utilities, the continuation of this aggregation role makes sense and should not be discouraged.

However, electric utilities should not be the only aggregator of customer load curtailments in these ISO markets. Due to the loss of distribution revenue and non-complete recovery of program costs, the incentives for utility aggregation of new load response are not extensive. Unless utility programs can be developed that give customers full access to the wholesale market and the ability to respond and profit from high prices, the potential for new demand response may be limited. Access to third-party aggregators can add value to both customers and to the wholesale market.

Probably the most valuable role for third-party aggregators is to aggregate small and other hard to reach customers. Small customers (i.e., less than 200-500 kW) cannot participate directly in either the ISO demand response (which typically have minimum load curtailment requirements of 1 MW) programs or most utility demand response programs (which have a 100 kW reduction minimum). In addition, these customers may not currently be customers of competitive retailers, and thereby cannot be aggregated by non-utility market participants. Access to third-party aggregators will allow this group of customers access to wholesale market and will increase the price elasticity of demand.

Since load curtailment is the only product being offered by third-party aggregators, they can be an important source of innovation. In addition, since they are not restricted to offering tariff-based programs, they can also be more flexible in the programs and curtailment schemes they offer.

Two innovative aggregation efforts that are being planned for implementation in New York demonstrate how new approaches can be used. In the first approach, ConsumerPowerlines last summer aggregated public schools to curtail their load. When the load was selected for curtailment during August, all of the students and faculty vacated and turned off load in their offices and classrooms. The student body was brought into an all-school assembly on energy conservation and the importance of demand response. In the second example, ConsumerPowerlines has aggregated all of the tenants within an apartment complex within their program. If they are notified, the tenants are given free passes to the local movie theater as long as they agree to turn off all non-essential equipment in their apartments when they leave. The movie theater stamps the tickets as further verification that customers participated. Note that in both examples only one interval meter is required for the whole building, not one for each tenant. The building's interval meter measures the total reduction achieved.

However, the costs of enabling technologies on other than a mass deployment may seriously hamper third party efforts. Estimates are that it may cost five to six times as much to install meters and other associated technologies on an ad hoc basis as opposed to doing it in a systematic mass deployment. Also, the value proposition for installation of advanced meters can be greater for a utility than a third party as it captures the benefits from using the technology for theft detection, billing, outage detection, system optimization, and other operational benefits.

4. *STATE REGULATORY ISSUES ASSOCIATED WITH ISO-BASED DEMAND RESPONSE PROGRAMS*

This section focuses specifically on issues associated with state regulation of demand response and the interaction of state regulation with ISO programs.[73] Section 2 reviewed the key issues associated with the design and operation of the ISO-based demand response programs. This section concludes with recommendations for state PUC action.

4.1 Issues Identified by State PUCs

Several interviews were conducted with state regulators and staff[74] to obtain a more detailed understanding of the key issues facing regulators with the ISO-based demand response programs. The states interviewed were within the regions served by ISOs with existing programs, and are therefore not representative of the opinions of states outside of currently functioning ISOs.

While regulators did identify several important implementation issues, what was more significant was the support of these ISO programs by regulators. In addition, the states interviewed did not indicate much opposition to the operation of the ISO programs. The interviewees were uniform in their support of ISO demand response programs and the lack of major issues associated with the ISO programs. If they were involved in the development and or coordination with ISOs, their roles were to either promote demand response, to ensure that the programs conform to state regulations, or to ensure that demand response programs were developed. Most importantly, the state participants did not identify the issue of FERC jurisdiction over ISO demand response programs as a significant issue.

The key issues identified by state PUCs include:

- *Involvement of smaller customers*. Many of the commissions interviewed raised the need to include smaller customers in ISO programs. The concern of those interviewed was that all customers should have access to these programs.
- *Overlap between retail programs and ISO demand response programs*. As was discussed earlier, several commissions such as New York have taken significant efforts to ensure that UDC programs are coordinated with ISO programs. The proper role of state regulators is to ensure that state policies and UDC tariffs are consistent with ISO market design and demand response programs. Besides demand response tariffs that are consistent with ISO programs, states should also implement dynamic pricing programs that provide customers the capability of responding to price signals or investing in metering or curtailment system infrastructure. FERC's jurisdiction is at the wholesale level, and it is their responsibility to ensure that ISO market designs incorporate demand response as an essential element. It is the responsibility

[73] Regulation of other utility activities, in particular POLR and standard offers, may be even more important for demand response than direct regulation of the programs. See Eric Hirst, *Barriers to Price-Responsive Demand in Wholesale Electricity Markets*, prepared for Edison Electric Institute, June 2002.
[74] Interviews were conducted with regulators from California, Maine, New York, Pennsylvania, and Vermont.

of the states to ensure that the benefits provided by demand response at the wholesale level are felt at the retail level.

The experience of California suggests that lack of coordination can create significant issues. An example where overlap is not a problem is in Vermont. While they are aware and were involved in the design of the programs, ISO-NE requires 100kW of demand to participate in ISO-NE programs. Few Vermont customers meet this threshold, so the overlap between the programs the Public Service Board helps to foster and the ISO programs is not an issue.

- *Cost Recovery*. As was discussed in Section 2, cost recovery of utility investments and expenditures has been a key issue for state regulators. California, New York, and Pennsylvania all indicated that these issues have been raised and explored in their states. Full resolution of how these cost should be recovered has not occurred. The importance of cost recovery was especially important in states with default service obligations coupled with rate caps. Most states have asked utilities to track costs for later recovery. The state that has taken the most active role towards addressing the problem is New York.
- *Aggregation*. The states interviewed did not express any major concerns with third-party aggregation of customer load curtailments.

4.2 Role of State Commissions in Promoting ISO-Based Demand Response

The role of state commissions in the design and implementation of ISO-based demand response should be both advisory and as a facilitator of programs. Most of the states interviewed indicated that they had participated in ISO working groups and had helped design the ISO programs. For example, the New York PSC and the Public Utilities Commission of Texas (PUCT) took active roles in the ISO working groups and design of programs. NYPSC staff indicated that their primary role was to ensure that the programs conformed to state regulations and were able to be implemented by their utilities in time for the summer peak demands. The PUCT has taken an even more active role and has proposed revisions to ISO protocols and has directed ERCOT to develop procedures that allow demand-side resources to actively participate in the ERCOT market.

4.3 Recommended State PUC Actions

In addition to playing an active in the design of ISO-based demand response and directing UDCs to implement these programs, greater effectiveness and customer participation would occur if state PUC could take the following actions:

- *Examine the relationship between flat retail rates during transition periods and sending correct price signals.* A major impediment to the development of price-responsive demand is the existence of rate caps and fixed default service rates. Customers have little incentive to adjust their demand pattern if their bills will not be significantly affected. This problem is particularly acute in California. The large customers who now have interval meters installed cannot fully utilize these meters to change their utility bills through shifting or curtailing usage. The positive experience of Puget Sound Energy with the installation of 320,000 advanced meters and the implementation of time-of-use should provide an indication that customers are not against dynamic pricing.

- *State PUCs should explore how all or only targeted customers can be transitioned onto dynamic pricing.* As long as dynamic pricing is voluntary, the full benefits and/or impact of its application will not be achieved. However, care needs to taken in the near term to not violate rate caps or significantly decrease UDC distribution revenues. Alternative rate structures that should be examined include two-part real-time pricing (RTP) and a variation of time-of-use rates which adds a critical period component for super-peaks.

  PUCs should also consider moving large portions of their customers onto mandatory dynamic pricing, combined with distribution of interval meters. Without a requirement, customer inertia may limit market penetration of programs. Although there may be resistance both from customers and politically, the experience of Puget Sound Energy has been that only a small fraction of customers have requested to be removed from their opt-out time-of-use program.

- *Support the development of standard market design for demand response*. Although there are some common features between the demand response programs implemented at the ISOs, each of the programs is different (e.g., different notification periods, price points, and pricing). Greater customer participation would likely occur, particularly from large national chains and corporations, if these customers did not have to track and understand multiple program offerings. To this end, a group led by RETX has developed and submitted to FERC a draft set of demand response programs.[75]

  FERC understands this need. In the FERC staff working paper, the use of demand response in wholesale markets is a key element, and a final rule on RTOs and standard market design will likely contain detailed rules and/or proforma tariffs that incorporate demand response. Nevertheless, the goal of standard market design should not be used to override state-specific and existing UDC demand response program offerings. In addition, uniformity of program design should not get in the way of innovation and the recognition of truly unique issues.

- *Explore state funding or rate-based funding of enabling technology.* Along with dynamic pricing and access to ISO programs, the other requirement for greater participation and effectiveness of demand response is access to enabling technology, particularly interval meters. State PUCs and legislative bodies should explore funding these programs through state general funds, through rate surcharges like societal benefits charges, or through explicit recovery in rates. Note that not all customers need to have interval meters. A small number of customers comprise a sizable proportion of electric demand. If these customers can gain access to these technologies, the level of demand response in electric markets will be greatly enhanced. There is also the option of states working with a regional entity (such as an ISO or multi-state planning entity) to spread the costs of a particular demand response program across the region or multi-state area. Regional allocation of these costs could be appropriate if the benefits can be demonstrated to accrue to all customers on the system.

[75] RETX, *Recommended FERC Actions to Facilitate Demand Response Resource Programs Within Regional Transmission Organizations and Independent System Operators*, presented at the FERC-DOE Demand Response Conference, February 14, 2002.

- *Reexamine the introduction of competition into metering.*[76] The introduction of competition into metering has not been successful. For instance, after an encouraging start in California, the degree of metering competition in the state remains limited. A key issue is that the economics of universal deployment and operation of meters is significantly more attractive than one-by-one meter installations, with some citing a ratio of 5 or 6 to 1 when compared to ad hoc deployment to mass deployment.[77] As a result, most competitive metering companies have had difficulty competing with UDCs for the provision and installation of meters, and limited installations have occurred. With the possible exception of Pennsylvania Power & Light and PECO Energy, most UDCs in competitive metering or restructured states have not engaged in large interval metering installations. Rate caps, concerns about recovery of meter costs, and potential stranded assets under competitive metering have muted UDC interest in providing interval meters to customers. Yet the proper business case for advanced metering should include other benefits that accrue to a utility such as remote meter reading, theft and outage detection, and system optimization. State regulators should ensure that all of these benefits are considered in any examination of the costs and benefits of meter deployment.

- *Ensure that UDC and ISO demand response programs are coordinated and can co-exist.* ISO programs are important new options for incorporating a demand response into electric markets. Nevertheless, the implementation of these programs needs to be conducted in a fashion that does not negatively impact existing utility load management programs. Many existing programs have been highly successful. It would be a loss opportunity if these programs would disappear without the development of a similar load response in the ISO programs. An example of the negative impact on existing programs is in Texas. Over 3,000 MW of previous curtailment capability has been lost under the new market design implemented at the ERCOT.

  There are several models on how this coordination can happen. New York directed its UDCs to implement the ISO programs to ensure they had the maximum impact on wholesale market prices and to limit customer confusion. PJM designed its programs so that the existing UDC programs that were used as capacity reserves had precedence over new ISO programs. Local load curtailment programs can be implemented that coexist and complement ISO programs. For example, Con Edison operates a program (Rider U) which allows the utility to direct load curtailments within specific localized areas because of distribution system problems.

- *Address the role of third-party aggregation.* While third-party aggregation will be key source of new demand response and innovation, particularly for smaller customers, there are fundamental issues associated with bypass, revenue impact, and cost recovery that will need to be explored and evaluated. The small customer aggregation pilots underway at the NYISO and PJM should provide some guidance on how to proceed with these issues.

- *Design programs with guaranteed payments for capability.* A clear outcome from market research on customer interest in demand response programs is the need for programs that provide guaranteed payments for participation. Customers will be less willing to disrupt their operations or invest in curtailment capability, technologies, and/or software if the benefits

[76] This recommendation is focused on competition in the ownership and installation of meters. Competition in the provision of metering services, such as meter data management, may still be desirable.
[77] Chris King, *Advanced Metering: Lessons Learned and Policy Issues*, American Energy Institute

associated with participation are uncertain and potentially small. To complement other demand response programs that are more voluntary in nature, contractual programs at either the retail or RTO level will be need to be developed. These programs will also need to be subject to the development of acceptable metering and verification procedures.

Where the program should reside and who pays the guaranteed payments is dependent on the purpose of the program. If it is reliability-based, then the program should be operated by the entity that operates the system dispatch and safeguards system reliability. The source of funds for the guaranteed payments could be collected from all loads or only affected zones. In a similar fashion, programs designed to address local reliability should be operated and funded by UDCs. If guaranteed payments are offered in market-based programs, the source of the funding should come from the entity that will directly benefits from reduced market prices, i.e., a LSE, as part of their suite of pricing options.