***Appeared in* Competitive Electricity Markets: Design, implementation, performance.**
Edited by Fereidoon P. Sioshansi; Elsevier Publishing; 2007.

DEMAND PARTICIPATION IN RESTRUCTURED MARKETS

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Chapter Summary[1]

Demand Response is of particular importance in restructured markets which face some unique challenges in maintaining resource adequacy and preventing market power abuse. By responding to prices, by providing an ancillary service, or by offering to curtail usage in response to an interruption request, the participation of consumers or loads can contribute to the efficient operation of an electricity markets. Establishing the policies and market structure which will enable demand participation has proven difficult to date. Nonetheless, advances in technology and reductions in infrastructure costs hold the potential to raise the demand participation to new heights.

1. Why Demand Side Participation is Important in Restructured Markets

In most markets, there is little need to make demand more elastic. In competitive markets for most goods and services, retail prices adjust to reflect the relative abundance or scarcity of the good or service and changes in the cost of providing it to the market, and consumers adjust their purchasing behavior accordingly. But inelastic demand has been and remains a feature of electricity markets.

In the 1980s and 1990s, the establishment of real-time pricing programs sought to address this problem, by providing consumers with prices designed to mimic competitive prices that would reflect short-run marginal costs.[2] More recently, critical peak pricing programs became a popular means of eliciting a response from consumers by providing

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[1] Fereidoon P. Sioshansi, Parviz Adib, Alison Silverstein, Charles Goldman, and Nat Treadway provided valuable comments on earlier drafts of this chapter.

[2] G. Barbose, C.A. Goldman, and B. Neenan 2004. "A Survey of Utility Experience with Real Time Pricing, LBNL-54238, November.

strong price signals in a limited number of high-cost or high-demand periods. Yet, aside from these exceptions, regulated retail prices seldom reflected the frequent changes in the value of electricity generated, transmitted, and distributed by the utility system and sold to an ultimate retail customer. Tariffs reflected the long-term average cost of providing electricity to a class of consumers. For smaller electricity consumers, the costs of metering energy usage at less than monthly intervals thwarted pricing schemes to reflect changes in the value of electricity in retail prices in hourly or 15-minute intervals on a wide-scale basis.[3] Load management programs and other types of "peak clipping" or "load shifting" demand-side management sought to elicit responses from consumers in situations where pricing programs might not prove effective. This includes situations where the costs of metering and settling smaller loads based on real-time prices might outweigh the benefits.

While demand-side participation is important in regulated markets, the response of consumers or "loads" to price signals is even more crucial to the efficient operation of restructured power markets. As noted by U.S. Federal Energy Regulatory Commission (FERC): "Demand response is essential in competitive markets, to assure the efficient interaction of supply and demand, as a check on supplier and locational market power, and as an opportunity for choice by wholesale and end-use customers."[4] The National Association of Regulatory Utility Commissioners (NARUC) has called for regulatory commissions to accommodate demand-side resources and "remove any unnecessary barriers to customer responses to such wholesale market price signals."[5] Through the Energy Policy Act of 2005, the U.S. Congress affirmed the importance of expanding demand response opportunities as a matter of national policy, stating:

> It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated.[6]

One factor cited as responsible for the collapse of California's competitive electricity market in 2000-2001 was an absence or inadequacy of demand response.[7]

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[3] See, for example: Michael O'Sheasy, "Demand Response: Not Just Rhetoric, It Can Truly Be the Silver Bullet," *The Electricity Journal*, December 2003; and Jay Zarnikau, Martin Baughman, and George Mentrup "Spot Market Pricing of Electricity," *Forum for Applied Research and Public Policy,* Winter 1990, Vol. 5, No. 4.

[4] Federal Energy Regulatory Commission. *Working Paper on Standardized Transmission Service and Wholesale Electric Market Design*, March 15, 2002.

[5] NARUC, *Resolution Regarding Equal Consideration of Demand and Supply Responses in Electricity Markets*, July 2000.

[6] *Energy Policy Act of 2005*, Section 1252(f). See also U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005*. February 2006.

[7] Ahmad Faruqui, Hung-Po Chao, Victor Niemeyer, Jeremy Platt, and Karl Stahlkopf, "Analyzing California's Power Crisis," *Energy Journal*, 22(4), 2001, pp. 29-52. See also James Sweeney, "California

Demand response encompasses changes in consumer electricity consumption decisions in response to changes in the price of electricity as well as programs which require consumers to curtail their usage at the request of an independent system operator (ISO), utility, or other authority in return for a price discount or payment. The U.S. Demand Response Coordinating Council offers a formal definition:

> Providing electricity customers in both retail and wholesale markets with a choice whereby they can respond to dynamic or time-based prices or other types of incentives by reducing and/or shifting usage, particularly during peak periods, such that these demand modifications can address issues such as pricing, reliability, emergency response, and infrastructure planning, operation, and deferral.[8]

The U.S. Department of Energy (DOE) similarly defines demand response as:

> Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at time of high wholesale market prices or when system reliability is jeopardized.[9]

Many of these definitions of demand response encompass the load management and innovative pricing concepts that attained popularity under regulation.

In markets with relaxed regulatory oversight, demand response can restrain prices to economically efficient levels.[10] A small amount of demand response can yield significant reductions in short-term wholesale electricity prices.[11] For example, recent analyses by the staff of the New England ISO suggests that a 500 MW increase in demand response participation would reduce wholesale costs by $32 million annually.[12] A 3% load reduction in the top 100 hours in five Mid-Atlantic zones could yield total annual benefits of from $138 to $281 million.[13]

Demand response becomes all the more important when it is recognized that most restructured electricity markets are far from “perfectly competitive.” Thus a reduction in demand in response to a price spike is crucial to constrain the ability of suppliers to raise

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Electricity Restructuring, The Crisis and its Aftermath,” in *Electricity Market Reform: An International Perspective* Ed. P. Sioshansi, Elsevier, 2006.

[8] http://www.demandresponseinfo.org/id46.htm

[9] U.S. DOE, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*, Feb. 2006.

[10] Michael Rosenzweig, Hamish Fraser, Jonathan Falk, and Sarah Voll, “Market Power and Demand Responsiveness: Letting Customers Protect Themselves,” *The Electricity Journal*, May 2003.

[11] Ahmad Faruqui and Stephen S. George, "The value of dynamic pricing," *The Electricity Journal*, July 2002; and Douglas Caves, Kelly Eakin, and Ahmad Faruqui (2000) “Mitigating Price Spikes in Wholesale Markets through Market-Based Pricing in Retail Markets,” *The Electricity Journal*, April 2000.

[12] ISO-New England, Staff White Paper, “Controlling Electricity Costs,” June 1, 2006.

[13] Brattle Group, *Quantifying Demand Response Benefits in PJM*, Prepared for PJM Interconnection and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007, p. 4.

prices to inefficient levels (i.e., price levels inconsistent with consumer willingness or ability to pay), due to the exercise of market power or other anticompetitive behaviors. Insufficient demand response is sometimes used as a justification for wholesale price caps (which in turn may dampen or jeopardize price response).[14]

In markets where an "energy only" approach is adopted to maintain resource adequacy, demand response may play an important role in maintaining a balance between supply and demand. This is particularly important in light of the cyclical nature of power plant construction activity. During the periods when a market is left with inadequate reserve margins, demand response can provide an important backstop.[15]

It is sometimes argued that demand side resources can be used to defer or displace transmission investments in either a regulated or competitive market. There have been few situations in which this potential benefit has been successfully exploited.[16] However, some encouraging programs have been launched in California, New York, and the Pacific Northwest region of the U.S.[17]

Carefully crafted demand response programs can be used to foster reliability in real-time system operations. High wholesale prices or participation in programs through which loads curtail in response to instructions from a system operator in return for some financial compensation, can assist the system operator in balancing supply and demand in real time and in managing reliability during emergency conditions.

Finally, when viewed as a call option, demand response may provide a variety of risk management benefits to an ISO or load-serving entity in a competitive market.[18]

As electricity markets are redesigned to facilitate wholesale and/or retail competition, stakeholders and policymakers face the challenge of ensuring that consumers are presented with accurate price or curtailment signals and the appropriate incentives to react to those signals. Yet, responses by retail energy consumers to price changes and the introduction of demand-side resources (e.g., interruptible or curtailable loads) into competitive markets primarily designed for power plants pose certain technical and economic challenges. Key policy questions include the following:

- Must demand-side participation be fostered with special programs, or can a means of promoting demand-side participation through a competitive market structure be found?

[14] Adib, Parviz, David Hurlbut, and Danielle Jaussaud, "Market Power and Market Monitoring," in this volume.
[15] See Parviz Adib, Eric Schubert, and Shmuel Oren, "Resource Adequacy: Alternative Perspectives and Divergent Paths," Chapter in this volume.
[16] FERC, *Assessment of Demand Response and Advanced Metering*, Staff Report, Docket No. AD-06-2-000, August 2006, p. x.
[17] See FERC (2006), pp. 115-117.
[18] See FERC (2006), pp. 11-12.

- To what extent can demand response be relied upon to match supply and demand, especially in markets which plan to rely upon "energy-only" resource adequacy mechanisms?
- How will changes in consumption in reaction to wholesale prices affect the need for generation and ancillary services?
- How should a consumer's need for sufficient time to respond to prices be balanced against an ISO's desire to reduce forecast errors (to increase the accuracy of prices) in near-real-time operations?
- Can demand-side resources provide the same types of ancillary services as supply-side resources (generators)?
- What metering policies are needed in order to facilitate beneficial demand response?
- Will new technologies come to the rescue?
- Can demand-side resources play a role in markets for transmission rights?
- Is a "quasi-LMP" market structure, in which power plants face nodal prices and loads face a different set of zonal prices, sustainable?

While these policy questions are difficult, the stakes are high, and the opportunities to improve electricity markets through effective demand response efforts are enormous. Indeed, efficient demand response can contribute to resolving many of the problems associated with market power, resource adequacy, and reliability discussed in other chapters of this volume.

This chapter reviews the challenges associated with facilitating demand-side participation in competitive markets for power, provides a summary of various demand-side initiatives in restructured markets in North America, and contributes a case study describing some of the problems faced in promoting demand-side participation in the Electric Reliability Council of Texas (ERCOT) market, often cited as the most successful of North America's restructured retail markets.

2. Barriers and Opportunities

In any electrical network – regulated or restructured – the costs associated with energy generation, transmission, distribution, and meeting various operational constraints change continuously over time. The costs associated with serving customers in different areas of a network may vary greatly. Yet, electricity consumers have traditionally faced flat system-wide rates, which varied seldom over time or space within a utility service area. Economic efficiency requires that prices bear some relationship to marginal costs, a condition which was seldom satisfied under traditional ratemaking.

Successful demand response requires the correct combination of customer characteristics, economic incentives, metering and communications technology, market design, and policy.

Fundamentally, consumers need the motivation and means to respond to price signals or indicators of reliability problems.[19] Certain loads (e.g., municipal wastewater pumping, pipelines, and steel mills) tend to possess considerable flexibility in their operations and are natural candidates for nearly any demand response initiative. Production at such facilities may be delayed during a high-price period at relatively little economic loss to the facility. Similarly, water heating can be deferred for a few hours with no noticeable loss of comfort to a residential consumer. Technologies capable of enabling demand response may include backup generation, control systems, load monitoring equipment, and energy storage devices. High penalties for failure to comply with curtailment requests and uncertain payments tend to discourage participation in voluntary curtailment programs.[20] Response may be affected by incentive levels, notice periods, the importance of energy costs to the consumer, the communications infrastructure, the customer's sophistication in energy consumption decisions, and a multitude of other customer-specific factors.

In a regulated market, a vertically integrated utility may realize a variety of benefits from the ability to control or reduce loads. The cost of operating expensive peaking capacity may be reduced. Generating capacity additions may be deferred. In some rare situations, transmission or distribution capacity additions could be deferred. Overall system reliability may benefit. In regulated markets, demand-side participation can be fostered by utilities and regulatory authorities through the establishment of interruptible tariffs and demand side management (e.g., load management) programs.[21]

However, in an unbundled market, there are some unique economic challenges associated with demand-side participation. Different entities may receive value from different segmented benefits. For example, a retailer could benefit from lower purchased power costs or the ability to better manage power procurement risks, a transmission and distribution services provider might be the beneficiary of deferred transmission or distribution improvements, and the ISO might benefit from an additional tool to maintain reliability. But, no single entity (i.e., the retailer, wires provider, or ISO) is likely to derive sufficient benefits within its own sphere of operations to justify the establishment of a program. The "value chain" has been severed and economies of scale and scope may be lost.[22] In competitive markets, the design of the market rules must be crafted to accommodate and facilitate demand-side participation. Alternatively, special demand response programs may be grafted onto the competitive market.

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[19] Hirst, p. 2.

[20] Bernie Neenan, Richard Boisvert, and Peter Cappers, "What Makes a Customer Price Responsive?," *The Electricity Journal*, April 2002.

[21] It is sometimes argued that load management programs are not true demand response if their deployment is not sufficiently driven by prices or market conditions.

[22] An excellent discussion of this is provided in Havel Nos Spine, Demand Response: The Future Ain't What It Used to Be -- Or is it?" *The Electricity Journal*, July 2002.

For a retailer, the possibility of stranded costs, which may result if the customer later switches suppliers, may discourage investments in metering, control technologies, and technical assistance necessary to implement a successful program. This is particularly true for residential direct load control, where program equipment infrastructure costs can be quite significant relative to the economic value of the demand reduction that can be realized.

While third-party demand reduction aggregators can play a valuable role in facilitating demand response in competitive markets, they face a number of barriers. Access to the meter may be an obstacle. Who owns the meter? Is it just a "cash register" for the retailer, or can it also be used by a third-party who is developing a demand response program? In some markets, retailers are concerned about energy services companies (ESCOs) and demand aggregators "interfering" with their relationship with their customer, particularly if demand response may have an impact on the retailer's procurement of generation. Settlement procedures may be complicated when one entity is selling generation to a retail consumer while another entity curtails or shifts the temporal pattern of the electricity which is consumed.

Reliable real-time communications between system operators and retail customer pose another obstacle. It has been noted that currently "the protocols for sending the signal that capacity is tight and voluntary load shedding is needed is time-consuming, error-prone, and mostly manual."[23] Further, the feedback from the customer back to the system operator may be insufficient to assure the operator that adequate demand response has been achieved in real time.

Customer education may also be needed. Some energy consumers may lack the knowledge and sophistication necessary to take advantage of demand response opportunities. They may not understand the load associated with various equipment, the flexibility that they may have with respect to equipment operation, and electricity market economics and opportunities.

Another challenge is political. Generation owners recognize the ability of demand response to reduce the value of generation assets, given the potential of demand response to constrain prices and provide a substitute for certain ancillary services and planning reserves. Generators often wield considerable power within the stakeholder processes used to design and operate markets. Consumers who could provide demand side resources have primary interests which lie outside of power markets. Consequently, demand response initiatives may be difficult to establish when a stakeholder process is used to design a competitive market. "Consumer segments" may be less united and powerful than other market participant interests, and have relatively less understanding of the energy business than power producers.

Demand response poses some interesting challenges for market monitors. In some situations, it may be difficult to distinguish "gaming" from demand response. For

[23] Scott Neumann, Fereidoon Sioshansi, Ali Vojdani, and Gaymond Yee, "How to Get More Response from Demand Response." *The Electricity Journal*, Vol. 19, No. 8, October 2006, p. 24.

example, if a scheduling entity or market participant informs the ISO that its supply will exactly equal demand, but, after seeing a high price, curtails load under its control in order to create a net injection into the market and earn a profit from the unscheduled net sale to the market, is the market participant guilty of any improper behavior? The answer should be *no*. Yet there may be some suspicion that the (net) supply available from the entity was not as limited as the market was led to believe. It is important that market monitors have the information and tools necessary to distinguish between these situations.

For ISOs, demand response can introduce some complications into the operation of power systems. In the absence of a priority pricing scheme[24] where the prices at which load will curtail are announced to the market, the ISO may have difficulty understanding the slope or elasticity of the market's aggregate demand curve in a real-time energy market. ISOs sometimes complain that demand response affects the accuracy of their near-term forecasts of demand, thus complicating the task of balancing demand and supply in real time. If more generation is scheduled than needed, additional costs may be imposed upon the market.

The usual problems associated with setting customer baselines and estimating the amount of demand reduction achieved through a demand response action can become more contentious in a competitive market setting, where multiple market participants (rather than a single vertically integrated utility) have a stake in the method of calculating demand response and in designing the formulas used for compensation.

In nodal or locational marginal cost (LMP) markets[25] further difficulties may arise when the power consumed by an energy consumer is settled on a zonal basis while generation resources are settled on a nodal basis. Customers served by the load serving entity will face average or muted zonal prices that will fail to reflect the true value of electricity consumed at a node or the value of a reduction in demand at a node. While the theory behind LMP markets clearly requires loads to be settled at nodal prices,[26] equity and technical concerns have resulted in compromises. It is difficult to charge some consumers more than other consumers for transmission congestion charges when they historically paid the same rates toward transmission investments to the same vertically-integrated utility prior to restructuring. Externalities may be a problem -- the actions of your neighbor on the transmission network could affect your transmission costs. There may also be practical difficulties in calculating and communicating node-specific prices to consumers and in the settlement process.

Finally, it should be noted that wholesale or retail rate caps may dampen price signals and response. Ironically, the concern over insufficient price elasticity that prompts policy-

[24] Shmuel Oren, Stephen Smith, and Robert Wilson, *Priority Service: Unbundling Quality Attributes of Electric Power*, EPRI Report EA-4871, Nov. 1986.

[25] See Chapter 6 by Sing in this volume.

[26] Schweppe, F.C., M.C. Caramanis, R.D. Tabors, and R.E. Bohn, *Spot Pricing of Electricity* (Norwell, MA: Kluwer Academic Publishers, 1988); and Martin Baughman, Shams Siddiqi, and Jay Zarnikau, "Advanced Pricing in Electrical Systems," *IEEE Trans. on Power Systems*, 1995.

makers to impose price caps reduces the incentives and interest by consumers in responding to prices.

In addition, there are many regulatory barriers to be overcome by demand response programs. In a recent report, FERC (2006) identified nine “regulatory barriers” to demand response, as presented in Table 1. Many of these appear to be applicable to demand response initiatives outside of the U.S., as well.

Table 1

REGULATORY BARRIERS FOR DEMAND RESPONSE IDENTIFIED BY FERC (2006)

1. **Disconnect between retail pricing and wholesale markets**. Retail rates for most customers are fixed, while wholesale prices fluctuate.
2. **Utility disincentives associated with offering demand response**. Reductions in customer demand reduce utility revenue. Without regulatory incentives such as rate decoupling or similar incentives, electric utilities lack an incentive to use or support demand response.
3. **Cost recovery and incentives for enabling technologies**. Utilities are reluctant to undertake investments in enabling technologies such as advanced metering unless the business case and regulatory support for deployment is sufficiently positive to justify the outlay. These investments may require an increase in rates. It is uncertain whether and how would regulators allow these costs to be recovered.
4. **The need for additional research on cost-effectiveness and measurement of reductions.** There are deficiencies in the measurement of demand response and assessment of its cost-effectiveness. Cost-effectiveness tests that have been used by regulators must be improved to reflect changes in the industry, especially in organized markets.
5. **The existence of specific state-level barriers to greater demand response**. Policies of retail rate regulators and state statutes in several states have created barriers to implementing greater levels of demand response, especially by exposing customers to time-based rates.
6. **Specific retail and wholesale rules that limit demand response.** Certain wholesale and retail market designs have rules and procedures that are not conducive to demand participation.
7. **Barriers to providing demand response services by third parties**. Shifting regulatory rules that allow third parties to provide demand response and potential sunset of various demand response programs are a disincentive to demand response providers. Because third parties often bear the risks of programs dependent on enabling technologies, they need long-term regulatory assurance or long-term contracts to raise the capital needed to invest in enabling technologies.
8. **Insufficient market transparency and access to data**. Lack of third-party access to data has been identified as a barrier to demand response. A related but more fundamental barrier related to data is timely access to meter data.
9. **Better coordination of federal-state jurisdiction affecting demand response.** While states have primary jurisdiction over retail demand response, demand response plays a role in wholesale markets under Commission (FERC) jurisdiction. Greater clarity and coordination between wholesale and state programs is needed.

While the challenges associated with promoting demand-side participation in a competitive market may be formidable, advances in technology are making some aspects of it more practical. Metering technology has advanced and the cost of metering loads in near-real-time has declined. An increasing number of utilities are now adopting or considering advanced system-wide smart meter technologies. With an advanced metering infrastructure, consumption of smaller customers can be more easily matched with prices and the amount of demand reduction obtained from small consumers can be measured directly from interval metering data rather than through statistical sampling techniques. The Internet, under-utilized paging networks, and other communications media also open up new avenues for communicating electricity prices to consumers. Finally, systems designed to control or optimize the operation of equipment at industrial facilities, commercial buildings, and homes and other enabling technologies have improved, expanding the horizon for more effective demand responses in the near future.

3. Demand-Side Participation: From Traditional Utility Efforts to Restructured Markets

In a traditional regulated utility setting, a very wide variety of programs and tariffs were established to improve customer exposure to price signals and provide demand reduction at the request of the utility. Such efforts include:[27]

- *Direct Load Control demand-side management programs,* involving the control of customer appliances or equipment (e.g., air conditioners, water heaters, or pool pumps) from a central location. The program participant receives an incentive payment or bill discount.
- *Curtailment programs*, providing a financial incentive to participants who agree to control their electricity-intensive equipment so as to reduce their electrical usage at the request of the utility.
- *Interruptible tariffs*, providing electricity at a discounted price to large industrial or commercial consumers who agree to interrupt their purchases at the request of the utility during a supply shortage or instantaneously in response to a system emergency.
- *Time-of-Use pricing*, charging different retail prices for electricity purchased during different blocks of time. Typically, different periods with a day receive different prices. The pricing periods and price differentials are predetermined to correspond with average historical price patterns.
- *Critical peak pricing*, permitting retail prices to reflect their true market values or provide a strong price signal a few times a year. Otherwise, prices will often follow a time-of-use pattern.
- *Real-Time Pricing*, changing prices on an hourly basis to reflect the cost of providing electricity to the consumer each hour. Customer baselines and other

[27] See also U.S. DOE, 2006.

features are often applied to ensure the utility's revenue neutrality with respect to the consumer's historical usage pattern.

These various products and services may be differentiated by:

- Whether the customer is exposed to a price signal (economic or market-based demand response) or curtailment requests by a utility (reliability or contingency-based programs).
- Advance notice periods, which may range from instantaneous response (interruptible service involving under-frequency relays) to day-ahead response (e.g., participation in a day-ahead energy market).
- Type of incentive provided to the participant, which may be a direct payment, a discounted electricity price, or time-based rates. DOE (2006) and FERC (2006) draws a distinction between "incentive-based demand response" and "time-based rates."
- The degree of commitment or cessation of control provided by the participant, which may range from third-party control over the operation of customer-owned equipment (e.g., direct load control) to voluntary actions (in the case of most price response programs).

Table 2. Demand Response Options	
Price-Based Options	**Incentive-Based Programs**
Time-of-use (TOU): a rate with different unit prices for usage during different blocks of time, usually defined for a 24 hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. *Real-time pricing (RTP):* a rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. Customers are typically notified of RTP prices on a day-ahead or hour-ahead basis. *Critical Peak Pricing (CPP):* CPP rates are a hybrid of the TOU and RTP design. The basic rate structure is TOU. However, provision is made for replacing the normal peak price with a much higher CPP event price under specified trigger conditions (e.g., when system reliability is compromised or supply prices are very high).	*Direct load control: a program by which the program operator* remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. *Interruptible/curtailable (I/C) service*: curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. Penalties maybe assessed for failure to curtail. Interruptible programs have traditionally been offered only to the largest industrial customers. *Demand Bidding/Buyback Programs:* customers offer bids to curtail based on wholesale electricity market prices or an equivalent. Mainly offered to large customers (e.g., one megawatt [MW] and over). *Emergency Demand Response Programs:* programs that provide incentive payments to customers for load reductions during periods when reserve shortfalls arise. *Capacity Market Programs*: customers offer load curtailments as system capacity to replace conventional generation or delivery resources. Customers typically receive day-of notice of events. Incentives usually consist of up-front reservation payments, and face penalties for failure to curtail when called upon to do so. *Ancillary Services Market Programs*: customers bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.

Source: U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005*. February 2006.

There are many similarities among the challenges and opportunities associated with promoting demand-side participation in markets with different structures. Yet, there are some differences, as well. Regulated tariffs are available in regulated markets. Regulators often deviate from market economics to design pricing structures that meet long-term societal goals. There tends to be greater certainty associated with the costs and benefits of participating in regulated programs or accepting service under regulated tariffs. In restructured markets, the forces of supply and demand, retailer pricing strategies, and stakeholder processes tend to shape opportunities for demand-side participation.

In a restructured competitive market, a load-serving entity might offer the same types of programs and pricing strategies as might be offered in a traditional regulated setting in order to shape its generation requirements. However, a variety of additional services might be offered, such as:

- *Direct access to a competitive wholesale market,* providing the consumer with direct exposure to real-time or day-ahead market prices.
- *Demand bidding,* allowing the consumer to submit a formal offer to curtail its electricity usage to a day-ahead or real-time market and receive a market price for the demand reduction.
- *Direct participation in ancillary services markets,* providing an interruptible energy consumer with an opportunity to provide an operating reserve.
- *Participation in Installed Capacity or ICAP markets,* paying an interruptible load an incentive in return for providing a call option that an ISO can exercise in order to curtail the load in the event of a system emergency.

Whether these services or opportunities are offered by a traditional vertically-integrated utility, a retailer, or the ISO or regional transmission organization (RTO) responsible for ensuring reliability may depend upon the market structure.

Of particular note are the reliability-focused programs operated by ISOs in the Northeastern U.S. and in California.[28] The New England ISO (ISO-NE), the New York ISO (NYISO), and the PJM ISO (serving a large region including Pennsylvania, New Jersey, Maryland, and the upper mid-west) have all established successful programs focused on reliability. Reliability-focused programs tend to be reflected in reserve margin calculations and system planning studies, while economic programs tend to be viewed as less reliable as a source of planning resources. Some prominent reliability-focused ISO-level demand response opportunities in U.S. markets are summarized in Table 3.

[28] For a survey of programs operated by utilities, see FERC, 2006.

Table 3
Reliability-Focused Programs Offered by Selected ISOs in the U.S.

ISO	Program	Number of Participants	Potential Demand Reduction (MW)
NY ISO	Emergency Demand Response Program	810	369
	ICAP/Special Case Resources	1,460	861
ISO-NE	Emergency Load Response	1,490	801
PJM	Emergency Load Response Program	4,427	1,081
Cal-ISO	Various programs operated by utilities	NA	1,800

Sources: Demand Response Department of ISO New England, "ISO New England/NEPOOL Demand Response Working Group Meeting," presentation, December 6, 2006; NYISO, "November 2006 Demand Response Registration," Price Responsive Load Working Group, presentation, December 8, 2006; PJM, "Load Response Activity Report, January through September 2006," September 30, 2006; and Email correspondence from Greg Fishman of the California ISO to Rebecca Farrell, December 1, 2006.

ISO-NE offers reliability programs with notice periods of 30 minutes or two hours, in addition to a real-time program. In 2006, 641 MW of load was available for interruption through the 30-minute program (in an ISO with a peak demand of 28,127 MW).[29] An additional 117 MW is enrolled in the real-time program and 26 MW was available through the two-hour program. Participants in the 30-minute program receive the higher of the real-time zonal price or $500/MWh for a minimum of two hours, while participants in the two-hour notice program earn the higher of the real-time zonal price or $350/MWh for a minimum of two hours. Real-time resources receive the higher of the real-time zonal price or $100 per MWh. The majority of the 30-minute notice demand response is in Connecticut, where a supplemental program provides up to an additional $150/kW-year in this transmission-constrained area. Participants in these ISO-NE programs qualify to participate in this ISO's market for installed capacity (ICAP) planning reserves. The ICAP market is an important revenue stream for program participants. The value of ICAPs in the New England market was $3.05/kW-month in December 2006.[30]

In the NYISO, two major reliability-focused programs are available: the Emergency Demand Response Program (EDRP) and the ICAP/Special Case Resources (SCR) program. In the EDRP program, 161 MW was available in New York City and Long Island in 2006, while 208 MW was available in the rest of the state.[31] Most of the EDRP

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[29] Demand Response Department of ISO New England, "ISO New England/NEPOOL Demand Response Working Group Meeting," presentation, December 6, 2006.
[30] Figures in this paragraph are from: ISO-NE, FERC Electric Tariff No. 3, Section III, Market Rule 1 – Standard Market Design, p. 263, at: http://www.iso-ne.org/regulatory/tariff/sect_3/section_iii_mr1_standard_mkt_design.pdf.
[31] Figures in this paragraph are from: NYISO, "November 2006 Demand Response Registration," Price Responsive Load Working Group, presentation, December 8, 2006, at: http://www.nyiso.com/public/webdocs/committees/bic_prlwg/meeting_materials/2006-12-08/agenda_2_registration_update_nov.pdf.

resource is provided through transmission owners. Nearly half of the SCR/ICAP resource is provided through demand-side aggregators. The New York market had a total peak demand of 33,939 MW in 2006. Participants in these two programs responded to five events in 2006.[32] SCR participants are provided at least two hours notice and receive the zonal real-time price for the duration of an event or four hours, whichever is greater. NYISO can activate the EDRP in response to a shortage of operating reserves or a major emergence, and will strive to provide at least two hours' notice. When a curtailment is requested, EDRP participants receive compensation for a four-hour period. For two hours or the duration of an event (whichever is greater) the participant receives the higher of the zonal real-time price or $500 per MWh. The zonal price is paid for the remainder of the four-hour period.

With a peak load of 144,796 MW, the PJM market is the largest of these three markets, and its reliability-focused programs are also much larger. PJM operates Emergency Load Response (ELR) and Active Load Management (ALM) programs.[33] Within the ELR, participants can receive both an energy payment and an ALM credit, or simply receive an energy payment (in the "Energy Only Option" which waives non-performance penalties, or "ALM Deficiency Charges"). Participants specify their notice time requirements. The minimum duration of a curtailment is two hours. Consumers without interval data recorders are permitted to participate in this program on a pilot basis.

Each of these markets in the Northeast offers programs focused on economics, as well. Each offers day-ahead and real-time markets, which permit demand-side participation.[34] Offers generally require specification of the quantity, price, start-up cost payment, and minimum run-time information. In most of these markets, there is a $1,000/MWh bid price cap.[35] Offers to the real-time market must be submitted one hour in advance in NYISO and PJM, and 20 minutes in advance in ISO-NE. ICAP Resources must submit bids into energy markets. Similar opportunities exist for loads to participate in energy markets in the Midwest ISO (MISO) market.

In California, comprehensive sets of reliability-focused programs have been implemented at the utility level, but with extensive coordination with the ISO. About 1,800 MW of demand reduction can be achieved through utility-administered reliability-focused programs.[36] Commercial and industrial customers can voluntarily sign up for their utilities' interruptible rate program and receive a reduced rate in exchange for reducing their energy demand to a firm service level under emergency conditions. In most cases, there are limits on how many times or how many hours they can be called on within a specified period of time. Currently, there are about 900 megawatts signed up statewide

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[32] Steve Isser, "Demand Response Survey" draft presentation to the ERCOT Demand Side Working Group, December 15, 2006.

[33] Figures in this paragraph are from: PJM, "Load Response Activity Report, January through September 2006," September 30, 2006, at: http://www.pjm.com/committees/working-groups/dsrwg/downloads/20061026-item-06-dsr-activity-thru-sept-2006.pdf. Further information is posted at: http://www.pjm.com/committees/working-groups/dsrwg/dsrwg.html.

[34] Demand side participation in the ISO-NE market may not yet be fully implemented.

[35] Some of this information is taken from Isser (2006).

[36] Email correspondence from Greg Fishman of the California ISO to Rebecca Farrell, December 1, 2006.

with the utilities. The second type of program is aimed at residential and smaller commercial customers who will allow their air-conditioner to be turned off for a specified number of minutes per hour under emergency conditions. They are typically compensated based on a flat payment. There are about 900 megawatts in those programs as well, aggregated statewide.

The sheer coverage of some of the demand response initiatives launched by investor-owned utilities in California is quite impressive. Table 4 provides a summary of the programs offered by Southern California Edison Company.

Table 4
Demand Response Initiatives of Southern California Edison

PROGRAM	Year	FEATURES							ELIGIBILITY					MARKET	
		Guaranteed Payment/ Discount	Pay for Performance	Limited Number of Events	Minimum Load Reduction	Interval Metering Req	Advance Notice	Penalty	Residential	Comm.(<200 kW)	Comm.(>200 kW)	Ind. (>500 kW)	Agricultural and Pump	Direct Access	Utility Service
Agricultural and Pumping Interruptible	'87	•		•	•			Yes					•	•	•
Air Conditioner Cycling Program - Base	'83	•		•				No	•	•	•	•		•	•
Air Conditioner Cycling Program - Enhanced	'01	•						No	•	•	•	•		•	•
Base Interruptible Program	'01	•		•	•	•		Yes				•		•	•
Large Power Interruptible	'79	•		•	•	•		Yes				•		•	•
Optional Binding Mandatory Curtailment	'01				•	•		Yes		•	•	•		•	•
Scheduled Load Reduction Program	'01		•	•	•	•	•	No		•	•	•	•		•
Demand Bidding Program	'03		•		•	•	•	No			•	•	•		•
California Power Authority Demand Reserves Program	'03	•	•	•	•	•	•	Yes		•	•	•	•	•	•
Critical Peak Pricing	'03	•	•	•		•	•	Yes			•	•	•		•
Critical Peak Pricing - Fixed or Variable	'03	•		•		•	•	Yes	•	•					•
SCE Energy $mart Thermostat[sm]	'02	•		•	•	•		Yes		•	•			•	•

Source: Mark Wallenrod, SCE, "SCE's Demand Response Programs and Resource Planning," PLMA Fall 2003 Conference, NY, Sept. 8, 2003.

In MISO, reliability-based programs are also implemented at the utility level.

Many ISOs in the U.S. are beginning to rely on demand-side resources as a source of operating reserves. As discussed in the following section, interruptible loads have provided operating reserves in the ERCOT market for over five years. The wholesale market of the Western Electricity Coordinating Council (WECC) allows interruptible loads to be used for non-spinning reserves, and pilot programs are underway to test the feasibility of using interruptible loads as spinning reserves.[37] In May 2006, the PJM market expanded opportunities for interruptible loads to provide operating reserves,[38] and the NYISO has committed to allowing customers to offer some ancillary services soon.[39] Further, ISO-NE is implementing a pilot to explore the feasibility of using dispatchable loads as ancillary services.[40]

In restructured wholesale markets where retail competition has not been introduced, some challenges have to be overcome in coordinating utility tariffs and programs with the ISO's efforts to preserve reliability. Who has the button?

An interesting development in some restructured markets has been the establishment of real-time pricing as the default service for industrial energy consumers.[41] This has been successfully introduced in New Jersey, Maryland, Pennsylvania, Delaware, New York, and Illinois (in the service areas of Ameren and Commonwealth Edison).[42] There has also been a proposal to use critical peak pricing as a default pricing scheme in California.[43] Greater direct exposure to market prices may serve to increase demand response.

Ontario is implementing the "smart meter" infrastructure necessary for future implementation of either simple time-of-use, critical peak pricing, or real-time pricing on a system-wide basis for residential energy consumers, [44] as is California. With this infrastructure, a number of innovative pricing approaches could be extended to smaller energy consumers.

Recent analyses suggest that despite all the recent policy pronouncements, advances in technology, and other attention afforded demand response, the actual amount of load involved in dispatchable demand response programs focused on providing system

[37] Mike Koszalka, "Load Control as Reserves in the West," AESP Brown Bag Seminar presentation, April 18, 2006.
[38] Bernie Neenan, Peter Cappers, and Jeremy Anderson, "Demand Response in Ancillary Services Markets," AESP Brown Bag Seminar presentation, April 18, 2006.
[39] Ibid.
[40] Ibid.
[41] Galen Barbose, Charles Goldman, and Bernie Neenan, "The Role of Demand Response in Default Service Pricing," *The Electricity Journal*, April 2006.
[42] Stephanie Folk, *"Illinois General Assembly Authorizes Residential Real-Time Electricity Pricing," ASEP Strategies Newsletter*, May 2006.
[43] Mike Messenger. "Getting to the Sweet Spot in Demand Response Markets: Why default CPP rates are Critical to the Development of Healthy Energy Markets in California," *AESP Strategies Newsletter*, July 2006.
[44] Gay Cook, Ontario, Canada's Plan to Implement Time-of-Use Rates, *AESP Strategies Newsletter*, July 2006.

reliability has fallen in recent decades.[45] About 5% of customers in the U.S. and Canada are involved in some type of demand response program, including direct load control, interruptible tariffs, curtailment programs, and time-of-use rates.[46] This amount is lower than in the mid-1990s. The U.S. DOE reports that total potential load management capability in the U.S. has fallen by 32% since 1996, although concerns have been expressed over some of the self-reported data contained in that report.[47]

It is also insightful to note that the electricity markets which have experienced the greatest declines in (at least dispatchable) demand response capability are those markets which have undergone the most extensive restructuring, such as ERCOT, the Mid-Atlantic Area Council (MAAC), and the Northeast Power Coordinating Council (NPCC). In many of these markets, regulated interruptible tariffs were terminated, energy efficiency activities were disrupted, and load management infrastructure became a stranded cost as a result of restructuring. It has proven difficult to re-build these types of resources to their pre-restructuring levels. Thus, restructuring activity may be at least partially responsible for the initial drop in load management capacity. On the other hand, the ISOs, under FERC's policy direction are helping to rebuild demand response capability. Moreover the demand response programs administered by ISO may be recognized as a more-solid resource than some of the interruptible or curtailable tariffs that may have been utilized less frequently or contained buy-through provisions.[48]

Figure 1 provides FERC's estimates of the changes in demand response capability in various markets between 1998 and 2003.[49] As the ERCOT case study presented later in this chapter suggests, it is very difficult to re-build a large base of demand side resources into a market once the regulated tariffs and programs designed to foster demand response are terminated.

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[45] Larry Barrett, "Load Response Resources Still Lagging," Barrett Consulting Associates Report, July 2006. See also FERC (2006)

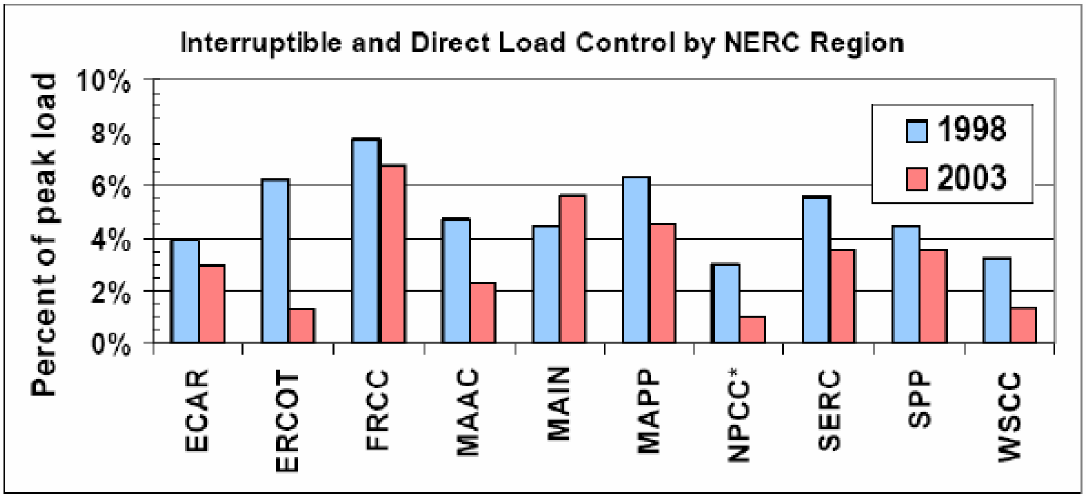
[46] FERC (2006), p. viii.

[47] U.S. DOE, 2006, p. xii.

[48] Charles Goldman contributed some of the insights reported here.

[49] The acronyms used in the table are: ECAR = East Central Area Reliability Coordination Agreement; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; MAAC = Mid-Atlantic Area Council; MAIN = Mid-America Interconnected Network; MAPP =Mid-Continent Area Power Pool; NPCC = Northeast Power Coordinating Council; SERC = Southeast Reliability Council; SPP = Southwest Power Pool; and WSCC = Western States Coordinating Council.

Figure 1
Load Management in NERC Forecasts



Source: Data from NERC 1998 and 2003 summer assessments. *NPCC data is for 1998 and 2002

Source: FERC (2006).

Certainly demand response initiatives are not confined to North America. European and Asian utilities have operated load control, curtailment, and interruptible programs for many years. Some of the more active utilities in this field have included electricity providers that have not undergone restructuring in the nations of France,[50] Taiwan, South Korea,[51] South Africa, and Japan.

As utility systems outside of North America have been restructured to introduce competition, similar challenges have been faced, and similar strategies to promote demand response have been tested. In October 2002, the Nordic Council of Ministers launched an Action Plan for Peak Production in the Nordic Electricity Market, with an initial task of promoting price elastic demand in the spot market.[52] Statnett, the Norwegian system operator, has used interruptible loads to provide operating reserves during high demand periods since 2000.[53] In this weekly market, offers are based on area, price, and size of curtailable load.

In Australia, the National Electricity Market Management Company (NEMMCO) relies upon 373 MW of reserves from demand-side resources.[54] Also, a demand bidding experiment has been launched in the Australian market.

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[50] The *tarif vert* of Electricite de France was probably the first time-differentiated electric utility tariff.
[51] The Korean Electric Power Company has operated curtailment programs and innovative rate design for many years.
[52] Margareta Bergström, DR in Competitive Electricity Markets Sweden. *PLMA/IEA Symposium on Demand Response*, September 2003, NY. Presentation.
[53] Björn Walther and Inge Harald Vognild, “Statnett’s Option Market for Fast Operating Reserves,” *Demand Response Dispatcher*, IEA DSM Task XIII Project, April 2005.
[54] Energy Users Association of Australia, “Energy Users are Helping Keep the Lights On the Summer,” press release, January 2006, at: http://www.euaa.com.au/press_releases.htm.

Italy hopes to transition over 2,000 MW of interruptible load formerly served under regulated tariffs into a day-ahead market, a congestion management market, and reserve/balancing markets.[55]

Tokyo Electric Power Company offers a variety of interruptible ("supply and demand adjustment contracts") and time-of-use rate options for industrial energy consumers. Thermal energy storage is also promoted through rate design. Residential consumers can select from a menu of time-of-use rate options, also.[56]

In summary, there have been a variety of efforts to utilize demand-side resources such as interruptible or curtailable loads in restructured markets. The survey provided above is by no means exhaustive. But it covers some of the better-known successful initiatives.

As noted above, the size of demand-side resources in many competitive markets have not yet matched their pre-restructuring levels. Why is this so? Every market is different, and different reasons may be cited for the decline of the demand-side resource base in different markets. Yet, the experiences of the ERCOT market offer some useful insights.

4. A Case Study of the ERCOT Market

Demand response activities in Texas' ERCOT market may be of particular interest. ERCOT is widely viewed as a successful restructuring initiative, and had a considerable base of interruptible loads prior to the introduction of customer choice.

About 85% of the electricity needs in the largest electricity-consuming state in the U.S. are satisfied through the ERCOT market. Because ERCOT is an 'intra-state' market with limited interconnections to other markets in the U.S., there is very little federal regulatory jurisdiction over ERCOT.

This electricity market has been restructured over the past decade to introduce greater competition in the wholesale and retail segments of the industry and to relax regulatory oversight. Senate Bill 373, enacted in 1995, required the Public Utility Commission of Texas (PUCT) to establish rules to foster wholesale competition and create an Independent System Operator (ISO) to ensure non-discriminatory transmission access and an equitable interconnection process for new generation capacity. In the summer of 1997, ERCOT became the first operating ISO in the U.S. Sweeping reforms were introduced by Senate Bill 7 (enacted in 1999), which allowed customers of the investor-owned utilities within ERCOT to choose among various retail electric providers for a retail supply of electricity beginning on January 1, 2002. SB 7 also provided the ISO

[55] Guido Cervigni, "Demand Response in the Design of the Italian Electricity Market," *Workshop on Enhancing Demand Response in Liberalised Electricity Markets*. Presentation. Paris, February 2003.
[56] Sources: Personal correspondence with Takashi Yamanaka and Tokyo Electric Power Company, "Overview of Load Leveling Activity," presentation, May 2005.

with much greater centralized control over the wholesale market and prompted the establishment of formal markets for ancillary services and balancing energy.[57]

Texas is home to a large number of industrial facilities involved in chemical production, petrochemicals, refinery operation, air separation, pulp and paper manufacturing, and steel production which can withstand short interruptions in their electricity supply with modest economic loss. Traditionally, these facilities were served through interruptible tariffs, which provided an electrical supply to the facility at a lower level of reliability in return for a discounted price. Consequently, the state has a very large base of industrial facilities, which can reduce or curtail electricity purchases in response to either an instruction from the ISO or in response to a price signal.[58]

Since restructuring, ERCOT has had a mixed record of promoting demand response. The introduction of interruptible loads into competitive markets for ancillary services has been generally successful. However, efforts to perpetuate or introduce other forms of demand response have met with limited success.

Prior to the full-scale restructuring of the ERCOT market in January 2002, ERCOT relied upon roughly 3,500 MW of interruptible load, group load curtailment programs, direct load control, and other load management programs to maintain reliability. As the ERCOT market was redesigned between 1999 and 2001 to foster competition, there was a fear that this large demand-side resource could be lost. Indeed, restructuring led to the termination of tariffs in the areas of ERCOT opened to retail competition. New policies required utilities to divest from “competitive energy services” such as load management programs. And there was (and still is) confusion regarding who would assume responsibility for overall resource adequacy. The PUCT ordered ERCOT to “Develop new measures and refine existing measures to enable load resources a greater opportunity to participate in the ERCOT market.” (PUCT, 2000). The steps taken and their track record are discussed below.

4.1. Using Interruptible Loads as a Responsive Reserve Ancillary Service

The restructured ERCOT market has probably been as successful as any market in the integration of interruptible loads into markets for ancillary services.

Many loads served under interruptible tariffs prior to restructuring are now providing ancillary services to the market. The design of ERCOT’s wholesale market permits Loads acting as Resources or “LaaRs” to compete “head-to-head” against generation resources to provide ancillary services, such as responsive reserves (provided by interruptible loads with under-frequency relays and which also agree to manual

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[57] See Parviz Adib and Jay Zarnikau, “Texas: The Most Robust Electricity Market in North America” in *Electricity Market Reform: An International Perspective* Ed. P. Sioshansi, Elsevier, 2006.

[58] Further background is provided in Jay Zarnikau, “Using Interruptible Load as an Ancillary Service in the Restructured ERCOT Market,” *US Energy Association Dialogue*, July, 2006. Available at: http://www.usaee.org/pdf/Aug06.pdf#13d

deployment or curtailment within ten minutes of notice) and non-spinning reserves (which can be interrupted by the ISO with 30 minutes of notice).[59]

LaaRs selected to provide these services through ERCOT's formal day-ahead market for ancillary services receive the market-clearing price for capacity. Alternatively, LaaRs may be self-arranged by a load-serving entity, in which case they would receive a negotiated price.

One LaaR (associated with a facility which also has generation) began providing regulation in late 2006 under a "Controllable Load" pilot program. Beginning in March 2007, LaaRs will be permitted to also provide replacement capacity. Demand-side resources can and have been proposed as substitutes for reliability-must-run generating units, but no proposals have been accepted to date. Demand-side resources are not presently used to manage transmission congestion.

In light of the pre-restructuring levels of industrial load served under instantaneous interruptible tariffs and armed with under-frequency relays, it was recognized that as much as 2,000 MW of load might be interested and capable of providing responsive reserves. As ancillary services markets were designed, this raised two concerns among the ISO's system operators and ERCOT's Reliability and Operations Subcommittee:

- If too large a share of responsive reserve requirements were provided by LaaRs, then there might not be adequate generation resources providing responsive reserves. Generating units with governors are better able to stabilize frequency in response to small deviations in frequency than LaaRs with their *off-or-on*, *all-or-nothing* response. Also, machines with *mass* are needed to maintain the stability of the network.
- There may be a possibility of "over-shoot" situations, where too much interruptible load might trip-off at the same time and raise frequency to an unacceptably high level.

Consequently, limits were placed on the amounts of responsive reserves provided by LaaRs. Initially, this limit was 25% of ERCOT's requirements for this ancillary service (i.e., 575 MW each hour, given ERCOT's normal requirement of 2,300 MW). Later this cap was raised to 50% of ERCOT's need for responsive reserves (normally, 1,150 MW per hour), as concerns surrounding over-shoot abated.[60] In addition, strict qualification criteria were introduced to preclude energy consumers whose load level could not be accurately predicted on a day-ahead basis from providing responsive reserves.

Within a couple of years after LaaRs were permitted to participate in wholesale market, the 1,150 MW cap was reached. Presently, 94 LaaRs (working with 10 scheduling entities) are qualified to provide ancillary services for a total capacity of 1,826 MW.

[59] LaaRs are permitted to provide Regulation on a pilot basis. In theory, LaaRs can also provide replacement capacity, although the systems necessary to permit interruptible loads to provide these services have not yet been fully implemented.

[60] ERCOT Staff for the Reliability and Operations Subcommittee, "Utilizing High-Set Load Shedding Schemes to Provide Response Reserve Services," November 2002.

While there has been a good mix of LaaRs by size, it is noteworthy that about one-half of the total quantity of LaaRs is provided by five very large industrial loads, as noted in Table 4.

Table 4: Categorization of LaaRs by Size

LaaR Capacity Range	Number of LaaRs	Total Capacity (MW)
1 to 10 MWs	66	283
11 to 50 MWs	20	388
51 to 100 MW	3	185
Greater than 100 MW	5	970

Source: ERCOT staff, "DSWG LaaR Bidding Update," February 22, 2006.

The excess supply of LaaRs relative to the cap has led to problems. As competition among LaaRs intensified for their limited share of the market for responsive reserves, many LaaRs began offering their interruption capability at increasingly-negative prices in hopes of securing a place among selected resources within the bid stack, and in anticipation that a higher-price generation resource would set the market-clearing price which all selected resources receive. However, concerns emerged over the consequences of an offer price as low as -$19,155 per MW actually setting the market clearing price. In such a case, all of the selected resources would then have to *pay* the market a substantial price. This credit risk led to the imposition of a temporary floor price that prohibited negative bids. The current prevailing proposal is to continue to prohibit negative bids by LaaRs until ERCOT adopts a nodal structure in 2009. At that time, separate markets could be established for LaaRs and generators providing responsive reserves.

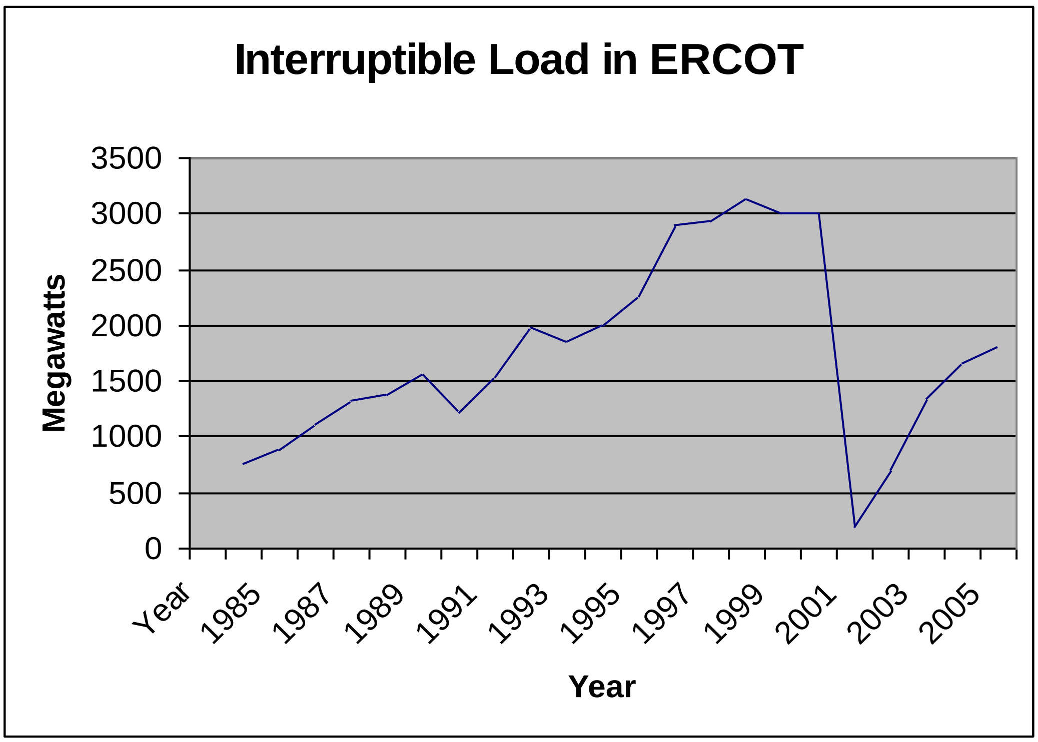
The cap and restrictive qualification requirements have also led to situations where interruptible loads have been ready, willing, and able to interrupt in order to balance supply and demand during reliability problems (e.g., the rolling blackouts which occurred on April 17, 2006), but could not be deployed since they were not selected by ERCOT to provide an ancillary service at that time.

The amount of interruptible load available to be dispatched by a utility prior to restructuring is compared to the amounts of load qualified as LaaRs in Figure 2. 3,200 MW of interruptible load was available in ERCOT prior to restructuring (not counting curtailment programs and residential direct load control). This amount dropped to almost nothing after interruptible tariffs were terminated. The amount of load qualified as LaaR is presently over 1,800 MW. However, the cap on LaaR participation providing responsive reserves of 1,150 MW tends to reduce the quantity of demand side resources that the ISO can rely upon to provide an ancillary service or interrupt to an emergency condition at any given time.[61]

[61] Note that a small, but increasing, amount of load provides regulation service and non-spinning reserves.

Given the cap on the amount of responsive reserves which can be provided by LaaRs and limits to the quantities of other ancillary services required by ERCOT, the pre-restructuring levels of interruptible load can not be attained unless new reliability-based programs are created. The total amount of interruptible load that the ISO can rely upon in an emergency is presently around 1,200 MW (the amounts of LaaR load that normally provides responsive reserves and non-spinning reserves). As noted earlier in Figure 1, ERCOT formerly had a relatively high demand-side resource that could be relied upon in an emergency, compared to other markets. Today, such demand-side resources available to the ISO are quite limited in ERCOT.

Figure 2



Sources: Data for 1985-1993 is from PUCT 1996 Statewide Electrical Energy Plan for Texas, June 1996, and represents interruptible loads plus a small contribution from various load cycling programs. Interruptible load data for 1994-1999 is from PUCT Project 22209 Annual Update of Generating Electric Utility Data, 2000. Data for 2000 and 2001 is from ERCOT Capacity, Demand and Reserve reports for those years. Data for 2002-2006 came from "Load Participation in ERCOT Ancillary Services Markets", April 18, 2006, AESP Brown Bag Seminar by Steve Krein, ERCOT staff. This figure also appears in Jay Zarnikau, "Using Interruptible Load as an Ancillary Service in the Restructured ERCOT Market," *US Energy Association Dialogue*, July, 2006.

4.2. Load Response to Price Signals or Programs Offered by Retail Electric Providers

ERCOT's market structure provides some incentives for large energy consumers to reduce power purchases during peak or high-price periods, including:[62]

- The design of transmission charges, which are based upon the consumer's contribution to demand during four peak times in summer months.
- The ability to purchase balancing energy (through a retail electric provider or REP) and the design of the wholesale market settlements system rewards qualified scheduling entities (QSEs) who can reduce generation needs during high price periods.
- Participation in demand response programs sponsored by REPs.

A large industrial energy consumer's transmission charge is based upon the consumer's contribution to ERCOT's coincident peak demand in four summer months. Often, transmission charges are treated as "pass-through" costs in the contracts offered by REPs. Consequently, larger energy consumers may see direct benefits by reducing their consumption during the four summer peaks, which are used to allocate transmission costs to consumers and REPs.

During the initial years of the restructured market (e.g., 2002 through 2005) consumers were free to deviate from scheduled load levels (in response to price changes, for example) with minimal penalties. "Passive load response" refers to a customer's deviation from its scheduled or anticipated load level in response to price signals (e.g., balancing energy prices or peak demand periods used to assign transmission costs) in situations where the customer has not formally offered its response to the market as a "resource." If the actual load level of a QSE turns out to be lower than its scheduled load level during a given 15-minute interval while its actual generation is equal to its scheduled generation, then the QSE is entitled to a payment or credit based on the energy imbalance multiplied by the balancing energy market price. This may provide energy consumers with an incentive to respond to wholesale market prices, provided their REP agrees to settle the consumer separately from other loads served through the REP.[63] This separate settlement normally requires the metering of a load's consumption at 15-minute intervals. At market-open in 2002, interval data recorders (IDRs) were required on energy consumers with a billing demand over 1 MW. The IDR threshold was later reduced to 700 kW.

Some industrial energy consumers rely on balancing energy (essentially, spot market power) to meet some or all of their electricity needs, actively monitor 15-minute

[62] In addition to the programs and activities mentioned here, there are a number of small demand response programs in ERCOT, which have nothing to do with the competitive market. These include Austin Energy's direct load control program, interruptible tariffs and programs offered by "non-opt-in entities" which include most of the municipal and rural electric cooperative systems in the ERCOT region, and the Load Management Standard Offer Programs which are regulated energy efficiency programs offered by transmission and distribution utilities including TXU Electric Delivery and AEP-Texas Central.

[63] Loads are permitted to submit formal offers into the market for balancing energy to reduce their consumption if their offer is accepted. However, there is no incentive for loads to participate in this formal market, since they can achieve the same economic benefits through passive load response without exposure to potential penalties for failing to comply with market rules in the formal balancing energy market.

balancing energy prices, and reduce electricity purchases when prices exceed threshold levels. The degree to which this practice is permitted has been subject to changing policies since the start of customer choice.

During the first years of the restructured market, there was a "balanced schedule requirement" (although some load serving entities ignored it). Later, a "relaxed balanced schedule requirement" was introduced, in part to encourage REPs and large loads to rely in part on balancing energy to provide near-real-time price signals and foster demand response. Under the relaxed balanced schedule policy, a load serving entity could elect to purchase a share of its generation requirements from the balancing energy market. While this leaves the REP un-hedged and exposed to price fluctuations in the balancing energy market, many REPs and large energy consumers found this strategy advantageous, particularly if they served loads with some capability to reduce energy usage in the face of high market prices.

While volatile, balancing energy prices tend to be lower than the average cost of firm generation obtained from bilateral contracts. However, following the April 2006 blackouts, ERCOT adopted a more risk-averse operating strategy through which it intentionally biased its short-term load forecast upward and greatly increased its reliance upon replacement capacity in increasing operating reserves. The practice of assigning the cost of procuring replacement capacity to QSEs who were "short" of scheduled capacity at the time the replacement capacity is needed greatly increased the cost of relying upon balancing energy to meet generation needs.

True "demand bidding" is permitted, whereby consumers can submit a formal offer to the balancing energy market describing a strike price at which they would curtail and a curtailment amount.[64] Under the balancing up load (BUL) program, a load that submits an offer and is struck can also receive a capacity payment based on the prevailing price of non-spinning reserves. However, the capacity payment has not been sufficient to induce consumers into submitting formal offers. Rules requiring all BULs under a QSE's control to be scheduled as a group and complicated baseline formulas (modeled after those developed for the New York ISO's Emergency Curtailment Program) have also been cited as impediments to program participation.[65] Instead, voluntary or passive load response is generally preferred.

Finally, some industrial consumers of energy participate in curtailment programs that are established by REPs. These are conducted outside of the formal ERCOT market and are used by REPs to shape their generation needs and reduce their costs.

If an energy consumer opts to offer its interruption capability into an ancillary services market, then its ability to react to wholesale balancing energy prices, avoid the four summer peaks, and participate in any REP-sponsored demand response programs will be constrained. If the load is providing responsive reserves, then ERCOT monitors the

[64] Note that a formal day-ahead market will not be established in ERCOT until 2009.
[65] Floyd Trefny, "BUL Program Status," Presentation at PUCT Demand Response Workshop, December 8, 2006, at: http://www.puc.state.tx.us/electric/projects/32853/32853.cfm.

load's level every three seconds to ensure that the load is available for interruption should the system need to rely upon the interruption to maintain frequency. A QSE could incur a penalty (a scheduling control error) if it is not providing its committed level of operating reserves. Thus many of ERCOT's most flexible, interruptible, or potentially price elastic electric loads will not react to prices. This appears to be most true for LaaRs which have a bilateral contract to provide responsive reserves to a REP/QSE and are self-scheduled. Two-thirds of the LaaRs providing ancillary services are self-arranged by a REP or QSE through bilateral contracts in this manner.

The amount of load that is actively responding to price signals is thought to be relatively small. A quantification of the price elasticity of demand of the twenty largest industrial energy consumers in Houston to wholesale electricity prices found that one or two are clearly responding to wholesale prices.[66]

Price elasticities have also been estimated for the aggregated block of all energy consumers in ERCOT with interval data recorders (representing roughly one-half of the demand for electricity in ERCOT). The average own-price elasticity for the aggregated block of all energy consumers in ERCOT with interval data recorders is quite small.[67]

Based on some simple comparisons of the aggregate load levels of transmission voltage (large industrial) energy consumers between days of likely 4 CP charges and adjacent days, the ERCOT staff has identified about 600 MW of aggregate demand response, or about a 1% reduction in demand.[68]

The deviations of large loads from their forecasted or scheduled levels in response to wholesale balancing energy prices, to avoid the four summer peaks, and participate in any REP-sponsored demand response programs has caused some scheduling and operating problems. The ERCOT staff has been unable to factor these responses into its short-term load forecasts[69] (although it is likely that bad weather forecasts have a much greater contribution to ERCOT's forecasting error than consumer response to price signals). These changes in demand in response to price changes complicate the ISO's task of matching supply and demand in real-time.

4.3. Demand-Side Resources that Failed to Make the Transition

A variety of programs and tariffs that the regulated vertically-integrated utilities relied upon for peak clipping or energy shifting failed to survive in the restructured market.

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[66] Jay Zarnikau, Greg Landreth, Ian Hallett, and Subal Kumbhakar, "Industrial Energy Consumer Response to Wholesale Prices in the Restructured Texas Electricity Market," forthcoming in *Energy – the International Journal*.
[67] Jay Zarnikau and Ian Hallett, "Aggregate Customer Response to Wholesale Prices in the Restructured ERCOT Market," draft 2007.
[68] Sam Jones, Paul Wattles, Steve Krein, ERCOT Emergency Load Response. PUCT Demand Response Workshop. September 15, 2006. See: http://www.puc.state.tx.us/electric/projects/32853/091506/ERCOT.pdf
[69] ERCOT Staff report to the PUCT, Open Meeting of August 23, 2006.

The direct load control program operated by Houston Lighting and Power Company (HL&P) prior to restructuring was sold to Comverge (pursuant to the Commission's Competitive Energy Services rules). However, Comverge was unable to continue the program, due to difficulties inherent in dealing with the many REPs who providing power to the program participants, extensive measurement and verification requirements placed upon the program by the ERCOT stakeholders, and problems in securing payments from the REPs and other market participants who were likely to realize a benefit from interruptions.

Similarly, curtailment programs were terminated as those utility organizations were unbundled. Energy efficiency programs and tariffs designed to promote the installation and operation of thermal energy storage were terminated at the start of restructuring, and diurnal differentials in balancing energy prices have been insufficient to interest REPs in providing programs or pricing incentives to promote such technologies in the competitive market.

4.4. New Programs Under Study for Today's Zonal Market

A confluence of factors sparked renewed interest in new demand response program opportunities in 2006. The PUCT voted to pursue an energy-only resource adequacy approach and higher caps on wholesale prices, which places greater reliance on demand response.[70] During rolling blackouts on April 17, 2006, there were industrial loads that were ready, willing, and able to be interrupted to restore reliability, but ERCOT had no mechanism to interrupt them. Many interruptible loads were not providing an ancillary service at the time, and there was no program through which curtailments could be requested. Actual planning reserves dipped below 3% during the summer of 2006. And, as noted above, a large "waiting list" of industrial interruptible loads who were willing and able to participate in the crowded ancillary services markets had developed.

In April 2007, ERCOT, with the support of the PUCT and despite opposition from many stakeholders, sought to implement an Emergency Interruptible Load Program (EILP). However, the offers to provide the service (about 150 MW of demand reduction) fell below ERCOT's minimum program participation level of 500 MW and the program was not operated during the months of April and May 2007. Additional solicitations for program participants will be held later in 2007.

A Tiered Frequency Response (TFR) program has been proposed by the Steel Mill Coalition. Under the proposed TFR program, interruptible loads would set their under-frequency relays to higher settings than loads providing responsive reserves and would

[70] See Chapter by Adib, Schubert, and Oren in this volume.

commit to long-term contracts.[71] Program participants in the EILP would curtail within 30 minutes notice if the second level of a system emergency was declared.[72]

4.5. Demand Response in the Future Nodal Market

When the ERCOT market transitions to a nodal design in 2009, it is likely to take "one step forward and two steps back." The new day-ahead energy market may open up opportunities for demand response by industrial loads with predictable and flexible energy needs. However, opportunities for loads to respond to real-time prices will become limited. Testifying on behalf of the staff of the PUCT, the Commission Consultant, David Patton, explained the concern over permitting demand response in real-time:

> Passive demand response occurs when loads reduce their consumption in response to prices they observe without actively submitting price-sensitive offers into the wholesale market. The prices that are posted are based on the load levels that ERCOT observes and the generation and load resource offers it has received from suppliers. If ERCOT posts a price 10 minutes in advance and loads respond, then the price for that interval is incorrect. For example, imagine on a high load day, ERCOT posts a price of $200 per MWh 10 minutes in advance. Further, assume that observing this price, load reduces its consumption by 2,000 MW. Finally, assume that the price would have been $100 per MWh had the 2,000 MW not been included in the dispatch. In this case, dispatch signals will cause generators to over-generate by 2,000 MW. In addition, ERCOT will not be revenue-neutral. Generators will have received payments for 2,000 MW of generation that will not be collected from the loads, since loads are not consuming that amount. Hence, an uplift charge will need be needed to collect the additional revenue needed to compensate the generation.[73]

For these reasons, the Texas Commission has been unwilling to permit demand response in real-time as it refines its wholesale market structure, even though the Commission has endorsed demand response as a policy goal and ERCOT has explicitly endorsed demand response in real-time as a feature of the future market structure.

To reduce forecasting error and to prevent loads from responding to prices in real-time, advanced notice of prices will be eliminated. Also, a penalty (the Reliability Unit Commitment Capacity Short Charge) will be used to discourage REPs (and their customers) from relying upon the market (as opposed to bilateral contracts and the forthcoming day-ahead market) to secure generation. Further complications arise from

[71] PUCT Docket No. 32615: Petition of Chaparral Steel Co., Structural Metals, Inc., and Nucor Steel for the Adoption of a Rule to Implement a Tiered Frequency Response Service.
[72] PUCT Docket No. 32853: Evaluation of Demand Response Programs in the Competitive Electric Market.
[73] Rebuttal testimony of David Patton on behalf of the Staff of the Public Utility Commission of Texas, PUC Docket No. 31540: Proceeding to Consider Protocols to Implement a Nodal Market in ERCOT Pursuant to PUC Substantive Rule 25.501. November 2005.

the use of zonal prices to settle energy purchases, while nodal prices are used to establish the value of a supply-side resource in the market. While taking these steps to discourage price-chasing may provide system operators with better demand forecasts, any demand response in real-time is likely to be sacrificed.

As the PUCT approved "nodal protocols" which included the features mentioned above to discourage demand response, it nonetheless expressed interest in exploring new avenues for demand response. Through a new project, the PUCT is considering mechanisms to:

- Insulate loads which are deemed to be price-sensitive from the Reliability Unit Commitment Short Charge.
- Provide some advance notice of real-time prices to loads (outside of the day-ahead market).
- Consider a proposal consistent with priority pricing, whereby loads would provide the ISO with a commitment to curtail at certain price points, in return for protection from various penalties and other incentives.[74]

4.5. Opportunities for Improvement

ERCOT has not yet succeeded in regaining its pre-restructuring levels of demand response. ERCOT went from having one of the nation's largest demand side base prior to restructuring to the smallest overall "existing demand response resource contribution" of any market in the U.S., at about 3% of peak demand.[75]

The need for vibrant demand response in ERCOT is only increasing. The PUCT is pursuing an "energy-only" resource adequacy mechanism, which places considerable emphasis on demand response to balance supply and demand over the long-run.

In addition, ERCOT is probably the nation's most concentrated market, and present problems with supplier market power are likely to become exasperated under a nodal market structure. Power plants under common ownership tend to be geographically clustered, reflected the old service areas of the traditional utility suppliers. There is concern among some observers that a wholesale pricing scheme which better recognizes transmission constraints will also tend to divide the ERCOT market into smaller sub-markets, where market share among suppliers could be more concentrated.

Clearly, a lot of work remains to ensure that North America's most successful restructured market provides adequate levels of demand-side participation. Yet, some optimism may be in order. New programs to facilitate demand-side participation are being explored. The PUCT appears willing to reconsider some of the policy decisions

[74] Jay Zarnikau, "Long-Term BUL Offers," Presentation to the ERCOT Demand Side Working Group, October 2005.
[75] FERC, 2006, p. 87.

that may be responsible for inhibiting demand response. Some of the larger transmission and distribution utilities in the areas of ERCOT opened to retail competition plan to deploy advanced metering systems. TXU Electric Delivery hopes to develop the nation's "first automated, smart electric grid."[76] The new Center for the Commercialization of Electric Technologies is working to develop and capture the benefits of advancing technologies in electric energy transmission, distribution and end-uses. New digital meters under study could be used to remotely control air-conditioning settings or activate "smart" appliances.

5. Conclusions

Restructuring has been pursued in part based on the premise that by unleashing the creative forces of competition, new pricing and service options will be provided to energy consumers that better reflect market economics. Exposure to market prices will foster economically efficient consumption decisions. Market forces, including a demand curve more accurately reflecting true price elasticity of demand rather than short-term inelastic demand, will balance supply and demand in operations and planning. Competition can be enhanced through demand-side participation in energy markets.

In markets which have restructured and introduced competition at the retail level, these goals have been achieved to a limited degree to date. New pricing options and features are indeed available in markets where customer choice has been introduced. Retailers realize that certain load-shaping actions can reduce their generation costs, as well as the cost of serving their retail customers. ISOs have introduced new curtailment programs to improve system reliability. New competitive markets for ancillary services and installed capacity credits permit loads to compete against generation assets to provide resources to the system. There are now plenty of examples of beneficial demand response efforts in restructured markets.

Yet, while policy-makers around the world recognize the importance of fostering demand response in competitive markets, the actual implementation of the market structure, rules, programs, technology, and policies necessary to achieve greater demand response has been extraordinarily slow and difficult. While there has likely been a general decline in dispatchable demand side resources in North America over the past decade, this decline is most pronounced in the markets which have achieved the greatest degree of restructuring.

Although the presence of bilateral arrangements between retailers and energy consumers "outside of the market" makes it difficult to accurately quantify the amount of demand response occurring in the competitive retail markets, it appears as though the post-restructuring levels of demand response in restructured markets is somewhat lower than the pre-restructuring amounts achieved through regulated interruptible tariffs, real-time pricing tariffs, time-of-use tariffs, thermal energy storage promotional programs, and load management demand side management programs.

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[76] "TXU Electric Delivery to Procure 400,000 Automated BPL Meters," *Transmission and Distribution World*, October 2006.

On a positive note, the potential for greater demand-side participation in electricity markets is greater than ever. Widespread deployment of smart metering systems will enable demand response by smaller energy consumers. Technology will advance. Hopefully, our understanding of consumer behavior and the policies and market structure necessary to enable demand response will similarly advance. Many of the new demand response programs administered by ISOs have demonstrated the value of curtailments or interruptions as a resource with considerable value, dispelling some tradition concerns that interruptible loads won't really interrupt when the system needs them to do so. As restructured markets mature and the potential value of demand response is better appreciated (or, if generation adequacy mechanisms continue to falter), perhaps we shall see an appreciable expansion in participation in demand response.

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