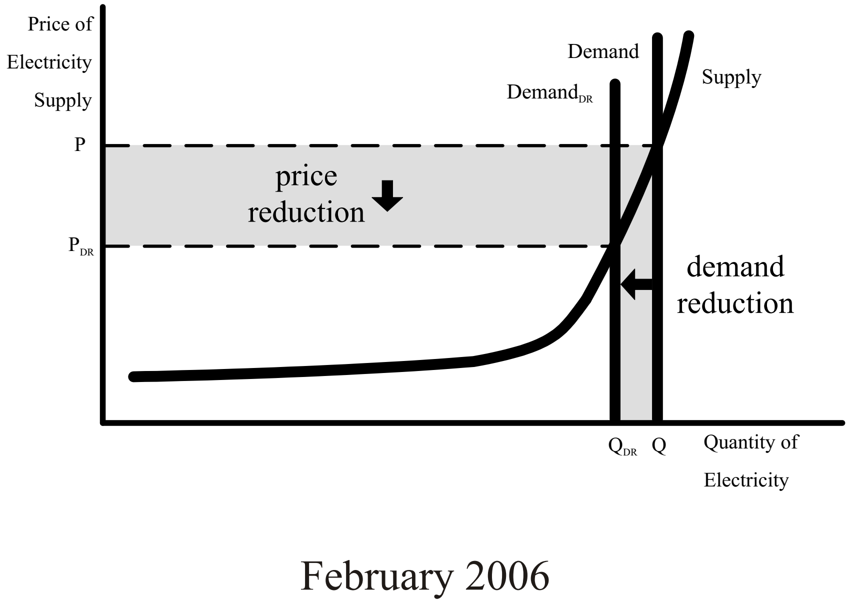
BENEFITS OF DEMAND RESPONSE IN ELECTRICITY MARKETS AND RECOMMENDATIONS FOR ACHIEVING THEM

A REPORT TO THE UNITED STATES CONGRESS PURSUANT TO SECTION 1252 OF THE ENERGY POLICY ACT OF 2005



February 2006

U.S. Department of Energy

The Secretary [of Energy] shall be responsible for… not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.

--Sec. 1252(d), the Energy Policy Act of 2005, August 8, 2005

EXECUTIVE SUMMARY

Sections 1252(e) and (f) of the U.S. Energy Policy Act of 2005 (EPACT)[1] state that it is the policy of the United States to encourage "time-based pricing and other forms of demand response" and encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public. The law also requires the U.S. Department of Energy (DOE) to provide a report to Congress, not later than 180 days after its enactment, which "identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007" (EPACT, Sec. 1252(d)).

Background

Most electricity customers see electricity rates that are based on average electricity costs and bear little relation to the true production costs of electricity as they vary over time. Demand response is a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized.

- *Price-based demand response* such as real-time pricing (RTP), critical-peak pricing (CPP) and time-of-use (TOU) tariffs, give customers time-varying rates that reflect the value and cost of electricity in different time periods. Armed with this information, customers tend to use less electricity at times when electricity prices are high.
- *Incentive-based demand response programs* pay participating customers to reduce their loads at times requested by the program sponsor, triggered either by a grid reliability problem or high electricity prices.

Limited demand response capability exists in the U.S. today.[2] Total demand response and load management capability has fallen by about one-third since 1996 due to diminished utility support and investment.

States should consider aggressive implementation of price-based demand response for retail customers as a high priority, as suggested by EPACT. Flat, average-cost retail rates that do not reflect the actual costs to supply power lead to inefficient capital investment in new generation, transmission and distribution infrastructure and higher electric bills for customers. Price-based demand response cannot be achieved immediately for all customers. Conventional metering and billing systems for most customers are not adequate for charging time-varying rates and most customers are not used to making electricity decisions on a daily or hourly basis. The transformation to time-varying retail rates will not happen quickly. Consequently, fostering demand response through

---

[1] Public Law 109-58, August 8, 2005.

[2] In 2004 potential demand response capability equaled about 20,500 megawatts (MW), 3% of total U.S. peak demand, while actual delivered peak demand reduction was about 9,000 MW (1.3% of peak).

incentive-based programs will help improve efficiency and reliability while price-based demand response grows.

The Benefits of Demand Response

The most important benefit of demand response is improved resource-efficiency of electricity production due to closer alignment between customers' electricity prices and the value they place on electricity. This increased efficiency creates a variety of benefits, which fall into four groups:

- *Participant financial benefits* are the bill savings and incentive payments earned by customers that adjust their electricity demand in response to time-varying electricity rates or incentive-based programs.
- *Market-wide financial benefits* are the lower wholesale market prices that result because demand response averts the need to use the most costly-to-run power plants during periods of otherwise high demand, driving production costs and prices down for all wholesale electricity purchasers. Over the longer term, sustained demand response lowers aggregate system capacity requirements, allowing load-serving entities (utilities and other retail suppliers) to purchase or build less new capacity. Eventually these savings may be passed onto most retail customers as bill savings.
- *Reliability benefits* are the operational security and adequacy savings that result because demand response lowers the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers.
- *Market performance benefits* refer to demand response's value in mitigating suppliers' ability to exercise market power by raising power prices significantly above production costs.

Quantifying the National Benefits of Demand Response

DOE reviewed recent studies that have quantified demand response benefits and assessed the analytical methods used and analyzed ten studies that estimated the benefits of actual or proposed demand response initiatives for specific regions. The results point out important inconsistencies in how demand response is currently measured.

To date there is little consistency in demand response quantification. Three types of studies have looked at demand response benefits; the time horizons and categories of benefits examined vary widely.

- *Illustrative analyses* quantify the economic impacts of demand response; the four studies examined here look within organized wholesale markets. These studies report relatively high levels of benefits in part because they assume high levels of demand response penetration over a large customer base and long-term sustained benefits.
- *Integrated resource planning studies* look at whether and how much to use demand response resources as part of a long-term resource plan. These studies

assume regional impacts over a long time period and report high levels of demand response benefits.

- *Program performance studies* measure the actual delivered value of demand response programs implemented by several independent grid operators (e.g., the PJM Interconnection [PJM], the New York Independent System Operator [NYISO], and ISO-New England [ISO-NE]). These studies report the lowest level of demand response benefits, in part because they reflect market conditions over a short time period and do not necessarily capture the full range of market circumstances or value long-term impacts.

Based on this review, DOE concludes that, to date, the estimated benefits of demand response are driven primarily by the quantification method, assumptions regarding customer participation and responsiveness, and market characteristics. Without accepted analytical methods, DOE finds that it is not possible to quantify the national benefits of demand response. Moreover, regional differences in market design, operation, and resource balance are important and must be taken into account. Estimates of demand response benefits are best done for service territories, states, and regions, because the magnitude of potential benefits is tied directly to local electric system conditions (e.g., the supply mix, the presence or absence of supply constraints, the rate of demand growth, and resource plans for meeting demand growth).

Recommendations

EPACT directs DOE to recommend how more demand response can be put in place by January 1, 2007. DOE concludes that eleven months is too short a time for meaningful recommendations to be implemented and have any practical impact. Instead, DOE offers recommendations to encourage demand response nation-wide, which are organized as follows:

- **Fostering Price-Based Demand Response**—by making available time-varying pricing plans that let customers take control of their electricity costs. More efficient pricing of retail electricity service is of the utmost importance.
- **Improving Incentive-Based Demand Response**—to broaden the ways in which load management contributes to the reliable, efficient operation of electric systems. Incentive-based demand response programs can help improve grid operation, enhance reliability, and achieve cost savings.
- **Strengthening Demand Response Analysis and Valuation**—so that program designers, policymakers and customers can anticipate demand response impacts and benefits. Demand response program managers and overseers need to be able to reliably measure the net benefits of demand response options to ensure that they are both effective at providing needed demand reductions and cost-effective.
- **Integrating Demand Response into Resource Planning**—so that the full impacts of demand response, and the maximum level of benefits, are realized. Such efforts help establish expectations for the short- and long-run value and contributions of

demand response, and enable utilities and other stakeholders to compare demand response options with other alternatives.

- **Adopting Enabling Technologies**—to realize the full potential for managing usage on an ongoing basis given innovations in communications, control, and computing. Innovations in monitoring and controlling loads are underway offering an array of new technologies that will enable substantially higher level of demand response in all customer segments.
- **Enhancing Federal Demand Response Actions**—to take advantage of existing channels for disseminating information, providing technical assistance, and expanding opportunities for public-private collaboratives. Enhancing cooperation among those that provide new products and services and those that will use them is paramount.

OVERVIEW: KEY FINDINGS AND RECOMMENDATIONS

Introduction

Sections 1252(e) and (f) of EPACT state that it is the policy of the United States to encourage “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.” It further states that “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 services markets shall be eliminated”. To help implement this new policy on demand response, the Act creates new requirements for electric utilities and states with respect to demand response. States are charged with conducting investigations to determine how those new provisions could be applied and whether to adopt widespread time-based pricing and advanced metering for utility retail customers.

EPACT directs DOE to encourage demand response by:

- educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects, and
- working with States, utilities, other energy providers, and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs (EPACT, Sec. 1252(d)).

The law also requires DOE to provide a report to Congress, not later than 180 days after its enactment, which “identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007” (EPACT, Sec. 1252(d)). This report fulfills that requirement.

Defining and Characterizing Demand Response

Demand response, defined broadly, refers to active participation by retail customers in electricity markets, seeing and responding to prices as they change over time. Currently, most customers see only flat, average-cost based electric rates that give them no indication that electricity values change over time, nor any incentive to vary their electric use in response to prices.

Demand response can be defined more specifically 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 times of high wholesale market prices or when system reliability is jeopardized.*

Lower electricity use in peak periods creates benefits by reducing the amount of generation and transmission assets required to provide electric service. Lower demand in response to high prices (particularly market clearing prices in an organized regional spot market) reduces the costs of electricity production and holds down prices in electricity spot markets. Reduced demand in response to system reliability problems enhances operators' ability to manage the electric grid—the network that transmits electricity from generators to consumers—and reduces the potential for forced outages or full-scale blackouts.

Why is Demand Response Important?

Demand response offers a variety of financial and operational benefits for electricity customers, load-serving entities (whether integrated utilities or competitive retail providers) and grid operators. Electric power systems have three important characteristics. First, because electricity cannot be stored economically, the supply of and demand for electricity must be maintained in balance in real time. Second, grid conditions can change significantly from day-to-day, hour-to-hour, and even within moments. Demand levels also can change quite rapidly and unexpectedly, and resulting mismatches in supply and demand can threaten the integrity of the grid over very large areas within seconds. Third, the electric system is highly capital-intensive, and generation and transmission system investments have long lead times and multi-decade economic lifetimes.

These features of electric power systems require that power grids be planned and managed for years in advance to ensure that the system can operate reliably in real time despite the many uncertainties surrounding future demands, fuel sources, asset availability and grid conditions. Working in a competitive bulk power market, load serving entities (integrated utilities or retail electric providers) buy or build from 60 to 95% of their electricity in advance, with the expectation that they will be able to generate or purchase enough spot market electricity in real time to meet changing system demands.

These challenges and uncertainties are what make demand response so valuable—it offers flexibility at relatively low cost. Grid operators—Independent System Operators (ISOs), Regional Transmission Organizations (RTOs) or utilities—and other entities can use demand response to curtail or shift loads instead of, traditionally, building more generation. And although it takes time to establish and recruit customers for a demand response program, well-structured pricing and incentive-based demand response can produce significant savings in close to real time, often at lower costs than supply-side resources.

Types of Demand Response

Demand response can be classified according to how load changes are brought about.

- *Price-based demand response* refers to changes in usage by customers in response to changes in the prices they pay and include real-time pricing, critical-peak pricing, and time-of-use rates. If the price differentials between hours or time periods are significant, customers can respond to the price structure with significant changes in energy use, reducing their electricity bills if they adjust the timing of their electricity usage to take advantage of lower-priced periods and/or avoid consuming when prices are higher. Customers' load use modifications are entirely voluntary.
- *Incentive-based demand response* programs are established by utilities, load-serving entities, or a regional grid operator. These programs give customers load-reduction incentives that are separate from, or additional to, their retail electricity rate, which may be fixed (based on average costs) or time-varying. The load reductions are needed and requested either when the grid operator thinks reliability conditions are compromised or when prices are too high. Most demand response programs specify a method for establishing customers' baseline energy consumption level, so observers can measure and verify the magnitude of their load response. Some demand response programs penalize customers that enroll but fail to respond or fulfill their contractual commitments when events are declared.[3]

The textbox below summarizes the major price-based and incentive-based demand response programs now in use.

EPACT encourages demand response that that allows customers to face the time-varying value of electricity and respond as they choose to those changes. Incentive-based demand response programs offer additional options to policymakers to help solve an area's or market's problems. For example, they can help address reliability problems or can be tailored to achieve specific operational goals, such as localized load reductions to relieve transmission congestion.

Over the long term, the maximum benefits of demand response will come about as the entire range of demand response programs are made available to customers—diversity has value on the demand side as well as the supply-side. Because power system and market circumstances change quickly, a variety of price-based and incentive-based demand response programs can help resolve longstanding industry challenges, such as matching the extended time required to site, approve and build generation and transmission assets to serve uncertain demand growth. In the meantime, it is necessary to understand how to identify and quantify the impacts and benefits of demand response, to facilitate effective and cost-effective implementation of demand response programs and enabling technologies.

---

[3] These performance-based requirements are intended to increase system operators' confidence that demand reductions will materialize when needed.

Demand Response Options

Price-Based Options

- *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).

Incentive-Based Programs

- *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 (or commercial) 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.

Current Demand Response Capability and Recent Initiatives

Limited demand response capability exists in the United States at present, as Figure O-1 illustrates. Several important trends are worth noting:

- Demand response potential in 2004 was about 20,500 megawatts (MW)—3% of total U.S. peak demand. Actual delivered peak demand reductions were about 9,000 MW, or 1.3% of total peak demand (EIA 2004).
- Total potential load management capability has fallen by 32% since 1996. Factors affecting this trend include fewer utilities offering load management services, declining enrollment in existing programs, the changing role and responsibility of utilities, and changing supply/demand balance. However, the demand-side

management (DSM) information reported by industry participants do not fully reflect current demand response activity levels.[4]

- Actual peak reductions are affected by the available installed load reduction capability (i.e., the demand response potential), whether utilities or grid operators need to call program events, and the extent to which enrolled participants respond during program events.
- In 2004, utilities reported spending about $515M on load management programs; this represents about a 10% decrease from the early to mid-1990s.

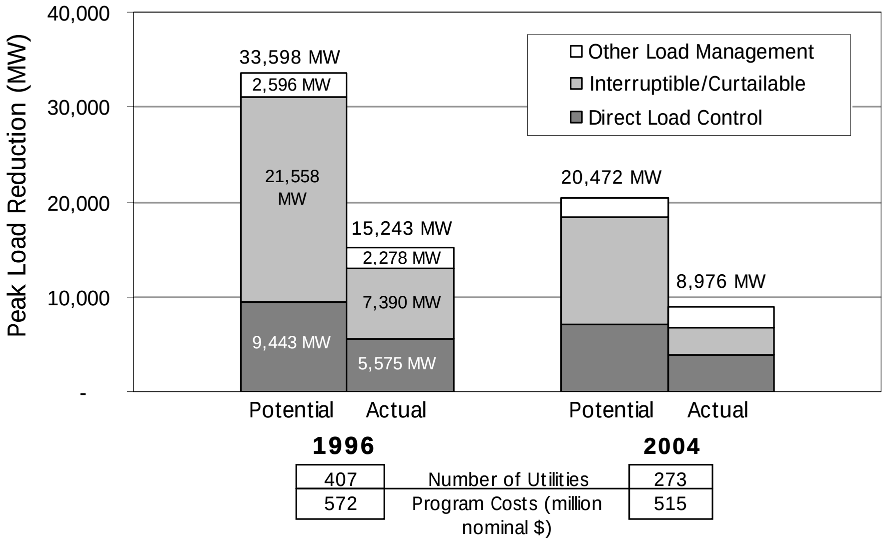


Figure O-1. Existing U.S. Demand Response Potential

A number of recent initiatives highlight renewed interest by federal and state policymakers, regional grid operators and utilities in strengthening demand response capability. Examples include:

- The Federal Energy Regulatory Commission (FERC) has recognized the value that demand response offers for grid reliability and resource adequacy, and has repeatedly encouraged its incorporation and expansion within regions with organized spot markets to enhance competition and more resource-efficient markets.
- Several regional grid operators (e.g., NYISO, PJM, ISO-NE, and the Electric Reliability Council of Texas [ERCOT]) have encouraged customer load participation and taken steps to integrate demand response resources into their wholesale markets.

---

[4] For example, information on time-varying tariffs (e.g. RTP, CPP, and TOU) is not systematically reported by utilities and competitive retailers do not systematically report the types and mix of contracts/products provided to retail customers.

- Regional initiatives and planning processes in New England and the Mid-Atlantic and the Pacific Northwest regions have involved many stakeholders and developed strategies to promote demand response and overcome barriers.
- Several states (Maryland, New Jersey, New York, and Pennsylvania) have adopted real-time pricing as the default service for large customers or implemented large-scale CPP pilot programs (e.g., California, Florida). Several utilities have aggressively implemented real-time pricing as an optional service for large customers and have attracted significant customer participation (e.g. Georgia Power, Duke Power, Tennessee Valley Authority).
- A number of utilities have deployed or are considering deploying advanced metering systems on a system-wide basis that enables "price-based" demand response for all customer classes.

DOE encourages more of these initiatives, shares Congress' views about the importance and value of demand response, and welcomes the opportunity to help make demand response a more effective, integral part of the nation's electricity markets and system.

Identifying the Benefits of Demand Response

Demand response produces benefits primarily as resource savings that improve the efficiency of electricity provision. It is instructive to trace the flow of these benefits through the market to ascertain who gains and by how much. Accordingly, the benefits of demand response can be classified in terms of whether they accrue directly to participants or to some or all groups of electricity consumers.

- *Participant bill savings*—electricity bill savings and incentive payments earned by customers that adjust load in response to current supply costs or other incentives.
- *Bills savings for other customers*—lower wholesale market prices that result from demand response translate into reduced supply costs to retailers and eventually make their way to almost all retail customers as bill savings.
- *Reliability benefits*—reductions in the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers.

Demand response also provides other benefits that are not easily quantifiable or traceable, but can have a significant impact on electricity market operation. Examples include:

- *Market performance*—demand response acts as a deterrent to the exercise of market power by generators;
- *Improved choice*—customers have more options for managing their electricity costs; and
- *System security*—system operators are provided with *more flexible resources* to meet contingencies.

Quantifying the Benefits of Demand Response

Quantifying the potential nation-wide benefits of demand response is a difficult undertaking requiring the following key information and assumptions:

- *Demand Response Options*—the types of time-varying rates and demand response programs currently offered (or potentially available);
- *Customer Participation*—the likelihood that customers will choose to take part in the offered programs;
- *Customer Response*—documenting and quantifying participants' current energy usage patterns, and determining how participants adjust that usage in response to changes in prices or incentive payments;
- *Financial Benefits*—developing methods to quantify the short- and long-term resource savings of load response under varying market structures;
- *Other Benefits*—identifying and quantifying any additional benefits provided by demand response resources (e.g., improved reliability); and
- *Costs*—establishing the costs associated with achieving demand response.

Estimates of the Benefits and Costs of Demand Response

DOE conducted a literature review to understand how previous studies have estimated the benefits of demand response and selected ten recent studies to analyze the methods used to quantify demand response benefits and their impact on the results.

Three types of studies have estimated the benefits of demand response:

- *Illustrative analyses* quantify the economic impacts of demand response within an electricity market. The four examples selected by DOE examined regions with organized wholesale markets. The benefits of demand response are hypothetical and speculative in these studies, often with few details of where the demand response comes from. The ability of these studies to accurately estimate demand response benefits depends on how closely actual circumstances match the assumptions used in the analysis.
- *Integrated Resource Planning (IRP) studies* assess whether and how much demand response resources should be acquired in a long-term resource plan, based on avoided supply costs and anticipated loads and resource needs. The three selected IRP studies were performed by organizations responsible for long-term, regional resource plans or as an illustration of how that planning process could be conducted to include and value demand response.
- *Program performance analyses* measure actual outcomes of demand response programs implemented by regional grid operators (ISO-NE, NYISO, PJM) and provide an after-the-fact estimate of delivered value. The three selected studies estimated the impacts of load curtailments on market prices, quantified the level and distribution of benefits and explicitly accounted for reliability benefits.

DOE found that the estimates of demand response benefits depend on key assumptions, even for studies that seemingly adopted the same market framework. For example, two studies commissioned to measure the nation-wide benefits of demand response from its integration into wholesale market operations produced wildly disparate estimates of $362 million and $2.6 billion per year.

Consequently, in this report, DOE normalized the estimated gross benefits to allow more informative comparisons.[5] This normalization adjusts for differences in the time horizon, market size and the level of customer participation across studies and expresses annual benefits in terms of dollars per system peak load. This provides a better understanding of the impact of study methodologies and assumptions that produced such disparate benefit estimates. Figure O-2 illustrates the results, comparing the range of normalized gross benefit values over all studies and by the three study categories.

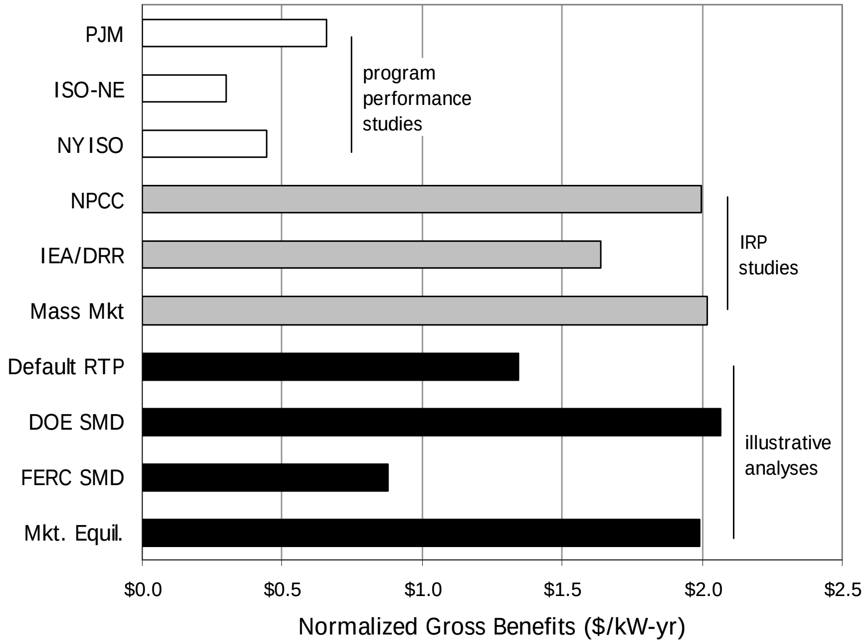


Figure O-2. Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies

Key findings from this cross-study comparison include:

- Even after normalizing results, the estimated gross benefits of demand response vary widely and are driven by the analytical methods used and the assumptions made.
- The illustrative analysis studies report relatively high gross benefits, in part because they assume high levels of demand response penetration over a large customer base and because they estimate demand response impacts under varying electricity market conditions over a multi-year time horizon.

---

[5] Net benefits were not reported because program cost data were not included in all ten studies.

- The IRP studies also report high levels of benefits because they consider and simulate the potential impacts of demand response over the full range of electricity market conditions over a multi-decade period. Their explicit treatment of key uncertainties allows demand response to be deployed during low probability but high consequence events over a long planning horizon. These studies assume that demand response programs and benefits will persist for as long as the physical assets they would complement or replace.
- The program performance studies conducted by regional grid operators report the lowest demand response benefits, in part because they reflect market conditions over a short time period and do not necessarily capture the full range of market circumstances. Program impacts and benefits also do not explicitly account for the forward value of demand response.

This analysis reveals that demand response is viewed and evaluated differently in regions with ISO- or RTO-managed organized spot markets than in regions with vertically integrated utilities with a monopoly franchise. Vertically integrated utilities internalize and pass through all of their energy production, transmission and distribution costs, so they (and their regulators) take a long-term view and evaluate demand response against the alternative of building (or buying) new generation. Thus, utilities with retail monopolies evaluate and measure demand response benefits primarily in terms of avoided capacity costs over the long run. In contrast, regions with organized wholesale markets have active energy trading opportunities with transparent market clearing prices (and in four of the seven ISO/RTO regions, no comparable capacity market), so they tend to evaluate demand response benefits primarily in terms of time-varying energy and capacity values in competitive markets. This view frames demand response benefits in the short run, and tends to understate long-term benefits.

Based on this review, DOE concludes that, to date, the estimated benefits of demand response are driven primarily by analysis methods, assumptions regarding customer participation and responsiveness, and market characteristics. Without standardized and accepted analytical methods to quantify the benefits of demand response, DOE finds that it is not possible to produce a meaningful estimate of the national benefits of demand response. Moreover, DOE recognizes that regional differences in market design, operation, and resource balance are important and must be taken into account. Estimates of demand response benefits are best done for service territories, states, and regions, because the magnitude of potential benefits is tied directly to local electric system conditions (e.g., supply mix, the presence or absence of supply constraints, the rate of demand growth, and resource plans for meeting demand growth).

DOE Recommendations

EPACT directed DOE to offer recommendations for achieving specific levels of demand response benefits by January 1, 2007. DOE concludes that it is not possible to offer recommendations in 2006 that can produce meaningful new demand response by January 2007.

The recommendations outlined below, and covered in more detail in Section 5 of this report, aim to expand the availability and effectiveness of demand response programs, expand the reach and effectiveness of enabling technologies, and suggest tasks for the electric industry to better analyze and use demand response in system planning and operations. These recommendations are summarized below and detailed in Table O-1.

- **Fostering Price-Based Demand Response—**by making available time-varying pricing plans that let customers take control of their electricity costs;
- **Improving Incentive-Based Demand Response—**to broaden the ways in which reliability-driven programs contribute to the reliable operation of electric systems;
- **Strengthening Demand Response Analysis and Valuation—**so that program designers, policymakers and customers can anticipate demand response impacts and benefits;
- **Adopting Enabling Technologies—**to realize the full potential for managing usage on an ongoing basis;
- **Integrating Demand Response into Resource Planning—**so that the full impacts of demand response are recognized and the maximum level of resource benefits are realized; and
- **Enhancing Federal Demand Response Actions—**to take advantage of existing channels for disseminating information and forming public-private collaboratives.

Table O-1: List of Recommendations

Fostering Price-Based Demand Response	In accordance with EPACT, State regulatory authorities must decide whether their utilities must offer customers time-based rate schedules (i.e., RTP, CPP and TOU rates) and advanced metering and communications technology. <u>Large Customers</u> • In states that allow retail competition, state regulatory authorities and electric utilities should consider adopting RTP as their default service option for large customers. • In states that do not allow retail competition, state regulatory authorities and electric utilities should consider offering RTP to large customers as an optional service. • Regional entities and collaborative processes, state regulatory authorities, and electric utilities should provide education, outreach, and technical assistance to customers to maximize the effectiveness of RTP tariffs. <u>Medium and Small Business Customers</u> • State regulatory authorities and electric utilities should investigate new strategies for segmenting medium and small business customers to identify relatively homogeneous sub-sectors that might make them better candidates for price-based demand response approaches. • State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for medium and small business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis. • State regulatory authorities and electric utilities should consider conducting policy or business case analysis of RTP for medium business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis. <u>Residential Customers</u> • State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for residential customers. Results from existing pilot programs should be carefully evaluated and included in the analysis. • State regulatory authorities and electric utilities should investigate the cost-effectiveness of offering technical and/or financial assistance to small business and residential customers to enable their participation in CPP or TOU tariffs and enhance their abilities to reduce demand in response to higher prices.
Improving Incentive-Based Demand Response	• Traditional load management (LM) programs such as direct load control of residential and small commercial equipment and appliances (e.g., air conditioners, water heaters, and pool pumps) with an established track record of providing cost-effective demand response should be maintained or expanded. • State regulatory authorities and electric utilities should consider offering existing and new participants in these LM programs "pay-for-performance" incentive designs, similar to those implemented by ISOs/RTOs and some utilities, which include a certain level of payment to customers who successfully reduce demand when called upon to do so during events. • Regional entities, state regulatory authorities, and electric utilities should consider including the following emergency demand response program features: o Payments that are linked to the higher of real-time market prices or an administratively-determined floor payment that exceeds customers' transaction costs; o "Pay-for-performance" approaches that include methods to measure and verify demand reductions; o Low entry barriers for demand response providers, and in vertically integrated systems, procedures to ensure that customers have access to these programs; and o Multi-year commitments from regional entities for emergency demand response programs so that customers and aggregators can make decisions about committing time and resources. • State regulatory authorities should investigate whether it would be cost-effective for default service providers to implement demand response. They should also provide cost recovery for demand response investments undertaken by distribution utilities.

Table O-1: List of Recommendations	
Strengthening Demand Response Analysis and Valuation	• A voluntary and coordinated effort should be undertaken to strengthen demand response analysis capabilities. This effort should include participation from regional entities, state regulatory authorities, electric utilities, trade associations, demand response equipment manufacturers and providers, customers, environmental and public interest groups, and technical experts. The goal should be to establish universally applicable methods and practices for quantifying the benefits of demand response.
Integrating Demand Response into Resource Planning	• FERC and state regulatory agencies should work with interested ISOs/RTOs, utilities, other market participants and customer groups to examine how much demand response is needed to improve the efficiency and reliability of their wholesale and retail markets. • Resource planning initiatives should review existing demand response characterization methods and improve existing planning models to better incorporate different types of demand response as resource options. • ISOs and RTOs, in conjunction with other stakeholders, should conduct studies to understand demand response benefits under foreseeable future circumstances as part of regional transmission planning and under current market conditions in their demand response performance studies.
Adopting Enabling Technologies	• State regulatory authorities and electric utilities should assure that utility consideration of advanced metering systems includes evaluation of their ability to support price-based and reliability-driven demand response, and that the business case analysis includes the potential impacts and benefits of expanded demand response along with the operational benefits to utilities. • State regulatory authorities and electric utilities should evaluate enabling technologies that can enhance the attractiveness and effectiveness of demand response to customers and/or electric utilities, particularly when they can be deployed to leverage advanced metering, communications, and control technologies for maximum value and impact. • State legislatures should consider adopting new codes and standards that do not discourage deployment of cost-effective demand response and enabling technologies in new residential and commercial buildings and multi-building complexes.
Enhancing Federal Actions	• DOE, to the extent annual appropriations allow, should continue to provide technical assistance on demand response to states, regions, electric utilities, and the public including activities with stakeholders to enhance information exchange so that lessons learned, best practices, new technologies, barriers, and ways to mitigate the barriers can be identified and discussed. • DOE and FERC should continue to coordinate their respective demand response and related activities. • FERC should continue to encourage demand response in the wholesale markets it oversees. • DOE, through its Federal Energy Management Program, should explore the possibility of conducting demand response audits at Federal facilities. • DOE and the Environmental Protection Agency should explore efforts to include appropriate demand response programs and pricing approaches, where appropriate, in the ENERGY STAR® and other voluntary programs.

TABLE OF CONTENTS

LIST OF TABLES AND FIGURES

Overview: Key Findings and Recommendations

Main Report

Appendices

ACRONYMS AND ABBREVIATIONS

A/C	air conditioning
AMI	advanced metering infrastructure
AMR	automated meter reading
AMS	advanced metering systems
CAISO	California Independent System Operator
CPP	critical peak pricing
DLC	direct load control (program)
DOE	United States Department of Energy
DSM	demand-side management
EIA	United States Energy Information Administration
EPACT	United States Energy Policy Act (of 2005)
ERCOT	Electric Reliability Council of Texas
EUE	expected un-served energy
FERC	Federal Energy Regulatory Commission
I/C	interruptible/curtailable (rate)
IRP	integrated resource plan (planning)
ISO	Independent System Operator
ISO-NE	ISO—New England (RTO)
kW	kilowatt
kWh	kilowatt-hour
LM	load management
LSE	Load Serving Entity
MISO	Midwest Independent System Operator
MW	Megawatt
NYISO	New York Independent System Operator
PJM	Pennsylvania/New Jersey/Maryland Interconnection (RTO)
PURPA	Public Utilities Regulatory Policy Act
RTO	Regional Transmission Organization
RTP	real-time pricing (rate)
SMD	Standard Market Design
SPM	Standard Practice Manual
SPP	(California) Statewide Pricing Pilot
TOU	time-of-use (rate)
VOLL	value of lost load

SECTION 1. INTRODUCTION

Sections 1252(e) and (f) of EPACT state that it is the policy of the United States to encourage “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.” It further states that “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 services markets shall be eliminated.” To help implement this new policy on demand response, the Act creates new requirements for electric utilities and states with respect to demand response. States are charged with conducting investigations to determine how those new requirements should be applied and whether to adopt widespread time-based pricing and advanced metering for utility retail customers.[6]

EPACT provides specific guidance to DOE in encouraging demand response. Specifically, the Secretary of Energy is authorized to:

- educate consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects; and
- work with States, utilities, other energy providers, and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs (EPACT, Sec. 1252(d)).

The law also requires DOE to provide a report to Congress, not later than 180 days after its enactment, that “identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007” (EPACT, Sec. 1252(d)).

This document is the report to Congress. DOE views the report requirements as consisting of two parts: the first, “identifies and quantifies the national benefits of demand response” is addressed by Sections 2, 3, and 4 of this report; the second, “makes a recommendation on achieving specific levels of such benefits by January 1, 2007”, is addressed by Section 5 of this report. Table 1-1 summarizes how this report is organized to respond to the EPACT requirements.

The report is further organized as follows:

- Section 2 characterizes and defines demand response options, summarizes the role of demand response in our nation’s provision of electricity, and introduces a framework for customer decisions about demand response.
- Section 3 includes a conceptual and qualitative discussion of the benefits of demand response.

---

[6] Public Law 109-58, August 8, 2005.

- Section 4 provides a comparative review and analysis of ten studies that estimate demand response benefits for specific regions or purposes. DOE also suggests methods and considerations for future state or regional efforts to quantify benefits of demand response.
- Section 5 presents specific recommendations for state, regional and federal agencies, electric utilities and consumers to enhance demand response in varying wholesale and retail market structures.
- There are several technical appendices. Appendix A lists interested parties that provided suggestions to DOE on actions or policies to encourage demand response. Appendix B provides a more in-depth conceptual and qualitative discussion of the benefits of demand response. Appendix C summarizes studies on customer response to time-varying prices and demand response programs (e.g. load impacts). Appendix D provides suggestions and technical discussion on protocols and methods for future state or regional efforts to quantify benefits of demand response.

Table 1-1. Response to EPACT Requirements

EPACT Requirement	Approach	Section of Report
Identify national benefits of demand response	• Synthesize literature and stakeholder input	Section 3
Quantify national benefits of demand response	• Review empirical studies of demand response benefits, normalize results and report range of estimates • Synthesize literature and stakeholder input to develop recommended methods	Section 4
Make recommendation on achieving specific levels of benefits by January 1, 2007	• Solicit stakeholder input and review literature to develop recommendations for encouraging and eliminating barriers to demand response	Section 5

Some discussion is warranted on how the report organization and content aligns with DOE's responsibilities for the report to Congress, as set forth in Section 1252(d) of EPACT.

With respect to the first major requirement ("identifies and quantifies the national benefits of demand response"), no existing study provides a comprehensive estimate of the net benefits of demand response *on a national scale*, nor was it possible for DOE to undertake such a detailed and complex analysis given the timeframe and resources available for completion of this report.[7] Instead, DOE selected ten studies that have estimated demand response benefits for specific regions or purposes that provide a range of estimates and illustrate important methodological issues (see Section 4). DOE believes that estimates of demand response benefits are most usefully done at a utility, state, or regional level, as part of policymakers' decisions on what is the appropriate level of demand response for that geographic footprint under consideration.

---

[7] While a number of studies have attempted to estimate local, regional, or national demand response benefits, empirically or conceptually, they lack a common methodological framework and scope.

With respect to the second requirement (“make a recommendation on achieving specific levels of such benefits by January 1, 2007”), DOE concludes that it is not possible to offer recommendations in 2006 that can produce significantly greater levels of demand response at a national level by January 2007. Instead, DOE offers a set of recommendations for consideration by state, regional and federal agencies, electric utilities and consumers to enhance demand response in a manner that is consistent with the existing market structures of various states and regions. DOE developed these recommendations after consideration of suggestions gained from a public input process in which interested parties provided suggestions, through a web survey, for actions to encourage demand response in different wholesale and retail market structures.[8]

Finally, this report makes the following new contributions to the continuing policy and technical discussions on demand response:

- It is the first study to systematically compare the results of existing quantitative assessments of demand response benefits that use different methods, types of demand response programs, and time horizons.
- It explicitly addresses differences in valuing demand response benefits in vertically integrated utility systems compared to organized electricity markets in which an ISO/RTO administers organized spot markets, and offers recommendations on valuation methods and policy approaches for policymakers.

---

[8] Appendix A identifies the contributing organizations.

SECTION 2. DEFINING AND CHARACTERIZING DEMAND RESPONSE

What is Demand Response?

Demand response, defined broadly, refers to participation by retail customers in electricity markets, seeing and responding to prices as they change over time. Any commodity market—oil, gold, wheat or tomatoes—consists of both sellers, or suppliers of the commodity, and buyers, or consumers of the goods. For a variety of reasons, very few consumers of electricity are currently exposed to retail prices that reflect varying wholesale market costs, and thus have no incentive to respond to conditions in electricity markets, with results that are detrimental to all.

Demand response may be defined more definitively 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 times of high wholesale market prices or when system reliability is jeopardized.*

From the perspective of the electric system as a whole, the emphasis of demand response is on *reductions* in usage at critical times.[9] Critical times are typically only a few hours per year, when wholesale electricity market prices are at their highest or when reserve margins are low due to contingencies such as generator outages, downed transmission lines, or severe weather conditions.

Demand response may be elicited from customers either through a retail electricity rate that reflects the time-varying nature of electricity costs, or a program—an attempt to induce customers to change their consumption behavior—that provides an incentive to reduce load at critical times. The incentive is unrelated to the normal price paid for electricity (e.g., supplemental) and may involve payments for load reductions, penalties for not reducing load, or both.

Demand response represents the outcome of an action undertaken by an electricity consumer in response to a stimulus and typically involves customer behavioral changes. However, its value to society is derived from its cumulative impacts on the entire electric system. Understanding and reconciling these two perspectives is key to characterizing and valuing demand response as well as recognizing its limitations.

The discussion in this section begins by establishing why demand response is important and classifying options for obtaining it. Information on current U.S. demand response capability is then presented. Next, demand response is characterized from the system perspective, illustrating how it fits into electricity system planning and scheduling.

---

[9] Demand response may also result in *increases* in electricity usage during the majority of hours when electricity prices are lower than average. This too results in more efficient use of the electric system and may also promote economic growth.

Finally, demand response is discussed from the customer perspective, focusing on how and why customers make decisions to participate and respond (or not).

Why is Demand Response Important?

There is a growing consensus that insufficient levels of demand response exist in the U.S. electric power system.

In recent years, there has been growing consensus among federal and state policymakers that insufficient levels of demand response exist in the U.S. electric power system (EPACT 2005, FERC 2003, NARUC 2000, GAO 2004 and 2005). Due to its physical properties, electricity is not economically storable at the scale of large power systems. This means that the amount of power plant capacity available at any given moment of time must equal or exceed consumers' demand for it in real time. Electricity also has few substitutes for certain end uses (e.g. refrigeration, lighting). The marginal cost of supplying electricity is extremely variable because demand fluctuates cyclically with time of day and season and can surge due to unpredictable events (e.g., extreme temperatures) and because generation or transmission capacity availability fluctuates (e.g., due to a generation plant outage or transmission line failure).[10] While the cost of electric power varies on very short time scales (e.g., every 15 minutes, hourly), most consumers face retail electricity rates that are fixed for months or years at a time, representing *average* electricity production (and transmission and distribution) costs.

The disconnect between short-term electricity production costs and time-averaged, fixed retail rates paid by most consumers leads to an inefficient use of resources.

This disconnect between short-term marginal electricity production costs and retail rates paid by consumers leads to an inefficient use of resources. Because customers don't see the underlying short-term cost of supplying electricity, they have little or no incentive to adjust their demand to supply-side conditions.[11] Thus, flat electricity prices encourage customers to over-consume—relative to an optimally efficient system in hours when electricity prices are higher than the average rates, and under-consume in hours when the cost of producing electricity is lower than average rates. As a result, electricity costs may be higher than they would otherwise be because high-cost generators must sometimes run to meet the non-price-responsive demands of consumers. The lack of price-responsive demand also gives

---

[10] LSEs must secure access to capacity for generation, transmission, and distribution in place before demand occurs, given that electricity can not be stored and must be supplied in real-time to meet geographically dispersed demand. Typically, the most costly generators to operate are only used when demand is at its highest or when other units are temporarily unavailable.

[11] This disconnect between short-term power costs and what retail electricity customers pay may also lead consumers to acquire appliances and pursue applications of electricity that build in long-term inefficiencies and barriers to change.

generators the opportunity to raise prices above competitive levels and exercise “market power” in certain situations.[12]

An important benefit of demand response is avoided need to build power plants to serve heightened demand that occurs in just a few hours per year.

In the long term, the impact of insufficient demand response may be even greater as non-price-responsive peak demand can result in long-term investments in expensive generation capacity. An important benefit of demand response is therefore avoidance of capacity investments in peaking generation units to serve heightened demand that occurs in just a few hours per year.

Demand response also provides short-term reliability benefits as it can offer load relief to resolve system and/or local capacity constraints. During a system emergency or when reserve margins are low, it may be necessary for a utility to ration end user loads to preserve system integrity and/or prevent cascading blackouts. Selectively curtailing service to customers that place lower values on loss of service and voluntarily elect to participate in an emergency demand response program is less expensive, less disruptive and more efficient than random rationing (e.g. curtailing loads via rotating outages).[13] It is also possible for time-varying rates (e.g., RTP) to provide load relief that can help resolve system capacity constraints as customers respond to high on-peak prices.

Many regions are facing significant energy price pressure, demands for substantial grid infrastructure modernization, and concerns regarding excessive reliance on natural gas to fuel electric generation. Improved demand response is critical to improving all of these situations.

Classifying Demand Response Options

There are two basic categories of demand response options: retail pricing tariffs and demand response programs. The specific options for demand response are defined and described in the textbox below.

Time-varying retail tariffs, which include TOU, RTP and CPP rates can be characterized as *“price-based” demand response*. In these tariff options, the price of electricity fluctuates (to varying degrees) in accordance with variations in the underlying costs of electricity production. Time-varying tariffs may be offered as an optional alternative to a

---

[12] Excessive market power has been measured in several electricity markets in the U.S. and attributed, among other reasons, to insufficient price-responsive load (Borenstein et al. 2000, ISO-NE 2005a, PJM Interconnection 2005a).

[13] Utilities (and now ISOs/RTOs) have developed several program designs that induce customers to reveal their private values/information on outage costs. One approach, based on demand subscription, allows customers to specify a firm service level (FSL) below which they cannot be curtailed and are priced at a higher rate than applies to any residual load, which is curtailable (Woo 1990, Spulber 1992). The customer agrees to curtail this interruptible load during a system emergency.

Demand Response Options

Policymakers have several tariff and program options for eliciting demand response. The most commonly implemented options are described below.

Tariff Options

(“price-based” demand response)

- *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. TOU rates often vary by time of day (e.g., peak vs. off-peak period), and by season and are typically pre-determined for a period of several months or years. Time-of-use rates are in widespread use for large commercial and industrial (C/I) customers and require meters that register cumulative usage during the different time blocks.
- *Real-time pricing (RTP):* a rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. RTP prices are typically known to customers on a day-ahead or hour-ahead basis.
- *Critical Peak Pricing (CPP):* CPP rates include a pre-specified high rate for usage designated by the utility to be a critical peak period. CPP events may be triggered by system contingencies or high prices faced by the utility in procuring power in the wholesale market, depending on the program design. CPP rates may be super-imposed on either a TOU or time-invariant rate and are called on relatively short notice for a limited number of days and/or hours per year. CPP customers typically receive a price discount during non-CPP periods. CPP rates are not yet common, but have been tested in pilots for large and small customers in several states (e.g., Florida, California, and North and South Carolina).

Program Options

(“incentive-based” demand response)

- *Direct load control:* a program in which the utility or system operator remotely shuts down or cycles a customer’s electrical equipment (e.g. air conditioner, water heater) on short notice to address system or local reliability contingencies. Customers often receive a participation payment, usually in the form of an electricity bill credit. A few programs provide customers with the option to override or opt-out of the control action. However, these actions almost always reduce customer incentive payments. Direct load control programs are primarily offered to residential and small commercial customers.
- *Interruptible/curtailable (I/C) service:* programs integrated with the customer tariff that provide a rate discount or bill credit for agreeing to reduce load, typically to a pre-specified firm service level (FSL), during system contingencies. Customers that do not reduce load typically pay penalties in the form of very high electricity prices that come into effect during contingency events or may be removed from the program. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers.
- *Demand Bidding/Buyback Programs:* programs that (1) encourage large customers to bid into a wholesale electricity market and offer to provide load reductions at a price at which they are willing to be curtailed, or (2) encourage customers to identify how much load they would be willing to curtail at a utility-posted price. Customers whose load reduction offers are accepted must either reduce load as contracted (or face a penalty).
- *Emergency Demand Response Programs:* programs that provide incentive payments to customers for measured load reductions during reliability-triggered events; emergency demand response programs may or may not levy penalties when enrolled customers do not respond.
- *Capacity Market Programs:* these programs are typically offered to customers that can commit to providing pre-specified load reductions when system contingencies arise. Customers typically receive day-of notice of events. Incentives usually consist of up-front reservation payments, determined by capacity market prices, and additional energy payments for reductions during events (in some programs). Capacity programs typically entail significant penalties for customers that do not respond when called.
- *Ancillary Services Market Programs:* these programs allow customers to 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.

regular fixed electricity rate or as the regular, default rate itself.[14] Customers on these rates can reduce their electricity bills if they respond by adjusting the timing of their electricity usage to take advantage of lower-priced periods and/or avoid consuming when prices are higher. Customer response is typically driven by an internal economic decision-making process and any load modifications are entirely voluntary.

Incentive-based demand response programs represent contractual arrangements designed by policymakers, grid operators, load-serving entities (utilities and retail electricity suppliers) to elicit demand reductions from customers at critical times called program "events".[15] These programs give participating customers incentives to reduce load that are separate from, or additional to, those customers' retail electricity rate, which may be fixed (based on average costs) or time-varying. The incentives may be in the form of explicit bill credits or payments for pre-contracted or measured load reductions. Customer enrollment and response are voluntary, although some demand response programs levy penalties on customers that enroll but fail to respond or fulfill contractual commitments when events are declared.[16] In order to determine the magnitude of the demand reductions for which consumers will be paid, demand response programs typically specify a method for establishing customers' baseline energy consumption (or firm service) level against which their demand reductions are measured.

Current U.S. Demand Response Capability

Limited demand response capability exists in the U.S. at present.

Limited demand response capability exists in the United States at present. The Energy Information Administration (EIA) has collected annual information on demand-side management (i.e., energy efficiency and load management) from industry participants since the early 1990s. Industry participants (mostly utilities) provide the following information on company-administered load management programs: potential peak reduction, actual peak reductions, and program costs. Potential peak reductions reflect the installed load reduction capability, in megawatts (MW), of program participants during the time of system peak, while actual peak reduction reflects the changes in the demand for electricity resulting from a load management program that is in effect at the same time that the utility experiences its annual peak load. Program costs include direct and indirect utility expenses (e.g., program administration, payments to participants, marketing).[17] Prior to 1997, utilities reported information on a more disaggregated basis based on type

---

[14] TOU rates are in common use as the default service for large commercial and industrial customers throughout the U.S. RTP has been offered as an optional rate for large customers at 40-50 utilities in the U.S., and has been adopted or is under consideration as the default electricity service for large customers in several states where customers can choose their retail supplier (e.g., New Jersey, Maryland, Pennsylvania, New York).

[15] Events may be in response to high wholesale electricity market prices or contingencies that threaten electric system reliability, which can occur at any time of the year.

[16] These performance-based requirements are intended to increase system operators' confidence that demand reductions will materialize when needed.

[17] Costs reported to EIA do not include those incurred directly by participating customers.

of demand response program, which included categories for direct load control (DLC) and interruptible/curtailable (I/C) rate programs.

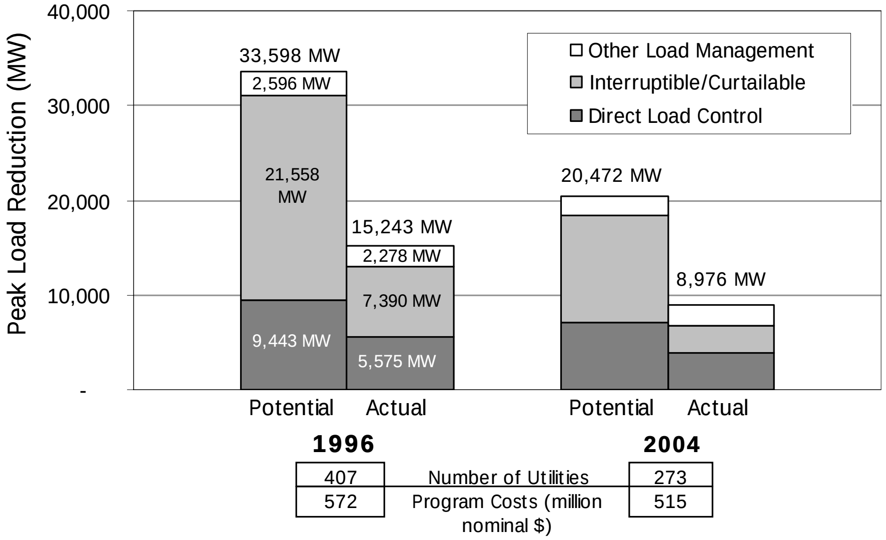


Figure 2-1. Existing U.S. Demand Response Potential

Figure 2-1 summarizes information on potential and actual peak reductions and program costs for 1996 and 2004.[18] Several trends are worth noting:

- Demand response potential in 2004 was about 20,500 MW, 3% of total U.S. peak demand. Actual delivered peak demand reduction was about 9,000 MW, about 1.3% of total peak (NERC 2005).
- Total potential load management capability has fallen by 32% since 1996. Factors affecting this trend include fewer utilities offering load management services (407 utilities in 1996 to 273 in 2004), declining enrollment in existing programs, the changing role and responsibility of utilities, and the increase in installed capacity The DSM information reported by industry participants to EIA does not fully reflect current demand response activity levels.[19]
- Actual peak reductions are affected by the available installed load reduction capability (i.e., the demand response potential), whether utilities or ISOs/RTOs called program events, and the extent to which enrolled participants respond during events.

---

[18] 1996 is both the year with the highest potential load reduction capability and the last year for which disaggregated information on demand response program type is available; 2004 is the most recent year of reported data.

[19] For example, utilities do not systematically report information on customer participation in optional “price-based” demand response programs (e.g. RTP, CPP, and TOU) and competitive retailers do not report the types and mix of contracts/products provided to retail customers. It is unlikely that all industry participants enrolled in ISO demand response programs are reporting their demand response activities.

- In 2004, utilities reported spending about $515M on load management programs; this represents about a 10% decrease from the early to mid-1990s.
- Although not shown explicitly in Figure 2-1, residential and industrial customers account for the bulk of actual peak load reductions (32% and 50% respectively) in 2004.

Market Structures for Electricity Production in the U.S.

Historically, the U.S. electric power industry has relied heavily on a market structure based on vertically integrated utilities that planned and operated electric generation, transmission and distribution systems on an integrated basis. Investor-owned utilities have an obligation to provide reliable service to customers in established, franchise service territories and are subject to regulation as a monopoly by state public utility commissions that set retail rates and review major capital investments and utility operations.

During the last decade, federal legislation (e.g., Energy Policy Act of 1992) and various Federal Regulatory Energy Commission (FERC) orders have helped create more competitive wholesale power markets with mandated open transmission access. Today almost every load-serving entity in the nation purchases some portion of its supply from these wholesale power markets, whether through bilateral contracts or in an organized spot market. Organized spot markets for wholesale electricity, operated by RTOs or ISOs) exist in the Northeast, Mid-Atlantic, much of the Midwest, and in Texas and California. ISOs/RTOs are typically responsible for maintaining grid reliability by overseeing and operating the high-voltage bulk power system and coordinating electricity generation, operating bid-based markets for spot energy (e.g. real-time, day-ahead, or ancillary services), and conducting long-term regional planning to identify system upgrade and expansion needs and overseeing capacity markets (in some cases).

In those states and regions without an ISO or RTO, electricity is delivered and transacted primarily by vertically integrated utilities through self-generation and bilateral contracts with significant state regulatory oversight of resource planning and rates.

Retail competition has been established in 18 states, which give customers additional choices in the supply and pricing of electricity. In these states, there have also been significant changes in the roles and responsibility of utilities (e.g. divesting of some generation assets, separation of competitive retail service function from transmission and distribution services which remain regulated).

A significant number of customers (20-25% of U.S. electric load) are also served by rural electric cooperatives or public power (municipal or public utility district) utilities. These entities have structural characteristics that are similar to vertically integrated utilities in that they typically have an obligation to serve customers in an established franchise service territory and many own generation, transmission and distribution assets, but their governance structure differs in that they are overseen by local authorities and boards. In a few states they are also regulated at the state level. Some public power utilities and rural cooperatives purchase some or all of their power requirements from vertically integrated utilities, generation and transmission cooperatives, power marketing authorities, or through wholesale markets and in some cases have developed load management resources to a greater extent than investor-owned utilities (Kexel 2004).[20]

---

[20] For some rural cooperatives, the primary reason for implementing load management programs was to reduce billed demand charges to the member cooperatives themselves and to reduce the capacity requirements of their Generation and Transmission cooperatives (Kexel 2004).

The Role of Demand Response in Electric Power Systems

In assessing the benefits of demand response, it is important for policymakers to be cognizant of the physical infrastructure and operational requirements necessary to construct and reliably operate an electric power system as well as regional differences in market structure and industry organization (see the previous textbox).

In all market structures, the management of electric power systems is largely shaped by two important physical properties of electricity production. First, electricity is not economically storable, and this in turn requires maintaining the supply/demand balance at the system level in real time. Mismatches in supply and demand can threaten the integrity of the electrical grid over extremely large areas within seconds. Second, the electric power industry is very capital intensive. Generation and transmission system investments are large, complex projects with expected economic lifetimes of several decades that often take many years to develop, site and construct.

These features of electric power systems necessitate management of electricity on a range of timescales, from years (or even decades) for generation and transmission planning and construction, to seconds for balancing power delivery against fluctuations in demand (see Figure 2-2). Decisions are made at several junctures along this timeframe. Generally speaking, the amount of load committed at each juncture declines as the time horizon approaches power delivery. For example, 70-80% of supplied load is often committed through forward energy contracts, months or even years before it is delivered. The amount of power arranged on a day-ahead basis varies, but is typically 10-25% of total requirements. In most cases, less than 5% of supply is committed in the last two hours before its delivery.

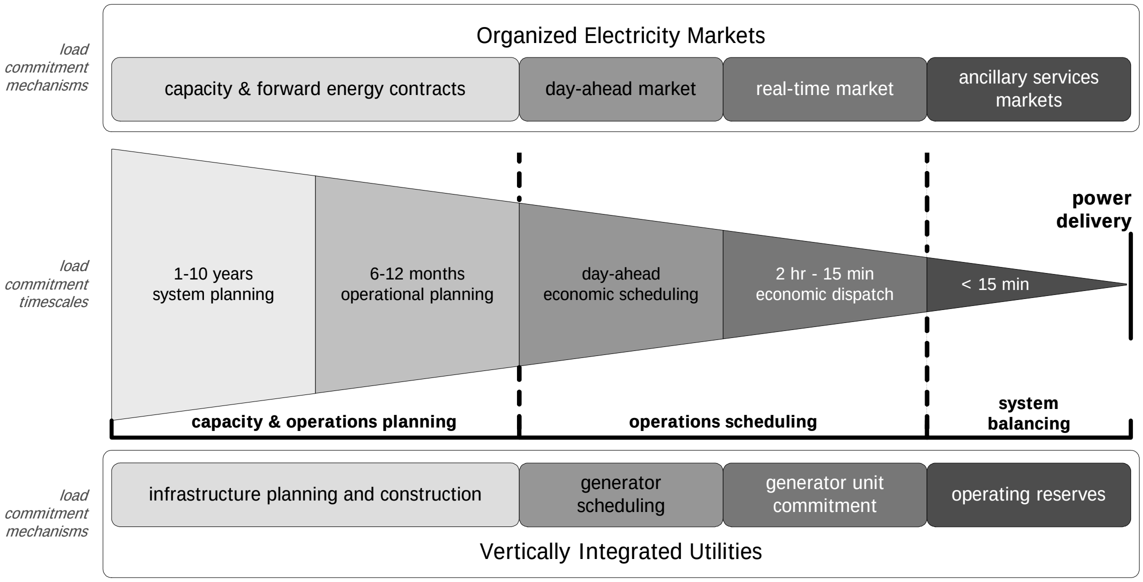


Figure 2-2. Electric System Planning and Scheduling: Timescales and Decision Mechanisms

The major infrastructure planning and operational power delivery decision timeframes are similar in regions with organized wholesale markets and in vertically integrated systems, although the mechanisms for committing energy supply responsibilities differ (see Figure 2-2). In states with retail competition, default service providers and competitive retailers often have a much shorter horizon for acquiring resources than a vertically integrated utility in a state without retail competition.

- *Capacity and operations planning* includes long-term investment and planning decisions. Capacity, or system, planning involves assessing the need for and investing in new generation, transmission and distribution system infrastructure over a multi-year time horizon. Operations planning involves scheduling available resources to meet expected seasonal demand and spans a period of months. In vertically integrated utility systems, these investments are typically evaluated in a utility resource planning process, subject to state regulatory review. In regions with organized wholesale markets, responsibility for these activities is more diffuse. An ISO or RTO engages in a long-term transmission planning process, while distribution utilities retain responsibility for distribution system planning and operations. ISO-administered energy and capacity markets (in some areas) determine the scheduling and operation of available resources to meet daily and seasonal needs and also provide price signals for investments in new generation plants. Utilities and competitive retail suppliers, collectively referred to as load-serving entities (LSEs), contract with generators to meet forward energy requirements.
- *Operations scheduling* refers to the process of determining which generators operate to meet expected near-term demand. This typically involves making day-ahead commitments based on the next day’s forecasted demand, with adjustments made in a period of hours down to 15 minutes to account for discrepancies in day-ahead and day-of demand forecasts as well as to account for any unexpected generation plant outages or transmission line problems. Day-ahead and real-time markets administered by ISOs or RTOs fulfill these responsibilities in regions with organized wholesale markets, using generator (or demand resource) offers as the mechanism for scheduling resources for dispatch. Vertically integrated utilities evaluate and schedule generation plants on a merit order basis ranked according to their variable operating costs.
- *System balancing* refers to adjusting resources to meet last-minute fluctuations in power requirements. In regions with organized wholesale markets, resources offer to provide various ancillary services, such as reactive supply and voltage control, frequency-responsive spinning reserves, regulation, and system black-start capability that are necessary to support electrical grid operation.[21] Vertically integrated utilities typically provide ancillary services as part of their integrated operation of the power system.

Ultimately, supply resources are valued according to the timescale of their *commitment* or *dispatch*. Yet because electricity is not storable, its *delivery* to consumers—the goal

---

[21] Reserves are a type of ancillary service for which ISO/RTO markets have been established in regions with organized wholesale markets. Generators (and loads) bid their availability to supply backup power with varying degrees of notice (usually from 30 minutes down to 10 minutes). Other types of ancillary services are typically contracted for directly by ISOs or RTOs.

around which power systems are constructed and managed—occurs in real-time, regardless of when it was committed and priced.

Demand response options can be deployed at all time scales of electricity system management.

Demand response options can be deployed at all timescales of electricity system management (see Figure 2-3) and can be coordinated with the pricing and commitment mechanisms appropriate for the timescale of their commitment or dispatch.[22] For example, demand response programs designed to alert customers of load response opportunities on a day-ahead basis should be coordinated with either a day-ahead market or, in a vertically integrated market structure, with the utility's generator scheduling process. Like generation resources, the actual *delivery* of customer load reductions occurs in real time.

Energy efficiency is a demand-side resource that can be integrated and valued as part of the system planning process and time horizon (Figure 2-3). Though not dispatchable, energy-efficiency measures often create permanent demand-reduction impacts as well as electricity savings.

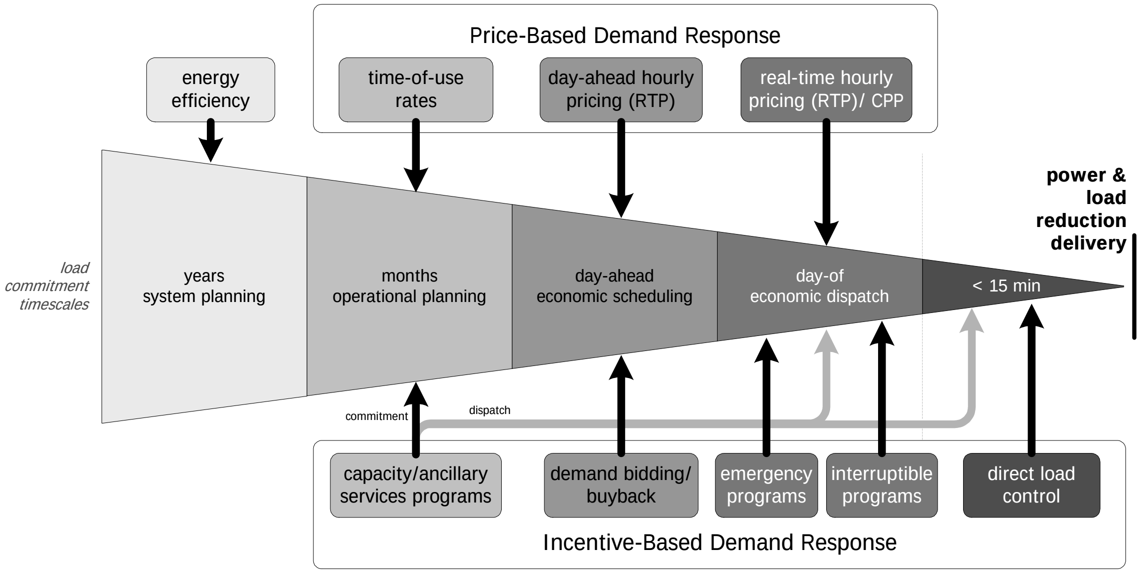


Figure 2-3. Role of Demand Response in Electric System Planning and Operations

If utility resource planners and system operators have a good sense of how their customers respond to changes in the price of electricity, price-based demand response options may be incorporated into system planning at different time scales (Figure 2-3):

---

[22] In some cases, demand response resources have been included in a Request for Proposals (RFP) process designed to alleviate short-term (e.g., 3-4 years), localized transmission capacity constraints. For example, ISO-NE issued an RFP for demand relief over four years in Southwest Connecticut, where construction of transmission capacity was delayed (Platts 2004), and Bonneville Power Administration issued an RFP for demand reduction, energy efficiency and distributed generation options to defer new transmission investments on a five-year timescale in 1994.

- *TOU rates,* which reflect diurnal and seasonal variations in electricity costs but are fixed months in advance, may be valued and integrated as part of operations planning.
- *RTP* provides hourly prices to customers with day-ahead or near-real-time notice, depending on the tariff design.[23] In wholesale markets with ISOs/RTOs, RTP prices are typically indexed to transparent, location-based, day-ahead or real-time hourly energy market prices; absent an organized spot market, utilities establish RTP "prices" based on the utility's marginal procurement costs.
- *CPP rates* are essentially TOU rates with the addition of a critical peak price that is called on a day-of basis.

Incentive-based demand response programs may be introduced at virtually all timescales of electric system management (Figure 2-3):

- *Capacity programs* involve load reduction commitments made ahead of time (e.g., months), which the system operator has the option to call when needed. The call option is usually exercised with two or less hours of notice, depending on the specific program design. Participants receive up-front capacity payments, linked to capacity market prices, from entities that otherwise would need to purchase comparable levels of generation to satisfy capacity reserve obligations.
- *Ancillary services programs* also involve establishing customer load commitments ahead of time. Customers whose reserve market bids are accepted must then be "on call" to provide load reductions, often with less than an hour's notice.[24]
- Load reductions from *demand buyback* or *bidding programs* are typically scheduled day-ahead, and incentive payments are valued and coordinated with day-ahead energy markets.
- *Emergency programs* are reliability-based, and payments for load reductions are often linked to real-time energy market prices (in regions with organized wholesale markets) or values that reflect customer's outage cost or the value of lost load. Program events are usually declared within 30 minutes to 2 hours of power delivery.
- *DLC programs* are typically reliability-based and can be deployed within minutes because the utility or system operator triggers the reduction directly, without waiting for a customer-induced response.[25]

---

[23] In some states (e.g., New Jersey, Maryland, Pennsylvania), RTP tariffs have been implemented that are indexed to real-time markets that do not communicate prices until after the fact. No studies assessing observed price response from this tariff design have been conducted. It is conceivable that customers look to near real time prices or day-ahead market prices posted by the PJM Interconnection, as a proxy and adjust their usage accordingly (Barbose et al. 2005).

[24] See Kirby (2003) and Kueck et al. (2001) for more information on customer load participation in ancillary services markets.

[25] DLC can also be used by LSEs to mitigate the impact of high wholesale market prices or manage system-demand related charges.

How Do Customers Accomplish Demand Response?

There are significant challenges in matching customers' preferences for demand response program features to system characteristics that drive value. From the customer perspective, investments in demand response and energy efficiency are both DSM strategies that can be used to manage energy costs. Participation in DSM programs (or making DSM investments) involves a series of decisions (see Figure 2-4).

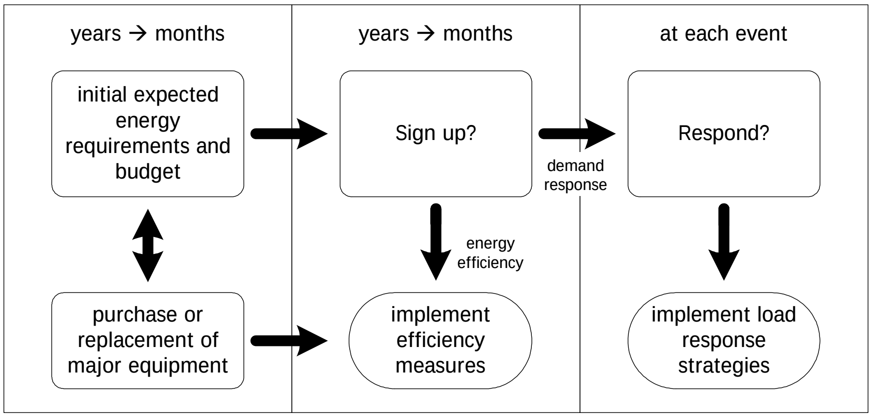


Figure 2-4. Customer Decisions for Demand-Side Management

First, customers implicitly or explicitly determine an initial energy budget based on their expectations of current and future average electricity prices and their household or facility energy needs (see Figure 2-5). The timeframe for this decision (or expectation) is typically monthly or annual, and decisions about purchasing or replacing major energy-using equipment may be made at the same time (see Figure 2-4). The decision-making process may be somewhat different for residential and small commercial customers, who may have a less formalized notion of their usage needs and budget than for large commercial or industrial facilities that may include energy costs as part of a specific operating budget.[26] Larger demand-metered customers are also more likely to be concerned with managing their peak demand in response to demand charges, which are typically included in their electricity tariffs.

Customer participation in demand response options involves *two* important decisions: whether or not to sign up for a voluntary program or tariff (or remain on the option in the case of a default tariff) and, subsequently, whether or not to respond to program events or adjust usage in response to prices as they occur (see Figure 2-4). This is in contrast to traditional energy-efficiency programs, in which customers invest in high-efficiency equipment in response to an existing program offered by a utility, state agency, or public benefits administrator that provides information, technical assistance and/or financial incentives.[27] In most cases energy-efficiency measures, once installed, continue to reduce

---

[26] This characterization of the customer decision process is more applicable to large, sophisticated, customers. There is a portion of the customer base, particularly many residential and small business customers that have limited understanding of their energy usage patterns and existing tariffs.
[27] Many customers also decide to invest in high efficiency equipment or measures based solely on their own internal economic decision criteria, apart from publicly funded programs.

energy usage over a multi-year economic lifetime, usually without much ongoing customer attention.[28] Compared to the initial usage and budget decision, which is relatively simple and familiar to customers, customers' decisions to enroll in demand response programs and to respond during events can be quite complex.

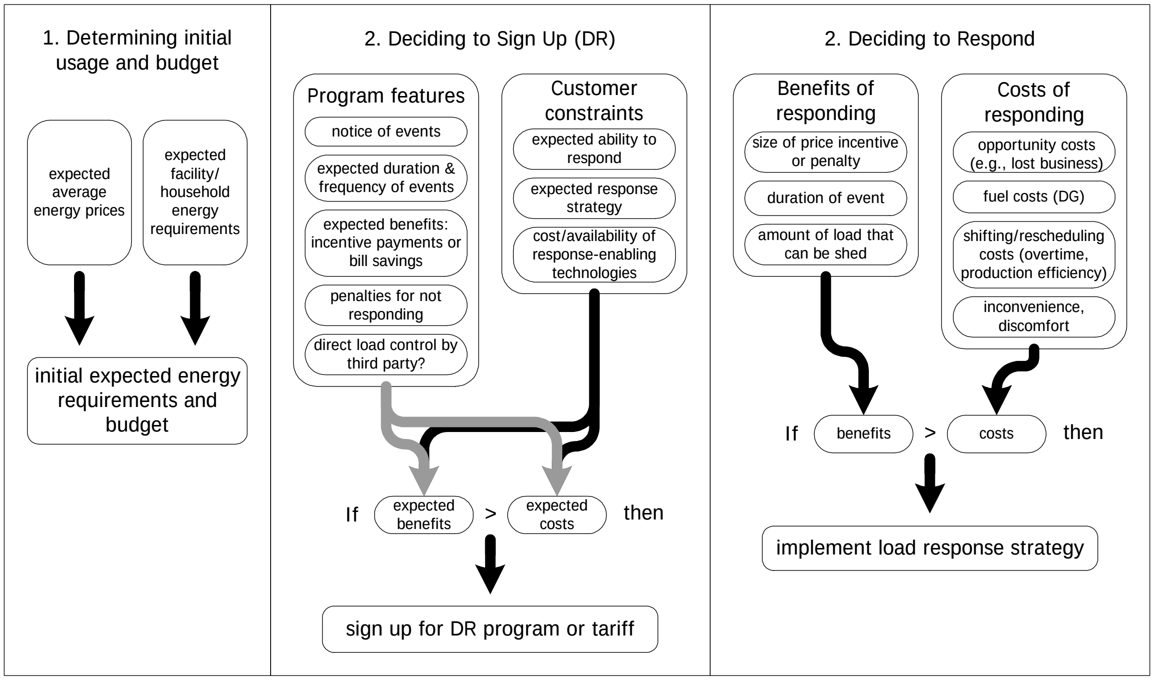


Figure 2-5. Factors Affecting Customer Decisions About Demand Response

The decision to sign up for demand response options involves evaluating offered program or tariff features and weighing the *expected* costs and benefits (see Figure 2-5). A demand response program may specify key parameters of interest to customers (e.g., maximum number of emergency events, payment if event is called), although there is significant uncertainty about the probability and timing of emergency events for the customer.

Ultimately, uncertainties in the costs and benefits of program participation represent risks to customers that may pose significant barriers to their signing up. For example, under RTP, future hourly prices are uncertain, making the benefits of participation difficult to predict.[29]

---

[28] Some energy-efficient equipment does require ongoing commissioning or maintenance to ensure energy savings continue to be realized over time, or savings may be affected by changes in customer usage of the equipment. Nonetheless, most energy-efficiency investments produce at least some level of savings over a period of years without further customer attention.

[29] However, the most popular form of RTP, two-part RTP, provides some financial protection against unexpectedly high prices, and the primary driver of participation is likely the expectation of *lower* average prices than under a standard tariff. Experience at successful programs (e.g., Georgia Power and Duke Power Company) has shown that some customers reduce load substantially during hours of high prices. Thus, RTP customers have the possibility of achieving bill savings from both lower prices overall, and from responding to high prices when they occur.

The relative certainty of a benefit stream may be as important to customers as the benefits themselves.

Potential participants in emergency demand response programs also face uncertainty about the number of demand response events in which they will be able to achieve benefits, and the payments they will receive when the events occur. Only in capacity-related demand response programs are up-front payments typically provided, in return for which customers agree to curtail on short notice when notified. The relative *certainty* of a benefit stream may be as important as the incentive payments themselves. While certain up-front investments, such as programmable thermostats, energy management systems or onsite generation equipment, may make responding easier, uncertainties about the benefits of responding can make these investment decisions difficult to justify.

Once enrolled, customers must decide whether or not to respond as events arise (see Figure 2-5). The benefits of responding are dependent on the actual financial incentive payment that applies to the given event (including the penalty for not responding), the number of hours that the event extends for, the amount of load the customer can shed, and may also include such considerations as the desire to help others by keeping the electric system secure.[30]

Customers may adopt one or more of three basic load response strategies (see the textbox below) and will assess the actual costs of responding in a specific situation. Their costs of responding depend in part on the type of response strategy undertaken. For example, customers who forego usage without making it up later incur costs due to lost productivity or foregone amenity. Customers that shift or reschedule their energy usage may incur costs from labor rescheduling, overtime pay or productivity losses from adjustments to their production process. If onsite generation is used to respond, fuel and maintenance costs are incurred. For any response strategy, inconvenience or discomfort to building occupants or tenants are likely to be important considerations and may be an important part of the cost-benefit decision, even if they are not directly monetized.

---

[30] Note that customers in DLC programs often do not have the choice about whether or not to respond during emergency events. Rather, their choices are focused on the decision to enroll or continue to participate in the program.

Types of Customer Load Response

Customers participating in demand response options may respond to high prices or program events in three possible ways:

- *Foregoing:* involves reducing usage at times of high prices or demand response program events without making it up later. For example, a residential customer might turn off lights or turn up the thermostat on an air conditioner during an event, or a commercial facility might turn off office equipment. In both cases, a temporary loss of amenity or comfort results.
- *Shifting:* involves rescheduling usage away from times of high prices or demand response program events to other times. For example, a residential customer might put off running a dishwasher until later in the day, or an industrial facility might reschedule a batch production process to the prior evening hours or the next day. The lost amenity or service is made up either prior to or at a subsequent time.
- *Onsite generation:* some customers may respond by turning on an onsite or backup emergency generator to supply some or all of their electricity needs. Although the customer may have little or no interruption to their electrical usage, their net load and requirements on the power system is reduced.

Load response strategies may be enhanced with technologies and techniques that allow for fully automated demand response. Pilot projects have demonstrated this potential (Piette et al. 2005), although few customers have yet adopted fully automated demand response.

SECTION 3. BENEFITS OF DEMAND RESPONSE

EPACT requires DOE to identify the benefits of demand response in this report. This section addresses this requirement with a conceptual discussion of the various benefits of demand response, how they are derived, to whom they accrue and how to correctly ascribe value to them. The latter is important to policymakers and utilities in determining how much and what types of time-varying rates and demand response programs to include in their resource portfolios.

The following considerations underlie this discussion of demand response benefits:

- *Customers adjust their electricity usage from typical levels in expectation of receiving benefits.* These benefits must be tangible and sufficient to compensate them for the costs they incur to provide demand response, or else they will not respond.
- *Customers and program administrators incur costs in achieving demand response.* Thus, any discussion of benefits must also define and recognize costs, and quantitative assessments should identify net benefits.
- Policymakers should consider the distributional impacts—*who bears the costs and who receives the benefits*—in designing and evaluating demand response strategies.
- *The durability of benefits must be taken into account*; short-term impacts should be distinguished from long-term impacts that provide benefits over a multi-year period.
- There are important *differences in the timing and distribution of demand response benefits* for vertically integrated utilities in states without retail competition compared to regions with organized wholesale markets and retail competition.

This section begins by identifying and discussing the costs of enabling and implementing demand response. Demand response benefits are then discussed, looking at benefits to participants, collateral benefits (which include economic and reliability benefits enjoyed by some or all market participants), and other benefits that are not easily quantifiable. Appendix B provides a more detailed discussion of collateral benefits, including a discussion of differences in the timing and flow of benefits in different market structures.

Demand Response Costs

The costs of realizing demand response can be distinguished as *participant* and *system* costs (see Table 3-1). Individual customers that curtail usage incur participant costs. Demand response program administrators incur system costs to create the infrastructure required to launch and support demand response, including providing incentive payments to customers. System costs may be recovered from ratepayers (either all ratepayers or designated classes of customers) or, in some cases, through “public benefits” charges on their electric bills. Cost recovery decisions are typically made with oversight from state regulatory agencies.

Table 3-1. Costs of Demand Response

Type of Cost		Cost	Responsibility/ Recovery Mechanism
Participant costs	Initial costs	Enabling technology investments	Customer pays; incentives may be available from public benefit or utility demand response programs to offset portion of costs
		Establishing response plan or strategy	Customer pays; technical assistance may be available from public benefits or utility demand response programs
	Event-specific costs	Comfort/inconvenience costs	Customer bears “opportunity costs” of foregone electricity use
		Reduced amenity/lost business	
		Rescheduling costs (e.g., overtime pay)	
		Onsite generator fuel and maintenance costs	
System costs	Initial costs	Metering/communications system upgrades	Level of costs and cost responsibility vary according to the scope of the upgrade (e.g., large customers vs. mass market), the utility business case for advanced metering system or upgrades, and state legislation/policies
		Utility equipment or software costs, billing system upgrades	Utility typically passes cost through to customers in rates
		Customer education	Ratepayers, public benefits funds
	Ongoing program costs[1]	Program administration/management	Costs are incurred by the administering utility, LSE or ISO/RTO and are recovered from ratepayers
		Marketing/recruitment	
		Payments to participating customers	
		Program evaluation	
		Metering/communication[2]	

[1] Ongoing program costs apply for incentive-based demand response programs and optional price-based programs only. For default-service time-varying pricing, ongoing costs are equivalent to any other default-service tariff offering.

[2] Metering/communications costs can include dedicated wire or wireless lines leased from a third-party telecommunications provider and costs to communicate pricing or curtailment information to customers or their energy services suppliers.

Customers undertaking load reductions may incur *initial* as well as *ongoing* costs to respond (see Table 3-1):

- *Initial costs* are incurred before a particular demand response behavior or action can be undertaken. They include devising a load response strategy that takes costs and benefits into account, and investing in enabling technologies to assist with load response. Enabling technologies include devices, such as “smart” thermostats, peak load controls, energy management control or information systems fully integrated into a business customer’s operations, and onsite generators deployed as backup to network service. Policymakers may find it appropriate to invest in customer education and/or technology rebate programs, using ratepayer or public benefits funds, to defray some of participating customers' initial costs, especially if they are barriers to the achievement of demand response potential.

- *Ongoing costs* are incurred by customers when they respond to high prices or demand response program events. These costs may be measurable financial costs (e.g., lost business activity, rescheduling costs such as employee overtime pay, fuel and maintenance costs from operating onsite generation) or more abstract measures of the value of electricity (e.g., the inconvenience or discomfort associated with load reductions).

Various system-wide costs are incurred in implementing demand response, which should be considered in assessing cost-effectiveness.

A variety of *system-wide costs*, which may be passed through to ratepayers or borne by utility or LSE shareholders, are associated with implementing demand response and require consideration in evaluating benefits. These include *initial costs* as well as *ongoing costs* for certain demand response options (see Table 3-1).

Initial costs can be organized into several functional categories, as follows:

Metering and communication system upgrade costs can present a significant barrier to widespread implementation of price-based DR.

- *Metering/communication system upgrade costs*. Customer retail rates typically charge only for the monthly volume of energy consumed, and for larger customers for maximum monthly demand. Time-varying tariffs (e.g., RTP, CPP) requires chronological measurement of energy usage or demand. This is typically accomplished by installing advanced metering systems (AMS) that measure and store energy usage at intervals of one hour or less and include communication links that allow the utility to remotely retrieve current usage information whenever need.[31] Metering and communications system upgrade costs depend on the existing technology as well as the applicable customer classes. Because the aggregate costs may be substantial, they can present a significant barrier to widespread implementation of time-varying tariffs especially for small and medium-sized customers and often raise cost responsibility and recovery issues. Advanced metering issues are discussed in the textbox below.
- *Utility billing system* upgrades may be necessary for some demand response options (e.g., RTP, CPP) because most legacy systems are not equipped to handle time-varying costs or usage. Pricing hourly (RTP), or having provision to price some hours differently (CPP), requires changing the way metered data are collected, processed, and stored.[32]

---

[31] Note that for some pricing applications (e.g., TOU rates) only usage by daily pricing period (peak and off-peak) needs to be recorded.

[32] RTP (and/or CPP) rates significantly increase the amount of usage data that must be collected (i.e., from two to four observations of customer demand and energy usage per month to at least 720 observations).

Advanced Metering to Support Price-Based Demand Response

Advanced metering is a key technology that enables many utility and customer functions. This textbox addresses four key questions regarding the role and cost of advanced metering.[33]

What is the relationship between price-based demand response and advanced metering? Price-based demand response (e.g., RTP or CPP) requires a tariff that links what the customer pays to the hourly wholesale costs of power. Advanced metering provides utilities with the capability to collect hourly interval or more frequent usage data, which is necessary to support RTP or CPP tariffs.

What is advanced metering? There are three basic types or classes of meters.

- *Conventional "kilowatt-hour" (kWh) meters* account for more than 90% of the current meter population. They record cumulative energy usage and are usually read once each month during an on-site visit by a utility employee.
- *Automated meter reading systems (AMR)* add a low power transceiver, a communication link, to a conventional kWh meter. The transceiver allows the meter to be read from a utility vehicle that drives by the customer site. These meter systems are usually limited by communication capability to collecting a single cumulative kWh reading. AMR speeds up the metering reading function and reduces utility personnel costs.
- *Advanced metering systems (AMS)*, also referred to as *advanced metering infrastructure (AMI)*, provide two features that distinguish them from conventional and AMR systems: (1) the capability to measure and store energy usage at intervals of one hour or less and, (2) a communication link that allows the utility to remotely retrieve current usage information to support customer billing and other utility operational functions.

Aren't advanced meters expensive? Advancements in communications and solid-state technology have reduced the cost of AMI to about $100 per meter if deployed system-wide. Costs to enhance and/or upgrade utility customer information and billing systems are extra. Several recent studies suggest that per-meter hardware and installation costs for advanced metering systems may be comparable to the cost of a new AMR system (King 2004).

What factors should be considered when evaluating the costs and benefits of advanced meters? Advanced metering (AMI) evaluations should consider three major categories of cost and benefit impacts:

- *Utility Operational Impacts:* AMI is first and foremost a technology for automating and improving basic utility operations. Interval metered customer usage data is essential to support billing, outage management, complaint resolution, forecasting, real-time dispatch, rate design and other utility functions. Benefits such as reductions in theft that do not impact utility revenue requirements also need to be addressed. Operational savings alone economically justified all 13 major AMI installations undertaken in North America through 2005. Utility business case analyses should account for the net impact of forecasted operational savings in estimating changes in the utility's revenue requirement from AMI deployment.
- *Demand Response Impacts:* AMI enables RTP, CPP and other forms of performance-based demand response.
- *Societal Impacts:* Societal impacts include improved customer service, environmental, equity and other benefits from more efficient utility operation.

Billing invoices must also be expanded to provide detailed, hour-by-hour accounting. Some utilities and load serving entities can accommodate these new pricing schemes at moderate cost if their existing billing systems are compatible with detailed usage accounting, while others may need to completely revamp or replace their entire billing systems (depending on the number of customers eligible for RTP or CPP).

[33] For more information on Advanced Metering Infrastructure, see http://www.energetics.com/madri/toolbox/.

- *Customer education* about the time-varying nature of electricity costs, potential load response strategies, and available retail market choices is often included in the rollout of demand response options.

Ongoing costs, including program administration and operation, marketing, evaluation, and customer recruitment costs, apply to incentive-based demand response programs and optional pricing tariff options that are offered in addition to customers' standard electricity tariff. For incentive-based demand response programs, additional costs also include payments to participating customers. For most default-service price-based options, there are no incremental ongoing costs relative to any other default-service tariff. However, depending on the type of metering/communication infrastructure used, ongoing equipment operation or leasing costs may apply.

Benefits of Demand Response

The benefits of demand response can be classified into three functional categories: *direct*, *collateral* and *other* benefits (see Table 3-2). Direct benefits accrue to consumers that undertake demand response actions, and collateral and other benefits are enjoyed by some or all groups of electricity consumers. Direct and collateral benefits can be quantified in monetary terms. Other benefits are more difficult to quantify and monetize.

Participant Benefits

Customers who adjust their electricity usage in response to prices or demand response program incentives do so primarily to realize *financial* benefits. In addition, they may be motivated by implicit *reliability* benefits (see Table 3-2).

- *Financial benefits* include cost savings on customers' electric bills from using less energy when prices are high, or from shifting usage to lower-priced hours, as well as any explicit financial payments the customer receives for agreeing to or actually curtailing usage in a demand response program.
- *Reliability benefits* refer to the reduced risk of losing service in a blackout. This benefit may be associated with an internalized benefit, in cases where the customer perceives (and monetized) benefits from the reduced likelihood of being involuntarily curtailed and incurring even higher costs, or societal, in which the customer derives satisfaction from helping to avoid widespread contingencies. Both are difficult to quantify but may nonetheless be important motivations for some customers.

The level of direct benefits received by participating customers depends on their ability to shift or curtail load and the incentives afforded by time-varying electricity prices and any additional program incentives that are offered.

Collateral Benefits

Demand response, through its impacts on supply costs and system reliability, produces *collateral benefits* that are realized by most or all consumers (see Table 3-2). It is these collateral benefits, which have system-wide impacts, that provide the primary motivation for policymakers' interest in demand response.

Table 3-2. Benefits of Demand Response

Type of Benefit	**Recipient(s)**	**Benefit**		**Description/ Source**
Direct benefits	Customers undertaking demand response actions	Financial benefits		• Bill savings • Incentive payments (incentive-based demand response)
		Reliability benefits		• Reduced exposure to forced outages • Opportunity to assist in reducing risk of system outages
Collateral benefits	Some or all consumers	Market impacts	Short-term	• Cost-effectively reduced marginal costs/prices during events • Cascading impacts on short-term capacity requirements and LSE contract prices
			Long-term	• Avoided (or deferred) capacity costs • Avoided (or deferred) T&D infrastructure upgrades • Reduced need for market interventions (e.g., price caps) through restrained market power
		Reliability benefits		• Reduced likelihood and consequences of forced outages • Diversified resources available to maintain system reliability
Other benefits	• Some or all consumers • ISO/RTO • LSE	More robust retail markets		• Market-based options provide opportunities for innovation in competitive retail markets
		Improved choice		• Customers and LSE can choose desired degree of hedging • Options for customers to manage their electricity costs, even where retail competition is prohibited
		Market performance benefits		• Elastic demand reduces capacity for market power • Prospective demand response deters market power
		Possible environmental benefits		• Reduced emissions in systems with high-polluting peaking plants
		Energy independence/ security		• Local resources within states or regions reduce dependence on outside supply

Collateral benefits can be categorized functionally as *short-term* and *long-term market impacts* as well as *reliability* benefits:

- *Short-term market impacts* are the most immediate and easily measured source of financial benefits from demand response. Broadly speaking, they are savings in variable supply costs brought about by more efficient use of the electricity system, given available infrastructure. More efficient resource use, enabled by building better linkages between retail rates and marginal supply costs, translates to short-term bill savings to consumers from avoided energy and, in some cases, capacity costs. Where customers are served by vertically integrated utilities, short-term benefits are limited to avoided variable supply costs. In areas with organized spot markets, demand response also reduces wholesale market prices for all energy traded in the applicable market. Reductions in usage during high-priced peak periods result in a lower wholesale spot market clearing price. The amount of savings from lowered wholesale market prices depends on the amount of energy traded in spot markets, rather than being committed in forward contracts.[34]

- *Long-term market impacts* hinge on the ability of demand response to reduce system or local peak demand, thereby displacing the need to build additional generation, transmission or distribution capacity infrastructure. Because the electricity sector is extremely capital-intensive, avoided capacity investments can be a significant source of savings. However, for demand response resources to reduce capacity costs, it must be available and perform reliably at high-demand periods throughout the year because it is displacing other capacity resources.

Demand response also provides reliability benefits, reducing the probability and severity of forced outages.

- *Reliability benefits* refer to reducing the probability and severity of forced outages when system reserves fall below desired levels.[35] By reducing electricity demand at critical times (e.g., when a generator or a transmission line unexpectedly fails), demand response that is dispatched by the system operator on short notice can help return electric system (or localized) reserves to pre-contingency levels.[36] These reliability benefits can be valued according to the amount of load that demand response load reductions removed from the risk of being disconnected and the value that consumers place on reliable service (the "value of lost load").

Appendix B provides a more detailed discussion of the collateral benefits of demand response to assist policymakers' understanding of economic efficiency gains, avoided capacity benefits and capacity program design and valuation issues, the impact of different market structures on the timing and distribution of short-term and long-term demand response benefits, and the identification and valuation of reliability benefits.

---

[34] Many load-serving entities currently purchase a substantial portion of their electricity in ISO-administered spot energy markets. In New York, a state with organized wholesale markets and retail competition, over 50% of electricity is traded in day-ahead and real-time spot markets, with the rest settled in forward contracts. In New England, about 40% of the electricity volume is traded in ISO-NE's spot markets, with about 60% committed in forward contracts.

[35] At times, system dispatchers are faced with either shutting off load to parts of the system, or risk an outage that affects many more customers and load. The loads that are shut off depend on exigent circumstances. Demand response reduces load and thereby lowers the likelihood of the need to impose forced outages. It also reduces the amenity impact of a given level of load shedding because it is distributed among customers according to their willingness and ability to curtail (given appropriate incentives) rather than, for example, cutting off all customers and all load served by a given substation.

[36] Dispatchable demand response resources include direct load control programs, interruptible/curtailable rates and emergency demand response programs. Reliability benefits derive from curtailments undertaken when all available generation has been exhausted and only load reductions can serve to restore system reliability to acceptable levels.

Other Benefits

Demand response can provide several *other benefits* that accrue to some or all market participants but are not easily quantified or monetized:

- *More robust retail markets.* In competitive retail markets, default-service RTP can stimulate innovation by retail suppliers (Barbose et al. 2005), and ISO/RTO-administered demand response programs can provide value-added opportunities for marketers (Neenan et al. 2003).
- *Improved choice.* Demand response can provide expanded choices for customers in varying retail market structures (e.g. states with or without retail competition) through additional options to manage their electricity costs.

Demand response can reduce the potential for generators to exert market power by with-holding supply.

- *Market performance benefits.* Demand response can also play an important role in mitigating the potential for generators to exert market power in wholesale electricity markets by withholding supply in order to cause prices to increase. Price-responsive demand mitigates this potential because demand reductions in response to high prices increase suppliers' risk of being priced out of the market. Demand response can provide this "market performance" benefit even if it is rarely exercised because the *prospect* of demand response may be a sufficient deterrent to prevent generators from attempting market manipulation.
- *Possible environmental benefits.* Demand response may provide environmental benefits by reducing the emissions of generation plants during peak periods. It may also provide overall conservation effects, both directly from demand response load reductions (that are not made up at another time) and indirectly from increased customer awareness of their energy usage and costs (King and Delurey 2005). However, policymakers should exercise caution in attributing environmental gains to demand response, because they are dependent on the emissions profiles and marginal operating costs of the generation plants in specific regions.[37] Emission reductions during peak periods need to be balanced against possible increases in emissions during off-peak hours as well as from increased use of onsite generation.

---

[37] See Holland and Mansur (2004) for an analysis of regional differences in the impacts of load response on net power plant emissions, and Keith et al. (2003) for an analysis of impacts of demand response resources on net power sector emissions in New England.

SECTION 4. QUANTIFYING DEMAND RESPONSE BENEFITS

Quantifying the potential nation-wide benefits of demand response, as EPACT charges DOE to accomplish, is a large and complex undertaking and involves several functional aspects:

- *Demand Response Options*—the types of time-varying rates and demand response programs that are currently offered (or potentially available);
- *Customer Participation*—the likelihood that a customer will choose to take part in the program;
- *Response*—documenting and quantifying participants' current energy usage patterns, and determining how participants adjust that usage in response to changes in prices or incentive payments;
- *Financial Benefits*—developing methods to quantify the level and distribution of short-and long-term resource savings of load response under varying market structures;
- *Other Benefits*—identifying and quantifying any additional benefits provided by demand response resources (e.g., improved reliability); and
- *Costs*—establishing the costs associated with achieving demand response.

Given differences in market structure among states, the lack of a uniform method to measure demand response benefits and significant data limitations and gaps, which could not be overcome in the time allotted for completion of this report, DOE has chosen to take a different approach to meet its mandate.[38]

DOE's approach in meeting its EPACT mandate is to summarize and compare the results of recent studies that quantified demand response benefits.

DOE's approach is to summarize and compare the results of a number of recent studies that have attempted to quantify demand response benefits under a variety of contexts and scopes and for different regions or markets. Results are used as a basis for recommendations that can guide future efforts to quantify demand response benefits at the regional market level.

This section begins by summarizing the results of recent studies of the intensity of customer response to time-varying pricing and other demand response programs to establish the extent to which participants adjust their usage in response to price changes or incentive payments. Then, ten selected studies of demand response benefits are reviewed to assess and compare the impact of varying demand response mechanisms, study methodologies, and wholesale and retail market structure. The estimates of demand response benefits are normalized to provide insight into the importance of some factors in

---

[38] A comprehensive study quantifying the national benefits of demand response would have to account for different types of demand response (e.g., time-varying tariffs, incentive-based demand response programs).

determining the level of benefits attributed to demand response. Finally, recommendations on practices, protocols, and standards for improving estimates of the benefits of demand response are summarized.

Intensity of Customer Demand Response

To quantify demand response benefits in aggregate, two key inputs are: (1) measures of customer acceptance and participation rates in dynamic pricing and demand response programs, and (2) measures of the extent to which individual customers curtail load in response to either time-varying prices or demand response program incentive payments i.e. intensity).

With respect to the first input, a number of studies have characterized drivers to customer participation as part of evaluations of demand response programs or pilot tariffs. Important factors in the customer's decision to enroll and participate include the level and type of incentives offered, program requirements and conditions (e.g., notice, duration, and frequency of curtailments), customer assessment of risks and value proposition (e.g., financial consequences for failure to curtail loads), and effectiveness of program design and implementation (e.g., marketing, customer education and information, technical assistance).

With respect to the second input, a relatively large number of studies characterize the extent to which customers respond to dynamic prices and demand response programs. Results are typically reported in terms of two measures (or indicators): 1) price elasticity or 2) absolute or relative load impact (e.g., kilowatt [kW] or percent load reduction).

Customer Response to Time-Varying Prices

Price elasticity is a normalized measure of the intensity of customers' load response to prices.

A price elasticity provides a normalized measure of the intensity of customers' load changes in response to price circumstances especially for time-varying rates or demand response programs that induce load modifications directly in response to price changes. It is defined as the percentage change in usage for a one-percent change in price, and takes on values of zero and above, in absolute terms.[39] For example, if a customer's price elasticity is 0.15, then a doubling (100% change) of price results in a 15% reduction in electricity usage, other things equal. Higher elasticity values

---

[39] This definition is for own-price elasticity, which is always *negative*; usage goes down as price goes up. There are several variations on the concept of price elasticity that relate to different aspects of the full consequences of the change in usage. For example, a cross-price elasticity measures the consequences of reduced electricity usage on other goods. If a customer buys less electricity, then it has more money to spend on other goods and services. A substitution elasticity characterizes how a customer shifts the use of electricity in one period of the day to another (e.g. peak versus off-peak) in response to price differences between the two periods. A substitution elasticity can have a *positive* value (or zero). The discussion in this section reports elasticity values on an absolute basis, with the sign always positive, to emphasize the differences in results among studies. Appendix C provides a more complete and technically accurate characterization of the study results.

translate into increased price response by customers. Price elasticity is a useful measure because it allows for comparison of the load response of customers facing different prices.

Figure 4-1 summarizes the results of studies that estimated the price response exhibited by customers that participated in voluntary programs that involved time-varying prices (see Appendix C for more detailed information):

- several existing RTP programs available to larger industrial and commercial customers that have been operating for many years;
- an ongoing residential real-time-pricing (RTP) pilot;
- the California CPP pilot conducted in 2003-4; and
- pooled results of five residential TOU pilots conducted in the late 1970s.[40]

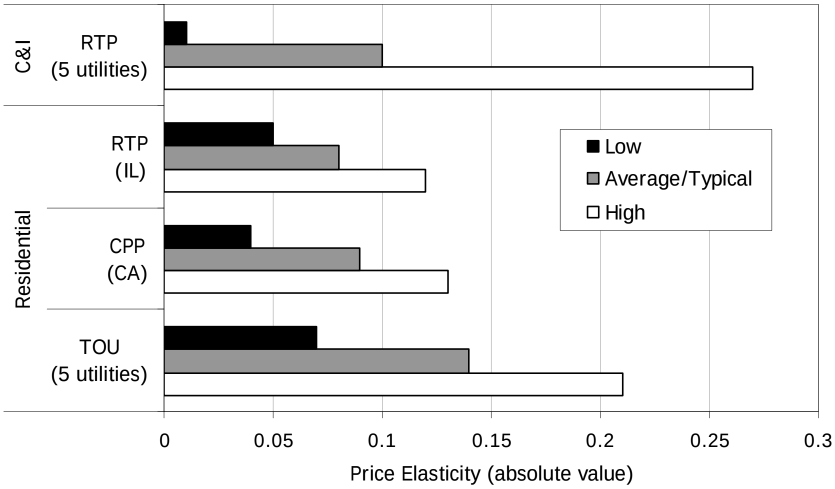


Figure 4-1. Customer Response to Time-Varying Prices: Price Elasticity Estimates

For each study, the low, average (or typical), and high estimates of price response are illustrated, although the interpretation of the low to high range values varies somewhat across studies. For example, the range in price elasticity values for a residential RTP pilot in Illinois are attributed to demographic differences within the pilot group, while for a pilot CPP program in California, the range in elasticity values primarily reflects climatic differences and saturation of air conditioning equipment among participant groups. For the residential TOU studies, the range of elasticity values reflects results across the five pilots.

Average price elasticities among the studies are fairly similar, ranging from 0.08 to 0.14 (in absolute value). The average elasticity value for RTP for large industrial and commercial customers (0.10) represents a typical value reported by several studies. The low and high elasticity values for commercial and industrial RTP customers exhibit the largest variation (i.e., 0.01 to 0.27) and reflect differences in the price responsiveness of

---

[40] See Appendix C for a more in-depth description of these studies and their results.

various market segments. Studies of large customers' response to RTP consistently find large differences in price elasticity across business categories. For example, a recent study of about 150 customers on RTP at Niagara Mohawk reported average elasticities of 0.16 for manufacturing customers, 0.10 for government/education customers, 0.06 for commercial/retail and 0.04 for healthcare facilities (Goldman et al. 2005).

The Residential RTP study (Illinois) reported similar price elasticities as the California residential CPP study (i.e., 0.08 to 0.09); both studies were conducted during a comparable time period (2004) but in different markets. Studies of residential customer response to time-varying prices often report that price elasticity is driven in part by the number of electricity devices present in the home. Climate also has a discernable affect, as do occupant characteristics and circumstances that affect when they are home and likely to be able to shut off devices or reduce usage.

Customer Response to Load Control Programs

Over one hundred U.S. utilities report that they currently offer residential or small commercial DLC programs that primarily target customers with air conditioning or domestic water heating load-control devices (EIA 2004).[41] A number of these programs have conducted relatively recent measurement and evaluation studies with results that are publicly available.

In some demand response programs (e.g., where customers do not directly respond to prices), their response is typically measured by the amount of load reduced.

For DLC programs and other types of demand response programs where customers are not directly responding to a price, the intensity of customers' response is typically measured in terms of an absolute or relative load impact (e.g., kW of load curtailed or percent of the customer's total load that is curtailed, either through equipment cycling or shedding).

Figure 4-2 summarizes reported load reduction estimates for large groups of customers with water heating load controls and various types of control strategies for air conditioning equipment (e.g., cycling the device on and off at a specified time interval, shutting the device off for a period of time, or resetting a thermostat set point) [see Appendix C for more detailed information].[42] Residential water heating DLC programs have typically yielded load reductions in the range of 0.3 to 0.6 kW per house; the magnitude and timing of the load impact depends on household and equipment size, ground water temperature and household usage patterns. DLC programs targeting residential air conditioning (A/C) have reported load reductions ranging from approximately 0.4 to 1.5 kW per customer over the course of an event. The magnitude of the load reduction per customer can strongly depend on climate, the control strategy deployed (e.g. 100% shed, duty cycling, thermostat reset) and the customer's air

---

[41] Demand-side management efforts include energy efficiency and/or load management programs.

[42] The results indicate the range of possible load impacts, although the values across studies are not readily comparable because of differences in program design features, cycling strategies, and climate.

conditioning usage levels absent load control. This is illustrated in Figure 4-2 by several studies that reported low and high load reduction values based on testing different cycling strategies at various temperature levels.

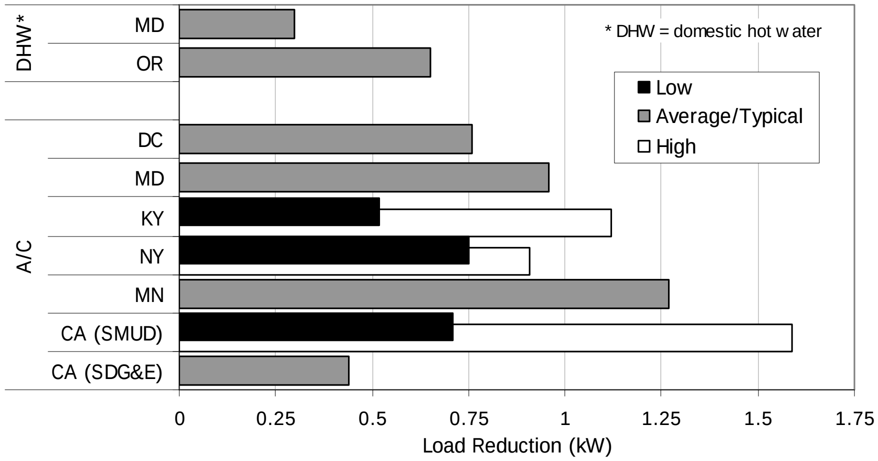


Figure 4-2. Estimated Load Impacts from Direct Load Control Programs

Impact of Enabling Technologies on Price Response

Studies of pilot programs combining pricing with enabling technologies provide important insights on the technical potential for demand response.

Some utilities have offered pilot programs targeted to mass-market customers that integrate CPP with enabling technology, specifically load control devices that receive price signals and can be programmed by customers to reduce A/C or other loads during critical peak periods (see Figure 4-3 and Appendix C). Several of these programs have obtained promising results. For example, in Florida, Gulf Power reported average load reductions of 40% during critical peak periods for groups of customers that could control multiple loads (e.g. A/C, water heating, pool pumps) (Levy Associates 1994). In California, a recent Statewide Pricing Pilot (SPP) sought to quantify the impact of “smart thermostats” with critical peak prices. The average load reduction of 220 residential customers with smart thermostats during critical peak days was approximately 0.64 kW, a 27% reduction during peak periods, approximately two-thirds of which was attributed to use of the smart thermostat. Among the 235 small business customers in the California SPP, the average peak period load reduction was about 14%, although the relative impact of the enabling technology was even more pronounced. These studies may reveal the technical potential for demand response in certain market segments when time-varying pricing is combined with enabling technology.

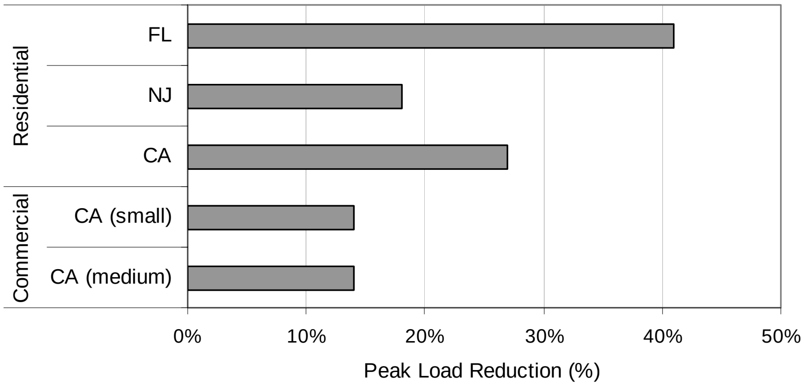


Figure 4-3. Load Response from Critical Peak Pricing and Demand Response Enabling Technologies

<u>Summary</u>

The following key findings and lessons can be drawn from this review of studies that examine customer response to time-varying prices and different types of demand response programs:

- Many initiatives have been undertaken that quantify the price-to-quantity relationship for various types of dynamic pricing and demand response programs. These data are critical because policymakers require price elasticity and load impact estimates as an input in estimating the benefit of specific demand response programs.
- Based on several of the more comprehensive studies, it is reasonable to assume that a group of large customers participating in well-designed RTP tariffs respond with a substitution elasticity of around 0.10 on average, which means that when peak prices rise by 50%, these customers will lower or shift their load to other times of the day by 5%.[43]
- Elasticities for groups of residential customers enrolled in TOU rates with significant differentials in peak to off-peak prices (e.g. factor of three) are also about 0.10—0.15.
- A small number of studies of residential customers on CPP rates, with very high critical peak prices ($.50/kWh or higher) report that that customers reduce load by an even greater amount than is reported in other studies for TOU. The recent California pilot, where the two designs were tested side-by-side, reports that the difference is almost a factor of two. However, the difference may be due to the large price differences between the two rate offerings.[44]

---

[43] The ability of customers enrolled in RTP tariffs to respond to prices is varied. Several studies report that 65-75% of the total measured price response is provided by about 20% of the customers on RTP rates.

[44] Two customers with identical price response capability (price elasticity) may exhibit different levels of load response if they face vastly different prices. This is because the nature of the response may increase with the nominal level of prices. The price elasticities estimated for TOU rates may be smaller than for CPP rates, because the customers never faced the higher CPP prices.

- Studies of customer response to time-varying prices should be construed as representing short-term price response. Relatively few participants on RTP or CPP tariffs automate their response behaviors and actions, either because they do not have the necessary equipment or because they do not have the technical expertise, time, or sufficient incentive to implement such changes. As a result, customers tend to rely on manual actions to shut down equipment or curtail usage. This surely constrains the frequency and extent to which loads can be reduced. As demand response becomes more widespread and time-varying prices become the default (or standard) service, some customers can be expected to make cost-effective investments in enabling technology to improve their marginal ability to respond, and thereby increase the price elasticity (or the percentage of load reduced).
- Some jurisdictions have enrolled large numbers of customers in direct load control programs. For mature load management strategies (e.g. cycling of residential air conditioners, water heaters), there are well-developed models, based on actual field studies and program evaluations, that can predict per-unit load impacts reasonably accurately and allow characterization of factors that influence the intensity of customers’ response (e.g. household size, income, equipment characteristics, schedule, weather).
- There has been relatively little emphasis on measuring and verifying the impacts of interruptible rates. The response of some customer market segments (e.g., small and medium-size business customers) has also received little research attention.
- Areas that warrant additional evaluation include: quantifying the impact of information and/or enabling technologies in customer decisions to participate in demand response options and the intensity of their response in specific market segments, understanding customer participation and response in markets that offer dynamic pricing and demand response (and energy efficiency) programs in order to assess potential synergies.

Quantifying the Value of Demand Response

Initial attempts to quantify the benefits of demand response arose after the passage of the Public Utilities Regulatory Policy Act (PURPA) in the early 1980s. PURPA set in motion initiatives to promote load management programs, using both pricing and load control mechanisms. Utilities needed to establish that paying loads to curtail was cost-effective; thus load management programs were justified on the specific cost savings they produced. The benefits were defined by the avoided capital and operating costs; utilities used available planning methods to establish how dispatched curtailments reduced the use of generation units.[45] Utilities evaluated these load management programs using an equivalence standard: load management had to produce service equivalent to the displaced generation but at a lower cost.

---

[45] Utility planning methods ranged from simple what-if calculations to in-depth and complex studies of the impacts on system operation.

During the 1980s, integrated resource planning initiatives further refined the process and tools used by utility planners to evaluate investments in load management and energy efficiency in lieu of constructing generation plant. Standardized cost-effectiveness tests were developed that specified both the scope of and methods to estimate the benefits, expressed in terms of avoided costs. The standardized tests were used to facilitate screening of programs and help establish a threshold criterion for program spending. Load management programs were also offered in states that did not require utilities to develop and file formal IRP plans. Utilities had to show that load management programs would reduce supply costs relative to an all-generation solution. In all states, program costs were ultimately allocated to consumers, as new generation would have been.

In the 1990s, as problems arose with the introduction of competition in wholesale (and retail) markets, demand response was seen as a critical feature of competitive wholesale markets. However, a measure of the benefits was needed to justify expenditures to achieve greater demand response. Efforts to estimate the benefits of demand response have proceeded on three parallel tracks.

First, studies were undertaken to demonstrate the benefits of demand response by comparing the operation of markets with and without adequate levels of customer response to hourly prices (Borenstein 2002). Theorists argued that demand response should be fostered as a matter of principle, because any market where customers are not exposed to changes in the costs of supplying power is by definition inefficient and not robustly competitive. Experimental trials in economic laboratories contributed to verifying these contentions (Smith and Kiesling 2005, Adilov et al. 2004).

Second, studies commissioned to assess the benefits of organized, competitive wholesale markets specifically quantified the benefits that might be attributable to demand response (ICF Consulting 2002, DOE 2003). Others sought to verify the extent of financial benefits by conducting simulations to link specific levels of demand response to decreases in market prices, some of which indicated that the benefits might be quite significant, in the billions of dollars even in regional markets (Braithwait and Faruqui 2001, Caves et al. 2000). The push to identify the role and value of demand response also found its way into regions that largely retained the vertically integrated structure. IRP studies began to look more closely at how demand response creates cost savings (NPPC 2005, Orans et al. 2004, Violette et al. 2006).

Third, as programs were introduced in organized markets to foster demand response, analytical methods were needed to determine the value of those load curtailments. Policymakers and market participants wanted assurances that the programs produced net benefits and were interested in the distribution of the benefits (e.g. reduced energy market prices and reliability impacts) among market participants (Boisvert and Neenan 2003).

There has been no coordinated effort to compare and synthesize contemporary methods of quantifying demand response benefits.

In summary, there have been a number of efforts to quantify the benefits of demand response in a variety of market settings and conditions. However, to date there has been no coordinated effort to determine whether this body of work allows us to estimate these benefits at the national level or provides detailed methods to quantify those benefits. EPACT places that obligation upon DOE.

Benefits of Demand Response: Review of Existing Studies

A literature review was undertaken to identify the body of information available to estimate the national benefits of demand response. Ten studies were selected to provide insight into how demand response benefits are quantified to analyze the methods used and to assess their impact on the results (see Table 4-1). They encompass most recent empirical studies of demand response benefits and can be classified into three categories:

- *Illustrative analyses* demonstrate the potential importance and/or quantify the economic impacts of demand response in a proposed market structure or hypothetical market circumstance. All four examples examined the potential for demand response benefits in organized wholesale markets. The approach taken is to create a base case reflecting the current market structure and conditions, estimate impacts of the proposed market structure changes (in the Standard Market Design [SMD] examples in Table 4-1), project how the electricity market would evolve with and without a specified amount of demand response, and then compare the results. In these studies, the benefits are hypothetical and speculative. The means for accomplishing demand response is often not explicitly addressed—it is presumed that demand response either occurs naturally in response to hourly prices or is induced through demand response programs—and the accuracy of the results depends on how well actual circumstances match assumptions used in the analysis.
- *Integrated Resource Planning* (IRP) studies assess whether and how much demand response resources ought to be acquired in a long-term resource plan based on avoided supply costs. They are typically undertaken by utilities in markets without retail competition. Demand response programs or dynamic pricing initiatives found to avoid capital and operating costs in excess of their implementation costs may be included in a utility's resource plan. Because vertically integrated utilities are responsible for securing additional capacity to meet anticipated customer loads, as well as administering proposed demand response programs or pricing initiatives, they have the ability to defer or eliminate other potential capacity additions to realize the avoided capacity (and energy) benefits. Three IRP studies are included in this analysis.
- *Program performance analyses* measure actual outcomes of demand response programs and provide an estimate of delivered value, rather than a forecast of benefits. The three program performance studies were conducted in states or regions with organized wholesale markets administered by ISOs/RTOs. These

studies estimate the impacts of load curtailments on market prices, quantify the level and distribution of benefits, and explicitly account for reliability benefits.

Demand Response Benefit Case Studies: Comparison of Key Features

The ten studies were assessed and compared along several key features that contextualize results and provide insight into issues that must be addressed to ensure more consistent, standardized approaches for valuing the benefits of demand response going forward. The following discussion refers to Table 4-1.

Market Character. The selected studies include examples from both organized spot markets and vertically integrated systems. The four illustrative analyses focus primarily on organized markets. Two of them (B and C in Table 4-1) look at nation-wide demand response impacts, because they were commissioned to quantify the benefits of the adoption of FERC's proposed standard market design (SMD). These studies included scenarios that examined the benefits of demand response over and above what the SMD was expected to deliver. The third study (D) provides a regional New England perspective, and the fourth focused on the California electricity market (A). Conversely, the three IRP studies (E, F and G) reflect a vertically integrated utility perspective, in which utilities define alternative strategies and assess their relative merits over a long planning horizon as a basis for up-front planning decisions. The three program performance studies (H, I and J) were conducted in regions where an ISO or RTO administers organized spot markets; they draw heavily on transparent market prices to measure actual performance benefits.

Market Analyzed. The selected studies vary considerably in their spatial scope and include national, regional, state, and individual utility system assessments. However, results from studies in more geographically focused settings (e.g., a utility, state or region) are sufficiently general that the results may apply elsewhere, after adjusting for program design features.

Peak Demand. The system peak demand of the market described in each study indicates market size. System peak load also serves as the denominator used to normalize reported gross benefits across studies; this helps reveal factors that affect reported demand response benefits.

Demand Response Mechanism. Eight of the studies either modeled or reported demand response benefits for specific types of demand response mechanisms. Four (A, D, E and F) estimated benefits for either RTP or CPP. Another four (C, H, I and J) estimated benefits for emergency demand response programs offered by utilities or ISOs. Six of these studies (C, F, G, H, I and J) also estimated benefits for demand bidding programs in which customers participate in day-ahead or real-time energy markets. Two studies (C and F) reported aggregated benefits for more than one demand response option. Aggregated benefit estimates for individual demand response programs were developed

Table 4-1. Benefits of Demand Response: Review of Selected Studies

		Illustrative Analyses				Integrated Resource Planning			Program Performance Analyses		
		Market Equilibrium DR[1]	FERC SMD[2]	DOE SMD[3]	Default RTP[4]	Mass Market DR[5]	IEA/DRR[6]	NPCC[7]	NYISO[8]	ISO-NE[9]	PJM[10]
1	**Study**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**
2	**Market Character**	**Organized Wholesale Markets**				**Vertically Integrated Utility**			**Organized Wholesale Market**		
3	**Market Analyzed**	CA	U.S.	U.S.	New England States	Midwest Utility	Sub-set of the MAAC Region	Northwest States	NY State	New England States	Mid-Atlantic States
4	**Peak Demand (MW)**	46,000	700,000	700,000	26,000	7,500	30,000	30,000	31,000	26,000	53,000
5	**DR Mechanism**	RTP	Price response only	DA-LBAR, EDR	Default Service RTP	CPP	DLC, DA-LBAR, CPP	DA-LBAR	DA-LBAR, EDR	DA-LBAR, EDR	DA-LBAR, EDR
6	**Time Horizon (start)**	Equilibrium	17 years (2004)	one year (2003)	5 yrs (2006)	20 years (2002)	20 years(2004)	20 years (2006)	Results for 2001-2004		
7	**Participating Load**	33% or more of load, no segment distinction	50% of customers in all regions	2% of load in economic, 2.5% in reliability	about 2% of system load	About 900,000 residential customers (100% participation)	15% penetration top-end	6% of peak demand (in 2020)	Participants in 1) emergency, 2) ICAP, or 3) energy DR programs. Subscribed load reduction from participating customers for all classes, ranging from 1 to 6%of system load		
8	**Implementation Costs**	Not reported	Not reported	Not reported	Implementation cost estimated (~10% of gross benefits)	Implementation and incentive costs estimated (~25% of gross benefits)	Implementation and incentive costs estimated (90% of gross benefits)	Implementation and incentive costs estimated (~53% of gross benefits)	Report B/C ratio by program for incentives-all exceed 1; separately report Implem. cost	Report B/C ratio by program for incentives-all exceed 1.	Report B/C based on incentives. Separately report implementation costs
9	**Analysis Method**	Simulated dispatch and capacity adjustments	Simulated market equilibrium	Simulated dispatch	Simulated LMP adjustments to RTP	Simulation of market impacts	Simulated optimal capacity expansion plan and corresponding energy dispatch: stochastic market characterization		Simulated LMP and Reliability adjustments to demand response		Redispatch LMP change
10	**Gross Benefits (Million $)**	$302	$52,236	$362	$350	$1,000	$1,476	$718	$7	$1	$15
11	**Gross Benefits ($/kW yr)**	**$6.57**	**$4.39**	**$0.52**	**$2.69**	**$6.67**	**$2.46**	**$1.20**	**$0.22**	**$0.04**	**$0.29**
12	**Normalized Gross Benefits ($/kW-yr.)**	**$1.99**	**$0.88**	**$2.07**	**$1.35**	**$2.02**	**$1.64**	**$1.99**	**$0.45**	**$0.30**	**$0.66**

References:
[1] Borenstein 2005
[2] ICF Consulting 2002
[3] DOE 2003
[4] Neenan et al. 2005
[5] Faruqui and George 2002
[6] Violette et al. 2006
[7] NPCC 2005
[8] NYISO 2004
[9] RLW Analytics and Neenan Associates 2004
[10] PJM Interconnection 2004

Abbreviations:

DLC	Direct Load Control
DA-LBAR	Day-ahead Load Bidding as a Resource (demand bidding)
EDR	Emergency Demand Response
CPP	Critical Peak Pricing
RTP	Real-time Pricing
LMP	Locational Marginal Price

from the ISO/RTO program performance studies (H, I and J). Two studies (B and G) did not specify the type of demand response mechanism studied.

The ten reviewed studies' time horizons vary considerably, from one to twenty years.

Time Horizon. The studies' time horizons vary considerably, ranging from one to 20 years. These differences are driven by differing study contexts, analysis methods, and market structure. Prospective studies tend to span a multi-year period. For example, the FERC SMD study (B) assesses cumulative impacts over a 17-year period because its primary focus was on the long-term benefits of SMD. In a somewhat different approach, the DOE SMD analysis (C) reports annualized estimates of demand response benefits for the 20-year study time horizon. IRP studies are by definition long-term planning exercises and all three examples (E, F and G) cover approximately 20 years. In contrast, the three ISO/RTO program performance studies (H, I and J) are retrospective evaluations that measure the actual benefits of demand response; all of these studies examine the benefits of programs that have operated over several years.

The types of customers targeted and assumed (or actual) market penetration rates varied significantly among the ten studies.

Participating Load. There are significant differences in the targeted population and the assumed or actual demand response market penetration rates among the ten studies. Two of the illustrative analysis studies (A, B) assume high market penetration rates; this contributes to relatively high estimates of gross savings (row 11 in Table 4-1). Participation rates are affected to a great extent by the assumed tariff design. For example, the mass market demand response study (E) evaluates the benefits arising from placing the subject utility's entire residential customer group on CPP to assess the impacts of a mandatory tariff. In contrast, the Default RTP study (D) estimates the potential benefits of implementing RTP as the default service for large industrial and commercial customers (with peak demand greater than 1 MW) in the New England states that have adopted retail choice (although customers can opt out in favor of alternative supply products that may offer fixed rates).

Forecasting levels of customer acceptance, participation and load response is critical to evaluating the impacts of voluntary demand response programs.

Forecasting levels of customer acceptance, participation, and load response are critical variables in voluntary demand response programs. The NPCC study (G) assumes that demand response will constitute about 6% of the resources used to meet the Pacific Northwest system peak after a 20-year ramp-up. The IEA/DRR study (F) assumes that demand response resources from three demand response programs and a dynamic pricing tariff will comprise about 15% of system peak demand after 20 years. The three ISO/RTO program performance studies draw on actual experience in enrolling customers in voluntary programs, rather than forecasts. However, estimating participation rates is complicated by difficulties in defining the eligible population.[46] In this analysis, subscribed load reductions as a fraction of system peak load are used to estimate participation rates; the results range from 1% to 6%.

Three out of ten studies did not report costs; cost reporting was inconsistent or incomplete among several other studies.

Implementation Costs. Practices for reporting participant and system costs necessary to achieve demand response vary significantly among the ten studies (see Table 3-1 for demand response cost reporting categories). Three of the illustrative analyses (A, B and C) did not report costs at all. Among studies that included costs, demand response costs were not reported uniformly or were incomplete. Four studies included *estimates* of costs (D, E, F and G). In two of them, both IRP studies (F and G), demand response was modeled as a generation resource by specifying its product characteristics (availability period, capacity, number and duration of event calls) and cost. The costs to the utility system of acquiring this "resource" (e.g., initial costs, on-going program administration, and payments to participating customers) were well characterized. Initial participant costs were partially accounted for through incentives to subsidize their initial equipment or other costs, but event-specific costs were not (see Table 4-1). The two studies that focused on pricing options (D and E) estimated incremental metering and billing costs. Study E also included customers' investments in enabling technologies.

The three ISO/RTO program performance studies (H, I and J) reported *actual* implementation costs to varying degrees. These studies highlight some of the issues involved in reporting and accounting for costs. All three reported direct incentive payments made to customers for curtailing load. Some ISOs/RTOs reported their program administration costs. Most participant costs were not reported, including event-specific costs incurred by participating customers (NYISO 2004, PJM Interconnection 2004).[47]

Analysis Methods. All of the studies used simulation techniques to derive estimates of demand response benefits.[48] Simulation involves characterizing how the market works in a base-case scenario through cause and effect relationships. Demand is modeled as a function of prevailing economic conditions, the presence of electricity-using devices, and the prices consumers pay. Other factors, such as weather, can have predictable influences, but only under known (after-the-fact) or hypothesized conditions. The modeling of

---

[46] To be eligible for ISO emergency demand response programs, customers must be able to shed 100 kW of load, although aggregations of small customers are typically allowed. As a result, the eligible population could be defined as: all customers, all customers over a certain size range (this requires assumptions about the percent of load that can be shed), or customers that can shed 100 kW. As a practical matter, larger industrial, institutional and commercial customers account for most of the subscribed load in ISO demand response programs.

[47] It can be challenging for ISOs to collect information on participant costs because they often do not interact directly with customers. Instead load aggregators enroll customers in ISO programs. Collecting participant cost information would require placing additional reporting requirements on load aggregators.

[48] Study E utilized a Total Resource Cost (TRC) test to determine the cost-effectiveness of implementing mass-market demand response.

energy supply costs is influenced by market structure and incorporates information on available generation units and their performance characteristics and fuel costs.

The illustrative analyses, all targeted to organized markets, focus on whether energy and (where applicable) capacity market prices would be sufficient to attract enough capacity to meet reliability standards at least cost. The goal of such simulations is to explore the conditions under which competitive market equilibrium is reached (as in study A) or to simulate market transactions within different market designs and measure key performance indicators such as capacity investment and market-clearing prices. The focus is on minimizing the resulting market prices.

The IRP planning studies were undertaken to answer the question of how much capacity to add, at what time, and to what extent energy efficiency or demand response resources should be implemented to meet capacity needs. The IRP simulations (F and G) explored the cost implications of alternative supply strategies over an extended period and analyzed major uncertainties (e.g. load growth, weather, capability of generation units, fuel prices) using probabilistic techniques to identify a risk-constrained, least-cost strategy.

The program performance studies (H, I and J) analyzed the extent to which wholesale market prices were influenced by customer load curtailments in response to program events and estimated the direct and collateral benefits of these lower prices (see Table 3-2 for a typology of demand response benefits). This involved simulating price formation at a sufficient degree of detail to estimate reductions in market prices. Reliability benefits were also simulated for the program performance studies using assumptions about the value of lost load (VOLL) to customers and the impact of emergency demand response program curtailments in restoring system reserves.[49]

Gross Benefits. The gross benefits reported are the total estimated dollar benefits from each study, without any offset for the costs associated with achieving the hypothesized or measured level of demand response. It is important to note that many individual studies reported a range of benefits, although there were differences in how these ranges were developed. For example, in several of the illustrative analyses and IRP studies, the range of reported demand response benefits were derived from scenarios based on differences in assumed price elasticities, participation rates, or the set of demand response programs offered. In contrast, in the program performance analyses, the ranges of benefits were primarily based on differences in the assumed value of lost load or expected un-served energy in emergency programs.

In Table 4-1, a single representative value for gross benefits is reported for each study, rather than the complete ranges. The choice of values was intended to place the studies on as comparable a basis as possible. For example, for illustrative analysis and IRP studies, the reported benefits estimates correspond to scenarios that most closely approximate a

---

[49] Reliability benefits are discussed in section 3 and Appendix B.

price elasticity of 0.10 for dynamic pricing options—a typical level of response based on the results of demand response impact studies discussed above.[50]

The ISO/RTO program performance studies present a different type of challenge for reporting gross benefits because these studies report actual customer response, and the programs have only been in existence for several years. Unlike the other studies, these estimated benefits reflect actual program outcomes, not an average of those expected over many years, which the other studies report (see the textbox below).

Estimating Normalized Demand Response Benefits from Program Performance Studies

- In Table 4-1, the demand response benefits reported for the NYISO study involve two components: (1) the weighted average of the annual reliability benefits for 2001-2004, where the weights represent market circumstances relative to expectations over a ten-year period, and (2) benefits from price reductions from scheduled day-ahead load curtailments. The majority of the reported benefits derive from reliability impacts, primarily from the 2003 Northeast blackout events.
- ISO-NE reported reliability benefits from its emergency demand response program for 2003 and 2005, but declared no events in 2004. The benefits reported are from 2003, which are approximately equal to the preliminary values for 2005.
- PJM attributes virtually all of its benefits to reduced real-time prices from customer self-scheduled curtailments that are paid the real-time market price. The reported benefits are averaged for 2003 and 2004.

Demand Response Benefit Case Studies: Discussion of Results

Gross benefits estimates vary widely, from $1 million to $52 billion.

The gross demand response benefits estimated by the ten studies span a very large range, from $1 million (M) to $52 billon (B) (see Table 4-1). Even among studies of similar scope, the estimates differ substantially. For the two national studies (B and C), annual gross benefits vary by a factor of eight (estimated at $3B and $360M). Differences in market scope and size, time horizon, analytic methods, the type and number of demand response resources represented, and assumed market penetration and customer responsiveness all affect the differing gross benefit estimates.

Normalization can make comparison of these results more informative. Accordingly, a gross benefit metric was devised to normalize the study results, incorporating and adjusting for several factors: market size, time horizon, and the assumed level of customer participation in a demand response program or pricing initiative. The gross benefits value (row 10 in Table 4-1) was first divided by the market's peak demand in

---

[50] Some studies included a scenario with that exact price elasticity assumption. In illustrative analysis studies where price elasticity was not an explicit variable included in the sensitivity analysis, a judgment was made as to the most comparable scenario in terms of customer price responsiveness.

2004 (row 4).[51] This removes some of the scale bias. However, there are also significant differences in the time horizon over which demand response benefits were calculated and the assumed level of participation in demand response programs that were simulated. To address these factors, the size-adjusted gross benefits were divided by the number of years in the study and then by a factor that normalized each study to an equivalent demand response participation rate of 10%.

Gross benefits of demand response reported in each study were normalized to adjust for differences in time horizon, level of customer participation, and market size to facilitate comparing different studies' estimates.

The resulting estimates of normalized gross benefits, measured in $/kW-year, provide a more comparable basis for understanding the methodological and market structure factors that influence the estimates of demand response benefits (see row 12 of Table 4-1). This metric, which gives an estimate of dollar value per kW of *system peak load* is different from avoided capacity costs, which are measured in the same units but represent a dollar value per kW of *avoided capacity* (see the textbox, below). These two metrics should not be directly compared.

Avoided-Cost Benefits of Demand Response vs. Normalized Gross Benefits

Some demand response programs (e.g., direct load control) have traditionally been regarded and analyzed as an effective capacity equivalent of generation in which the primary source of benefits is the avoided capacity cost from displacing a generation resource. Often, demand response programs are evaluated against an avoided cost standard: the costs of a demand response program are compared to a capacity alternative on the basis of their costs per kW-year. For example, if a peaking unit requires revenues to cover investment costs of $75/kW-year, which can be interpreted as the utility's avoided capacity costs. If a demand response program costs $50/kW-year, then the net benefits are about $25/kW-year. In this example, the annualized benefits of demand response are expressed in terms of net benefits ($) per *unit of avoided capacity* (kW); this is how the industry typically quantifies the value or cost of demand response.

Although the *units* are the same, it is important not to confuse the industry approach described above with the *normalized gross benefits* estimated for the ten studies included in this report. This metric expresses the studies' annual gross benefits in terms of dollars per unit of system peak load. It is calculated by dividing estimated benefits by the number of years covered by the study and the peak demand (kW) of the target market. The meaning and interpretation of this metric is different from avoided-cost benefits. Because normalized gross benefits are divided by the peak demand *of the entire market*, the values estimated for these ten studies ($0.30-2.00/kW-year) are much lower than the avoided capacity benefits of demand response, and they should not be compared with the value or cost of demand response used in conventional analyses of capacity or supply costs. Rather, this indicator was constructed solely to facilitate a comparative review of these demand response benefit studies.

---

[51] This adjustment approach, using system peak demand as a proxy for market size, may produce some bias across studies, particularly for studies that cover 20 years because peak system demand is likely to increase over that period. However, given data availability constraints, peak demand in 2004 was adopted for forward-looking studies with long time horizons and peak demand at the time of study completion was used for other studies.

The normalized gross benefits are plotted for the ten studies in Figure 4-4, and the average and range of values for each type of study are shown in Figure 4-5.

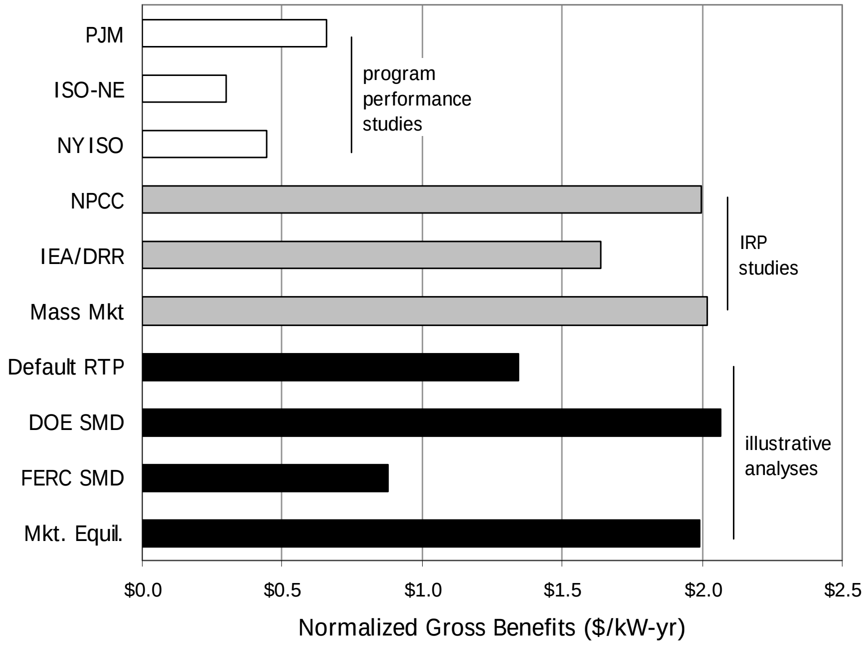


Figure 4-4. Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies

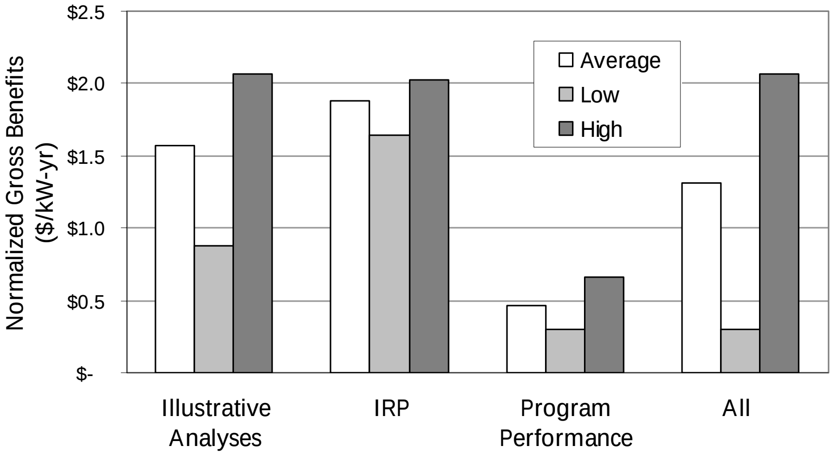


Figure 4-5. Normalized Gross Demand Response Benefits by Type of Study

DOE highlights the following key findings and observations based on this comparative review and analysis of these benefit studies.

There is a noticeable difference in the normalized demand response benefits of program performance analysis studies in organized markets relative to those of the illustrative and IRP studies (see Figure 4-4). This is largely attributable to differences in analytic methods.

The demand response benefit values estimated by program performance analyses, in normalized gross savings ($0.30 to 0.65/kW-year), are 70-75% lower than the average values for the other two types of studies (see Figure 4-4 and Figure 4-5), even after adjusting for differences in participation rates. This is largely attributable to the analytic methodology employed, which looks backward at limited, observable demand response program results. The illustrative and IRP studies typically estimate the *forward* market value of demand response over many years with assumed perfect foresight about demand response penetration and impact. These studies conduct market simulations over the full distribution of possible electricity market conditions in which demand response is deployed, during years when its value is small and others with extreme conditions where demand response provides significant value. In IRP studies, the long planning horizon in conjunction with the explicit treatment of key uncertainties allows demand response resources to be deployed during low probability but high consequence events (NPPC 2004; Violette et al. 2006).

In contrast, the program performance studies reflect market conditions over a very short time period, with only one instance of an extreme condition (the 2003 blackout, captured in the NYISO study only). These studies do not fully reflect the distribution of market circumstances likely to be encountered over a 20-year period, so they represent market conditions that are on average less favorable for demand response.

Lower estimated benefits for ISO programs illustrate the challenge of fostering demand response without a way to fully recognize its potential long-term value to the electricity system under the full range of market circumstances and conditions.

The difference between the average values reported in the three ISO/RTO program studies and the other two types of studies does not mean that demand response is less valuable in organized regional markets, but only demonstrates the challenge of fostering demand response absent the ability to recognize and reward the full forward value of demand response over a long planning horizon.

Under current practices, the market-impact value attributed to demand response is significantly affected by market structure (e.g. organized market vs. vertically integrated systems (Figure 4-4).

The market-impacts value of a demand response mechanism in a vertically integrated utility system may be different—perhaps significantly—from its valuation in an organized market with a similar customer base, resource mix, and supply/demand balance. In vertically integrated systems, demand response is valued largely according to avoided capacity costs, determined by the amortization of a peaking capacity unit ($70-100/kW-year), with some incremental savings (typically 5-15%) attributable to avoided short-term energy production costs. Moreover, qualified demand response resources are essentially deemed to achieve the pre-established avoided capacity benefits, or some portion thereof, for several years in the future.[52]

---

[52] Updated avoided cost methods for the Standard Practice Manual tests traditionally used for energy efficiency and some load management programs have incorporated market prices for time periods that they

In organized wholesale markets administered by an ISO or RTO, demand response is typically valued over the short term, based on prevailing market prices or reliability circumstances at the time of an event. For example, in some organized markets, customers can offer curtailable load as capacity resources (e.g., through capacity-based demand response programs). Capacity market prices, which are an indication of the value of these resources, have recently been much lower than the reference cost of a new peaking unit in most ISOs and RTOs (ISO-NE 2005b, PJM Interconnection 2005c). At times, the value of capacity, as reflected in capacity or energy market prices, may be substantially higher in regions with organized markets than in vertically integrated systems, although currently the reverse is true; this is reflected in the three ISO/RTO program performance studies.

Assumptions about customer acceptance and participation rates significantly affect estimated gross demand response benefits.

Among studies that examined impacts of demand response pricing strategies (A, D and E), gross savings estimates (row 11 in Table 4-1) are much higher in those studies that assumed higher market penetration rates (i.e., percent of customers facing dynamic prices compared to overall system loads). Studies A and E, which assumed either mandatory CPP or high customer acceptance of RTP, exhibited higher gross savings than study D, which did not.

The reporting and accounting of participant and utility/ISO/RTO system demand response costs are inconsistent.

Evaluations of existing ISO/RTO demand response programs report system costs, but not participant costs. Utility experience evaluating energy efficiency programs demonstrates that it is possible to collect and report information on initial participant costs (e.g., investments in enabling technologies or energy audits).[53] On-going (event-specific) participant costs are unlikely to be explicitly included in future analyses. As a practical matter, customers quantify these types of costs and indicate their acceptance of the participation costs when they enroll in a voluntary demand response program or optional pricing tariff and respond during events.[54] It is probably most feasible to reflect these costs in estimating participation rates and the aggregate price elasticity of program participants, rather than directly in benefit/cost tests.

---

are available (e.g. observable forward prices) and use costs of an existing peaking plant for periods prior to the need to construct a new peaking unit (Orans et al. 2004).

[53] However, in contrast to a utility-sponsored program, it is often more difficult for the ISO to communicate directly with customers to establish their costs. Customers typically enroll through a utility, competitive retailer or a demand responses service provider. The ISOs can request that these entities collect customer data, but are hard-pressed to make it a condition of participation.

[54] Violette et al (2005) suggests that it can be assumed that the upfront and ongoing payments to customers for participating in a demand response program fully account for the value of foregone electricity consumption and any costs incurred by the customer related to the demand response event or curtailment call. Otherwise the customer would not have decided to enroll and participate.

The ten studies reviewed also differed significantly in their treatment and estimates of advanced metering costs. This is partly attributable to differences in the availability of advanced metering systems among utilities, and the target markets and types of demand response mechanisms assumed in the studies. For example, among IRP analyses, Study E assumed relatively low incremental meter reading and data management costs to support dynamic pricing among residential customers because the subject utility already had a fixed network, automated meter reading system in place. Study F included costs of metering and incremental data management for business customers only, while Study G did not appear to have explicitly accounted for these costs at all.

Given the lack of standardized or generally accepted techniques and frameworks to estimate demand response benefits and report program costs, it is not particularly useful to report net benefits for our sample of ten studies (several of which included no cost estimates).

Quantitative assessments should estimate and report ***net*** *demand response benefits.*

Quantitative assessments should ideally estimate *net* demand response benefits; this is not possible given the information provided by existing studies. Three studies did not account for costs at all. The three IRP studies and one of the illustrative analyses provided ranges of estimated benefits and compared them to ranges in estimated costs. While they draw general conclusions about the relative merits of including specific demand response pricing or program options in the modeled systems, these studies are not framed in terms of achieving specific levels of benefits. As a result, they do not provide any direct insights for DOE to use in recommending specific levels of demand response benefits as directed by Section 1252 of EPACT.

Establishing Protocols and Practices for Estimating Demand Response Benefits

Fostering demand response is an industry responsibility and obligation. Doing so requires that stakeholders make informed decisions on the financial and non-financial implications of introducing (or mandating) time-varying rates (i.e., price-based demand response) and programs to acquire demand response under specific circumstances (i.e., incentive-based demand response). To do this, policymakers need reliable and consistent methods for estimating the implications of the alternatives available to them. Current practices and protocols for valuing demand response provide a foundation for developing these methods, but are ill adapted to valuing demand response in several important ways. There is still work to be done to develop appropriate valuations tools and standard practices for evaluating demand response options.

It is premature to focus on setting national demand response goals or specific achievement targets.

Based on the findings of this study it is premature to focus on setting national demand response goals or specific achievement targets as EPACT instructs DOE to do. Nonetheless, demand response can and should be fostered in all market structures because it plays a vital role in achieving efficient market operation.

An immediate goal should be refining analytic methods and practices to recognize the full benefits of demand response.

Thus, one immediate goal should be refining analytic methods and practices to recognize the full benefits of demand response. Improvements in methods used to quantify and report the benefits and costs of demand response are needed and achievable. These improved analytic methods and practices will provide policymakers and market participants with tools to establish program performance standards, measure progress, and assess the performance and value of demand response initiatives.

Drawing from the body of literature on demand response valuation and the findings of this report, DOE offers the following recommendations for establishing standardized methods and protocols that enhance practices for estimating the benefits of demand response (see Appendix D for more detailed discussion):

1. DOE recommends that stakeholders collaborate to adopt conventions and protocols for estimating the benefits of demand response and, where appropriate, develop standardized tests that evaluate demand response program potential and performance.

2. DOE recommends that these protocols: (1) clarify the relationships and potential overlap among categories of benefits attributed to demand response to minimize double counting, (2) quantify various types of benefits to the extent possible, and (3) establish qualitative or ranking indices for benefits that are found to be too difficult to quantify.

3. DOE recommends that FERC and state regulatory agencies work with interested ISOs/RTOs, utilities, other market participants, and customer groups to examine how much demand response is needed to improve the efficiency and reliability of wholesale and retail markets.[55]

4. DOE recommends that regional planning initiatives examine how demand response resources are characterized in supply planning models and how the benefits are quantified. More accurate characterization of certain types of demand response resources may require modifications to existing models or development of new tools.

5. DOE recommends that, in regions with organized wholesale markets, ISOs and RTOs should work with regional state committees to undertake studies that assess the benefits of demand response *under foreseeable future circumstances* as part of their regional transmission expansion plans as well as under current market conditions.

---

[55] Issues to consider in this assessment include ability of demand response to obviate the need for active market mitigation, and potential impact of demand response on supplier market power and system reliability.

SECTION 5. RECOMMENDATIONS FOR ACHIEVING THE BENEFITS OF DEMAND RESPONSE

Section 1252(d) of EPACT requires DOE to submit a report that (1) "identifies and quantifies the national benefits of demand response," and (2) "makes a recommendation on achieving specific levels of such benefits by January 1, 2007."

Sections 3 and 4 of this report identify and quantify demand response benefits. Based on the findings of this study, DOE has determined that it is not appropriate to develop recommendations on achieving specific levels of demand response benefits by January 1, 2007. The eleven months between submission of this report and January 2007 do not allow time for meaningful recommendations to be successfully implemented. Instead, DOE offers a set of recommendations for consideration by state, regional and federal agencies, electric utilities and consumers to enhance demand response in a manner consistent with state and regional conditions.

The recommendations are organized as follows:

- *Fostering Price-Based Demand Response*—by making available time-varying pricing plans that let customers take control of their electricity costs;
- *Improving Incentive-Based Demand Response*—to broaden the ways in which load management contributes to the reliable, efficient operation of electric systems;
- *Strengthening Demand Response Analysis and Valuation*—so that program designers, policymakers and customers can anticipate how demand response delivers benefits;
- *Integrating Demand Response into Resource Planning*—so that the full impacts of demand response are recognized, and the maximum level of resources benefits are realized;
- *Adopting Enabling Technologies*—to realize the full potential for managing usage on an ongoing basis; and
- *Enhancing Federal Demand Response Actions*—to take advantage of existing channels for disseminating information and forming public-private collaboratives.

DOE developed these recommendations after a public input process in which interested parties were asked to provide suggestions in response to a web survey for "how to advance demand response in all markets." DOE considered the recommendations from the 40 organizations that submitted responses,[56] looked at other recent demand response studies,[57] and developed its own views. The recommendations reflect DOE's best judgment of the actions needed to advance demand response across the nation.

---

[56] Appendix A identifies the contributing organizations.
[57] These are listed in the References.

The primary audiences for the recommendations include:

- regional entities and market stakeholders (such as ISOs, RTOs, and multi-state entities involved in the electricity sector);
- Federal and State legislative and regulatory authorities (including FERC, public utility commissions, public service commissions, and state utilities boards);[58]
- electric utilities (such as those regulated by the states, as well as electric cooperatives, municipal utilities, and public utility districts) and load serving entities;
- electricity customers; and
- other stakeholders such as consumer and environmental groups, curtailment service providers, energy services companies, and equipment manufacturers.

Fostering Price-Based Demand Response

Retail electricity prices that are linked to contemporaneous supply costs or prices are one of the principal mechanisms for accomplishing demand response. Since the passage of the Public Utilities Regulatory Policy Act of 1978 (Public Law 95-617) there has been interest in and support for efforts to implement retail rates that reflect the marginal costs of providing electricity. The aim is to provide time-varying price signals that encourage customers to reduce demand when the costs of providing electricity are relatively high. Section 1252 of EPACT (under Subtitle E—Amendments to PURPA) directs State regulatory authorities to decide whether their utilities should offer customers time-based rate schedules (i.e., RTP, CPP and TOU rates) and advanced metering and communications.

Large Customers

RTP is an effective means of facilitating demand response for large commercial and industrial customers.[59] Default service RTP tariffs that index hourly prices to day-ahead markets support demand response and retail market development by giving customers more notice and certainty of the financial consequences of their response. RTP tariff designs that offer customers a fairly predictable financial benefit, and allow them to financially hedge their exposure to price risks (e.g., through a two-part RTP with a consumer baseline and/or financial risk management products), are effective in vertically integrated systems.

---

[58] A recent study by the Government Accountability Office (GAO 2004) concluded that a majority of the actions to address demand response involve retail markets and thus come under the jurisdiction of the states, based on provisions of the Federal Power Act. In EPACT, Congress did not require the states to do demand response but instead required them to consider and investigate demand response and time-based metering based on changes to the Public Utility Regulatory Policies Act of 1978. Congress also authorized DOE and FERC to encourage demand response through information and education on benefits, barriers, and technologies as well as technical assistance. Absent additional legislative changes from Congress, actions of Federal [regulatory] agencies that affect demand response are limited to wholesale markets.

[59] See Barbose et al. (2004 and 2005) and Goldman et al. (2005).

- *In states that allow retail competition, state regulatory authorities and electric utilities should consider adopting RTP as their default service option for large customers.*

- *In states that do not allow retail competition, state regulatory authorities and electric utilities should consider offering RTP to large customers as an optional service for large customers.*

Customer Sizes

There is no standard classification of customer size. The following classifications are adopted for this report:

Large customers are those with electric demand **exceeding 1,000 kilowatts** and generally include manufacturing plants, office and large hospital complexes, skyscrapers, and university campuses.

Medium business customers are those with electric demand of **100-1,000 kilowatts** and generally include many types of commercial buildings such as ‘big box” retail stores and office buildings, warehouses, and light industrial facilities.

Small business customers are those with electric demand **below 100 kilowatts** and generally include small commercial buildings, retail stores, and restaurants.

Residential customers are a subset of small customers and include single-family homes, town houses, and apartments, most of which have electric demand below **10 kilowatts**.

Customers on RTP need to understand their electricity consumption patterns in substantial detail and also need to be aware of their capabilities to curtail or shift discretionary usage. For example, facility audits can help identify and assess operational strategies and/or technologies for responding to hourly prices. Financial incentives for energy management control systems, distributed energy systems, or automated controls may, in certain cases, be warranted.

- *Regional entities and collaborative processes, state regulatory authorities, and electric utilities should provide education, outreach, and technical assistance to customers to maximize the effectiveness of RTP tariffs.*

<u>Medium and Small Business Customers</u>

Medium and small business customers comprise a highly diverse mix of businesses and types of buildings. These customers are not typically targeted for price-based demand response to the same extent as large commercial and industrial customers. As a result, the experience base about what does and does not work is much less developed, and this lack is a deterrent to the implementation of price-based or other demand response mechanisms.

The diversity of medium and small business customers makes it relatively difficult to design pricing approaches that can elicit predictable and cost-effective demand response across diverse customer circumstances, (e.g., schools, grocery stores, “big box” retail outlets, private sector office buildings, government facilities, warehouses, and restaurants). Each of these has different decision-making processes, patterns of demand, and types of equipment. A library of case studies about customer and utility experiences with price-based demand response would help customers see how demand response can work in their business by seeing how it works in comparable businesses.

- *State regulatory authorities and electric utilities should investigate new strategies for segmenting medium and small business customers to identify relatively homogeneous sub-sectors that might make them better candidates for price-based demand response approaches.*

There is evidence that RTP could be suitable for medium-sized businesses, particularly among the larger customers in this group (e.g., those with demand above 300-500 kW).[60] CPP may also provide an effective means for introducing demand response to medium and small businesses, particularly those served by vertically integrated systems. There may be circumstances where policy or business cases can be made for offering RTP or CPP as the standard rate (vertically integrated systems) or as the default service (competitive retail markets).

- *State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for medium and small business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.*

- *State regulatory authorities and electric utilities should consider conducting policy or business case analysis of RTP for medium business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.*

Residential Customers

Several electric utilities have conducted large-scale CPP pilots that included residential customers and found encouraging results, including high acceptance and demand reduction in certain customer segments.[61]

- *State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for residential customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.*

Residential (and small business) customers represent a special challenge for price-based demand response. Most residences (and small businesses) lack information on their electricity-using appliances and equipment and are not familiar with demand response enabling technologies that can facilitate effective energy management.

- *State regulatory authorities and electric utilities should investigate the cost-effectiveness of offering technical and/or financial assistance to small business*

---

[60] See Barbose et al. (2005).
[61] See Charles River Associates (2005).

and residential customers to enable their participation in CPP or TOU tariffs and enhance their abilities to reduce demand in response to higher prices.

Improving Incentive-Based Demand Response

Experience has shown that the effectiveness of incentive-based demand response programs is closely correlated to how programs are designed and offered to customers.[62] Program design considerations include eligibility criteria, curtailment terms and conditions (e.g., notice, duration, and frequency of events), incentive payments, cost recovery, and procedures to measure and verify demand reductions.

- *Traditional load management (LM) programs such as direct load control of residential and small commercial equipment and appliances (e.g., air conditioners, water heaters, and pool pumps) with an established track record of providing cost-effective demand response should be maintained or expanded.*

In some cases, these LM programs must be adapted to new market structures or circumstances, which involves rethinking program design features related to triggering events (e.g., only system emergencies or other economic and emergency criteria), linking payments to actual performance, considering improvements or enhancements to control technologies, improving system communications, or enhancing monitoring/verification capabilities to allow LM programs to participate in various wholesale electricity markets (e.g., capacity, reserves). When adapting LM from vertically integrated systems to other market structures (e.g. markets with retail competition and vertical de-integration), a key issue to address is the fact that with the proliferation of market actors (e.g. competitive retailers, "wires-only" utilities), no single entity has the incentive to pursue the full benefits of demand response.

- *State regulatory authorities and electric utilities should consider offering existing and new participants in these LM programs "pay-for-performance" incentive designs, similar to those implemented by ISOs/RTOs and some utilities, which include a certain level of payment to customers who successfully reduce demand when called upon to do so during events.*

Some emergency demand response programs have been able to provide reliability benefits to regional entities, electric utilities, and customers in a cost-effective manner. Certain program design features have been particularly effective in achieving both consumer enrollment and performance during times of system need.

- *Regional entities, state regulatory authorities, and electric utilities should consider including the following emergency demand response program features:*
    - *Payments that are linked to the higher of real-time market prices or an administratively-determined floor payment that exceeds customers' transaction costs;*

---

[62] Policymakers need to recognize that it takes at least six months and often up to several years to build demand response capability, depending on the type of program adopted.

    - *"Pay-for-performance" approaches that include methods to measure and verify demand reductions;*
    - *Low entry barriers for demand response providers, and in vertically integrated systems, procedures to ensure that customers have access to these programs; and*
    - *Multi-year commitments from regional entities for emergency demand response programs so that customers and aggregators can make decisions about committing time and resources.*

Electric utilities that own and operate distribution systems only may have limited interest in implementing demand response programs for customers that remain on default service, especially in cases where supply for those customers is contracted out to another entity.

- *State regulatory authorities should investigate whether it would be cost-effective for default service providers to implement demand response. They should also provide cost recovery for demand response investments undertaken by distribution utilities.*

Strengthening Demand Response Analysis and Valuation

Additional work is needed to standardize reporting of demand response costs, benefits, and valuation methods before it will be possible to establish appropriate levels of demand response benefits. A stronger analytical infrastructure for demand response will help electric utilities, customers, retail suppliers, ISOs/RTOs, and state, regional, and federal agencies to properly assess demand response capabilities, business cases, and resource plans.

- *A voluntary and coordinated effort should be undertaken to strengthen demand response analysis capabilities. This effort should include participation from regional entities, state regulatory authorities, electric utilities, trade associations, demand response equipment manufacturers and providers, customers, environmental and public interest groups, and technical experts. The goal should be to establish universally applicable methods and practices for quantifying the benefits of demand response.*

Public-private partnerships of this type have been successful in addressing similar challenges by fostering better information exchange and helping to build consensus. DOE can help to facilitate the formation of such a partnership, but the objectives, work plans, experts, and resources need to come from the members. Appendix D of this report contains additional information on needed demand response analysis and valuation information, tools, and techniques. Key needed activities include:

- Developing standardized methods to evaluate demand response potential and performance and identify appropriate tests for foreseeable programs and circumstances;

- Clarifying the different categories of demand response benefits, developing methods to quantify those benefits that can be quantified and qualitative or ranking indices for those that are difficult to quantify;
- Developing methods to estimate demand response impacts on wholesale electricity costs and reliability, and the benefits and savings that are passed through to retail customers, thus clarifying the link that demand response provides between wholesale and retail markets;
- Documenting the impact of price-based demand response on wholesale electric market prices and costs based on actual demand response program results; and
- Establishing a database of existing demand response programs to (1) document a track record of program performance with respect to reliability protection, (2) gain insight into the factors that influence performance, and (3) identify ways to use demand response most effectively to deal with reliability challenges.

Integrating Demand Response into Resource Planning

Electric resource adequacy is paramount to ensuring reliable, secure, and affordable electric market operations. It is appropriate for regional entities, state regulatory authorities, and electric utilities to ask how much demand response is needed (and is enough) for ensuring resource adequacy, given market structures and system conditions.

Existing studies confirm the view that even low levels of demand response can improve resource adequacy and the efficiency of market operations. However, existing studies do not address, nor provide methods for, establishing optimal levels or target goals for demand response in specific market settings.

- *FERC and state regulatory agencies should work with interested ISOs/RTOs, utilities, other market participants and customer groups to examine how much demand response is needed to improve the efficiency and reliability of their wholesale and retail markets.*[63]

Current resource planning methods often fail to characterize demand response resources properly. For example, RTP is often evaluated as a resource that can be dispatched to serve demand, rather than as reductions in the timing and level of demand. Also, the flexibility of being able to add, or limit, certain types of demand response resources, from one year to the next, based on system needs, is often not fully reflected in resource plans.

- *Resource planning initiatives should review existing demand response characterization methods and improve existing planning models to better incorporate different types of demand response as resource options.*

---

[63] Issues to consider in this examination include the ability of demand response to obviate the need for active market mitigation, the impact of demand response on supplier market power, and the ability of demand response to enhance reliability.

In wholesale markets where ISOs/RTOs administer organized spot markets, the primary focus is on short-term demand response impacts and benefits. More effort should be devoted to characterizing long-term impacts and potential benefits. In the absence of forward markets for demand response, and the potential for a stream of benefits, demand response value will depend primarily on current market conditions.

- *ISOs and RTOs, in conjunction with other stakeholders, should conduct studies to understand demand response benefits under foreseeable future circumstances as part of regional transmission planning and under current market conditions in their demand response performance studies.*

Adopting Enabling Technologies

Recent advances in information and communication technologies have expanded metering functionality, and increased the potential for lower metering costs. DOE believes these enabling technologies have the potential to produce demand response offerings that are more attractive and cost-effective for electric utilities and customers.

Advanced metering systems are one of the most important demand response enabling technologies, particularly for mass-market customers.[64] They can also improve regional grid operators and electric utilities' grid management and operations capabilities because they enable access to real-time and disaggregated information on demand conditions in local areas. While a number of U.S. utilities have committed to system-scale deployment of advanced metering systems, in many of those cases the business case focused primarily on the utility's operational and business benefits (e.g., reduced meter reading costs, outage and tamper detection, and energy profiling).

- *State regulatory authorities and electric utilities should assure that utility consideration of advanced metering systems includes evaluation of their ability to support price-based and reliability-driven demand response, and that the business case analysis includes the potential impacts and benefits of expanded demand response along with the operational benefits to utilities.*

There are other key demand-response enabling technologies, including advanced HVAC and lighting controls, "grid friendly" appliances,[65] smart thermostats, and distributed

---

[64] Advanced metering systems encompass a range of solid-state devices that are capable of measuring electricity consumption for whatever time interval is desired (e.g., minute-by-minute, hourly, or for specified "critical peak periods"). They often include equipment and software for communicating consumption and other relevant customer information to utilities automatically, thus eliminating the need for meter readers. The infrastructure that is needed to support advanced metering systems can be extensive and typically includes the meter manufacturers, distributors, and services providers; software developers; communications equipment and services providers (e.g., radio, cable, telephone, and power lines); and electric utilities.

[65] The grid-friendly appliance is a concept that includes refrigerators and other home appliances which contain special computer chips that enable utilities and/or demand response providers, with the use of wide-area data acquisition and control systems, to determine the operational status of home appliances and provide the ability to control its electricity consumption during times of system need.

energy devices such as advanced turbines and micro-turbines, high efficiency engines, thermal and electric energy storage, thermally-activated heating and cooling equipment, fuel cells, photovoltaic arrays, and small-scale combined heat and power (CHP) systems. In addition, advanced designs for integrating and configuring these devices for "whole building," or multi-building applications need to be evaluated, particularly those that can be optimized for energy, economic, and environmental performance. These include building automation systems and concepts such as "zero-energy homes," "low-peak communities," "district CHP systems," "GridWise™," "Intelligrid," and "microgrids."

- *State regulatory authorities and electric utilities should evaluate enabling technologies that can enhance the attractiveness and effectiveness of demand response to customers and/or electric utilities, particularly when they can be deployed to leverage advanced metering, communications, and control technologies for maximum value and impact.*

- *State legislatures should consider adopting new codes and standards that do not discourage deployment of cost-effective demand response and enabling technologies in new residential and commercial buildings and multi-building complexes.*

Enhancing Federal Actions

Sections 1252 (d), (e), and (f) of EPACT contain provisions for DOE, FERC, and other federal agencies to encourage demand response. DOE has been encouraging demand response through information exchange, technical assistance, and technology development and transfer activities. In wholesale markets, FERC has been encouraging the increased use of demand response. For example, FERC and the ISOs/RTOs have been addressing the integration and use of demand response in regions with organized spot markets, and the potential impact of demand response on the market power of suppliers.

- *DOE, to the extent annual appropriations allow, should continue to provide technical assistance on demand response to states, regions, electric utilities, and the public including activities with stakeholders to enhance information exchange so that lessons learned, best practices, new technologies, barriers, and ways to mitigate the barriers can be identified and discussed.*[66]

- *DOE and FERC should continue to coordinate their respective demand response and related activities.*

---

[66] Information exchange topics include, for example, how the states are addressing the Section 1252 provisions of EPACT for advanced metering and demand response, how demand response potentially affects utility revenues and profits, and how utility ratemaking and incentive mechanisms potentially affect demand response adoption and program success.

- *FERC should continue to encourage demand response in the wholesale markets it oversees.*[67]

Section 103 of EPACT includes a provision whereby all federal facilities are to have metering capabilities—and to the extent practical, advanced meters or advanced metering devices—by October 1, 2012.

- *DOE, through its Federal Energy Management Program, should explore the possibility of conducting demand response audits at Federal facilities.*

Although not always the case, in certain circumstances it is possible for demand response programs and pricing approaches to have a favorable impact on energy efficiency and the environment.

- *DOE and the Environmental Protection Agency should explore efforts to include appropriate demand response programs and pricing approaches, where appropriate, in the ENERGY STAR® and other voluntary programs.*

---

[67] Examples of this include: encouraging expanded efforts by the ISOs and RTOs to (1) find ways for customers to participate in spot, day-ahead, and ancillary service markets; (2) determine whether current or proposed reliability rules need to be changed to accommodate demand response; and (3) support even greater levels of information exchange and collaboration on demand response across regions of the country.

REFERENCES

Adilov, Nodir, Thomas Light, Richard Schuler, William Schulze, David Toomey and Ray Zimmerman, 2004, "Self-Regulating Electricity Markets?" paper presented at Advanced Workshop in Regulation and Competition, Rutgers Center for Research in Regulated Industries 17th Annual Western Conference, San Diego, CA, June 24.

Baltimore Gas and Electric Company (BGE), 2002, "Evaluation of the Load Impacts of the Electric Water Heater Load Control Program (Rider 6) Summer 2002" December.

Baltimore Gas and Electric Company (BGE), 2003, "Evaluation of the Load Impacts of the Electric Water Heater Load Control Program (Rider 6) Summer 2003" March.

Barbose, Galen, Charles Goldman and Bernie Neenan, 2004, "A Survey of Utility Experience with Real Time Pricing" LBNL-54238, December.

Barbose, Galen, Charles Goldman, Ranjit Bharvirkar, Nicole Hopper, Mike Ting and Bernie Neenan, 2005, "Real Time Pricing as a Default or Optional Service for C&I Customers: A Comparative Analysis of Eight Case Studies" report to the California Energy Commission, Lawrence Berkeley National Laboratory: LBNL-57661, August.

Boisvert, Richard N. and Bernard F. Neenan, 2003, "Social Welfare Implications of Demand Response Programs in Competitive Electricity Markets" report to Lawrence Berkeley National Laboratory: LBNL-52530, April.

Bosivert, Richard, Peter Cappers, Bernie Neenan, and Bryan Scott, 2004, "Industrial and Commercial Customer Response to Real-time Electricity Prices" Neenan Associates, December 10.

Borenstein, Severin, 2002, "The Theory of Demand-Side Price Incentives" in *Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets*, Hewlitt Foundation Energy Series, San Francisco CA, October.

Borenstein, Severin, 2005, "The Long-Run Efficiency of Real-Time Pricing" *The Energy Journal* 26(3):96-116.

Borenstein, Severin, James Bushnell and Frank Wolak, 2000, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market" University of California Energy Institute: PWP-064, August.

Borenstein, Severin, Michael Jaske, and Arthur Rosenfeld, 2002, "Appendix B. GulfPower's Residential Service Variable Price Option" in *Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets*, Hewlitt Foundation Energy Series, San Francisco CA, October.

Braithwait, Steven, 2000, “Residential TOU Price Response in the Presence of Interactive Communication Equipment” in Pricing in Competitive Electricity Markets, Faruqui, A. and K. Eakin (eds.), Kluwer Academic Publishers: Dordecht, Netherlands.

Braithwait, Steven, 2003, “Demand Response is Important – But Let’s Not Oversell (or Over-Price) It” *The Electricity Journal* 16(5):52-65.

Braithwait, Steven and Ahmad Faruqui, 2001, “The Choice Not to Buy; Energy $avings and Policy Alternatives for Demand Response” *Public Utilities Fortnightly* 139(6).

Braithwait, Steven and Kelly Eakin, 2002, “The Role of Demand Response in Electric Power Market Design” report to the Edison Electric Institute, October.

Braithwait, Steven and Michael O’Sheasy, 2002, “RTP Customer Demand Response—Empirical Evidence on How Much Can You Expect” In Electricity Pricing in Transition, A. Faruqui and K. Eakin eds., Kluwer Academic Publishers: Dordecht, Netherlands.

California Public Utilities Commission (CPUC), 2001, “Economic Analysis of Demand-Side Management Programs and Projects”, October. Available at http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/resource5.doc

California Public Utilities Commission (CPUC), 2003, “R.02-06-001 Third Report of Working Group 2 on Dynamic Tariff and Program Proposals,” CPUC OIR on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing, January 16.

Caves, Douglas W., Laurits R. Christensen and Joseph A. Herriges, 1984, “Consistency of Residential Customer Response in Time of Use Pricing Experiments” *Journal of Econometrics* 26: 179-203.

Caves, D., K. Eakin and A. Faruqui, 2000, “Mitigating Price Spikes in Wholesale Markets Through Market-Based Pricing in Retail Markets” *The Electricity Journal* 13(3):13-23.

Charles River Associates, 2005, “Impact Evaluation of the California Statewide Pricing Pilot” final report to the California Energy Commission, March 16.

Energy Information Administration (EIA), 2004, “Form EIA-861 Database: Annual Electric Power Industry Data”. Available at http://www.eia.doe.gov/cneaf/electricity/page/eia861.html

EPACT, 2005, *U.S. Energy Policy Act of 2005*, Public Law 109-58, August 8.

Faruqui, Ahmad, and Stephen George, 2002, “The Value of Dynamic Pricing in Mass Markets” *The Electricity Journal* 15(6):45-55.

Faruqui, Ahmad and Stephen George, 2005, “Quantifying Customer Response to Dynamic Pricing” *The Electricity Journal* 18(4):53-63.

Federal Energy Regulatory Commission (FERC), 2003, “White Paper: Wholesale Power Market Platform”, April 28.

Goldman, Charles, Nicole Hopper, Ranjit Bharvirkar, Bernie Neenan, Richard Boisvert, Peter Cappers, Donna Pratt, and Kim Butkins, 2005, “Customer Strategies for Responding to Day-Ahead Market Hourly Electricity Pricing” LBNL-57128, August.

Government Accountability Office (GAO), 2004, “Consumers Could Benefit from Demand Programs, but Challenges Remain” GAO-04-844, August.

Government Accountability Office (GAO), 2005, “Electricity Restructuring: Key Challenges Remain” GAO-06-237, November.

Holland, Stephen P. and Erin T. Mansur, 2004, “Is Real-Time Pricing Green?: The Environmental Impacts of Electricity Demand Variance” University of California Energy Institute: WP-136, August.

Horowitz, Marvin, 2002, “2001 Load Impact Evaluation of Pepco’s Direct Load Control Active Load Management Programs” March 29.

ICF Consulting, 2002, “Economic Assessment of RTO Policy” prepared for the Federal Energy Regulatory Commission, February 26.

ISO New England (ISO-NE), 2005a, “2004 Annual Markets Report” July 15. Available at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html

ISO New England (ISO-NE), 2005b, “Regional System Plan 2005” October 20.

Keith, Geoff, Bruce Biewald, David White and Mike Drunsic, 2003, “Modeling Demand Response and Air Emissions in New England” prepared for the U.S. Environmental Protection Agency, revised September 4.

KEMA-Xenergy, 2004, “Final 2004 Smart Thermostat Program Impact Evaluation” prepared for San Diego Gas & Electric Company, February 25.

Kexel, Duane, 2004, “Demand Response Economics in New Power Markets: final report” report to the Cooperative Research Network, National Rural Electric Cooperative Association, August.

King, Chris, 2004, “Advanced Metering Infrastructure: Overview of System Features and Capabilities” presented at Joint Workshop of the California Resources Agency, California Energy Commission and California Public Utilities Commission, September 30.

King, Chris and Dan Delurey, 2005, “Energy Efficiency and Demand Response: Twins, Siblings or Cousins?” *Public Utilities Fortnightly* March, 54-61.

King, Chris S. and Sanjoy Chatterjee, 2003, “Predicting California Demand Response” *Public Utilities Fortnightly* 141(13):27.

Kirby, Brendan J., 2003, “Spinning Reserve from Responsive Loads”, Oak Ridge National Laboratory ORNL-TM-2003/19, March.

Kueck, J., B. Kirby, R. Staunton, J. Eto, C. Marnay, C. Goldman and C.A. Martinez, 2001, “Load As a Reliability Resource in Restructured Electricity Markets” report to the California Energy Commission, ORNL/TM2001/97, LBNL-47983, June 1.

Levy Associates, 1994, “TranstexT Advanced Energy Management System Project Review” July.

Lopes, Joseph S., 2004, “Case Studies in Central A/C Thermostat Control” presented at Metering America conference, San Diego, CA, March.

NARUC, 2000, “Resolution Regarding Equal Consideration of Demand and Supply Responses in Electric Markets” National Association of Regulatory Utility Commissioners (NARUC) Board of Directors, July 26.

Neenan, B., D. Pratt, P. Cappers, J. Doane, J. Anderson, R. Boisvert, C. Goldman, O. Sezgen, G. Barbose, R. Bharvirkar, M. Kintner-Meyer, S. Shankle and D. Bates, 2003, “How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance” report to the New York Independent System Operator and New York State Energy Research and Development Agency, January.

Neenan, B., P. Cappers, D. Pratt and J. Anderson, 2005, “Improving Linkages Between Wholesale and Retail Markets Through Dynamic Retail Pricing: Preliminary Results” report to the New England Independent System Operator, December.

New England Demand Response Initiative (NEDRI) 2003, “Dimensions of Demand Response: Capturing Customer Based Resources in New England’s Power Systems and Markets,” July.

New York Independent System Operator (NYISO), 2003, “NYISO 2003 Demand Response Programs (Attachment I): Compliance Report to FERC” FERC Docket No. ER01-3001-00, December. Available at http://www.nyiso.com/public/index.jsp

New York Independent System Operator (NYISO), 2004, “NYISO 2004 Demand Response Programs (Attachment I): Compliance Report to FERC” FERC Docket No. ER01-3001-00, December. Available at http://www.nyiso.com/public/index.jsp

North American Electric Reliability Council (NERC), 2005, "2005 Long-Term Reliability Assessment", September. Available at ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2005.pdf

Northwest Power and Conservation Council (NPCC), 2005, "The Fifth Northwest Electric and Conservation Plan" NPCC Document 2005-07, July.

Orans, Ren, C.K. Woo, Brian Horii, Snuller Price, Arne Olson, Carmen Baskette and Joel Swisher, 2004, "Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs" report to the California Public Utilities Commission, October 25.

Patrick, Robert H. and Frank Wolak, 2001, "Estimating the Customer-level Demand for Electricity under Real-time Market Prices" National Bureau of Economic Research Working Paper 8213, April.

Peak Load Management Alliance (PLMA), 2002, "Demand Response: Design Principles for Creating Customer and Market Value" November. Available at www.peaklma.com.

Platts, J. E., 2004, "Final Report on Evaluation and Selection of Resources in SWCT RFP for Emergency Capability: 2004-2008", ISO-New England, October 4.

Public Interest Energy Research Demand Response Research Center (PIER DRRC), 2005, "Research Opportunity Notice DRRC RON-01: Establish the Value of Demand Response" July.

Piette, M. A., O. Sezgen, D. Watson, N. Motegi, C. Shockman, and L. ten Hope, 2005, "Development and Evaluation of Fully Automated Demand Response in Large Facilities" California Energy Commission: CEC-500-2005-013, January.

PJM Interconnection, 2004, "Assessment of PJM Load Response Programs (Revised)" compliance report to the Federal Energy Regulatory Commission, Docket No. ER02-1326-006, October 31.

PJM Interconnection, 2005a, "2004 State of the Market" March 8. Available at http://www.pjm.com/markets/market-monitor/som.html

PJM Interconnection 2005b, "Regional Transmission Expansion Plan," September.

PJM Interconnection 2005c, "Whitepaper on PJM Forward Energy Reserve: A Centralized Call Option Market Proposal." PJM Inteconnection Docs #304175v1.

Portland General Electric (PGE), 2004, "Direct Load Control Pilot for EWH: Pilot Evaluation and Impact Measurement" filed with the Oregon Public Utilities Commission, October.

RLW Analytics and Neenan Associates, 2004, "An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2004" Annual Demand

Response Program Evaluation submitted to FERC, December. Available at www.ISO-NE.com.

Ruff, Larry E., 2002, "Economic Principles of Demand Response in Electricity" report to the Edison Electric Institute, October.

Smith, V. and L. Kiesling, 2005, "A Market-Based Model for ISO-Sponsored Demand Response Programs: White paper prepared for a Multi-Client Study: A Critical Examination of Demand Response Programs at the ISO Level: End Goal, Implementation, and Equity" Center for the Advancement of Energy Markets, Distributed Energy Financial Group, August.

Spulber, D.F., 1992, "Capacity-Contingent Nonlinear Pricing by Regulated Firms" *Journal of Regulatory Economics* 4(4):299-320.

Stoft, Steven 2004, *Prepared Direct Testimony before the Federal Regulatory Energy Commission* FERC Docket No. ER03-563-030, August 31.

Summit Blue Consulting, 2004, "Evaluation of the Energy-Smart Pricing Plan: Final Report" prepared for Community Energy Cooperative, February.

Summit Blue Consulting, 2005, "Evaluation of the 2004 Energy-Smart Pricing Plan: Final Report" prepared for Community Energy Cooperative, March.

Taylor, T., P. Schwarz, and J. Cochell, 2005, "24/7 Hourly Response to Electricity Real-Time Pricing with up to Eight Summers of Experience" *Journal of Regulatory Economics* 27(3):235-62.

U.S. Department of Energy (DOE), 2003, "Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design" DOE/S-0130, April 30.

Violette, Daniel and Michael Ozog, 2003, "Mass-Market Demand Management Offerings: Evaluation Methods Assessment and Results" presented at the International Energy Program Evaluation Conference, Seattle WA, August.

Violette, Daniel, Rachel Freeman and Chris Neil, 2006, "DRR Valuation and Market Analyses, Volume II: Assessing the DRR Benefits and Costs" task status report to the International Energy Agency Demand-Side Programme: Task XIII: Demand-Side Resources Project, January 6.

Woo, C.K., 1990, "Efficient Electricity Pricing with Self-Rationing" *Journal of Regulatory Economics* 2(1):69-81.

York, Dan and Marty Kushler, 2005, "ACEEE's Third National Scorecard on Utility and Public Benefits Energy Efficiency Programs: A National Review and Update of State-Level Activity" American Council for an Energy Efficient Economy: ACEEE-U054, October.

APPENDIX A. ORGANIZATIONS THAT PROVIDED INPUT ON RECOMMENDATIONS

American Council for an Energy-Efficient Economy
American Public Power Association
Apogee Interactive, Inc.
Arkansas Public Service Commission
Battelle-Pacific Northwest National Laboratory
BP Solar
California Department of Water Resources State Water Project
California Energy Commission
California Public Utilities Commission
Constellation Energy
Consumer Energy Council of America
Cornell University
Demand Response and Advanced Metering Coalition
Distributed Energy Financial Group
Duke Power
East Kentucky Power Cooperative
Edison Electric Institute
Energy Connect Inc.
Grid Services, Inc.
Hunt Technologies, Inc.
Idaho Public Utilities Commission
Invensys Controls
ISO New England, Inc.
Itron
Louisville Gas and Electric
M.Cubed
National Rural Electric Cooperative Association
New York State Department of Public Service
PJM Interconnection, LLC
San Francisco Community Power Cooperative
Solar Turbines, Inc.
Southern California Edison Company
Steel Manufacturers Association
SUEZ Energy NA
The Cool Solutions Company
The Stella Group, Ltd.
U.S. Department of Energy—Building Technologies Program
United States Demand Response Coordinating Committee
Utilipoint International, Inc.
Utility Economic Engineers

APPENDIX B. ECONOMIC AND RELIABILITY BENEFITS OF DEMAND RESPONSE

This Appendix provides a more detailed conceptual discussion of the economic and reliability benefits of demand response than was included in Section 3. First, short-term market impacts are described, drawing on economic theory to show how demand response can result in improved economic efficiency, and distinguishing how these benefits are manifested under different market structures. Next, long-term economic benefits from avoided capacity investments are discussed along with issues in designing and implementing programs designed with this goal in mind. Differences in how short-term and long-term economic benefits are realized and passed on to consumers are then described for vertically integrated utilities and regions with ISO/RTO spot markets. Finally, reliability benefits are described along with concepts used to value them.

Short-Term Market Impacts: Supply Costs and Market Prices

This section provides a detailed discussion of how customer load reductions lower energy supply costs in the short term. First, the basic source of short-term market benefits—improved economic efficiency brought about by allowing consumers to make electricity usage decisions based on marginal, rather than average, supply costs—is described. Differences in how these benefits are manifested in regions with differing market structures are then discussed.

Societal Benefits

In evaluating policies or structural changes that impact how markets work, economists distinguish between societal gains, which benefit everyone, and financial flows that involve gains by some at the expense of others, called transfers. In the absence of a way to weigh the relative impact on individuals of gains and losses (i.e., a change in utility), economists argue that policies should primarily be judged on their net outcome, which is defined by the level of societal benefits (see the textbox below).

Demand response produces societal benefits, which are resource savings, by reducing the gap between time-varying marginal supply costs and retail electricity rates based on average costs. Economic theory asserts that the most efficient use of resources occurs when consumption decisions are based on prices that reflect the marginal cost of supply. In a competitive market, this is defined by the intersection of a good's supply and demand curves (see Figure B-1). In electricity markets, the marginal electricity supply curve is constructed by ordering generators from lowest to highest operating costs (often referred to as "merit order").[68] Due to the technical characteristics of electricity generation equipment, the supply curve—the upward curving line in Figure B-1—tends

---

[68] Certain generators may be required to run, regardless of their marginal operating costs, to maintain reliability in areas with constrained generating and/or transmission capacity, which limits the ability of least-cost resources to serve local demand.

to increase very steeply at its upper end.[69] This means that when demand approaches the industry's installed capacity, each additional increment of demand imposes increasingly more cost than the previous one. In other words, the marginal cost of electricity becomes most sensitive to changes in demand when demand is already high.[70]

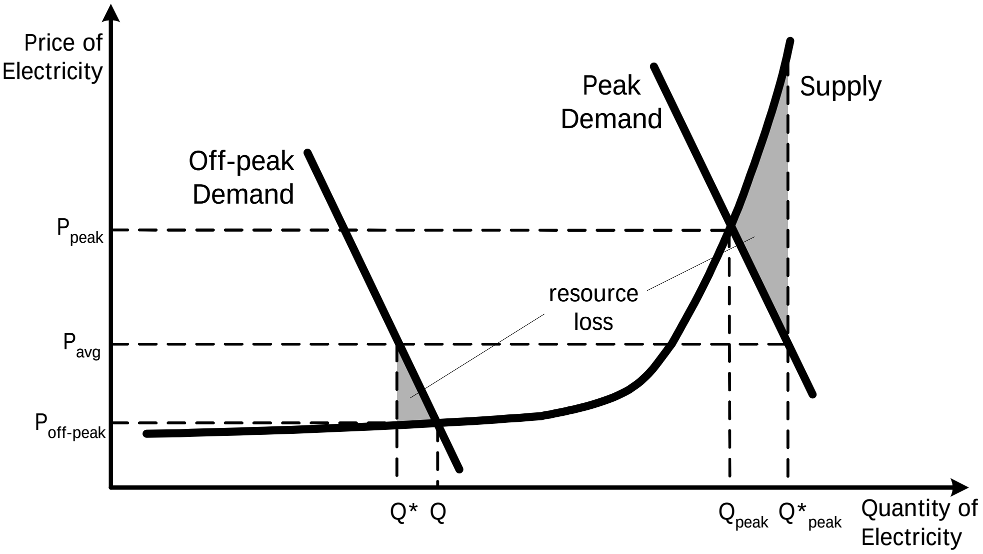


Figure B-1. Inefficiencies of Average-Cost Pricing

Like most goods, the demand for electricity exhibits declining marginal value (i.e., the marginal value of additional consumption declines as consumption increases). Electricity demand is characterized by a downward-sloping line, regardless of how electricity is priced. But, if the price that consumers pay never varies, demand appears to be perfectly inelastic, and is characterized by a vertical line. Moreover, consumers' demand for electricity also depends on the time of day, with more usage typically occurring during the "peak" afternoon and early evening hours and less at other times. This phenomenon is driven by the economic activity of businesses and residential customer lifestyles and usage patterns, but is also influenced by electricity rates that are the same throughout the day. For simplicity, the two lines labeled "peak" and "off-peak" in Figure B-1 represent consumer demand.

The most efficient pricing and usage of electricity is determined by the intersection of the supply and demand curves in Figure B-1. In other words, during off-peak periods, the efficient price of electricity should equal $P_{off\text{-}peak}$ and consumers would use an amount of

---

[69] The long, flat portion of the electricity supply curve represents "base-load" power plants, such as nuclear, hydroelectricity and coal plants that have very low operating costs and are run most hours of the year. Base-load plants are typically large with similar characteristics. The steeply inclining portion of the supply curve represents "peaking" plants that are used to meet peak demand needs and may be run only a few hours per year. These plants are typically natural gas- or oil-fired combustion turbines that are less expensive to build than most base-load technologies but have higher operating costs. Peaking plants are typically smaller units with varied operating characteristics.

[70] High demands do not always lead to high prices. If the entire portfolio of capacity is available, then the marginal unit may be relatively low cost. The steepest part of the supply curve is encountered when demands are especially high (e.g. a heat wave) or generation is short due to forced outages, or both.

electricity equal to Q, and during peak hours, the efficient price should equal P_{peak} and consumers would use Q_{peak} units of electricity. However, most consumers currently pay electricity tariffs that reflect average, rather than marginal, electricity supply costs; this is represented by P_{avg} in Figure B-1. Actual usage therefore reflects the intersection of the demand curves with this average price, resulting in less than the social optimal usage in off-peak periods (Q*) and more than the social optimal usage in peak periods (Q^*_{peak}) relative to the optimally efficient system.

Distinguishing Societal Benefits from Rent Transfers

Economists make a distinction between *transfers*—the benefits of a policy initiative that amount to gains for some at the expense of others—and *social welfare gains* that inure to society as a whole. Social welfare gains are desirable because they derive from efficiency improvements that benefit all market participants. These benefits provide a strong rationale for policymakers to invest consumers' money in initiatives to realize such gains. Transfers result in some market participants being better off than others. In the case of demand response, lower market prices reduce revenue to suppliers and lower costs to consumers. The economists' task is to quantify the relative marginal gains and losses to the individuals involved.

Some economists caution that treating market price reductions as benefits is misleading, and may result in policies that undermine, rather than enhance, market efficiency (Ruff 2002). Specifically, they contend that using the bill savings from price reductions, which largely amount to transfers, to justify demand response incentive payments to customers actually raises electricity prices in the long term. They contend that merchant generators count on the profits (called scarcity rents) realized when prices are high to recoup their capital costs and achieve the rate of return their investors require. If these profits are reduced because policymakers use them to justify customer curtailment incentives, then investors will become more skeptical and require higher returns, which, the argument concludes, results in higher prices in the long run.

This is the basis for many of the objections to allowing customers to bid load curtailments as resources into ISO/RTO spot markets, called "demand bidding as a resource." However, other economists contend that if demand response moves the wholesale market to greater economic efficiency and the result is a more appropriate supply and demand balance, then the elimination of those artificial rents to generators corrects a market distortion and prevents investments that are not needed based on how customers value electricity.

Another objection to demand bidding raised by some economists is their claim that customers on default service have no right to the energy, since the utility rates require that it be served, but do not give the customer any contractual rights to that supply. This could be corrected by requiring that in order to bid curtailments into spot energy markets, the customer would have to demonstrate that it has contractual rights to that power. As an alternative, these critics propose "self-financing" demand response whereby the inherent savings from avoiding paying high market prices is the inducement for customers to curtail, and no payment has to be made to achieve that result (Braithwait 2003).

These arguments have only been raised for demand response programs that allow customers to offer curtailments as resources in centrally organized spot markets. Yet, substantially the same transactions characterize demand bidding and CPP programs run by vertically integrated utilities.

Economists refer to the inefficiencies that arise when retail prices do not reflect marginal supply costs as "dead-weight losses" or resource losses (i.e., the loss of societal welfare when resources are not used optimally). The resource losses from average cost pricing are illustrated by the shaded triangles in Figure B-1. In the off-peak period, electricity that would have value to consumers if it were priced according to its marginal supply cost is not consumed—this represents a loss to society in economic activity that would have occurred but did not. In the peak period, consumers that do not pay the full marginal cost of power consume excessive amounts of electricity at a cost in excess of the value it provides them. Because this occurs at the steeply inclining portion of the electricity supply curve, these costs can be substantial.[71]

The short-term market-impacts benefit of demand response lies in reducing or eliminating this resource loss, thereby improving net social welfare. The combined resource loss from all peak and off-peak hours—and thus the potential for short-term demand response benefits—depends on how widely average and marginal electricity costs vary. For example, in a tightly constrained market, where peak demand is often very close to supply limits, the potential short-term efficiency benefit from implementing demand response can be substantial.

Supply Cost and Market Price Impacts in Regions with Differing Market Structures

Short-term market impacts are illustrated for vertically integrated utilities in Figure B-2. The supply curve typically reflects the utility's supply costs, including its own generation plants and any incremental wholesale power purchases. If demand is forecast to be Q, then a demand reduction that moves consumption to Q_{DR} results in an avoided utility supply cost equal to the shaded area in Figure B-2.

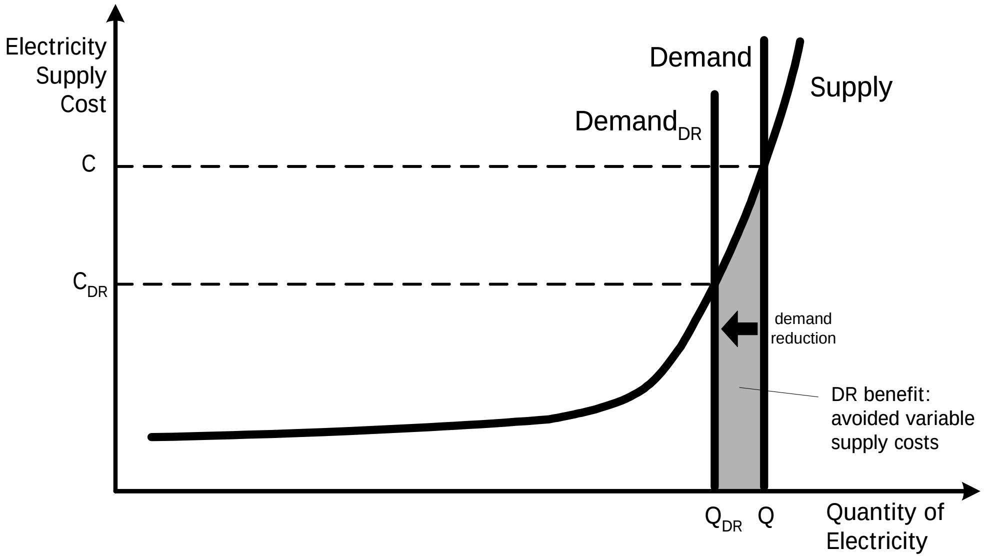


Figure B-2. Impact of Demand Response on Vertically Integrated Utility Supply Costs

The same load reduction produces more extensive impacts in regions with organized wholesale markets because of the way these wholesale markets are designed. The supply curve is developed by arranging generators' offer bids in merit order from lowest to

---

[71] Electricity pricing that does not reflect supply costs results in societal losses both when costs are high, and when they are low. However, the extent of these losses is greater at elevated supply costs, and therefore correcting prices in these periods has captured the attention of policymakers and market designers.

highest. Because of competition among generators, generators' offer bids reflect their marginal operating and maintenance costs and in some circumstances additional margins to recover fixed costs. LSEs also bid their expected load requirements into the market, producing a demand curve.[72] The bid price of last generator needed to serve the LSE's purchases sets the market clearing price for the whole market. This means that a demand reduction from Q to Q_{DR} not only provides the avoided variable cost savings observed for vertically integrated utilities (the shaded area to the right in Figure B-3), but it also lowers the price of all other energy purchased in the market. This second market impact, represented by the shaded rectangle in Figure B-3, is dependent on the level of price reduction—the difference between P and the new price P_{DR}—and the amount of energy bought in the applicable market. LSEs typically commit their expected energy requirements with a mix of bilateral forward contracts with generators and purchases in day-ahead and real-time markets. This is represented by the dotted line in Figure B-3. The extent of customer savings from price reductions thus depends on how much energy is purchased in spot markets.[73]

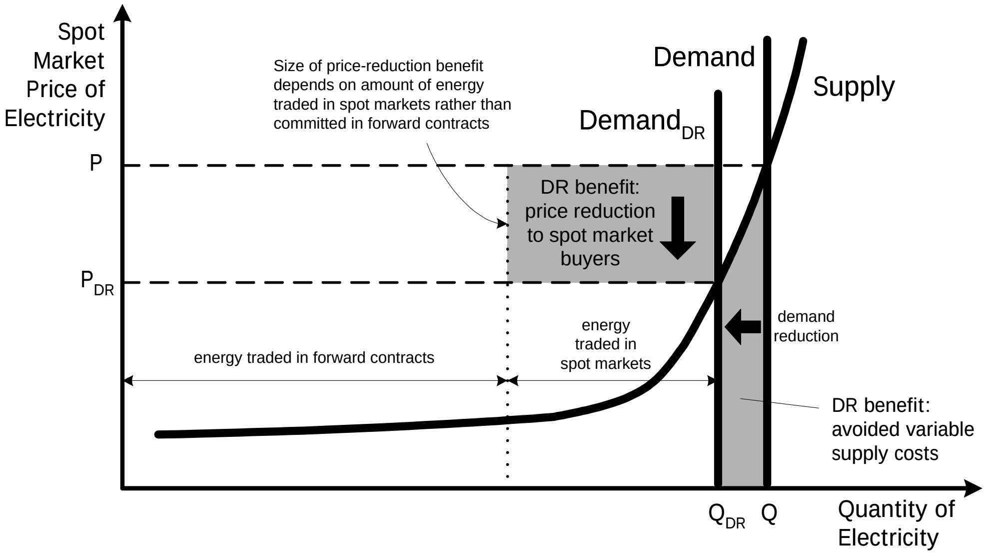


Figure B-3. Impact of Demand Response in Regions with Organized Wholesale Markets

In regions with organized wholesale markets, if, over time, customers routinely respond to high prices by curtailing or shifting loads, then additional, longer-term savings will result. Thus, if demand response consistently reduces market prices and volatility, bilateral contract prices will also drop over time, as reduced price risk in day-ahead and real-time markets pushes longer-term contract prices down. This is because LSEs may be willing to pay less for hedged forward contracts and will buy instead from the spot market if generators do not offer lower forward contract prices. In this way, lower energy

---

[72] In this example, demand is represented by a vertical line for simplicity (i.e., it is presumed to be fixed). Currently, most LSEs bid fixed quantities of electricity in spot markets, so this characterization is appropriate.

[73] In New York, a state with organized wholesale markets and retail competition, over 50% of electricity is traded in day-ahead and real-time spot markets, with the rest settled in forward contracts. In New England, about 40% of the electricity volume is traded in ISO-NE's spot markets, with about 60% committed in forward contracts.

prices resulting from short-term demand response market impacts can eventually extend to the entire market.[74]

Long-term Market Impacts: Capacity Benefits

The long-term market impacts of demand response hinge on reducing the *system peak demand*—the highest instantaneous usage by consumers in a particular market. Reducing system peak demand can avoid or defer the need to construct new generating, transmission and distribution capacity, resulting in savings to consumers**.** This applies for both vertically integrated utilities and organized wholesale markets, although capacity costs are allocated differently. This benefit can be specifically elicited from customers through capacity-based demand response programs (e.g., DLC, I/C rates or ISO/RTO capacity based programs) or may result from consistent load reductions from price-based demand response options (e.g., RTP). For example, in a capacity-based demand response program, load reductions timed to reduce load from a level that otherwise would have established the system maximum demand can yield large benefits for all consumers. Historical system maximum demand, adjusted for planned reserves, establishes ongoing generating capacity requirements, usually on an annual or semi-annual basis. For example, if the maximum demand served in a control area during the past summer was 5,000 MW, then that demand would serve as the basic capacity target for the next summer, to which an additional reserve margin (e.g., 18%) would be added.[75] If the existing infrastructure were insufficient to serve the resulting 5,900 MW capacity requirement, additional capacity would be necessary. Since generating capacity is expensive, ranging from about $50,000 to over $100,000 per MW-year (depending on the type and location of generating units), demand response that displaces the need for new infrastructure can produce substantial avoided cost savings.

Demand response programs designed to reduce capacity needs are valued according to the marginal cost of capacity. By convention, marginal capacity is assumed to be a “peaking unit”, a generator specifically added to run in relatively few hours per year to meet peak system demand. Currently, peaking units are typically natural gas turbines with annualized capital costs on the order of $75/kilowatt-year (kW-year) (Orans et al. 2004, Stoft 2004). Thus, if demand response programs avoid 100 MW of generating capacity, the avoided capacity cost savings would be $7.5 million per year in this example. If the total program costs were $50/kW-year, including incentive payments to participating customers, then other customers realize the rest as savings (e.g., $2.5 million per year in this example), which may eventually be reflected in lower rates and bills. As long as there is some sharing of benefits, all customers benefit from others’ participation in a capacity demand response program.

---

[74] Whether or not savings from short-term market price impacts and reduced forward contract prices brought about by incentive-based demand response programs should be treated as societal benefits is a subject of controversy (see the textbox on “Distinguishing Societal Benefits from Rent Transfers”, earlier in this Appendix).

[75] Reserve margins vary in electricity markets across the U.S., but are typically 15-18%.

Transmission and distribution system capacity investments are also capital-intensive, and demand response that reduces local maximum demand in areas nearing infrastructure capacity can also provide significant avoided cost savings.

Realizing Capacity Benefits: Establishing and Reducing System Peak Demand

Capacity-based demand response programs are designed to replace generation investments and participants receive up-front capacity payments tied to this avoided cost. To realize this benefit and justify making the capacity payments, system operators must be able to dispatch curtailments that actually avoid building new capacity. This is accomplished in one of two ways: (1) predicting when system peak demand will exceed historic levels and dispatching load reductions accordingly or (2) dispatching curtailments when a designated peaking generation unit would otherwise be in service.

Dispatching demand response to avoid increasing system peak demand involves predicting when peak demand is likely to exceed historic levels absent any curtailments. Electric systems are generally either winter or summer peaking, meaning that annual demand is seasonal. However, demand can exceed historic peak levels several times during the peak season, which may span several months. To ensure that a capacity program truly does reduce peak demand, operators may need to dispatch the program several times during the peak season to account for forecast error. For participating customers, multiple curtailment obligations can be burdensome. To improve the attractiveness of capacity programs to customers, limits are sometimes are placed on how many curtailments can be called in a particular season.

The alternative method is to dispatch capacity-based demand response programs when an existing plant designated to meet peak demand would be needed to serve expected demand, absent any curtailments. This practice is somewhat more straightforward in regions with organized wholesale markets because transparent market rules direct dispatch operations. However, vertically integrated utilities have similar unit dispatch rules that could be used. Here too, limits may be placed on how frequently curtailments are called for.

Both methods of dispatching demand response to realize capacity value require provisions for periodic testing of customer response as well as penalties for non-performance. Testing is necessary to certify that customers truly have the capability to deliver the contracted curtailments on an on-going basis. Penalties serve to reinforce their obligation to be available and deliver load reductions when called. However, establishing appropriate penalty levels can be challenging. Increased penalty levels make demand response commitments more reliable and more valuable to the system operator, but are likely to reduce the amount of demand response committed by customers.[76] Program designers must balance the attractiveness of the program to customers against the potential consequences of forced outages that affect a large number of customers at costs well in excess of the avoided cost payment participating customers receive.

Because the avoided capacity cost savings calculation is prospective, so is the value of a capacity-based demand response program. This raises issues in forecasting the timing of system peak demand, or the highest 10-30 load hours of the year, so that calls for demand reductions actually moderate system maximum demand as designed. Since forecasting involves errors, program administrators/sponsors must make provisions to ensure the

---

[76] One useful strategy may be to recruit larger numbers of customer participants by dropping or reducing penalties for non-performance. Even though each customer is a less reliable source of demand response in the absence of penalties, the larger number of participants could increase the total expected demand response. The adoption of such a strategy would require evaluation of accumulated experience on the effect of various levels of penalties on customer performance.

demand response program is called often enough to effectively lower the forecast of system peak demand (see the textbox above).

Timing and Distribution of Market Impacts of Demand Response

Differences in market structure influence the timing and distribution of short-term and long-term market impacts of demand response in important ways. These differences are illustrated in this section by tracing the market impacts and resulting benefits of demand response in two types of market structure: 1) "vertically integrated systems", in which a vertically integrated utility with a retail monopoly franchise engages in some wholesale market transactions but operates in a region without an ISO or RTO, and 2) regions with organized wholesale markets in which ISOs/RTOs administer spot markets and retail competition is enabled at the state level. These illustrative combinations of retail and wholesale market structures reflect the current situation in many states or regions, although other retail/wholesale market structures are prevalent in the U.S.[77]

In this section, the examples suggest that the market impacts of demand response within organized spot markets produce benefits in a *shorter* timeframe than those for a vertically integrated, monopoly utility.

Market Impacts of Demand Response for Vertically Integrated Utilities

Vertically integrated utilities are responsible for making capacity investment decisions (whether to build new generation itself or to purchase supply contracts from other sources such as independent power producers), subject to regulatory oversight and approval, and for planning and operating the electricity grid and ensuring reliability. Retail rates are determined administratively, based on the average cost of supplying all three major facets of electricity production and delivery—production, transmission and distribution—and expected sales volumes. Embedded in retail rates are marginal costs to supply power, such as fuel, operating and maintenance costs, as well as a return on investment for un-depreciated utility-owned generation.

The economic impacts of demand response for a vertically integrated utility operating with a retail monopoly franchise are depicted in Figure B-4. Short-term demand response benefits may be traced as follows:

- Depending on the timing and type of demand response option, customers' load changes may be integrated into the utility's scheduling and dispatch decisions on a day-ahead or near-real-time basis.
- Changes in load (e.g., reductions in usage during high-priced peak periods) offset a portion of usage that otherwise would have been met by production from high-

---

[77] For example, utilities in some states are still vertically integrated and retain a retail monopoly franchise but are part of an organized regional wholesale market administered by an ISO or RTO (e.g., some parts of MISO, Vermont).

operating-cost power plants or purchases during the load response event (see Figure B-2).[78]

- This lowers the average variable electricity cost, which should be manifested eventually as customer bill savings through lower regulated electricity rates.

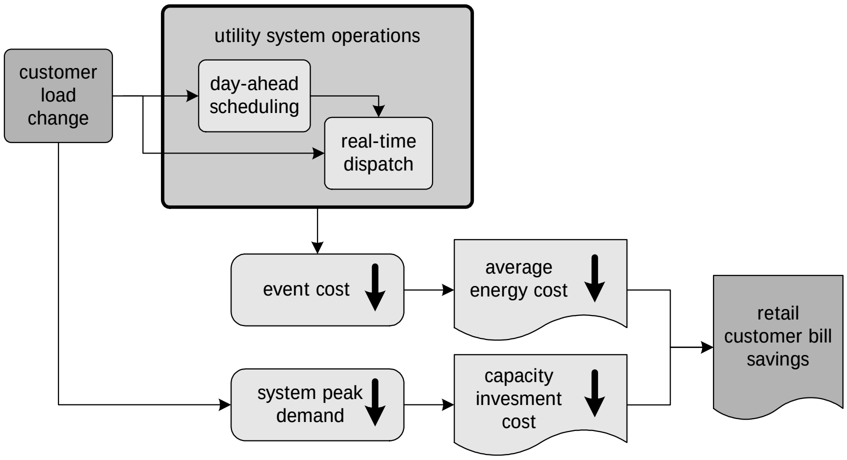


Figure B-4. Market Impacts of Demand Response for Vertically Integrated Utilities

The utility's return on capacity investments is recovered separately from its marginal costs to produce or purchase electricity and operate the electric grid. Thus, in vertically integrated systems, in the absence of a mechanism to reveal marginal capacity or reliability costs in unit operating costs, the short-term market impacts of demand response are limited to efficiency improvements in operating costs (including energy production and purchase costs) alone.[79]

In the long term, demand response that reduces peak demand growth directly averts the need for utilities to build more power plants, power lines and other capacity-driven infrastructure or to buy new capacity and energy from other suppliers (see Figure B-4). Because capacity investments are usually fully recovered—along with a pre-established return on investment—through higher retail electricity rates, these long-term benefits are realized over a multi-year period and can result in significant savings to consumers.

In vertically integrated, stand-alone utility systems, demand response is most useful to improve generation and transmission asset usage, avoid new capacity construction or purchases, and create more flexibility to assure reliable system operations. This influences the types of demand response programs preferred by vertically integrated utilities, as well as how they value and compensate demand response program participants.

---

[78] The converse is true for increases in load at times when the marginal cost of electricity is lower than the average retail price.

[79] Some utilities quantify the marginal value of reliability in their RTP tariffs quoting hourly prices to participants for changes in their usage from an established base amount; those hourly prices contain an explicit ($/kWh) marginal reliability (outage cost) element to reflect exigent reserve conditions (Barbose et al. 2004)

Market Impacts of Demand Response in Regions with Organized Wholesale Markets

About 60% of U.S. load is served by utilities or load serving entities that operate in regions with wholesale markets administered by ISOs/RTOs. Retail competition is also allowed in many of the states in these regions. These last-price wholesale electric commodity markets pay all competitively dispatched load a price determined by the last successful bid, which also sets the market clearing price. The market clearing price covers operating or production costs for the dispatched load (if each generator bids at least its marginal supply cost). If supply is very tight relative to demand, spot market energy prices will rise as more expensive units set the market clearing price. As a result, all units get the higher price, which includes creating ”scarcity rents” for suppliers with costs below that of the marginal, price-setting unit.[80] Accordingly, spot energy prices serve as signals about whether additional supply- or demand-side capacity investments are needed, and what level of return to expect.

Three organized markets (NYISO, PJM, and ISO-NE) have established capacity payment mechanisms to create an additional stream of revenues for generators to recoup their investment costs. LSEs are required to purchase capacity in these markets to meet the expected peak demand of the customers they serve.

The impacts of demand response in an organized wholesale spot market are depicted in Figure B-5.[81]

The short-term market impacts of specific demand response events can be traced as follows:

- Depending on the timing and type of demand response option, customers’ load changes may be integrated into day-ahead or real-time energy markets [as indicated by the arrows at the top of Figure B-5).
- Reductions in load during high-priced peak periods move marginal usage down the electricity supply curve (see Figure B-3), lowering market clearing prices during the demand response event (the event price in Figure B-5).
- This lowers LSEs’ purchasing costs in the applicable wholesale market during the event. These savings may be captured by the LSE initially, but ultimately a significant share should be passed on to their customers (LSE event energy cost in Figure B-5).[82]

---

[80] This argument assumes that generators must recovery all of their revenue requirements and variable running costs, from energy sales at spot market prices. Some markets impose capacity requirements on LSEs that constitute a form of investment cost recovery for generators selling in those markets.

[81] The Midwest ISO (MISO), ERCOT and the California ISO (CAISO) all do not operate capacity markets.

[82] In some states, public utility commissions have adopted tariffs that specify the percent of savings that a regulated LSE providing default service must pass on to their customers. Eventually, competitive pressures should motivate LSEs to pass a significant portion of purchase cost savings to their customers.

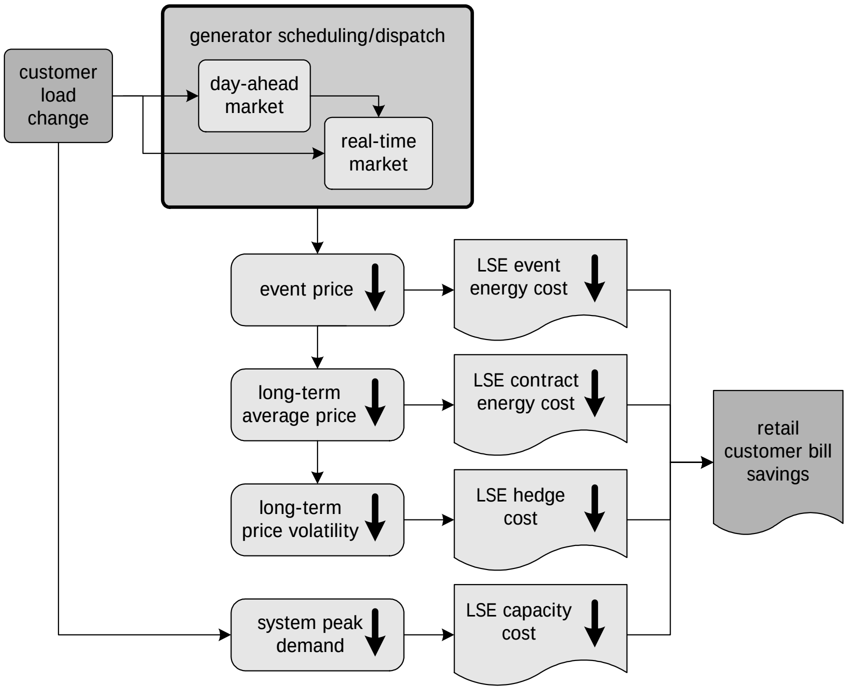


Figure B-5. Market Impacts of Demand Response in Regions with Organized Wholesale Markets

In regions with organized spot markets, demand response can produce cascading positive market impacts in the medium or long-term, realized over months or years (see Figure B-5):

- Reduced average market clearing prices can reduce forward contract costs for LSEs; these savings are then passed on to their customers (LSE contract energy cost in Figure B-5)
- Reduced volatility in market clearing prices puts downward pressure on risk premiums incorporated into hedged pricing products offered by competitive LSEs (LSE hedge cost in Figure B-5) and may lower transaction prices
- Lower forecast peak demand, resulting from demand response, also reduces LSEs' capacity acquisition requirements (LSE capacity cost in Figure B-5).

Long-term market impacts are less clear in organized wholesale and competitive retail markets compared to a vertically integrated utility system. A vertically integrated utility is allowed to directly pass through its capacity investment to customers in rates and likely most of its purchased energy and capacity costs as well; savings realized from demand response that avoids "uneconomic" investments or expenditures for peaking capacity are a direct source of cost savings to customers. In contrast, in organized spot markets, investment risk for new resources is assumed by the private sector. The combination of lower market clearing prices and reduced capacity requirements will dampen capacity investment signals, which should reduce construction of unneeded new power plants.

In summary, because organized spot markets use energy market clearing prices to pay generators for operating, but often only a fraction of the committed capacity costs, the long-term capacity savings benefits of demand response may not be fully monetized and paid to demand response providers. Because the spot market valuation of demand response is linked to wholesale market clearing prices (for energy and capacity) rather than avoided capacity costs, this creates different payment streams and priorities between the two market structures. Policymakers need to recognize these differences in designing demand response options and evaluating benefits derived from market impacts under these different market structures.

Reliability Benefits

In addition to improving the efficiency of electricity markets, demand response can provide value in responding to system contingencies that compromise the dispatcher's ability to sustain system-level reliability, and increase the likelihood and extent of forced outages. Electric systems in the U.S. conduct long-term planning exercises to specify the level of resources required to serve the system's anticipated maximum load reliably in the long term. Typically, planning reserve margins are 15-18% of historic maximum system demand.

System operators arrange for some of the available generation resources to serve as reserves to cover real-time load-serving requirements and avoid outages; operating reserves of 5-7% of forecast demand must be maintained at all times. The system operator typically uses standby generators, ready to be run in less than 30 minutes, to deal with abrupt changes in load or unexpected loss of generator or transmission availability. Demand-response based load reductions can be used to replace some of this stand-by generation to rebalance load and supply.

Demand response can supplement system reliability by providing load curtailments that help restore reserves, providing incremental reliability benefits to the system.[83] Customers participating in emergency demand response programs receive incentive payments for reducing load when called upon by the system operator. They receive no up-front capacity payments in some program designs because they are not counted on as system resources for planning purposes. Instead, they are supplemental resources, the need for which is not foreseeable, or even likely, but possible. They represent an additional resource for reliability assurance, distinct from capacity-based demand response programs (see the textbox below).

---

[83] The capacity they provide can be particularly valuable if located in what operators call "load pockets", localized areas with a shortage of available resources to serve load when a generator is out of service.

Roles of Capacity and Emergency Demand Response Programs

Emergency demand response programs provide benefits distinct from capacity-based demand response programs. In capacity programs, customers are paid incentives based on the avoided cost of new generation capacity and are counted among planned reserves. As such, they become part of the overall portfolio of resources assembled to meet system reserve requirements. Capacity-based demand response does not provide incremental system reliability—it supplants conventional resources in meeting established reliability goals, simply replacing what a generator that was not built would have provided.

In contrast, emergency demand response programs provide incremental reliability benefits at times of unexpected shortfalls in reserves. When all available resources, including capacity demand response programs, have been deployed and reserve margins still cannot be maintained, curtailments under an emergency demand response program reduce the likelihood and extent of forced outages. Load curtailments under emergency demand response programs are therefore valued according to their impact on system reliability.[84]

System operators generally dispatch emergency demand response programs only after exhausting all available capacity and operating reserves. When operating reserves are called upon to go from standby status to actually producing energy to serve load, the level of remaining operating reserves drops if additional replacement resources are not available. This is analogous to a consumer drawing down savings to pay an unexpected bill, leaving them more vulnerable to consequences from further unanticipated expenses.

System operators can reduce this vulnerability by asking emergency program participants to curtail load, thereby reducing system demand and operating reserve requirements. This means that some generating resources can revert to their standby status and be ready for another contingency event, and can be likened to a cash infusion to restore savings in the consumer analogy. The curtailment allows the operator to maintain reliability at prescribed or target levels (Kueck et al. 2001). At the margin, this form of demand response provides value, although it is not priced in any market.

Figure B-6 illustrates this impact, and provides a way to estimate these reliability benefits. The portrayed system has been scheduled to provide D_1 units of energy (including required reserves) at a price of P_1 at a specific time.[85] As the delivery time approaches, a system contingency arises that effectively pushes the supply curve to the left (e.g., a generator outage) or customer demand to the right (e.g., an unexpected surge in demand, as portrayed in the figure by the move from D_1 to D_2), so that supply and demand no longer intersect. This reserve shortfall is represented by the demand curve D_2. Activating an incentive-based demand response program initiates customer demand reductions that bring system demand back to D_1, thereby eliminating the reserve shortfall.

---

[84] It is possible that an emergency demand response program, while not explicitly designed to fulfill capacity requirements , may nonetheless be capable of providing some level of capacity benefits as well.

[85] In this example, customer demand is represented by a vertical line, because in a reliability event, which occurs within minutes or seconds of power delivery, demand may be viewed as fixed.

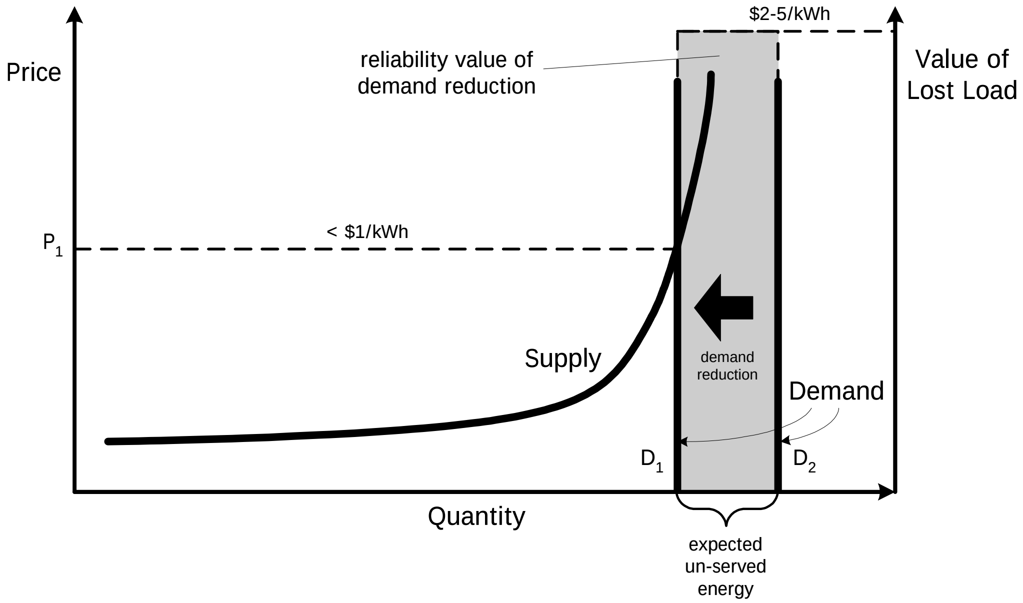


Figure B-6. Valuing the Reliability Benefits of Demand Response

While the price of served energy is determined by market conditions (P_1 in Figure B-6), the value of the demand reduction is defined by the decreased likelihood of a forced outage. Economists define the concept of *value of lost load* (VOLL) as the proper measure of improved reliability, since it reflects customer's marginal value for electricity under these circumstances. The product of VOLL and the *expected un-served energy* (EUE), the load that otherwise would not have been served, monetizes the value of the load curtailments (see the textbox below). This is represented by the shaded rectangle in Figure B-6 in the case where the curtailed load corresponds exactly to the amount of expected un-served energy.

Emergency demand response programs can provide low-cost, incremental resources to preserve reliability in various market structures; at present, the most prominent examples are implemented by the Northeast ISOs.

Value of Lost Load and Expected Un-Served Energy

"Value of lost load" (VOLL) is a measure of how customers value electric reliability, or what they would be willing to pay to avoid a loss of service. It varies among customers but is almost always greater than the retail price of electricity because customers incur costs from being disconnected without notice. Customer values factored into VOLL include inconvenience or discomfort, loss of sales or productivity (e.g., at retail premises or factories), large cleanup and restart costs (e.g., at pharmaceutical companies), and overtime costs to make up for lost production. Given the wide range of customer circumstances and difficulties in predicting which customers will be affected by a particular outage, the accepted industry practice is to adopt a VOLL of $2-5/kilowatt-hour (kWh), which represents an average value across the entire market.

"Expected un-served energy" (EUE) is a measure of the magnitude of a reserve shortfall. It takes into account the change in the likelihood of a curtailment and the consequences of such an event: how much load would have been forced off-line by dispatchers in such circumstances if the curtailments had not been undertaken. NYISO concluded that during the service restoration effort following the 2003 northeast blackout, demand response curtailments reduced forced outages kWh for kWh, because they enabled smoother service restoration. However, under other, less extreme conditions, curtailments were found to produce less than proportional reductions in EUE (NYISO 2003).

APPENDIX C. INTENSITY OF CUSTOMER DEMAND RESPONSE

This Appendix summarizes DOE's review of selected studies that have attempted to quantify the intensity of customer response to time-varying prices and demand response programs. First, different types of price elasticity used to measure demand response intensity are introduced. Next, the results of studies that estimated price elasticities for large and small customers exposed to time-varying rates are summarized. Some studies have examined the demand response intensity of programs targeting demand response-enabling technologies; these results are compared next. Finally, the results of studies that estimated load impacts from direct load control programs are summarized.

Indicators of Demand Response Intensity

For rate options and demand response programs that elicit load modifications directly in response to price changes, the intensity of customers' demand response is typically expressed in terms of their *price elasticity* (see the textbox below). Price elasticity provides a normalized measure of the intensity of customers' load changes in response to price circumstances. In analyzing price response, it is important to not confuse reported own-price and elasticity of substitution values. *Own-price elasticity* is defined as the percentage reduction in electricity usage in response to a one percent increase in the price of electricity. In analyzing price response among large industrial and commercial customers, it is common instead to estimate the *elasticity of substitution*, which measures the propensity of customers to shift electricity usage from peak to off-peak periods in response to changes in relative peak and off-peak prices. The substitution elasticity is defined as the percentage change in the ratio of peak to off-peak electricity usage in response to a one percent change in the ratio of off-peak to peak electricity prices. Various factors may influence customers' price elasticity, including the nominal level of prices. For example, some customers may be relatively unresponsive when prices are low but find it worthwhile to reduce load at very high prices. This characteristic of price elasticity has important implications for the design and evaluation of time-varying pricing and demand response programs.[86]

For DLC programs or other types of demand response programs where customers are not directly responding to a price, the intensity of customers' response is typically measured in terms of an absolute or relative load impact (e.g., kW or percent load reduction).

---

[86] If price response increases with relative prices, then it is important to account for this factor when estimating how customers will respond to prices or to a demand response program incentive. A specific price threshold may be necessary to obtain a significant response among a group of customers.

Price Elasticity: Insights and Sources of Confusion

Price elasticity is a normalized (for the relative price change) measure of the intensity of how usage of a good (in this case electricity) changes when its price changes by one percent. It facilitates a comparison of the intensity of load changes among customers since the price change has been factored out; the price elasticity is a relative measure of response. For example, Customer A, with an elasticity of 0.25, responds to the same relative price change much more than Customer B, who has an elasticity of 0.05 (i.e., five times more relative to the customer's usage level). But, not five times greater than another customer in absolute terms, unless they have exactly the same load. This highlights the relative comparison of intensity that a price elasticity response provides; the basis is each customer's load. Consequently, some studies prefer to report and compare customers' actual percentage changes in load. This is insightful, as long as the load changes were in response to the same change in prices.

A potential source of confusion comes from differences in how price elasticity is reported. Some analysts report the *own-price elasticity*, which is expected to be negative, since a one percent increase in price would be expected to cause usage to go down, all other things equal. It is a useful measure of how customers adjust to increases in the price of electricity by adjusting the consumption of other goods. This is especially useful when evaluating longer-term adjustments to changes in electricity price. Other analysts report the *substitution elasticity*, which takes on only positive values. The substitution elasticity focuses on how consumers substitute one good for another, or goods in different time periods for one another, when relative prices change. Specifically, if the price of electricity varies substantially from one time period to another, and customers can shift usage among those periods, then the appropriate measure of price response is how relative usage changes in those periods. The substitution elasticity is therefore defined as the relative change in usage in the two periods (e.g., the ratio of the peak to off-peak usage) for a one percent change in the relative prices in those periods (the ratio of the off-peak to peak price). Note that the price term uses the inverse price ratio, which is why substitution elasticities are positive (e.g., a higher peak price decreases the off-peak to peak price ratio, causing peak load to be reduced and therefore the peak to off-peak load ratio to decline).

On an absolute value basis, ignoring the sign, own-price and substitution elasticities are similar in that they both measure relative changes, so a value of zero corresponds to no change in usage regardless of the change in price (i.e., perfectly price inelastic), and absolute values progressively greater than zero indicate relatively higher price response. They are roughly similar measures of intensity on a nominal basis—a substitution or an own-price elasticity of 0.50 both indicate relatively high changes in load in response to price changes. But because these two elasticity values measure a different characterization of how usage is adjusted to price changes (i.e., price in one period vs. relative prices in two periods), there is no simple way to cross-map reported values. They should be used in the appropriate context: the own-price elasticity when the circumstances involve reduced electricity usage and the substitution when shifting from one time to another characterizes price response.

In this report, substitution elasticities are always reported as a positive number and own-price elasticities as a negative number.

Price Elasticity Estimates

For mass-market (residential and small commercial) customers, there is an extensive price elasticity literature examining the load impacts from TOU rates. Not surprisingly, the estimates produced by these various studies span a wide range, reflecting both methodological differences and situational factors (e.g., related to customer characteristics or program design). Caves et al. (1984) pooled data from five residential TOU pilots implemented in the U.S. in the latter half of the 1970s (see Table C-1). The average elasticity of substitution derived from this pooled data set was 0.14, but elasticities varied by a factor of three, from 0.07 to 0.21, depending on the household's electric appliance holdings (Faruqui and George 2002). King and Chatterjee (2003) reviewed price elasticity estimates from 35 studies of residential and small commercial customers published between 1980 and 2003. They report an average own-price elasticity of –0.3 among this group of studies, with most studies ranging between –0.1 and –0.4. Several studies have also examined the intensity of residential (and small business) customers' response to CPP and RTP tariffs and isolated the affect of various factors and customer circumstances. A recent study at Commonwealth Edison in Illinois of the first residential RTP pilot in the U.S. found notably lower demand response intensity than has been observed for small customers; own-price elasticities were –0.04 in 2003 and –0.08 in 2004 (Summit Blue Consulting 2005). However, the weather during these two summers was unseasonably cool and A/C usage and hourly prices were correspondingly low, which suggests that the price response may be higher under more extreme conditions.

An evaluation of a recent residential CPP pilot in California estimated a statewide average elasticity of substitution of 0.09 on critical peak days occurring between July and September and reported that the average statewide reduction in peak period energy use on critical peak days was about 13% (Faruqui and George 2005).[87] However, the elasticity varied by more than a factor of three across five climate zones, reflecting regional trends in temperature and A/C saturation (which varies from 7% to 73% of households). The study also found substantial differences between customers' price elasticities during the hotter summer months (July—September) and during the shoulder months of May, June and October—also indicative of differences in A/C usage.

Information on the price elasticity of large commercial and industrial (C&I) customers is based primarily on studies that examined customers' response to RTP. These studies have employed several types of demand models producing different types of price elasticity measures and have examined variations with time of day, price level, and customer characteristics (e.g., business type, presence of onsite generation, number of years on RTP).

---

[87] Impacts varied across climate zones, from 7.6% in the relatively cool coastal climate zone (e.g. which includes San Francisco) to 15.8% in inland, hot climates of California (Faruqui and George 2005).

Table C-1. Demand Response Program and Pricing Studies: Estimated Price Elasticity of Demand

Type of Program	Target Market	Region (Utility)	Demand Response Impact (average per customer)	Comments
TOU	Residential	U.S (utilities in five states)	Elasticity of Substitution **0.14** average; **0.07** to **0.21** range depending on electric appliance holdings	Pooled results from five residential TOU pilots in the late 1970s. Sources: Caves *et al.* (1984) and Faruqui and George (2002).
TOU/ CPP	Residential and Small Commercial	U.S. and International (various utilities)	Own-Price Elasticity **-0.3** (average of 35 studies); **-0.1** to **-0.8** range across the studies	The authors calculated the simple average of own-price elasticity estimates from 35 studies of TOU or CPP. Source: King and Chatterjee (2003)
CPP	Residential	California (PGE, SCE, SDG&E)	Elasticity of Substitution **0.09** average (July-Sept.); **0.04** to **0.13** range across climate zones	Population of about 1,000 residential customers, including control groups, in 2003/4 California Statewide Pricing Pilot. Elasticity range across climate zones attributed to differences in A/C saturation (7-73%). Source: Charles River Associates (2005)
Day ahead RTP	Residential	Illinois (Com Ed, Community Energy Cooperative)	Own-Price Elasticity **-0.04** average (2003); **-0.08** average (2004); **-0.05** to **-0.12** range across customer segments (2004).	Population of about 1,000 customers in 2004; $0.12/kWh maximum hourly price. Own-price elasticities were reported for six different customer segments defined in terms of housing type (single- or multi-family) and A/C equipment type (window, central, or none). Source: Summit Blue Consulting (2005)
	Med./Large C&I (>200 kW)	Georgia (Georgia Power)	Own-Price Elasticity **-0.01** to **-0.28** range across customer segments and hourly price levels	Population of about 1,600 customers. Elasticities were estimated for seven different customer segments at four different price levels, ranging from $0.15 to $1.00/kWh. Source: Braithwait and O'Sheasy (2002)
	Med./Large C&I (>100 kW)	U.K. (Midlands Electric)	Hourly Own-Price Elasticity **-0.01** to **-0.27** range in maximum hourly elasticities, across customer segments	Population of about 500 customers, most with peak demand >1 MW. Hourly own-price and substitution elasticities were calculated for each of five different industry classifications. Source: Patrick and Wolak (2001)
	Large C&I (>1 MW)	North and South Carolina (Duke Power)	Average Peak-Period Own-Price Elasticity **< -0.01** to **-0.38** range across customers	Population of about 50 customers, some with 8 years experience on RTP. Hourly own-price were calculated for each customer, and averaged over the peak period (2:00-9:00 p.m.). Source: Taylor *et al.* (2005)
	Large C&I (>1 MW)	Southwest U.S. (Central and Southwest Services)	Elasticity of Substitution **0.10 to 0.27** range across customer segments and definitions of the peak period	Population of 54 customers, segmented into two groups, with firm day-ahead hour-ahead notice of hourly prices. Elasticities estimated for each group and for different definitions of the peak period. Source: Boisvert *et al*. (2004)
	Large C&I (>2 MW)	New York (Niagara Mohawk)	Elasticity of Substitution **0.11** (average); **0.02** to **0.16** range across customer segments	Population of about 150 customers. Individual customer elasticities vary substantially within sectors: e.g., most manufacturing customers are either highly responsive or not at all. Source: Goldman *et al*. (2005)

Note: Elasticity values are the averages of all participants' elasticity at all price levels, unless otherwise noted. Elasticity of substitution values are for intraday substitution between peak and off-peak periods, while own-price elasticities are the average value, unless noted as hourly.

Braithwait and O'Sheasy (2002) analyzed data from participants in Georgia Power's RTP program, the largest in the country. The authors estimated own-price elasticities for seven different business customer segments and examined differences across hourly price levels. Most customer segments exhibited larger price elasticities at higher prices. The most responsive customer segment was a group of very large industrial customers (peak demand > 5 MW) who, in exchange for slightly lower base rates, had opted to receive notification of hourly prices on an hour-ahead (rather than day-ahead) basis. This group exhibited a price elasticity of –0.18 to –0.28 across the range of reported prices ($0.15/kWh to $1.00/kWh), which was double the elasticity of any other group. The least responsive customer segments, consisting of smaller C&I customers that neither had onsite generation nor had previously participated in the utility's curtailable rate, exhibited price elasticities of –0.06 or lower at all price levels.

A study of about 150 large customers at Niagara Mohawk estimated an average substitution elasticity of 0.11 among those that faced day-ahead hourly prices (Goldman et al. 2005). However, the average elasticity varied substantially across business categories (e.g., average elasticities were 0.16 for manufacturing customers, 0.10 for government/education customers, and 0.02 for health care facilities) and even more within them (e.g., half of the industrial customers were very inelastic, and half were relatively elastic).

Studies of the large C&I RTP programs offered by Duke Power and Midlands Electric (in the U.K.) estimated average hourly own-price and substitution elasticities (Taylor et al. 2005, Patrick and Wolak 2001). Both studies found a substantial range in own-price elasticity values over the course of the day and among customers. Among the 50 or so participants in Duke's program, the average hourly price elasticity during peak period hours ranged from less than –0.01 to –0.38. This study also concluded that many large C&I customers exhibit complementary electricity usage across blocks of afternoon hours. That is, high prices in one hour result in reduced usage in that hour as well as in adjacent hours. This is consistent with industrial batch process loads that, once started, must continue for a specified period, and with other business practices that exhibit similar relationships (e.g., rescheduling of labor shifts). Usage in many other hours of the day was found to be a substitute to the afternoon hours. The study of Midlands Electric's customers also found substantial variation in the magnitude and hourly pattern of price elasticity among different industrial classifications. Customers in the water supply industry were the most price-responsive, with a maximum hourly own-price elasticity of –0.27, while all of the other industrial classifications in the participant population exhibited price elasticities of less than –0.05 in all hours.

Impact of Enabling Technologies on Price Response

A small number of utilities have offered pilot programs targeted at mass market customers that integrate CPP with enabling technology, specifically load control devices that receive price signals and can be programmed by customers to reduce A/C or other loads during critical peak periods (see Table C-2).

Table C-2. Load Response from Enabling Technologies in Combination with CPP

Enabling Technology	Target Market	Region (Utility)	Demand Response Impact (average per customer)	Comments
Thermostat reset	Residential	California (SDG&E)	**0.64 kW** (**27%**) average peak period load reduction on critical peak days; **0.4 kW** attributed to enabling technology.	2003/2004 pilot program with about 220 residential customers and about 235 C&I customers, including control groups. Customers had “smart thermostats” that could be programmed to raise the temperature set point during critical peak periods. Analysis distinguished between enabling technology and behavioral components of price response. Peak period prices on critical peak days averaged $0.65/kWh for residential customers, $0.87/kWh for customers with <20 kW peak demand and $0.71/kWh for larger C&I customers. Source: Charles River Associates (2005)
	Small/Med. C&I (<200 kW)	California (SCE)	Customers with <20 kW peak demand: **0.95 kW** (**14%**) average peak period load reduction on critical peak days; attributed entirely to enabling technology. Customers with 20-200 kW peak demand: **3.1 kW** (**14%**) average peak period load reduction on critical peak days; **2.5 kW** attributed to enabling technology.	
Control of multiple loads (A/C, heat pump, water heater, pool pump, and/or appliances)	Residential	New Jersey (GPU)	Elasticity of Substitution **0.3** (average)	Pilot program results from summer 1997. Critical peak price was $0.50/kWh. Source: Braithwait (2000)
	Residential	Florida (Gulf Power)	**2.7 kW** (**41%**) average load reduction during critical peak periods	Estimated response from current *GoodCents Select* program. Source: Borenstein *et al*. (2002).
	Residential	Upper Midwest (AEP)	Winter: **3.5-6.6 kW** Summer: **1.5-2.0 kW**	Pilots conducted at three AEP utilities in the early 1990s with about 600 customers, including control groups. Critical peak price ranged from $0.15-$0.29/kWh among the three utilities. Source: Levy Associates (1994)

An evaluation of the recent Statewide Pricing Pilot in California sought to quantify the incremental impact of this type of technology on customers’ demand response. Groups of residential and small commercial participants in this pilot faced CPP and had “smart thermostats,” which customers could pre-program to automatically raise their temperature settings by a specified number of degrees during critical peak periods. The statistical model used in the evaluation decomposed these customers’ total load reduction during critical peak periods into a “technology component” (i.e., the portion of the load reduction attributable to use of the smart thermostat) and a “price component” (i.e., the portion attributable to manually-implemented actions). The average load reduction by residential customers with smart thermostats during critical peak days was approximately 0.64 kW, approximately two-thirds of which was attributed to use of the smart thermostat. Among small business customers, the relative impact of the enabling technology was even more pronounced.

A handful of utilities elsewhere in the U.S. have implemented residential CPP pilots in which participants were provided with thermostats that they could program to control their A/C and other appliances (pool pumps, heat pumps, and electric water heaters) during critical peak periods. Studies of these programs have typically found that participants exhibited a relatively high intensity of demand response. For example, an analysis of GPU's pilot (in New Jersey) measured a substitution elasticity of 0.3, which is higher than most elasticity of substitution values estimated from residential TOU pilots (Braithwait 2000). Studies at Gulf Power and American Electric Power (AEP) where multiple loads could be controlled in response to critical peak prices reported that average load reductions among a sample of customers were in the 35-40% range (Levy Associates 1994).

Load Impacts from Direct Load Control

Approximately 180 U.S. utilities (out of the 1,118 investor-owned, municipal, and rural cooperative utilities that reported demand-side management efforts) report that they currently offer residential DLC programs that primarily target specific appliances, such as air conditioners or water heaters, of mass market customers (EIA 2004).[88] Various control strategies (e.g., cycling the device on and off at a specified frequency, shutting the device off, or resetting a thermostat set-point) are utilized during prescribed conditions depending on end use, control equipment vintage, and program design.[89] Several of these programs have conducted relatively recent measurement and evaluation studies with results that are publicly available. In DLC programs, because the utility controls the switch, the customer cannot be said to exhibit price response, per se, although the change in the customer's load is measurable. The most appropriate measure of demand response impact for this program type is simply the average or expected load reduction (in absolute or percentage terms), rather than the price elasticity.

Table C-3 summarizes the measured impact from selected evaluations of DLC programs that targeted customers with air conditioning or water heating load control devices. The results indicate the range of possible load impacts, although the individual values are not readily comparable because of the differences in program design features, cycling strategies, and climate. DLC programs targeting residential A/C have reported load reductions ranging from approximately 0.4 to 1.5 kW per customer over the course of an event. The magnitude of the load reduction per customer can strongly depend on climate, the corresponding level of A/C usage that would occur absent load control, and the control strategy deployed (e.g. 100% shed, duty cycling). Furthermore, when customers have the ability to over-ride the curtailment via their thermostat, the average response per customer has generally been found to decline (sometimes substantially) over the course of each event. Residential water heating DLC programs have yielded load reductions in the range of 0.2 to 0.6 kW per house. The magnitude and timing of the load impact depends on equipment size, ground water temperature and household size and operating use patterns.

---

[88] Demand-side management efforts include energy efficiency and/or load management programs.

[89] In newer DLC programs, particularly those that use thermostat-based controls, customers can typically over-ride curtailments on an event-by-event basis, either by pushing an "over-ride" button on their thermostat, logging onto a program website, or calling the utility. If they do over-ride a curtailment event, customers typically forfeit a portion of their incentive payment or are charged a penalty.

Table C-3. Direct Load Control Programs: Estimated Load Impacts

Type of Program	Target Market	Region (Utility)	Demand Response Impact (average per customer)	Comments
A/C temp. reset (with over-ride option)	Residential	SDG&E	**0.44 kW** (average); **0.10-0.81 kW** (range over 12 events)	Sample of about 100 customers (including control group) with 12 test events in summer 2004. Source: KEMA-Xenergy (2004)
A/C cycling (with over-ride option)	Residential and Small Commercial	New York (LIPA)	**0.75-0.91 kW** (residential) **1.01-1.43 kW** (small commercial)	Ranges in average hourly load reductions over a single event day with 50% cycling. Based on 12,000 residential customers and 2,000 commercial customers. Source: Lopes (2004)
A/C cycling (no over-ride option)	Residential	Minnesota (Xcel Energy)	**1.27 kW**	Based on interval metering at large number of customer sites; 50% cycling frequency. Source: Xcel Energy (2004)
		California (SMUD)	**0.71-1.59 kW**	Pilot program results from summer 2002. The lower bound corresponds to a cycling frequency of 33% and outdoor temperature of 96-100° F; the upper bound corresponds to a cycling frequency of 66% and an outdoor temperature of >100° F. Source: Violette and Ozog (2003).
		Kentucky (LG&E, KU)	**0.52-1.12 kW**	Interval metering measurements at 20 customer sites. The lower bound corresponds to a cycling frequency of 33% and outdoor temperature of 90-95° F; the upper bound corresponds to a cycling frequency of 66% and an outdoor temperature of >95° F. Source: Violette and Ozog (2003).
		Maryland and D.C. (Pepco)	**0.96 kW** (MD) **0.76 k**W (DC)	Measured impact for hour ending 17:00, based on 20-year average system peak day weather; 43% cycling off strategy. Source: Horowitz (2002)
Electric water heater cycling		Oregon (PGE)	**0.65 kW**	Load reductions measured at 0800. Source: PGE (2004)
		Maryland (BGE)	**0.2 kW** (at 5 PM) **0.3 kW** (at 7 PM)	Load reductions measured at 1700 and 1900. Source: BGE (2002, 2003)

APPENDIX D. STANDARDS, PROTOCOLS AND PRACTICES FOR ESTIMATING THE BENEFITS OF DEMAND RESPONSE

In Section 4 of this report, DOE offers several recommendations on establishing standardized methods and protocols and enhancing practices for estimating the benefits of demand response. This Appendix provides further discussion that supports these recommendations.

> *1. DOE recommends that stakeholders collaborate to adopt conventions and protocols for estimating the benefits of demand response and, where appropriate, develop standardized tests that evaluate demand response program potential and performance.*

Policymakers and industry participants should develop standardized tests that are applicable and appropriate for the evaluation and cost-effectiveness screening of demand response resources. Standard Practice Manual (SPM) tests are widely used among state regulatory commissions and utilities to evaluate and screen energy efficiency programs (CPUC 2001).[90] Historically, a number of states and utilities have also used these tests for cost-effectiveness screening of load management programs and, recently, there have been some efforts to modify the SPM tests to enhance their usefulness for evaluating demand response resources in the context of competitive wholesale markets (CPUC 2003; Violette et al. 2006, Orans et al. 2004). However, there is general consensus that a more comprehensive evaluation framework is needed to fully capture the benefits of demand response (PIER DRRC, 2005).

Some of the challenges in developing standardized tests appropriate for demand response are revealed by comparing energy efficiency and demand response resources. While it is relatively straightforward to identify and estimate the peak demand and energy reduction impacts of energy efficiency, this is much more difficult for most demand response options. Because most demand response options are relatively new, our ability to predict program participation rates and assess how specific program designs and dynamic pricing affect customer behavior is still rudimentary.[91] Moreover, many forms of demand response turn on behaviors that are price- or incentive-driven, and may change in response to changing market circumstances. Uncertainties in estimating demand response impacts over a multi-year period mean that demand response benefit (and cost) estimates are equally uncertain.

---

[90] The SPM describes several tests that evaluating demand-side management programs from various perspectives: Participant Test, Ratepayer Impact Measure (RIM) Test, Total Resource Cost (TRC) Test, and Program Administrator (formerly Utility) Test.

[91] Load reduction impacts are well characterized for residential DLC programs that have operated for many years, although there have been issues in determining the extent to which customers remove load control switches or over-ride load curtailments. For interruptible/curtailable programs, little information exists from which long-term performance can be predicted. For thermostat-based programs, limited information gathered through several large pilots is available to shed light on customer behavior. For optional RTP tariffs, substantial evidence shows that customer attrition can be a significant problem when major price shocks occur.

In contrast, 15-20 years of implementation experience and tens of millions of dollars spent evaluating energy efficiency programs has produced well-developed methods for forecasting market penetration and estimating first-year energy savings, expected economic lifetime and the persistence of savings for most energy-efficiency measures and programs. This task is further eased because most energy efficiency measures produce savings that are not dependent upon customer behavior.

The SPM tests, which use avoided costs to characterize benefits, have shortcomings in the way in which they characterize the value of demand response to the electric system and customers. Despite recent advances, these tests are not well suited to estimating the value of dispatchable demand response resources. For example, SPM tests have limited ability to reflect the value of capacity in critical peak hours, and the potential of demand response to mitigate episodic, high spot market prices is therefore undervalued. Other aspects of demand response benefits, such as quick ramp-up (relative to constructing new generation resources), and reliability benefits, are also not captured by SPM tests. A more comprehensive analytic framework is needed to fully evaluate and assess the benefits of demand response. At present, summarizing the benefits and costs for some types of demand response resources by means of a standardized test may be premature.

> *2. DOE recommends that these protocols: (1) clarify the relationships and potential overlap among categories of benefits attributed to demand response to minimize double counting, (2) quantify various types of benefits to the extent possible, and (3) establish qualitative or ranking indices for benefits that are found to be too difficult to quantify.*

Policymakers and analysts assessing the merits of demand response mechanisms need to clarify the relative importance of benefits that are difficult to quantify.

Some demand response advocates allude to benefits, such as market power deterrence, risk mitigation and avoided pollutant emissions—that are not quantified but are presumed to be substantial (PLMA 2002; NEDRI 2003; Violette et al. 2006).[92] Not only are such benefits difficult to quantify, but care must be taken to avoid double-counting benefits from other sources (e.g., market-power reduction benefits must be disentangled from other market price impacts). Parties seeking to justify greater expenditures on demand response often assert the existence of such benefits. Policymakers, however, are often wary of including these benefits as criteria for designing policies to foster demand response. Research to determine the magnitude of these impacts and to develop methods for quantifying or incorporating them into benefit/cost analyses, without double counting, is needed.

> *3. DOE recommends that FERC and state regulatory agencies work with interested ISOs/RTOs, utilities, other market participants, and customer groups to examine*

---

[92] These non-quantified demand-response benefits are discussed in more detail in section 3 (see *Other Benefits*).

> *how much demand response is needed to improve the efficiency and reliability of wholesale and retail markets.*

It is appropriate for state and regional policymakers to ask how much demand response is sufficient for their specific market structure and system conditions. A number of demand response studies confirm that a little demand response can go a long way towards improving the efficiency and operations of electricity markets, both in theory and practice. However, existing studies do not address how to identify optimal, or target, levels of demand response in specific market settings. Initiatives should be launched at the appropriate market level (e.g. state or region) to establish relevant goals and appropriate targets for demand response.

As part of the process of determining how much demand response is needed, it is also important to address the appropriate mix of different types of demand response options (e.g. emergency demand response programs, direct load control, time-varying pricing) and any timing issues related to demand response resource deployment and ramp-up (Violette et al. 2006). Although this is not a problem today given the low participation rates in dynamic pricing and demand response programs, it is important to acknowledge that there may be a potential for diminishing returns in the value of demand response beyond certain levels of saturation. For example, the level of price-based demand response is somewhat self-limiting—if at some point demand response becomes widespread, customers may find that their savings from load response actions deteriorate as the impact of their collective response on market prices grows.

> *4. DOE recommends that regional planning initiatives examine how demand response resources are characterized in supply planning models and how the benefits are quantified. More accurate characterization of certain types of demand response resources may require modifications to existing models or development of new tools.*

Resource planning methods currently used to characterize demand response resources are too constraining and rigid to capture the full benefits of all types of demand response resources**.** In vertically integrated systems, long-term resource planning models characterize demand response as a way to avoid generation (and in some cases transmission and distribution) investment costs. Demand response is typically portrayed as a generation unit, which can either be dispatched indiscriminately or with some restrictions on the total frequency or hours of service. This characterization does not fully describe the differences between generation and demand response resources.

Certain types of demand response resources provide benefits that generation cannot. For example, capacity-based demand response programs can provide equivalent capacity to generation investments but with greater flexibility. This is because some types of demand response resources can be implemented more quickly than a power plant can be sited and built, and customers often prefer or are willing to accept a shorter time commitment than is necessary to amortize a power plant.[93] These flexibility benefits are particularly important from a system cost perspective that includes and explicitly accounts for the uncertainties in demand growth or generation unit retirement schedules and costs. Resource planners' avoided cost studies should explore the implications and value of flexible demand response program options as both long-term and short-term operational resources to deal with generation load balance and transmission and distribution adequacy challenges.

Moreover, long-term resource planning models often do not fully recognize or represent the benefits of price-based options such as RTP. RTP ties hourly retail prices to prevailing wholesale market supply costs. To fully account for its potential benefits, RTP should be portrayed as a change in demand in response to prices, not as a resource dispatched to serve demand. Moreover, the RTP prices in tariffs offered by vertically integrated utilities often reflect both marginal supply costs and reliability value of load curtailments. These hour-by-hour impacts, which are carefully measured in ISO/RTO demand response program performance studies, can get overlooked in a long-term resource planning exercise.[94]

On the other hand, peaking generation resources have some characteristics that are more desirable to resource planners than demand response resources. For example, system operators have high confidence that generation resources will come online when needed, whereas customers may decide not to respond when a demand response resource is called. This makes it more difficult to predict the precise amount of available resources on a given day. Another advantage of supply resources is that they can provide certain ancillary services, such as voltage support and re-starting the electrical grid after a blackout, that demand response resources cannot. These considerations should also be incorporated into planning models to appropriately characterize and assess available resources.

> *5. DOE recommends that, in regions with organized wholesale markets, ISOs and RTOs should work with regional state committees to undertake studies that characterize the benefits of demand response under foreseeable future circumstances as part of their regional transmission expansion plans as well as under current market conditions in their demand response program performance studies.*

---

[93] The capacity programs implemented by several ISOs do not involve long-term customer commitments (customers may participate for only a few months if they wish). These programs have demonstrated reasonably predictable and stable performance without putting "iron in the ground"—generation assets whose costs must be recovered over 20 years or more (NYISO 2003). Emergency programs that require no commitment on the customer's part have attracted substantial participation by customers that delivered curtailments on a pay-for-performance basis, and are a potentially cost-effective way to increase system reliability.

[94] Moreover, RTP may result in increased usage during off-peak periods when prices are lower. Increased unit utilization lowers the overall average cost of capital, another important source of benefits that may not be adequately reflected in current study practices.

In regions with organized spot markets, analytic methods focus primarily on assessing the short-term impacts of ISO/RTO demand response programs; more work is needed to assess the potential long-term benefits of demand response resources. ISOs/RTOs that offer demand response programs provide annual performance assessments to FERC that focus primarily on realized, short-term impacts. These assessments provide policymakers, market participants, and customers with information on both the level and distribution of demand response benefits and resource costs.[95] However, in the absence of a forward electricity market that would create a steady stream of guaranteed annual benefits, the value of demand response necessarily depends primarily on current market conditions.

However, ISOs and RTOs can and should provide information on the future value of demand response within their regional markets. Most ISOs and RTOs conduct or coordinate long-range planning studies that focus on developing coordinated system expansion plans that identify projects that can ensure electric system reliability, reduce congestion and also provide market signals for planning and running generation and transmission systems and demand-side management projects (ISO-NE 2005b; PJM Interconnection 2005b). One goal of the studies is to use forecasts of regional load/resource balance to identify needed investments to forestall potential supply shortfalls that could lead to high price volatility. The extent to which demand response is considered in these regional transmission expansion plans is evolving over time. ISOs, RTOs and regional state committees are well positioned to recognize the long-term benefits of demand response and incorporate demand response into their long-term system plans.[96] Another option would be to facilitate a forward market in demand response, as PJM has proposed (PJM Interconnection 2005c).

---

[95] Because benefits can vary from year to year and opportunities to participate are not always available, it is important that load aggregators and customers are made aware of how benefits and costs (i.e., incentive payments) may vary with market circumstances.

[96] Efforts are already beginning in this area. A recent pilot study by ISO-NE that compared the value of RTP and other types of demand response programs under alternative market circumstances was intended to facilitate discussions of this issue among policymakers, ISOs, load serving entities, and customer groups (Neenan Associates 2005).