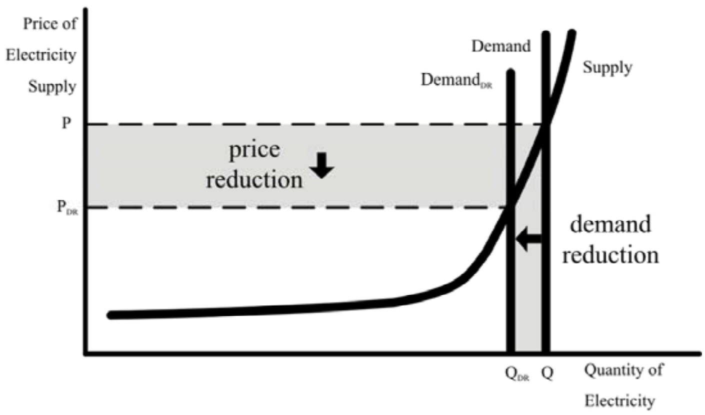
EXCERPT FROM:

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

A REPORT TO THE UNITED STATES CONGRESS



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http://www.electricity.doe.gov/documents/congress_1252d.pdf

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

(Omitted from excerpt)

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

(Omitted from excerpt)

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SECTION 1. INTRODUCTION

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.
- 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

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.[4] 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.

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[4] 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).[5] 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.[6] 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

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[5] 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.

[6] 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.[7]

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).[8] 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

[7] 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).

[8] 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.[9] 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".[10] 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.[11] 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

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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

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[9] 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).

[10] 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.

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

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 2-1). 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.

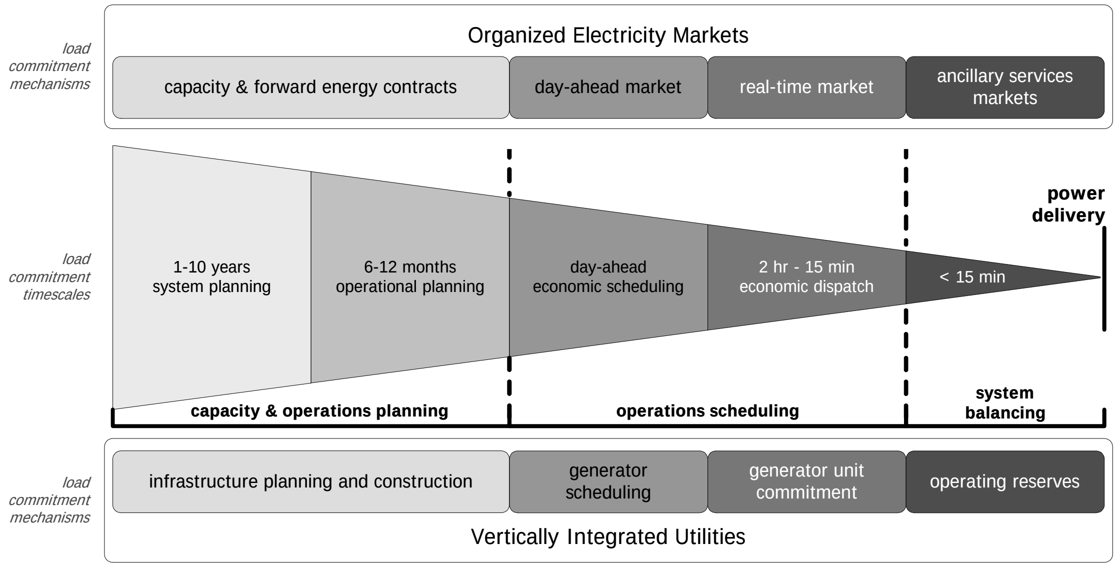

Figure 2-1. Electric System Planning and Scheduling: Timescales and Decision Mechanisms

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 2-1). 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.[12] 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 around which power systems are constructed and managed—occurs in real-time, regardless of when it was committed and priced.

[12] 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.

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 2-2) and can be coordinated with the pricing and commitment mechanisms appropriate for the timescale of their commitment or dispatch.[13] 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 2-2). Though not dispatchable, energy-efficiency measures often create permanent demand-reduction impacts as well as electricity savings.

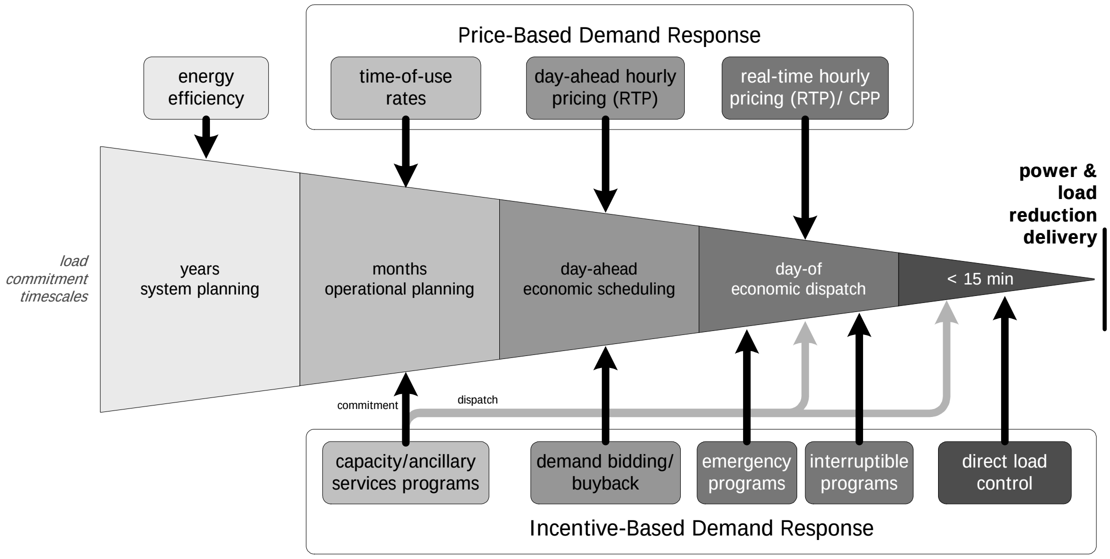

Figure 2-2. Role of Demand Response in Electric System Planning and Operations

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 2-2):

- *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.

[13] 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.

- *RTP* provides hourly prices to customers with day-ahead or near-real-time notice, depending on the tariff design.[14] 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 2-2):

- *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.[15]
- 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.[16]

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

[14] 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).

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

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

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 2-3).

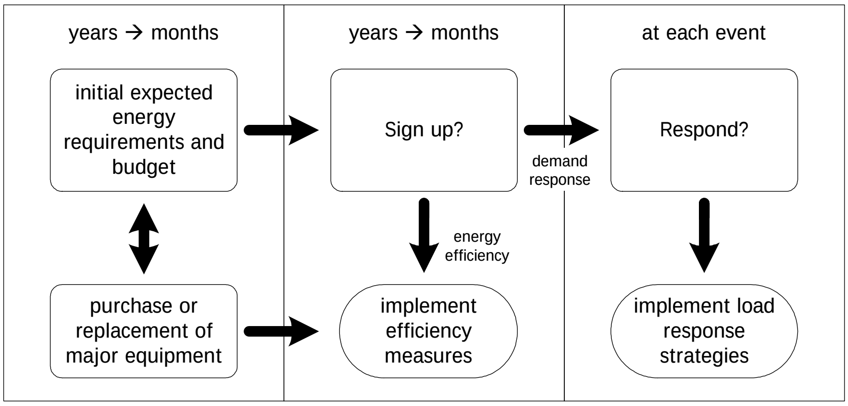

Figure 2-3. Customer Decisions for Demand-Side Management

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 2-4). 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 2-3). 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.[17] 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 2-3). 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.[18] In most cases energy-efficiency measures, once installed, continue to reduce energy usage over a multi-year economic lifetime, usually without much ongoing customer attention.[19] Compared to the initial usage and budget decision, which is

[17] 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.
[18] 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.
[19] 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

relatively simple and familiar to customers, customers' decisions to enroll in demand response programs and to respond during events can be quite complex.

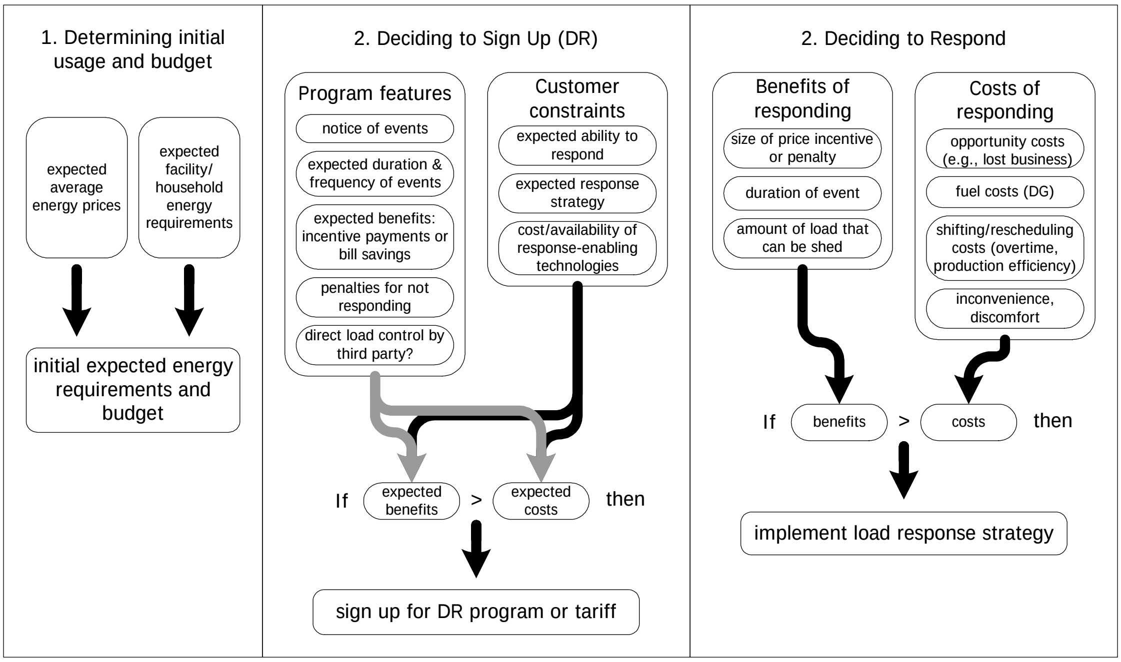

Figure 2-4. Factors Affecting Customer Decisions About Demand Response

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 2-4). 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.[20]

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equipment. Nonetheless, most energy-efficiency investments produce at least some level of savings over a period of years without further customer attention.

[20] 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 2-4). 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.[21]

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.

[21] 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 0-1). 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 0-1. 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 0-1):

- *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 0-1).

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.[22] 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.[23]

[22] Note that for some pricing applications (e.g., TOU rates) only usage by daily pricing period (peak and off-peak) needs to be recorded.
[23] 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.[24]

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).
[24]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 0-2). 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.

<u>Participant Benefits</u>

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 0-2).

- *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.

<u>Collateral Benefits</u>

Demand response, through its impacts on supply costs and system reliability, produces *collateral benefits* that are realized by most or all consumers (see Table 0-2). It is these collateral benefits, which have system-wide impacts, that provide the primary motivation for policymakers' interest in demand response.

Table 0-2. 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.[25]

- *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.[26] 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.[27] 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.

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[25] 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.

[26] 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.

[27] 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.[28] 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.

[28] 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.