- 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.

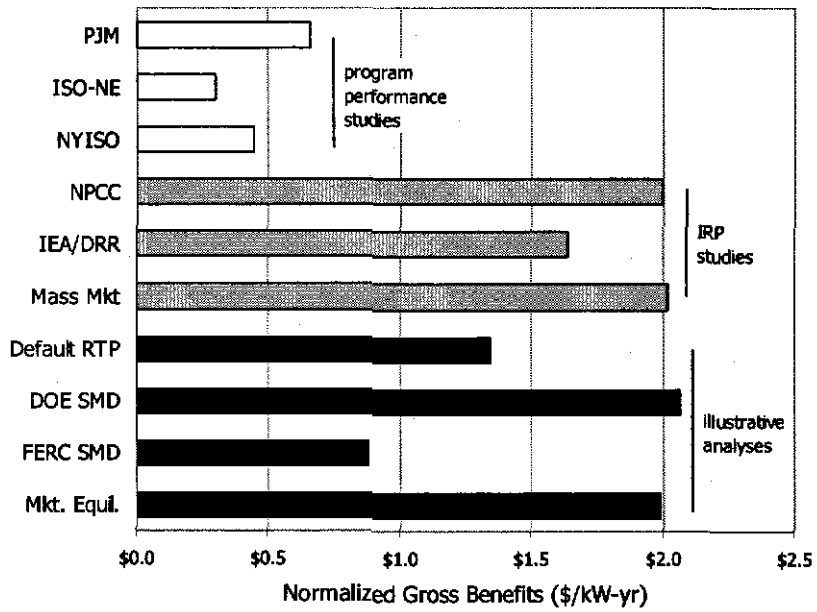


**Figure 4-4. Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies**

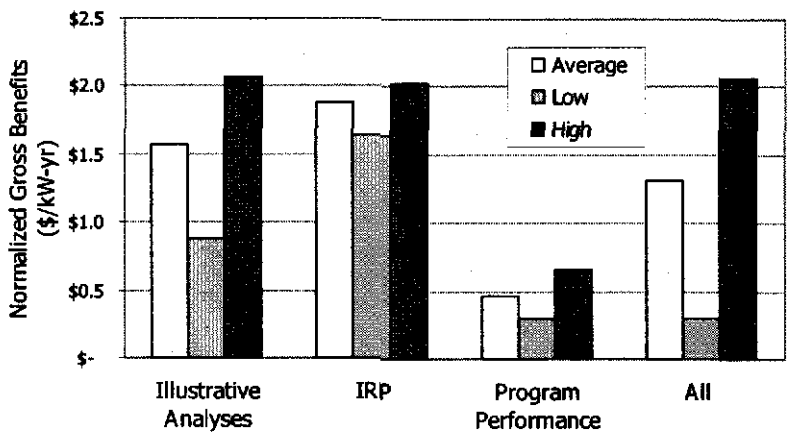


**Figure 4-5. Normalized Gross Demand Response Benefits by Type of Study**

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.*

Medium and Small Business Customers

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