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Via Overnight Mail

July 10, 2009

Public Utilities Commission of Ohio
PUCO Docketing
180 E. Broad Street, 10th Floor
Columbus, Ohio 43215

In re: Case No. 09-535-EL-EEC, 09-536-EL-EEC and 09-537-EL-EEC

Dear Sir/Madam:

Please find enclosed an original and twenty (20) copies of COMMENTS OF THE OHIO ENERGY GROUP IN SUPPORT OF AMENDED APPLICATION filed today in the above-referenced matter.

Copies have been served on all parties on the attached certificate of service. Please place this document of file.

Respectfully yours,

David F. Boehm, Esq.
Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Encl.
Cc: Certificate of Service
Steven Lesser
Greg Scheck
David Blank

CERTIFICATE OF SERVICE

I hereby certify that true copy of the foregoing was served by electronic mail (when available) or ordinary mail, unless otherwise noted, this 10^{TH} day of July, 2009 the following:

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BEFORE THE
PUBLIC UTILITY COMMISSION OF OHIO

In The Matter Of The Energy Efficiency and Peak Demand Reduction Program Portfolio of Ohio Edison Company, The Cleveland Electric Illuminating Company And The Toledo Edison Company	:	**Case Nos.**	**09-535-EL-EEC** **09-536-EL-EEC** **09-537-EL-EEC**

COMMENTS OF THE OHIO ENERGY GROUP IN SUPPORT OF AMENDED APPLICATION

On July 2, 2009 Ohio Edison, Toledo Edison, and Cleveland Electric Illuminating ("Companies") filed an Amended Application which seeks to have the Commission recognize the value of having the ability to interrupt certain industrial load as a legitimate demand response program, without the necessity of actually requiring the industrial consumers to curtail their manufacturing processes. The Ohio Energy Group supports the Companies.

In its March 25, 2009 Order in the Companies' ESP proceeding (Case No. 08-935-EL-SSO) the Commission approved a Stipulation which defined the provisions of the Companies' ESP for the next two years. Attachment B to the Stipulation set forth the terms and conditions for interruptible service. These included:

1) the dollar amount per Kw of capacity available for curtailment to meet system emergencies;
2) the dollar amount per Kw of capacity for curtailment on an economic dispatch basis;
3) the maximum number of hours per year (870) which can be curtailed for economic reasons as well as an economic buy-through provision.

4) a provision which allows economic curtailment only when the MISO day ahead price exceeds 150% of the wholesale price resulting from the ESP competitive bid process;
5) a provision which allocates the cost of the emergency interruptible credits to all consumers; and
6) a provision which allocates the cost of the economic interruptible credits to non-residential rates GS and GP, plus allocating to those rate schedules the revenue received from economic buy-through events.

These very detailed interruptible terms and conditions have subsequently been incorporated into Commission approved tariffs. The winning bids in the ESP competitive bidding process presumably reflected the value of not having to serve the interruptible load during: 1) a system emergency; or 2) when MISO market prices are high. In this way the interruptible load benefited all non-shopping consumers.

The Commission approved ESP Stipulation and resulting tariffs do not allow the Companies to actually interrupt their customers on the days and hours when a system peak is projected to occur in order to qualify as demand response under Revised Code 4928.66 or the Commission's rules. But the interruptible load that was approved in the ESP should be considered as a valid demand response program because the Companies have the ability to curtail for emergency or economic reasons. The costs of buying the ability to curtail load are currently reflected in existing rates, and the value of interruptible load is reflected in the winning bids. If the Companies are forced to implement very costly additional demand response programs such as direct thermostat control of residential air conditioning, then rates to consumers will be unnecessarily increased. Under that scenario consumers will be paying for demand response twice. If the approved interruptible program does not count as demand response and the Companies cannot meet the 2009 mandates and are penalized, then such a penalty would be punitive given the Commission approved ESP Stipulation.

With respect to the merits of the question of whether the ability to curtail (rather than actual curtailment) should count as demand response, the U.S. Department of Energy does not require actual curtailment. On the contrary, the interruptible rate program currently in place as a result of the ESP Stipulation is precisely the type of demand response program that the U.S. DOE believes should be encouraged.

In February 2006 the U.S. Department of Energy issued *"A Report To The United States Congress Pursuant To Section 1252 Of The Energy Policy Act Of 2005"* entitled *"Benefits Of Demand Response In Electricity Markets And Recommendations For Achieving Them."* (Executive Summary attached). According to the Report, demand response can be *"price-based"* (such as real-time-pricing or time-of-use tariffs) or *"incentive-based." "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."* (Executive Summary at V). Incentive-based demand response programs include *"Interruptible/curtailable (I/C) service: curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies."* (Executive Summary at xii). These incentive-based demand response programs (such as interruptible/curtailable service) are *"designed to induce"* reduced usage at times when market prices are high or reliability is jeopardized, but do not necessarily result in actual curtailments at the hour of the system peak. As stated in the Report demand response can be defined more specifically as: *"Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments <u>designed to induce</u> lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."* (Executive Summary at ix, emphasis added).

Finally, the U.S. DOE Report to Congress recognizes that the impact of demand response programs on actual peak reductions is contingent on a number of factors, including whether utilities or grid operators need to call program events. *"Actual peak reductions are affected by the available installed load reduction capability (i.e., the demand response potential), whether utilities or grid operators need to call program events, and the extent to which enrolled participants respond during program events."* (Executive Summary at xiii).

In other words, incentive-based demand response programs such as interruptible/curtailable load are valuable and are to be encouraged, even if interruptions or curtailments are not called at the time of the system peak. The type of incentive-based demand response programs described in the DOE Report are exactly the type of interruptible programs approved in the Companies' ESP.

In the context of today's real world conditions the Companies waiver request is reasonable. We are in the middle of a global recession and electric demand is dramatically down. There is certainly no reliability need for actual curtailments in 2009. Penalizing the Companies for the failure to meet the 2009 demand response requirements when we are in the middle of the summer Peak Season and the ink is hardly dry on the Commission's rules seems unreasonable. Such penalties would understandably foster an attitude in the Companies that *"this will not happen again and we will meet the Commission's demand response requirements in the future no matter how costly the programs will be to consumers."* That would be bad for consumers in the long term.

This Commission has historically struck an appropriate balance between the interests of consumers and utility shareholders. In this matter, FirstEnergy's position is reasonable.

Respectfully submitted,

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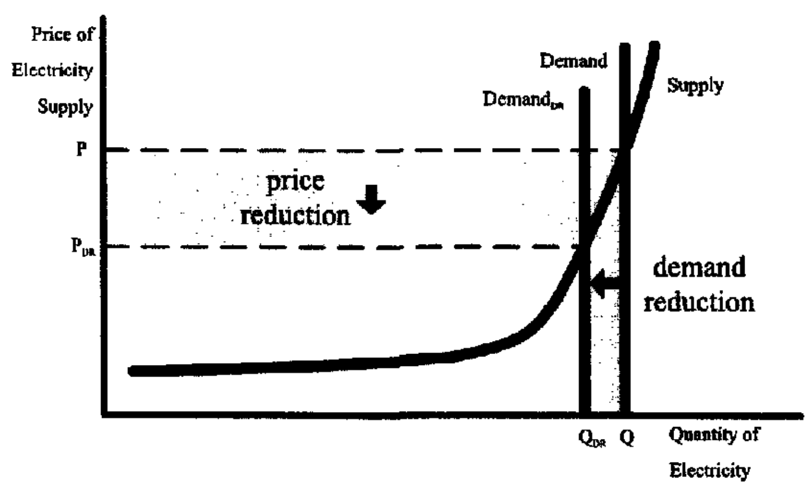
COUNSEL FOR THE OHIO ENERGY GROUP

July 10, 2009

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

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



February 2006

U.S. Department of Energy

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

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

EXECUTIVE SUMMARY

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

Background

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

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

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

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

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

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

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

The Benefits of Demand Response

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

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

Quantifying the National Benefits of Demand Response

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

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

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

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

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

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

Recommendations

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

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

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

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

OVERVIEW: KEY FINDINGS AND RECOMMENDATIONS

Introduction

Sections 1252(e) and (f) of EPACT state that it is the policy of the United States to encourage "time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them." It further states that "deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary services markets shall be eliminated". To help implement this new policy on demand response, the Act creates new requirements for electric utilities and states with respect to demand response. States are charged with conducting investigations to determine how those new provisions could be applied and whether to adopt widespread time-based pricing and advanced metering for utility retail customers.

EPACT directs DOE to encourage demand response by:

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

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

Defining and Characterizing Demand Response

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

Demand response can be defined more specifically as:

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

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

Why is Demand Response Important?

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

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

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

Types of Demand Response

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

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

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

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

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

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

Demand Response Options

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

<u>Current Demand Response Capability and Recent Initiatives</u>

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

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

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

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

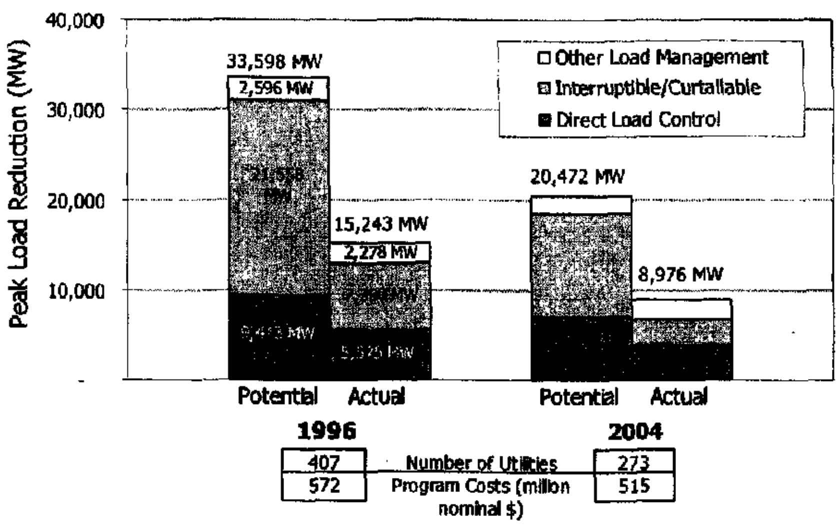


Figure O-1. Existing U.S. Demand Response Potential

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

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

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

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

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

Identifying the Benefits of Demand Response

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

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

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

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

Quantifying the Benefits of Demand Response

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

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

Estimates of the Benefits and Costs of Demand Response

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

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

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

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

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

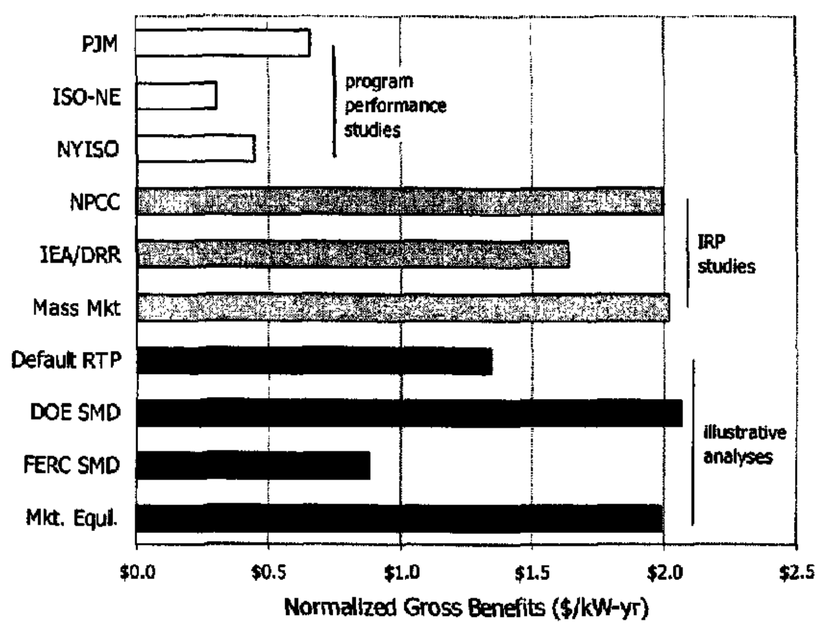

Figure O-2. Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies

Key findings from this cross-study comparison include:

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

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

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

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

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

DOE Recommendations

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

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

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