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The opinions and views expressed in this staff report do not necessarily represent those of the Federal Energy Regulatory Commission, its Chairman or individual Commissioners, and are not binding on the Commission.

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<http://www.ferc.gov/industries/electric/indus-act/demand-response.asp>

Executive Summary

The level of and interest in electric demand response and advanced metering increased significantly beyond the activities discussed in the first report by the staff of the Federal Energy Regulatory Commission. The Commission staff's first report, *Assessment of Demand Response and Advanced Metering*, August 2006,¹ presented the results of a comprehensive nationwide survey of these activities. This year's report provides an informational update on developments and reflects on activity since issuance of the 2006 report.

The Commission staff intends to publish another comprehensive report on demand response and advanced metering in 2008 and every even year thereafter, with informational update reports in the intervening years.

Demand Response

An electric demand-response activity is an action taken to reduce electricity demand in response to price, monetary incentives, or utility directives so as to maintain reliable electric service or avoid high electricity prices. Demand reduction activities occur principally during the summer when electricity demand is highest in most regions, and demand reductions from these demand-response activities proved crucial to the reliable operation of electric markets during the record-setting peaks that occurred in July and August of 2006. Estimates of demand reductions in Regional Transmission Organization (RTO) and Independent System Operator (ISO) regions with organized wholesale markets lowered system peaks between 1.4 and 4.1 percent on these peak days. These demand reductions resulted from a combination of RTO/ISO demand-response programs, utility retail demand response, and voluntary customer demand reductions.

Several states and individual utilities took actions to introduce more opportunities for demand response and price-responsiveness. These actions include the adoption of time-based rates and the adoption of demand-response policies (which includes deployment of enabling technologies such as advanced metering). States such as California, Connecticut, Illinois, Maryland, and Michigan have encouraged more demand response and customer access to information about their energy consumption. Utilities like Pepco and Wisconsin Public Service introduced or revised demand-response programs.

Two important new developments since the 2006 report at the wholesale level are the inclusion of demand resources in forward capacity markets and ancillary services markets at RTOs and ISOs and the development of new reliability-based demand-response programs.

The Commission in the past year has actively encouraged the use of demand response in several ways. It has encouraged organized wholesale power markets to use demand response as they would use generation where it is technically capable. Over the last year, it addressed demand response in a number of orders addressing wholesale market design proposals filed by the various RTOs and ISOs. The Commission revised its Open Access Transmission Tariff regulations in Order No. 890 to require transmission service providers to incorporate demand response into their transmission planning

¹ The Energy Policy Act of 2005 (EPAct 2005) section 1252(e)(3) requires the Federal Energy Regulatory Commission (Commission) to prepare and publish an annual report that assesses electric demand-response resources and advanced metering. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005) (EPAct 2005 section 1252(e)(3)). The first report is available on line at <http://www.ferc.gov/legal/staff-reports/demand-response.pdf>.

processes and to require them to allow demand resources to provide certain ancillary services, where appropriate, on a comparable basis to generation resources. It also directed that NERC's mandatory reliability standards, addressed in Order No. 693, be revised to incorporate demand response. A recently issued Advance Notice of Proposed Rulemaking by the Commission proposed several measures to enhance competition in organized wholesale markets, including demand-response enhancements.

In addition to its direct regulatory actions, the Commission has encouraged demand response through public conferences and collaborative efforts with its state regulatory colleagues. Among other activities, the Commission held a technical conference on April 23, 2007 to examine problems and possible solutions for increased use of demand response in wholesale markets. In November of 2006, the Commission and the National Association of Regulatory Utility Commissioners began a demand-response collaborative effort, co-chaired by Commissioner Jon Wellinohoff, to coordinate the efforts of the state and federal electric regulators to integrate demand response into retail and wholesale markets and planning.

Based on this review of various demand-response activities in the last year, Commission staff has identified the following demand-response trends:

- Increased participation in demand-response programs
- Increased ability of demand resources to participate in RTO/ISO markets
- More attention to the development of a smart grid that can facilitate demand response
- More interest in multistate and state-federal demand-response working groups
- More reliance on demand response in strategic plans and state plans
- Increased activity by third parties to aggregate retail demand response.

Advanced Metering

A number of utilities are planning an installation of advanced metering in the next several years; and indications from state regulatory proceedings suggest that the interest in advanced metering will continue. Although not all announced plans will necessarily go into effect, in the last year utilities announced new deployments of more than 40 million advanced meters between 2007 and 2010. Advanced metering refers to technologies and communications systems necessary to record customer consumption at least hourly and allow for daily or more frequent retrieval of the consumption data. Advanced metering can enhance an electric customer's ability to reduce demand in response to a higher price and an electric utility's ability to meter and monitor the customer's electricity use. Such metering can also allow an electric utility to provide a variety of innovative services to benefit customers and to reduce the utility's costs of operations.

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I. Introduction

The Energy Policy Act of 2005 (EPAc 2005) section 1252(e)(3)² requires the Federal Energy Regulatory Commission (FERC or Commission) to prepare and publish an annual report, by appropriate region, that assesses electric demand-response resources, including those available from all consumer classes.³ The Commission published its first report, *Assessment of Demand Response and Advanced Metering* (“2006 FERC Demand Response Assessment”), in August 2006.⁴ The 2006 report was comprehensive and reported on first-of-their-kind surveys of demand response and advanced metering.

This year’s report provides information on demand response and advanced metering, with an emphasis on results, activities, and regulatory actions taken over the last year. Information was compiled from readily accessible data and reports, Regional Transmission Organization (RTO) and Independent System Operator (ISO) annual reports, and discussions with market participants and industry experts. For this year, and every odd numbered year thereafter, Commission staff will publish an informational report on demand response and advanced metering that largely utilizes publicly available information. Next year’s report will feature the results of another comprehensive nation-wide survey on demand response and advanced metering. (Commission staff will conduct a comprehensive survey every other year thereafter.) Staggering the reporting in this way will allow FERC staff to provide a more informed analysis in each bi-yearly report while still reporting on the advances in demand response on an annual basis. In keeping with this publishing plan, the 2008 report will include the results of the next comprehensive surveys of national demand response and advanced metering.

This informational report has two substantive chapters. **Chapter II** includes a review of the estimated 2006 demand response in RTO and ISO markets and programs, developments in the use of demand response at the state and federal levels, a discussion of the issues associated with the level of demand response achieved, trends in the use of demand response, a summary of activity on demand response in the retail and wholesale sectors that occurred in the past year, and a discussion of barriers to increased demand response. This chapter also contains a summary of Commission demand-response activities.

Chapter III discusses developments associated with advanced metering in the past year. In particular, it includes a summary of state activity in response to EPAc 2005 requirements for states to hold proceedings on advanced metering, a discussion of recent changes in the definition and functionality

² Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005) (EPAc 2005 section 1252(e)(3)).

³ EPAc 2005 directs the Commission to identify and review:

- (A) saturation and penetration rates of advanced meters and communications technologies, devices and systems;
- (B) existing demand response programs and time-based rate programs;
- (C) the annual resource contribution of demand resources;
- (D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes;
- (E) steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party; and
- (F) regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.

⁴ FERC, *Assessment of Demand Response & Advanced Metering: Staff Report*, Docket No. AD06-2, August 7, 2006, available at: <http://www.ferc.gov/industries/electric/indus-act/demand-response.asp>.

Introduction

associated with advanced metering, a review of state and utility advanced metering initiatives and meter installations, and a discussion of issues associated with advanced metering.

This informational report has six appendices. Appendix A is a glossary of terms used in the report. Appendix B contains documentation that supports the estimates of RTO and ISO demand response during summer 2006. Appendix C is a summary of NERC's estimate of achievable and reliable demand response from interruptible demand and direct load control in 2006 and 2007. Appendix D provides a summary of demand-response participation in RTO/ISO markets. Appendix E includes a status report on state proceedings in response to EPCRA 2005 section 1252(b) requirements. Appendix F lists major utility advanced metering implementation projects.

II. Demand Response

This chapter reviews developments associated with demand response that have occurred since the issuance of the 2006 report. It provides a brief contextual definition and review of demand response and covers the following topics:

- Demand Response Developments at the Wholesale and Retail Level
- Observations about Demand Response Activity

Definition of Demand Response

In the 2006 FERC Demand Response Assessment, Commission staff noted that demand response refers to actions by customers that change their consumption (demand) of electric power in response to price signals, incentives, or directions from grid operators, and adopted the definition of “demand response” that was used by the U.S. Department of Energy (DOE) in its February 2006 report to Congress:

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.⁵

As such, the 2006 FERC Demand Response Assessment did not include energy efficiency in the definition of demand response; it relied on the idea that the changes in electricity use are designed to be short-term in nature, centered on critical hours during a day or year when demand is high or when reserve margins are low. In the intervening year, national and state legislative and regulatory bodies, as well as utility programs and tariff filings, have increasingly relied upon energy efficiency as a tool to reduce system peak demand and meet capacity requirements. In addition, at least one RTO, ISO New England (ISO-NE), has adopted (and the Commission has approved) market rules that allow energy efficiency to be bid into forward capacity auctions.⁶ Consequently, while this section focuses on demand response, it occasionally discusses energy efficiency where appropriate. In addition, this report uses the phrase “demand resources” to refer to the set of demand-response and energy efficiency resources and programs that can be used to reduce demand or reduce electricity demand growth.

Demand Response Developments

Demand response plays an increasingly important role in energy markets. As discussed below, demand response played a key role in RTO/ISO energy markets in 2006. In addition, and as discussed later, the states and FERC advanced the role of demand response on several fronts.

⁵ U.S. Department of Energy, 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, 6.

⁶ *ISO New England, Order Conditionally Accepting Market Rules and Requiring Compliance Filing*, 119 FERC ¶ 61,045 (2007).

Levels of Demand Response in Wholesale Markets

During the summer of 2006, the use of demand response proved necessary to the reliable operation of electric markets during peak hours. Summer peak demand in 2006 broke load records across the country due to sustained and severe heat events. Demand reductions during the heat wave came from actions by and programs of a combination of RTOs and ISOs, utilities and load serving entities (hereinafter, referred to generally as “utilities”), and non-utility demand-response service providers. Many utilities, in and out of RTOs and ISOs, invoked emergency demand-response programs, interruptible programs, and direct load control to manage their portfolios and maintain local or balancing area reliability. RTOs and ISOs activated reliability-based demand-response programs⁷ and appealed for load reductions to reduce the system peak and to maintain system reliability. Participants in RTO and ISO demand bidding programs⁸ curtailed load in response to high wholesale prices during the heat events.

NERC, in its 2007 Summer Assessment, concluded that NERC-wide application of demand-response programs increased to about 21,900 MW from the 2006 Summer Assessment estimate of about 20,700 MW.⁹ Using the 2006 peak demand of about 851 GW, this suggests that about three percent of NERC-wide peak demand can be reduced from interruptible demand and direct load control. The level of interruptible demand in 2007 was about the same as in 2006; the increase came from direct load control in 2007. The Western Electricity Coordinating Council region shows an increase in interruptible demand of approximately one-half percent and the Florida Reliability Coordinating Council region shows a similar increase in direct load control.¹⁰

Focusing on RTO and ISO markets, which generally provide readily available information on demand response, demand-response reductions were between 1.4 and 4.1 percent of system peaks on record-breaking peak days. Figure II-1 summarizes demand-response levels on peak days in each RTO and ISO, and also displays estimates of the level of customer enrollment¹¹ in demand-response programs for each RTO and ISO for 2007. While the percent of total load was small, even small load reductions at system peak can have a large impact on reducing stress on electric delivery systems when operating reserves are in near-shortage conditions.¹²

⁷ “Reliability-based” demand-response programs refer to programs that are activated during system emergencies or to maintain local or system reliability. Reliability-based demand-response programs typically include emergency demand-response programs, capacity market programs, direct load control, interruptible/curtailable rates, and ancillary-services market programs. See the 2006 FERC Demand Response Assessment for additional information on these programs.

⁸ “Demand bidding” programs encourage large customers to offer to provide load reductions at a price at which they are willing to be curtailed, or to identify how much load they would be willing to curtail at posted prices. These programs are sometimes referred to as “economic” programs.

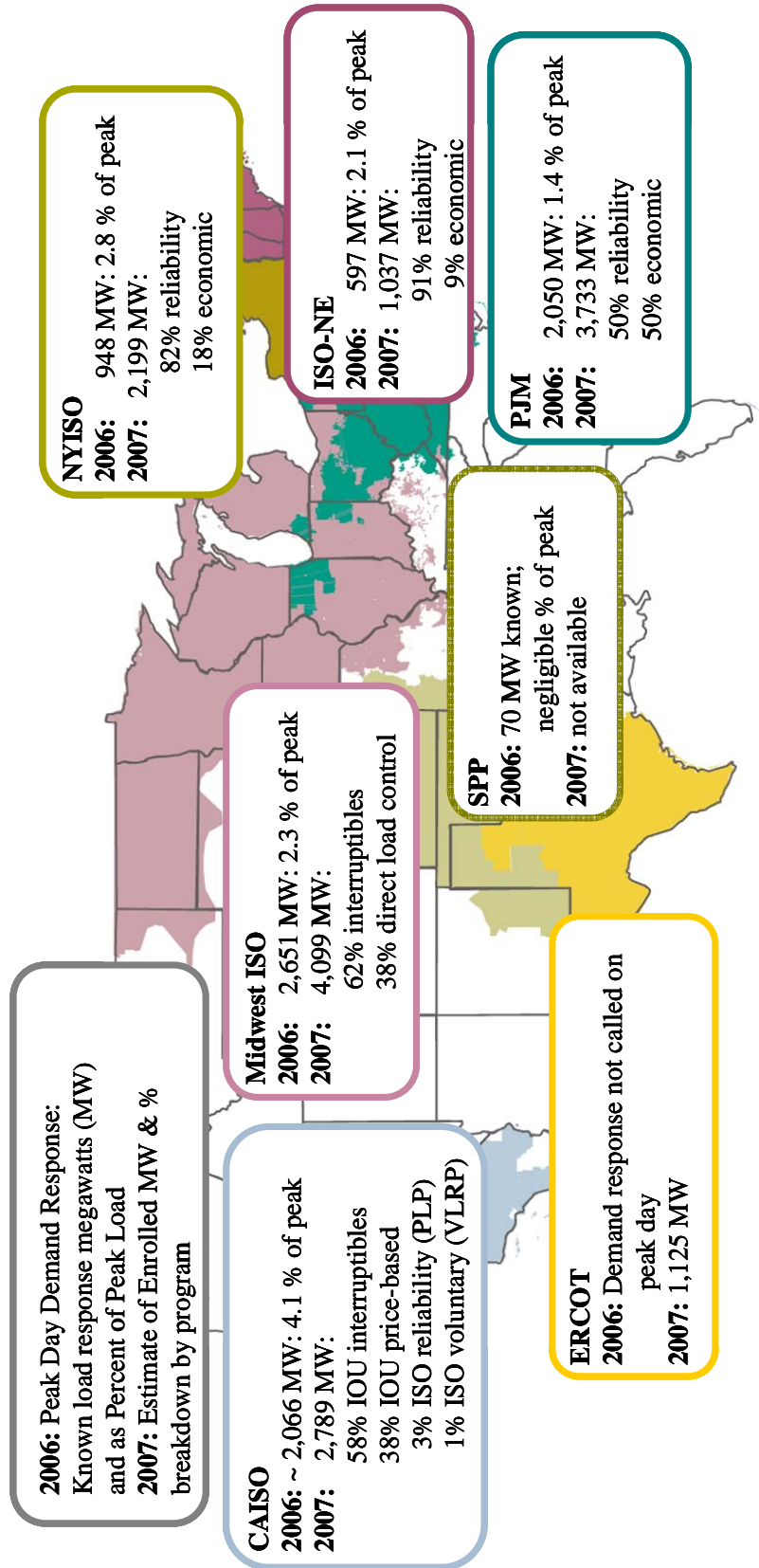
⁹ NERC, *2007 Summer Assessment: The Reliability of the Bulk Power Systems in North America*, June 2007, 8.

¹⁰ See Appendix C for NERC’s estimate of achievable and reliable demand response from interruptible demand and direct load control in 2006 and 2007 as a percentage of total regional internal demand (total internal demand is defined by NERC as total regional peak demand).

¹¹ “Enrollment” is used in this report to refer to the amount of customer participation in a demand-response program. Participation refers to either the number of customers or the amount of MW registered for a program and meeting eligibility criteria. Customer participation in a program does not necessarily mean that the customer will actively adjust its consumption in response to grid operator direction or price signals. Consequently, enrollment typically measures potential demand reduction that could be achieved.

¹² Commission staff reviewed the levels of demand response achieved during the 2006 summer heat waves. Commission staff conducted numerous interviews with RTO and ISO representatives and other market participants, consulted RTO and ISO post-summer written evaluations and updated the data in these evaluations using recently published RTO and ISO “State of the Market Reports,” and periodic demand-response reports. Appendix B documents the information provided in Figure II-1, including sources, definitions, and calculations, where appropriate.

Figure II-1. Summer 2006 demand response contributions and summer 2007 program enrollments



Notes: Estimates and calculations of demand response in summer 2006 include conservation, interruptible resources, and price-based responses. Midwest ISO 2006 data is based on August 1, its 2nd peak day, when it called on and measured demand response.

Source: See Appendix B for details; includes data from RTOs/ISOs, NERC, FERC staff analysis of data.

In addition to emergency procedures invoked by RTOs and ISOs, there were calls for voluntary conservation in many areas, to which customers responded by reducing their electricity use, often without being compensated. We note that quantifying voluntary conservation is difficult with current measurement techniques. Thus, total reductions may have been greater than 1.4 to 4.1 percent of system peaks on record-breaking days.

Focusing more narrowly, demand response in certain load pockets, such as southwest Connecticut and New York City-Long Island, was even higher, at six percent and four percent of regional peak load on record-breaking days, respectively.¹³ The significance of the need to target response in areas with the highest need led the New York ISO (NYISO) to file a proposed rule change with the Commission to enhance its dispatch of reliability-based demand response when the system is stressed. Effective July 1, 2007, the NYISO can activate its Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) in one or more of eight sub-load pockets in New York City to reduce load either when reserve shortfalls are anticipated, or when low voltage conditions exist or are anticipated.¹⁴ These programs were activated on July 19, 2007 to reduce use of damaged cables in midtown Manhattan due to a steam pipe explosion.¹⁵

In addition to supporting reliability, operation of demand response can facilitate inter-system sales. For example, operation of NYISO's demand-response programs on August 2, 2006 allowed the ISO to support the reliability and market needs of its neighboring RTOs. On its peak day, not only did demand response support the reliable operation of the NYISO, the demand-response programs also allowed for the export of 1,300 MW of emergency energy to New England during the afternoon.¹⁶ The NYISO also operated demand-response programs in three western New York zones to provide voltage support for scheduled sales to PJM. These inter-system sales would likely not have been possible without demand response.¹⁷

According to various RTOs and ISOs that reported on summer 2006 market prices, the 2006 demand-response reductions reduced wholesale electricity prices. Reductions in wholesale prices varied regionally. PJM reported that demand response achieved on August 2, its record peak day, "reduced wholesale energy prices by more than \$300 per megawatt-hour (MWh) during the highest usage hours." It estimated that the reductions in use resulted in system-wide savings in energy payments of \$230 million during the peak hours that day, and more than \$650 million in energy payments for the week.¹⁸ ISO-NE analyzed the effect of demand reductions on locational marginal prices (LMPs) for the months of April to September, during the hours with interruptions when demand response was called. It estimated a \$1.74/MWh average decrease in LMPs for those months.¹⁹ The Midwest ISO

¹³ Southwest Connecticut curtailments: phone conferences and emails between FERC staff and H. Yoshimura, ISO-NE; SWCT peak load from Connecticut Valley Electric Exchange, www.cvx.com. Peak load data for New York City (Zone J)-Long Island (Zone K) from NYISO: http://www.nyiso.com/public/market_data/load_data.jsp, link for "Integrated Real-Time Actual Load." Peak curtailment calculated by FERC staff using data in *NYISO 2006 Demand Response Programs*, submitted to the Commission, January 16, 2007.

¹⁴ NYISO, Docket No. ER07-862-000 (July 3, 2007).

¹⁵ Personal communication with NYISO staff, July 19, 2007.

¹⁶ Mark Lynch (NYISO) described the ISO's reliability-based program participants: "one-half of these customers, representing one-third of the total megawatt load reduction potential, are located in New York City." FERC Technical Conference on Demand Response in Wholesale Markets, April 23, 2007 (hereinafter, "FERC Wholesale Demand Response Technical Conference"), transcript, 23.

¹⁷ Monthly conference call between Commission staff and NYISO staff, September 13, 2006.

¹⁸ PJM Interconnection, LLC, press release, August 17, 2006.

¹⁹ ISO-New England, "2006 Annual Markets Report," June 11, 2007, 11.

found that there was a decline of \$100-\$200/MWh in market clearing prices on August 1 when 2,650 MW responded to its call for demand reductions in response to a Maximum Generation Warning.²⁰

While demand reduction resources can benefit both the reliable operation and the economically efficient operation of the power system, recent analysis by the Lawrence Berkeley National Laboratory (LBNL) on the role of demand response in the summer of 2006 suggests that there were differences in response rates²¹ between reliability-based programs and “economic” programs such as demand bidding programs.²² Reliability-based programs, which carry penalties for not responding when called, had high participation rates: the response rate in the California utility interruptible rates programs and the California Power Authority’s Demand Reserves Partnership was 83 percent; the response rate in NYISO’s capacity market program, ICAP/Special Case Resources, was 62 percent.²³ Demand bidding programs had lower response rates: maximum load reduction achieved in the Demand Bidding Programs offered by California utilities was 19 percent of enrolled resources; in the PJM Day-Ahead Load Response Program, maximum load reduction was four percent of enrolled resources.²⁴

The LBNL analysis also highlighted the differences in system operator confidence between these two types – that dispatchable or reliability-based programs play a system reliability role, whereas economic programs play a market efficiency role. According to the study:

However, a number of utility representatives indicated that they did not yet regard economic DR programs [such as demand bidding] or dynamic pricing [such as real-time pricing or critical peak pricing] as “firm” resources based on their experience to date. In interviews, some described these options as fulfilling a different role than reliability programs: improving the overall efficiency of electricity markets, rather than providing a specific demand-response resource. Others were simply more comfortable with their ability to count on reliability options – particularly for more traditional programs such as [interruptible or curtailable] rates and DLC programs – to provide load reductions that could compete with (and supplant) supply-side peaking resources.²⁵

While LBNL found these results, Midwest ISO and ERCOT nonetheless have taken action to improve the ability to utilize reliability-based demand response during system emergencies and reserve shortages. These improvements were based on their experiences with demand response during the spring and summer 2006 heat waves.

²⁰ “Independent Market Monitor Review: 2006 Peak Load Event,” presentation by David B. Patton to the Midwest ISO Board of Directors’ Markets Committee, September 20, 2006, 16. In his review, Patton noted that wholesale prices on July 31, when demand response was not called, ranged from \$200 to \$350 per megawatt-hour (MWh). On August 1, however, when emergency conditions were declared and demand response was activated, “prices generally ranged from \$50 to \$150 per MWh and were less than \$100 in the highest demand hour.” By inference, there was a price difference of at least \$100-\$200/MWh on August 1.

²¹ I.e., percent of the potential demand reductions that could be achieved from demand-response programs, based on customer enrollment in the programs, that were actually achieved.

²² E.g., NYISO’s Day-Ahead Demand Response Program.

²³ Nicole Hopper, Charles Goldman, Ranjit Bharvirkar and Dan Engel, “The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response,” *The Electricity Journal* (June 2007), 67.

²⁴ Hopper, *et al.*, 68.

²⁵ Hopper, *et al.*, 69.

After its summer 2006 experience with demand response, the Midwest ISO sent a survey to its balancing authorities to assess the amount, geographic diversity, and type of demand response in its market footprint. Midwest ISO subsequently changed its Emergency Event Rules to align them with NERC Emergency steps for conservation, interruptible resources, and customer-sited generation. Midwest ISO created three regional zones – West, Central, and East – to allow it to target response reductions geographically. It also created two levels of interruptions beyond conservation, 50% and 100%, to be called by balancing authorities. The procedures were “tested” during a February 2007 cold spell, and were being refined prior to summer 2007, based on that experience.²⁶

Following the rolling blackouts on April 17, 2006, ERCOT petitioned the Texas Public Utilities Commission (PUC) for expedited review of a proposed emergency service, meant to bridge its calling on its “Load Acting as a Resource” program (LaaRs) and involuntary load shedding. In April, the Texas PUC approved the Emergency Interruptible Load Service (EILS) as an interim option. Texas has so far issued two RFPs for emergency resources under EILS, with a 500 MW minimum subscription level. The second RFP received more response than the first, but less than half the minimum. It plans a third RFP. Third party aggregators may participate in the RFP, but there may be insufficient value for these aggregators to participate.²⁷ Providers in this plan are not paid regular capacity payments, as has proven attractive in other ISOs, but are paid for performance only. ERCOT envisions needing this program only rarely.

Commission Demand Response Actions in the Last Year

The Commission continues to assess demand response as it relates to ensuring wholesale competitive markets and reliable grid operations. The Commission’s actions were both reactive and proactive. The Commission positively responded to RTO and ISO applications concerning demand-response programs; some of the same programs that were relied upon by RTOs and ISOs in meeting the peak needs in 2006. It also took up the issue of demand response generically when it addressed the role of demand response in several rulemakings, including in transmission planning, provision of ancillary services, and reliability standards. Outreach activities continued, with the Commission holding two technical conferences on demand-response issues and continuing the state-federal collaborative.

Key Demand Response Commission Orders (August 2006 to July 2007)

- **California ISO MRTU Order** - The Commission’s order allows loads with demand-response capability to participate in the California ISO (CAISO) day-ahead, real-time, and ancillary services markets under comparable requirements as supply, and receive the equivalent market value.²⁸
- **Midwest ISO Resource Adequacy** - The Commission required Midwest ISO to explain any pre-conditions for its Energy Only Market implementation, such as demand-response programs and longer term energy contracts. The Commission further directed Midwest ISO to describe how load-serving entities (LSEs) can react to wholesale prices when managing their load in the aggregate, or when and how retail demand response behind an LSE can participate directly in the wholesale market.²⁹

²⁶ Midwest ISO, “Emergency Procedures Workshop,” March 12, 2007 and Conference call between Midwest ISO and Commission staff, March 28, 2007.

²⁷ Phone interview with Dan Jones, ERCOT IMM, June 5, 2007.

²⁸ *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 10 (2006) (CAISO MRTU Order), *order on reh’g*, 119 FERC ¶ 61,076 (2007).

²⁹ *Midwest Indep. Transmission Sys. Operator Corp.*, 116 FERC ¶61,292, at P 1, 55 (2006).

- **Southwest Power Pool Rehearing** - The Commission directed the Southwest Power Pool (SPP) to make tariff modifications to put in place a \$1,000/MWh bid cap until such time that there are sufficient demand-response programs in SPP's market to permit the lifting of the bid cap. In addition, the Commission directed SPP to work with utilities and state regulators to consider how to allow the participation of demand resources in the imbalance market (e.g., as interruptible demand or behind the meter generation).³⁰
- **ISO-New England Forward Capacity Market (FCM)** - The Commission approved a settlement that provided ISO-NE with a FCM in which demand resources can compete with supply-side resources for capacity payments.³¹
- **PJM Regional Transmission Expansion Planning (RTEP)** - The Commission accepted PJM's commitment to evaluate the extent to which demand response could eliminate the need for an economic-based upgrade to PJM's RTEP protocol.³² The Commission directed PJM to make a compliance filing describing how generators and demand-response providers will be incorporated into the economic planning process.³³
- **PJM Reliability Pricing Model (RPM)** - The Commission clarified that demand-response resources may participate in RPM auctions, may set the market clearing price, and may receive revenues for load reductions as Interruptible Load Resources.³⁴ The Commission also directed PJM to examine in a compliance report barriers to entry to energy efficiency.³⁵

The Commission recently stated, "our goal is for RTOs and ISOs to develop rules to ensure the treatment of supply and demand resources on a comparable basis to the extent each is technically capable of providing the service."³⁶ By allowing demand to be on an equal footing with supply, wholesale markets are opened to demand response, helping to keep wholesale prices and wholesale price volatility in check. Demand response can also diminish the potential for market manipulation by reducing generator market power. The extent to which demand response is in the organized markets is captured in Appendix D.

Recent Rulemakings

In the last year, the Commission issued two final rules directly addressing aspects of demand response. In doing so, the Commission recognized the role of demand resources in wholesale markets, and in the reliable operation of the bulk power system.

Order No. 890: Preventing Undue Discrimination and Preference in Transmission Service

On February 16, 2007, the Commission issued Order No. 890,³⁷ which addresses and remedies opportunities for undue discrimination under the *pro forma* Open Access Transmission Tariff (OATT), adopted in 1996 by Order No. 888.³⁸ In Order No. 890, the Commission adopted several

³⁰ *Southwest Power Pool*, 116 FERC ¶ 61,289, at P 44, 62 (2006).

³¹ *Devon Power LLC*, 115 FERC ¶61,340, at P 22, *order on reh'g*, 117 FERC ¶ 61,133 (2006).

³² *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,218, at P 3 (2006), *reh'g pending*.

³³ *Id.* P 24.

³⁴ *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 31 (2006).

³⁵ *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at P 204 (2007).

³⁶ *Wholesale Competition in Regions with Organized Electric Markets*, 72 Fed. Reg. 36,276 (July 2, 2007), FERC Stats. & Regs. ¶32,617, P 35 (2007) (Competition ANOPR).

³⁷ *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), *reh'g pending*.

³⁸ *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order

critical reforms. Of them, reforms addressing transmission planning and ancillary services included roles for demand resources. Specifically, the Commission modified its open access transmission policies to allow for the incorporation of demand response in local and regional planning processes, if they “are capable of providing the functions assessed in a transmission planning process, and can be relied upon on a long-term basis.”³⁹ Similarly, the Commission found that the sale of other ancillary services, including energy imbalance, operating reserve, and spinning reserve by load resources “should be permitted where appropriate on a comparable basis to service provided by generation resources.”⁴⁰ The Commission modified its *pro forma* OATT to effectuate the inclusion of these resources.

Order No. 693: Mandatory Reliability Standards

The Commission certified NERC as the Electric Reliability Organization responsible for the development of mandatory, enforceable reliability standards, pursuant to the Energy Policy Act of 2005.⁴¹ On March 16, 2007, in Order No. 693, the Commission approved the first set of 83 mandatory and enforceable Reliability Standards and directed modification to 58 of these standards, in accordance with the provisions of new section 215 of the Federal Power Act (FPA)⁴² and part 39 of the Commission’s regulations.⁴³ Of importance to demand-response resources, the Commission directed the incorporation of additional resources and technologies, such as demand-side management (DSM) and demand response, in the revisions to various reliability standards.

Of the 83 approved reliability standards and the Glossary of Terms Used provided by NERC, the following twelve standards directly relate to demand-side issues and demand response.

- Standard BAL-002-0: Disturbance Control Performance
- Standard BAL-005-0: Automatic Generation Control
- Standard EOP-002-2: Capacity and Energy Emergencies
- Standard MOD-016-01: Actual and Forecast Demands, Net Energy for Load, Controllable DSM
- Standard MOD-019-0: Forecasts of Interruptible Demand and DCLM Data
- Standard MOD-020-0: Providing Interruptible Demands and DCLM Data
- Standard MOD-021-0: Accounting Methodology for Effects of Controllable DSM in Forecasts
- Standard TPL-001-0: System Performance Under Normal Conditions
- Standard TPL-002-0: System Performance Following Loss of a Single BES Element
- Standard TPL-003-0: System Performance Following Loss of Two or More BES Elements
- Standard TPL-004-0: System Performance Following Extreme BES Events
- Standard VAR-001-0: Voltage and Reactive Control

In approving the reliability standards, the Commission took the first steps in recognizing the need for consistency in the inclusion of demand response in system modeling. The approved modeling, data,

No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997). *order on reh’g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh’g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

³⁹ *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, at P 479.

⁴⁰ *Id.* P 888.

⁴¹ *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh’g*, 117 FERC ¶ 61,126 (2006).

⁴² 16 U.S.C. 824o.

⁴³ 18 C.F.R. 39.

and analysis (MODs) standards, MOD-019-0, MOD-020-0, and MOD-021-0, recognize the current lack of documentation of demand resources and direct proper reporting of demand response and the effects of time of use rates, interruptible demands, and direct load control management in forecasting peak demand and net energy. Order No. 693 found that standardizing the principles for reporting and validating demand-response information will provide consistent and uniform evaluation of demand response to facilitate system operator confidence in relying on such resources.⁴⁴

Under BAL-002-0, the reliability standard uses contingency reserves to balance resources and demand to return the interconnection frequency to within defined frequency limits following a reportable generator loss on the system.⁴⁵ By directing modifications to this reliability standard, the Commission attempted to include other technologies that may be relied upon to provide contingency reserves in order to maintain the interconnection frequency. In doing so, the Commission chose to allow for the “comparable treatment of demand-side management with conventional generation or any other technology and to allow DSM to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option.”⁴⁶

BAL-005-0 aids in maintaining the interconnection frequency by requiring that all generation, transmission, and customer loads be within the metered boundaries of a balancing authority area, and establish the functional requirements for the balancing authority’s regulation service, including its calculation of Area Control Error.⁴⁷ In this instance, the Commission directed modification to the title of the reliability standard to be “as neutral as to the source of regulating reserves and allow for the inclusion of a technically qualified DSM and direct control load management as regulating reserves.”⁴⁸

The reliability standard, EOP-002-2,⁴⁹ requires that a balancing authority may have the authority to bring all necessary generation on line, communicate about the energy and capacity emergency with the reliability coordinator and coordinate with other balancing authorities. The Commission determined that demand resources provide an additional tool for meeting this standard. The Commission also determined that the scope of demand response covers more resources than interruptible load and therefore directed the standard be modified to include demand-response resources if they meet technical requirements comparable to those required of other resources.

MOD-019-0 and MOD-020-0 ensure that past and forecasted demand data are available for past event validation and future system assessment.⁵⁰ In its assessment, the Commission determined that controllable load can be as reliable as other resources and directed that it be subject to the same reporting requirements. To meet these requirements, the ERO has been directed to modify the two MOD Standards to allow for the development of a process “to require reporting of the accuracy, error and bias of controllable load forecasts.”⁵¹ In doing so, the Commission stated that it believes that this will enable planners to paint a more reliable picture of the amount of controllable load available at the time, and allows for a more accurate assessment of system reliability. In MOD-021-0, the Commission directed the ERO to provide an additional requirement standardizing principles on reporting and validation of demand-response program information and “allow for resource planners to

⁴⁴ Order No. 693, FERC Stats. & Regs. ¶ 31,241 at P 1298.

⁴⁵ *Id.* P 316.

⁴⁶ *Id.* P 333.

⁴⁷ *Id.* P 387.

⁴⁸ *Id.* P 404.

⁴⁹ *Id.* P 567.

⁵⁰ *Id.* P 1266, 1280.

⁵¹ *Id.* P 1276.

identify any corrective actions” needed “to improve forecasted demand responses for future forecasts.”⁵²

Through directing modifications to the MOD reliability standards, the Commission continued to emphasize the importance of demand response and its contribution to the reliability of the system by directing modifications that will require system operators to accurately document the amount of demand-response resources available for planning purposes. Accurate documentation of demand-response resources should provide assurances sought by some system operators and garner support for continued and possibly greater reliance on demand response in system planning and operations by demonstrating the dependability of demand resources.

The Commission also directed modification to the transmission planning standards (TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0) and the voltage and reactive control standard (VAR-001-0). In the TPL standards, the Commission included demand response and demand-side management as two of a range of variables that should be included in sensitivity studies of critical system conditions.⁵³ In VAR-001-0, the Commission also noted that demand response and demand-side investment can reduce the need for reactive power capability, and directed the inclusion of demand response among permissible reactive resources.⁵⁴

Advanced Notice of Proposed Rulemaking on Wholesale Competition in Regions with Organized Electric Markets

The Commission recently issued the Wholesale Competition Advanced Notice of Proposed Rulemaking (ANOPR).⁵⁵ In the ANOPR, the Commission examined possible reforms to enhance competition within organized wholesale markets, including reforms associated with demand-response policies. The Commission proffered four demand-response proposals: 1) allow demand resources to provide certain ancillary services (e.g., spinning and supplemental reserves and generator imbalance) in all RTO/ISO markets when demand resources meet the necessary technical requirements;⁵⁶ 2) eliminate charges for taking less energy in real-time than purchased in the day-ahead market during system emergencies;⁵⁷ 3) allow retail demand-response aggregators to bid demand reductions on behalf of retail customers directly into the organized markets;⁵⁸ and 4) modify the market power mitigation rules when demand is nearing the amount of available supply.⁵⁹ These proposed reforms have the potential to further the competitiveness of the RTO/ISO markets.

Other

The Commission has also encouraged demand response outside of its orders. Most recently, the Commission convened a technical conference on demand response on April 23, 2007.⁶⁰ During this technical conference, panelists discussed the interplay between demand response and grid operations and markets, how to effectively evaluate and measure demand response, and how demand resources can be integrated into the transmission planning process, either as an alternative or a complement.

⁵² *Id.* P 1294.

⁵³ *Id.* P 1706.

⁵⁴ *Id.* P 1879.

⁵⁵ Competition ANOPR, FERC Stats. & Regs. ¶ 32,617.

⁵⁶ *Id.* P 59-61.

⁵⁷ *Id.* P 62-67.

⁵⁸ *Id.* P 68-74.

⁵⁹ *Id.* P 75.

⁶⁰ FERC Wholesale Demand Response Technical Conference.

Panel members provided the Commission with useful feedback concerning the benefits of demand response and where efforts may be required to encourage further penetration of demand-response programs into the market. An example offered was the Electric Power Research Institute's (EPRI) Dynamic Energy Management initiative which attempts to meet the needs of utilities and other stakeholders in deploying technologies to help with smart power delivery, operation, load management, and end-use system.⁶¹

Aside from sponsoring technical conferences, the Commission participates in a National Association of Regulatory Utility Commissioners (NARUC)-FERC Collaborative Dialogue on Demand Response.⁶² This collaborative, which began in November of 2006, explores the coordination of efforts between the states and federal government in order to promote and integrate demand response into retail and wholesale markets and planning.⁶³ Participants at the initial meeting in November identified various issues and goals that supported the overall objective of removing regulatory and market barriers to demand-response integration. These goals included increased regional coordination, providing proper price signals, sponsoring demand-response studies, and educating customers. NARUC and the Commission continued their dialogue at the NARUC Winter Meetings in February 2007 and the NARUC Summer Meetings in July 2007 to discuss demand-response policy and decide potential next steps.⁶⁴

Developments in Retail Markets

Since the 2006 FERC Demand Response Assessment, several states and individual utilities took actions to introduce greater demand response and price-responsiveness into retail markets. In particular, a growing number of states are directing the implementation of time-based rates. Activity in the retail sector should improve demand responsiveness and partially address the need for wholesale-retail coordination identified in the 2006 FERC Demand Response Assessment.⁶⁵ A sampling of state actions follows.

State Legislative and Regulatory Activity

- **California.** The California Public Utilities Commission (CPUC) continued its support of demand response, directing changes to 2007 utility demand-response programs, and initiating a rulemaking on measurement and verification and cost-effectiveness.⁶⁶
- **New York.** In April 2006, the New York Public Service Commission directed utilities to place their largest customers on real-time pricing (based on day-ahead NYISO LMPs) as their default tariff.⁶⁷ The utilities phased in their start dates through January 2007. Most

⁶¹ Richard A. Spring (Kansas City Power & Light), Presentation at the FERC Wholesale Demand Response Technical Conference, 2.

⁶² Competition ANOPR, FERC Stats. & Regs. ¶ 32,617 at P 45.

⁶³ *Id.*

⁶⁴ NARUC-FERC Demand Response Collaborative, *available at*: <http://www.naruc.org/displaycommon.cfm?an=1&subarticlenbr=514>.

⁶⁵ 2006 FERC Demand Response Assessment, 133.

⁶⁶ CPUC Decision (D.) 06-11-049, November 2006 ("Order Adopting Changes to 2007 Utility Demand Response Programs"), and "Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols," Rulemaking 07-01-041, Jan. 2007.

⁶⁷ New York State Public Service Commission (NYPSC) Order, Case 03-E-0641 (adopting mandatory hourly pricing for investor-owned utilities), April 24, 2006, *available at*: http://www.dps.state.ny.us/Mandatory_Hourly_Pricing.html.

- utilities' real-time tariffs apply to customers with demands greater than 1 or 2 MW (depending on the size of the customer). The PSC anticipates that utilities will lower these size thresholds over the next few years. Customers have the option of staying with their original utility (full service), or migrating to an energy service company (i.e., independent electricity retailers). There are currently 2,225 customers representing 5,348 MW subject to this real-time pricing tariff. It is also not yet clear how many of these customers will also participate in NYISO demand-response programs.⁶⁸
- **Illinois.** In 2006, Illinois enacted legislation requiring electric utilities to consider and evaluate the use of dynamic pricing to enable customer demand response,⁶⁹ and directing the Illinois Commerce Commission to evaluate whether such pricing and advanced metering would produce net benefits (for customers).⁷⁰ Illinois also mandated that large utilities in the state offer residential real-time pricing programs run by an independent program administrator. Commonwealth Edison proposed to continue and expand its residential hourly real-time pricing (RTP) in 2007 as the "Energy Smart Pricing Plan."⁷¹ ComEd's default RTP rates for large customers "are indexed to the day-ahead energy market, for which hourly prices are published a day in advance."⁷² Ameren Illinois chose the Community Energy Cooperative to run its "Power Smart Pricing" program. While Ameren's program promotion will begin in earnest in the fall of 2007, the Community Energy Cooperative has already begun enrolling customers based on calls from interested customers. Ameren will also offer select customers a "PriceLight," which delivers price signals via a glowing orb which changes colors based on current price levels.⁷³
 - **Connecticut.** Connecticut enacted a comprehensive energy act with features promoting energy efficiency, demand response, advanced metering, and renewable energy. The act removes key barriers to utility promotion of demand reductions (either from energy efficiency or demand response), by requiring distribution companies to decouple distribution revenues from sales in future rate cases. It requires the Connecticut Department of Public Utility Control to implement two tiers of time-of-use (TOU) rates by January 2008; the first is mandatory TOU rates for larger customers whose demand is 350 kW or more and the second is voluntary critical-peak pricing or real-time pricing for all customer classes. All electric utilities must submit a plan to deploy advanced metering infrastructure systems as a prelude to TOU rates. Advanced metering infrastructure systems must be in place by January 2009, and any customer may obtain a meter on demand, with costs recoverable in distribution rates. Further, the act directs the Department of Public Utility Control to "develop a real-time energy report for daily use by television and other media" to inform the public about current real-time energy demand, real-time changes to energy demand, emphasize the importance of reducing peak and provide estimates of economic benefits from such reductions, and provide tips on energy efficiency measures.
 - **Maryland.** On June 8, 2007, the Maryland Public Service Commission (PSC) announced a public capacity planning conference and a collaborative process. The conference will include an examination of demand reduction potential, from the state and regional

⁶⁸ Email and phone communications with Christopher L. Graves, NYPSC, June 8 and 14, 2007.

⁶⁹ 220 ILL. COMP. STAT. 5/16-107(b-5) (2006).

⁷⁰ *Commonwealth Edison Co.*, Illinois Commerce Commission Docket 06-0617 (filed September 13, 2006). (considering "Proposed revisions to Rate BES-H, Basic Electric Service-Hourly Energy Pricing").

⁷¹ www.knowledgeproblem.com, November 11, 2006.

⁷² Galen Barbose, Ranjit Bharvirkar, et al., "Killing Two Birds with One Stone: Can Real-Time Pricing Support Retail Competition and Demand Response?," LBNL-59739, August 2006, 5.

⁷³ *Issue Alert*, May 16, 2007.

perspectives.⁷⁴ The collaborative process, prompted by three recent utility filings, was to consider four issues relating to advanced metering initiatives (AMI) and demand side management (DSM).⁷⁵ The Office of Staff Counsel reported its findings to the PSC on areas of agreement and disagreement in the DSM/AMI collaborative on July 6, as required. The collaborative was unable to reach consensus on the four areas it examined: technical standards for advanced meters; the extent to which demand programs would be offered on a competitively-neutral basis; cost recovery of advanced metering and demand-response programs; and, the appropriate measures of cost effectiveness in demand-response programs.⁷⁶ Separately, the Commission approved decoupling mechanisms as part of Delmarva's and Pepco's rate cases to encourage energy efficiency. This allows utilities to modify their distribution rates—to make up lost revenue and to cover fixed costs—if customers conserve more and demand for electricity drops.⁷⁷

- **Michigan.** Michigan's governor issued an executive directive for the Michigan Public Service Commission (Michigan Commission) to develop a comprehensive plan for meeting the state's electric power needs. The report, issued on January 31, 2007, recommended that the Commission be authorized to require the immediate use of active load management by utilities and that pilot programs be designed to assist customers in managing the electric load and reducing the costs.⁷⁸ The Michigan Commission directed its staff on June 12 to begin a collaborative process to develop a demand-response program that would allow customers to lower their monthly bills by deciding to use power at less expensive off-peak hours.⁷⁹

Utility Demand Response Activities

In addition to actions at the state level since the 2006 report, there has been a spate of recent utility announcements of programs and tariffs that include demand response, time-based rates, energy efficiency, and advanced metering. Connecticut Light & Power supported its filed plan to implement advanced metering infrastructure (AMI) with the Connecticut DPUC by noting that advanced metering infrastructure will not only increase energy efficiency, but also help the company manage demand by giving its customers access to time-of-use rates.⁸⁰ Pepco Holdings announced its plans to include energy efficiency and demand-response programs, coupled with “innovative technologies”, for nearly all their operating companies in Maryland,⁸¹ Delaware,⁸² and the District of Columbia.⁸³ It intends to file soon in New Jersey. Energy East Corporation has announced its plan to implement advanced metering in New York and Maine, noting: “the end game with the metering is to drive down demand,

⁷⁴ Maryland Planning Conference scheduled for July 26-27, 2007, resulting from Order No. 81423 in Case No. 9099, issued May 23, 2007; conference notice issued June 8, 2007.

⁷⁵ Maryland Collaborative Process, Case No. 9111, Order No. 81448, issued June 8, 2007.

⁷⁶ Maryland PSC, Office of Staff Counsel, “Report on the Advanced Metering Initiative and Demand Side Management Collaborative,” Case 9111, July 2, 2007.

⁷⁷ Maryland PSC, Press Release, July 20, 2007.

⁷⁸ *Michigan's 21st Century Energy Plan*, submitted to Governor Jennifer M. Granholm by J. Peter Lark, Chairman, Michigan Commission, January 31, 2007, and MPSC press release, January 31, 2007. All related documents available at <http://www.cis.state.mi.us/mpsc/electric/capacity/energyplan/index.htm>.

⁷⁹ Michigan Commission Press Release, June 12, 2007, available at: http://www.michigan.gov/mpsc/0,1607,7-159-16400_17280-170116--,00.html.

⁸⁰ CL&P Press Release, April 2, 2007, available at: <http://www.cl-p.com/companyinfo/newsreleases.asp>. CL&P's DPUC filing is in response to Docket No. 05-10-03.

⁸¹ Pepco Press Release, March 21, 2007.

⁸² Delmarva Press Release, March 21, 2007.

⁸³ Pepco Press Release, April 5, 2007.

get people to conserve more, and reduce need to build more power plants.”⁸⁴ Upper Peninsula Power hoped to enroll its first customer in a real-time pricing program for industrial customers directly connected to the grid by July 1, 2007.⁸⁵

Baltimore Gas & Electric (BGE) won approval for its AMI pilot in April 2007. BGE states that it hopes to use the advanced metering system to send price and load control signals, enhance distribution automation and distributed generation control, and integrate demand response with smart thermostats and load control devices. Wisconsin Public Service modified its interruptible program to accommodate the Midwest ISO’s day-ahead market.⁸⁶ Hawaii, Idaho, Missouri, and New Jersey are conducting other pilots.⁸⁷

Trends and Observations

Since Commission staff issued its 2006 report, demand response is increasingly incorporated into organized markets, including the successful bidding of demand response into RTO/ISO capacity markets and auctions and the growing participation of demand response in ancillary services markets. State and federal regulators continue to explore, initiate and respond to proposals for including demand-response resources in energy markets. Entities are increasingly including demand response in strategic plans and state plans; enrollment in RTO/ISO demand-response programs is on the rise (see Table II-2); and there is a renewed commitment to cross-jurisdictional demand-response working groups.

Bidding of Demand into RTO/ISO Capacity Markets and Auctions

PJM held the first capacity auction in its forward capacity market (known as the Reliability Pricing Model, or RPM) in April 2007, for the June 2007 to May 2008 planning year. Forty-one percent of cleared offers, or 127.6 MW, were demand-response offers.⁸⁸ Demand-response cleared offers quadrupled to 536 MW in the second auction held for 2008-2009. The RPM auction process is designed to send locational price signals to attract resources to areas where they are most needed.⁸⁹ ISO-NE initiated its Forward Capacity Market this spring. The Forward Capacity Market allows five categories of demand resources to participate, including energy efficiency, load management, distributed generation, and real-time demand response. In the “show of interest” held in February 2007, 2400 MW, or 20 percent of bids, were from demand resources. ISO-NE will evaluate these bids and hold the final auction in February 2008 for June 2010 delivery.

Growing Participation of Demand Response in Ancillary Services Markets

There is a growing ability of demand resources to participate in ancillary services markets. As shown in Table D-1 in Appendix D, several RTOs and ISOs include demand response in ancillary markets. Some of these continue to consider the ability of demand response to participate in other ancillary

⁸⁴ Energy East Press Release, quoting Mark Siwak, Director of Investor Relations, June 15, 2007.

⁸⁵ Platts *Megawatt Daily*, May 23, 2007, 11.

⁸⁶ Dennis Derricks (Wisconsin Public Service Corporation), FERC Wholesale Demand Response Technical Conference, transcript, 86.

⁸⁷ Ahmad Faruqui, Ryan Hledik, Sam Newell, and Johannes Pfeifenberger, *Power of Five Percent: How Dynamic Pricing Can Save \$35 Billion in Electricity Costs*, Brattle Group Discussion Paper, May 2007, 3.

⁸⁸ PJM news release, April 16, 2007, available at <http://www.pjm.com/contributions/news-releases/2007/20070416-rpm-auction-results.pdf>.

⁸⁹ PJM news release, July 13, 2007, available at: <http://www.pjm.com/contributions/news-releases/2007/20070713-2nd-rpm-results.pdf>.

services markets, while other RTOS and ISOs have open cases on the inclusion of demand response in these markets. PJM opened its ancillary services market to demand response on May 1, 2006, as Synchronized Reserves.⁹⁰ Table II-1 shows there has been active participation in this market in terms of cleared megawatt-hours between August 2006 and June 2007; participation appears to vary seasonally.

Table II-1. PJM synchronized reserve participation

Month	Cleared MWh
August 2006	1,613
September 2006	5,354
October 2006	31,074
November 2006	27,915
December 2006	25,125
January 2007	35,210
February 2007	5,104
March 2007	8,675
April 2007	17,275
May 2007	17,897
June 2007	8,859

Source: www.pjm.com: Demand Response Working Group

ISO-New England implemented a demand-response reserves pilot program “to determine if small generation and demand response resources of less than 5 MW can provide a functionally-equivalent reserves product.”⁹¹ Because two-way communications and telemetry equipment used by larger resources (for measurement, control, and dispatch) can be cost-prohibitive to smaller resources, part of the pilot program’s goal is to evaluate lower-cost, two-way communications alternatives. This program, initiated in October 2006, will continue to run through the summer of 2007.⁹²

In the past year, ERCOT’s Independent Market Monitor (IMM) suggested changes to the way participants in their “Load Acting as a Resource” program (LaaRs) bid into the market.⁹³ Current rules allow a maximum of 1,500 MW of LaaRs to be nominated, although at least 1,800 MW of LaaRs were qualified in the summer of 2006. The IMM believes the bidding rules are inefficient because they encourage bidding behavior that prevents competition from selecting the most efficient resources to provide responsive reserves. The changes it recommended in its 2005 State of the Market (SOM) Report “were not adopted in the zonal market because of timing and resource issues.” While they were initially approved for implementation in the nodal market (December 2008), the proposed changes failed to gain sufficient votes at the Technical Advisory Committee level. The IMM will be urging reconsideration of these recommendations in its 2006 SOM.⁹⁴

⁹⁰ 114 FERC ¶61,201, February 24, 2006.

⁹¹ ISO-NE, *2006 Annual Markets Report*, 118.

⁹² Henry Yoshimura (ISO-NE), FERC Wholesale Demand Response Technical Conference, transcript, 15-17.

⁹³ Potomac Economics, Ltd., Advisor to Wholesale Market Oversight, Public Utility Commission of Texas, *2005 State of the Market Report for the ERCOT Wholesale Electric Markets*, July 2006, 106.

⁹⁴ Email from and phone interview with ERCOT’s Independent Market Monitor, June 5, 2007.

Increased Participation in ISO Demand Response Programs

If one looks strictly at enrollment in terms of amount of potential demand reduction, the reliability programs in the three eastern RTOs had the greatest increases in the last few years (see Table II-2). ISO-NE nearly doubled its enrolled base between 2006 and 2007. RTO/ISO 2006 data demonstrate increased levels of energy reductions in the RTO and ISO demand bidding programs (labeled as “economic” in Table II-2), despite stable levels of customer participation and enrollment in programs. Energy reductions in the NYISO’s Day-Ahead Demand Response Program (DADRP) increased to 3,479 MWh in 2006 from 2,100 MWh in 2005.⁹⁵ Monthly energy demand reductions in PJM’s Day-Ahead and Real-Time Economic Programs increased from 24,395 MWh in August 2005 to 46,541 MWh in August 2006. Annual demand reductions in PJM doubled, from 129,769 MWh in 2005 to 260,417 MWh in 2006.⁹⁶

Table II-2. Enrollment changes in eastern ISO reliability and economic programs⁹⁷

(MW enrolled)	PJM		ISO-NE		NYISO	
Year	Reliability	Economic	Reliability	Economic	Reliability	Economic
2003	1,631	651	263	117	1,531	354
2004	2,622	876	248	103	1,570	411
2005	3,424	2,210	277	190	1,605	395
2006	2,410	1,101	580	168	1,720	389
pre-summer '07	2,155	1,578	940	97	1,810	389
change, 2003-07	32%	143%	257%	-17%	18%	10%
change, 2006-07	-11%	43%	62%	-42%	5%	0%

Source: ISO demand response presentations, “State of the Market” reports, and email correspondence with staff.

More National and Regional Attention on Measurement and Verification of Demand Reductions

The 2006 FERC Demand Response Assessment report identified the need for additional research on cost-effectiveness and measurement of demand reductions as a regulatory barrier. Important activities at the state, RTO/ISO, and national levels have begun to address this. The CPUC is actively examining cost-effectiveness and measurement in a rulemaking proceeding (R.07-01-041).⁹⁸ The ISO-NE developed a measurement and verification protocol to support demand resource participation in the Forward Capacity Market.⁹⁹ This protocol represents much of the latest research on measurement at the wholesale level. The NARUC-FERC demand response collaborative examined measurement and verification at its February 2007 meeting. The Commission convened a panel at its

⁹⁵ David Lawrence, NYISO, in conference call with FERC staff and NYISO staff, December 14, 2006.

⁹⁶ PJM, “Load Response Activity Report: January through December (2005 and) 2006,” available at: <http://www.pjm.com/committees/working-groups/dsrwg/dsrwg.html>.

⁹⁷ Programs: PJM Reliability: Emergency Load Response Program; PJM Economic: Economic Load Response Program (real-time and day-ahead options); PJM “Load” is Load Management, was “ALM”; ISO-NE Reliability: Real-Time (RT) 30-minute, real-time 2-hour, and Profiled; ISO-NE Economic: real-time price response (RTPR), Day-ahead load response program (DALRP); NYISO Reliability: Emergency Demand Response Program (EDRP), Installed-capacity Special Case Resources (SCR); NYISO Economic: Day-Ahead Demand Response Program (DADRP).

⁹⁸ CPUC, Rulemaking 07-01-041, January 2007.

⁹⁹ ISO-NE, *Measurement and Verification of Demand Reduction Value from Demand Resources*, Manual M-MVDR, April 2007, available at: [http://www.iso-ne.com/rules_proceeds/isone_mnls/m_mvdr_measurement_and_verification_demand_reduction_\(revision_0\)_04_13_07.doc](http://www.iso-ne.com/rules_proceeds/isone_mnls/m_mvdr_measurement_and_verification_demand_reduction_(revision_0)_04_13_07.doc).

April 23, 2007 demand response technical conference to address measurement and verification in wholesale markets. Finally, the North American Energy Standards Board (NAESB) initiated a project to examine measurement and evaluation of demand resources at both the retail and wholesale levels.¹⁰⁰

Increased Focus on the Development of the Smart Grid

The use of a smart grid allows for greater implementation of demand response. Over the past year, the concept of the “smart grid” – or at least the term – was the subject of increased attention. National-level meetings, such as the U.S. Department of Energy-sponsored GridWeek in April 2007, were held. Strategic planning documents like PJM’s April 2007 “Bringing the Smart Grid Idea Home” also emphasized the importance of a smart grid in the efficient operation of the electric system.¹⁰¹ Congress has held several hearings on the subject during the 110th Congress, and there have been several pieces of draft legislation on the issue.¹⁰²

More Multistate and State-Federal Demand Response Working Groups

The 2006 report noted that “greater clarity and coordination between wholesale and state programs is needed.” Since the issuance of that report, an increasing number of groups are working to promote cooperation and coordination across multiple jurisdictions to enhance demand response in retail and wholesale markets, and to promote intersecting policies that support common goals.

For example, regulators in the Organization of MISO States convened the Midwest Demand Responsive Initiative (MWDRI) in February 2007 to examine demand-response issues, and have met several times.¹⁰³ A collaborative effort in the Pacific Northwest, the Pacific Northwest Demand Response Project, also formed since the last Commission staff report and held its first meeting in May 2007. The Mid-Atlantic Distributed Resources Initiative (MADRI) continues to meet to discuss and research demand-response issues in the Mid-Atlantic region.

As was discussed earlier, federal and state regulators began a “Collaborative Dialogue on Demand Response” at the November 2006 NARUC Annual Convention.

More Reliance on Demand Response in Strategic Plans and State Plans

RTOs and ISOs, Public Power Authorities, and states increasingly incorporate elements of demand response, energy efficiency, advanced technologies, and the smart grid in their plans and policies. PJM’s 2007 Strategic Plan states that PJM should prepare its system to develop a communications protocol for a smart grid, work with states to encourage AMI deployment, and continue its work to implement demand response in its markets. The CAISO specifically identifies demand response as a critical item in its five-year strategic business plan. TVA’s latest strategic plan includes many energy efficiency and demand-response components. Both Connecticut and Michigan have recognized the importance of demand response and energy efficiency in the future of their own energy infrastructures.

¹⁰⁰ See <http://www.naesb.org/dsm-ee.asp> for more information.

¹⁰¹ PJM, *Bringing the Smart Grid Idea Home*, April 2007.

¹⁰² Both the U.S. Senate and House have held hearings and markups of legislation to promote the development of a smart grid. For example, the Subcommittee on Energy and Air Quality of the Committee on Energy and Commerce held a hearing on “Facilitating the Transition to a Smart Electric Grid” on May 3, 2007. Also, the U.S. House of Representatives passed on August 4, 2007, H.R. 3221, “New Direction for Energy Independence, National Security, and Consumer Protection Act,” which contains the “Smart Grid Facilitation Act of 2007.” Text of bill available at: http://www.rules.house.gov/110/text/110_hr3221.pdf.

¹⁰³ Midwest Demand Responsive Initiative, available at <http://misostates.org/MWDRI%20list.htm>.

Connecticut's comprehensive energy act requires the consideration of conservation and load-management standards and programs. The Michigan Public Service Commission's "21st Century Energy Plan" recommends the immediate use of active load management and recommends that the state invest in energy efficiency.

Increased Activity by Third Parties in Aggregating and Providing Demand Response

Third-party providers who generally aggregate demand reductions across customer groups and bid a percent of their enrolled base into the market provide an important avenue for customers to contribute to demand reduction that they might not otherwise have. Third-party providers provide a mechanism for customers to bid into energy markets without having to understand and track energy markets or multiple RTO/ISO or state rules. PJM's Andy Ott stated:

They're actually providing a very valuable service, because each individual entity who can provide demand response, can't afford to take the time to understand the market in depth, the wholesale market, so you have curtailment service providers actually providing a function to provide commonality, to allow those megawatts to come to the market. That's absolutely valuable, and we see their actions every day.¹⁰⁴

Demand-response aggregators delivered significant levels of demand reductions during the summer of 2006.¹⁰⁵ RTOs and ISOs estimate that aggregators' contribution to load reductions comprise a sizable portion of the enrolled customers in their reliability-based programs. For example, in NYISO's ICAP/Special Case Resources program, aggregators provided 91 percent of participating customers, and 53 percent of demand reductions in 2006.¹⁰⁶

TVA similarly notes that third party aggregators are a big part of their business case in rolling out its pilot program for commercial and industrial customers, because the aggregators have the manpower, time, and money to run a program.¹⁰⁷

Third-party aggregators have also been active in signing long-term demand contracts with utilities. The California PUC issued an order directing utilities to cooperate with aggregators, and to pursue requests for proposals for additional demand response.¹⁰⁸ EnerNOC won two "Negawatt Network" contracts for 40 MW each with Pacific Gas & Electric (PG&E) and with Southern California Edison (SCE) that were approved by the CPUC.¹⁰⁹ EnerNOC also entered into a ten year Negawatt Network contract with Public Service of New Mexico (amount not announced) in support of New Mexico's Efficient Use of Energy Act.¹¹⁰ Comverge will provide San Diego Gas & Electric (SDG&E) and PG&E with up to 100 and 50 megawatts of capacity, respectively, for their residential and small commercial and industrial customers. The CPUC also approved a five-year agreement between PG&E

¹⁰⁴ Andrew Ott (PJM), FERC Wholesale Demand Response Technical Conference, transcript, 11.

¹⁰⁵ Demand-response aggregators of retail customers, such as EnerNoc and Comverge, are also known as curtailment service providers or aggregators of retail customers (*see* Competition ANOPR, FERC Stats. & Regs. ¶ 32,617). In interviews with ISO-NE and NYISO, the growing importance of these aggregators was stressed by the RTO or ISO demand-response coordinators.

¹⁰⁶ NYISO, *2006 Demand Response Programs*, filed with the Commission, January 16, 2007, 5.

¹⁰⁷ Conference call between Staff and members of the Demand Response Coordinating Committee, June 8, 2007.

¹⁰⁸ CPUC Decision (D.) 06-11-049, November 2006.

¹⁰⁹ EnerNOC press releases, March 2, 2007, and March 20, 2007.

¹¹⁰ EnerNOC press release, March 15, 2007.

and Energy Curtailment Specialists, Inc., for a minimum of 40 MW from commercial and industrial customers.¹¹¹

Barriers Remain

A review of the experience with the development of demand-response policies since the publication of the 2006 FERC Staff Demand Response Assessment suggests that, in addition to the regulatory barriers identified in the 2006 report,¹¹² there are two additional regulatory barriers.

- **Lack of sufficient real-time information sharing.** A clear lesson from the summer 2006 heat waves and record system peaks is the need for greater real-time coordination and real-time information sharing on demand-response activities run by ISOs, utilities, and unregulated providers. Coordination issues were an issue in CAISO and Midwest ISO, less so in PJM and ERCOT. Staff undertook numerous interviews with multiple participants to piece together the picture of demand response this summer. For these four RTOs and ISOs, not one of them collected or had access to all responses. That is, they were unaware or unsure of the extent of participation by retail programs, conservation, or other resources which were central to their ability to maintain system reliability on peak days.
- **Continuing barriers to implementing critical peak pricing tariffs.** Critical-peak pricing (CPP), a time-of-use rate which includes an extreme price to be used either during system emergencies or periods of high wholesale prices, dramatically reduced peak demand and was acceptable to smaller customers during a statewide pricing pilot in California.¹¹³ While the number of utilities which have announced plans for CPP programs has increased, they are reluctant to rely on elasticity data which came exclusively from the California pilot results, and many still feel they first need to conduct pilots to test customer response in their own service territories.¹¹⁴

¹¹¹ ECS press releases, March 7, May 8, and June 5, 2007.

¹¹² The 2006 FERC Staff Demand Response Assessment identified the following regulatory barriers:

- Disconnect between retail pricing and wholesale markets.
- Utility disincentives associated with offering demand response.
- Cost recovery and incentives for enabling technologies.
- The need for additional research on cost-effectiveness and measurement of reductions.
- The existence of specific state-level barriers to greater demand response.
- Specific retail and wholesale rules that limit demand response.
- Barriers to providing demand-response services by third parties.
- Insufficient market transparency and access to data.
- Better coordination of federal-state jurisdiction affecting demand response.

¹¹³ 2006 FERC Demand Response Assessment, 57-60.

¹¹⁴ Wayne Harbaugh, "BGE Pilot," presentation to MADRI, May 14, 2007, *available at*: http://www.energetics.com/MADRI/pdfs/MADRI_CPP_Pilot_0507_Harbaugh.pdf.

III. Advanced Metering

Interest and investment in advanced metering (referred to here as advanced metering infrastructure or AMI) continues to gain momentum. A number of large utilities announced planned AMI deployments, filed with their state regulatory commissions, and/or received approval to recover AMI investments from ratepayers since the publication of the last report. In addition, a number of state legislatures and state public utility commissions have issued new rulemakings, orders, and/or initiatives in support of AMI investment (and time-based rates). These new announced deployments and state activity are important because they will create the necessary infrastructure and capability to support demand response.

This chapter has four sections:

- Definition and Background
- Developments in Advanced Metering
- Recent AMI Initiatives by States and Utilities
- Issues and Challenges

Definition and Background

The 2006 FERC Demand Response Assessment defined advanced metering as follows:

Advanced metering is a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point.¹¹⁵

This report continues to so define advanced metering, but notes that functionality and capability of advanced metering (which includes advanced meters, communications networks, and data management systems) are evolving.

What makes meters “advanced” or “smart” is the underlying technology. Advanced metering is based on digital electronic and fixed network communications technologies. Through the use of these technologies, advanced metering enables potential operational benefits and efficiencies and provides support for demand response and energy efficiency programs previously unsupported with older electro-mechanical meters. AMI’s most basic functions involve reading and recording customer electric (and/or gas or water) usage at programmed hourly intervals (or shorter term intervals or on-demand), and then storing and forwarding that information over fixed networks for use by customers and customer-based systems, grid operators, and utilities. Among the most valuable capabilities of AMI in terms of providing operational efficiencies and cost savings are automated remote meter readings and remote outage detection, diagnosis, and restoration.

AMI is significant as a demand-response enabling technology, as well, because the capability to provide quality hourly or shorter-term interval data readings is needed to support time-based rates.¹¹⁶ Time-based rates, such as real-time pricing, allow customers to be charged rates that vary dynamically over some period, e.g., hourly, based on the underlying wholesale cost of electricity in the day-ahead (or real-time

¹¹⁵ 2006 FERC Demand Response Assessment, 17.

¹¹⁶ Demand Response and Advanced Metering Coalition (DRAM) comments before the State of New York Public Service Commission in the Matter of Competitive Metering, Case 00-E-0165.

market). AMI can also allow customers to see their usage and the corresponding price for that usage and to modify their usage in response to the price. AMI can also provide utilities and grid operators the capability to monitor electric usage by an individual customer as well as by groups of customers, and to perform automated or manual load control and distribution system operations and maintenance.

The communications networks that advanced metering uses may either be configured to allow one-way or two-way communications.¹¹⁷ Two-way AMI networks allow communications between both the customer and the meter and between the grid operator and the meter. One-way communications networks, by comparison, are only designed to support reporting of customer usage from the meter out to the utility and/or to grid operators. Two-way AMI communications networks enable the grid operator to control a customer's usage and remotely diagnose and repair outages. Additionally, two-way AMI communications networks can provide price information or system conditions to the customer and in-home devices, such as smart thermostats, air conditioning units, and computer networks that link to in-home appliances. Consequently, two-way AMI networks have greater capacity to support various forms of demand response.

AMI requires the use of fixed networks to communicate usage data and should not be confused with mobile networking that requires drive-by or walk-by meter readings. Fixed networks used for advanced metering may be either wireless-based (e.g., radio frequency (RF)) or wired (such as power line communications or broadband over power line) or may be a combination of both wireless and wired networking.

In contrast with AMI and its fixed communications networks, meters can also be read by drive-by or walk-by remote readers. These drive-by or walk-by readers are generally referred to as automated meter reading (AMR) technology. However, some AMR meter implementations do use fixed networks. AMI and AMR are competing technologies, with the implementation of AMR possibly discouraging the installation of the more demand response-friendly AMI. This "competition" is discussed below.

Through May 2007, AMR meters are still out-shipping AMI meters.¹¹⁸ Notably, however, a number of utilities have recently announced plans to deploy AMI meters to replace not only electro-mechanical meters, but also replace previously installed AMR meters (e.g., Connecticut Light & Power).¹¹⁹ At least one analyst forecasts that AMI meter sales will outpace AMR meter sales within 3 to 5 years.¹²⁰ Together AMR and AMI meter sales have been experiencing approximately 20 percent compounded growth yearly over the past several years.¹²¹ Such compounded growth is forecasted to continue for the next 5 to 6 years.¹²² However, AMI near-term growth potential may be capped by existing and near-term available manufacturing capability limitations.¹²³

¹¹⁷ *Id.*

¹¹⁸ Personal communication with Howard Scott (Cognyst Advisors), June 6, 2007. Cognyst publishes the *Scott Report: AMR Deployments in North America*, which tracks advanced metering shipment data and trends.

¹¹⁹ CL&P compliance filing, "Advanced Metering Infrastructure Plan," in Docket No. 05-10-03 Order No. 7.

¹²⁰ Howard Scott.

¹²¹ *Id.*

¹²² *Id.*

¹²³ *Id.*

AMI Functions

The list of functions being required of AMI systems by various utilities is growing. The following list is a compilation of typical specifications listed by a number of utilities in their recent AMI RFPs.¹²⁴

- ability to provide time-stamped interval data for each customer, at least hourly, but often as short an interval as 15 or 30 minutes,
- option of remote disconnect/connect for some or all meters,
- ability to remotely upgrade meter firmware,¹²⁵
- ability to send messages to equipment in or around customer home to support demand response,
- positive notification of outage and restoration (promising both significant cost savings and customer service benefits),
- capability to remotely read meters on-demand,
- voltage flagging capability if voltage is outside of range configurable by utility,
- voltage interval reading capability at same interval as meter readings,
- tamper flagging capability,
- memory to store specified number of days of readings on meters (anywhere from 7 to 45 days, depending on the utility),
- support for some form of prepay metering,
- daily register reading of meters, often at midnight,
- inclusion of data warehousing systems -- seen as increasingly necessary to store large volumes of data gleaned from AMI and meter data management systems (MDM),
- tight integration with MDM into overall operations management systems -- with links to accounting, billing, reporting, outage management, and other operations systems, and
- ability to extend AMI and smart grids to multiple in-home appliances connected together as part of a home-area network (HAN).

Two notable AMI requirements added to the list of specifications in RFPs since the last report are remote connect/disconnect capability and connectivity between the grid and HANs.

Remote Connect/Disconnect

Remote connect/disconnect is a key new feature and has been included as a requirement in “almost every request for information or RFP issued by major investor owned utilities or large municipals in the last year.”¹²⁶ Southern California Edison in particular, has been a big proponent of this capability because it has over five million customers, and well over one million of those customers on average move per year.¹²⁷ With remote connect/disconnect, Southern California Edison is able to disconnect a residence when the prior owner vacates and then reconnect remotely when the new customer needs it.¹²⁸ This feature is important for other reasons as well. In Texas, remote connect/disconnect makes it possible to

¹²⁴ Patti Harper-Slaboszewicz (Utilipoint), May 16, 2007.

¹²⁵ “Computer programming instructions that are stored in a read-only memory unit rather than being implemented through software.” *The American Heritage® Dictionary of the English Language*, Fourth Edition, 2007, Houghton Mifflin Company.

¹²⁶ Patti Harper-Slaboszewicz (Utilipoint), May 30, 2007, *IssueAlert*, available at <http://www.utilipoint.com/issuealert/article.asp?id=2863>.

¹²⁷ *Id.*

¹²⁸ *Id.*

easily switch customers from one competitive retail provider to another as needed.¹²⁹ Remote connect/disconnect may also be valuable for its ability to avoid extended outages and overloading of transformers at critical peak by allowing grid operators to disconnect customers where lines are stressed.¹³⁰

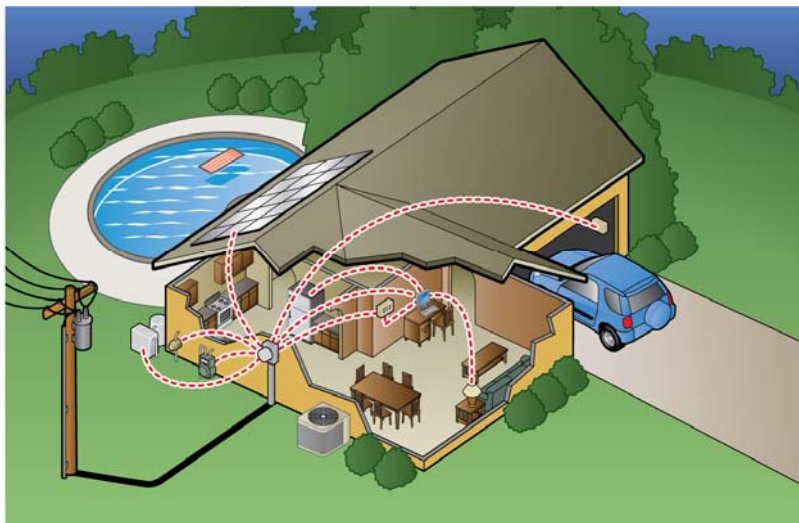
Home-Area Networks

The ability to connect to a HAN is another AMI feature that has gained attention in the last year. A HAN “is a network contained within a user's home that connects a person's digital devices, from multiple computers and their peripheral devices to telephones, VCRs, televisions, video games, home security systems, "smart" appliances, fax machines and other digital devices that are wired into the network.”¹³¹ Including a HAN module into the meter allows multiple in-premise (or in-home) appliances to be interconnected, yet individually identifiable, potentially affording the following benefits:

- remote load control over multiple in-home appliances,
- enhanced ability, with its two-way communications capability, to measure, verify and dispatch demand response, and
- feedback displays to consumers showing them the billing effects associated with usage of various appliances.¹³²

An illustration of the interconnectedness of HANs with AMI and various devices inside and outside of a home is shown in Figure III-1. As this figure illustrates, a HAN-enabled electric meter can serve as the hub of communications.

Figure III-1. Illustration of AMI and home-area-networks



Source: Southern California Edison

¹²⁹ *Id.*

¹³⁰ *Id.*

¹³¹ Webopedia.com (<http://www.webopedia.com/TERM/H/HAN.html>).

¹³² UtilityAMI High-Level Requirements, Revision 2.7, Approved August 4, 2006, available at http://www.electricitydeliveryforum.org/pdfs/UtilityAMI_High-Level_Reqv2-7Approved.pdf.

A significant issue associated with enabling device interconnection is choosing and configuring a particular open-standard HAN connectivity solution. Several competing protocols are available. Due largely to its inclusion in the Southern California Edison AMI concept, Zigbee, a HAN wireless mesh protocol received particular focus.¹³³ Other non-proprietary HAN wireless networks also are available, e.g., Z-Wave, Home-Plug, WiFi, Bluetooth, Insteon, and EIA 709.

Developments in Advanced Metering

Since last year's Commission staff report, AMI gained support from a number of initiatives. For example, at its 2007 Winter Meeting, the National Association of Regulatory Utility Commissioners (NARUC) issued a resolution that recognized the benefits of advanced metering. The resolution calls for elimination of barriers to advanced metering and recommends that state commissions provide investment incentives and accelerated depreciation to help utilities quickly recover their advanced metering investments.¹³⁴

Recent AMI Initiatives by States and Utilities

This section reviews state AMI initiatives, including the status of the AMI proceedings that were required in EAct 2005, and recent announcements of utility AMI deployment.

EAct 2005 PURPA Metering Assessments

Section 1252(b) of EAct 2005 added a new section 115(i) to the Public Utility Regulatory Policies Act of 1978 (PURPA)¹³⁵ that requires states to investigate demand response and time-based metering. Section 115(i) of PURPA states that "each state regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs." Section 1252(b) also requires states to report their findings to Congress by August 8, 2007.

By July 2007, most states had open proceedings to discuss the EAct provisions. States, such as Ohio, commenced comprehensive proceedings to examine the advanced metering PURPA standard. Other states, such as California, did not institute a specific PURPA proceeding, but have been engaged in detailed, ongoing proceedings relating to AMI. Twelve states have concluded their proceedings, with two deciding that it was appropriate for their utilities to provide and install time-based meters. Another 11 opted to not require it. Information on the activities of state regulatory agencies in response to EAct 2005 is included in Appendix E.

¹³³ ZigBee is a low-cost, low-power, industry standard (IEEE 802.15.4) control system for appliances and applications that is adaptable to many different configurations and situations. It securely allows communications using the 8 AES 128 bit encryption standard (the same standard that is used in ATM machines) between devices such as lighting controls, thermostats, energy display, and security systems. HAN protocols such as ZigBee can provide a control link to demand-response equipment, allowing verifiable participation in demand-response programs. [Project No. 31418 -- Rulemaking Related to Advanced Metering, Initial Comments of Coalition of Retail Marketers, December 18, 2006]

¹³⁴ NARUC Winter 2007, "Resolution to Remove Regulatory Barriers To the Broad Implementation of Advanced Metering Infrastructure", adopted February 21, 2007, *available at* <http://www.naruc.org/associations/1773/files/resolutions/winter07/res.to.remove.regulatory.barriers.to.the.broad.implementation.of.advanced.metering.infrastructure.pdf>.

¹³⁵ Pub. L. No. 95-617, 92 Stat. 3117 (1978) (codified in U.S.C. titles 15, 16, 26, 30, 42, and 43).

State AMI Activity

In addition to the proceedings required by EAct 2005, many states have engaged in additional activity on advanced metering. State regulators have taken actions ranging from the approval of smart meter projects or AMI deployment to re-establishing collaborative efforts and workshops to issuing rulemakings. Table III-1 details activity in certain individual states.

Table III-1. State AMI initiatives

State	Activity
California	<p>PG&E—received approval of its Smart Meter project application from the CPUC.</p> <p>SDG&E—received approval of its smart meter project following a settlement with the utility, the PUC’s Division of Ratepayer Advocates, and advocacy group the Utility Consumers Action Network.¹³⁶</p> <p>SCE—requested approval for its Phase II AMI Pre-Deployment Activities and Cost Recovery Mechanism is pending before the CPUC.¹³⁷</p>
Connecticut	<p>The state of Connecticut passed a new DR-AMI bill requiring utilities in the state to:</p> <ul style="list-style-type: none"> ○ install new “smart” meters and associated technologies capable of measuring real-time prices, in support mandatory TOU pricing. ○ deploy AMI by January 1, 2009.¹³⁸ <p>Connecticut Light & Power—submitted its AMI plan, which is pending before the DPUC.¹³⁹</p>
District of Columbia	<p>The DC PSC approved a pilot program (PowerCentsDC), which allows residential customers involved with the pilot to test three different pricing schedules.¹⁴⁰ It is said to be a first of its kind pilot in the electric industry.¹⁴¹</p>

¹³⁶ SDG&E's "smart meter" program receives final state approval, April 12, 2007, available at http://public.sempra.com/newsreleases/viewpr.cfm?PR_ID=2150&Co_Short_Nm=SDGE.

¹³⁷ SCE's *Application for Approval of Advanced Metering Infrastructure Pre-Deployment Activities and Cost Recovery Mechanism*, available at http://www.sce.com/NR/rdonlyres/5F9E844C-9958-431D-B822-A6B72F544174/0/01_2007_AMI_Phase_II_legal_Insert.pdf.

¹³⁸ CL&P compliance filing “Advanced Metering Infrastructure Plan,” in Docket No. 05-10-03 Order No. 7. See also Sections 13(a) and 13(c) of Connecticut’s Public Act 05-01, *An Act Concerning Energy Independence* (“EIA”).

¹³⁹ *Id.*

¹⁴⁰ Formal Case No. 1002, In The Matter Of The Joint Application Of Pepco And The New RC. Inc. For Authorization And Approval Of Merger Transaction. DC PSC Order No. 14166 (January 12, 2007).

¹⁴¹ Transmission & Distribution World, *Pilot Program to Help Washington DC Customers Manage Electricity Bills* (May 9, 2007), available at http://tdworld.com/info_systems/highlights/sensus-smart-metering-contract/index.html.

Table III-1. State AMI initiatives (Cont.)

State	Activity
Maryland	<p>BG&E—the MD PSC approved BGE’s demand-response pilot program¹⁴² and BGE’s request for rate schedule changes and surcharges to cover a Phase I pilot of the proposed AMI deployment.¹⁴³</p> <p>Pepco—filed for authority to establish surcharges to support DSM and AMI deployment initiatives;¹⁴⁴ and received approval to establish a DSM Collaborative and AMI Advisory Group.¹⁴⁵ The DSM Collaborative would review and discuss Pepco’s proposed DSM programs. The AMI Advisory Group would “be kept apprised of the progress, status, components and development of Pepco’s AMI installation.”¹⁴⁶ Pepco proposed that the advisory group be comprised at minimum of Pepco, the Maryland PSC, the Office of People’s Counsel (OPC), and the Maryland Energy Administration.¹⁴⁷</p>
New York	<p>New York State Public Service Commission (NYSPSC)—issued an Order requiring electric utilities to conduct AMI cost-benefit studies and file comprehensive plans for development and deployment of advanced metering systems.¹⁴⁸</p> <p>Con Edison and Energy East (Rochester Gas & Electric (RG&E) and New York State Electric & Gas (NYSEG))—have filed their plans.¹⁴⁹ In its plan, Energy East suggested that with NYSPSC approval, RG&E and NYSEG could begin meter installation as early as 2008.¹⁵⁰</p> <p>Con Edison—filed a proposal for an electric rate increase which included \$340 million to install AMI and AMR (May 4, 2007).¹⁵¹</p>

¹⁴² BG&E filing with MD PSC, January 23, 2007, *available at* http://webapp.psc.state.md.us/Intranet/CaseNum/NewIndex3_VOpenFile.cfm?filepath=C%3A%5CCasenum%5C9100-9199%5C9111%5CItem_1%5CBourland1-23-07.pdf.

¹⁴³ *Id.*

¹⁴⁴ Application Of PEPCO For Authorization To Establish A Demand Side Management Surcharge And An Advance Metering Infrastructure Surcharge And To Establish A DSM Collaborative And An AMI Advisory Group (March 21, 2007).

¹⁴⁵ Pepco DSM/AMI application (March 21,2007).

¹⁴⁶ *Id.*

¹⁴⁷ *Id.*

¹⁴⁸ Notably, Con Edison in its compliance filing, proposes full AMI deployment except where it already had installed automated meter reading in Westchester. There it proposes to upgrade the automated meter reading system with pole top collectors that allow more frequent than once per month readings (Con Edison compliance filing, March 28, 2007).

¹⁴⁹ Advanced Metering Infrastructure Overview and Plan, Rochester Gas and Electric Corporation New York State Electric and Gas Company, February 1, 2007, *available at* http://www.dps.state.ny.us/NYSEG_RGE_AMI_Filing.pdf.

¹⁵⁰ *Id.*

¹⁵¹ Con Edison of New York's Electric Rate Case Filing - May 4, 2007, *available at* <http://investor.conedison.com/phoenix.zhtml?c=61493&p=irol-newsArticle&ID=995985&highlight=>.

Table III-1. State AMI initiatives (Cont.)

State	Activity
Ohio	<p>PUC of Ohio—adopted recommendations to require state electric distribution companies to file reports that included a list of advanced metering technologies and costs.¹⁵² In that same decision, the PUC of Ohio “indicated that all electric distribution utilities should offer tariffs to all customer classes, which are, at a minimum, differentiated according to on- and off-peak wholesale periods. Moreover, it noted that time-of-use meters should be made available to customers subscribing to the on- and off-peak tariffs.”¹⁵³</p> <p>PUC of Ohio—initiated proceeding 07-646-EL-UNC to establish AMI workshops to study the cost/benefits of AMI deployment strategies and cost recovery mechanisms.¹⁵⁴ The first workshop was set for July 26, 2007.¹⁵⁵</p>
Pennsylvania	<p>PA PUC—tasked the Pennsylvania Demand Side Response Working Group to perform cost-benefit assessments for all utilities to further develop their advanced metering infrastructure.¹⁵⁶</p> <p>Commonwealth of Pennsylvania— issued a policy statement stating the public should have access to historic billing data and real time metered data to facilitate retail choice, demand side response, and energy conservation initiatives.¹⁵⁷</p>

¹⁵² Case No. 05-1500-EL-COI.

¹⁵³ Before the PUC of Ohio, In the Matter of the Commission-Ordered Workshop Regarding Smart Metering Deployment, Case No. 07-646-EL-UNC (June 27, 2007), *available at* <http://dis.puc.state.oh.us/TiffToPDF/A1001001A07F27B23701E87977.pdf>.

¹⁵⁴ Case No. 07-646-EL-UNC, PUC of Ohio (June 27, 2007).

¹⁵⁵ Case No. 07-646-EL-UNC, PUC of Ohio (June 27, 2007).

¹⁵⁶ NOTICES: Investigation of Conservation, Energy Efficiency Activities and Demand Side Response by Energy Utilities and Ratemaking Mechanisms to Promote Those Efforts; Doc. No. M-00061984 [36 Pa.B. 6485] [October 21, 2006], Public Meeting held September 28, 2006.

¹⁵⁷ Final Policy Statement on “Default Service and Retail Electric Markets,” § 69.1812. Information and data access (Docket No. M-00072009).

Table III-1. State AMI initiatives (Cont.)

State	Activity
Texas	<p>State of Texas—passed legislation (House Bill 2129) in 2006 allowing utilities to use surcharges to fund advanced meters.¹⁵⁸</p> <p>PUC of Texas—issued a proposed rulemaking that lists minimum functionality criteria utilities would be required to meet with their advanced metering deployments. The Texas rulemaking added several advanced capabilities to the minimum functionality criteria, such as two-way communications, capability to provide timely customer usage data to retail electric providers, capability for customers to receive pricing signals from their retail electricity providers or a designated customer agent, and the ability to upgrade capabilities as technology advances.¹⁵⁹ The proposed rulemaking also states that an electric utility “shall not deploy an AMS (advanced metering system) that has not been successfully installed previously with at least 500 advanced elsewhere in the world, except for pilot programs.”¹⁶⁰</p> <p>On September 29, 2006, the PUC of Texas reported to the Texas legislature its finding that there are no barriers to AMI in Texas.¹⁶¹</p>
Vermont	Vermont Public Service Board—opened a docket requiring both statewide AMI and utility-by-utility AMI cost-benefit studies. ¹⁶²

Large Utility AMI Deployment Plans and Activity

AMI market activity, as measured by the number of meters planned or installed, increased nearly three-fold from 2005 to 2006, and is projected to double again by 2008. Utilities are signing contracts, filing AMI plans with regulators, operating AMI pilot programs, issuing RFPs for AMI infrastructure or consulting assistance, and announcing plans to implement AMI. This section documents these deployment announcements.¹⁶³

Figure III-2 shows a general trend of increased market activity, based on the number of meters installed or planned through 2006, and projections for 2007 and 2008. However, this implementation was heavily influenced by PG&E’s 2006 announcement of 5 million meters (PG&E accounted for two-thirds of the meters in 2006). If all of the announced deployments since the last report that are indicated in this Figure actually occur, over 40 million new advanced meters will be deployed in the next several years.¹⁶⁴ But given the influence of particularly large, individual utilities, penetration may be focused in certain geographic areas.

¹⁵⁸ PUC of Texas, Project No. 31418 Proposal for Publication of Amendments.... etc., as approved at the October 26, 2006 Open Meeting.

¹⁵⁹ *Id.*

¹⁶⁰ *Id.*

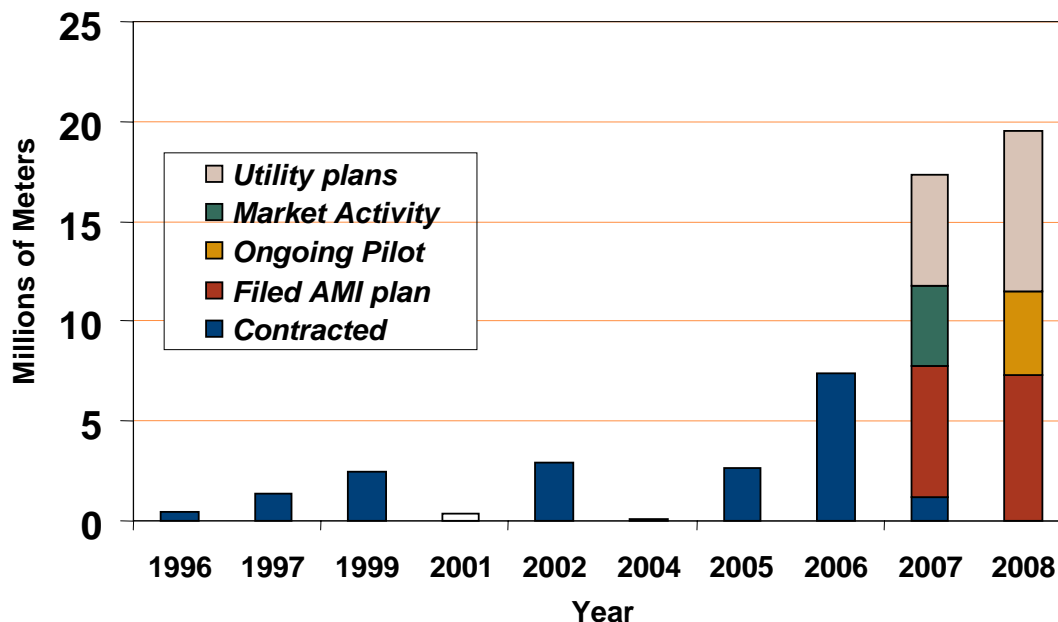
¹⁶¹ PUC of Texas, January 2007, Report to the 80th Texas Legislature on “Scope of Competition in Electric Markets in Texas, available at http://speakuptexas.com/electric/reports/scope/2007/2007scope_elec.pdf.

¹⁶² Vermont Public Service Board, Smart Metering RFP available at <http://publicservice.vermont.gov/energy-efficiency/SmartMeterRFP.pdf>.

¹⁶³ Of course, the most firm indication of market activity is when a utility has an agreement or has signed a contract with an AMI vendor. However, until the AMI enabled meter is actually installed, utilities may make changes or delay their AMI purchasing activity.

¹⁶⁴ Commission staff estimates that if these announcements result in deployments, the market penetration of advanced metering in the U.S. could be over 20 percent by the end of 2010.

Figure III-2. AMI market activity, actual and projected

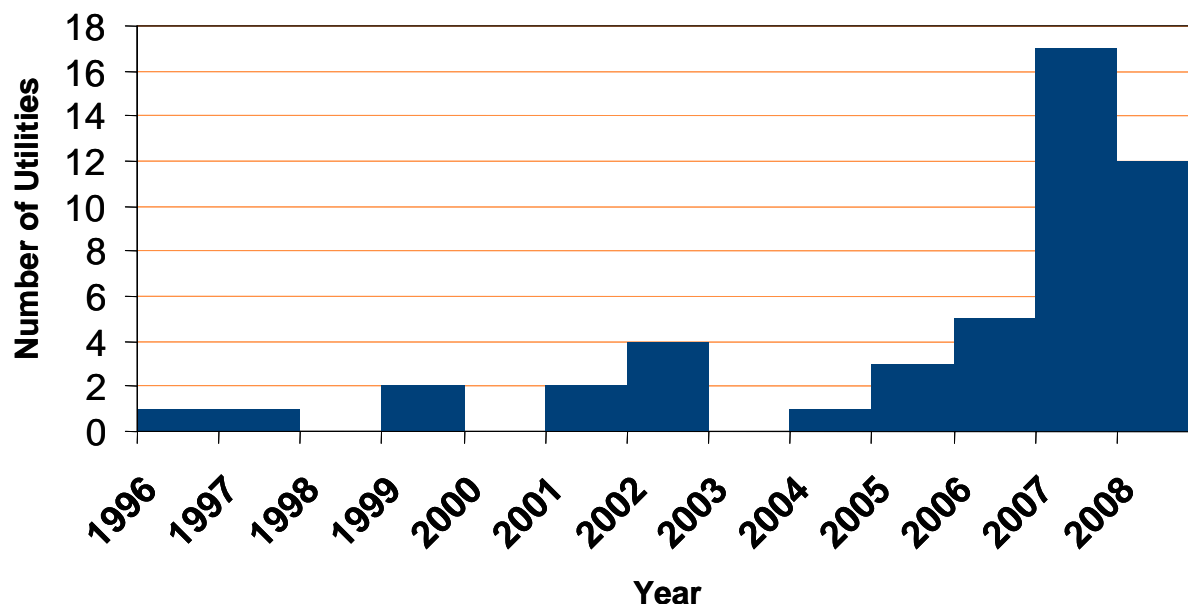


Source: UtiliPoint International

Notes:

- Contracted: the utility and the AMI vendor announced an agreement and/or signed a contract.
- Filed AMI plan: the investor owned utility filed a plan to invest in AMI with its regulator.
- On going pilot: the utility is actively engaged in piloting AMI systems from one or more AMI vendors.
- Market activity: the utility has issued RFPs for either AMI or an AMI consultant, or has hired an AMI consultant to prepare an RFP for AMI.
- Utility plans: the utility has publicly announced plans for investing in AMI.

Because one utility can have such a large impact on data, another means to assess trends in utility AMI deployments is through counting the number of utility announcements per year. This adjusts for the impact that one or two large utilities, such as PG&E, can have on the number of meters deployed. Figure III-3 presents the trend in AMI deployment as measured by the number of large utility deployments.

Figure III-3. Number of utilities announcing AMI deployments

Source: UtiliPoint International

In 2006, five utilities announced large deployments of AMI, and by 2007 an additional 17 large AMI deployment announcements are expected, with various degrees of certainty. Five have been announced to date. Projections suggest that 2007 and 2008 should continue the trend of increasing activity in the market.

A detailed list of some of the large AMI deployments that have been announced or are expected with some level of confidence by the end of 2008 can be found in Table F-1 in Appendix F.¹⁶⁵ Of particular note in this list are several recent announcements.

- Pepco Holdings, Inc., filed a Blueprint for the Future with Delaware, District of Columbia, and Maryland, which includes plans to deploy AMI for all of its customers to support demand response, the environment, improve customer service, and reduce operational costs.
- The three California investor-owned utilities are all pursuing AMI with strong encouragement from the CPUC. PG&E is in the early stages of deploying their 5.1 million meters while SCE and SDG&E are expected to begin deployment in 2007 or 2008. Together these three utilities represent over 10 million meters.
- Duke Energy has also announced plans to deploy AMI in its Kentucky operations. In testimony filed with the Public Service Commission of Kentucky in 2006, Duke Energy noted that “Duke Energy Kentucky expects to deploy AMI infrastructure in the near future.”¹⁶⁶ Another large utility (close to five million meters), American Electric Power, is evaluating AMI “for

¹⁶⁵ Table F-1 in Appendix F is based on a forecast of implementation compiled by Patti Harper-Slaboszewicz of UtiliPoint International under contract to FERC.

¹⁶⁶ Direct Testimony of Bruce L. Sailors on Behalf of Duke Energy Kentucky, In the Matter of Consideration of the Requirements of the Federal Energy Policy Act of 2005 Regarding Time-Based Metering, Demand Response, and Interconnection Service, May 19, 2006, 10.

deployment initially within our largest urban areas. AEP has performed a detail analysis for Columbus, Ohio, and is awaiting regulatory review before proceeding further.”¹⁶⁷

- Large cooperatives and municipal utilities are also implementing advanced metering. The City of Tallahassee, Florida (108,000 meters) has announced plans for AMI in 2007,¹⁶⁸ as well as plans for the deployment of smart thermostats.

Issues and Challenges

In its review of issues associated with advanced metering, Commission staff identified three important issues and challenges:

- Technological obsolescence concerns
- Deployment decisions
- Interoperability and open standards

Technological Obsolescence Concerns

According to its many proponents, AMI technology has arrived. Most of the issues facing AMI that remain are associated with deployment strategies. Still, issues of uncertain meter life-expectancy and risk of post-installation technological obsolescence remain, which would result in having to replace the meters before original costs are recovered. Notably, metering analysts report that a number of recent RFPs have, as a result, included requirements for warranties of advanced metering equipment and have required that the firmware be remotely upgradeable, in order to mitigate these risks.¹⁶⁹

Deployment Decisions

AMI implementations come with a significant price tag, even as the cost of the advanced meters themselves continues to decrease. This is especially true for large and full-featured AMI deployments. Furthermore, utilities and their regulators are faced with evaluating a number of alternative metering products, network configurations, and deployment strategies in designing and evaluating AMI systems for cost-effectiveness over the life of the meters. Pilots or test-phase deployments continue to be used extensively to assess costs and benefits and to allow both utilities and their customers to test and “try out” various AMI products, configurations, and features.

Interoperability and Open Standards

As discussed in more detail in last year’s Commission staff report, there are technology standards on common functionality of AMI systems. In particular, ANSI standard C12.19 (Utility Industry End Device Tables) enables metering data and data tables to be transferred from one computer application and system to another. The next standard, ANSI standard C12.22 (Protocol Specification for Interfacing to Data Communications Networks), which would enable C12.19 metering data structures to be shared over any combination of “physical” network media,¹⁷⁰ is pending.

¹⁶⁷ “Utility Considering its Advanced Metering Options”, Energy Pulse, J. Carr and D. Fitchett, February 16, 2007.

¹⁶⁸ At the March 28, 2007 City Commission meeting, the decision to invest in Smart Metering and Smart thermostats was approved by the City Commission which oversees the city utility. See <http://www.talgov.com/commission/meetings/agendas/070328.cfm>.

¹⁶⁹ Information provided FERC by Patti Harper-Slaboszewicz (Utilipoint), May 16, 2007.

¹⁷⁰ Notably, the state of Texas has included C12.22 compliance among its list of minimum AMS features that a utility is required to include with its AMS deployment.

Since last year's Commission staff report, utilities looking to deploy AMI with HAN-connectivity have focused attention on how to configure HAN to AMI systems connections.¹⁷¹ HAN connectivity represents a new opportunity for advanced metering, but also introduces a new issue. The heart of the issue is whether the utility-owned meter should serve as the connection (or "gateway") to the HAN, or whether AMI-based gateways only serve to exclude competitive third-party HAN solutions. In other words, deploying advanced meters with grid-to-HAN gateway switches makes those gateways part of the utility-provided metering solution. Some AMI consultants as well as HAN solution vendors argue that third party HAN connectivity solutions do not need utility-based advanced meter gateway switches.¹⁷² Proponents of utility-based gateways, on the other hand, argue that utilities are best positioned to provide meter-to-HAN connectivity services and that use of these gateways allows needed central administration and verification for load control and demand-response purposes, e.g., "to provide Critical Peak Pricing (CPP) and other emergency event customer notifications.," "...provide better confirmation that these notifications were both sent and received," and "significantly reduce the need to outsource such communication activities to third party providers."¹⁷³

¹⁷¹ Information provided to FERC staff by Patti Harper-Slaboszewicz (Utilipoint), May 16, 2007.

¹⁷² Personal communications with Roger Levy (Levy and Associates), May 31, 2007.

¹⁷³ Supplemental Testimony Supporting Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism; *VOLUME 5 – Advanced Integrated Meter(AIM) Directional Cost Benefit Analysis and Future Benefits Allocation*; Before the Public Utilities Commission of the State of California (August 1, 2005). See http://www.sce.com/NR/rdonlyres/F595B029-0189-4C2B-932A-B589BA052B49/0/SCEMarch30_2005_Application_Vol5.pdf

Appendix A: Glossary for the Report

Actual Annual MWh change: The actual sum of MWh changes due to customer participation in a sponsored Demand Response (DR) program.

Actual MWh Change: The total annual change in energy consumption (measured in MWh) that resulted from the deployment of demand-response programs during the year.

Actual Peak Reduction (APR): The coincident reductions to the annual peak load (measured in megawatts) achieved by customers that participate in a demand-response program at the time of the annual system peak of the utility or ISO. It reflects the changes in the demand for electricity resulting from a sponsored demand-response program that is in effect at the same time a utility or ISO experiences its annual system peak load, as opposed to the installed peak load reduction capability (i.e., Potential Peak Reduction). It should account for the regular cycling of energy efficient units during the period of annual system peak load. For curtailment service providers (CSP), the actual peak reduction should include the demand-response load provided at the time of the peak for the region in which they aggregate customer load. For utilities, it should include the demand-response load at the time of the utility annual system peak load. For RTOs/ISOs, it should include the demand-response load at the time of the RTO/ISO annual system peak load.

Advanced Metering Infrastructure (AMI): AMI or “advanced metering” is defined as a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point. AMI includes the communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection and distribution of information to customers and other parties such as competitive retail providers, in addition to providing it to the utility itself.

Ancillary Services: Those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system. Ancillary services supplied with generation include load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services.

Ancillary Service Market Programs: Demand-response programs in which customers bid load curtailments in RTO/ISO 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 RTO/ISO, and may be paid the spot market energy price.

Asset Management: The ability to leverage the value of metering data and other available information to increase the value of utility investments and/or to improve customer service. One example is using hourly interval data to measure the load on transformers at the time of the system peak.

Automated Meter Reading: automatic or automated meter reading -- allows meter read to be collected without actually viewing or touching the meter with any other equipment. One of the most prevalent examples of AMR is mobile radio frequency whereby the meter reader drives by the property, and equipment in the car receives a signal sent from a communication device under the glass of the meter.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection

frequency in real time.

Bid Limits: The maximum \$/MWh bid that can be submitted by a program participant.

Billing or Revenue Meter: Meters installed at customer locations that meter electric usage and possibly other parameters associated with a customer account and provide information necessary for generating a bill to the customer for the customer account.

Capacity Market Programs (CAP): Demand-response programs in which customers offer load curtailments as system capacity to replace conventional generation or delivery resources. Customers typically receive day-of notice of events and face penalties for failure to curtail when called upon to do so. Incentives usually consist of up-front reservation payments.

Commercial sector: An energy-consuming sector that consists of service-providing facilities and equipment belonging to: businesses; federal, state, and local governments; and other private and public organizations, such as religious, social, or fraternal groups. The commercial sector includes institutional living quarters, sewage treatment facilities, and street lighting. Common uses of energy associated with this sector include space heating, water heating, air conditioning, lighting, refrigeration, cooking, and running a wide variety of other equipment. Note: This sector includes generators that produce electricity and/or useful thermal output primarily to support the activities of the above-mentioned commercial establishments.

Conservation. Conservation includes consumer actions or decisions to use less energy, perhaps by reconsidering priorities and eliminating some energy use. Actions could include turning off extra lights, raising thermostats in summer or lowering them in winter, and taking pre-vacation steps such as turning off power strips or lowering water-heater temperatures. Conservation and energy efficiency (see separate definition) are often used as though they are synonymous, because both reduce kilowatt hours used by consumers.

Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

Cooperative Electric Utility: An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from federal income tax laws. Most electric cooperatives were initially financed by the Rural Utilities Service (formerly the Rural Electrification Administration), U.S. Department of Agriculture.

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).

Curtailed Service Provider (CSP): Demand-response load providers that are not necessarily load serving entities. CSPs may sponsor demand-response programs and sell the demand-response load to utilities, RTOs and/or ISOs.

Customer Account: A record at the energy provider that identifies an entity receiving electric service at one or more locations within the utility service footprint. The identified entity is responsible for paying the cost of energy consumed and metered at the location(s) on the account. There may be no meter associated with the customer account (such as with street lights), or one or more meters associated with a particular customer account.

Demand: Represents the requirements of a customer or area at a particular moment in time. Typically calculated as the average requirement over a period of several minutes to an hour, and thus usually expressed in kilowatts or megawatts rather than kilowatt-hours or megawatt-hours. Demand and load are used interchangeably when referring to energy requirements for a given customer or area.

Demand Bidding: A demand-response program where customers or curtailment service providers offer bids to curtail based on wholesale electricity market prices or an equivalent. Mainly offered to large customers (e.g., one MW and over), but small customer demand-response load can be aggregated by curtailment service providers and bid into the demand bidding program sponsor.

Demand Response (DR): 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.

Demand Response Aggregator: A company who bids demand reductions or acts an agent on behalf of retail customers directly into the RTO's or ISO's organized markets. Demand-response aggregators act as an intermediary for many small retail loads that cannot individually participate in the organized market because they lack standing as an LSE or because they individually cannot meet a requirement that a demand-response bid be of minimum size.

Demand Response Event: A period of time identified by the demand-response program sponsor when it is seeking reduced energy consumption and/or load from customers participating in the program. Depending on the type of program and event (economic or emergency), customers are expected to respond or decide whether to respond to the call for reduced load and energy usage. The program sponsor generally will notify the customer of the demand-response event before the event begins, and when the event ends. Generally each event is a certain number of hours, and the program sponsors are limited to a maximum number of events per year.

Demand Response Load: The load reduction that results from demand-response activities.

Demand Resources: The set of demand response and energy efficiency resources and programs that can be used to reduce demand or reduce electricity demand growth.

Demand-Side Management (DSM): The planning, implementation, and monitoring of activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It does not refer to energy and load-shaped changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Direct Load Control (DLC): A demand-response activity 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.

Duration of Event: The length of an Emergency or Economic Demand Response Event in hours.

EIA ID Number: Unique identification number assigned by EIA to companies and entities operating in the electric power industry.

Economic Demand Response Event: A demand-response event in which the demand-response program sponsor directs response to an economic market opportunity rather than for reliability or because of an emergency in the energy delivery system of the program sponsor or the RTO/ISO.

Elasticity of Demand: The degree to which consumer demand for a product responds to changes in price, availability or other factors.

Electric Reliability Council of Texas (ERCOT): The electric reliability organization which ensures reliable and cost-effective operation of the grid in the Texas area.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. Included are investor-owned electric utilities, municipal and state utilities, federal electric utilities, and rural electric cooperatives. A few entities that are tariff based and affiliated with companies that own distribution facilities are also included.

Emergency Demand Response Event: A demand-response event called by the program sponsor in response to an emergency of the delivery system of the demand-response sponsor or of another entity such as a utility or ISO.

Emergency Demand Response Program (EDRP): A demand-response program that provides incentive payments to customers for load reductions during periods when reserve shortfalls arise.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatt-hours.

Energy Efficiency: Refers to using less energy to provide the same or improved level of service to energy consumers in an economically efficient way. Energy efficiency uses less energy by employing products, technologies, and systems to use less energy to do the same or better job than by conventional means. Energy efficiency saves kilowatt-hours on a persistent basis, rather than being dispatchable for peak hours, as are some demand-response programs. Energy efficiency can include switching to energy-saving appliances (such as Energy Star® certified products) and advanced lighting (compact fluorescent or LED lighting); improving building design and construction (better insulation and windows, tighter ductwork, use of high-efficiency heating, ventilation, and air conditioning); and redesigning manufacturing processes (advanced electric motor drives, heat recovery systems) to use less energy, thus reducing use of electricity and natural gas.

Enhanced Customer Service: The ability to offer ultimate customers the choice of bill data, additional rate options such as real time pricing or critical peak pricing, verify an outage or restoration of service following an outage, more information to understand a customer concern over an electric bill, reduce bill estimates when a meter read is not available, opening or closing of an account due to customer relocation without requiring a site visit to the meter(s), and/or more accurate bills.

Enrollment: The amount of customer participation in a demand-response program. Participation refers to either the number of customers or the amount of MW who have registered for a program and have met eligibility criteria. Customer participation in a program does not necessarily imply that the customer will actively adjust their consumption due to direction from a grid operator or price signals. Consequently, enrollment typically measures potential demand reduction that could be achieved.

Fixed Network: A fixed network refers to either a private or public communication infrastructure which allows the utility to communicate with meters without visiting or driving by the meter location.

Florida Reliability Coordinating Council (FRCC): The FRCC is one of eight Regional Reliability Councils in the lower 48 states that comprise the North American Electric Reliability Corporation (NERC). It covers Peninsular Florida, east of the Apalachicola River.

Gas Meter: A meter that measures natural gas usage for ultimate customers.

Home-Area Network (HAN): Network contained within a user's home that connects a person's digital devices, from multiple computers and their peripheral devices to telephones, VCRs, televisions, video games, home security systems, "smart" appliances, fax machines and other digital devices that are wired into the network.

ICAP Credit: An RTO or ISO capacity credit to satisfy a resource requirement.

Independent System Operator (ISO): An organization that has been granted the authority to operate, in a nondiscriminatory manner, the transmission assets of the participating transmission owners in a fixed geographic area. ISOs often run organized markets for spot electricity.

Industrial: The energy-consuming sector that consists of all manufacturing facilities and equipment used for producing, processing, or assembling goods. The industrial sector encompasses the following types of activity: manufacturing; agriculture, forestry, and fisheries; mining; and construction. Overall energy use in this sector is largely for process heat and cooling and powering machinery, with lesser amounts used for facility heating, air conditioning, and lighting. Fossil fuels are also used as raw material inputs to manufactured products. This sector may include energy deliveries to large commercial customers, and may exclude deliveries to small industrial customers which may be included in the commercial sector. It also may classify by using the North American Industry Classification System or on the basis of energy demand or annual usage exceeding some specified limit set by the energy provider.

Industrial Customer: Electric power consumers which usually consume large amounts of electricity and are usually in the manufacturing, construction, mining, agriculture, fishing or forestry industries. Utilities usually classify service to these consumers based on their power demand or an annual usage amount which exceeds some specified limit.

Interface with Water or Gas Meters: The ability of the AMI network to collect water or gas meter readings and to transmit the gas or water meter readings over the AMI network to an entity that can provide the gas or water meter readings to the gas or water utility providing the service.

Interruptible/Curtailable Service (I/C): Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. Penalties may be assessed for failure to curtail. In some instances, the demand reduction may be affected by direct action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as Interruptible Demand. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers. Interruptible Demand as reported here does not include Direct Control Load or price responsive demand response.

Interval Data: Interval data is a fine-grained record of energy consumption, with readings made at regular intervals throughout the day, every day. Interval data is collected by an interval meter, which, at the end of every interval period, records how much energy was used in the previous interval period. Common forms of interval data include 15-minute data and hourly data.

Investor-Owned Utility (IOU): A utility organized under state law as a publicly traded corporation for the purposes of providing electric power service and earning profits for its stockholders.

Kilowatt (kW): One thousand watts.

Kilowatt-hour (kWh): One thousand watt-hours.

Line Loss: Electric energy lost because of the transmission of electricity. Much of the loss is thermal in nature.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Load Acting as a Resource (LaaR): An interruptible program operated by ERCOT in which customers may qualify to provide operating reserves.

Load Forecasting: The estimation of future load requirements for specified intervals for a period of time. The load forecast may provide an estimate of hourly loads for a group of ultimate customers for the next five years, for example.

Load Management: Demand management practices directed at reducing the maximum kilowatt demand on an electric system and/or modifying the coincident peak demand of one or more classes of service to better meet the utility system capability for a given hour, day, week, season, or year.

Load-serving entity (LSE): Any entity, including a load aggregator or power marketer, that serves end-users within a control area and has been granted the authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end-users located within the control area.

Maximum Demand: This is determined by the interval in which the 60-minute integrated demand is the greatest.

Maximum Hourly Load: The highest amount of demand that is measured or expected to be curtailed at a certain point in time.

Megawatt (MW): One million watts of electricity.

Megawatt-hour (MWh): One thousand kilowatt-hours or 1 million watt-hours.

Meter Data Management: Meter data management provides utilities a place to store meter data collected from advanced meters. Utilities that install AMI usually invest in meter data management to provide storage for the large number of meter readings that will be collected each year per meter. Meter data management can also translates raw meter data into systems, such as billing, customer service, etc., that require meter data transformed in a particular way.

Midwest Reliability Organization (MRO): The Midwest Reliability Organization (MRO) is one of eight Regional Reliability Councils in the lower 48 that comprise NERC. Its members include the following states: Minnesota, Wisconsin, Iowa, North Dakota, South Dakota, Nebraska, Montana, Illinois and Upper Peninsula of Michigan.

Minimum Term: The minimum length in years that customers are obligated to participate in a demand-response program.

Municipality: A village, town, city, county, or other political subdivision of a state.

National Association of Regulatory Utility Commissioners (NARUC): A non-profit organization whose members include the governmental agencies that are engaged in the regulation of utilities and carriers in the fifty states, the District of Columbia, Puerto Rico.

North American Electric Reliability Corporation (NERC): The organization certified by the Commission as the reliability organization for the nation's bulk power grid. NERC consists of eight Regional Reliability Councils in the lower 48 states. The members of these Councils are from all segments of the electricity supply industry - investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers.

Operating Company: The name a utility uses in doing business within a particular state associated with a particular service territory.

Outage Management: The response of an electric utility to an outage affecting the ultimate customers of the electric service. The utility may use the AMI network to detect outages, verify outages, map the extent of an outage, or verify the service has been restored after repairs have been made.

Peak Demand: The maximum load during a specified period of time.

Potential MWh Change: The potential total annual change in energy consumption (measured in MWh) that would result from the deployment of demand-response programs. It reflects the total change in consumption if the full demand reduction capability of the program were deployed, as opposed to actual MWh change during the year.

Potential Peak Reduction: The potential annual coincident peak load reduction (measured in megawatts) that can be deployed from demand-response programs. It represents the load that can be reduced either by the direct control of the utility system operator or by the consumer in response to a utility request to curtail load. It reflects the installed load reduction capability, as opposed to the Actual Peak Reduction achieved by participants, during the time of annual system peak load. It should account for the regular cycling of energy efficient units during the period of system peak load. For utilities, it should be the potential sum of demand reduction capability to their annual peak load (measured in megawatts) achieved by the program participants. For an RTO or ISO, it should be the sum of coincident reduction capability to the RTO or ISO achieved by participants at the time of system peak of the RTO or ISO. Similarly, for CSPs, it should be the sum of coincident reduction capability sponsored by the CSP and achieved by demand-response program participants at the time of the peak for the region in which the CSP is aggregating customer load.

Power Marketers: Business entities, including energy service providers, that are engaged in buying and selling electricity, but do not own generating or transmission facilities. Power marketers and energy service providers, as opposed to brokers, take ownership of the electricity and are involved in interstate trade. Power marketers file with the Federal Energy Regulatory Commission (FERC) for status as a power marketer. Energy service providers may not register with FERC but may register with the states if they undertake only retail transactions.

Power Quality Monitoring: The ability of the AMI network to discern, record, and transmit to the utility instances where the voltage and/or frequency were not in ranges acceptable for reliability.

Premise Device/Load Control Interface or Capability: The ability of the AMI network to communicate directly with a device located on the premises of the ultimate customer, which may or may not be owned by the utility. These might include a programmable communicating thermostat or a load control switch.

Pre-Pay Metering: A metering and/or software and payment system that allows the ultimate customer to pay for electric service in advance.

Price Responsive Demand Response: All demand-response programs that include the use of time-based rates to encourage retail customers to reduce demands when prices are relatively high. These demand-response programs may also include the use of automated responses. Customers may or may not have the option of overriding the automatic response to the high prices.

Pricing Event Notification Capability: The ability of the AMI network to convey to utility customers participating in a price responsive demand-response program that a demand-response event is planned, beginning, ongoing, and/or ending.

Provision of Usage Information to Customers: The ability of the AMI network to convey to ultimate customers information on their usage in a timely fashion. Timely in this context would be dependent on the customer class, with larger customers generally receiving the information with less lag time than residential customers.

Public Utility: An enterprise providing essential public services, such as electric, gas, telephone, water, and sewer under legally established monopoly conditions.

Public Utility District: Municipal corporations organized to provide electric service to both incorporated cities and towns and unincorporated rural areas.

Publicly Owned Electric Utility: A class of ownership found in the electric power industry. This group includes those utilities operated by municipalities, political subdivisions, and state and federal power agencies (such as BPA or TVA).

Railroad and Railway Electric Service: Electricity supplied to railroads and interurban and street railways, for general railroad use, including the propulsion of cars or locomotives. Such electricity is supplied under separate and distinct rate schedules.

Real Time Pricing (RTP): A retail rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. RTP prices are typically known to customers on a day-ahead or hour-ahead basis.

Reduce Line Losses: The ability to use the AMI network to lower the line losses on the transmission system.

Regional Transmission Organization (RTO): An organization with a role similar to that of an independent system operator but covering a larger geographical scale and involving both the operation and planning of a transmission system. RTOs often run organized markets for spot electricity.

Reliability-Based Program: Programs that are activated during system emergencies or to maintain local or system reliability. Reliability-based demand-response programs typically include emergency demand-response programs, capacity market programs, direct load control (DLC), interruptible/curtailable rates, and ancillary-services market programs.

Remotely Change Metering Parameters: The ability to change parameters associated with a particular revenue or billing meter, such as the length of the data interval measured, without a site visit to the meter location.

Remote Connect/Disconnect: The ability to physically turn on or turn off power to a particular billing or revenue meter without a site visit to the meter location.

Residential: The energy-consuming sector that consists of living quarters for private households. Common uses of energy associated with this sector include space heating, water heating, air conditioning, lighting, refrigeration, cooking, and running a variety of other appliances. The residential sector excludes institutional living quarters. This sector may exclude deliveries or sales to apartment buildings or homes on military bases (these buildings or homes may be included in the commercial sector).

Response Time: The maximum notice and lead time that a demand-response program sponsor provides to demand-response program participants prior to an economic or emergency demand-response event.

Responsive Reserve: The daily operating reserves in ERCOT that are intended to help restore the frequency of the interconnected transmission system within the first few minutes of an event that causes a significant deviation from the standard frequency.

Retail: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, also are included in this category.

Revenue Assurance: A set of activities designed to increase the revenue from providing electric service to ultimate customers, including locating meters without associated customer accounts, relatively high line losses compared with other similar locations, energy theft, and/or improper metering installations.

Service Territory: The area within a particular state where an electric utility is allowed to provide ultimate customers for distribution, transmission, or energy services.

Smart Grid: Real-time visualization technologies on the transmission level and smart meter and communications technologies on the distribution level that enable demand response, distributed energy systems (generation, storage, thermal), consumer energy management systems, distributed automation systems and smart appliances.

Smart Metering: See definition for Advanced Metering

Smart Thermostat: Thermostats that adjust room temperatures automatically in response to price changes or remote signals from system operators. Also known as programmable communicating thermostats.

Specific Event Limits: The maximum number of events that can be called during a year.

Southwest Power Pool (SPP): The Southwest Power Pool is both the RTO and NERC reliability organization for Kansas, Missouri, Oklahoma, and part of New Mexico.

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one centralized manager or operations supervisor.

Theft Detection: The ability to detect when a revenue or billing meter has been potentially tampered with and to indicate a potential energy theft in progress that should be further investigated by the utility.

Time-Based Rate (TBR): A retail rate in which customers are charged different prices for different times during the day. Examples are time-of-use (TOU) rates, real time pricing (RTP), hourly pricing, and critical peak pricing (CPP).

Time-of-use (TOU) Rate: 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. Daily pricing blocks might include an on-peak, partial-peak, and off-peak price for non-holiday weekdays, with the on-peak price as the highest price, and the off-peak price as the lowest price.

Transformer: A device that operates on magnetic principles to increase (step up) or decrease (step down) voltage.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers.

Transportation: An energy consuming sector that consists of electricity supplied and services rendered to railroads and interurban and street railways, for general railroad use including the propulsion of cars or locomotives, where the electricity is supplied under separate and distinct rate schedules.

Type of Organization: in fielding the FERC Survey, this allowed Commission staff to identify the type of organization that best represents the energy market participant. The possible categories were : Investor-owned utilities (IOU), Municipal Utility (M), Cooperative Utility (C), State-owned Utility (S), Federally-owned Utility (F), Independent System Operator (ISO), Regional Transmission Operator (RTO), Curtailment Service Provider (CSP), or other (O).

Ultimate Consumer: A consumer that purchases electricity for its own use and not for resale.

Uncommitted Capacity: Generating resources that are physically located in the region, but are not dedicated or contractually committed to serve load in the region.

Watt (W): The unit of electrical power equal to one ampere under a pressure of one volt. A watt is equal to 1/746 horsepower.

Watt-hour (Wh): The electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

Year of Study: Identification of the projected years covered by a specified study.

Appendix B: Documentation of 2006 Demand Response Estimates

Table B-1 provides additional support for Figure II-1 on the level of demand response achieved during summer 2006. Following Table B-1 are the source notes for Figure II-1 and Table B-1.

Table B-1. Summary of RTO and ISO area demand response in summer 2006

Transmission System Operator	Date of Summer 2006 Peak Load	Actual System Peak (MW)	Projected System Peak (MW)	Demand Response (MW)	Demand Response as Percent of System Peak	Emergency Procedures and Levels called by System Operators
CAISO	24 Jul *	50,270	52,336	2,066	4.1%	Emergency Stages 1 & 2
ERCOT	17 Aug *	62,339	64,567	Not called	Not applicable	Yellow: Conservation Needed
SPP	19 Jul *	42,227	Not applicable	Not called	Unknown	None called
Midwest ISO	1 Aug	113,750	117,000	2,651	2.3%	Max Gen Warning; NERC EEA2
PJM	2 Aug *	144,644	148,001	2,050	1.4%	Not called outside Mid-Atlantic
Mid Atlantic	2 Aug *	62,017	64,067	2,050	3.3%	Full Emergency Load Response
NYISO	2 Aug *	33,939	35,018	948	2.8%	Emergency DR activated
ISO-New England	2 Aug *	28,130	28,490	597	2.1%	OP4- Action 12
SW Conn.	2 Aug *	3,701	4,070	227.1	6.1%	OP4- Action 12

Sources: Numbers in this table are based on data available to Commission staff, including RTO and ISO publications, and interviews with RTOs and ISOs and with other market participants. The column “demand response as percent of peak” includes conservation estimates. Demand response for CAISO is based on staff estimates, due to lack of comprehensive, ISO-collected data. Data for MISO is for August 1, when demand response was called and measured. MISO’s peak day was July 31.

* New record peak in peak demand

Source Notes for Figure II-1 and Table B-1

<u>RTO or ISO and Data Item</u>	<u>Figure II-1</u>	<u>Table B-1</u>	<u>Data</u>	<u>Unit(s)</u>	<u>Data Source, Source note, or Derivation Method</u>	
<u>New England Independent System Operator (ISO-NE)</u>						
ISO-NE summer 2006 data:						
Forecast peak load	✓		28,490	MW	Source is ISO New England (ISO-NE), unless otherwise noted. See also, H. Yoshimura (ISO-NE), FERC Wholesale Demand Response Technical Conference, transcript, 14-19; and Yoshimura & Whitley, submitted "Responses to FERC".	
Actual peak load		✓	28,130	MW		
Maximum Hourly Reduction			625	MW		
Peak day, hour		✓	2-Aug-06	3-4 p.m.		
Peak hour reduction	✓	✓	597	MW		
Peak hour reduction	✓	✓	2.1%			
Peak hour reliability reduction:			513	MW		
ISO-NE 2006 Emergency Levels and Procedures						
ISO-NE summer 2007 demand-response resources:						
Total ISO-NE enrollment	✓		1,036.6	MW		Enrolled MW as of June 2007
of which economic	✓		97.1	MW	NEPOOL Participants Committee Meeting, June 8, 2007, 20.	
of which reliability	✓		939.5	MW	NEPOOL Participants Committee Meeting, June 8, 2007, 20.	
<u>New York Independent System Operator (NYISO)</u>						
NYISO summer 2006 data:						
Forecast peak load	✓		35,018	MW	Source is New York ISO (NYISO), unless otherwise noted. NYISO website: http://www.nyiso.com/public/market_data . "Operations & Market Performance: Summer 2006," September 13, 2006. "Operations & Market Performance: Summer 2006," September 13, 2006. "Responses to FERC," FERC Wholesale Demand Response Technical Conference, transcript, 3. FERC analysis: total reduction divided by peak load (both MW). Details of Emergency Demand Response are described below. "NYISO's Demand Response Programs 2007," PowerPoint presentation. Enrolled MW, as of May 2007. email from NYISO to FERC staff. email from NYISO to FERC staff.	
Actual peak load		✓	33,939	MW		
Peak day, hour		✓	2-Aug-06	3-4 p.m.		
Peak hour reduction	✓	✓	948	MW		
Peak hour reduction	✓	✓	2.8%			
NYISO 2006 Emergency Levels and Procedures						
NYISO summer 2007 demand-response resources:						
Total NYISO enrollment	✓		2,199	MW		
of which economic	✓		389	MW		
of which reliability (EDRP & ICAP/SCR)	✓		1,810	MW		

Source Notes for Figure II-1 and Table B-1 (Cont.)

RTO or ISO and Data Item	Figure II-1	Table B-1	Data	Unit(s)	Data Source, Source note, or Derivation Method
<u>PJM Interconnection, Inc. (PJM)</u>					
PJM summer 2006 data:					
Forecast peak load	✓		148,001	MW	PJM, "State of the Market Report, Briefing: 2006 (SOMB)," March 21, 2007; available at www.pjm.com/markets/market-monitor/downloads/mmu-presentations/20070321-item-12-som-nrc-briefing-2007.pdf .
Actual peak load, total market	✓		144,644	MW	PJM, "SOMB", 10.
Peak day, hour	✓		2-Aug-06	4-5 p.m.	PJM, email to FERC Staff.
Peak hour reduction, total market	✓		2,050	MW	SOM, Vol. I, 12-13; available at: www.pjm.com/markets/market-monitor/som.html
Peak hour reduction, total market of which Full Emergency Load Response	✓		1.4%		FERC analysis: total reduction divided by peak load (both MW)
Actual peak load, Mid-Atlantic zone	✓		799	MW	Hopper, et. al., <i>Electricity Journal</i> , June 2007, 67.
Peak reduction, Mid-Atlantic zone	✓		62,016	MW	PJM: www.pjm.com/services/system-performance/historical.html
Peak reduction, Mid-Atlantic zone	✓		2,050	MW	PJM, www.pjm.com/services/system-performance/historical.html
Peak reduction, Mid-Atlantic zone	✓		3.3%		PJM, "SOMB", p. 10; FERC divided total reduction by Mid-Atlantic peak, where emergency conditions were called.
PJM 2006 Emergency Levels and Procedures					
Summer 2007 Demand Resources including economic	✓		3,733	MW	Details of Full Emergency Load Response are described below
including reliability	✓		1,578	MW	PJM, enrolled MW as of July 2007
	✓		2,155	MW	2006 SOM, 101; 2005 SOM, 82; "Load Response Activity Report, Jan-June 2007", available at: www.pjm.com/committees/working-groups/dsrwg/downloads/20070724-item-02-dsr-activity.pdf
<u>Midwest Independent System Operator, Inc. (MISO)</u>					
MISO summer 2006 data:					
Forecast peak load	✓		117,000	MW	Source is Midwest ISO (MISO), unless otherwise noted
Actual peak load	✓		113,750	MW	"Summer 2006 Review & Discussion," presentation, 9/6/06, 11. Real-Time Market Reports, August 2006: http://www.midwestmarket.org/mkt_reports/rt_ex/20060802_rt_ex.pdf
Day and hour of measured reduction	✓		1-Aug-06	3-4 p.m.	"2006 Load Management Response Survey," summary, January 5, 2007.
Peak hour reduction, August 1 including interruptible resources	✓		2,651	MW	Actual reductions, based on MISO survey to Balancing Authorities
Peak hour reduction, August 1	✓		1,387	MW	"2006 Load Management Response Survey," summary, January 5, 2007.
	✓		2.3%		FERC analysis: total reduction divided by peak load (both MW) Details of MISO, Maximum Generation Warning & NERC EEA2 are described below.
MISO 2006 Emergency Levels and Procedures					
MISO summer 2007 demand-response resources:					
Summer 2007 Demand Resources including interruptible resources	✓		4,099	MW	Enrolled MW as of April 2007.
including direct load control	✓		2,534	MW	"2007 MISO Summer Readiness Workshop: Resource Assessment," April 6, 2007, 6.
	✓		1,565	MW	

Source Notes for Figure II-1 and Table B-1 (Cont.)
Figure Table

RTO or ISO and Data Item	II-1	B-1	Data	Unit(s)	Data Source, Source note, or Derivation Method
<u>Electric Reliability Council of Texas (ERCOT)</u>					
ERCOT summer 2006 data:					
Forecast peak load	✓		64,567	MW	Public Utility Commission of Texas, Wholesale Market Oversight web site.
Actual peak load	✓		62,339 Demand Response not called	MW	ERCOT, <i>2006 Annual Report</i> , May 2007, 6.
Peak hour reduction	✓		17-Aug-06	MW	LaaRs were not called on for system reliability purposes on peak day.
Peak day, hour			17-Aug-06	4-5 p.m.	Public Utility Commission of Texas, Wholesale Market Oversight.
LaaRs use on peak day			1,150	MW	Email, call with ERCOT IMM: LaaRs served as operating reserves on peak day. ERCOT called no emergencies called on peak day.
ERCOT 2006 Emergency Levels and Procedures					
ERCOT summer 2007 demand-response resources:					
Summer 2007 Demand Resources:	✓		1,985	MW	Registered, as of end, 2006; Source, Potomac Economics, External Market
Load Acting as a Resource (LaaRs)	✓		1,150	MW	Monitor for ERCOT (but limited to 1,150 MW for responsive reserves at a time).
Emergency Interruptible Load Service			not yet known	MW	Texas issued RFP for at least 500 MW .emergency interruptible resources; minimum level not met at press time.
<u>Southwest Power Pool, Inc. (SPP RTO)</u>					
SPP summer 2006 data:					
Actual peak load	✓		42,284 Demand Response not called	MW	Source is the Southwest Power Pool (SPP), unless otherwise noted. <i>2006 State of the Market Report</i> , SPP, Inc., May 16, 2007 draft, 11.
Peak hour reduction				MW	SPP had no ISO-level programs in place; SPP IMM conversation with FERC staff.
Peak hour reduction	✓		70	MW	SPP knew anecdotally of a utility program, which called its interruptible resources.
Peak day, hour	✓		19-Jul-06	4-5 p.m.	SPP, email with market monitor. SPP called no emergencies called on peak day.
SPP 2006 Emergency Levels and Procedures					
SPP summer 2007 demand-response resources:					
Summer 2007 Demand Resources	✓		unknown	MW	SPP, conversation with market monitor.

Source Notes for Figure II-1 and Table B-1 (Cont.)

RTO or ISO and Data Item	Figure		Data	Unit(s)	Data Source, Source note, or Derivation Method
	II-1	B-1			
California Independent System Operator (CAISO)					
CAISO summer 2006 data:					
Forecast peak load	✓		52,336	MW	Source is California ISO (CAISO), unless otherwise noted.
Actual peak load	✓		50,270	MW	"Alert, Warning, Emergency and Power Watches,"
Peak day, hour	✓		24-Jul-06	1-2 p.m.	2006 Annual Report: Market Issues & Performance, April 5, 2007, 6.
Peak hour reduction	✓	✓	2,066	MW	CAISO
Peak hour reduction	✓	✓	4.1%		FERC estimate: difference between forecast & actual peak load; reduction divided by actual peak; includes conservation estimates.
Peak hour reduction			1,191 MW		Details of Emergency Stages and "Conservation critical" are described below.
CAISO 2006 Emergency Levels and Procedures					
CAISO summer 2007 demand-response resources:					
Total Enrollment (& program type); of which:	✓				
IOU price-responsive (economic)	✓		2,789	MW	Ahmad Faruqi & Ryan Hledik, The Brattle Group, for the California Energy Commission (CEC), <i>The State of Demand Response in California</i> .
IOU interruptible programs (reliability)	✓		1,056	MW	CEC-200-2007-003-D, April 2007, 17.
ISO: Voluntary Load Response Program	✓		1,613	MW	CAISO, conference call with FERC staff, January 2007.
ISO: Participating Load Program	✓		15 - 50	MW	Conference call with FERC staff, January 2007.
			~ 85	MW	

Definitions for Table B-1:

Transmission System Operator: RTOs (regional transmission organizations) and ISOs (independent system operators) are responsible for dispatch of system resources, including generation and demand response. Most of the demand-response programs are invoked by the RTOs or ISOs for system reliability needs on peak days.

Date: This column indicates the date of the system peak in the summer of 2006. The exception is the Midwest Independent System Operator (MISO), which called on demand-response resources on August 1 and 2, but not on July 31, the date of its system peak. Except for MISO, all of the peak load data in this table were record peaks.

Actual System Peak (MW): This column indicates the system peak in megawatts, as reported by the RTO or ISO. The number in the table is the “integrated hourly load” measured by the system operator, rather than the “five minute interval” data, which sometimes produces a different peak number. The difference between those two measures, and the fact that initial data is usually revised based on final metering data a few months after the original report, can lead to multiple numbers being reported even by the same entity.

Projected System Peak (MW): These demand numbers, in megawatts of expected load, are those the RTOs and ISOs projected earlier on the peak day as the market area’s expected load peak for the day. The expected peak demand forecast is often revised throughout the day on days with extreme conditions. In some cases, particularly for California, Commission staff estimated total conservation and demand response based on the difference between these two numbers.

Demand Response as Percent of System Peak in Load pockets (MW, percent): These numbers were broken out for two RTOs and ISOs, when reported, because much of the relief came from the most congested load pockets. RTOs and ISOs may have had programs that targeted enrollment in their most congested areas. This detail is illustrated beneath the RTO/ISO in Table B-1.

Emergency Procedures and Levels Called by System Operators:

Different emergency procedures are embodied in the operating procedures of each market. Not every market declared an emergency on their peak day. Some only called for conservation. The following explains what levels were called for during emergencies, and their meaning.

CAISO: California used both voluntary conservation and demand-response programs. Some were invoked by the ISO; others are called by utilities. These are the highlights of the conservation alert and maintenance restrictions, as well as Stage 1 and 2 Emergencies called by the ISO.

- CAISO announced a “Power Watch” the prior day, and displayed a “Conserve-O-Meter” on www.CAISO.com with an arrow pointing to “Red: Conservation Critical.” CAISO called on its Voluntary Load Reduction Program, and issued a “restricted maintenance order” (RMO) from 6 a.m. to 8 p.m. Under an RMO, no one can do any maintenance without permission from the ISO.¹⁷⁴
- The CAISO called Stage 1 and 2 Emergencies. Normal operations are when the forecast reserve level is greater than 7%. A Stage 1 Emergency is called when the forecast reserve level is less than 7%; it was in effect from 10 a.m. to 9 p.m. During Stage 1, the ISO called on its Voluntary Load Reduction Program. The ISO declares a Stage 2 Emergency when it expects operating reserves to fall below 5%; this was in effect from 1 p.m. to 9

¹⁷⁴ CAISO, “Alert, Warning, Emergency and Power Watches,” (AWE); excel spreadsheet tab “2006 AWE record”.

p.m. During Stage 2, the ISO calls for load in interruptible programs to curtail; most of these are under the IOU's control.¹⁷⁵

ERCOT: The Public Utility Commission of Texas (PUCT) website displays a daily conservation alert. On ERCOT's peak day, the alert was at: "Yellow: Conservation Needed." This indicates that the PUCT expects a peak demand day, but that, given available capacity, there should be sufficient resources if people conserve. No emergency levels were declared on ERCOT's peak day.¹⁷⁶

SPP: The Southwest Power Pool did not declare an emergency condition on its peak 2006 day.¹⁷⁷

MISO: The Midwest Independent System Operator (MISO) did not call for demand response on its peak day, July 31, 2006. August 1 was included in Table B-1 and Figure II-1 because MISO measured the effects of demand response on the second peak day. On July 31 - August 2, MISO used a combination of its Generation Emergency Procedures, and NERC Energy Emergency Alerts (EEA). The ISO procedures were revised prior to the summer of 2007, so these definitions are not current.¹⁷⁸

- A "Maximum Generation Warning" was declared from 10:42 a.m. to 6:27 p.m. (EST) on August 1. A "Max Gen Warning" meant that operating reserves would probably be needed to meet load.
- A NERC EEA1 was in effect from 12 noon to 7:00 p.m. for the entire market footprint. An EEA1 denotes that all available resources are committed to meet demand.
- A NERC EEA2 was in effect for the Central and East regions from 10:42 a.m. to 5:49 p.m. An EEA2 invokes public appeals for conservation, the interruption of non-firm load (according to contracts), and "demand-side management" (DSM) measures. All interruptible and DSM programs were run by utilities in the MISO footprint, rather than by the MISO.

PJM: PJM implemented Full Emergency Load Response in the Mid-Atlantic control zone on August 2, between 2 p.m. and 7 p.m. "Full Emergency Load Response combines in one construct the energy payment provided for previously by the Emergency Load Response Program and the capacity credit earned as an Active Load Management resource. Performance of Full Emergency resources is mandatory."¹⁷⁹ PJM's other emergency option, Energy only, was not called in August 2006.

NYISO: Emergency demand response activated. The NYISO activated its Emergency Demand Response Program (EDRP) and its Installed Capacity / Special Case Resources (SCR) in two regions on August 2.¹⁸⁰ These resources were called in Zones J (New York City) and K (Long Island) from 1 p.m. to 8 p.m. to meet local reliability rules. EDRP and

¹⁷⁵ CAISO, "AWE"; excel spreadsheet tab 2006 AWE record, and CAISO, "Demand Response, Where We Are Now," January 25, 2007 PowerPoint presentation.

¹⁷⁶ The Public Utility Commission of Texas (PUCT) has conservation alert levels posted on its main page: <http://www.puc.state.tx.us/>. Conversations and emails with Danielle Jaussaud, Market Oversight, PUCT.

¹⁷⁷ Conversations with SPP market monitoring staff.

¹⁷⁸ MISO, "Summer 2006 Review & Discussion," PowerPoint presentation, September 6, 2006.

¹⁷⁹ Email from PJM, VP of Federal Government Policy, about peak period demand response for summer 2006.

¹⁸⁰ NYISO, monthly call with FERC staff and Market Monitors, August 8, 2006, and NYISO, "Operations and Market Performance: Summer 2006," discussion draft for September 13, 2006 call.

SCR resources were activated in Zones A, B, and C (West, Genesee, and Central zones in Western New York area) to support voltages, and to allow NYISO to export 2,500 MW of scheduled power to PJM. ICAP/SCR resources are sometimes activated prior to EDRP resources. SCR is activated in response to a forecast or actual operating reserve deficiency.¹⁸¹

ISO-NE: OP4 is one of the ISO's operating procedures; it refers to a series of actions the ISO can take when it is in a capacity sufficiency situation. They are documented in its "Operating Procedures: OP 4 – Action During a Capacity Deficiency (2005)."¹⁸² The actions taken on its peak 2006 day included:

- OP4-Action 9 was called from 12:15 p.m. to 6:00 p.m. (EDT). In Action 9, the ISO requests voluntary load curtailment from market participants' facilities, and calls for interruptions in its "Real-Time Demand Response – 30 Minutes or Less Notification" program.
- OP4-Action 12 was called from 1:00 p.m. to 4:45 p.m. Under Action 12, the ISO implements a five percent voltage reduction. It calls on interruptible resources enrolled in its "Real-Time Demand Response – 30 Minutes or Less Notification" program. At OP4 – 12, ISO-NE announces a NERC EEA Level 2 alert (see MISO for EEA2 details).

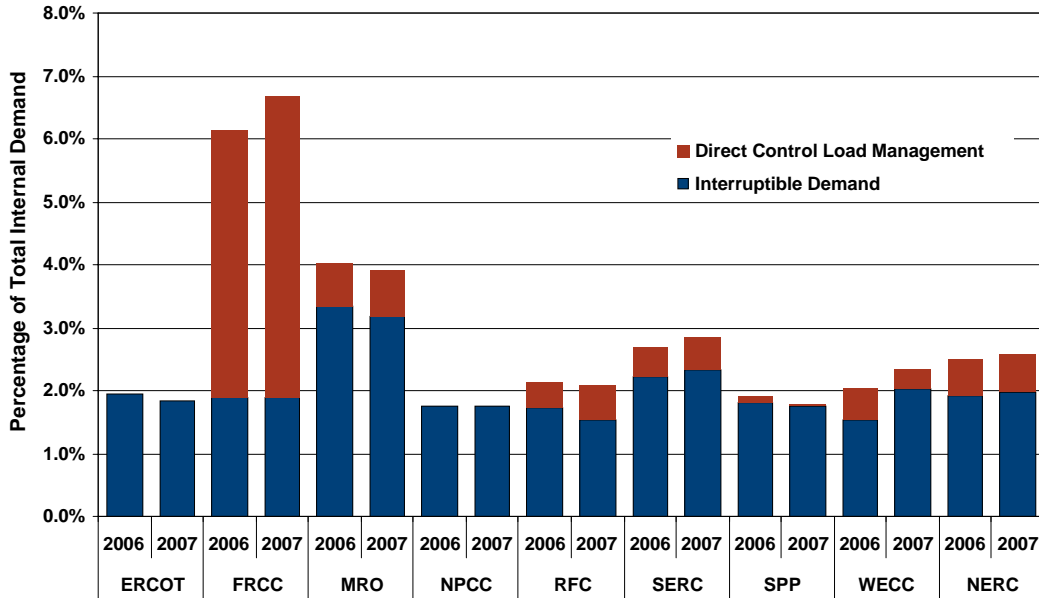
¹⁸¹ NYISO, "Demand Response Programs," March 15, 2006.

¹⁸² *ISO-NE Operating Procedures*, "OP 4 – Action During a Capacity Deficiency," revision 6, effective Aug 5, 2005, 5-6.

Appendix C: North American Electric Reliability Corporation Estimates of Demand Response Availability

This appendix summarizes NERC’s estimates of the level of demand response by NERC region in 2006 and 2007. NERC bases its numbers on an estimate of the availability of demand response on a firm basis, and reflects demand reductions from only traditional interruptible/curtailable load or direct load control. NERC does not include demand bidding programs or time-based rate programs.¹⁸³ To support future estimates of demand response, NERC’s planning and operations committee has authorized a task force to examine how the response from other demand-response programs can reliably be counted.¹⁸⁴

Figure C-1. Demand response by NERC region



Source: NERC, 2007 Summer Assessment

¹⁸³ NERC has directed that reductions from economic or price-based program should be added back into load, but it is not known whether it is universally done.

¹⁸⁴ Staff conversation with NERC, June 8, 2007.

Appendix D: Overview of Demand Response in RTO and ISO Markets

In order to gain a better understanding of the Commission's actions related to demand response, it is helpful to see an overview of demand-response participation in each of the seven RTOs and ISOs.¹⁸⁵ The following table includes this information, indicating the status of RTO and ISO market rules for demand response: already in place, subject to ongoing proceedings, or subject to regional initiatives to explore greater demand response. Additional detail on RTO/ISO demand response, and commission actions in each RTO and ISO follows. As of 2007, demand-response resources are increasingly being integrated into various organized electricity markets, including ancillary services, energy, and capacity markets. The level to which these resources can now participate in these markets varies depending on the individual RTO or ISO. Additional proposals and initiatives are underway within RTO/ISO regions to further integrate demand resources.

¹⁸⁵ Table D-1 includes information related to demand-response participation in ERCOT. Note that the report incorporates this information in order to be comprehensive, but the Commission does not have jurisdiction over this RTO.

Table D-1. Demand response status in RTOs and ISOs

Market Element	NYISO		ISO-NE		PJM		CAISO		MISO		SPP		ERCOT	
	H	O	H	O	H	O	H	O	H	O	H	O	H	O
Demand Response Program	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Emergency Situation DR Program	✓		✓		✓		✓		✓		✓		✓	
Real Time DR Bids	✓		✓		✓		✓		✓		✓		✓	
Day Ahead DR Bidding into Market	✓		✓		✓		✓		✓		✓		✓	
Capacity Market DR Participation	✓		✓		✓		✓		✓		✓		✓	
DR in Long-Term Tx Planning	✓		✓		✓		✓		✓		✓		✓	
Bid Price Floor or Cap for DR	✓		✓		✓		✓		✓		✓		✓	
Ancillary Services DR Participation	✓		✓		✓		✓		✓		✓		✓	
Reactive Supply & Voltage Control			✓											
Regulation		✓												
Spinning	✓		✓		✓		✓		✓		✓		✓	
Non-spinning (10 Min.)	✓		✓		✓		✓		✓		✓		✓	
Long Term Supplemental (30 Min.)	✓		✓		✓		✓		✓		✓		✓	
Generator Imbalances														

Notes:

H: History and in place

O: Open dockets and actions

I: Initiatives that are being discussed

* For retail and state initiatives "H" and "O" represent activities before a state(s).

New York ISO

NYISO has a working real-time market and has been directed by the Commission to integrate demand side resources into this market as well as its ancillary services market. The New York Public Service Commission placed all medium and large customers on real-time pricing based on locational marginal pricing (LMP) as their default rate.

Demand Response Program

NYISO markets include demand response, under the Emergency Demand Response Program (EDRP)¹⁸⁶ and the Incentivized Day-Ahead Economic Load Curtailment Program,¹⁸⁷ since 2001. The NYISO also recently filed proposed tariff revisions to clarify, modify, and make consistent the activation of its demand-response Special Case Resources (SCR) program and EDRP.¹⁸⁸ Further, NYISO prepares a semi-annual report on demand side management programs and new generation additions, as required by the Commission.¹⁸⁹

Emergency Situation Demand Response Programs

NYISO updated and made permanent the EDRP and the installed capacity (ICAP) Special Case Resources Program and DADRP to back demand off the power grid in emergencies.¹⁹⁰

Real-Time Demand Response Bids – Higher of Bid or LMP

The Commission ordered NYISO to integrate demand side resources into the real-time energy market by the third quarter of 2007.¹⁹¹

Day-Ahead Demand Response Bidding into Market

Demand response participates in NYISO day-ahead markets through the DADRP.¹⁹²

Capacity Market Demand Response Participation

Resources in the ICAP Special Case Resources Program can participate in the NYISO's capacity markets.¹⁹³

Demand Response in Long-Term Transmission Planning

NYISO includes demand-response modeling as part of the assessment undertaken to meet its installed capacity requirement as well as in its comprehensive reliability planning process.¹⁹⁴

Bid Price Floor or Cap for Demand Response

Demand response in NYISO has a bid price floor.¹⁹⁵

Ancillary Services Demand Response Participation

¹⁸⁶ N.Y. Indep. Sys. Operator, Inc., 95 FERC ¶ 61,136 (2001).

¹⁸⁷ This program is also known as the Day-Ahead Demand Response Program (DADRP). See *N.Y. Indep. Sys. Operator, Inc.*, 95 FERC ¶ 61,223 (2001).

¹⁸⁸ See Docket No. ER-07-862.

¹⁸⁹ N.Y. Indep. Sys. Operator, Inc., 97 FERC ¶ 61,095 (2001).

¹⁹⁰ *N.Y. Indep. Sys. Operator, Inc.*, 113 FERC ¶ 61,089 (2005).

¹⁹¹ *N.Y. Indep. Sys. Operator, Inc.*, 116 FERC ¶ 61,043(2006).

¹⁹² *N.Y. Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,374(2003).

¹⁹³ *N.Y. Indep. Sys. Operator, Inc.*, 95 FERC ¶ 61,136(2001); *N.Y. Indep. Sys. Operator, Inc.*, 113 FERC ¶ 61,089.

¹⁹⁴ See Docket No. ER07-862; *N.Y. Indep. Sys. Operator, Inc.*, 116 FERC ¶ 61,043(2006).

¹⁹⁵ *N.Y. Indep. Sys. Operator, Inc.*, 109 FERC ¶ 61,101 (2004).

After Commission guidance in 2004, NYISO market rules allow for greater market participation by demand side resources. Demand side resources now provide ancillary services for demand-response participation as a regulation, spinning, non-spinning and long-term supplemental resource and are included in synchronous reserve markets. NYISO will fully integrate them into the ancillary services market by September 2007.¹⁹⁶

ISO New England

New England has been facing the prospect of an electricity supply shortage. Activating demand response through a forward capacity market could help lessen the potential problem. In addition, Connecticut, Massachusetts, and Vermont have each been examining their policies with regard to demand response and time-based rates.

Demand Response Programs

As a member of the New England Power Pool (NEPOOL), ISO-NE markets have helped NEPOOL reduce consumption in peak periods since 2002 through a demand-side management plan known as the NEPOOL Load Response Program.¹⁹⁷ NEPOOL's Load Response Program includes the following: (1) Day-Ahead Demand Response Program; (2) Real-Time 30 Minute Demand Response Program; (3) Real-Time Two Hour Demand Response Program; (4) Real-Time Price Response Program; and (5) Real-Time Profiled Response Program. Participants in these programs provide measurement results demonstrating the extent of curtailment.¹⁹⁸

Emergency Situation Demand Response Programs

ISO-NE has used the Real-Time Demand Response Program to ease load demands in emergency situations and encourage an increase in the amount of interruptible load available during capacity shortages in NEPOOL since 1999.¹⁹⁹

Real-Time Demand Response Bids – Higher of Bid or LMP

Demand response submits real-time bids when it participates in the ISO-NE Real-Time 30 Minute Demand Response Program; Real-Time Two Hour Demand Response Program; Real-Time Price Response Program; and Real-Time Profiled Response Program.

Day-Ahead Demand Response Bidding into Market

Demand submits day-ahead bids when it is a part of the ISO-NE *Day-Ahead Demand Response Program*.

In 2005, the Commission directed ISO-NE to implement an integrated clearing approach Day-Ahead Load Response Program (DALRP). In response, the ISO-NE submitted a compliance filing requesting the approval of a sequential clearing methodology for the DALRP which would be replaced with an integrated clearing methodology after the infrastructure for direct demand participation was in place as part of the ancillary services market. The Commission granted this request but directed ISO-NE to implement an integrated clearing methodology.²⁰⁰

¹⁹⁶ *N.Y. Indep. Sys. Operator, Inc.*, 106 FERC ¶ 61,111 (2004); *N.Y. Indep. Sys. Operator, Inc.*, 116 FERC ¶ 61,043.

¹⁹⁷ *N.Y. Indep. Sys. Operator, Inc.*, 100 FERC ¶ 61,287 (2002).

¹⁹⁸ *Id.*

¹⁹⁹ *ISO New England, Inc.*, 88 FERC ¶ 61,304 (1999).

²⁰⁰ *New England Power Pool, Inc.*, 111 FERC ¶ 61,064 (2005); *New England Power Pool, Inc.*, 117 FERC ¶ 61,165 (2006).

Capacity Market Demand Response Participation

In June 2006, FERC approved a settlement providing for a Forward Capacity Market (FCM) in ISO-NE. The FCM employs: (1) a forward resource adequacy auction in which ISO-NE would procure 100 percent of the forecasted installed capacity requirements for each commitment period; (2) a descending clock auction held far enough in advance of the commitment period to allow participation by new market entrants; (3) penalties for non-performance; and (4) a transition period.²⁰¹ Pending approval of auction market rules before FERC, ISO-NE plans to hold the first auction in February 2008 for resources that can provide capacity beginning in June 2010.²⁰² ISO-NE's next step in the FCM process will be to evaluate "show of interest" proposals it received and notify applicants in October 2007 if they are eligible to participate.²⁰³

Demand-response resources in Real-Time Demand Response Programs can qualify as an ICAP resource in ISO-NE. There is a pilot underway which will run at least through summer 2007 that should help ISO-NE find better ways to measure the reductions demand-response resources are providing in close to real time.²⁰⁴

Ancillary Services Demand Response Participation

The ancillary services ISO-NE demand-response resources provide are: reactive supply and voltage control; regulation; spinning; non-spinning; long term supplemental; and generator imbalances.

Demand Response in Long-Term Transmission Planning

ISO-NE considers the contribution of demand-response resources in meeting projected demand and evaluating the adequacy of installed capacity. Its modeling to support the development of installed capacity requirement values is based on assumptions regarding generating and demand-response resources, system load forecasts, and the reliability benefits from direct connections to neighboring power systems.²⁰⁵

Bid Price Floor or Cap for Demand Response

ISO-NE's Day-Ahead Demand Response Program subjects demand-response resources to a bid floor and a bid ceiling.²⁰⁶

²⁰¹ *Devon Power LLC*, 115 FERC ¶ 61,340 (2006).

²⁰² *Platt's Inside FERC*, page 14, March 26, 2007.

²⁰³ *Megawatt Daily*, page 1, Vol. 12 No. 53, March 19, 2007.

²⁰⁴ Technical Conference Transcript, Docket No. AD07-11, April 23, 2007, page 31, line 22 – page 32, line 17, <http://www.ferc.gov/EventCalendar/Files/20070504072920-AD07-11-04-23-07.pdf>.

²⁰⁵ *ISO New England, Inc.*, 118 FERC ¶ 61,157 (2007).

²⁰⁶ *New England Power Pool*, 101 FERC ¶ 61,344 (2002).

PJM Interconnection, LLC

PJM allows demand response to participate in energy and ancillary services markets, and gives installed capacity credits for demand resources that commit to curtail when directed. PJM continues to work on full integration of demand response as a capacity resource in the Commission-approved Reliability Pricing Model (RPM). A regional initiative composed of the five original PJM states, the Mid-Atlantic Distributed Resources Initiative (MADRI), has been operating since 2004, and continues to meet to examine and support policy on demand response and distributed generation.

Demand Response Programs

Since 2002, PJM has offered a financial incentive to its customers to reduce consumption as its LMP rises. This Economic Load Response Program provides for reductions on both a real-time and day-ahead basis, as well as an additional incentive to participants who reduce load relative to a LMP.²⁰⁷ The Commission authorized a non-hourly metered pilot program which will allow PJM to determine whether an alternative demand reduction measurement mechanism can become permanent.²⁰⁸

In December 2006, the Commission directed PJM to conduct a forum for discussions to identify and rectify barriers to entry of demand response by February 20, 2007 and to file a report on the status of the additional process for pursuing demand response and incorporating energy efficiency applications by August 20, 2007. In addition, the Commission directed PJM to incorporate into its tariff by February 2007, the eight criteria in Schedule 6 of the Reliability Assurance Agreement and the rules in the PJM manuals associated with standards and procedures for demonstration that a resource has the capability to provide a reduction in demand, the calculation of the Demand Response Factor and Unforced Capacity Value of a demand resource, and rules and procedures for verifying the performance of demand resources.²⁰⁹

PJM utility members are implementing or have proposed to implement greater demand response and energy efficiency into the market. For example, Com Ed has supported a residential real-time pricing (RTP) collaborative within Chicago. The Illinois Commerce Commission has recently adopted a policy and Illinois has a new law with provisions that will provide all residential customers with the ability to select RTP. Legislation enacted by the Illinois General Assembly in June 2006 required each electric utility serving more than 100,000 customers to submit real-time pricing tariffs to the Illinois Commerce Commission for approval. BG&E (in Maryland) and Pepco Holdings have announced new initiatives to promote energy efficiency and demand response. Pepco DC is implementing an advanced metering/rates/smart thermostat pilot under DC PSC jurisdiction.

The penetration rates of advanced metering in PJM are notable because they are increasing. The Reliability First Corporation footprint has the highest penetration rate of advanced metering in PJM. Pennsylvania has the highest penetration in the U.S.

Emergency Situation Demand Response Programs

PJM manages critical power situations under its Emergency Load Response Program.²¹⁰

²⁰⁷ *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,227 (2002).

²⁰⁸ *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,201 (2006).

²⁰⁹ *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006).

²¹⁰ *PJM Interconnection, L.L.C.*, 92 FERC ¶ 61,059 (2000); *PJM Interconnection, L.L.C.*, 95 FERC ¶ 61,306; *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,139 (2002); *PJM Interconnection, L.L.C.*, Docket No. ER04-1193 (2004)

Real-Time Demand Response Bids – Higher of Bid or LMP²¹¹

Real-time demand-response bids reflect LMP in PJM.

Day-Ahead Demand Response Bidding into Market²¹²

Demand response can bid into the PJM day-ahead market.

Capacity Market Demand Response Participation

Participants in PJM’s Full Emergency Load Response Program Forum can receive ICAP credit.²¹³ The Commission has specifically considered and responded to concerns that PJM did not allow demand response to compete on a level playing field with generation to solve reliability problems in the PJM Reliability Pricing Model proceeding.²¹⁴ As a result, demand-response resources participate in RPM auctions, are eligible to set the market clearing price, and may receive revenues for load reductions as Interruptible Load Resources in a manner similar to that provided under PJM’s Active Load Management rules. LSEs rely on demand response when acting to meet PJM’s Fixed Resource Requirement.

Ancillary Services Demand Response Participation²¹⁵

Demand-response resources can directly participate in synchronized reserve and regulation service markets. The PJM OATT has a one-minute snapshot verification method to determine whether a demand-response participant actually reduced load during a Synchronized Reserve Event. Synchronized reserves replaced PJM’s former spinning reserve market and are provided by both generation and demand resources.

Demand Response in Long-Term Transmission Planning

In November 2006, the Commission conditionally accepted PJM’s Regional Transmission Expansion Planning Protocol (RTEP) and directed PJM to evaluate the extent to which demand response or new generation could eliminate the need for an economic-based upgrade. In addition, the Commission directed PJM to delineate ways in which generators and demand-response providers will be included in the economic planning process. The Commission also required PJM to clarify the timeline for including demand response, generation, or merchant transmission proposals into each annual RTEP.²¹⁶

Bid Price Floor or Cap for Demand Response

PJM has no bid price floor or cap for demand response.

(unpublished letter order); *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,201 (2006).

²¹¹ See information about real-time demand-response bids in previous sections and *PJM Interconnection, L.L.C.*, 92 FERC ¶ 61,059; *PJM Interconnection, L.L.C.*, 95 FERC ¶ 61,306; *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,139; *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,227 (2002); *PJM Interconnection, L.L.C.*, Docket No. ER04-1193 (2004) (unpublished letter order); and *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,201.

²¹² See information about demand-response day-ahead bidding in previous sections and *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,227 and *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,201 .

²¹³ *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,201.

²¹⁴ *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331.

²¹⁵ *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,201.

²¹⁶ *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,218 (2006).

California ISO (CAISO)

The development and current status of CAISO demand response is related to and influenced by the 2000-2001 California electricity crisis. The CAISO demand-response policies and procedures will be operational when the Commission-approved market redesign and technology upgrade (MRTU) becomes effective in January 2008.

Demand Response Programs

In July 2002, the Commission accepted, rejected, and modified in part the California Comprehensive Market Redesign Proposal (MD02 Proposal).²¹⁷ In its analysis, the Commission stated that it would “implement a West-wide market power mitigation program” that approves a competitive market design. The Commission stated demand response, at the retail level, was not within its authority to implement. However, the Commission did require the CAISO to change the rules of its spinning reserve markets to enable the full participation of demand response as a resource.

In September 2006, the Commission approved the CAISO MRTU. MRTU will provide loads with demand-response capability (1) the opportunity to participate in the CAISO day-ahead, real-time, and ancillary services markets under comparable requirements as supply, and (2) corresponding market value. In that order, the Commission also (1) directed CAISO to work with all interested parties in developing demand-response proposals and that those proposals be filed with the Commission and (2) encouraged Local Regulatory Authorities to ensure that demand-response resources included in their individual resource adequacy plans are made available to the CAISO. The CAISO has stated it will continue its Participating Load Program year-round under the MRTU.²¹⁸

In January 2007, the CAISO presented a workplan for the integration of retail/wholesale policies, programs, and market designs at a Board of Governors meeting.

In June 2007, the Commission issued an order on some of the compliance filings CAISO has made in response to the Commission’s September 2006 order.²¹⁹ The Commission directed the CAISO to file a status report by August 2007 which (1) details the progress made toward these efforts; (2) includes a future action plan for increased demand-response participation in MRTU; and (3) documents the results of at least one additional CAISO-sponsored stakeholder forum. In the June 2007 order, the Commission instituted the requirement that the CAISO file annual reports evaluating its demand-response programs, including the amount of demand response it has elicited. The first report is due January 15, 2008. At a minimum, the CAISO’s report must include: (a) information on customer enrollment for each demand-response program in terms of the number of customers and total potential in load reduction in MWs; and (b) information on total load reductions achieved per program per event during the prior year, including the CAISO’s system load at time of curtailments, total MWs reduced, total payments for reductions and effects of the demand-response programs on wholesale prices.

Advanced metering is being implemented in CAISO markets per a California Public Utilities Commission (CPUC) directive by investor-owned utilities. PG&E has begun implementation. SDG&E will recover metering costs through rates and increase the functionality of its meters to support demand response. Southern California Edison has developed a proposal to implement an advanced metering prototype.

²¹⁷ *Cal. Indep. Sys. Operator Corp.*, 100 FERC ¶ 61,060(2002).

²¹⁸ *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 (2006).

²¹⁹ *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,313 (2007).

Emergency Situation Demand Response Programs

The CAISO has no emergency situation demand-response programs.

Real-Time Demand Response Bids – Higher of Bid or LMP

The CAISO MD02 created a Participating Load Program for demand-response resources.²²⁰ Since 2003, CAISO has called on participating demand-response resources in this program based on bids they submit in response to real-time dispatch instructions from CAISO and uses LMP and an Integrated Forward Market as part of its congestion management system.²²¹ Demand resources are treated the same as generation and settled at the applicable nodal price. Single load or aggregate load greater than 1 MW can participate as a demand-response resource in this market and must meet the CAISO's telemetry and metering requirements to participate.

Day-Ahead Demand Response Bidding into Market

Participating load will be able to bid/self-schedule in day-ahead markets under MRTU.

Capacity Market Demand Response Participation

The CAISO has no central capacity market. However, Local Regulatory Authorities establish the extent to which demand response counts toward the LSEs' resource adequacy requirements. The September 2006 order encouraged Local Regulatory Authorities to ensure that demand-response resources included in their resource adequacy programs can be made available to the CAISO in a way that is compatible with the CAISO's reliability needs and reduces CAISO's backstop procurement.²²²

Ancillary Services Demand Response Participation

Demand-response resources in the CAISO's Participating Load Program can participate in the CAISO's markets and provide ancillary services.

Demand Response in Long-Term Transmission Planning

The CAISO accounts for demand response and energy efficiency in transmission planning studies by reducing by the appropriate amount the peak load assumed in the studies. Demand response and energy efficiency are at the top of the "loading order" in the procurement plans of utilities within the CAISO.

Bid Price Floor or Cap for Demand Response

The CAISO has no bid price floor or cap for demand response.

²²⁰ *Cal. Indep. Sys. Operator Corp.*, 100 FERC ¶ 61,060.

²²¹ *Cal. Indep. Sys. Operator Corp.*, 105 FERC ¶ 61,140 (2003).

²²² *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 .

Midwest ISO

The Midwest ISO currently uses an energy-only market approach and relies on price responsive demand to maintain power system reliability.²²³ In February 2007, Midwest ISO made a filing at the Commission to institute an ancillary services market. Among other things, the Midwest ISO filing proposed to expand the integration of demand resources into ancillary services and energy markets.

Midwest ISO has a demand response task force that is working on recommendations. The Midwest ISO has administered a survey to find out how much demand response is available and was provided during summer 2006 peak demand periods.²²⁴ A heightened level of state involvement on demand response has been occurring through the Organization of Midwest ISO States and with the Midwest Demand Response Initiative.

Demand Response Programs

Demand-response resources have been participating in Midwest ISO markets in a manner comparable to generation resources since 2004.²²⁵ In February 2007, Midwest ISO submitted various OATT revisions in compliance with Commission orders to implement a day-ahead and real-time ancillary services market, which was to be simultaneously co-optimized with its existing day-ahead and real-time energy market.²²⁶ Although the Commission rejected the proposal in June 2007 because it was lacking a market power analysis and a readiness plan, the Commission provided detailed guidance so Midwest ISO could re-file a complete proposal quickly and the Midwest ISO could meet its market start date of spring 2008.

Emergency Situation Demand Response Programs

Midwest ISO has considered demand-response resources in emergency situations since 2004. Midwest ISO identifies Demand Response Resources (DRRs) available only in Maximum Generation Emergencies. The ability of DRRs to respond as intended is verified as part of the registration process for DRR certification. Midwest ISO measures the responses of DRRs through metering or statistical estimation and exempts these resources from certain penalties that apply to generation resources.

A September 2006 technical conference found that: (1) Midwest ISO's proposed Adequate Ramp Capability (ARC) procedure for shortage and emergency conditions in its real-time market would not have a direct effect on the deployment of demand-response capability; (2) in most cases, available demand response is controlled by Midwest ISO's balancing authorities and is not under Midwest ISO's direct operational control; (3) to the extent ARC procedures improve the accuracy of market prices, market participants will have a clear incentive to take advantage of potential demand reduction response capability; (4) most Midwest ISO demand response is not designed for ARC's short-term,

²²³ See Constellation Energy Presentation at <http://www.ingaa.org/Documents/Foundation%20Meetings/Foundation%202005%20Annual%20Meeting%20Presentations/Saturday11-5/2.%20Simon%20Julie%2011-5-05.pdf>, (Constellation Energy Presentation).

Also, Ronald McNamara discussion of Incorporating Demand Response into Regional Transmission Planning in the Midwest, <http://www.ferc.gov/EventCalendar/Files/20060125092052-McNamara,%20MISO.pdf> (McNamara Discussion).

²²⁴ *The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response*, by Nicole Hopper, Charles Goldman, Ranjit Bhavirkar, and Dan Engel: <http://eetd.lbl.gov/ea/EMS/reports/62754.pdf>. Also, presentation by Charles Goldman for MWDRI, http://misostates.org/MWDRI_DR_Resources_v6042507.pdf.

²²⁵ *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163 (2004).

²²⁶ See Docket No. ER07-550-000.

quick response procedures; and, (5) Midwest ISO stakeholders have started a demand response taskforce in Midwest ISO which could address how demand-response programs might be designed or re-designed to help account for the short-term, quick response times ARC contemplates.

Revised ARC procedures became effective in January 2007. In May 2007, Midwest ISO made a filing to exempt from Real-Time Revenue Sufficiency Guarantee Charges (RSG Charges) entities either decreasing load, increasing behind-the meter generation, increasing their level of imports, or decreasing their level of exports, in compliance with the Midwest ISO's directives during a declared emergency.²²⁷

Real-Time Demand Response Bids – Higher of Bid or LMP

The Midwest ISO tariff provides for demand-response resource offers into its real-time market. Some of the policies for real-time demand-response bids may be affected by the anticipated re-filing of the Midwest ISO ancillary services market proposal.²²⁸

The price volatility make-whole payment (PV MWP) program that has been in place since December 2006 pays generators when real-time prices are insufficient. The PV MWP applies to demand-response resources because in Midwest ISO they are treated like generators.²²⁹

Day-Ahead Demand Response Bidding into Market

Midwest ISO allows demand-response resource offers into its day-ahead market. The day-ahead offer cap does not apply to demand-response resources, and the offers are submitted at actual verifiable prices.²³⁰

Capacity Market Demand Response Participation

The Midwest ISO has no central capacity market. However, in 2004 the Midwest ISO Resource Adequacy and Capacity Market Working Group recommended dispatchable demand response, verifiable load reduction and renewable resources participate in capacity market. Demand response has participated accordingly.²³¹

Ancillary Services Demand Response Participation

Midwest ISO is currently engaged in an active ancillary service market design and is expected to re-file a proposal soon so its ancillary market can begin in spring 2008.²³²

Demand Response in Long-Term Transmission Planning²³³

Midwest ISO has produced two expansion plans – one in 2003 and another in 2005. As required by Commission policy, Midwest ISO develops transmission expansion plans to address the reliability of the transmission system it operates and controls and to support competitive electric power supply for its markets. The process considers all market perspectives, including demand-side options, and results in an “energy-only market” approach.

²²⁷ See Docket No. ER07-885-000.

²²⁸ *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311.

²²⁹ *Midwest Indep. Transmission Sys. Operator, Inc.*, 117 FERC ¶ 61,325 (2006).

²³⁰ *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,335 (2005).

²³¹ OMS Fact Sheet No. 2 at http://www.misostates.org/OMS_Fact_Sheet_No2RAWG.pdf.

²³² *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311.

²³³ See *Constellation Energy Presentation* and *McNamara Discussion*.

Bid Price Floor or Cap for Demand Response

Midwest ISO markets have no bid price floor or cap for demand response.

Southwest Power Pool (SPP)

SPP's market structure is significantly different from other RTO market structures. SPP's imbalance market is a simple real-time energy market without: (1) a day-ahead market; (2) market-based resource adequacy mechanisms such as a capacity market; or, (3) a multi-part bidding mechanism to ensure recovery of start-up and minimum-load costs. SPP's market is based on a physical rights model, as opposed to the use of financial transmission rights.

Demand Response Programs

SPP will file a demand-response program proposal with the Commission by August 1, 2007.²³⁴ The Commission has already accepted important elements of a SPP mitigation plan that protect customers by addressing well-defined structural barriers to competition, market concentration issues, a current lack of demand response in SPP, and potential market transition difficulties. The Commission directed SPP to include a bid cap in its tariff that will start three months after market implementation and continue until SPP makes a showing that sufficient demand response exists in the market to allow removal or increase of the bid cap. In addition, the Commission directed SPP to file by the summer of 2007 modifications to its tariff to incorporate procedures for the commitment in the day-ahead process and dispatch in the imbalance market of interruptible demand, behind the meter generation, and other demand resources that are capable of providing imbalance service, or provide an explanation and rationale for not including such provisions in its tariff.

Emergency Situation Demand Response Programs

A bid cap protects customers from the current lack of emergency situation demand-response programs.

Real-Time Demand Response Bids - Higher of Bid or LMP

SPP implemented an energy imbalance market and will provide the Commission with a report a year from implementation on ways it can incorporate demand response into its imbalance market.²³⁵

Day-Ahead Demand Response Bidding into Market

SPP will be filing modifications to its tariff related to demand-response bidding into the day-ahead market by summer 2007.²³⁶

Capacity Market Demand Response Participation

SPP has no capacity market.

Ancillary Services Demand Response Participation

The SPP market has no ancillary services: buyers ensure their own resource adequacy outside of market mechanisms; sellers do not have to bid into the imbalance market.

Demand Response in Long-Term Transmission Planning

The Commission expects SPP to meet Commission requirements for consideration of demand response during its conduct of long-term transmission planning processes.

²³⁴ *Southwest Power Pool, Inc.*, 116 FERC ¶ 61,289 (2006).

²³⁵ *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,289 (2006).

²³⁶ *Id.*

Bid Price Floor or Cap for Demand Response

The SPP has no bid price floor or cap for demand response.

Electric Reliability Council of Texas (ERCOT)

ERCOT is a state-chartered (state mandated), nonprofit corporation that controls and operates the transmission facilities in Texas. The ERCOT electricity market is a “bilateral” market, with market participants meeting their electricity needs primarily through bilateral contracts. Retail Electric Providers (REP) must contract with a qualified scheduling entity (QSE) to provide scheduling services for their load customers. Resource Entities have (1) generation facilities that can provide energy; and/or (2) loads that are capable of reducing demand; and/or (3) reserve capacity. Resource Entities must also be represented by a QSE. Only QSEs can submit schedules and bids to ERCOT and settle financially with ERCOT. In many cases REPs may be part of the same company as the QSE, and so may contract for energy supply through direct agreements with generators.

ERCOT assists market participants in meeting their balanced-schedule requirements by providing for ancillary services and a balancing energy market in which QSEs can buy additional resources to correct generation-load imbalances.

Demand Response Programs

ERCOT has had a Demand Side Working Group (DSWG), which was created at the direction of the Texas PUC, since 2001. Its mission is “to identify and promote opportunities for demand-side resources to participate in ERCOT markets, and to recommend adoption of Protocols that foster optimum load participation in all markets.”

ERCOT has relied on over 4,000 megawatts of demand response, primarily interruptible load and direct load control programs, to maintain system reliability. One of the goals established by the Texas PUC as part of the 2003 wholesale market redesign was that load resources were to have reasonable opportunities for greater participation in energy and ancillary services markets in the future.²³⁷

There are three types of load resources, or demand-side resources, in ERCOT:

- Load Acting as a Resource (LaaR);
- Qualified Balancing Up Load (BUL); and,
- Voluntary Load Response.

Voluntary Load Response provides for customers to “self-direct”, a decision to reduce consumption from scheduled or anticipated level in response to price signals. Only customers who have not already offered a demand response to the market through the LaaR or BUL offerings can bid in loads under the voluntary response offering. Voluntary loads may financially benefit whenever Market Clearing Prices of Energy (MCPEs) are high or if a QSE faces a schedule that creates congestion in the transmission system only if it has negotiated a favorable REP and/or QSE contract.

²³⁷ *A Critical Examination of ISO-Sponsored Demand Response Programs A White Paper Prepared for the Multi-Client Study: A Critical Examination of Demand Response Programs at the ISO Level: End Goals, Implementation and Equity* Organized by the Center for the Advancement of Energy Markets and Distributed Energy Financial Group, LLC Prepared by Grayson Heffner and Freeman Sullivan. August 2005 (*Heffner & Sullivan*) and presentation materials at http://www.ercot.com/services/training/wholesale_presentations

Loads contracting through a QSE to provide balancing energy are referred to as Balancing Up Loads. BULs are paid only if ERCOT directs them to reduce demand and they respond. Dispatched BULs receive both an energy payment—based on the Market Clearing Price for Energy—and a capacity payment—based on the Market Clearing Price for Capacity (MCPC).

ERCOT pays QSEs and the QSEs may flow the payment to the REP, who may, in turn share it with the customer who reduced the load. REP products for interruptible customers vary and a retail customer can choose how it is compensated for its interruptible load.

Qualified customers with interruptible loads can provide operating reserves under the LaaR program. LaaRs are paid the same as generators in ERCOT. Selected operating reserves providers are also eligible for a capacity payment, regardless of whether the interruptible load is actually dispatched. This program may be the most demand-friendly ancillary services program in the U.S.

Emergency Situation Demand Response Programs

ERCOT requires Retail Electric Providers to provide operating reserves to it on short notice. Operating reserves can be either power from generation resources the REPs control or reductions in the load the REPs are serving. If an REP fails to provide its required minimum operating reserves, ERCOT purchases the difference through day-ahead ancillary services markets.

Real-Time Demand Response Bids - Higher of Bid or LMP

QSEs representing Resource Entities bid into a real time market in ERCOT.

Day-Ahead Demand Response Bidding into Market

QSEs representing Resource Entities bid into a day-ahead ancillary services market in ERCOT.

Capacity Market Demand Response Participation

Balancing Up Loads contracting through a QSE who provide balancing energy are paid only if they are selected by ERCOT and reduce load in response. If dispatched, BULs receive both an energy payment—based on the Market Clearing Price for Energy—and a capacity payment—based on the Market Clearing Price for Capacity.

Ancillary Services Demand Response Participation

There are 11 ancillary service programs, eight of which accommodate participation by loads.²³⁸

Demand Response in Long-Term Transmission Planning

ERCOT works directly with the Transmission/Distribution Service Providers, stakeholders/market participants through three Regional Planning Groups (North, South, and West).²³⁹ ERCOT requires that studies on proposed expansion projects consider both transmission and non-transmission solutions to performance deficiencies where possible.²⁴⁰ Stakeholders have an opportunity to comment on proposals and offer alternative solutions. ERCOT staff performs independent review and provides recommendations.

²³⁸ *Heffner & Sullivan.*

²³⁹ *ISO/RTO Electric System Planning Current Practices, Expansion Plans, and Planning Issues*
A Report Prepared by the ISO/RTO Planning Committee March 2006,
http://www.ercot.com/news/presentations/2006/IRC_PC_Planning_Report_Final_02_06_06.pdf (Electric Planning Report).

²⁴⁰ *Id.* (Electric Planning Report) and *Transmission Expansion: Transmission Expansion: Impact of Projects on Marginal Costs in ERCOT Impact of Projects on Marginal Costs in ERCOT*, Presentation to ERCOT Board of Directors on August 16, 2005 by Bill Bojorquez, Director of Transmission Services, ERCOT
<http://www.ercot.com/news/presentations/2005/ce-legislative-day2005.pdf>

Bid Price Floor or Cap for Demand Response

QSEs representing Resource Entities have no bid price floor or cap.

Appendix E: E Pact 1252 AMI Proceedings Update

The U.S. Demand Response Coordinating Committee (DRCC) has monitored and tracked the implementation by state regulatory commissions of Section 1252 of the Energy Policy Act of 2005. The following is a state-by-state status report prepared by DRCC on such state activity as of July 1, 2007. The status of state proceedings in several additional states could not be ascertained, and they are not listed in this status update. This does not imply that these states have not taken action on AMI. For example, The California Public Utility Commission has been proactive in deploying AMI throughout its utilities.

The DRCC believes it has captured all of the pertinent activity and actions and interpreted them appropriately. Due to the scope and nature of state regulatory activities, however, parties interested in a particular state are encouraged to review the activities in that state in more detail. Also, in some states there has been considerable activity in the area of demand response and advanced metering outside of a formal proceeding on E Pact 1252. The DRCC has attempted to highlight some of these other activities, and the following listing of them is not meant to be inclusive of all such activity.

E Pact 1252 Proceedings Status Summary

States with Open E Pact 1252 Proceedings	27
States with Closed E Pact 1252 Proceedings	12
States Deciding to Adopt E Pact 1252	2
States Deciding not to Adopt E Pact 1252	11
States Deferring Decision to Adopt E Pact 1252	4

E Pact 1252 State-by-State Status

Alabama

- **Proceeding Opened: August 2006**
- Current Status: Open.

Alaska

- **Proceeding Opened: August 2006**
- Current Status: Open. A Commission Order in June 2007 noted that it is “inclined to deny” adoption of Section 1252, but wishes to further develop the record before making a final determination.

Arizona

- **Proceeding Opened: January 2006**
- Current Status: Open. A workshop was scheduled to be held in June 2007.

Arkansas

- **Proceeding Opened: January 2006**
- Current Status: Open. In July 2007, utilities filed proposed “quick start” efficiency programs, some of which include demand response. A workshop and public hearing were held in May 2007.

Colorado

- **Proceeding Opened: March 2006**
- **Deferred Decision to Adopt EPart 1252 until March 2008**
- Current Status: Open. Via a December 2006 Order, the Commission deferred consideration of EPart 1252 until March of 2008, pending a review of the results from the state’s demand-response pilot program.

Delaware

- **Proceeding Opened: May 2006**
- **Decision: Declined Adoption of EPart 1252**
- Current Status: Open. Via a January 2007 Order, the Commission decided not to adopt EPart 1252. The proceeding, however, remains open.

District of Columbia

- **Proceeding Opened: July 2006**
- Current Status: Open. Via a May 2007 Order, the Commission formed a Working Group, which is to file a report with the Commission by July 2007.

Florida

- **Proceeding Opened: January 2007**
- Proceeding Closed: March 2007
- Decision: Declined Adoption of EPart 1252

Georgia

- **Proceeding Opened: August 2006**
- Current Status: Open.

Idaho

- **Proceeding Opened: July 2006**
- Proceeding Closed: January 2007
- **Decision: Declined Adoption of EPart 1252 but indicated intent to revisit it in utility rate cases**
- The Commission found that the “ubiquitous scope” and “implementation timeline” of EPart 1252 are unrealistic and, therefore, declined to adopt it. The Commission, though, agrees with the spirit of the standard and has started smart metering programs with three utilities.

Illinois

- **Proceeding Opened: July 2006**
- Current Status: Open. Via a June 2007 Order the Commission found that Illinois utilities have complied with state standards that satisfy the “federal comparable standard test.” The proceeding is still open, however, as the Commission needs to determine “whether it is appropriate to require utilities to provide time-based meters to *all* customers.”

Indiana

- **Proceeding Opened: July 2006**
- Current Status: Open. In May 2007 the Commission received Proposed Orders submitted by parties to the proceeding.

Iowa

- **Proceeding Opened: June 2006**
- Proceeding Closed: March 2007
- **Decision: Declined Adoption of EPACT 1252**

Kansas

- **Proceeding Opened: August 2006**
- Current Status: Open.

Kentucky

- **Proceeding Opened: February 2006**
- **Proceeding Closed: December 2006**
- **Decision: Declined Adoption of EPACT 1252**

Louisiana

- **Proceeding Opened: December 2005**
- Current Status: Open. The Commission will vote on a Final Proposed Rule at its August 2007 meeting. The Final Proposed Rule was issued in April 2007 and does not specifically approve, reject, or otherwise take action on the PURPA standard. Instead, it provides the framework for how advanced metering and demand-response programs should be deployed. Meetings and workshops have been held.

Maryland

- **Proceeding Opened: April 2006**
- **Deferred Decision to Adopt EPACT 1252**
- Current Status: Open. Via a February 2007 ruling, the Commission deferred its decision on EPACT 1252.

Michigan

- **Proceeding Opened: January 2007**
- **Decision: Most utilities meet the PURPA Standard**
- Current Status: Open. Via a January 2007 Order, the Commission initiated this proceeding and announced that all Michigan utilities subject to EPACT 1252 already satisfy the PURPA standard, save two: Edison Sault and Midwest Energy Cooperative. The Commission created a separate proceeding for each utility, though it did not close this proceeding.

Minnesota

- **Proceeding Opened: August 2006**
- Current Status: Open.

Missouri

- **Proceeding Opened: June 2006**
- Current Status: Open.

Montana

- **Proceeding Opened: May 2006**
- **Proceeding Closed: December 2006**
- **Deferred Decision to Adopt EPart 1252**
- Commission deferred determination of whether to adopt the smart metering provision of EPart 2005 until next general electric case for each utility.

Nevada

- **Proceeding Opened: June 2006**
- **Proceeding Closed: January 2007**
- **Deferred Decision to Adopt EPart 1252**
- The Commission deferred decision about EPart 1252 pending its evaluation of research submitted by parties to the proceeding.

New Hampshire

- **Proceeding Opened: April 2006**
- Current Status: Open.
- **Decision: Adopted EPart 1252**
- In a June 2007 Order, the Commission adopted EPart 1252. While the Commission did not mandate real-time pricing for all default service customers, it did issue several directives to facilitate the development of dynamic rates and smart metering systems. The proceeding remains open.

New Mexico

- **Proceeding Opened: September 2006**
- Current Status: Open. Workshop was held in January 2007.

New York

- **Proceeding Opened: August 2006**
- **Proceeding Closed: July 2007**
- **Decision: Declined Adoption of EPart 1252**
- The Commission determined that it already provides a “time-based metering and communications standard comparable to PURPA.”

North Carolina

- Proceeding Opened: August 2006
- Current Status: Open. Via a February 2007 Proposed Order, the Commission’s Staff recommended declining adoption of EPart 1252.

North Dakota

- **Proceeding Opened: July 2006**
- Current Status: Open.

Ohio

- **Proceeding Opened: December 2005**
- Current Status: Open.
- **Decision: Adopted EPart 1252**
- Via a March 2007 Finding and Order, the Commission adopted EPart 1252 and directed electric distribution companies to offer dynamic pricing to all customer classes and to make available smart meters to all customers. This proceeding is still open, however, and

further activity is planned. In May 2007, the Commission opened a new proceeding to facilitate a series of technical workshops on EPACT 1252.

Rhode Island

- **Proceeding Opened: July 2006**
- Current Status: Open.

South Carolina

- **Proceeding Opened: December 2005**
- Current Status: Open.

South Dakota

- **Proceeding Opened: June 2006**
- Current Status: Open. Both a hearing and a workshop were held during May 2007.

Tennessee

- **Proceeding Opened: July 2006**
 - **Proceeding Closed: January 2007**
 - **Decision: Declined Adoption of EPACT 1252**
 - Note: This proceeding was specifically for Entergy Arkansas.
- **Proceeding Opened: July 2006**
 - **Proceeding Closed: January 2007**
 - **Decision: Declined Adoption of EPACT 1252**
 - Note: This proceeding was specifically for Kentucky Utilities Company.
- **Proceeding Opened: February 2006**
 - **Proceeding Closed: August 2006**
 - **Decision: Declined Adoption of EPACT 1252**
 - Note: This proceeding was specifically for Appalachian Power.

Texas

- **Proceeding Opened: August 2006**
- Current Status: Open.

Utah

- **Proceeding Opened: June 2006**
- **Proceeding Closed: February 2007**
- **Decision: Declined Adoption of EPACT 1252**

Vermont

- **Proceeding Opened: December 2005**
- **Proceeding Closed: February 2007**
- **Decision: Declined Adoption of EPACT 1252**

Virginia

- **Proceeding Opened: February 2006**
- **Proceeding Closed: July 2006**
- **Decision: Declined Adoption of EPACT 1252**

Washington

- **Proceeding Opened: April 2006**

- Current Status: Open. In July 2007, the Commission issued a draft Interpretive and Policy Statement that declines adoption of EPart 1252 because the Commission already established a policy relative to the 1980 PURPA standards that is comparable to EPart 1252.

West Virginia

- **Proceeding Opened: May 2006**
- **Proceeding Closed: December 2006**
- **Decision: Declined Adoption of EPart 1252**

Wyoming

- **Proceeding Opened: August 2006**
- Current Status: Open.

Appendix F: Utility AMI Implementation Projection

Table F-1 contains a detailed list of some of the large AMI deployments that have been announced or are expected with some level of confidence by the end of 2008. This forecast of implementation was compiled by Patti Harper-Slaboszewicz of UtiliPoint International under contract to FERC.

Table F-1. Utility AMI Implementation Projection

Utility	AMI type	Meters	Year	Status
Kansas City Power and Light	Fixed RF	473,863	1996	Contracted
Puget Sound Energy	Fixed RF	1,325,000	1997	Contracted
Exelon (PECO)	Fixed RF	2,100,000	1999	Contracted
United Illuminating (CT)	Fixed RF	320,000	1999	Contracted
Lee County Electric Cooperative	PLC	185,280	2001	Contracted
Pedernales Electric Cooperative	PLC	200,698	2001	Contracted
Austin Energy	Fixed RF	125,864	2002	Contracted
PPL (PA)	PLC	1,353,024	2002	Contracted
WE Energies (WI)	Fixed RF	1,000,000	2002	Contracted
Wisconsin Public Service	PLC	425,000	2002	Contracted
Bangor Hydro	PLC	125,000	2004	Contracted
Colorado Springs	Fixed RF	400,000	2005	Contracted
TXU	PLC	265,000	2005	Contracted
TXU	BPL	2,000,000	2005	Contracted
CenterPoint	Fixed RF and BPL	1,900,000	2006	Contracted
Chatham Kent	Fixed RF	100,000	2006	Contracted
City of Seattle	Fixed RF	400,000	2006	Contracted
PG&E (CA)	PLC	5,100,000	2006	Contracted
Southern Company	Fixed RF	35,000	2006	Contracted
Arizona Public Service	Fixed RF	800,000	2007	Utility plans
Austin Energy	Fixed RF	230,000	2007	Contracted
BGE	TBD	1,000,000	2007	Filed AMI plan
Consolidated Edison	BPL	500,000	2007	Utility plans
Consumers Energy	Fixed RF	1,700,000	2007	Utility plans
DTE Energy	TBD	1,300,000	2007	Utility plans
Duke Energy in Kentucky	Fixed RF	250,000	2007	Utility plans
Florida Power and Light	Fixed RF	100,000	2007	Contracted
Hawaiian Electric Company	Fixed RF	3,000	2007	Contracted
Northeast Utilities	Fixed RF	1,181,880	2007	Filed AMI plan
Southern California Edison	Fixed RF	4,475,000	2007	Filed AMI plan
Tallahassee, city of	TBD	107,780	2007	Utility plans
WE Energies (WI)	Fixed RF	100,000	2007	Contracted
Xcel Energy	Fixed RF	710,000	2007	Contracted
Utilities active in market	TBD	3,960,000	2007	Market Activity
American Electric Power	TBD	4,730,000	2008	Utility plans
Anaheim Utilities	Fixed RF	110,635	2008	Utility plans
Consolidated Edison	TBD	1,900,000	2008	Utility plans
CPS Energy	TBD	627,210	2008	Utility plans
Duke Energy in NC	TBD	2,200,000	2008	Filed AMI plan
Energy East	TBD	1,229,788	2008	Filed AMI plan
Florida Power and Light	TBD	3,900,000	2008	Pilot Ongoing
Hawaiian Electric Company	TBD	291,580	2008	Pilot Ongoing
Pepco Holdings	Fixed RF	1,830,000	2008	Filed AMI plan
Portland General	TBD	775,000	2008	Filed AMI plan
San Diego Gas and Electric	TBD	1,300,000	2008	Filed AMI plan
Central Vermont Public Service	TBD	175,000	2010	Utility plans

Source: Utilipoint International

Notes: PLC: Powerline carrier

BPL: Broadband-over-powerlines

Fixed RF: Refers to AMI that includes a network infrastructure based radio frequency (RF) communications independent of the distribution network. Usually the meters send data to and receive data from other meters, data collectors, and/or communication towers.

TBD: To be decided. The utility has not yet announced and/or selected AMI technology



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