FEDERAL ENERGY REGULATORY COMMISSION

ASSESSMENT OF
Demand Response & Advanced Metering

STAFF REPORT

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Assessment of Demand Response and Advanced Metering
Staff Report

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Executive Summary

Energy Policy Act of 2005

Section 1252(e)(3) of the Energy Policy Act of 2005 (EPAct 2005)[1] requires the Federal Energy Regulatory Commission (Commission) to prepare a report by appropriate region, that assesses electric demand response resources, including those available from all consumer classes. Congress directed that this report be prepared and published not later than one year after the date of enactment of the EPAct 2005, and specifically to identify and review the following for the electric power industry:

- saturation and penetration rate of advanced meters and communications technologies, devices and systems;
- existing demand response programs and time-based rate programs;
- the annual resource contribution of demand resources;
- the potential for demand response as a quantifiable, reliable resource for regional planning purposes;
- 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
- regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.

Commission Staff Activities

In preparing this report, Commission staff undertook several activities:

- Developed and implemented a first-of-its-kind, comprehensive national survey of electric demand response and advanced metering. The FERC Demand Response and Advanced Metering Survey (FERC Survey) requested information on (a) the number and uses of advanced metering, and (b) existing demand response and time-based rate programs, including their current level of resource contribution.
- Requested and received written comments from interested persons on a draft version of the FERC Survey, and on key issues and challenges that Commission staff should examine. Thirty-one entities provided written comments to the proposed survey.
- Held a public technical conference on January 25, 2006 at Commission headquarters in Washington, D.C.; obtained comments from five panels with over 30 participants.
- Surveyed 3,365 organizations in all 50 states representing every aspect of the electric delivery industry: investor-owned utilities, municipal utilities, rural electric cooperatives, power marketers, state and federal agencies, and unregulated demand response providers. The voluntary survey had a response rate of about 55 percent.

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[1] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005) (EPAct section 1252(e)(3)). The full text of section 1252 is attached as Appendix A.

- Collected information on the role of demand resources in regional transmission planning and operations through review of regional transmission documents, and through interviews with regional representatives.
- Conducted a detailed review of the literature on and experience with advanced metering, demand response programs, and time-based rates.

Advanced Metering

By specifically designating saturation and penetrations rates of advanced meters and communication technologies, devices and systems as a matter to be covered in this report, Congress in section 1252 (e)(3) of EPAct 2005 recognized that the penetration of advanced metering[2] is important for the future development of electric demand responsiveness in the United States. In studying this issue, Commission staff examined the state of the technology and the market penetration of advanced metering.

One result of the FERC Survey is that advanced metering currently has a penetration of about six percent of total installed, electric meters in the United States. An analysis of market penetration by region indicates that there are differences in how much advanced metering has been adopted across the United States (see Figure ES-1). The parts of the United States associated with the ReliabilityFirst Council (RFC)[3] and Southwest Power Pool (SPP) had the highest regional overall penetration rates of 14.7 percent and 14 percent, respectively. Advanced metering penetration for the remaining regions in the United States is lower than the national average.

Commission staff also developed estimates of the penetration of advanced metering by state. These state-by-state estimates should provide a useful baseline in the state deliberations on smart metering required by EPAct 2005[4] and any future state proceedings on advanced metering. Table ES-1 displays the penetration rate of advanced metering in the ten states with the highest penetration. The remaining states reported lower penetration rates.

Market penetrations also differ by type of organization. The estimate of market penetration of advanced metering is highest among rural electric cooperatives at about 13 percent. Investor-owned utilities have the next highest penetration at close to six percent. This suggests that small, publicly-owned entities such as electric cooperatives have been actively pursuing automated and advanced meter reading.

Existing Demand Response Programs and Time-Based Rates

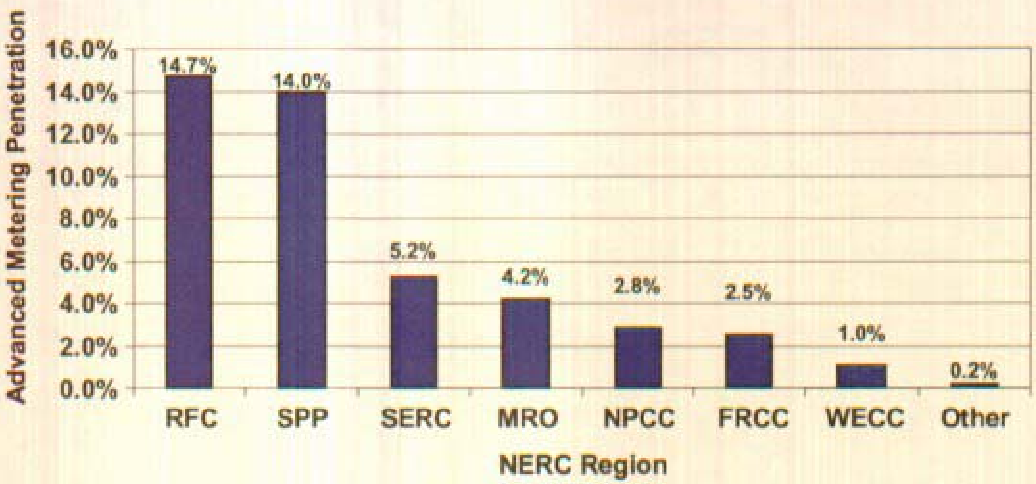
In this report, Commission staff adopted the definition of "demand response," that was used by the U.S. Department of Energy (DOE) in its February 2006 report to Congress:

[2] For purposes of this report, Commission staff 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."

[3] Reliability*First* Corporation (RFC) is located in the Mid-Atlantic and in portions of the Midwest.

[4] EPAct 2005 section 1252(b)

Figure ES-1. Penetration of advanced metering by region[5]



Source: FERC Survey

Table ES-1. States with the highest penetration of advanced metering

State	Advanced Metering Penetration
Pennsylvania	52.5%
Wisconsin	40.2%
Connecticut	21.4%
Kansas	20.0%
Idaho	16.2%
Maine	14.3%
Missouri	13.4%
Arkansas	12.9%
Oklahoma	7.2%
Nebraska	6.8%

Source: FERC Survey

[5] Regional definitions used in this figure and subsequent figures are (See Chapter I for a NERC region map):

- Electric Reliability Council of Texas, Inc. (ERCOT)
- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability*First* Corporation (RFC)
- SERC Reliability Corporation (SERC), which covers most of the Southeast.
- Southwest Power Pool, Inc. (SPP)
- Western Electricity Coordinating Council (WECC)
- Other (Alaska and Hawaii)

> 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.[6]

Demand response under this definition can be categorized into two groups: incentive-based demand response and time-based rates. Incentive-based demand response includes direct load control, interruptible/curtailable rates, demand bidding/buyback programs, emergency demand response programs, capacity market programs, and ancillary services market programs. Time-based rates include time-of-use rates, critical-peak pricing, and real-time pricing.

Based on the results of the FERC Survey, Commission staff found that the use of demand response is not widespread. Only approximately five percent of customers are on some form of time-based rates or incentive-based program. The most common demand response programs offered are direct load control, interruptible/curtailable programs, and time-of-use rates, but only about 200 entities reported that they offer these programs. Interest in time-based rates and demand response programs is growing, and results from recent programs and pilots are encouraging.

The FERC Survey also requested information on the potential peak reduction that existing demand response programs represent. Nationally, the total potential demand response resource contribution from existing programs is estimated to be about 37,500 MW. The vast majority of this resource potential is associated with incentive-based demand response. Figure ES-2 shows a breakdown of resource contribution by reliability region and by customer type. Because peak loads vary significantly among reliability regions, it is useful to characterize the existing demand response potential capability relative to each region's summer peak demand. Demand response resource potential ranges from three to seven percent in most North American Electric Reliability Council (NERC) reliability regions, with the notable exception of the MRO region (20 percent). The NERC regions of the country with the largest demand response resource contributions (as a percent of the national total) are RFC (22 percent), SERC (21 percent), and MRO (16 percent).

Demand response programs and time-based rates are offered by all forms of electric companies that serve customers. Publicly-owned utilities (electric cooperatives, political subdivisions, and municipal utilities) account for 55 percent of entities reporting that they offer time-of-use rates to residential customers. A similar distribution reported that they offered direct load control programs.

Investor-owned utility programs account for 47 percent of national demand response resource contributions, followed by Independent System Operator/Regional Transmission Organization (ISO/RTO) administered demand response programs, which contribute 19 percent of national demand response resources (see Figure ES-3).

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[6] 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 (February 2006 DOE EPAct Report).

Demand Response in Regional Transmission Planning and Operations

To a degree, generation, transmission, and demand response are substitutes, depending on the location of generation or demand response. As a substitute for generation, demand response can serve as a local peaking resource and thereby assist resource adequacy. As a substitute for transmission and distribution infrastructure, demand response can reduce the need for new transmission or distribution expansion to bring generation to a local area. At minimum, demand response can provide relief for an overloaded transmission system, and can defer the need for infrastructure.[7] Time-based rates and direct-load-control can be used to target specific hours when system needs are greatest.

Demand response is not treated in transmission planning uniformly across regions, and demand response is typically not directly assessed during transmission planning. It is included only indirectly in most transmission planning. Existing or expected demand response resources are incorporated into reliability assessments either as modifications to expected load or as responsive resources. New demand response resources are typically not included as potential solutions to transmission adequacy problems. System planners do not consider demand response equally when they examine options for dealing with transmission inadequacies. If they do consider demand response, it is as a temporary solution until a permanent transmission enhancement is in place. Commission staff found that many regional transmission organizations state that their responsibility is limited to identifying transmission concerns and evaluating proposed solutions, not primarily encouraging demand response. Bonneville Power Administration, the Midwest ISO, and the PJM Interconnection were the only large entities that reported having policies to consider demand response in transmission planning; however, these have not yet resulted in demand response projects.

How to model demand response and how to measure demand response so it can be better included in electric regional planning is a challenge. In one sense, demand response is like insurance. Modeling its value correctly involves forecasting and uncertainty. A review of recent research suggests that demand response has a key role to play in regional planning. For demand response resources to be valued correctly in regional resource planning, resource plans must be made for a sufficiently long planning period. Demand response can meet peak resource needs and reduce the likelihood of low-probability, high-consequence and potentially costly events. Adding demand response resources to regional plans requires modeling that address uncertainties such as fuel prices, weather, and system factors. Modeled properly, demand response can be an important tool for risk management.

Demand response can also serve as operating reserves. Several demand response programs such as direct load control can provide the timely response necessary to provide these reserves. Load participating in these programs is continuously poised to respond but only has to reduce consumption when a reliability event occurs. Moreover, while customers providing such operating reserves do not normally reduce transmission loading, they can reduce the amount of transmission capacity that must be held in reserve to respond to contingencies. This reserve capability of demand response both reduces the need for new transmission and increases the utilization of existing transmission to provide energy from low cost generation.

[7] For example, ISO-New England obtained demand response in 2004 through the "Gap RFP" to address local reserve concerns within Southwest Connecticut.

The eligibility of demand response resources to provide operating reserves has been limited in most regions and is typically limited to providing supplemental (non-spinning) and slower reserves. Restrictions on demand response providing spinning reserve have eased recently in some areas. For example, ERCOT allows demand response as a supplier of spinning reserve. PJM allows demand response to supply synchronized reserves and regulation.

Based on comments received and Commission staff review of regional transmission planning and operations procedures, Commission staff has identified several actions and steps that could be taken to enable greater use of demand resources. The merits of taking the following steps should be considered by appropriate transmission planners and state and federal regulators:

- Assure that regions that schedule resources to meet either energy or reserve needs properly recognize the capabilities and characteristics of demand resources.
- Assure that requirements are specified in terms of functional needs rather than in terms of the technology that is expected to fill the need. This applies to ancillary services as well as to transmission enhancement.
- Accommodate the inherent characteristics of demand response resources (just as generation resource characteristics are accommodated).
- Allow appropriately designed demand response resources to provide all ancillary services including spinning reserve, regulation, and frequency response reserves.
- Allow for the consideration of demand response alternatives for all transmission enhancement proposals at both the state and ISO/RTO level. At the minimum, transmission expansion planning procedures would allow demand response resources to be proposed and considered as solutions at congested interfaces or in load pockets, along with local generation or transmission enhancements. This consideration would be done early in the process, and include a reporting and assessment of alternatives considered.
- When appropriate, treat demand response as a permanent solution, similar to transmission enhancements.
- Develop better demand response forecasting tools for system operators, to increase the usefulness and acceptability of demand response.

Regulatory Barriers

Commission staff identified several regulatory barriers to improved customer participation in demand response, peak reduction and critical peak pricing programs. These barriers are based on input received from parties in written comments, comments filed and discussion heard at the FERC Demand Response Technical Conference, a review of demand-response program experience, and through a comprehensive literature review. Key regulatory barriers include:

- **Disconnect between retail pricing and wholesale markets**. Retail rates for most customers are fixed, while wholesale prices fluctuate. Placing even a small percentage of customers on tariffs based on marginal production costs, can allocate resources more efficiently.
- **Utility disincentives associated with offering demand response**. Reductions in customer demand reduce utility revenue. Without regulatory incentives such as rate decoupling or similar incentives, electric utilities lack an incentive to use or support demand response.
- **Cost recovery and incentives for enabling technologies**. Utilities are reluctant to undertake investments in enabling technologies such as advanced metering unless the business case and regulatory support for deployment is sufficiently positive to justify the outlay. These

investments may require an increase in rates. It is uncertain whether and how would regulators allow these costs to be recovered.

- **The need for additional research on cost-effectiveness and measurement of reductions.** There are deficiencies in the measurement of demand response and assessment of its cost-effectiveness. Cost-effectiveness tests that have been used by regulators must be improved to reflect changes in the industry, especially in organized markets.
- **The existence of specific state-level barriers to greater demand response.** Policies of retail rate regulators and state statutes in several states have created barriers to implementing greater levels of demand response, especially by exposing customers to time-based rates. Several states have laws that restrict the ability of regulators to implement critical peak pricing and other forms of time-based rates.
- **Specific retail and wholesale rules that limit demand response.** Certain wholesale and retail market designs have rules and procedures that are not conducive to demand participation. For example, the standard lengthy wholesale settlement periods utilized in ISO/RTO markets delays payment to participating retail customers.
- **Barriers to providing demand response services by third parties.** Shifting regulatory rules that allow third parties to provide demand response and potential sunset of various demand response programs are a disincentive to demand response providers. Because third parties often bear the risks of programs dependent on enabling technologies, they need long-term regulatory assurance or long-term contracts to raise the capital needed to invest in enabling technologies.
- **Insufficient market transparency and access to data.** Lack of third-party access to data has been identified as a barrier to demand response. Greater transparency of unregulated retailer price offers and information on the amount of load under time-based rates or pricing would assist grid operation and planning. A related but more fundamental barrier related to data is timely access to meter data.
- **Better coordination of federal-state jurisdiction affecting demand response.** While states have primary jurisdiction over retail demand response, demand response plays a role in wholesale markets under Commission jurisdiction. Greater clarity and coordination between wholesale and state programs is needed.

Conclusions

Based on the results of the FERC Survey, input from interested persons, and an extensive examination of regional and national trends in electric demand response programs policy, Commission staff concludes that demand response has an important role to play in both wholesale and retail markets. The potential immediate reduction in peak electric demand that could be achieved from existing demand response resources is between three and seven percent of peak electric demand in most regions. However, the technologies needed to support significant deployment of electric demand response resources, such as advanced metering, have little market penetration.

Demand response deserves serious attention. Staff recommends that the Commission: (1) explore how to better accommodate demand response in wholesale markets; (2) explore how to coordinate with utilities, state commissions and other interested parties on demand response in wholesale and retail markets; and (3) consider specific proposals for compatible regulatory approaches, including how to eliminate regulatory barriers to improved participation in demand response, peak reduction and critical peak pricing programs. Staff also encourages states to continue to consider ways to actively encourage demand response at the retail level. In particular, staff recommends that the Commission and states work cooperatively in finding demand response solutions.

Chapter I. Introduction

Energy Policy Act of 2005

The Energy Policy Act of 2005 (EPAct 2005) section 1252(e)(3)[8] requires the Federal Energy Regulatory Commission (Commission) to prepare a report, by appropriate region, that assesses electric demand response resources, including those available from all consumer classes. Specifically, EPAct 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.*

Commission Staff Activities

In preparing this report, Commission staff undertook several activities. First, Commission staff developed and implemented a national survey of demand response and advanced metering in the electric sector. Commission staff released a draft version of the survey for public comment, and over 25 parties provided comments.

Second, comments were solicited from interested parties on the key demand response and advanced metering issues and challenges that Commission staff should examine. Over 30 parties provided written comments. Commission staff held a technical conference on demand response and advanced metering (FERC Technical Conference) on January 25, 2006 at Commission headquarters in Washington, DC. The FERC Technical Conference allowed the Commission and staff to gain valuable information regarding the key issues and challenges concerning the development of demand response resources in wholesale and retail markets, what experiences has industry had with implementing demand response and time-based rate programs, how to define advanced metering, and

[8] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005) (EPAct 2005 section 1252(e)(3)). The full text of section 1252 is attached as Appendix A.

what challenges and barriers exist to greater saturation of advanced metering. The conference also provided a regional perspective on demand response and advanced metering issues as a result of participation by representatives from around the country. Thirty-one panelists participated in the technical conference.

Third, commission staff reviewed the literature and experience on advanced metering, demand response programs, and time-based rates. As part of this review, information on the role of demand resources in regional transmission planning and operations were collected through review of regional transmission documents, and through interviews with regional representatives.

Demand Response and Advanced Metering Survey

Due to the lack of detailed data and information on the deployment of advanced metering, and the lack of data of sufficient detail on existing electric demand response and time-based rate programs, Commission staff developed and implemented a first-of-its-kind nation-wide survey to fill this information gap. The FERC Demand Response and Advanced Metering Survey (FERC Survey) requested information on (a) the number of advanced meters and their use, and (b) existing demand response and time-based rate programs, including their current level of resource contribution.

In March 2006, the Commission received final Office of Management and Budget (OMB) approval of the FERC Survey. The FERC Survey was implemented as a web-based survey to expedite data retrieval and ensure consistency. Responses to the survey were requested from 3,365 organizations from all 50 states representing all aspects of the electric delivery industry: investor-owned utilities, municipal utilities, rural electric cooperatives, power marketers, state and federal agencies, and unregulated demand response providers.[9]

More than 1,850 entities responded to survey (a response rate of over 55 percent). Information gathered through the survey serves as the basis for the estimates of saturation of advanced metering, the information on existing demand response and time-based rate programs, and estimates of resource contribution included in this report. The results of this survey should prove useful for future policy discussions, particularly state-level examinations of smart metering directed by EPAct 2005.[10]

Report Organization

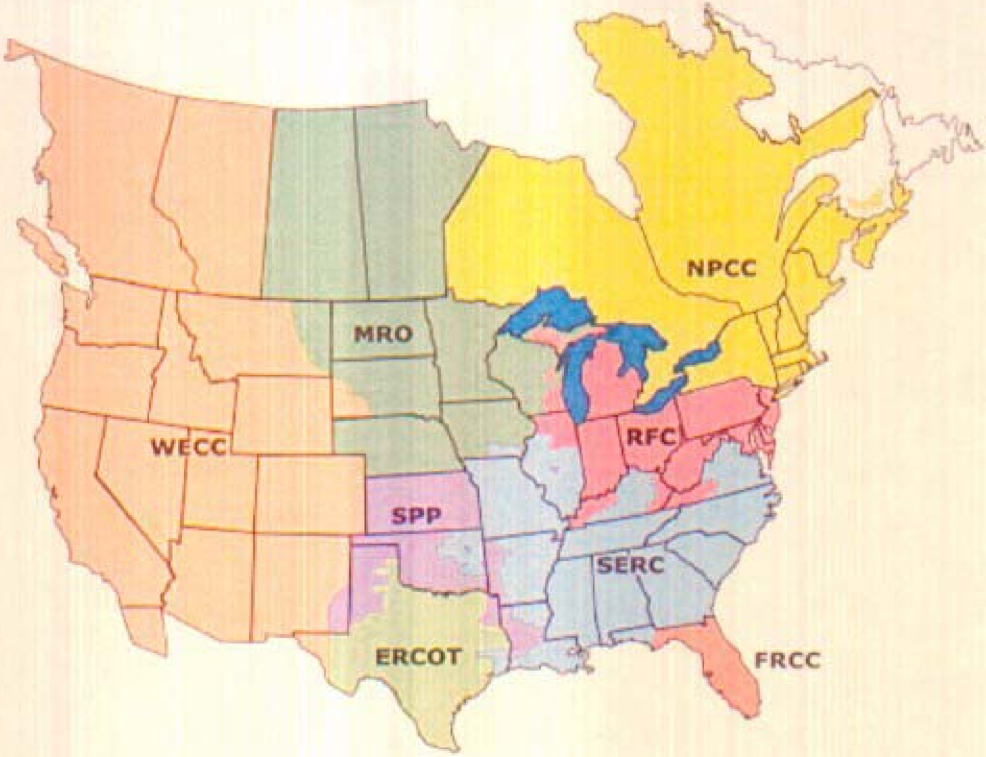
The report begins with an executive summary and introduction which describes the report structure. It then delves deeper into the issues of demand response and advanced metering, detailing the information that Commission staff learned regarding the six issue areas required by EPAct 2005 section 1252(e)(3).

Chapter 2 includes a background on demand response. This chapter includes a definition of demand response, a discussion of the various types of demand response programs, and examination of the benefits associated with demand response.

[9] Appendix F includes detailed information on the survey and sample design, and the OMB approval process. Appendix G lists the respondents to the survey.

[10] EPAct 2005 section 1252(b).

Figure I-1. NERC Region Map



Chapter 3 reviews advanced metering, and estimates the saturation of advanced metering nationally, regionally, by type of utility, customer class, and by state based on the results of the FERC Survey. This chapter also summarizes the key components of advanced metering, benefits and costs of advanced metering, and issues associated with the deployment of advanced metering.

Chapter 4 examines time-based rates and demand response programs. Each of the various time-based rates and demand response programs are discussed in detail. The number of entities offering time-based rates and demand response programs are presented by type of entity and program type. This chapter also reviews the motivation behind increased interest in these programs, and explores the issues and challenges associated with the programs. The chapter concludes with a review of recent developments.

Chapter 5 considers the size of demand response as a resource. It explores the size of the existing demand response resource in MWs, considering results from the FERC Survey. The FERC Survey yielded information on the potential resource contribution as well as the actual use of resources in 2005.

Chapter 6 considers the potential and role of demand response in regional planning, with a focus on regional transmission planning and operations. This consideration includes a review of its current role along with a process for incorporating demand resources in resource plans. This chapter examines how demand response is utilized regionally, and provides steps that could be taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource.

Chapter 7 summarizes and analyzes the barriers identified in comments and in key reports and filings, and provides recommendations for future Commission deliberation.

Regional Definitions

For the purposes of reporting the results of the assessment of demand response and advanced metering by region, as requested by Congress, this report will follow the regional definitions provided by the North American Electric Reliability Council (NERC). Eight regional reliability councils comprise the NERC in the lower 48 states. These regional reliability councils include:

- Electric Reliability Council of Texas, Inc. (ERCOT)
- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability*First* Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool, Inc. (SPP)
- Western Electricity Coordinating Council (WECC)

Figure 1-1 displays the configuration of these regions as of July 2006. Alaska and Hawaii are categorized as Other.

Commission staff chose to use the NERC regions because they reflect the topology of the electric power sector, and the fact that many electric utilities cross state boundaries. Furthermore, wholesale market designs, resource requirements, and customer characteristics tend to vary by NERC regions.

Chapter II. Background on Demand Response

The purpose of this chapter is to provide background and context for the discussions of electric demand response and advanced metering that are contained in later chapters. This overview of demand response and advanced metering includes definitions and history of the use of these programs

Topics discussed in this chapter include:

- Definition of demand response
- Types of demand response
- Role of demand response in retail and wholesale markets
- Benefits of demand response
- Use of demand response in the United States
- Customer price-responsiveness
- Role of enabling technologies

Definition of Demand Response

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. In this report, Commission staff 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.[11]

The crux of demand response that this definition addresses is that it is an active response to prices or incentive payments. 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. Customer responses to high market prices can reduce consumption; this can shave wholesale market prices on a regular basis and thereby dampen the severity of price spikes in wholesale markets on extreme days. Customer response to incentives is an important tool available to operators of the electric grid to address reserve shortages, or for load-serving entities (LSEs) to incorporate in their portfolios to match customer demand with available supply, and where available to individual customers to better manage their costs of doing business.

If changes in electricity prices last for a long time or are expected to do so, a longer-term price-based reduction in consumption through investment in energy efficiency or change in customer behavior may occur. Energy efficiency and conservation are often achieved while consumers are involved in demand response programs through (a) actions taken by consumers to conserve their consumption of electricity during high price periods as they become more aware of their energy-usage patterns, or (b)

[11] 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 (February 2006 DOE EPAct Report), 6.

consumer investments in more energy-efficient lighting and appliances to lower their demand in all hours. Demand response programs coupled with direct feedback and specific education or advice have helped customers in some demand response programs reduce their consumption of electricity by up to 10 percent.[12] Energy efficiency and conservation are not directly included in the definition of demand response programs for purposes of our review and report.[13]

Demand response plays a key role in linking the retail and wholesale sectors of electric markets. End-use customer response to prices or incentives primarily involves retail activities, and oversight of these activities generally is subject to retail regulation at the state or local level. Nevertheless, federal regulatory interests are implicated because of the importance of demand response in wholesale markets and its effect on wholesale market prices, the need for demand response as an emergency resource for grid operators. Consequently, it is important to improve coordination of state and federal electric policies that affect demand response, to achieve more effective regulation of electric markets.

Types of Demand Response

This report reviews two primary categories of demand response: incentive-based demand response and time-based rates. Each category includes several major options:

- Incentive-based demand response
  - Direct load control
  - Interruptible/curtailable rates
  - Demand bidding/buyback programs
  - Emergency demand response programs
  - Capacity market programs
  - Ancillary-services market programs

- Time-based rates
  - Time-of-use
  - Critical-peak pricing
  - Real-time pricing

Incentive-based demand response programs offer payments for customers to reduce their electricity usage during periods of system need or stress. By adjusting or curtailing a production process, shifting load to off-peak periods, or running on-site distributed generation, customers can reduce the level of demand that they place on distribution networks and the electric grid. Customers who participate in incentive-based demand response programs either receive discounted retail rates or separate incentive payments. Vertically integrated electric utilities and other LSEs such as cooperatives, municipal utilities, or unregulated retailers offer these programs on a retail basis directly to customers. At a wholesale level, the impetus comes from independent system operators (ISOs) or regional transmission organizations (RTOs) and power marketers. These programs can be triggered either for reliability or economic reasons. In the wholesale demand response programs, customer load

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[12] Chris King and Dan Delurey, "Efficiency and Demand Response: Twins, Siblings, or Cousins?," *Public Utilities Fortnightly*, 143 # 3, March 2005.

[13] The U.S. DOE, the National Association of Regulatory Utility Commissioners (NARUC), and the National Association of State Energy Officials are preparing an assessment of energy efficiency in response to EPAct 2005 section 139.

reductions are aggregated by retail customers, and then provided to the wholesale provider, such as an ISO, in exchange for an incentive.

The second type of demand response is comprised of time-based rates. A range of time-based rates are currently offered directly to retail customers; not all are time-varying, but they may promote customer demand response based on price signals. These are different from flat rates, which are unvarying and offer no price signals. Flat rates are often assigned to residential customers, and are the only option in the absence of meters that can record time-differentiated usage (except block rates). Customer demand response, incentivized by time-varying price signals, is one way for electricity customers to move away from flat or averaged pricing and to promote more efficient markets.

The two categories of demand response are highly interconnected and the various programs under each category can be designed to achieve complementary goals. For example, by adjusting customer load patterns or increasing price responsiveness, large-scale implementation of time-based rates can reduce the severity or frequency of price spikes and reserve shortages, thereby reducing the potential need for incentive-based programs. Care needs to be taken in their implementation to ensure that these programs do not work at cross-purposes.

Chapter IV continues the examination of these demand response types and their current use in the United States.

Role of Demand Response in Retail and Wholesale Markets

A truly functioning electricity market incorporates dynamic supply and demand forces. A frequent criticism of current wholesale market designs is that the demand-side of the market is not active; thereby creating the potential for supplier market power. Enabling demand-side responses as well as supply-side responses increases economic efficiency in electricity markets and improves system reliability.[14]

Not all consumers need to respond simultaneously for markets to benefit by lowered overall prices. One study suggested that shifting five to eight percent of consumption to off-peak hours and cutting another four to seven percent of peak demand could save utilities, businesses, and customers as much as $15 billion a year.[15] Another posited, "20 percent of customers account for 80 percent of price response."[16] Others find that "only a fraction of all customers, perhaps as few as five percent, are needed to discipline electricity market prices."[17] In its comments to the Commission, the Demand Response and Advanced Metering Coalition (DRAM) said it "believes that demand response typically is capable of providing demand reductions of 3-5 percent of annual peak load for periods up to 100 hours or so per year."[18] In California's statewide pricing pilot, 80 percent of load reduction came from 30 percent of customers.[19]

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[14] See especially Chapter 4 of Sally Hunt, *Making Competition Work* (New York: John Wiley & Sons, 2002).

[15] Justin A. Colledge, et al., "Power by the Minute," McKinsey Quarterly 2002 #1, 74-75.

[16] Goldman, Charles and Roger Levy, *Demand Response in the U.S.: Opportunities, Issues, and Challenges.* Presentation at the National Town Hall Meeting on Demand Response, Washington, DC, June 21, 2005, 20.

[17] Bernie Neenan, Richard N. Boisvert, and Peter A. Cappers, "What Makes a Customer Price-Responsive?" *The Electricity Journal*, 15 #3 (April 2002), 52.

[18] Demand Response and Advanced Metering Coalition (DRAM), comments filed in Docket AD06-2, December 19, 2005, 5.

[19] Susie Sides (San Diego Gas & Electric), FERC Technical Conference on Demand Response and Advanced Metering, January 25, 2006 (hereinafter, "FERC Technical Conference"), transcript, 205.

Midwest ISO (MISO) Vice President Ron McNamara's comments at the January 25, 2006 FERC Demand Response and Advanced Metering Technical Conference (FERC Technical Conference) and at DRAM's January 2006 National Town Meeting on Demand Response support the need for demand response. He stated that industry tends to take load as a given, regardless of price, but that markets work best when prices are constrained by supply and demand. He added that scarcity pricing needs to come through as a real price signal, even while long-term bilateral contracts are the foundation of a market.[20] Demand response programs provide markets with a second set of tools to respond to high prices or capacity shortages. DRAM suggests that markets without demand response tools use more power than they need to: demand response can mitigate market power and be a least-cost, faster-track solution to relieving areas of constrained supply (congestion pockets).[21]

ISO-New England's president and CEO, Gordon van Welie, echoed that belief at an April 2006 demand response summit. He said there are two ways to meet the growing demand for electricity at a time of high natural gas prices: reduce demand or increase supply. His staff's analysis found that two demand-side actions could save New England customers. Reducing electricity use by five percent during peak hours (through conservation and energy efficiency) would save consumers $580 million annually. A 500-MW increase in demand response participation which would cut wholesale costs by $32 million – a total of $612 million annually. Alternatively, the supply-side solution would add 1,000 MW of low-cost plants, saving consumers $600 million. The business-as-usual scenario, based on a five percent annual increase in demand, would keep electricity costs high and increase total costs by $700 million each year.[22] Similar arguments were offered by the New York Public Service Commission in a recent order. The New York commission found that planners who rely solely on the supply-side will over-build the system for the few hours of annual system peak, rather than leveling that peak through conservation and demand response.[23]

The role that each form of time-based rates or incentive-based demand response plays in electric system planning and operations depends on the timeframe of the response. For example, real-time pricing or critical-peak pricing, which directly reflect wholesale prices, affect supply scheduling in day-ahead markets and during real-time dispatch. Time-of-use rates does not induce as rapid or large responses. Incentive-based demand resources such as direct load control, capacity, and ancillary services programs can be used as reserves during real-time, as reserves in day-ahead scheduling and dispatch, or as capacity resources in system planning. By contrast, energy efficiency can be viewed as a resource during system planning because of its long-term effects.

Use of Demand Response in the United States

Time-based rates and other forms of demand response have been used within the electric power industry for decades. For many utilities, demand response was a part of their portfolio of resources and was activated during reserve shortages or periods of high prices. Two of the oldest forms of demand response have been interruptible/curtailable tariffs and time-of-use (TOU) rates. Many utilities place large industrial consumers that have interval meters on mandatory TOU rates. In the

[20] Ron McNamara (MISO), FERC Technical Conference, transcript, 177-180.

[21] DRAM, comments filed in Docket AD06-2, December 19, 2005, 2.

[22] Gordon van Welie, speech to 2006 "ISO-NE Demand Response Summit," April 27, 2006; and ISO-New England, Staff White Paper, *Controlling Electricity Costs*, June 1, 2006 (the latter revised the figures slightly from the speech).

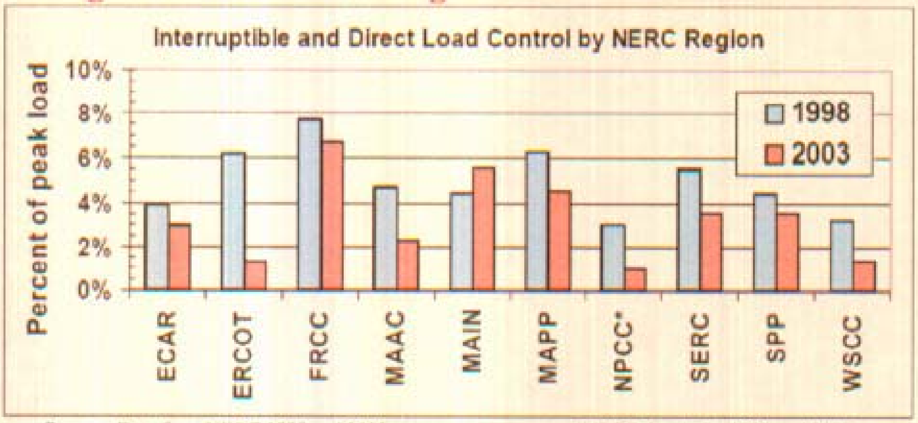
[23] New York State Public Service Commission, Order Denying Petitions for Rehearing and Clarification in Part and Adopting Mandatory Hourly Pricing Requirements, issued and effective April 24, 2006, 2. [hereinafter NYPSC Order, April 24, 2006] See Chapter VI for a further discussion of the incorporation of demand resources into planning.

past decade, these trends have reversed, and new types of participants and demand response programs have begun to appear.

The use of demand response programs, also known as load management or as demand-side management, increased markedly in the 1980s and early 1990s. This increase was driven by a combination of directive in the Public Utility Regulatory Policies Act of 1978 (PURPA)[24] to examine time-based rate standards, and by state and federal regulatory and policy focus on demand-side management and integrated resource planning. Regulatory support and technical advances in controls, communications, and metering led to a marked increase in load management, particularly direct load control programs and interruptible/curtailable service tariffs.

There are regional differences in the current use of demand response and how its use has changed over the past decade. Data collected from regional reliability councils and electric utilities by North American Electric Reliability Council (NERC) in its Energy Supply & Demand database provides a snapshot of regional potential and historical trends. Figure II-1 illustrates that Florida Reliability Coordinating Council (FRCC), Electric Reliability Council of Texas, Inc. (ERCOT), and the MidAmerican Power Pool (MAPP) had the largest percentage of demand response capability in 1998. It also shows that the amount of load management included in regional forecasts declined between 1998 and 2003. Regions with larger relative declines include ERCOT, Northeast Power Coordinating Council (NPCC), Mid-Atlantic Area Council (MAAC), and Western Systems Coordinating Council (WSCC). In 2003, due to the decline in capability in ERCOT and an increase in capability in

Figure II-1. Load Management in NERC Forecasts



Source: Data from NERC 1998 and 2003 summer assessments. *NPCC data is for 1998 and 2002

Mid-America Interconnected Network (MAIN), the regions with the largest percentage capability are FRCC, MAIN, and MAPP.[25]

[24] Title I of PURPA stated as its purpose (1) conservation of energy supplied by electric utilities, and (2) optimal efficiency of electric utility facilities and resources (section 101). PURPA section 111 directed states to consider several federal standards, including (1) time-of-day rates, (2) interruptible rates, and (3) load-management techniques. Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (1978) (codified in U.S.C. sections 15, 16, 26, 30, 42, and 43).

[25] Note that since 2003, the configuration of the NERC reliability regions has changed. Portions of ECAR and MAIN are now in the Relibilty*First* NERC region along with MAAC. Most of MAPP is now served by the Midwest Reliability Organization (MRO). SERC has expanded and now serves portions of ECAR, MAIN, and SPP.

According to the literature on this issue, a contributing factor behind the decline shown in Figure II-1 has been the waning of electric utility interest and investment in demand response over the past decade, due to changes in industry structure and the result of state electric restructuring plans.[26] State and utility programs were dismantled in many restructured states that had previously supported extensive programs. In several states, such as Texas, load management was deemed a competitive service and regulated distribution companies were directed to divest their holdings.[27] In other states, utility divestiture of generation or transfer of the provider-of-last-resort (POLR) obligation removed a significant driver for utility investment by splitting up the benefits of demand response across multiple parties. Ample capacity reserves in many parts of the United States also contributed to declining utility interest and investment. Many states, such as Nevada, still support demand response and load management and operate integrated resource-planning programs that frequently include demand response and energy efficiency.

Benefits of Demand Response

Beyond the broad improvements in market efficiency and market linkages discussed above, demand response creates multiple, specific benefits for market participants and for the general efficiency and operation of electric markets. The following list of benefits encompasses many of the benefits referenced in the DOE report.[28]

Participant Benefits

Customer adoption of demand response is based on the expectation of financial or operational benefits:[29]

- **Financial benefits** include cost savings on customers' electric bills from using less energy when prices are high, or from shifting usage to lower-priced hours, as well as any explicit financial payments the customer receives for agreeing to or actually curtailing usage in a demand response program. The significant increases in fuel and electricity costs that have occurred over the last several years provide additional motivation for customers to control and reduce their energy consumption.
- **Reliability benefits** refer to customer perceived benefits from the reduced likelihood of being involuntarily curtailed and incurring even higher costs, or societal, in which the customer derives satisfaction from helping to avoid widespread shortages.

Market and System Benefits

A key policy goal in implementing demand response is to create market, reliability, and social welfare benefits, including:[30]

[26] Raynolds and Cowart document this decline in *Electricity Reliability White Paper: Distributed Resources and Electric System Reliability*, 2000.

[27] More than 3,500 MW of capability from interruptible contracts no longer exist in Texas. Steven Braithwait, B. Kelly Eakin, Laurence D. Kirsch, "Encouraging Demand Participation In Texas' Power Markets," Laurits R. Christensen Associates Inc., prepared for the Market Oversight Division of the Public Utility Commission of Texas, August 2002.

[28] February 2006 DOE EPAct Report, 26-29.

[29] February 2006 DOE EPAct Report, 26.

[30] The short-term and long-term market benefits, along with the reliability benefits description are drawn from the list of "Collateral Benefits" included in February 2006 DOE EPAct Report, 27-28.

- **Short-term market impacts** are savings in variable supply costs brought about by more efficient use of the electricity system, given available infrastructure. In particular, price responsiveness during periods of scarcity and high wholesale prices can temper high wholesale prices and price volatility. Decreases in price spikes and volatility should translate into lower wholesale and retail prices. Where customers are served by vertically integrated utilities, short-term benefits are limited to avoided variable supply costs. In areas with organized spot markets, demand response also reduces wholesale market prices for all energy traded in the applicable market. The amount of savings from lowered wholesale market prices depends on the amount of energy traded in spot markets. The New York Public Service Commission suggests that demand response can also reduce a state's dependence on natural gas-fueled generation.[31]
- **Long-term market impacts** are associated with the ability of demand response to (a) reduce system or local peak demand, thereby displacing the need to build additional generation, transmission, or distribution capacity infrastructure, and (b) adjust the pattern of customer loads, which may result in a shift in the mix of peak versus baseload capacity.
- **Operational and capital cost savings** occur as system operators, LSEs, and distribution utilities benefit from avoided generation costs as well as avoided or deferred transmission and distribution costs. Since demand response can begin to be deployed in a relatively rapid fashion, demand response can contribute to the resolution of problems in load pockets on a shorter time frame than building new generation, transmission, or distribution, which can take years to complete.
- **System reliability benefits.** By reducing electricity demand at critical times (e.g., when a generator or a transmission line unexpectedly fails), demand response that is dispatched by the system operator on short notice can help return electric system (or localized) reserves to pre-contingency levels.

Additional Benefits Created by Demand Response

Other demand response benefits noted in studies are more difficult to quantify; their magnitude will likely vary by region. The importance and perceived value of each of these benefits is subject to debate. Additional benefits may include:[32]

- **More robust retail markets**. Demand response promotes and creates additional options in retail markets. For example, default-service real-time pricing can stimulate innovation (e.g., alternative index-based products or curtailment products) by retail suppliers.[33] The availability of ISO/RTO-administered demand response programs can provide value-added opportunities for marketers and the ability of customers to monetize their demand reductions.
- **Additional tools to manage customer load**. Demand response provides expanded choices and tools for customers in states with and without retail competition to manage their electricity costs.
- **Risk Management**. Demand response allows customers, retailers, and utilities to hedge their risk exposure to system emergencies and price volatility. Retailers can hedge price risks by

[31] NYPSC Order, April 24, 2006, 1-2.

[32] The more robust retail markets, market performance benefits, and possible environmental benefits, are drawn from the list of "Other Benefits" included in the February 2006 DOE EPAct Report, 29.

[33] Galen Barbose, et al., *Real Time Pricing as Default or Optional Service for C&I Customers: A Comparative Analysis of Eight Case Studies*, Lawrence Berkeley National Laboratory: LBNL-57661, August 2005.

creating callable quantity options (contracts for demand response) and by creating price offers for customers who are willing to face varying prices. Customers can explicitly incorporate demand response into their operations and electricity purchases on an individual facility or enterprise basis. Utilities can use demand response programs to hedge their portfolio. This form of hedging is particularly important when utilities have default service obligations under rate freezes or caps.[34]

- **Market performance benefits**. Demand response can also play an important role in mitigating the potential for generators to exert market power in wholesale electricity markets. In organized markets, during periods of high demand and inadequate supply, market-clearing prices can escalate to high levels as more expensive-to-operate generation is dispatched. Without price-response mechanisms to lower demand as market-clearing prices increase, the potential for supplier market power abuse (such as capacity withholding) is heightened. Price-responsive demand mitigates market power potential because these reductions increase suppliers' risk of being priced out of the market. Customers who lower their consumption increase the number of suppliers in the market, reducing concentration and making collusion more difficult just when competitive concerns are the most severe. Sufficient amounts of price-responsive demand may reduce the need to use price caps and other market mechanisms such as installed capacity markets.
- **Linking wholesale and retail markets**. Demand response can help link retail and wholesale markets through greater customer price-responsiveness to wholesale price changes and by increased hedging opportunities.
- **Possible environmental benefits**. Demand response may provide conservation effects, both directly from load reductions (that are not made up at another time) and indirectly from increased customer awareness of their energy usage and costs.[35] Demand response may provide environmental benefits by reducing generation plants' emissions during peak periods. Reductions during peak periods should be balanced against possible emissions increases during off-peak hours, as well as from increased use of on-site generation. If the implementation of demand response contributes to reduced generation facility construction, there may be additional environmental and aesthetic benefits. These conservation and environmental impacts can be either positive or negative, and will likely vary by region.[36]

Multiple studies have attempted to quantify these benefits. The Electric Power Research Institute concluded that "… a 2.5% reduction in electricity demand statewide could reduce wholesale spot prices in California by as much as 24%; a 10% reduction in demand might slash wholesale price spikes by half."[37] McKinsey estimated national benefits of time-sensitive pricing to be $15 billion.[38] An ICF Consulting study for the Commission estimated a $4 billion savings in annual system operating costs if customers were exposed to peak-period price signals.[39] These benefits also flow to society as a whole, not just to participants.[40]

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[34] David Kathan, *Policy and Technical Issues Associated with ISO Demand Response Programs*, prepared for NARUC, July 2002.

[35] King and Delurey, 2005.

[36] Stephen P. Holland and Erin T. Mansur, "The Distributional and Environmental Effects of Time-Varying Prices in Competitive Electricity Markets," CSEM Working Paper (WP-143), May 2005.

[37] Taylor Moore, "Energizing Customer Demand Response in California," *EPRI Journal*, Summer 2001, 8.

[38] Colledge, 2,7.

[39] ICF Consulting, *Economic Assessment of RTO Policy*, prepared for FERC, February 2002.

[40] Colledge, 2.

The Commission has recognized the benefits of demand response in multiple orders over the last six years. For example, in a 2001 order addressing the California crisis, the Commission stated:

> Without a demand response mechanism, the [independent system operator] is forced to work under the assumption that all customers have an inelastic demand for energy and will pay any price for power. There is ample evidence that this is not true. Many customers, given the right tools, can and will manage their demand. . . . A working demand response program puts downward pressure on price, because suppliers have additional incentives to keep bids close to their marginal production costs and high supply bids are more likely to reduce the bidder's energy sales. Appropriate price signals to customers thus help to mitigate market power as high supply bids are more likely to reduce the bidders' energy sales. Suppliers thus have additional incentive to keep bids close to their marginal production costs. Demand-side price-responsive bids will also help to allocate scarce supplies efficiently.[41]

The Commission also noted the value of incentive-based demand response in maintaining grid reliability in a 2002 PJM order:

> PJM is responsible for ensuring the short-term reliability of the interstate transmission system. When system reliability events require PJM to implement measures to protect the transmission system (i.e., PJM declares a Maximum Generation Emergency), encouraging load reductions and the use of on-site generation is an important tool in maintaining transmission reliability.[42]

Evidence of Customer Price-Responsiveness

Offered time-based rates, customers choose whether to adjust their consumption or not. Their decision to adjust consumption is driven by the costs and benefits of taking one of the following actions: (a) adjusting routine business activity specifically to avoid paying higher than average prices; (b) forgoing discretionary usage; and (c) deploying distributed or on-site generation. The ability of customers to respond to prices requires the following conditions: that time-based rates are communicated to them; that they have load control systems that allow them to respond to price signals (e.g., by shedding load, automatically turning appliances down or off, or turning on an on-site generator); and that customers have meters that can measure consumption by at least the time of day so the utility can determine how much power was used at what time and bill accordingly.

Experiences in New York, Georgia, California, and other states and pricing experiments have demonstrated that customers do take actions to adjust their consumption, and are responsive to price (i.e., they have a nonzero price elasticity of demand). Georgia Power Company's successful real-time pricing tariff option has demonstrated that industrial customers who receive real-time prices based on an hour-ahead market are relatively price-responsive (price elasticities ranging from approximately –0.2 at moderate price levels, to –0.28 at prices of $1/kWh or more) given the short-time period in which to act. Among day-ahead real-time pricing customers, price elasticities range from approximately –0.04 when prices are at moderate levels to –0.13 when customers are exposed to higher prices.[43] A critical peak-pricing experiment in California in 2004 determined that small residential and commercial customers are price responsive and will produce significant reductions.

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[41] *San Diego Gas and Electric Co.*, 95 FERC ¶61,148, at 62,555 (2001).

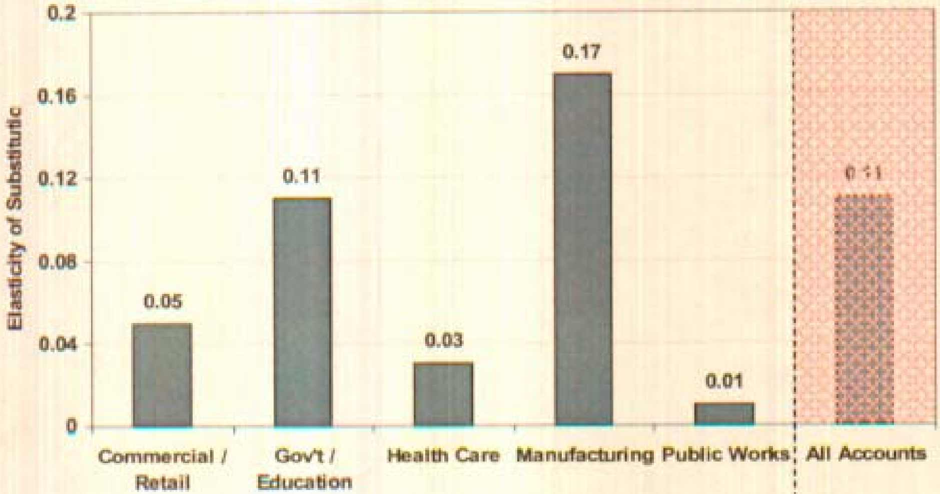
[42] *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,139 at n. 18 (2002).

[43] Industrial Consumers, comments filed in Docket No. AD05-17-000, November 18, 2005, 39.

Participants reduced load 13 percent on average, and as much as 27 percent, when price signals were coupled with automated controls such as controllable thermostats.[44]

Customer price-responsiveness varies significantly by market segment among commercial and industrial users (See Figure II-2). A study of Niagara Mohawk Power (now National Grid) customers in the real-time pricing program found nearly a third of those who were unable to curtail in the Niagara Mohawk program also were enrolled in a NYISO emergency demand response program (EDRP); nearly two-thirds had received some sort of capacity payments. These non-price-responsive customers may have valued perceived reliability needs more highly than perceived price needs. The study noted that "industrial customers who were also enrolled in the EDRP showed dramatically increased responses during EDRP events (0.40 on event days vs. 0.03 on non-event days); for these customers, the EDRP program appears to entice price response that their Niagara Mohawk tariff did not."[45]

Figure II-2. Elasticity of substitution varies by customer market segment



Source: Goldman, et al., *Customer Strategies for Responding to Day-Ahead Market Hourly Electricity Pricing*. LBNL-57128, August 2005.

Role of Enabling Technology

A key requirement for most demand response programs and time-based rates is the availability of enabling technology. For states or utilities to implement demand response and time-based rates, customers would need meters that record usage on a more frequent basis, preferably hourly. Introducing other demand technologies such as smart thermostats (i.e., thermostats that adjust room temperatures automatically in response to price changes or remote signals from system operators) would increase the amount of load that could be reduced under a demand response program. Advances in integrated circuitry, control systems, and communications technologies have significantly increased the functionality of advanced metering and demand response technologies. These advances have the potential to provide more power system and societal benefits than those achievable with

[44] Charles River Associates. *Impact Evaluation of the California Statewide Pricing Pilot: Final Report*. March 16, 2005.

[45] Charles Goldman, et al., *Does Real-time Pricing Deliver Demand Response? A Case Study of Niagara Mohawk's Large Customer RTP Tariff*. Lawrence Berkeley National Laboratory: LBNL-54974, August 2004.

existing demand response programs. These advances make automated customer responses possible in more situations, allowing both greater customer receptivity and higher utility confidence that customers can and will respond to price-based demand response.

Examples of enabling technologies include, but are not limited to,[46]

- interval meters with two-way communications capability that allow customer utility bills to reflect their actual usage pattern rather than an average load profile for that customer class
- multiple, user-friendly communication pathways to notify customers of load curtailment events
- energy-information tools that enable near-real-time access to interval load data, analyze load curtailment performance relative to baseline usage, and provide diagnostics to facility operators on potential loads to target for curtailment
- demand-reduction strategies that are optimized to meet differing high-price or electric system emergency scenarios
- load controllers and building energy management control systems that are optimized for demand response and which facilitate automation of load curtailment strategies at the end use level
- on-site generation equipment, used either for emergency back-up or to meet primary power needs of a facility

The prices for technologies to implement time-based rates and automated customer responses have been falling, just as their capabilities have been rising. In his seminal book, *Spot Pricing of Electricity*, Professor Fred Schweppe of Cornell University posited that demand response was an integral part of a market model. His analysis envisioned technology solutions that may have seemed futuristic in 1988, including automatic thermostat controls and customer warnings when the spot prices to run an appliance would exceed a pre-determined cost. He posited that as time goes by, "appliance manufacturers would start to produce appliances designed to be able to exploit time-varying prices."[47]

Communication technologies for notifying customers about system emergencies or price events also are important. Whether programs are adopted in restructured electricity markets or in traditional regulated markets, LSEs can adopt real-time and critical-peak pricing by notifying customers through pagers, cell phones, the Internet, and other means. The more communications channels used, the greater the likelihood of customer response.

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[46] Charles Goldman, Grayson Heffner, and Michael Kintner-Meyer, *Do "Enabling Technologies" Affect Customer Performance in Price-Responsive Load Programs?*, August 2002: LBNL-50328, 10.

[47] Fred C. Schweppe, *Spot Pricing of Electricity* (Boston: Kluwer Academic Publishing, 1988), chapter 4.

Chapter III. Advanced Metering and Market Penetration[48]

This chapter addresses the first area, in EPAct section 1252(e)(3), that Congress directed the Commission to consider:

> *(A) saturation and penetration rates of advanced meters and communications technologies, devices and systems.*

This chapter contains a detailed analysis of the state of advanced metering, and estimates the saturation and penetration of advanced metering in the electric power sector across the United States. It also discusses the importance of advanced metering for electric demand response, describes the available forms of advanced metering and key technological developments in metering and communications equipment.

To develop this estimate of advanced metering penetration, Commission staff conducted a comprehensive and first-of-its-kind survey of metering. The FERC Demand Response and Advanced Metering Survey[49] (FERC Survey) requested information on electric industry meters in all 50 states, with attention to meters that measure usage in short time intervals and with meter data retrieval more frequent than monthly. The results of this survey suggest that advanced metering achieved almost a six percent penetration in the United States electric meter market by the end of 2005.

This chapter builds on the discussion of demand response and time-based rate programs included in Chapter II, and is organized into five sections:

- Definition of advanced metering
- Description of the components and technologies associated with advanced metering
- Presentation of the estimates of market penetration based on information received in the FERC Survey
- Costs and benefits associated with the deployment of advanced metering
- Issues associated with advanced metering

What is advanced metering?

Commission staff defines "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.

The key concept reflected in this definition is that advanced metering involves more than a meter than can measure consumption in frequent intervals. Advanced metering refers to the full measurement and collection system, and includes customer meters, communication networks, and data management

[48] This chapter reflects the views and the assistance of Patti Harper-Slaboszewicz of UtiliPoint International.
[49] See Appendix F for a description of the FERC Survey.

systems. This full measurement and collection system is commonly referred to as advanced metering infrastructure (AMI).

Commission staff chose this definition based on (a) a review of the state-of-the-art of metering and communications technology, (b) specifications for "smart metering" or advanced metering in recent utility solicitations,[50] (c) what type of meters and infrastructure is necessary to support demand response and to provide additional utility operational benefits beyond reducing metering costs,[51] and (d) definitions of advanced metering included in the EPAct 2005.[52]

Overview of Advanced Metering

The need to bill customers for their electricity consumption has historically been the primary reason to read electric meters. Today, with advances in metering technology and communication systems, advanced meters and infrastructure can provide additional value to utilities by enhancing customer service, reducing theft, improving load forecasting, monitoring power quality, managing outages, and supporting price-responsive demand response programs. For example, if electric load serving entities (LSEs) read meters every day, customer service representatives can assist a customer starting or ending service in one phone call, or more easily handle high bill complaints. With more frequent, hourly reads, customer demand can be totaled across meters served by a feeder line or transformer. This allows electric distribution companies to properly size equipment to handle peak loads, and increase the reliability of service while reducing costs. Hourly reads can also improve the accuracy of load forecasting, allowing LSEs to sell more power into the wholesale market, or reduce spot market purchases.[53]

Advanced metering also supports time-based rates. Monthly-only meter reads limit available rate options and does not support the provision of usage information in real-time to customers (see Chapter IV for a full description of alternative rate offerings). Hourly meter reading capabilities permit current and future innovative rate designs. These innovative rate designs can include retail rates designed to encourage customers to curtail energy use when wholesale prices are high and to make short-term or long-term changes to slow the growth of peak demand, and wholesale programs operated by Independent System Operators and Regional Transmission Organizations (ISO/RTOs) that are designed to curtail consumption during periods of high wholesale prices or system emergencies.[54] In

[50] Recent requests for proposals for automated meter reading have included a fixed network requirement, and the requirements almost always involve measuring interval data hourly and collecting the data at least once per day. Exceptions have included more stringent requirements, for example, CenterPoint, a large utility in Texas, issued an RFP in January 2006 requesting 15 minute interval data.

[51] Jana Corey, Director, Advanced Metering Infrastructure (AMI) Initiative for PG&E, provided the following written testimony in support of PG&E's filing for the AMI project: "Over time, the operational benefits are expected to cover 89 percent of the costs and PG&E continues to estimate that the additional customer demand response benefits will allow the total benefits to exceed the total AMI Project cost." "Section I Advanced Metering Infrastructure Project A.05-06-028 - Supplemental Testimony Pacific Gas and Electric Company Chapter 1 AMI Project and Project Management", Application 05-06-028, filed October 13, 2005 with California Public Utilities Commission.

[52] EPAct 2005 section 1252 (included in Appendix A) references advanced metering as a "suitable meter," a "device to enable demand response," "advanced metering with communications," and "time-based meters with communication devices." The section header includes the term "Smart Metering." EPAct 2005 section 103 offers a more specific definition: "advanced meters or advanced metering devices that provide data at least daily and that measure at least hourly consumption of electricity."

[53] Patti Harper-Slaboszewicz, "Market Trends in AMR and Demand Response," prepared for Automatic Meter Reading Association (AMRA), 2005.

[54] Roger Levy, "Meter Scoping Study," prepared for the California Energy Commission, March 2002.

meter readings up through the data collection network to the AMI host system. The data analysis and storage of the meter data is managed by meter data management (MDM) systems. Each of these components is discussed in greater detail below.

Metering

Electric meters have historically been used to measure, at the minimum, consumption of electricity in kWh over a monthly or other similar billing period. Meters installed at larger commercial and industrial customers often also measured maximum demand in kW and other power quality parameters. Up until the last decade or so, these meters, especially for smaller customers, were based on electromechanical designs. Over time, electromechanical meters have become highly reliable and typically last for up to 40 years.

In recent years, metering has gone through a transformation from electromechanical meters to solid state, electronic meters. The shift towards solid state meters is driven in part by their additional functionality,[57] but the strongest driver for the rising market share of solid state meters is investment in automated meter reading (AMR) or AMI. With AMI or AMR enabled meters, the utility will plan to change out the meter when the AMI or AMR communications fails or is replaced. Thus, the shorter useful life of the solid state meter compared to electromechanical meters is less important.

Along with the shift towards solid state meters, there also has been a gradual transition from manual meter reading to AMR, and onto AMI, and utilities are at various stages of adopting automation. Many utilities continue to employ meter readers to walk routes to read utility meters once a month. However, the number of utilities that use meter books and later key in the readings is dwindling. Hand-held electronic meter books began replacing meter books in the 1980s, which allow the meter reader to physically connect to the meter or key in the meter reading. Meter reads can then be downloaded to the utility billing system, which reduces transcription errors and speeds up the billing process. This system works fairly well for collecting meter reads for monthly bills but still requires the meter reader to get reasonably close to the meter on the customer's property.[58] AMR and AMI were developed to allow meter reading to be more efficient and less-costly through remote meter reading. In particular, deployments of AMI can also support more frequent meter reading.

The design of the meter and the technology used does have implications for its ability to be part of an AMI system. To enable an electromechanical meter to communicate with an AMI system, an electronic meter module is installed "under-the-glass" of the meter. This module counts and records electronically the spinning of the disk within the meter. This retrofit solution does have limitations, however. The AMI measurement is performed independently of the meter measurement which may result in a discrepancy between the usage displayed by the electromechanical meter and what is reported via the AMI system. Retrofit of solid state meters to communicate with AMI systems is more straightforward and most meters currently being deployed have the ability to accommodate communication modules from multiple AMI vendors and technologies.

Utilities tend to meter medium-sized customers with demand meters. However, these customers are not large enough to be metered with the more sophisticated metering used for the largest customers of utilities. Demand meters measure the maximum demand during the billing period along with the

[57] Solid state meters provide the ability to measure loads at lower levels, increased measurement frequency, increased accuracy, data storage capability, measurement of additional parameters, and ease of upgrading meter functionality or integrating communication technology.

[58] Roger Levy, 2002.

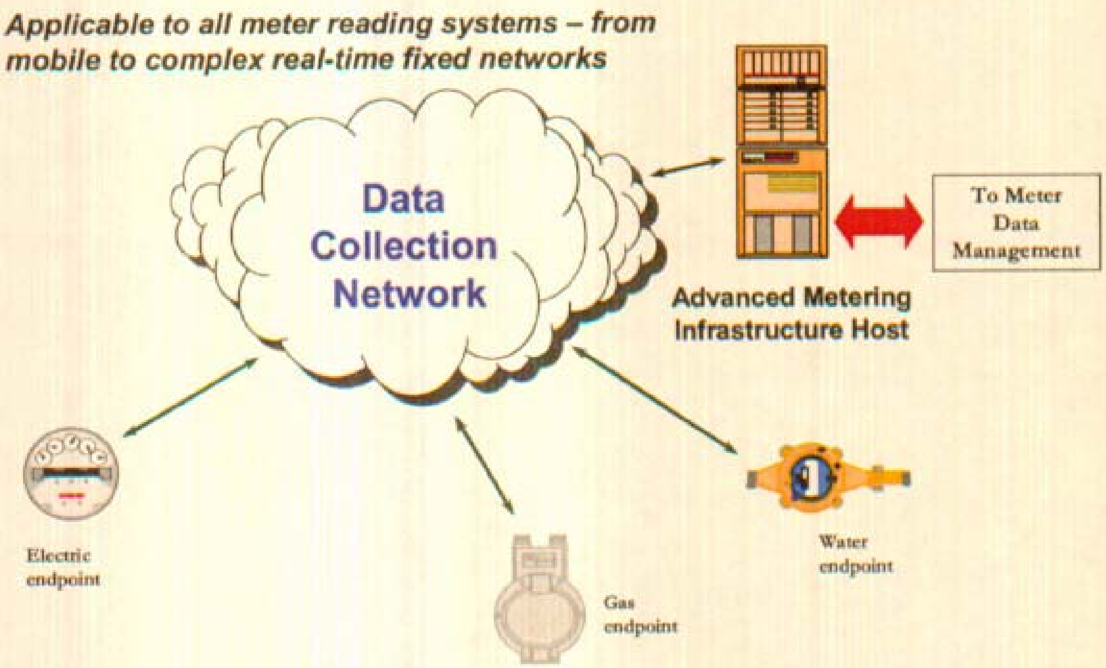
many time-based pricing pilots and implementations of time-based pricing, a key consideration has been to provide timely information to customers, and almost all time-based rate pilots or implementations have used advanced metering.[55] Nevertheless, some electric utility representatives believe that the added expense of advanced metering is not needed to support time-based rates, and that deployment of time-of-use meters is sufficient to achieve benefits.[56]

The remainder of this section presents the key building blocks of advanced metering and discusses the available technologies.

Building Blocks of Advanced Metering

Advanced metering or AMI consists of various components, including meters enabled with communications, a data collection network, and an AMI host system and database. Figure III-1 provides an overview of the building blocks of advanced metering. Note that while the focus of the discussion in this chapter will be on electric metering, AMI can also be deployed to collect data from gas and water meters.

Figure III-1. Building blocks of advanced metering



Source: UtiliPoint International

As is shown in Figure III-1, advanced metering has several components. Each customer meter is equipped with the ability to communicate with a network. A customer meter and the associated communication is commonly referred to as an "endpoint." The communication system endpoints send

[55] The following time-based pricing pilots/implementations have depended on advanced metering: Gulf Power GoodCents, California Statewide Pricing Pilot, PSE&G myPower Pilot Program, Anaheim Spare the Power Days program.

[56] See for example, Alan Wilcox (Sacramento Municipal Utility District), FERC Technical Conference, transcript, 134-137.

energy measurement. The difficulty has been with how to reset the demand measurement once the maximum demand has been recorded for the current billing period without actually physically visiting the meter site. With AMI, if the utility retrieves the maximum demand daily, it is no longer necessary to manually reset the demand measurement.

The transition to solid state metering occurred some time ago for larger customers. Conversion to a new AMI system for larger customers is typically driven by the need to change communications technologies. For example, many electric utilities are converting from using analog cellular to other communication technologies as cellular companies drop support for analog cellular.

For all customers, there are a variety of choices for meters, solid state or electromechanical, and most AMI vendors have developed AMI modules for more than one meter vendor. Large purchases of meters today are usually related to a rollout of AMI, and purchase is guided by the selection of the AMI technology rather than by the selection of a particular meter. AMI has thus contributed to the treatment of meters as commodities by utilities.

AMI Data Collection

AMI data collection involves the collection and retrieval of meter data without physically visiting the meter site, and is typically done by means of a fixed network.[59] Today, electric utilities use various types of AMI systems. The different types of AMI systems available on the market today are:

- Broadband over power line
- Power line communications
- Fixed radio frequency (RF) networks
- Systems utilizing public networks (landline, cellular, or paging)

Each of these different AMI system types are examined in more detail below.

Broadband Over Power Line (BPL)[60]

BPL works by modulating high-frequency radio waves with the digital signals from the Internet. These high frequency radio waves are fed into the utility grid at specific points, often at substations. They travel along medium voltage circuits and pass through or around the utility transformers to subscribers' homes and businesses. Sometimes the last leg of the journey, from the transformer to the home, is handled by other communication technologies, such as Wi-Fi.

As seen in Figure III-2 below, substations receive power from power plants over high voltage lines, and then step down the voltage to transmit power to distribution transformers over medium voltage circuits. Each medium voltage circuit services 20-25 distribution transformers which convert the medium voltage down to the voltage level used within most homes and businesses (110v/220v). Between one and six homes are connected to each distribution transformer which translates to about 100 homes passed per medium voltage circuit.

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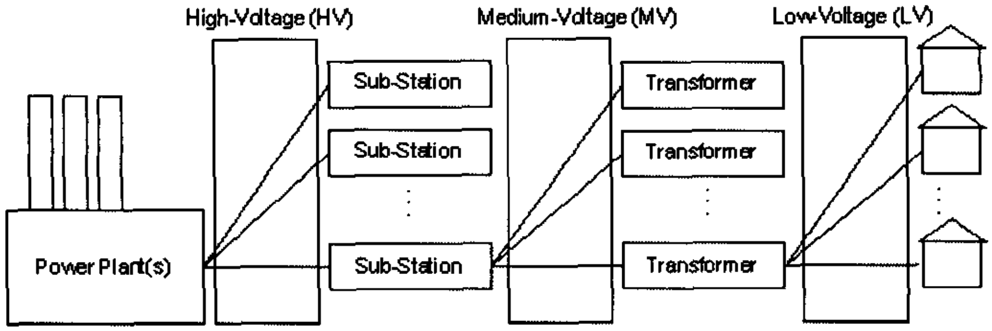
[59] A fixed network refers to either a private or public communication infrastructure which allows the utility to communicate with meters without visiting or driving by the meter location.

[60] The information in this section relies heavily on facts provided in a seminar presented in 2005 by UtiliPoint: Ethan Cohen, UtiliPoint, "BPL Hope, Hyperbole, and Reality," April 2005.

Figure III-2. Stylized Grid diagram



Source: Bruce Bahlmann, Birds-Eye.Net and UtiliPoint® International

To implement BPL, a utility must interconnect substations (many of which are already interconnected using fiber). The BPL signal is then injected onto the medium voltage circuits at the substations. Due to the tendency of transformers to filter the high-frequency BPL signal, at each distribution transformer one of three things can happen: the signal is pushed through the transformer, the transformer is bypassed, or the signal is provided to the customers using a Wi-Fi device physically located near the distribution transformer.

In Europe, there are typically 100 customers served on a distribution line with transformers at each end of the span. In contrast, the United States distribution system has one transformer serving six to ten customers, which increases the relative cost in the United States.[61]

Major vendors of broadband over powerlines include Ambient, Amperion, Current Technologies, Main.net, and PowerComm Systems.

Power Line Communications (PLC)

PLC systems send data through powerlines by injecting information into either the current, voltage or a new signal. This can be accomplished by slightly perturbing the voltage or current signal as it crosses the zero point or adding a new signal onto the power line. The system normally has equipment installed in utility substations to collect the meter readings provided by the endpoint, and then the information is transmitted using utility communications or public networks to the utility host center for the PLC system. The low frequency signals used in PLC communications in the United States are not filtered out by distribution transformers.

PLC systems are particularly well suited to rural environments, but have also been successfully used in urban environments.[62] For utilities with both rural and suburban areas in their service territory, PLC provides an option for using one AMI technology for the entire service territory for electric meters. PLC systems initially targeted residential and small commercial metering, but are now able to read for larger customers as well.

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[61] "Is the Ambient system compatible with all distribution systems?" Frequently asked questions on Ambient Corporation website, http://www.ambientcorp.com/pages/faqs-UTILITY.htm, "For all practical purposes, yes. In the US and Canada, all systems are essentially the same from a BPL perspective. In other countries, differences in voltage, frequency and configuration (specifically, the number of customers on each distribution transformer) can impact equipment and system design. In general, the higher density of customers per transformer in Europe and other countries works in favor of BPL."

[62] PPL Electric Utilities has used PLC in Pennsylvania and, more recently, Pacific Gas & Electric selected a PLC system for its electric AMI system for both rural and suburban areas.

Major vendors of power line communications include Cannon Technologies, DCSI, and Hunt Technologies.

Fixed RF Systems

In basic fixed radio frequency (RF) systems, meters communicate over a private network using RF signals. Each meter communicates via the network directly to a data collector or a repeater. Repeaters may forward information from numerous endpoints to the more sophisticated devices called data collectors.

Data collectors often store the meter readings from meters within range. The data collectors then upload the meter readings to the AMI host system at preset times using the best communication method available, ranging from public networks to microwave to Ethernet connections. The communications between the data collector and the network controller are usually two-way, and allow the network controller to query for a recent meter reading and the status of one or a group of meters.

From 1994 to 1999, this type of automated meter reading system was selected for every large fixed network deployment in the United States.[63] Since 1999, fixed RF has been selected in seven of the 12 large fixed network deployments.

More advanced RF networks have also been developed and implemented. Within these more advanced systems, the meters themselves may form part of the network, and meters are not required to communicate directly or indirectly with a repeater or the data collector. One example of an advanced RF AMI network is shown below in Figure III-3. In this system, endpoints can communicate directly with towers (similar to super data collectors) or via a 'buddy" meter. Other advanced systems are designed with endpoints that form a mesh network, and where some of the endpoints within the mesh may function as data collectors and meters. The flexibility provided by advanced RF AMI systems is generally thought to offer advantages in terms of better coverage and more robust communications.

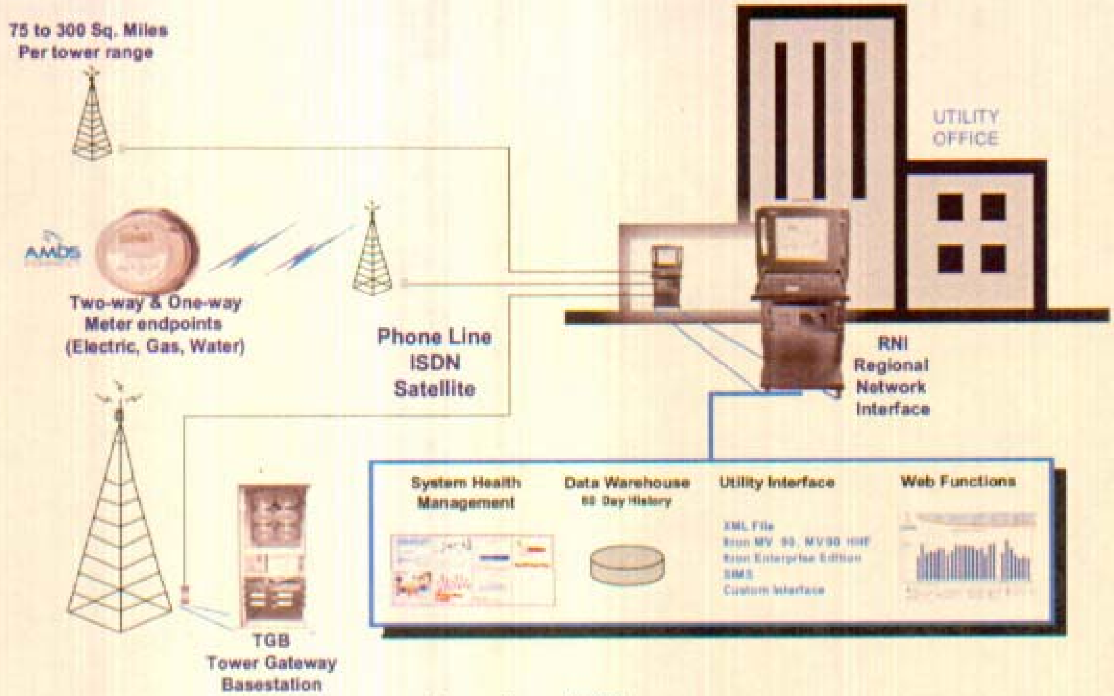
One of the key features of the more advanced RF networks that appeal to utilities is the ability of the network to "self heal."[64] If the endpoints have more than one communication path to the main hub of the system, and the best path is no longer available, endpoints can change their communication path. This is very important to utilities because changes in the service territory are ongoing. New buildings are constructed, trees or other shrubbery are planted or grow, and other changes occur which affect RF communications.

Major vendors of fixed RF systems include Cellnet, Elster, Hexagram, Itron, Sensus/AMDS, Silver Spring Networks, Tantalus, and Trilliant.

[63] See Table III-3 later in this chapter for a list of recent deployments.

[64] Bruce Carpenter, Portland General Electric, "PGE Mesh Metering Tests", September 2005

Figure III-3. Advanced RF Network system overview



Source: Sensus/AMDS

Systems Utilizing Public Networks

These systems utilize existing public networks such as paging, satellite, internet and/or telephony (cellular or landline) networks to provide for communications between meters and utilities. One key advantage of these systems is the ability to deploy AMI across a wide area with low densities, and the possible lower upfront cost of deployment since the utility does not need to build a private infrastructure. Some systems rely on paging networks while others rely on cellular or landline telephone networks. Some have used satellite communications. Three key limitations include: being subject to the coverage provided by the public networks; changing protocols (this is especially true in the cellular segment); and operational costs.

With AMI systems based on public networks, if there is coverage at the customer location, installation costs are limited to installing the new endpoint, and setting up the service. Utilities are not required to install any communication infrastructure, which can speed up the deployment process.

All of these systems have been used for larger customers and small rollouts of AMI, but recently these systems are being considered for much larger rollouts for smaller customers.[65]

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[65] Hydro One in Ontario announced in April 2005 it had selected Rogers Wireless Inc./SmartSynch to provide 25,000 "Smart Meters" as part of a pilot program. The Smart Synch system relies on a selection of various public networks for communications.

Meter Data Management

Meter data management provides utilities a place to store meter data collected from the field. 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. If utilities opt for hourly interval data, this results in 8,760 meter readings per meter year, compared to 12 each year for a meter that is read once per month. For a utility of even modest size, the storage requirements and data processing can become substantial.

Meter data management can also be configured to meet the specific requirements of other utility applications. For example, with meter data management, meter data can be provided in the same manner to all applications, or it can provide data in the exact form that each application requires. If the utility bills residential customers on the total usage for the billing period, the meter data management can total all of the daily reads to provide the billing system the total usage for each customer.

Estimates of Advanced Metering Market Penetration from FERC Survey

In order to respond to the direction from Congress to assess market penetration of advanced metering by region, Commission staff undertook a comprehensive survey of electric delivery companies and other entities that might own or operate retail electric meters to learn how they use their advanced metering systems, and for how many meters utilities they have deployed to collect information that could be used to support demand response. This section reports on the results of this survey.

FERC Survey

Commission staff asked respondents to provide information on how often customer usage data is collected, and the frequency of the data measurement. This allowed the survey to provide meaningful benchmarks for advanced metering, showing statistics for a range of metering sophistication.

In the FERC Survey, Commission staff requested respondents that own or operate customer meters to provide information by customer class on the number of customer meters they own and/or operate, and how energy usage is measured and retrieved. Electric utilities and other entities divide energy measurement into several categories based on how often the data is collected, and the frequency of the data intervals.

Commission staff also asked entities to distinguish between whether the installed metering and/or advanced metering system in place is capable of meeting the stated requirements or is being used in accordance with the stated standards. Collection of data on whether meters are capable covers situations where electric utilities are not using the AMI system to the fullest extent, but could in the future without a separate physical trip to retrofit or replace the customer meter.

Entities were asked to divide the number of meters in the following categories for each customer class that are *being used* or *capable of being used*:

1. For those meters where meter reads are collected at least daily, how many are collecting interval data where:

Intervals <= 15 minutes.
Interval is > 15 minutes and <= hourly.

2. For those meters where meter reads are collected at least monthly but not as often as daily, how many are collecting interval data where:
   Intervals <= 15 minutes.
   Intervals are > 15 minutes and <= hourly.
3. For those meters where measurement is collected for two to four peak periods (on, shoulder, off, etc.) per day, how many are:
   Collecting for intervals greater than hourly but less than daily (two hour intervals, three hour intervals, etc.).
   Providing daily peak period totals.
   Providing monthly totals for each peak period

Consistent with our earlier definition of advanced metering, the penetration estimates presented below reflect meters that are currently *used* to collect measurements with data intervals of an hour or less, and a data retrieval frequency of at least daily.

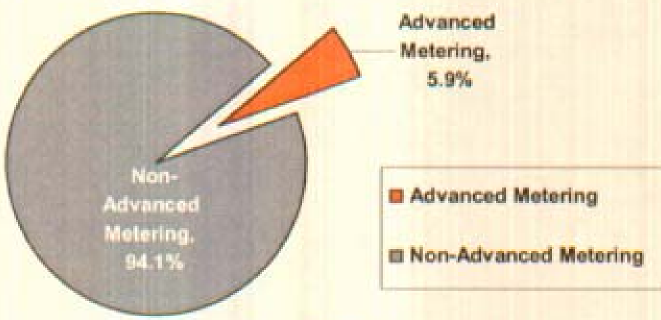
It is still unclear how demand response requirements will be incorporated into advanced metering or whether it will be common practice to use the AMI systems to send demand response signals to customers or to load control equipment. Therefore, Commission staff elected to ask respondents about other features of AMI, besides measurement and data retrieval.

Advanced Metering Market Penetration Estimates

The results of the FERC Survey indicates that advanced metering or AMI currently has a low market penetration of less than six percent in the United States (See Figure III-4).[66] This result is lower than past estimates, which had suggested the penetration rate was closer to 10 percent.[67]

The following discussion breaks down the advanced metering penetration results by customer class, region, customer class and region, and by state.

Figure III-4. United States penetration of advanced metering



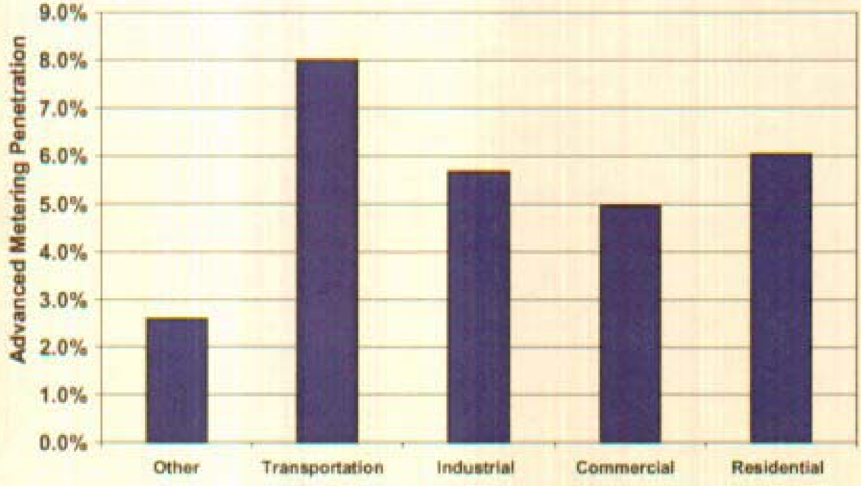
Source: FERC Survey

[66] UtiliPoint International, under contract with the Commission for the purposes of this Report, performed analysis and tabulation of results

[67] Chris King, eMeter "Advanced Metering Infrastructure (AMI) Overview of System Features and Capabilities," prepared for presentation at a joint meeting of the CPUC, CEC, and the Governor's Cabinet of California, September 30, 2004.

A breakdown of the national results by customer class (Figure III-5) suggests that the market penetration estimates of advanced metering for the primary customer classes (residential, commercial, and industrial) are relatively close to the national penetration estimate. The highest penetration rate (eight percent) is associated with transportation customers.

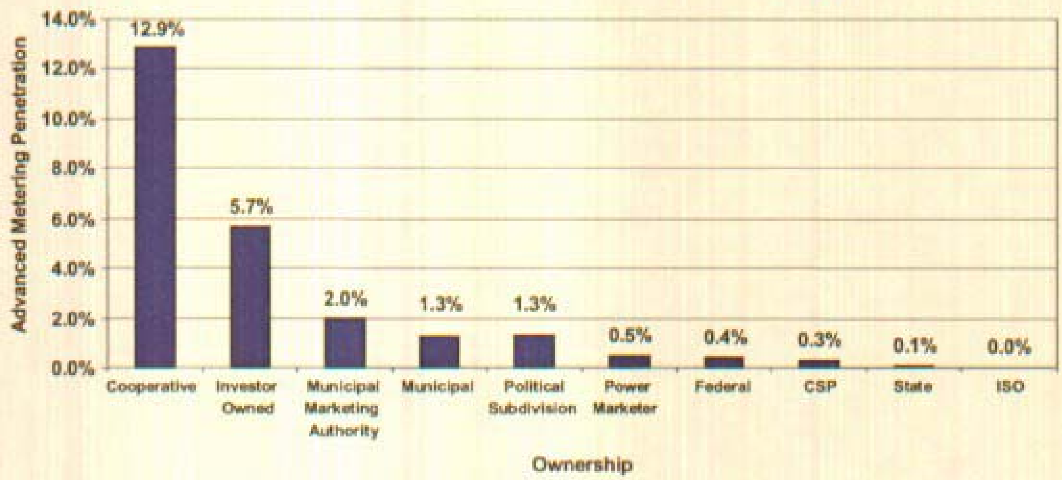
Figure III-5. Penetration of advanced metering by customer class



Source: FERC Survey

Examination of market penetration by type of entity and ownership (see Figure III-6) indicates that electric cooperatives have deployed the greatest level of advanced metering, with overall penetration of 12.9 percent. Investor-owned utilities have the next highest level of penetration at 5.7 percent, close to the national average.

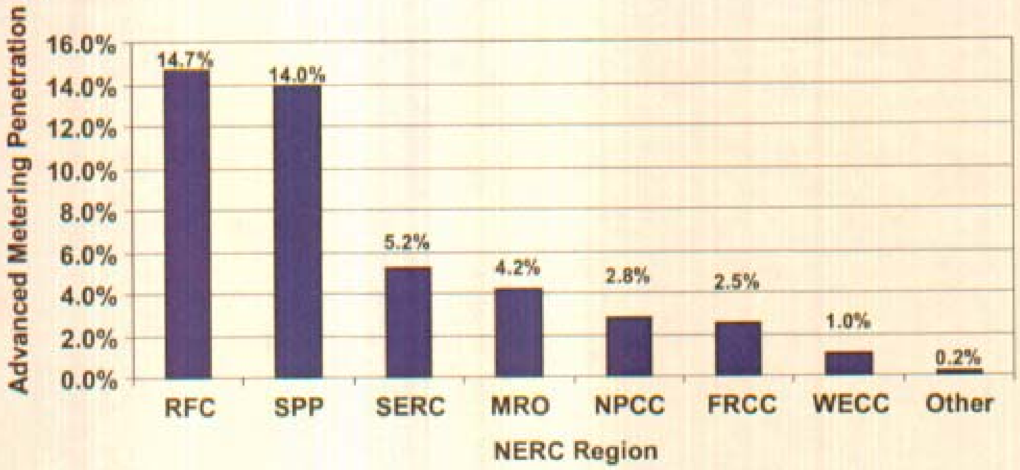
Figure III-6. Penetration of advanced metering by ownership



Source: FERC Survey

An analysis of market penetration by region indicates that there are differences in how much advanced metering has been adopted across the United States (see Figure III-7) in the footprints of the various NERC regional reliability councils. The Reliability*First* Council (RFC), which covers the Mid-Atlantic and portions of the Midwest, and the Southwest Power Pool (SPP), with overall penetration rates of 14.7 percent and 14.0 percent respectively, show the highest regional penetration.

Figure III-7. Penetration of advanced metering by NERC region[68]



Source: FERC Survey

Table III-1 further breakdown of the regional market penetration estimates by customer class.[69] The penetration of advanced metering for the residential and commercial classes is the highest in the RFC and SPP regions. All other NERC regions have lower than average penetrations of AMI for residential and commercial classes. For the industrial class, the MRO, RFC and NPCC regions enjoy a penetration rate higher than average, and all of the other regions are below average.

Table III-2 includes estimates of the penetration of advanced metering by state. These state-by-state estimates may prove a useful baseline in the state deliberations on smart metering required by EPAct 2005[70] and any future state proceedings on advanced metering.

There is wide variation in the number of advanced meters that have been installed across the states. The five states with the highest penetration of advanced meters are Pennsylvania, Wisconsin, Connecticut, Kansas, and Idaho. Most states have reported much lower penetration of advanced meters.[71]

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[68] Regional definitions used in this figure and subsequent figures and tables are based on NERC regions. See Chapter I for a map of these regions.

[69] Examples of transportation customers are rapid transit customers. Other customers include wholesale customers, street lights, and customers that do not fit into the other categories.

[70] EPAct 2005 section 1252(b).

[71] The penetration estimates for several states such as Louisiana and Mississippi do not reflect complete information. Electric utilities serving these states were unable to provide a full inventory of meters due to the impacts of Hurricanes Katrina and Rita in 2005.

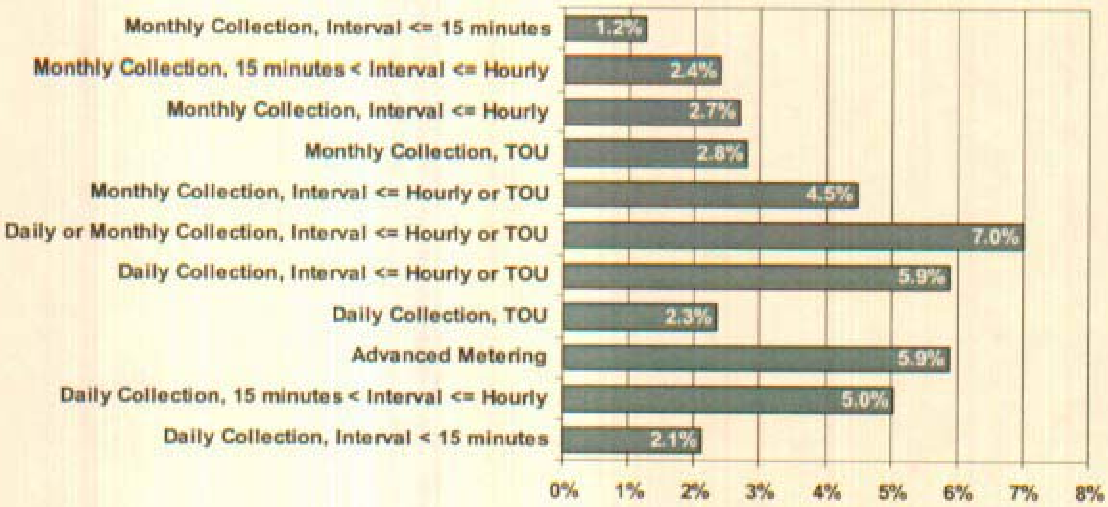
Table III-1. Penetration of AMI by region and customer class

Region	Residential	Commercial	Industrial	Transportation	Other
RFC	15.0%	13.6%	11.1%	68.4%	0.4%
SPP	15.2%	8.9%	2.6%	15.7%	5.8%
SERC	5.4%	2.6%	2.9%	50.3%	4.6%
ERCOT	4.6%	2.0%	3.4%	0.0%	0.1%
MRO	4.1%	5.3%	7.2%	0.4%	0.6%
NPCC	2.8%	2.9%	9.2%	1.3%	6.3%
FRCC	2.8%	0.6%	2.8%	0.0%	0.0%
WECC	0.9%	1.4%	5.2%	0.5%	2.9%
Other	0.3%	0.0%	0.6%	0.0%	0.0%
Total	6.0%	5.0%	5.7%	8.0%	2.6%

Source: FERC Survey

In order to provide a complete picture of meter reading, estimates for the market penetration of meter reading with measurement intervals and collection frequencies other than at least once an hour and read at least once daily. The penetrations for various combinations of measurement intervals and collection frequencies are included in Figure III-8. Analysis of these results suggests that even with the most expansive definition of advanced metering (which includes time-of-use measurement intervals and monthly meter reads), the penetration of meters capable of supporting time-based rates is still only seven percent.

Figure III-8. Advanced metering data interval and collection frequency penetration estimates



Source: FERC Survey

Table III-2. Penetration of advanced metering by state

State	Advanced Meters	Non-Advanced Meters	Total Meters	Penetration
Alaska	1,358	303,565	304,922	0.4%
Alabama	75,861	2,332,450	2,408,311	3.1%
Arizona	34,342	2,638,468	2,672,810	1.3%
Arkansas	183,449	1,234,925	1,418,374	12.9%
California	41,728	14,206,721	14,248,449	0.3%
Colorado	95,582	2,237,762	2,333,344	4.1%
Connecticut	592,147	2,174,220	2,766,367	21.4%
Delaware	12	416,518	416,530	0.0%
District of Columbia	245	231,470	231,715	0.1%
Florida	243,591	9,429,060	9,672,651	2.5%
Georgia	118,239	4,221,386	4,339,625	2.7%
Hawaii	10	465,304	465,314	0.0%
Idabho	119,024	614,525	733,549	16.2%
Illinois	83,903	5,557,111	5,641,014	1.5%
Indiana	22,103	3,311,080	3,333,183	0.7%
Iowa	21,590	1,072,588	1,094,178	2.0%
Kansas	259,739	1,038,977	1,298,716	20.0%
Kentucky	119,221	2,207,524	2,326,745	5.1%
Lousiana	112	1,359,878	1,359,990	0.0%
Maine	112,104	673,197	785,301	14.3%
Maryland	641	2,573,546	2,574,187	0.0%
Massachusetts	6,613	3,644,426	3,651,039	0.2%
Michigan	29,065	4,665,504	4,694,569	0.6%
Minnesota	15,019	2,482,308	2,497,327	0.6%
Mississippi	101	985,411	985,512	0.0%
Missouri	400,310	2,596,411	2,996,721	13.4%
Montana	739	531,930	532,669	0.1%
North Carolina	7,208	4,521,491	4,528,699	0.2%
North Dakota	10,201	413,665	423,866	2.4%
Nebraska	64,442	885,019	949,461	6.8%
Nevada	17	1,194,001	1,194,018	0.0%
New Hampshire	19,070	755,259	774,329	2.5%
New Jersey	15,502	3,851,148	3,866,650	0.4%
New Mexico	4,708	887,354	892,062	0.5%
New York	6,933	7,988,548	7,995,481	0.1%
Ohio	2,199	6,079,222	6,081,421	0.0%
Oklahoma	138,602	1,788,326	1,926,928	7.2%
Oregon	5,284	1,820,389	1,825,673	0.3%
Pennsylvania	3,176,455	2,879,274	6,055,729	52.5%
Rhode Island	402	484,196	484,598	0.1%
South Carolina	65,726	1,987,174	2,052,900	3.2%
South Dakota	18,192	544,768	562,960	3.2%
Tennessee	110	3,044,306	3,044,416	0.0%
Texas	572,836	12,514,011	13,086,847	4.4%
Utah	239	1,051,350	1,051,589	0.0%
Vermont	1	329,966	329,967	0.0%
Virginia	139,601	3,189,764	3,329,365	4.2%
Washington	41,366	2,967,267	3,008,633	1.4%
West Virginia	30	668,972	669,002	0.0%
Wisconsin	1,199,432	1,782,717	2,982,149	40.2%
Wyoming	89	1,384,782	1,384,871	0.0%

Source: FERC Survey

Survey results on the use of advanced metering for outage detection and management (40 percent) are lower than might have been expected from anecdotal industry reports. Anecdotal reports in the industry have suggested significant savings from the use of AMI in outage management, especially for restoration. This may reflect a recent recognition that meter data management is necessary to build the interface between utility outage management systems and AMI. As utilities invest in meter data management, the use of AMI for outage management may increase.

Recent Deployments of AMI Systems

To supplement the market penetration estimates drawn from the FERC Survey and to review patterns in the use of the various AMI types, Commission staff assessed information from recent deployments of AMI. There have been a number of contracts signed for fixed network automated meter reading and AMI over the past 10 years (see Table III-3 and Figure III-10). System-wide deployments of AMI began in 1994 with large fixed RF deployments. The deployment rate for large roll-outs[72] continued at a steady pace until 2000, when activity dropped off. Deployments increased again in 2006 with the PG&E contract for nine million gas and electric meters, and will likely grow in 2007 and 2008.[73]

Table III-3. Announced Large AMI Deployments in U.S.

Utility	Commodity	AMI type	Number	Year Started
Kansas City Power & Light (MO)	Electric	Fixed RF	450,000	1994
Ameren (MO)	Electric & Gas	Fixed RF	1,400,000	1995
Duquesne Light (PA)	Electric	Fixed RF	550,000	1995
Xcel Energy (MN)	Electric & Gas	Fixed RF	1,900,000	1996
Indianapolis Power & Light (IN)	Electric	Fixed RF	415,000	1997
Puget Sound Energy (WA)	Electric & Gas	Fixed RF	1,325,000	1997
Virginia Power	Electric	Fixed RF	450,000	1997
Exelon (PA)	Electric & Gas	Fixed RF	2,100,000	1999
United Illuminating (CT)	Electric	Fixed RF	320,000	1999
Wisconsin Public Service (WI)	Electric	PLC	650,000	1999
Wisconsin Public Service (WI)	Gas	Fixed RF	200,000	2000
JEA (FL)	Electric	Fixed RF	450,000	2001
PPL (PA)	Electric	PLC	1,300,000	2002
WE Energies (WI)	Electric & Gas	Fixed RF	1,000,000	2002
Bangor Hydro	Electric	PLC	125,000	2004
Ameren (IL)	Electric & Gas	Fixed RF	1,000,000	2006
Colorado Springs	Electric	Fixed RF	400,000	2005
Laclede	Gas	Fixed RF	650,000	2005
TXU	Electric	BPL	2,000,000	2005
PG&E (CA)	Electric	PLC	5,100,000	2006
PG&E (CA)	Gas	Fixed RF	4,100,000	2006
Hundreds of Small Utilities	Electric & Gas	Various	5,000,000	2004

Source: UtiliPoint International

[72] Large-scale deployments involve more than 100,000 meters.

[73] Large utilities (including San Diego Gas and Electric, Portland General Electric, Florida Power and Light, and CenterPoint Energy) have issued a number of RFPs within the past six months for advanced metering. Other large utilities are likely to go forward with large deployments over the next couple of years. The possible additional deployments are shown in Figure III-10 as "Pending" (shown in Orange).

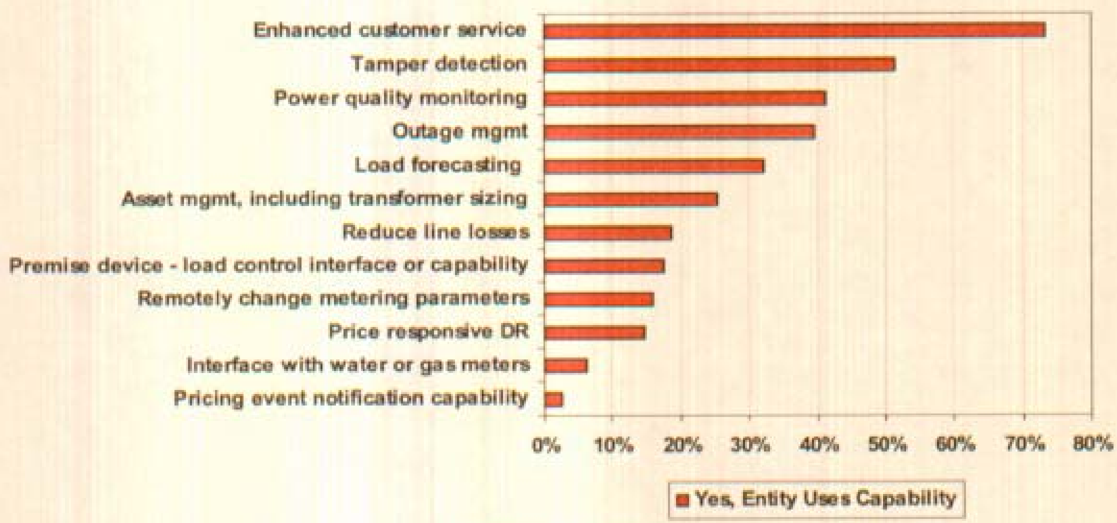
Uses of Advanced Metering

Commission staff also asked respondents to the FERC Survey how they used their systems and which functions the AMI systems provides them. Specifically, the FERC Survey asked organizations who have installed AMI systems to identify which of the following possible AMI features they used:

- Remotely change metering parameters
- Outage management
- Pre-pay metering
- Remote connect/disconnect
- Load forecasting
- Reduce line losses
- Price responsive demand response
- Enhanced customer service
- Asset management, including transformer sizing
- Premise device/load control interface or capability
- Interface with water or gas meters
- Pricing event notification capability
- Power quality monitoring
- Tamper detection
- Other

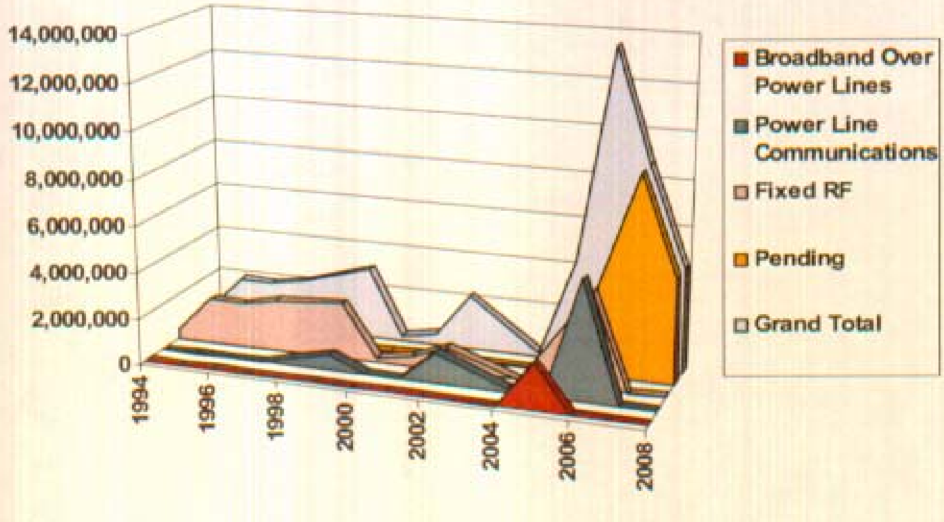
Figure III-9 shows the results of this query. The most often reported function was "Enhanced customer service," and the least often reported was "pricing event notification capability." Other uses that received a relatively high percentage of usage were tamper detection and power quality monitoring.

Figure III-9. Reported uses of AMI system by entities that use AMI



Source: FERC Survey

Figure III-10. Large AMI deployments



Source: UtiliPoint International

Figure III-10 illustrates that fixed RF had the majority of the market for system-wide deployments through 2002, but power line communications and broadband over power lines emerged as alternatives in 2004 and 2005. Two deployments of the advanced fixed RF systems are approaching large deployment status: Elster Electricity at Salt River Project (now approaching 75,000 endpoints) and Sensus/AMDS at Alabama Power Company (50,000 endpoints).

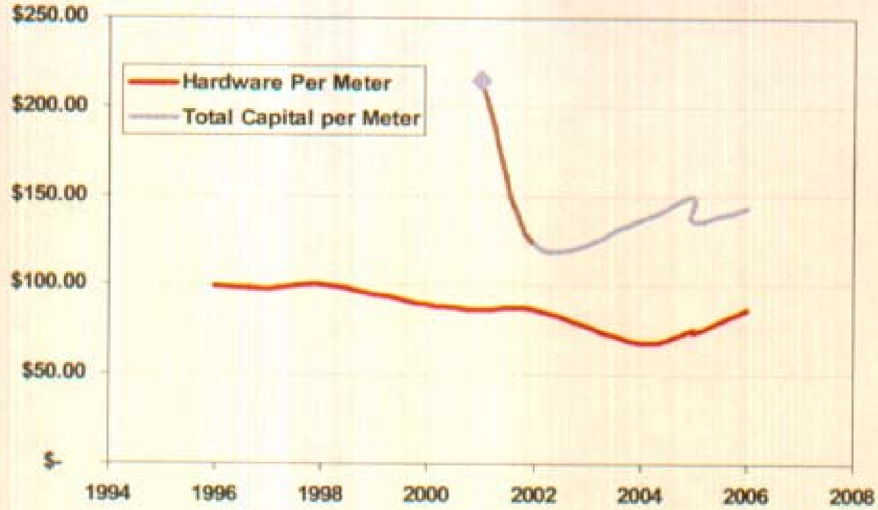
Costs and Benefits Associated with Advanced Metering

Electric utility deployment of advanced metering will need to be cost-effective for the utilities and for their ratepayers. This section reviews recent information on the costs and benefits associated with advanced metering.

Costs of Deploying Advanced Metering

The total capital cost of deploying AMI has not declined significantly even though the AMI and meter vendor revenue per meter has gradually declined by approximately 23 percent over the past 10 years. The total capital costs of deploying AMI include the hardware costs (meter modules, network infrastructure, and network management software for AMI system), as well as installation costs, meter data management, project management, and information technology integration costs. Examination of data obtained on 10 large AMI deployments over the last decade, suggests that AMI hardware costs have decreased during this time period. This trend can be seen in Figure III-11.

Figure III-11. Total AMI capital and hardware costs per meter



Source: UtiliPoint International

In the late 1990's, the hardware costs per meter averaged $99.[74] By 2005/2006, the average hardware cost per meter had decreased to $76. The capital costs of installing the AMI communications infrastructure, in contrast, have stayed relatively constant except for the deployment at Jacksonville Electric Associates in 2001 (which included water and electric meters), generally bound by $125 per meter on the low end and $150 on the high end. Table III-4 below shows the hardware and total detailed data on each of the 10 deployments.

There is considerably more expense and capital investment involved for a successful deployment of AMI than metering and AMI system components. Deployment costs include:

- Project management
- Installation of meters and network
- Meter data management
- Information technology integration costs with meter data management and other systems

For the AMI deployments where both the hardware costs per meter and the total AMI capital cost per meter were available, the hardware costs per meter represented as low as 50 percent and as high as 70 percent of the total AMI capital costs. A study by Charles River Associates found that hardware costs represented only 45 percent of total costs (see Figure III-12 for a breakdown of AMI System Costs).

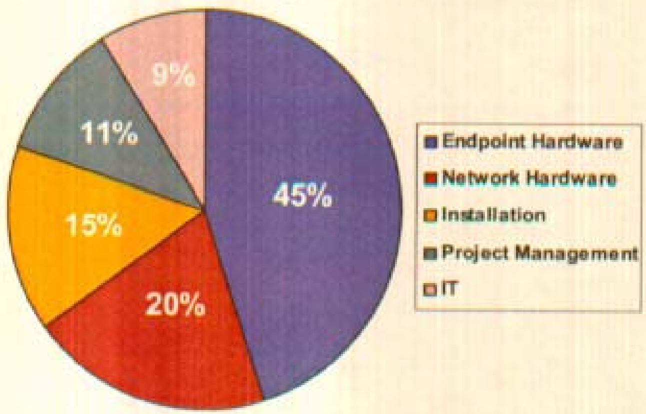
[74] All dollar values are nominal dollars.

Table III-4. AMI Cost Benchmarks

Utility	Year	Meters (millions)	Hardware (millions)	Total Capital (millions)	Hardware per meter	Total Capital per Meter
DLCo	1996	0.6	$60	-	$99.23	-
Virginia Power	1997	0.5	$44	-	$97.78	-
PREPA	1998	1.3	$130	-	$100.00	-
ENEL	2000	30.0	$2,673	-	$89.10	-
JEA	2001	0.7	-	$150		$214.29
PPL	2002	1.3	$112	$160	$86.15	$123.08
Bangor Hydro	2004	0.1	$7.50	$15.0	$68.18	$136.36
TXU	2005	0.3	$19	$38	$75.60	$150.00
PG&E	2005	9.8	$721	$1,328	$73.57	$135.48
SDG&E	2006	2.3	$199	$329	$86.43	$143.04

Source: Utilipoint International

Figure III-12. AMI System Cost Breakdown



Source: David Prins et. al. (CRA International), "Interval Metering Advanced Communications Study," August 2005

Benefits Associated with Advanced Metering

The deployment of advanced metering creates multiple benefits. These benefits include:

- Meter reading and customer service
- Asset management
- Value added services
- Outage management
- Financial

This section presents the benefits that have been identified in the metering literature and from industry stakeholders.[75]

Utility Meter Reading and Customer Service Benefits

Implementation of advanced metering or AMI can significantly reduce meter reading expenses and capital expenditures, and can also increase the accuracy and timeliness of meter reading and billing. In particular, eliminating estimated bills is a key driver for investment in automated meter data collection systems. Utilities rarely are able to estimate total consumption for a month accurately, even using weather and historical monthly consumption data. This is especially true for residential customers during vacations and customer moves (e.g., students attending college and returning home). Additional benefits include improved employee safety from the reduced need to visit customer facilities or enter customer premises, and reduced employee turnover and training needs.

While many of these same meter readings can be achieved by automated meter reading, advanced metering allows additional benefits due to the ability to query the meter frequently, or as needed. For example, utilities need to report on sales on a monthly basis. Without actual meter readings, this is an estimate, and utilities have found this to be a labor intensive report to produce. With advanced metering, utilities can prepare this report using actual meter readings as of midnight on the last day of the month.

Asset Management Benefits

Advanced metering can provide important information to assist in electric utility asset management. First, proper sizing of equipment, based on detailed and accurate data on customer demand and usage patterns can be a sizeable benefit for some utilities. In the past, operational managers have been at a disadvantage when defending their requests for capital investment in distribution equipment. Executive management could easily see the impact on the bottom line of the investment in terms of increased debt /capital spending, but operational managers did not always have good tools to demonstrate the corresponding value of making distribution capital expenditures. Advanced metering provides information that can be used to model the benefits and risks of not investing. In one case, Oklahoma Gas and Electric considered raising the load levels on distribution transformers. Using estimates for load that distribution transformers carried at peak times, similar to what can be developed using the information provided by advanced metering, it was clear to management that lowering the load levels on distribution transformers was the more prudent choice. Lowering load levels was selected even though it caused the utility to increase capital spending.[76] The benefits of avoiding failures of distribution transformers outweighed the costs, something the operational managers had not been able to show without reliable estimates of peak load on transformers.

Another key asset management benefit provided by advanced metering is the ability for electric utilities to more efficiently monitor and maintain the distribution equipment necessary to reliably deliver power to customers. These benefits include theft detection, improving cost allocation across the customer base, deferring investment, and predictive maintenance of equipment.

Other asset management benefits include:

- Vegetation management

[75] A recent meeting of the AMI-MDM Working Group, which focuses on meter data management issues associated with advanced metering, developed a comprehensive listing of benefits. This list of benefits can be found at www.amimdm.com. The discussion in this section draws from the ADM-MDM list.

[76] Patti Harper-Slaboszewicz (UtiliPoint), "Distribution Planning – A Tale of Two Utilities," November 2005.

- Improved information on voltage levels at customer premises
- Reduced manual testing of a sample of meters through built-in electronic meter self-diagnostics

Ability to Offer Value-Added Services

Advanced metering also provides benefits that are typically not available with manual meter reading or with AMR. These additional benefits include new or improved services that utilities can offer to customers with advanced metering, including additional rate options, flexible billing cycles, benchmarking of energy usage (especially important for commercial customers with similar set-ups in multiple locations), aggregation of accounts and/or synchronization of multiple account billing and meter reading, web services based on the more timely information provided by advanced metering, and bill prediction for large and small customers, including weather forecast data. With timely access to data, customer service representatives can also use interval data to more easily explain why bills are higher than expected. The interval data will show not only the total usage for each day but also when it was used.

Outage Management Benefits

Advanced metering can provide outage management benefits if configured appropriately. The most important benefit from the implementation of advanced metering in outage management is during restoration. After the work crews finish the first round of repairs, utilities can use advanced metering on customer premises to check for additional problems before work crews leave the area. This avoids needing to recall work crews to fix problems not handled in the first round of repairs, and can allow power to be restored faster.

Another important benefit is to verify an outage before sending a truck to respond to the outage by checking for power to customer meters. The problem could be on the customer side of the meter. Utilities achieve cost savings by not dispatching a truck unnecessarily, and the customer can begin effecting repairs faster if the problem is on their side of the meter. Responding faster to small outages is another important benefit, especially in terms of improving customer service and improving regulatory relations. Utilities can restore power faster and often during regular hours, and customers are not faced with reporting the outage and then waiting for repairs to be made.

Over time, utilities expect that, as customers learn that the AMI system send information on outages to the utility, call center volume during outages will be significantly reduced. When customers do call in, utilities will be able to provide a better estimate of repair times.

Financial Benefits

Financial benefits accrue not only from utility efficiency gains, but also indirectly from complaints and faster service restoration. For example, faster restoration and shorter outages may result in better outage metrics, which in turn may impact the earnings of some utilities. Improved cash flow stems from reducing the time it takes the utility to produce a bill after the meter is read. Before advanced metering, the average time for read-to-bill date is three to five days, and with advanced metering, this usually drops to one or two days.

Benefit Estimates

A key issue is how to quantify the benefits listed above. According to Gary Fauth and Michael Wiebe:

> Properly measured, AMR benefits can amount to between $1.35 and $3.00 per customer per month, over the useful life of the hardware. In contrast, AMR in many situations can cost $1.25 to $1.75 per customer per month, measured over the useful life of the hardware and including both capital and operating costs. These cost and benefit numbers by themselves produce a positive business case outcome in most cases. Business cases for AMR can produce internal rates of return ranging from 15 to 20% and payback periods of less than six years.[77]

Utilities have reported significant benefits associated with improved outage management. For example, PPL, a large investor owned utility in Pennsylvania, has achieved savings of 10 percent in restoration costs after large outages.[78] PPL also reported that it has reduced the number of estimated bills from an average of four to six percent of the total number of bills it processes to less than one percent. Ameren has achieved savings of $2 million annually by using its AMI system to measure the load on its distribution transformers at the system peak, and by reducing the size and inventory of transformers.[79]

Bangor Hydro's AMI system saved time and money by eliminating a problem where customers would call and report an outage before traveling to remote fishing camps to avoid having to wait for service crews should there be an outage. Now, if customers call, the utility can immediately verify power to the meter before the customer leaves home. In another example, PG&E has estimated it makes 48,000 truck rolls each year for single no-outage calls, and could save $4.3 million annually with AMI.[80]

Data from PG&E's AMI business case suggests that savings associated with meter reading are only a part of the benefits that can be achieved with AMI. PG&E has estimated that 46 percent of the benefits that they estimated in their business case were unrelated to meter reading.

Current Issues Associated with Advanced Metering

While there are benefits to advanced metering and AMI, there is not universal attraction to its implementation. What follows is an identification and discussion of issues associated with advanced metering and AMI.

AMI specifications

Most requests for proposals (RFPs) from electric utilities now include a requirement for delivering interval data, at least hourly, for all meters connected to the network on a daily basis. The requirement for interval data for all customers is relatively new, and reflects the increased functionality and performance of AMI products on the market. However, billing and settlement requirements in organized wholesale markets may influence what utilities specify in their RFPs. If wholesale settlement is based on 15 minute interval profiles, utilities may be more likely to ask for 15 minute intervals for all customers. While the need to support time-based rates may prompt regulators to support an investment in AMI, the requirements for AMI are usually based on other considerations,

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[77] Gary Fauth and Michael Wiebe, "Fixed-Network AMR: Lessons for Building the Best Business Case", AMRA newsletter, September 2004, 5.

[78] David Prins, et al. (CRA), "Interval Metering Advanced Communications Study," August 2005, 24.

[79] Prins, et al., 25.

[80] Prins, et al., 24.

such as operational efficiencies and wholesale settlement. Consequently, consistent AMI specifications may be difficult to achieve in the near-term.

Advanced Metering and Price Responsive Demand Response Networks

With advanced metering, utilities can offer customers a variety of time-based rates, either charging higher prices when wholesale prices are high or offering rebates when customers reduce energy consumption during times of high prices, often called critical peak periods. AMI provides the information necessary to support the billing process and gives customers timely updates on their energy use and bills.

An open question that is being discussed, is whether the AMI system should be used to provide price signals or notification of system emergencies. In some cases, the AMI system itself will likely provide the communication backbone to transmit signals to the end-use controllers, and in other cases, other networks will be used.

If the AMI system is selected to transmit the signal to an appliance, the signal will not necessarily travel through the meter. An appliance such as a load control device may be designed to be treated as another node on the system, and communicate independently of the meter. Alternatively, the signal may be relayed to the load control device through another node on the system, such as the data collector or tower.

A number of utilities use networks other than AMI systems to communicate with smart thermostats[81] (see Figure III-13 for an example smart thermostat) and other load control devices, such as paging or FM radio. The California Energy Commission (CEC) is currently considering revising the building codes to require smart thermostats. As part of this proposal, the CEC is proposing sending a one-way broadcast signal using FM radio to smart thermostats, but the three investor-owned utilities in California did not support this concept as the only communication option. Rather, the utilities indicated that they wanted to use their AMI systems, once installed, for controlling these devices.[82]

Figure III-13. Example of a Smart Thermostat

Source: Converge

[81] The temperature settings on smart thermostats, also known as programmable communicating thermostats (PCT), can be remotely adjusted through signals from a central controller or by a customer.

[82] Committee Workshop, California Energy Resources Conservation and Development Commission, Feb. 13, 2006.

Other jurisdictions are having similar discussions, and the industry has not yet decided on a consistent approach for integrating smart thermostats and dedicated customer display devices into AMI. For regions with significant retail activity, the picture is more complex because electric distribution companies will likely be the owners of the AMI systems, but they may not necessarily be the entities offering demand response programs. This lack of consistency may complicate future deployments of equipment and procedues until standard approaches are adopted.

Providing Timely Information to Customers

The provision of timely, useful information to residential and commercial customers can assist customers in responding to time-based rates and to otherwise help in managing their energy costs. However, the degree to which customers use this information and the vehicle for providing the information is at issue.

For customers with central air conditioning or heating, the trend is to use the smart thermostat as a customer display device to provide information on the current price in effect, whether a critical peak period is in effect, and other information specific to controlling the temperature within the home.[83] The example smart thermostat in Figure III-13 can provide price information.

There is also interest in providing customers with daily bill updates which could also be displayed on smart thermostats.[84] The thermostat vendors have modified the design of thermostats to accommodate price responsive demand response programs, providing a large screen on the smart thermostat that can display a variety of information for customers.

For those without central air conditioning or heating, what information to provide to customers is still being explored, as well has how to provide the information. Utilities that have posted usage information on websites have reported that few customers take advantage of the service, and of those that do, most visit the site only once or twice. Customers have indicated in several studies that they prefer to receive information about their energy usage with their bill.[85] Utilities are also considering providing or offering customers dedicated in-home display devices. Utilities will likely continue to post information on line for those interested, and over time, it is expected that the industry will learn what information customers find useful to manage their energy bills.[86]

Results from the FERC Survey suggest that only a tiny fraction of U.S. electricity customers receive interval usage information by any means, and the smallest proportion can view their usage via the AMI system. The FERC Survey asked how many customers had access to hourly interval data and the ways in which they receive that information. Figure III-14 displays the survey results. 760 entities responded to this question while 310 entities said that at least one customer receives interval usage

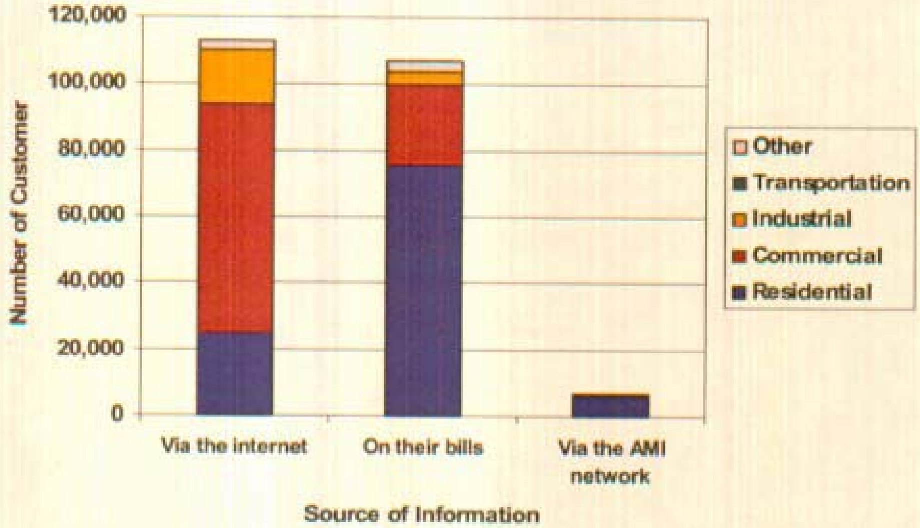
[83] The CEC is pursuing this approach in California and is currently considering revising building standards to require a PCT wherever a setback thermostat is currently required. Using the PCT as a display device avoids the need for a dedicated in-home display device, and the customers already associate the PCT with energy.

[84] Providing customers with a daily bill update is part of the design of the SmartPowerDC program, a new dynamic pricing pilot in the District of Columbia. The SmartPowerDC program is managed by the Smart Meter Pilot Project (SMPPI). SMPPI is a non-profit corporation with a board membership of Pepco, the DC commission, two consumer advocacy groups, and the meter readers union.

[85] Idaho Power reported these findings based on their dynamic pricing pilot in 2006.

[86] Vendors are developing in-home display devices in response to utility interest. Some are similar to PCTs except that the device is not also a thermostat. Another version is to glow different colors depending on the current price. See Committee Workshop Before the California Energy Resources Conservation and Development Commission, In the Matter of Systems Integration Framework Programmable Communicating Thermostat (PCT), Feb. 16, 2006.

Figure III-14. Number of customers receiving interval usage information by customer class and source of information



Source: FERC Survey

information. Only about 226,000 nationwide customers receive interval usage information via at least one source: internet, bills, and AMI.

There is also considerable discussion of how to provide customers with useful information from the customers' point of view rather than the utility's point of view. Was their usage significantly higher yesterday, even accounting for weather? Does their energy usage change more in response to weather than their neighbors? Would they be better off on a different rate schedule? In interviews with participants in the California Pricing Pilot program, customers evaluated the program differently from utilities. From the customer perspective, the program was successful if the customer saved money, or if they had the opportunity to save money, with the program.[87] There is agreement among consumer advocates and regulators that customers understand time and money, and that giving customers the opportunity to receive information to better help them in managing their energy bills is a good thing.[88]

Interoperability and Standard Interfaces

Interoperability refers to the ability of suppliers to design and build products to meet standards established by an industry group. From 1996 to 1998, the American National Standards Institute (ANSI) issued new standards for meter communications and meter data storage developed in collaboration with the Automated Meter Reading Association (AMRA), Canadian standards bodies, numerous utilities, all major meter manufacturers, and others over a five year period. The standards released as a result of that effort were:[89]

[87] Craig Boice, "What Drives the Response in Demand Response", Boice Dunham Group, April 13, 2005.
[88] This is one of the motivations of the SmartPowerDC program.
[89] Ted York, "Exploring ANSI Standards in Meter Communications," *Electricity Today*, March 2000.

- C12.18 - 1996 Protocol Specification for ANSI Type 2 Optical Port
  - For reading a meter using infrared optical port when data stored in tables as specified in C12.19
- C12.19 - 1997 Utility Industry End Device Tables
  - This standard defines a set of flexible data structures for use in metering products, including the option of including vendor defined tables
- ANSI C12.21-1998 Protocol Specification for Telephone Modem Communication
  - This extends the C12.18 and C12.19 to telephone modem communications

The next step, ANSI C12.22 - Protocol Specification for Interfacing to Data Communications Networks, covers network communications, which is pertinent to communicating with meters over a network as opposed to point-to-point communications.[90] The adoption of the new standard (expected by the end of the year) and the recent announcement by Itron that its new AMI system will conform to the standard will put pressure on other AMI vendors to adapt their systems to conform as well. For the moment, even though some utilities have expressed an interest in open standards, which is consistent with C12.22, it has not been a major factor in recent AMI selections. That is likely to change, as evidenced by SCE and SDG&E. SCE has listed open protocols to be a requirement of AMI,[91] and of interest by SDG&E in their latest filing on AMI. However, SDG&E also noted that "Any new AMI technologies or new market product offerings would need to provide SDG&E customers with additional value and functionality or reduced costs such that the net incremental benefits from the potential new technology or offering exceeds the cost to convert or change from the selected SDG&E AMI solution set(s)."[92] This suggests that SDG&E would evaluate a new product with open standards to see if the value of the new product exceeds the cost of using the new product. For SDG&E, open standards is a feature of AMI, whereas for SCE it is a requirement. These two utilities illustrate the different attitudes toward open standards.

There is a clear consensus on the need for standard interfaces between systems, such as between the host AMI system and MDM, and between MDM and other utility data systems. This would also apply to interfaces with DR networks and systems.[93]

Security

Utilities need to take reasonable precautions to protect customer privacy, and to maintain the security of the grid. Monthly meter reads are not regarded as particularly valuable other than for generating a customer bill. Hourly meter reads, especially when viewed over a long time span, can provide a significant amount of information about customers. Interval data stored to provide a history of energy use must be secure from unauthorized use.

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[90] Point-to-point communications includes using a hand-held device to read the meter, covered in ANSI c12.18, or telephone modem communications, covered in ANSI c12.21. Network communications involve communications of one-to-many, or many-to-many, as are involved with advanced metering.

[91] "Advanced Metering Infrastructure -- Frequently asked questions," and "Why is SCE interested in an AMI solution using open standards and interoperability," *available at* http://www.sce.com/PowerandEnvironment/ami/faqs/.

[92] Chapter 8 Summary of AMI Implementation and Operations, Prepared Supplemental, Consolidating, Superseding and Replacement Testimony of Ted Reguly, San Diego Gas & Electric Company before The Public Utilities Commission of the State of California, March 28, 2006.

[93] EnerNex Corporation, "Advanced Metering and Demand Responsive Infrastructure: A Summary of the PIER/CEC Reference Design, Related Research and Key Findings Draft," prepared for California Energy Commission, June 1, 2005.

There is disagreement regarding the level of security that is required when meter data is transmitted from the endpoint to the AMI host system. The discussions that have taken place in various industry groups[94] on standard interfaces within the AMI system have addressed security requirements, including discussions on encryption, verification of successful communication, and verification of identity of devices. The overall goal is to ensure that only authorized devices provide and receive meter data, and that unauthorized devices are not able to provide or receive meter data.[95]

Costs and Benefits to Include in Business Case Analyses

Recent examinations of the business case for advanced metering have used a wide variety of costs and benefits in their assessments.[96] For example, some business cases include demand response as an explicit benefit, while others do not. These differences make it difficult for retail rate regulators to compare proposals and deployments across electric utilities under their review, and for electric utilities to comprehensively judge whether they should deploy advanced metering.[97]

[94] Various industry groups discussing reference designs, standards, and best practices such as OpenAMI, UtilityAMI, IntelliGrid, and AMI MDM have discussed security of customer meter data.

[95] Paul DeMartini (SCE), FERC Technical Conference, transcript, 89:10-90:13, 109:12-110:9; and Chris King, (eMeter), transcript, 106:22-107:5.

[96] See Chapter 2, "AMI Business Vision, Policy and Methodology", Prepared Supplemental, Consolidating, Superseding and Replacement Testimony of Edward Fong, San Diego Gas & Electric Company, before The Public Utilities Commission of the State of California, Mar. 28, 2006, TR-7. SDG&E included DR benefits in their business case. See also "Section I Advanced Metering Infrastructure Project A.05-06-028 - Supplemental Testimony Pacific Gas and Electric Company Chapter 1 AMI Project and Project Management," Application 05-06-028, filed October 13, 2005 with the California Public Utilities Commission. PG&E did not explicitly include DR benefits in their business case filing, but estimated that DR benefits would provide enough benefits to make the AMI investment worthwhile.

[97] Recent work by McKinsey & Company, Inc. with vendors, utilities, consultants and regulators has resulted in a consensus, pro forma modeling platform for business case development. This business case model is still under development, and will be made public at energydelivery.mckinsey.com.

Chapter IV. Existing Demand Response Programs and Time-Based Rates

This chapter addresses the second area, in EPAct Section 1252(e)(3), that Congress directed the Commission to consider:

(B) existing demand response programs and time-based rate programs.

The discussion within this chapter reviews the various demand response programs and time-based rate options currently in existence. In addition to reviewing these programs, the results of the first-of-its-kind, comprehensive FERC Demand Response and Advanced Metering Survey[98] (FERC Survey) were used to determine how prevalent these programs and rates are nationally and regionally. The results of this survey suggest that the use of demand response is not widespread. Only approximately five percent of customers are on some form of rate-based or incentive-based program. The most common demand response programs offered are direct load control programs, interruptible/curtailable tariffs, and time-of-use rates.

This chapter is organized into six sections and builds on the discussion of demand response and time-based rate programs included in Chapter II. These sections include:

- Discussion of incentive-based demand programs
- Discussion of time-based demand response programs
- Results from FERC Survey on the use of demand response
- Motivations for industry and customer interest in demand response programs
- Issues and challenges associated with implementing demand response programs
- Demand response activities at the state, regional, and federal level

Incentive-Based Demand Response Programs

The first form of demand response includes an inducement or incentive for customer participation, instead of the direct price signals associated with time-based rates. Because they do not rely on direct responses of customers to prices, which is difficult to measure or predict, incentive-based demand response programs provide a more active tool for load-serving entities, electric utilities, or grid operators to manage their costs and maintain reliability.

The types of incentive-based programs that exist include:

- Direct load control
- Interruptible/curtailable rates
- Demand bidding/buyback programs
- Emergency demand response programs
- Capacity market programs
- Ancillary-service market programs

[98] See Appendix F for a description of the FERC Survey.

This section reviews these programs, and explores implementation experience with these programs.

Direct Load Control

Direct load control (DLC) programs refer to programs in which a utility or system operator remotely shuts down or cycles a customer's electrical equipment on short notice to address system or local reliability contingencies in exchange for an incentive payment or bill credit. Operation of DLC typically occurs during the times of system peak demand. However, DLC is also operated when economic to avoid high on-peak electricity purchases.

DLC has been in operation for at least two decades. A variety of utilities developed and deployed large programs in the late 1960s,[99] and expanded those programs significantly during the 1980s and 1990s. By 1985, 175 residential customer direct-load control projects and 99 commercial projects were in place at electric utilities.[100] The FERC Survey found that 234 utilities reported direct load-control programs. Florida Power & Light has implemented the largest program, with 740,570 customers.

The most common form of DLC is a program that cycles the operation of appliances such as air-conditioners or water heaters. In these programs, a one-way remote switch (also known as a digital control receiver) is connected to the condensing unit of an air conditioner or to the immersion element in a water heater. By remotely switching off the load at the appliance, peak loads can be reduced. Although the actual reductions vary by size of the appliance, customer usage patterns, and climate, the demand reductions for each air conditioner is about 1 kW and for water heaters about 0.6 kW. The operation of the switch is controlled through radio signals (for older systems) or through digital paging. Depending on the duty cycle selected, the switch turns off the condensing unit or element for the full duration of an event or for various fractions of an hour (e.g., a common duty cycle is 15 minutes off during an hour). DLC programs also typically limit the number of times or hours that the customer's appliance can be turned off per year or season.

In recent years, remote switches have become more sophisticated through new technologies. Virtually all of the new switches are individually addressable, meaning that individual switches can be controlled independently. This allows more targeted reductions to address localized problems. Software upgrades can now be done wirelessly and communication with switches can be conducted using public paging networks instead of building and maintaining expensive communications networks. Most switches also contain multiple relays so that air conditioners and water heaters can be controlled by the same switch with independent control strategies for each relay.

In addition, remote control of individual appliances is being supplanted by remote control of smart, or programmable, communicating thermostats in recently implemented programs. DLC programs that use these smart thermostats, such the Long Island Power Authority's LIPA Edge program, remotely adjust the temperature settings on the thermostats. During the summer the utility can remotely adjust the temperature upward to reduce demand. After an event, the temperature setting is readjusted to the pre-event, customer-selected level. Some smart thermostat programs also provide the customer the ability to change the thermostat settings through the Internet.

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[99] According to the EPRI, Detroit Edison was the first utility to implement a load control program in 1968, EPRI, *The Demand-Side Management Information Directory*, EPRI EM-4326, 1985.

[100] EPRI EM-4326, 3-2.

While DLC has been an important demand response resource for many years, and while several utilities have recently implemented or increased the size of programs, several key utilities have been mothballing or phasing out their programs, especially in restructured states. For example, since load management was designated a competitive service in the Texas restructuring act, CenterPoint Energy Houston Electric's air conditioner cycling program was sold and eventually shut down. Similarly, Pepco suspended its Kilowatchers Club air conditioner cycling program after it sold its generation assets when Maryland's electric sector was restructured. There is also concern that the equipment in older programs operated by many utilities is aging and degrading.[101]

Interruptible/Curtailable Rates

Customers on interruptible/curtailable service rates/tariffs receive a rate discount or bill credit in exchange for agreeing to reduce load during system contingencies. If customers do not curtail, they can be penalized. Interruptible/curtailable tariffs differ from the emergency demand response and capacity-program alternatives because they are typically offered by an electric utility or load-serving entity, and the utility/load serving entity (LSE) has the ability to implement the program when necessary.

Interruptible/curtailable tariffs are generally filed tariffs with regulatory commissions and offered to a utility's largest customers. Typical minimum customer sizes to be eligible for interruptible/curtailable tariffs range from 200 kW for the base interruptible program in California to 3 MW in American Electric Power's (AEP) Ohio service territory. Customers on these rates agree to either curtail a specific block of electric load or curtail their consumption to a pre-specified level. Customers on these rates typically must curtail within 30 to 60 minutes of being notified by the utility. The number of times or hours that a utility can call interruptions is capped (e.g., AEP-Ohio will not call its interruptible/curtailable customers more than 50 hours during any season).[102] In exchange for the obligation to curtail load, interruptible/curtailable tariff customers receive either discounted rates or a bill credit when they curtail.

Interruptible programs are also not for all customers. In particular, customers with 24 hour-a-day, seven-days-a-week operations or continuous processes (e.g., silicon chip production) are not good candidates. Similarly, schools, hospitals, and other customers that have an obligation to continue providing service are also not good candidates.

While interruptible/curtailable tariffs have been in place for decades, there is concern amongst resource planners about whether interruptible/curtailable tariffs provide a reliable and sustainable resource. The number of customers taking interruptible/curtailable tariffs from utilities has dropped in the last decade.[103] The cause for this drop is a combination of the impacts of restructuring, reductions in price discounts associated with interruptible/curtailable tariffs due to the current excess capacity in much of the country, and customer departure because of perceived risk.

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[101] Frank Magnotti, Comverge, presentation to MADRI Workshop, June 2006, 3.

[102] During that winter of 2000-2001, as of January 22, 2001, PG&E had exhausted its interruptible program, having called upon 140 customers for 100 hours each. Jane M. Clemmensen, "Californians Facing a Power-Strapped Summer," *EC&M*, April 1, 2001.

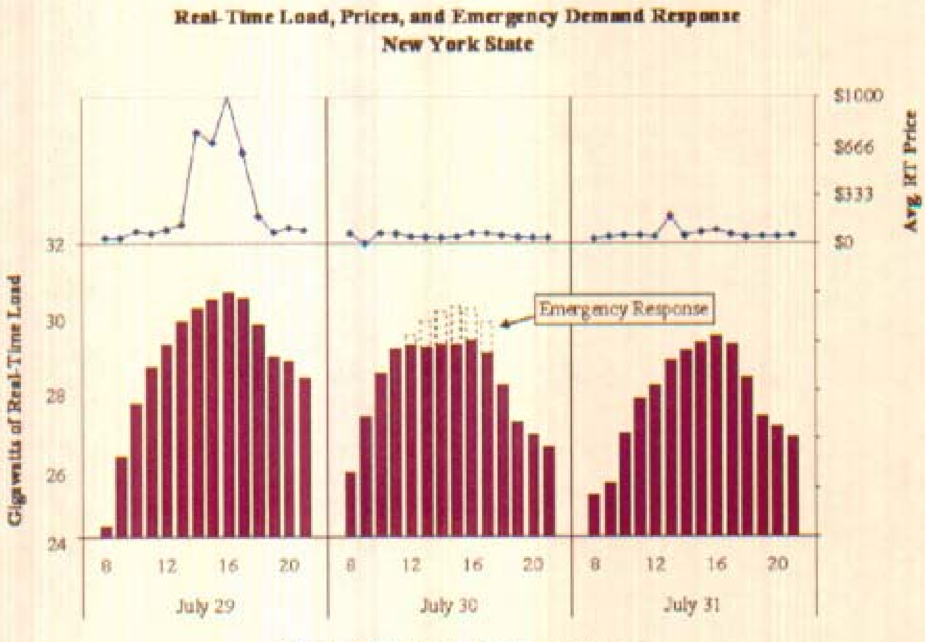
[103] See the experience in California -- Charles A. Goldman, Joseph H. Eto, and Galen L. Barbose, *California Customer Load Reductions during the Electricity Crisis: Did they Help to Keep the Lights On?*, Lawrence Berkeley National Laboratory: LBNL-49733, May 2002.

Emergency Demand Response Programs

Emergency demand response programs have developed in the last decade. Emergency demand response programs provide incentive payments[104] to customers for reducing their loads during reliability-triggered events, but curtailment is voluntary.[105] Customers can choose to forgo the payment and not curtail when notified. If customers do not curtail consumption, they are not penalized. The level of the payment is typically specified beforehand.

While emergency programs are offered by electric utilities, these programs are most closely associated with their use at Independent System Operators/Regional Transmission Organizations (ISO/RTO). In particular, the Emergency Demand Response Program (EDRP) at the New York Independent System Operator (NYISO) has been successful in achieving a high level of participation, and operation of the EDRP has provided a key resource during periods of reserve shortage in New York over the last several years. Figure IV-1 portrays the importance of the EDRP during a reserve shortage that occurred during July 2002. During this event, the NYISO was concerned about the high peak demands and real-time price spikes on July 29, 2002. Based on a forecast of similar or hotter weather on July 30, NYISO operated its EDRP and capacity program. The combined impact of these two programs significantly reduced peak demand and reduced the real-time price during July 30.

Figure IV-1. Impact of NYISO emergency demand response during July 2002



Source: David Patton, Potomac Economics

The voluntary nature of emergency demand response programs does have implications for its use in grid operation and planning. Since there is no contractual obligation to curtail, system operators

[104] Typical payments are $350/MWh or $500/MWh of curtailed demand.

[105] Utilities have requested voluntary curtailments from customers during system emergencies in the past, but did not pay customers for these curtailments.

cannot accurately forecast how much load curtailment will occur when the program is activated. Consequently, participants in these programs do not receive capacity payments.

Capacity-Market Programs

In capacity-market programs, customers commit to providing pre-specified load reductions when system contingencies arise, and are subject to penalties if they do not curtail when directed. Capacity-market programs can be viewed as a form of insurance. In exchange for being obligated to curtail load when directed, participants receive guaranteed payments (i.e., insurance premiums). Just like with insurance, in some years load curtailments will be not be called, even though participants are paid to be on call. Capacity market programs are typically offered by wholesale market providers such as ISOs/RTOs that operate installed capacity (ICAP) markets, and are the organized market analog of interruptible/curtailable tariffs.

In addition to agreeing to the obligation to curtail, capacity-market program eligibility is based on a demonstration that the reductions are sustainable and achievable. For example, the requirements to receive capacity payments in NYISO's Special Case Resources program are: minimum load reductions of 100 kW, minimum four-hour reduction, two-hour notification, and to be subject to one test or audit per capability period.[106] These requirements are designed to ensure that the reductions can be counted upon when they are called. LSEs that have programs or offerings that meet the eligibility requirements can receive capacity credits or count the capacity toward ICAP requirements.

ISO/RTO capacity programs have been important resources in recent years. NYISO operated the Special Case Resources program during the July 30, 2002, reserve shortage event (displayed in Figure IV-1), and relied on Special Case Resources to help restore power after the August 14, 2003, blackout. The ISO New England (ISO-NE) relied upon its capacity program assets to forestall rolling blackouts in southwest Connecticut during the summer 2005 heat wave. The PJM Interconnection (PJM) relied on demand response assets in its Active Load Management program in the Baltimore-Washington region during the same heat wave.

Many curtailment service providers (CSPs) and customers prefer these programs because they provide guaranteed payments, instead of the prospect of uncertain payments. Grid operators like the capacity programs because they represent a firm resource that can be implemented quickly.[107] The level of the capacity payments that have been offered in NYISO and ISO-NE (e.g., $14/kW-month in the 2005-06 ISO-NE Winter Supplemental Program) have contributed to increased customer interest.[108]

Demand Bidding/Buyback Programs

One of the newest types of incentive-based demand response programs is the demand bidding/buyback program. Demand bidding/buyback 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

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[106] NYISO, Installed Capacity Manual, section 4.12.

[107] For example, in anticipation of a cold winter and natural gas shortages in New England, ISO-NE implemented a winter supplemental capacity program in December 2005. Curtailment service providers were able to enroll more than 333 MW of new demand-response capacity by January 18, 2006. http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/mtrls/2006/feb12006/winter_supplemental_program_update_02-01-2006.ppt

[108] See http://www.iso-ne.com/genrtion_resrcs/dr/sp_proj/wntr/wsp_factsheet_120105.pdf. In areas such as PJM where the value of capacity is lower, the applicable capacity program has not been as successful.

be willing to curtail at posted prices. These demand-bidding programs provide a means to elicit price-responsiveness when prices begin to increase. Both vertically integrated utilities and ISOs/RTOs operate these programs. If customer bids are cheaper than alternative supply options or bids, the load curtailments are dispatched and customers are obligated to curtail their consumption. These programs are attractive to many customers because they allow the customer to stay on fixed rates, but receive higher payments for their load reductions when wholesale prices are high. Customers, who are not on time-based rates, can use the demand-bidding programs to receive value for their reductions. Otherwise, these customers are on fixed retail rates.

The most well-known forms of demand-bidding programs are operated by the ISOs. There are two forms of these programs. The first incorporates demand bids directly into the optimization and scheduling process. In programs such as NYISO's Day-Ahead Demand Response Program (DADRP), customers typically bid a price at which they would be willing to curtail their load and the level of curtailment in MW on a day-ahead basis. If these bids are selected for operation during the security-constrained dispatch process, then customers must execute the curtailment the next day. If they do not reduce their load, they are subject to a penalty. In the second form of demand bidding, the customer acts as price-taker. A good example of this program is the Real-Time Price Response Program at the ISO-NE. When participants in this program reduce consumption when notified, they receive the market-clearing price, whatever it may be, as payment.

The ISOs have suggested that demand-bidding programs are transitional programs that will be supplanted by retail pricing that reflects and signals wholesale prices. The stated goal of the PJM Economic Program is to "provide a program offering that will help in the transition to an eventual permanent market structure whereby customers do not require subsidies to participate but where customers see and react to market signals or where customers enter into contracts with intermediaries who see and react to market signals on their behalf."[109]

Electric utilities also operate demand-bidding programs. While several of these programs (e.g., Con Edison's Day Ahead Demand Reduction Program) are designed to aggregate customers for participation in ISO demand-bidding programs, several utilities operate these programs to meet their own resource needs. For example, WE Energies has operated the Power Market Incentives program for several years. In this program, the utility identifies how much it is willing to pay for load curtailments. Participating customers respond to this request and if they are accepted they are obligated to reduce their consumption.

Nevertheless, operation of these demand bidding/buyback programs has been the subject of controversy, particularly over the issue of who is responsible for the costs associated with successful bids. A 2002 National Association of Regulatory Utility Commissioners (NARUC) report examined this controversy and concluded that there was no consensus on the issue and additional effort would be needed to examine the issue.[110] The issue is still active in 2006, particularly in PJM, where discussions continue to determine the size of the incentive provided in PJM's Economic Program. For example, in a recent case, AEP asserted that "while, in certain circumstances, incentives may be effective to launch a program, the continued use of economic incentives for a permanent program is inappropriate. This issue needs to be addressed now rather than ignored in order to avoid a program

[109] PJM, Market Monitoring Unit, *2004 State of the Market*, March 8, 2005, 87.

[110] David Kathan, *Policy and Technical Issues Associated with ISO Demand Response Programs*, prepared for NARUC, 2002.

that cannot stand on its own merits."[111] PJM intends to complete these stakeholder discussions within the year.

Ancillary Services

The final type of incentive-based demand response is ancillary-service market programs. Ancillary-services programs allow customers to bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.[112]

In order to participate in ancillary-service markets, customers must be able to adjust load quickly when a reliability event occurs. The response duration depends on the nature of the event and the type of reserve being supplied, but is typically provided in minutes rather than the hours required when peak shaving or responding to price signals. There is typically a higher minimum size for reductions and customers are required to install advanced real-time telemetry. These short timeframes and program requirements limit the type of resources that can participate. These resources could include large industrial processes that can be safely curtailed quickly without harm to equipment, such as air products or electric-arc steel furnaces, large water pumping load, or remote automatic control of appliances such as air conditioners.[113]

At present, only the CAISO and ERCOT allow a limited amount of demand response to participate in their ancillary-services markets. The Participating Load Program at the CAISO allows qualifying loads to bid directly into the CAISO non-spin and replacement reserve and supplemental energy markets. At present the primary resource in the Participating Load Program is the large water pumps operated by the California Department of Water Resources. The Loads Acting as a Resource (LaaR) program in ERCOT currently provides more than 1,800 MW of responsive reserves through automatic under frequency relays. In order to qualify as a LaaR, the load, breaker status, and relay status must have real-time telemetry to ERCOT.

PJM, ISO-NE, and NYISO are in various stages of the development of allowing demand response to participate in ancillary-service markets. While ISO-NE and NYISO are still in the process of implementing the software and optimization changes necessary to allow demand to provide reserves, PJM began allowing demand response to provide synchronized reserves on May 1, 2006.

Time-Based Rate Programs

The second form of demand response is time-based rate programs. Historically, utilities offered small, or low-volume, commercial and residential customers a flat rate based on their average cost of serving that customer class. These flat rates were developed based on historical regulatory principles of rate design that were originally articulated by noted utility rate expert, James Bonbright. According to Bonbright, rates should be fair, simple, acceptable, effective, equitable, nondiscriminatory, and

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[111] AEP, comments filed in Docket ER06-406, January 18, 2006.

[112] The role of demand response resources in providing ancillary services is discussed in greater detail in Chapter VI.

[113] See Brendan J. Kirby, *Spinning Reserve From Responsive Loads*, Oak Ridge National Laboratory: ORNL/TM-2003/19, March 2003, for a discussion of how residential direct load control programs are capable of meeting 10-minute operating reserve rules.

efficient.[114] The regulatory process balances these principles, which reflect the competing interests of customers, utilities, and social justice.[115]

Utilities or other LSEs buy the power to serve these customers through a combination of long-term contracts, ownership of generating plants, or purchases on the spot wholesale markets (based on day-ahead or day-of, or real-time, electricity prices). Since prices of electricity have locational and/or time-based differences, an average price for all customers needs to build in a risk premium for the supplier, who bears the risk of price volatility in wholesale markets.[116]

Economists and policy-makers increasingly have been arguing in favor of time-based rates (also known as dynamic pricing) for retail customers, a practice that can link wholesale and retail markets. The primary objective of incorporating time-based rates in retail electric markets is to send price signals to customers that reflect the underlying costs of production. By exposing at least some customers to prices based on these marginal production costs, resources can be allocated more efficiently.[117] Furthermore, price-based demand response can be used by retail providers in both restructured and non-restructured states to reduce or shape customer demand to balance electricity use and overall costs. Alternatively, flat electricity prices based on average costs, according to the U.S. Department of Energy (DOE), can lead customers to "over-consume – relative to an optimally efficient system in hours when electricity prices are higher than the average rates, and under-consume in hours when the cost of producing electricity is lower than average rates."[118] Basing customer rates on wholesale prices also has the benefit of increasing price response during periods of scarcity and high wholesale prices, which can help moderate generator market power.

Rates and pricing that are considered time-based include time-of-use (TOU) rates, critical peak pricing (CPP), and real-time pricing (RTP). These programs expose customers to varying levels of price exposure – the least with TOU and the most with RTP. Figure IV-2 illustrates the type of hourly price variation customers would face under the different time-based rates.

Each of these tariff types is described in greater detail below, using current program examples and issues raised by each type.

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[114] James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd ed. (Arlington, VA: Public Utilities Reports, 1988).

[115] Bernie Neenan, "Focusing on Issues of Rate Design," Utilipoint *IssueAlert,* March 10, 2006; and Frederick Weston, "Dynamic Pricing: Options and Policies," white paper for MADRI regulatory subgroup, November 2005, 1.

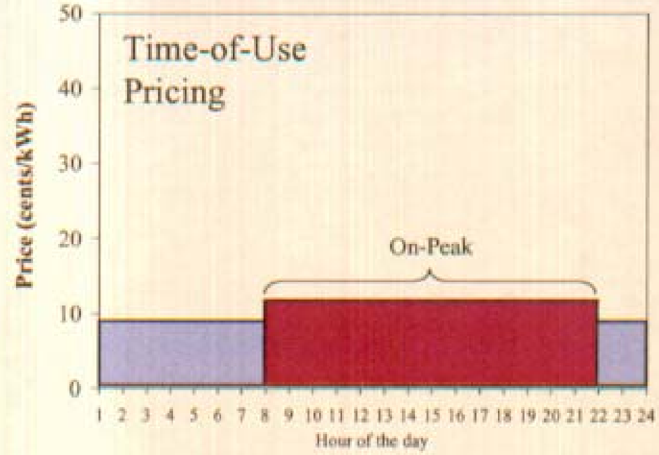
[116] Eric Hirst, "The Financial and Physical Insurance Benefits of Price-Responsive Demand," *The Electricity Journal* 15 #4 (2002), 66-73.

[117] There is a substantial literature on setting rates based on marginal costs in the electric sector. See, for example, M. Crew and P. Kleindorfer. *Public Utility Economics* (New York: St. Martin's Press, 1979, and B. Mitchell, W. Manning, and J. Paul Acton. *Peak-Load Pricing* (Cambridge: Ballinger, 1978). Other papers suggest that setting rates based on marginal costs will result in a misallocation of resources (see S. Borenstein, "The Long-Run Efficiency of Real-Time Pricing," *The Energy Journal* 26 #3 (2005)). Nevertheless, the literature also indicates that marginal cost pricing may result in a revenue shortfall or excess, and standard rate-making practice is to require an adjustment (presumably to an inelastic component) to reconcile with embedded cost-of-service. Various rate structures to accomplish marginal-cost pricing include two-part tariffs (see W. Kip Viscusi, John M. Vernon and Joseph E. Harrington. *Economics of Regulation and Antitrust*, 3rd ed. (Cambridge: MIT Press, 2000)) and allocation of shortfalls to rate classes.

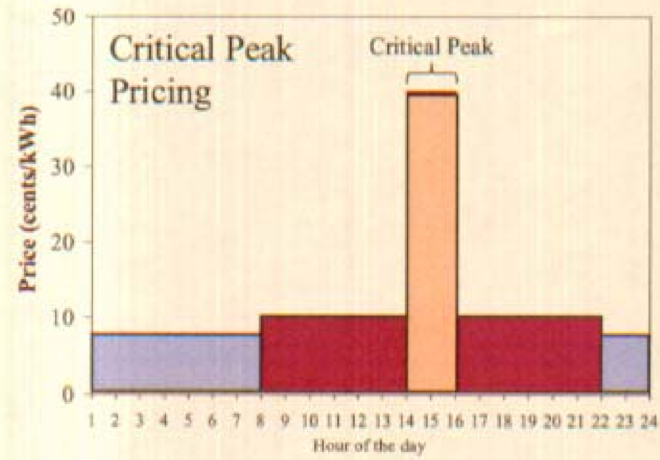
[118] DOE February 2006 EPAct Report, 7.

Figure IV-2: Time-based pricing hourly variations

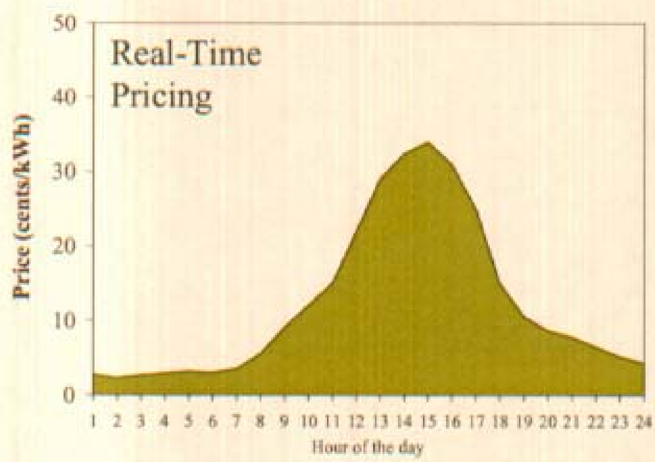
Time-of-Use (TOU) Pricing: These daily energy or energy and demand rates are differentiated by peak and off-peak (and possibly shoulder) periods.



Critical Peak Pricing (CPP): CPP is an overlay on either TOU or flat pricing. CPP uses real-time prices at times of extreme system peak. CPP is restricted to a small number of hours per year, is much higher than a normal peak price, and its timing is unknown ahead of being called.



Real-Time Pricing: RTP links hourly prices to hourly changes in the day-of (real-time) or day-ahead cost of power. One option is 'one-part' pricing, in which all usage is priced at the hourly, or spot price. A second approach is 'two-part' pricing.



Source: Weston & Shirley, *Scoping Paper on Dynamic Pricing: Aligning Retail Prices with Wholesale Markets*, June 2005, pp. 4-5 (definitions); and Goldman, et al., *Customer Strategies for Responding to Day-Ahead Market Hourly Electricity Pricing*, Lawrence Berkeley National Laboratory: LBNL-57128, August 2005 (graphics).

Time-of-Use Rates

Time-of-use (TOU) rates are the most prevalent time-varying rate, especially for residential customers. Most customers are exposed to some form of TOU rates, if only with rates that vary by six-month seasons. For instance, a summer-peaking utility may charge a higher rate for the energy use part of a bill than for the same amount of electricity consumed during the off-peak six months. This is a seasonal (time-varying) rate.

More sensitive time-of-use rates establish two or more daily periods that reflect hours when the system load is higher (peak) or lower (off-peak), and charge a higher rate during peak hours. Off-peak hours are usually some part of the evening and night, as well as weekends. The length of the on-peak period varies, but can last between 8 a.m. and 8 p.m. By way of example, the on-peak period for residential TOU rates at the Kansas City Power and Light is from 1 p.m. to 7 p.m.

The definition of TOU periods differs widely among utilities, based on the timing of their peak system demands over the day, week, or year. TOU rates sometimes have only two prices, for peak and off-peak periods, while other tariffs include a shoulder period or partial-peak rate. Some TOU rates apply year-round, although many tariffs include two seasons.

History

Utilities' TOU rates or TOU pilot offerings have risen and fallen over time, in part depending on regulatory encouragement or restructuring disincentives. DOE's predecessor agency, the Federal Energy Administration, sponsored 16 demonstration TOU pilots between 1975 and 1981.[119] Experiments tested single and multiple TOU rates, and lasted from six months to three years. The group which offered multiple rates included programs in Arizona, California (Los Angeles Department of Water and Power and Southern California Edison), Puerto Rico, Wisconsin, and North Carolina (Carolina Power & Light). EPRI later pooled the data from these experiments to estimate price elasticities of demand. They found the estimated elasticity of substitution was -0.14 (in other words, a doubling of on-peak to off-peak ratio would result in a drop of 14 percent in the corresponding quantity ratio). One of the last comprehensive national surveys of demand response programs in the United States prior to the current FERC Survey was conducted by EPRI in 1994. That survey gathered information on "1,959 demand-side efforts conducted by 512 electric utilities."[120] Respondents reported 55 competitive rate programs offered by 39 utilities; only three of these included residential customers. The competitive rate programs involved more than 590,000 customers, including 559,000 residential customers. Some of the competitive rates were experimental; others included real-time pricing.[121] Another survey category was load management rate programs; EPRI survey respondents cited 177 of these, including 80 TOU rate programs with over 500,000 participants.[122] The bulk of TOU program participation came from residential customers participating in voluntary programs offered by four utilities: Pacific Gas & Electric, California (four programs, including a residential one with 102,000 participants); Baltimore Gas & Electric, Maryland (voluntary for 31,956 residential participants; mandatory for new single-family homes, with 39,092 customers);

[119] Ahmad Faruqui & Stephen George, "The Value of Dynamic Pricing in Mass Markets," *The Electricity Journal*, 15 (6) July 2002, 47-48.

[120] EPRI, *1994 Survey of Utility Demand-Side Programs and Services: Final Report*, November 1995, TR-105685, iii.

[121] EPRI, TR-105685, section 1.6.

[122] EPRI, TR-105685, section 2.6.

Metropolitan Edison, Pennsylvania[123] (68,946 residential participants); and Salt River Project, Arizona (46,549 participants).

Many utilities now require their larger commercial and industrial (C&I) customers to be on TOU rates. TOU rates are common outside of the United States. Electricité de France (EdF) has offered TOU rates for decades; it now also offers a "Tempo" critical peak rate, layered on a TOU rate; "Tempo" employs color-coded signals sent by power line carrier to a customer's plug-in device on a day-ahead basis, as well as smart thermostats and programmable space and water-heating controls.[124] As different U.S. states began to restructure, especially where utilities divested their generation, utilities allowed their TOU (or other load-response) demand response programs to lapse, particularly for smaller customers.[125]

Implementation Experience

Experience with TOU rates and customer acceptance of the rates has varied widely across the United States. The experiences of utilities with residential TOU rates in Arizona and Washington are instructive.

Salt River Project Agricultural Improvement and Power District (SRP) and Arizona Public Service (APS) residential TOU programs. APS and SRP, which compete in the Phoenix area, are cited as having residential participation rates that approach one-third of their customers.[126] Demand response is important for an area that is growing as rapidly as Phoenix, and competition seems to contribute to the utilities offering attractive time-based packages that work.

APS offers two residential TOU plans plus a flat-rate plan. Its Time Advantage plan has energy-only charges, which better suits customers who use 60 percent or more of their power off-peak. The Combined Advantage plan features much lower hourly energy prices, but adds a demand charge based on a customer's peak use. SRP offers residential and business TOU plans plus a basic residential plan. SRP advises customers to opt for the E-26 TOU plan only if they use at least 1,000 kWh in summer periods and if they can shift usage to off-peak hours. SRP's TOU customers save about eight percent on their annual bill. Those customers who find that they are not saving are allowed to revert to the basic plan, but must remain on it for at least one year. Each utility's plan has peak and off-peak hours that vary seasonally, but no shoulder period.

Both SRP and APS recognize the importance of customer education. Their web sites feature calculators for customers to compare costs under time-based and flat plans, along with energy-saving tips and advice on choosing a plan based on usage patterns. Interestingly, both utilities require unlimited physical access to customers' meters, which must be read more than once monthly.[127]

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[123] Metropolitan Edison is now part of FirstEnergy Corporation.

[124] Energy & Environmental Economics, *A Survey of Time-of-Use Pricing*, Summer 2006 (forthcoming), prepared for the U.S. Environmental Protection Agency, section E.2, and http://particuliers.edf.fr/article343.html (accessed June 26, 2006).

[125] For instance, prior to its divestiture of generation assets, Pepco (Maryland) required large residential customers to be on TOU rates. After divestiture, existing customers were allowed to elect non-TOU tariffs; new Pepco customers have been unable to sign up for time-of-use rates if they did not have TOU meters. Pepco is currently running the SmartPowerDC program, a dynamic pricing pilot in Washington, D.C.

[126] Demand Response and Advanced Metering Coalition (DRAM), comments filed in Docket AD06-2, December 19, 2005, 4.

[127] APS and SRP web sites: http://www.aps.com/aps_services/residential/rateplans/ResRatePlans_8.html; http://www.aps.com/aps_services/residential/rateplans/ResRatePlans_9.html; http://www.srpnet.com/prices/home/tou.aspx

Puget Sound Energy (PSE) began a TOU pilot in June 2001; it installed new meters. PSE enrolled 240,000 customers who moved from flat rates to its TOU program. During the mid-day period (10 a.m. to 5 p.m.), TOU customers paid the same amount (5.8¢/kWh) as those on flat rates. Morning (6 a.m. – 10 a.m.) and evening (5 p.m. – 9 p.m.) periods were priced only one cent higher. Enthusiastic customers achieved five-to-six percent peak reductions, and conserved 5 percent in the first year. PSE instituted a $1/month charge to recoup part of its metering costs in July 2002. This substantially cut into customer savings. In the fall of 2002, customers began receiving cost comparisons of TOU bills with what they would have paid on flat rates; 90 percent were saving less than the metering charge. Washington state discontinued the TOU pilot in November 2002.[128]

Evaluations of the PSE program included several possible explanations for the need to discontinue the program. PSE is a winter-peaking utility, which normally faces mild weather and energy prices well below the national average; right before the pilot, prices were exceptionally high and volatile. By the fall of 2002, prices were lower and less volatile, due to the abatement of the California energy crisis (and critical need to export power to California). According to Eric Hirst, "dynamic pricing induces customers to reduce their electricity consumption when prices are high; the same customers will increase their use when prices are low. Dynamic pricing can hedge against high gas prices or low-hydro years. But, dynamic pricing benefits are not evenly distributed: "price increases during low-priced periods are much less than the price reductions during high-price periods."[129] Other analyses noted a lack of sufficient difference between PSE's peak and off-peak prices. Regions with less mild weather might offer higher incentives (in terms of rate differences) to shift usage to off-peak hours.[130] The absence of automated equipment and prior customer education about their energy consumption habits may have also minimized response rates.

Issues

All time-based rates other than seasonal rates require meters that register customer electricity consumption based on time-of-day or more frequent billing blocks. Traditional meters for smaller customers that were installed several years ago, or even newer remotely readable ones, do not necessarily record time-of-day usage. The additional capital and operating cost of replacing or upgrading these meters can be included in separate customer charges, as determined by individual public utility commissions, if customers choose TOU rates. Alternatively, if AMI systems are deployed, the necessary infrastructure would be in place to support TOU rates.

Regulators who implement TOU plans need to decide how many periods are relevant: two daily; peak and off-peak plus a shoulder; weekends as off-peak; or seasonal differences layered on the time-of-day periods. The size of the price-spread between peak and off-peak hours is important so that customers perceive real price signals, but also so they can achieve bill savings without a loss of revenue to utilities.

[128] Washington Utilities and Transportation Commission (UTC), Puget's Time-of-Use Program: http://www.wutc.wa.gov/webimage.nsf/0/62515a89dde8130388256ae800699ca5?OpenDocument (accessed June 15, 2006).

[129] Direct Testimony of Eric A. Hirst on Behalf of Puget Sound Energy, Inc., November 26, 2001, before the Washington Utilities and Transportation Commission, 11-12.

[130] See Lewis Nerenberg, "From Promise to Progress", UC Santa Cruz, May 2005, 4-7; and Dan Delurey, "Retail Demand Response", IEA Workshop presentation, Paris, France, February 2003, 4-6.

Critical Peak Pricing

Critical Peak Pricing (CPP) is a relatively new form of retail TOU rates that relies on very high, critical peak prices, as opposed to the ordinary peak prices in TOU rates. A specified high per-unit rate for usage is in operation during times that the utility defines as critical peak periods. CPP events may be triggered by system contingencies or high prices faced by the utility in procuring power in the wholesale market. Unlike TOU blocks, which are typically in place for 6 to 10 hours during every day of the year or season, the days in which critical peaks occur are not designated in the tariff, but dispatched on relatively short notice as needed, for a limited number of days during the year. CPP rates can be superimposed on either a TOU or time-invariant rate. While CPP is price-based, the fact that it is called in real-time at periods of extreme system stress makes it equally a reliability-based demand response.

CPP rates have several variants, including:

- **Fixed-period CPP (CPP-F).** In CPP-F, the time and duration of the price increase are predetermined, but the days when the events will be called are not. The maximum number of called days per year is also usually predetermined. The events are typically called on a day-ahead basis.
- **Variable-period CPP (CPP-V).** In CPP-V,[131] the time, duration, and day of the price increase are not predetermined. The events are usually called on a day-of basis. CPP-V is typically paired with devices such as communicating thermostats that allow automatic responses to critical peak prices.
- **Variable peak pricing (VPP).** This is a recent form of CPP that has been proposed in New England.[132] As with CPP, the off-peak and shoulder period energy prices would be set in advance for a designated length of time, such as a month or more. In the version proposed in Connecticut, the peak price for each peak-period hour would be set each day based on the average of the corresponding ISO Day-Ahead Connecticut Load Zone locational marginal prices (LMPs), adjusted to account for delivery losses and other costs typically recovered volumetrically. The advantage of VPP is that it more directly links the wholesale market to retail pricing.
- **Critical peak rebates.** In critical peak rebate programs, customers remain on fixed rates but receive rebates for load reductions that they produce during critical peak periods.

History

CPP rates are relatively uncommon in the United States; the first major implementation occurred at Gulf Power in 2000. Overseas, France's EdF has used a variation on CPP as its default residential rate since the late 1980s. Recent adoption of CPP rates in the United States is based on the realization that some of the price spikes experienced between 1998 and 2001 could have been drastically diminished had there been real-time (or near real-time) signals to customers to curtail their electricity use. The FERC Survey found that 25 utilities currently offer CPP tariffs or pilots.

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[131] Charles River Associates (CRA), *Impact Evaluation of the California Statewide Pricing Pilot: Final Report*, March 16, 2005 for a discussion of CPP-F and CPP-V.

[132] Filed Testimony of Bernard F. Neenan on Behalf of ISO New England Inc. before the Connecticut Department of Public Utility Control, Docket No. 05-10-03, February 10, 2006.